A FRAMEWORK FOR ASSESSING THE RELIABILITY OF WIND ENERGY CONVERSION SYSTEMS

BY

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THESIS

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During the last decade, wind power generation has seen rapid development. According to the U.S. Department of Energy, achieving 20% wind power penetration in the U.S. by 2030 will require: (i) enhancement of the transmission infrastructure, (ii) improvement of reliability and operability of wind systems and (iii) increased U.S. manufacturing capacity of wind generation equipment. This research will concentrate on improvement of reliability and operability of wind energy conversion systems (WECSs).

The increased penetration of wind energy into the grid imposes new operating conditions on power systems. This change requires development of an adequate reliability framework. This thesis proposes a framework for assessing WECS reliability in the face of external disturbances, e.g., grid faults and internal component faults. The framework is illustrated using a detailed model of type C WECS - doubly fed induction generator with corresponding deterministic and random variables in a simplified grid model. Fault parameters and performance requirements essential to reliability measurements are included in the simulation. The proposed framework allows a quantitative analysis of WECS designs; analysis of WECS control schemes, e.g., fault ride-through mechanisms; discovery of key parameters that influence overall WECS reliability; and computation of WECS reliability with respect to different grid codes/performance requirements.
To my grandpa Henryk
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CHAPTER 1

INTRODUCTION

1.1 Motivation

During the last decade, power generation from renewable resources has seen rapid development, thanks mainly to political and social support, as a result of high fossil fuel prices and greenhouse effects. For renewable resources, such as photo-voltaics or hydrogen fuel cells, research has led to various preliminary designs. Even though many solar panel designs are currently on the market, their efficiency is relatively low and usage is limited mainly to low voltage applications. However, wind power is at a different stage of development. Most of the wind energy conversion systems (WECSs) that are currently installed are based, especially when it comes to mechanical and aerodynamic properties, on their forerunners from the 1980s and 1990s. The construction of wind farms with dozens of WECSs is economically feasible and leads to relatively large amounts of generated power. For these reasons many utilities have chosen wind power as the renewable source that they will support and invest in (Fig. 1.1).

Reports such as 20% Wind Energy by 2030 by the U.S. Department of Energy [2] confirm that political support can evolve into policy. And, as shown in Europe, the incentives created by governments have led to an increase in the number of wind farm installations. In [2] it is further stated that achieving 20% wind power penetration in the U.S. by 2030 can be done reliability and economically (with a cost of energy less than than $0.5/MWh). However, achieving that goal will require: (i) enhancement of the transmission infrastructure, (ii) improvement of reliability and operability of wind systems and (iii) increased U.S. manufacturing capacity of wind generation equipment. This research will concentrate on improvement of reliability and operability of WECSs.
The increased penetration of wind energy into the grid imposes new operating conditions on power systems. This change requires development of an adequate reliability framework. This thesis proposes a framework for assessing WECS reliability in the face of external disturbances, e.g., grid faults, and internal component faults. The framework is illustrated using a detailed model of type C WECS - doubly fed induction generator with corresponding deterministic and random variables in a simplified grid model. Fault parameters and performance requirements essential to reliability measurements were included in the simulation. The proposed framework allows a quantitative analysis of WECS designs; analysis of WECS control schemes, e.g., fault ride-through mechanisms; comparison of different vendors’ WECS designs; discovery of key parameters that influence overall WECS reliability; and computation of WECS reliability with respect to different grid codes/performance requirements.

1.2 Problem Statement

Two important issues hindering the widespread use of power generation based on wind energy are (i) wind speed variability [3] and (ii) WECS reaction to grid disturbances [4]. Wind speed randomness results in variability of power generation; thus the requirement of continuous power delivery cannot be fulfilled. Current WECSs cannot provide reactive power support for the entire duration of a fault, and older WECSs also have
problems with energy dissipation during a fault. Even though most newly installed WECSs have fault ride-trough (FRT) capabilities, many utilities still choose to shut down wind farms during grid faults, thus showing that this problem has not yet been fully resolved.

1.2.1 Wind power generation randomness - steady-state analysis

The impact of wind-based power generation on system reliability has been widely investigated in past years. This problem has been approached from two main directions: massive simulation and analytical methods. An example of the first is Monte Carlo simulation [5], [6], an algorithm that is based on random (or semi-random) and repetitive sampling for results computation. Examples of the second group are Markov chains [7], loss of load probability (LOLP) techniques [8], universal genetic functions [9] and the convolution theorem [10]. The Markov chain method is a stochastic process based on a Markov property. With some simplification, the Markov property states that the description of the present state is sufficient to represent the future evolution of the system. A Markov chain, then, can describe dynamic behavior of analyzed phenomena better than classical probabilistic models. LOLP may not precisely describe dynamic behavior, but it can still be superior in calculating the overall system reliability level by combining the probability of certain load levels with probability of certain levels of generation. This technique disregards all dynamic considerations but is a very good tool for economic analysis.

1.2.2 WECS reaction on disturbances - dynamic analysis

WECS reaction to grid disturbances has also been a subject of extensive research, but in most cases the research has lacked proper analysis of its effectiveness and impact on system reliability. The first intuitive approach to WECS dynamic modeling was to include generators (primarily induction machines) as negative load [11]. Unfortunately, many contemporary WECSs are more complex than typical induction generators. This is why so many single dynamic WECS models have been developed [12], [13], [14],
Planning and construction of most grids worldwide was a long process. Even with strong political and social support, substantial change in grid design and control will not take place in only a few years. This means that future WECSs must adjust to grid standards - not the other way around. Many researchers have acknowledged this fact, as seen in the large number of publications involving WECS control. Different control strategies and designs of WECSs include real power control for smoothing shaft fluctuations [16], control strategies incorporating core saturation [17] and control to minimize the impact of inter-area oscillations [18]. Designs such as redundant leg for WECS back-to-back converters [19] and switching fault ride-through strategy [20] are also interesting samples of new design trends. The fact that a WECS has to adjust to the grid standards means also that the WECS reliability analysis must be performed not only on the WECS model, but also on the grid model. What is more, the WECS and grid control schemes have to be modeled precisely, as their coupling may have a big influence on the overall reliability.

1.3 Overview of Proposed Reliability Framework

To capture overall WECS reliability, as shown in Fig. 1.2, a reliability measure will be computed within the proposed framework. Reliability measure characterizes a particular WECS working under specified conditions (grid characteristics) with regard to specified fault types. This means that for reliability measure computation characteristics of WECS, grid and injected faults are needed. Those characteristics consist of constant and random variable parameters. Parameters chosen to be random variables must have their probability distribution functions. Each value of the variable parameter will have a corresponding importance factor. For example, wind speed could be defined as a WECS characteristics random variable. Assessing WECS reliability for just one wind speed would lead to over- or underestimation. Thus WECSs should be tested for different wind speeds with corresponding probabilities. Fault characteristics can be treated in a similar way. Three-phase faults that create the most severe and problematic conditions for WECSs are much less likely than one-phase
faults that lead to low voltage drops. Disregarding one-phase faults would not lead to a reliability measure that corresponds with reality.

Figure 1.2: WECS reliability framework defined through reliability measure.

This framework uses predefined models of the grid and WECS that treat the parameters mentioned above as inputs. Based on the values of those inputs, simulations will be performed. Each simulation will either fulfill the performance requirements or not, based on the parameters that are tracked. Performance requirements are also an input for the framework. The reliability measure computed for different performance requirements can take different values. For example, testing a WECS with Danish FRT requirements will lead to higher value of reliability than testing the same WECS for with German FRT requirements, which are more strict. The proposed reliability framework is presented in detail in Chapter 2.

1.4 Literature Review - Wind Reliability

As mentioned before, many reliability analyses concentrate on randomness of wind power generation [21]-[29]. In [22] statistical analysis, based on load and wind generation curves, is presented. The goal is to produce an optimal working point that maximizes reliability and minimizes cost.
Unfortunately an analysis like this assumes only “1,0” (unit out or unit working) availability for a particular WECS. There is no model of WECS components and their dynamic reaction to different internal and external phenomena. This approach is justified by the fact that studies like [22] are mainly economic analyses.

In [23], which also belongs to the group describing wind power generation, wind farm modeling in the reliability assessment of the power system is presented. Even though this study has very little in common with the one presented in this thesis, it is worth emphasizing that it concentrates on assessing the reliability of the entire power system. This assessment forces the authors to make numerous simplifications and to concentrate only on the concept of steady-state power generation. In this thesis, however, the reliability of WECSs (not the power system with WECSs) will be assessed.

Studies presented in [25],[26],[27] utilize the Markov chain to describe power generation changes and generator failures. Using slightly different approaches from those mentioned in the paragraph above, they present a method to compute reliability measures, such as loss of load probability or loss of load expectation curves.

Some of the previous work concentrates on techniques for wind forecasting and its impact on system reliability [28]. Forecasting is essential to maintain the system integrity. But, unfortunately, without other techniques it will not quantitatively describe system reliability.

There also has been extensive work which uses previously mentioned random power generation techniques to describe the reliability of different combinations of generating systems. In [29] reliability evaluation of a system consisting of a WECS, diesel engines and batteries is presented, while in [30] the reliability of a micro-grid with photovoltaic panels and WECS is analyzed. But those studies still concentrate on the reliability analysis from an economic perspective without including dynamic phenomena.

Others, like [31], use statistical data of different WECS elements for single WECS reliability assessment, disregarding the relationships between each of those components and the grid. A similar issue can be seen in [32], where the failure rate of single WECS components is calculated based on their base failure rate and environmental stress factors, such as temperature. Reliability of a WECS computed in this manner disregards
any correlation and influence between components. What is more, this method does not include events such as grid faults, which can cause a much faster degradation of components than their failure rate would suggest. In [33] WECS semiconductor fault-tolerant design is presented. Its superiority over typical designs is proved, based on a reliability analysis of both systems. But this analysis is based on Markov chains that only represent distinct failures of each component, while during an actual semiconductor failure most likely to occur during stressful conditions (such as external or internal WECS short-circuits), many different components can exert pressure on other components. Those mutual relations cannot be presented using the reliability analysis shown in [33]. Reliability analysis as in [34] conducts a yearlong fault observation of one wind power plant. Even though [34] reflects reality exactly, it does not define any flexible analysis scheme.

Extensive research has also been done on WECS reaction to grid failures [35],[36],[37]. Each of these studies presents different techniques that can improve WECS reaction to grid disturbances. For example, [35] proposes usage of a series of braking resistors that could help dissipate the additional energy stored in rotor circuits during the fault. In [37] is presented the idea of using two switches that can activate a rotor protection device during the fault (crowbar) and connect the rotor converter in parallel with the grid side converter. While those concepts mentioned in this paragraph might prove to be very successful, it can be argued that they lack proper validation and reliability analysis. Those designs are tested for just a few different voltage drops, while the reliability analysis presented in this thesis tests the designs for numerous combinations of parameters that a WECS will encounter during a fault. The work presented in this thesis provides a framework for quantitative analysis of WECS designs and comparison of different vendors’ WECSs, along with key parameters that influence WECS reliability.

1.5 Wind Energy Conversion Systems: State of the Art

At this point, it is necessary to elaborate on what stands behind the term WECS. Current state-of-the-art electrical generators for WECSs can be divided into four main types - A,B,C and D.

The WECS configuration denoted as type A (Fig. 1.3) is one the first
design types. It is based on an induction generator connected with a fixed-speed wind turbine. This design needs two additional components for grid connection. The first one is a soft-starter to decrease current transients during startup phase. The second is a group of capacitors. Capacitors are needed because an induction generator produces active power and consumes reactive power. Consumption of reactive power is not desired for generators, so capacitors are needed to compensate for that consumption. Thanks to this enhancement, a generator can work closely to a zero value of production or consumption of reactive power. Unfortunately this type of compensation does not allow flexible reactive power control.

The type B WECS (introduced by Vestas) generator is designed to work with limited variable speed wind turbine. Thanks to the variable resistor, shown in Fig. 1.4, the rotor slip can be controlled. This limited control (0-10% of synchronous speed) allows limited power output control. Another advantage of this design is the elimination of slip rings (maintenance problems), because the rotor resistance is controlled through optical communication. The capacitor bank and soft-starter role is analogous to the type A design.

Construction of the last two types was possible thanks to rapid development of high-power electronic devices. The type C can be formally called a variable speed generator with partial scale frequency converter.
This design uses two AC/DC converters with a capacitor between them to control the WECS. These converters are rated at 25% of total generator power.

The wound rotor induction generator configuration shown in Fig. 1.5 is also known as a doubly fed induction generator (DFIG). The term “doubly” comes from the fact that the rotor winding is not short-circuited (as in classical “singly-fed” induction machine), but a voltage is induced from the rotor-side converter. The magnitude, phase shift and frequency of this voltage are controlled. That allows the rotor speed to be controlled at a much higher range than in A and B (from 0.5 to 1.3 times the synchronous speed). This WECS can work closer to the optimal point and extract more energy from wind. At the same time, converters allow control of the reactive power flow. Depending on the working scheme, they can keep a constant value of the produced reactive power or keep the terminal voltage constant. In this regard, the type C reactive power exchange is similar to conventional power plants.

The type D design (Fig. 1.6) uses a full-scale frequency converter with different types of generators. The most common one is the permanent magnet synchronous generator (PMSG). This design allows full control over active and reactive power production and has a high wind energy extraction value. Full power control improves power and frequency stability in the grid and reduces the short circuit power.

Figure 1.5: Type C wind energy conversion system design [38].

Figure 1.6: Type D wind energy conversion system design [38].
Most type D designs do not need a gearbox, which is a great advantage. These designs have multipole synchronous generators, which unfortunately are very heavy. The biggest disadvantage, which may be a huge barrier, is the cost of the converters. There is also a problem with high harmonic frequencies pushed into the grid. The D WECS type is being developed by the Enercon, Made and Lagerwey companies.

1.6 Modeling Choice - Type C

WECS models are essential for understating many of the phenomena taking place in grids with high wind penetration. These models can range from very simplified ones – such as modeling an induction generator (type A) as negative load for large power system stability studies, to extremely detailed ones, which include electro-magnetic transients and distributed line parameters. The choice of the detail level of the model used can be seen Chapter 3. In addition to the level of detail, the decision of which WECS type is going to be modeled is important. For the current state of the art, the DFIG (type C) seems to be the best WECS representative. It is the most commonly installed generator in wind power generation, as shown in Figure 1.7.

![Figure 1.7: Worldwide installed WECS units per year, 1994-2006 [39].](image)

As displayed in Fig. 1.8, type C WECSs are experiencing rapid market share increase. DFIG accounts now for more than 45% of the total WECS installed. Based on the graph trends, this percentage will not experience a rapid drop in the next few years, and there is high probability that it will

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continue to increase. It seems plausible that the type D WECS market share will also increase. The rate of this increase is uncertain and will depend heavily on the price of high power electronic components, their mean lifetimes, and their maintenance cost. For these reasons, in this research we chose DFIG to showcase the framework proposed in Chapter 2.

![Figure 1.8: Worldwide share of cumulative installed wind power for different WECS concepts [39].](image)

### 1.7 Fault Ride-Through Mechanisms

One of the applications of the reliability framework is a comparison and qualitative analysis of fault-ride trough mechanisms. FRT can be defined as the ability of a wind turbine to withstand certain grid faults without shutting down. A second definition of FRT states that the turbine will not only have to remain connected, but also meet requirements regarding reactive and active power support. To fulfill the FRT requirement (for both definitions), a wind turbine must remain connected to the grid for a voltage drop with corresponding duration as shown in Fig. 1.9. In recent years, numerous countries have introduced new grid codes regarding wind power generation. The purpose of those codes is to allow the system to maintain high reliability, while allowing wind penetration to increase.

These codes with regard to FRT can be divided into two main groups, but it is necessary to bear in mind that this division is artificial and some codes can avoid a clear segregation. The first group consists of grid codes
that are designed for power systems where wind penetration is still relatively low. In this group the first definition of FRT is implemented. Countries from this group could be Italy (1.2% of wind penetration in 2007, [1]), the United Kingdom (1.5%) or the USA (0.8%).

The second group consists of countries where wind generation has a much higher grid penetration. Those countries’ grid codes use the second definition of FRT, in which WECS support during disturbances is required. Representative of this group are Germany (6.8% of wind penetration in 2007) and Spain (9.8%). Generally those requirements specify the period of time (100 ms - Spain, 20 ms - Germany), after the fault started, during which WECS can draw reactive power from the grid. This time period is usually used by WECS to cope with the additional energy in its rotor circuits. FRT grid codes also specify the period of time (150 ms - Spain, 500 ms - Germany) after grid recovery, during which the WECS has to inject a specific value of reactive current into the grid. The values of the reactive current support are defined by each code and can be a function of power factor and voltage drop level. Denmark’s (19.7% of wind penetration in 2007) grid code does not specify the values presented, but it states: “During the voltage dip the reactive power control must be changed from normal operation to maximum voltage support strategy so that the normal grid voltage is re-established as soon as possible.” In Chapter 5 the Danish and US wind power grid code requirements for WECS are presented in detail.
1.8 Summary of Thesis

Chapter 2 constructs the framework for assessing the reliability of WECSs. It also explains how this reliability can be computed and the inputs needed. Chapter 3 describes WECS characteristics and models that are necessary for measuring reliability. Chapter 4 presents a second group of inputs that characterize the grid and faults. Chapter 5 explains the concept of reliability requirements that define WECS failure with respect to reliability measurement. Chapter 6 is a case study, which shows the example of the reliability measure computation and the framework application. Chapter 7 presents conclusions.
The framework that assesses WECS reliability, briefly mentioned in Chapter 1, is based on the structure depicted in Fig. 2.1. This framework provides a unified measure of reliability for a particular WECS working under different conditions, subject to different faults, both on the grid side and on the WECS side, using set performance requirements. Sections 2.1-2.3 elaborate on the elements that constitute the proposed framework.

Figure 2.1: WECS reliability framework defined through reliability measure.

2.1 Framework Inputs

The reliability framework consists of four main input groups/characteristics. The first three define WECS, grid, and fault
characteristics. The forth group comprises performance requirements that the WECS has to meet in the presence of internal and grid faults given different operational scenarios. Each group of characteristics consists of different variables, which are divided into two groups: deterministic and random. The choice of random variables is arbitrary. Indeed, most of the variables are assumed deterministic. Random variables $x_1, x_2, ..., x_n$ are characterized by their probability density functions $f_1(x_1), f_2(x_2), ..., f_n(x_n)$.

WECS characteristics feed the WECS model. Similarly, grid characteristics are an input for the grid model. Fault characteristics can feed both models. If the fault variables are an input to the WECS model, then a simulation of an internal fault takes place. When the grid model receives fault parameters, an external fault is being simulated.

Performance requirements are defined slightly differently than WECS, grid and fault characteristics. These requirements can consist of maximum and minimum values that certain variables can take. For example, performance requirements can set a maximum value of the rotor current. In this case if the rotor current value will exceed the maximum value defined by the requirements, this particular simulation has not fulfilled performance requirements. Such information is essential for a reliability model, as the reliability framework treats simulations that have and have not fulfilled the requirements differently. In most of the cases performance requirements track not one, but multiple values.

WECS, grid and fault characteristics are defined in detail in Chapters 3 and 4. Chapter 5 more closely presents the concept of performance requirements that define the WECS failure.

2.2 Framework Models

The proposed framework consists of a WECS model, a grid model and a probabilistic reliability model. The WECS model can range from a very simple relation between wind speed and output power, to an extremely detailed model that can simulate electromagnetic transients in the WECS generator. Similarly, the grid model can use the infinite bus concept or a detailed dynamic model of numerous grid lines with loads and generators. The choice of detail level of those models is based on the goals of the
analysis. For utility purposes, where numerous simulations for different grid conditions are needed, simplified models might be a better choice. But for a wind turbine vendor, for whom a simulation time requirement is not an obstacle, very detailed models are better.

The WECS and grid models are connected by an interconnection sub-model. This interconnection is especially important in cases when grid and WECS models are using different reference frames and a transformation between them is needed (such as the $dq_0$ to $abc$ transformation). The WECS and grid models are defined in detail in Chapters 3 and 4. The reliability model will be presented in detail in Section 2.3.

### 2.3 Reliability Model

The goal of the reliability model is to provide a unified measure of WECS reliability $R_{weecs}$, based on the performance requirements for the values of the variables of interest. In order to compute the $R_{weecs}$ random variables, used as the framework inputs, one needs to have their probability density functions (pdf). Figure 2.2 illustrates wind speed random variable, with corresponding three probability density functions. One of those pdfs has to be chosen to represent the wind speed for reliability assessment.

![Figure 2.2: Rayleigh probability density function for 3 different average wind speeds - $V_w = 7.75, 8.4, 9.95 \text{ m/s}$.](image)

The reliability measure is defined as:
\[ R_{wees} = 1 - \int \int \int \ldots \int_D f(x_1, x_2, x_3, \ldots, x_n) \, dx_1 \, dx_2 \, dx_3 \ldots dx_n \]  

(2.1)

where \( f(x_1, x_2, x_3, \ldots, x_n) \) is the joint probability density function (pdf) and \( D \) consists of zero or more \( n \)-dimensional regions, which in summary define the space for which failure has occurred, which is defined by the performance requirements.

Failure can be defined in numerous ways, but for the implementation followed in this thesis, each dynamic simulation that violated performance requirements (grid code) results in a failure. The independence of random variables is assumed. Random variables \( x_1, x_2, x_3, \ldots, x_n \) are assumed to be independent; therefore, the joint pdf in (2.1) can be written as 

\[ f(x_1, x_2, \ldots, x_n) = f_1(x_1) f_2(x_2) \ldots f_n(x_n). \]

Thus, the continuous reliability measure can be rewritten as:

\[ R_{wees} = 1 - \int \int \int \ldots \int_D f_1(x_1) f_2(x_2) f_3(x_3) \ldots f_n(x_n) \, dx_1 \, dx_2 \, dx_3 \ldots dx_n \]

\[ = 1 - \prod_{i=1}^{n} \int_{D_i} f_i(x_i) \, dx_i \]  

(2.2)

where regions \( D_i \) create the total fault space, \( D = D_1 \times D_2 \times \ldots \times D_n \) (Cartesian product). The method for creating a three-dimensional fault space is now presented. The first integration region, \( D_1 \), is the sum of sections of random variable \( x_1 \) for which failure has occurred:

\[ D_{13} = \{(x_{11}, x_{12}) \cup (x_{13}, x_{14}) \cup (x_{15}, x_{16}) \ldots (x_{1k-1}, x_{1k})\} \text{ for } \bigwedge \bigvee \]  

(2.3)

and \( D_1 \) is defined for each value of \( x_3 \). It is necessary to define \( D_1 \) in this manner, as it may take different shapes for different values of \( x_3 \). Next, the definition of fault region \( D_2 \) for the second random variable \( x_2 \) is needed. Region \( D_2 \) is also defined separately for each value of \( x_3 \). Computation of \( D_2 \) is based on the previously defined \( D_1 \). For every subregion of \( D_1 \) \((x_{1m-1}, x_{1m})\) two functions must be defined \((g_{up} \text{ and } g_{down})\).
Figure 2.3: Example illustrating principle of defining the integration subregion of the second variable \( x_2 \) based on the integration subregion \((x_{11}, x_{12})\) of the first variable \( x_1 \).

As can be seen in Fig. 2.3, upper \( g_{up}(x_1) \) and lower \( g_{down}(x_1) \) functions mark the boundaries of the two-dimensional fault space. Without these functions, the subregion of \( D_2 \) would be defined only by its maximum and minimum values, \( x_{21} \) and \( x_{22} \). That would lead to an overestimation – the integration process would increase the fault space. This two-dimensional overestimation is shown in Fig. 2.3 as a square, while the true fault region lies between \( g_{up} \) and \( g_{down} \). In the next step it is necessary to define the very small increment, \( \Delta \), for variable \( x_1 \) that divides each subregion \((x_{1m-1}, x_{1m})\) into much smaller parts. Knowing that fault region \( D_2 \) can be defined for each value of \( x_3 \) and each subregion of \( x_1 \) \((x_{1m-1}, x_{1m})\):

\[
D_{2x_3x_1\in(x_{1m},x_{1m+1})} = \{ ((g_{down}(x_{1m}+\Delta), g_{up}(x_{1m}+\Delta)) \text{ for } x_1 \in (x_{1m}, x_{1m}+\Delta)) \cup \\
((g_{down}(x_{1m}+2\Delta), g_{up}(x_{1m}+2\Delta)) \text{ for } x_1 \in (x_{1m}+\Delta, x_{1m}+2\Delta)) \cup ...
\]

\[
... \cup ((g_{down}(x_{1m+1}), g_{up}(x_{1m+1})) \text{ for } x_1 \in (x_{1m}+l\Delta, x_{1m+1}))) \} \tag{2.4}
\]

where \( m=1,2...k \). After this procedure, region \( D_1 \), with respect to \( x_3 \), and region \( D_2 \), with respect to \( x_1 \) and \( x_3 \), are defined. Then, integration after the values of \( x_3 \), also with a certain step \( \Delta \), \( \int_{x_3}^{x_3+\Delta} \) can be done. Each integration step of \( x_3 \) consists of the sum of numerous integration subregions \( D_1 \) and \( D_2 \). By summing the value of the integral for each \( x_3 \) integration step, such that all values of \( x_3 \) are computed, final value of the reliability measure for three continuous random variables is found.
This method leads to over- or underestimation, because single values of \( g_{up} \) and \( g_{down} \) represent groups of variables contained in \( \Delta \) sections. Nevertheless, this estimation error is far smaller than in the case when, instead of bounding function, extreme values are used. The estimation error will decrease as \( \Delta \) goes to zero.

As the computing times of each simulation are relatively long, discretization of random variables \( x \) and their probability density functions \( f(x) \) is done. The discretized random variable \( X \) does not represent a single value, but rather a group of values contained in \((x_{beg}, x_{end})\). The value of \( X \) is equal to the average value of the group that it represents, which is \( \frac{(x_{beg} + x_{end})}{2} \). The discretized probability of \( X \) is computed from:

\[
P(X) = \int_{x_{beg}}^{x_{end}} f(x) dx
\]

(2.5)

where \( f(x) \) is the continuous pdf. An example of discretized pdf for wind speed variable can be seen in Fig. 2.4.

![Discretized wind speed probability distribution](image)

Figure 2.4: Discretized wind speed probability distribution.

Taking into account the independence condition for discrete case \( (P\{X_1, X_2...X_n\} = P\{X_1\}P\{X_2\}...P\{X_n\}) \), the reliability measure can be defined as:

\[
R_{wecs} = 1 - \sum_{i=1}^{F} P_1(X_{1i})P_2(X_{2i})P_3(X_{3i})...P_n(X_{ni})
\]

(2.6)

where \( F \) is the number of simulations with failure, and the measure \( i \) corresponds to the simulations in which failure occurred.

The procedure for computing \( R_{wecs} \) starts with defining which
parameters (WECS, grid and fault characteristics) are random variables. After gathering those variables’ distributions and discretizing them, simulation may start. The simulation model will be defined in Chapters 3 and 4. A separate simulation is performed for each combination of discrete input random variables. Each simulation results in “failure” or “no failure.” Those where failure occurred are marked and used for reliability-measure computation.

If failure has occurred in all of the simulations, then the reliability measure is:

\[
R_{\text{wecs, all failure}} = 1 - \sum_{i=1}^{k} P_1(X_1)P_2(X_2)P_3(X_3)...P_n(X_n) = \\
= 1 - \prod_{i=1}^{n} \int_{D_i} f_i(x_i) \, dx_i = 0
\]  (2.7)

where \( k \) is the number of all simulations, and subregions \( D_i = \{x_i \in R\} \) (all possible random variables values are part of the fault region \( D \)). WECS with the reliability measure equal to 0 has not complied with performance requirements for any combination of input WECS, grid and fault characteristics.

If during all simulations no failure took place, the reliability measure is equal to:

\[
R_{\text{wecs, no failure}} = 1 - \sum_{i=1}^{0} P_1(X_1)P_2(X_2)P_3(X_3)...P_n(X_n) = \\
= 1 - \prod_{i=1}^{n} \int_{D_i} f_i(x_i) \, dx_i = 1
\]  (2.8)

where subregions \( D_i = \{\emptyset\} \). For this case no values of input WECS, grid and fault characteristics lead to a violation (WECS particular design and control fulfill the grid requirements for all tested conditions).
CHAPTER 3
WECS MODEL AND CHARACTERISTICS

WECS models are essential for understating many of the phenomena taking place in the grid when there is high wind power penetration and are necessary for the proposed reliability assessment. For the reasons presented in Section 1.6, DFIG is chosen as a WECS model to showcase the proposed framework.

Figure 3.1: Simplified scheme of DFIG dynamic model.

3.1 WECS Model

A block diagram of the DFIG model is presented in Fig. 3.1, which shows the main elements of the model:

- mechanical torque model
- two mass turbine model
• 5th-order induction generator model
• rotor side converter control
• pitch control
• dc-link model
• grid side converter control

Each element will be presented in detail in Sections 3.1.1-3.1.7. An additional steady-state model was created to produce the initial state values for the dynamic model (initialization stage).

3.1.1 Mechanical torque model

The computation of mechanical torque, $T_m$, is based on power, $P_m$, curves [38] that take as inputs instantaneous values of turbine angular speed, $\omega_{turb}$, pitch angle, $\beta$, and wind speed, $V_w$:

$$P_m = \frac{1}{2} \rho \pi R^2 C_p(V, \beta, \omega_{turb}) V_w^3$$  \hspace{1cm} (3.1)

where $\rho$ is the air density, $R$ is the radius of an area covered by the wind turbine and $C_p$ is the power coefficient. The power coefficient is defined as [38]:

$$C_p = c_1\left(\frac{c_2}{\lambda_i} - c_3\beta - c_4\beta\beta^3 - c_6\right)e^{-\frac{c_7}{\lambda_i}}$$  \hspace{1cm} (3.2)

where

$$\lambda_i = \left[\frac{1}{\lambda + c_8\beta} - \frac{c_9}{\beta^3 + 1}\right]^{-1}, \quad \lambda = \frac{\omega_{turb} R}{V_w}$$  \hspace{1cm} (3.3)

$\lambda$ is a tip speed ratio and constants $c_1 - c_9$ are defined in Appendix A. From (3.1)-(3.3) the mechanical torque of the turbine shaft can be computed:

$$T_m = \frac{P_m}{\omega_{turb}}$$  \hspace{1cm} (3.4)

Figure 3.2 illustrates DFIG mechanical power as a wind-speed function. This curve does not give realistic results above rated wind speed $V_r$, as no pitch control is present ($\beta = 0$).
Figure 3.2: Mechanical power $P_m$ as a function of wind speed, with pitch angle $\beta$ equal to zero, based on power curves. Different colors of the function correspond with different control strategies determined by wind speed $V_w$ - for blue $V_w \in (V_{cut-in}, V_{min\ opt})$, for green $V_w \in (V_{min\ opt}, V_r)$, for red $V_w \in (V_r, V_{cut\-off})$.

The initialization stage for the mechanical torque computation is based on several assumptions. First of all, precise data for a particular turbine design (for use in (3.2)-(3.3)) are unknown and power curves provided by the manufacturers are only approximations. This is why the assumption is made that for rated WECS electrical power $P_r$, working with rated wind speed $V_r$ and pitch angle $\theta$ equal to zero, the power coefficient reaches its maximum value $C_{pmax}$. After iteration, the optimal tip speed ratio $\lambda_{opt}$, corresponding to $C_{pmax}$, is found. The next step is to compute blade radius $R$:

$$R = \sqrt{\frac{2P_r}{\rho \pi C_{pmax} V_r^3}}$$ (3.5)

Rotational speeds of the generator electrical field, $\omega_{gen}$, generator rotor shaft, $\omega_{rotor}$, and turbine shaft, $\omega_{turb}$, are defined with regard to all WECS working conditions (see Appendix A). Turbine rotational speed is defined through (3.30). Rotor and generator rotational speeds are assumed to change in a range of -50% to +20% of the synchronous speed. The synchronous speed of generator electrical field $\omega_s$ is equal to $\frac{f_{grid}}{2\pi}$. The gear ratio, $K$, of a WECS can be computed through these rotational speed values:
\[ K = \frac{\omega_{\text{rotor}}}{\omega_{\text{turb}}} \]  
\[ (3.6) \]

The generator electrical-field angular speed is defined using \( \omega_{\text{rotor}} \) and a number of pole pairs, \( P \), on the generator rotor:

\[ \omega_{\text{gen}} = \frac{P}{2} \omega_{\text{rotor}} \]  
\[ (3.7) \]

All angular speed per-unit values (see Appendix A) correspond to each other, \( \omega_{\text{turb\,pu}} = \omega_{\text{rotor\,pu}} = \omega_{\text{gen\,pu}} \).

![Graph of DFIG turbine angular rotational speed vs. wind speed in steady-state](image)

**Figure 3.3**: DFIG turbine angular rotational speed \( \omega_{\text{turb}} \) with regard to wind speed \( V_w \) in steady-state, \( V_r = 14 \text{ m/s} \), \( V_{\text{cut-in}} = 4 \text{ m/s} \), \( V_{\text{cut-off}} = 25 \text{ m/s} \).

Figure 3.3 illustrates the relationship between wind speed \( V_w \) and \( \omega_{\text{turb}} \). It is assumed that for rated wind speed \( V_r \), turbine speed \( \omega_{\text{turb}} \) equals \( 1.2\omega_s \) (electrical field synchronous speed rotation). For \( V_w > V_r \), \( \omega_{\text{turb}} \) is kept constant through pitch or stall control. Lowering the wind speed value leads to a decrease in the \( \omega_{\text{turb}} \), up to \( 0.5\omega_s \), which corresponds to the minimal optimal wind speed, \( V_{\text{min\,opt}} \). Between \( V_{\text{min\,opt}} \) and wind cut-in speed, \( V_{\text{cut-in}} \), the DFIG works with constant speed \( 0.5\omega_s \). Below wind speed, \( V_{\text{cut-in}} \), and above \( V_{\text{cut-off}} \), DFIG produces no energy.

The steady-state relationship between mechanical power and turbine rotational speed is shown in Fig. 3.4 and can be divided into three regions. For the first region, \( \omega_{\text{gen\,pu}} = 0.5 \), and the mechanical power extracted from the wind is relatively low. The reason for this high drop in efficiency is the need to keep a minimal value of generator angular speed. That affects the wind-tip speed ratio, \( \lambda \), which no longer works at its optimal value. The second region is defined between \( 0.5\omega_s \) and \( 1.2\omega_s \). For this region, the
higher wind energy extraction of variable-speed WECS than constant-speed WECS can be noticed. In this region (corresponding to wind speed $V_w \in (V_{\text{min opt}}, V_r)$), the power coefficient, $C_p$, reaches its maximum value, $C_{p \text{max}}$, by tracking the optimal tip-speed ratio, $\lambda_{\text{opt}}$. In the third region, $\omega_{\text{gen}}$ is limited to $1.2\omega_s$. This causes the tip-speed ratio to diverge from its optimal value, even though the mechanical power would still increase with wind speed. To limit this power increase, protective control must be added.

Maximum and minimum generator speed values are limited by several technical issues. The first limitation involves the magnitude of rotor voltage needed to keep the excitation ($\frac{V_r}{s}$) for high slip values. Based on the example from [41], the speed range $\pm 30\% \omega_s$ forces the converter to be equal to at least 30% of the machine rating. The increase of the converter rating might not be economically feasible, as it would destroy the very concept of DFIG limited rating converters. Another issue is the limitation on switching frequency of insulated-gate bipolar transistors (IGBT) that are part of the rotor (RSC) and grid-side converters (GSC). For these reasons, WECS energy production efficiency is limited by the angular speed of the generator.

Figure 3.5 illustrates the turbine mechanical-power output as a wind speed function. In order to compute this steady-state curve, previous shown relations are needed – $V_w(\omega_{\text{turb}})$ (Fig. 3.3), $P_m(\omega_{\text{turb}})$ (Fig. 3.4), and $\beta(V_w)$. Steady-state pitch control implemented in this model can be defined as:
$\beta = K(V_w - V_r)$ for $V_w \in (V_r, V_{cut-off})$ \hspace{1cm} (3.8)

where coefficient $K = 2.19$, and $\beta$ is only computed above the rated wind speed. For example, the pitch angle value will equal zero for $V_r$ and $24.19^\circ$ for $V_{cut-off}$.

Dynamic $P_m(\omega_{turb})$ for $V_w = 7, 9, 12, 14 \text{ m/s}$ and steady-state optimal power tracking curve

The dynamic mechanical-torque computation model is based on (3.1)-(3.8). If the wind speed is keep constant during a fault, the mechanical torque will depend only on its initial steady-state point, $\omega_{turb}$ and $\beta$. Figure 3.6 shows the mechanical power, $P_m$, dynamic curves for four different wind speeds, where it can be seen that an increase in the angular speed of the turbine causes the mechanical power to decrease. According to (3.3), a change in $\omega_{turb}$ causes a change in the tip-speed ratio. For that reason, if the DFIG works in steady-state with $\lambda_{opt}$ and $\omega_{turb}$ changes, then the turbine will not operate with its maximum wind energy extraction.
capabilities ($\lambda \neq \lambda_{opt}$). This leads to a decrease in mechanical power. Figure 3.7 illustrates dynamic mechanical torque curves. Mechanical torque extracted from the wind, $T_m$, is an input to the next part of the model — the two-mass system.

Dynamic $T_m(\omega_{turb})$ for $V_w = 7, 9, 12, 14 \text{ m/s}$ and steady-state optimal power tracking curve

![Figure 3.7: Dynamic $T_m$ mechanical power plots as a function of turbine rotational speed $\omega_{turb}$ for four wind speeds $V_w = 7, 9, 11, 14 \text{ m/s}$, and a plot of steady-state optimal power tracking curve.](image)

### 3.1.2 Two-mass system

In the two-mass model the turbine mass is connected to the generator rotor mass through a shaft system. The two-mass model is based on an assumption that the value of turbine inertia, $H_t$, is different from the generator rotor inertia, $H_g$, and for most WECS designs, $H_t$ is an order of magnitude greater than $H_g$. Using this two-mass model, the turbine angular speed is defined by:

$$2H_t \frac{d\omega_{turb, pu}}{dt} = T_{m, pu} - D(\omega_{turb, pu} - \omega_{rotor, pu}) - K_s \theta \quad (3.9)$$

where $D$ is the damping coefficient, $K_s$ is the shaft stiffness, and $\theta$ is the angle of shaft twist in radians. In this model, only the damping factor resulting from the turbine and rotor speed difference has been taken into account. The generator rotor angular speed is defined as
\[ 2H_g \frac{d\omega_{\text{rotor pu}}}{dt} = D(\omega_{\text{turb pu}} - \omega_{\text{rotor pu}}) + K_s \theta - T_e \]  

(3.10)

where \( T_e \) is the per-unit electrical torque of the generator. Shaft twist angle between turbine mass and rotor mass can be defined as:

\[ \frac{d\theta}{dt} = (\omega_{\text{turb pu}} - \omega_{\text{rotor pu}}) \omega_{\text{base rps}} \]  

(3.11)

where \( \omega_{\text{base rps}} \) is the base (usually grid) angular speed in radians per second. The initialization stage, for this element of the model, results in initial values of \( \omega_{\text{turb}}, \omega_{\text{rotor}} \) and \( \theta \). Steady-state shaft twist equals:

\[ \theta_0 = \frac{T_{m0}}{K_s} \]  

(3.12)

### 3.1.3 Fifth-order induction generator model

The induction generator model can be expressed by a fifth-order differential equation in the \( dq0 \) reference frame with per-unit variables:

\[
\begin{align*}
V_{ds} &= R_s I_{ds} - \Psi_{qs} + \frac{1}{\omega_{\text{base rps}}} \frac{d\Psi_{ds}}{dt} \\
V_{qs} &= R_s I_{qs} + \Psi_{ds} + \frac{1}{\omega_{\text{base rps}}} \frac{d\Psi_{qs}}{dt} \\
V_{dr} &= R_r I_{dr} - \frac{1}{\omega_{\text{base rps}}} \frac{d\theta_r}{dt} \Psi_{qr} + \frac{1}{\omega_{\text{base rps}}} \frac{d\Psi_{dr}}{dt} \\
V_{qr} &= R_r I_{qr} + \frac{1}{\omega_{\text{base rps}}} \frac{d\theta_r}{dt} \Psi_{dr} + \frac{1}{\omega_{\text{base rps}}} \frac{d\Psi_{qr}}{dt} \\
\frac{d\theta_r}{dt} &= \omega_{e \text{ rps}} - \omega_{\text{gen rps}}
\end{align*}
\]

(3.13)

where \( V_{ds,qs} \) are stator voltages in the \( dq0 \) axis, \( V_{dr,qr} \) are rotor voltages, \( I_{ds,qs} \) stator currents, \( I_{dr,qr} \) rotor currents, \( \Psi_{ds,qs,dr,qr} \) are respectively stator and rotor fluxes, \( R_{s,r} \) are stator and rotor circuit resistances respectively, and \( \omega_{e \text{ rps}} \) is the grid electrical-field pulsation (usually equal to \( \omega_{\text{base rps}} \)). It has been assumed that \( V_s = V_{ds} + jV_{qs}, V_r = V_{dr} + jV_{qr}, I_s = I_{ds} + jI_{qs}, I_r = I_{dr} + jI_{qr} \). The difference between (3.13) and classical fifth-order induction generator equations is that voltages \( V_{dr} \) and \( V_{qr} \) are not zero. Instead they are set by rotor and grid-side converter control. To solve
where $X_{s,r}$ are stator and rotor circuit reactances, and $X_m$ is the magnetizing reactance, all in per unit values (p.u.). Per unit values are created by dividing the value to be converted by the nominal (or rated) value. By combining (3.13) and (3.14) (except the $\frac{d\theta_r}{dt}$ equation) only the differential equations with four unknowns, rotor and stator currents remain; the stator voltages are imposed by the grid and the rotor voltages are controlled. Solving those equations without initial conditions would lead to an infinite number of solutions. For this reason the initialization stage of the fifth-order DFIG model is extremely important.

In order to solve the initialization problem, it is necessary to take into account the DFIG power balance relations. As can be seen in Fig. 3.8, the DFIG is connected to the grid through stator and grid-side converter terminals. The active power, $P_e$, produced by DFIG, which without tacking into account mechanical and electrical losses, is equal to mechanical power $P_m$, is distributed through those terminals. When $\omega_{gen} > \omega_s$ (sup-synchronous operation), then the active power is flowing to the grid through the stator and rotor circuits. For $\omega_{gen} < \omega_s$ (sub-synchronous operation), the stator circuit is still supporting the grid with active power, but the rotor circuit is consuming active power. For both cases, the total active power produced has to be equal to the sum of the stator and rotor active powers:

$$P_e = P_{wecs} = P_s + P_r$$

During normal operation, the GSC works with power coefficient $\cos(\delta)$ equal to 1 ($S = P, Q = 0$), which means that the GSC is only exchanging (producing or consuming) active power with the grid. This situation may change during network disturbance, such as voltage drop, but then control
is applied to restore pre-fault conditions. The great advantage of using converters is in the fact that RSC may work with active $P_r$ and reactive power $Q_r$ consumption (used for excitation of stator) and, thanks to the dc-link and GSC, the power consumption from grid side has an active character. The steady-state reactive power produced by DFIG comes totally from the stator circuit:

$$Q_e = Q_{wecs} = Q_s$$

(3.16)

Depending on grid characteristics and requirements, the DFIG can work without any exchange of reactive power with the grid, with a power coefficient equal to 1 (which is the case mainly for strong systems, with small wind penetration), or it can follow set values of $Q_s$ to consume or produce reactive power and help the grid operator to maintain voltage stability (this type of operation is implemented in weaker grids with high wind power penetration).

In order to start a dynamic simulation, stator and rotor-circuit voltages and currents have to be known — $V_s$, $V_r\angle\alpha$, $I_r$, $I_s$. From the upper circuit in Fig. 3.8, it can be inferred that those four unknowns correspond to three circuit equations. This circuit can be solved in numerous ways. The method presented in this study creates two independent circuits from the original one. The first has only a stator voltage source, and the rotor voltage is short-circuited; the second has rotor-voltage source and short-circuited
stator voltage. Active and reactive powers of the rotor and stator can be expressed without their currents - \( I_s = I_{s1} + I_{s2} \), \( I_r = I_{r1} + I_{r2} \). Taking into account the properties \( P_s + jQ_s = V_sI_s^* \), \( P_r + jQ_r = \frac{V_r}{s}I_r^* \), it follows that:

\[
P_s(V_s, V_r, \alpha, s) = \frac{V_s^2}{C_3} \left( \frac{R_s R_r^2}{s^2} + R_s (X_r + X_m)^2 + X_m^2 \frac{R_r}{s} \right) + \frac{V_s V_r X_m}{C_3 s} (C_1 \sin(\alpha) - C_2 \cos(\alpha)) \tag{3.17}
\]

\[
Q_s(V_s, V_r, \alpha, s) = \frac{V_s^2}{C_3} \left( (X_r + X_m)(X_r X_r + X_m X_s + X_m X_r) \right) + \frac{R_r^2}{s^2} (X_s + X_m) + \frac{V_s V_r X_m}{C_3 s} (C_1 \cos(\alpha) + C_2 \sin(\alpha)) \tag{3.18}
\]

\[
P_r(V_s, V_r, \alpha, s) = \frac{V_r^2}{C_3 s} \left( \frac{R_r^2}{s} + X_s (X_s + X_m) \frac{R_r}{s} + R_s X_m^2 \right) + \frac{R_r X_m}{s} (X_s + X_m) - \frac{V_s V_r X_m}{C_3} (C_1 \sin(\alpha) + C_2 \cos(\alpha)) \tag{3.19}
\]

\[
Q_r(V_s, V_r, \alpha, s) = \frac{V_r^2}{C_3 s} \left( (X_r + X_m) R_r^2 + X_s (X_s + X_m)(X_r X_r + X_m X_s + X_m X_r) \right) + \frac{V_s V_r X_m}{C_3} (C_1 \cos(\alpha) - C_2 \sin(\alpha)) \tag{3.20}
\]

where

\[
C_1 = \frac{R_s R_r}{s} - X_s X_r - X_s X_m - X_m X_r,
\]

\[
C_2 = R_s X_r + \frac{R_s X_m}{s} + X_m (R_s + \frac{R_r}{s}),
\]

\[
C_3 = C_1^2 + C_2^2,
\]

and slip \( s = \frac{\omega_{e rps} - \omega_{\text{gen rps}}}{\omega_{e rps}} \).

Solution of (3.17)-(3.20) is not straightforward, as all powers are functions of many unknowns. If the generator electrical parameters and \( V_s \) are known, and \( (\omega_{\text{gen rps}}) \) needed for initial slip value computation has been acquired in the Section 3.1.1, only two unknowns are left — voltage \( V_r \) with its corresponding phase angle \( \alpha \). To solve this problem, an iteration procedure is applied.

The iteration procedure uses inputs \( P_e \) and \( Q_e \). While \( P_e \) is determined by wind speed, \( Q_e \) can be set by the operator. The value of \( Q_e \) can be limited by the converters’ rating. This provides excitation for the generator. Power set values are needed for \( f_1 \) and \( f_2 \) computations:

\[
f_1 = P_s(V_r, \alpha) - P_r(V_r, \alpha) - P_e \tag{3.21}
\]

\[
f_2 = Q_s(V_r, \alpha) - Q_e \tag{3.22}
\]

Next Jacobian \( J \) can be defined:
\[
J = \begin{bmatrix}
\frac{\partial f_1}{\partial V_r} & \frac{\partial f_1}{\partial \alpha} \\
\frac{\partial f_2}{\partial V_r} & \frac{\partial f_2}{\partial \alpha}
\end{bmatrix}
\]  
(3.23)

The iteration procedure of finding \( V_r \) and \( \alpha \) that fulfill the requirements \( f_1 \simeq 0, f_2 \simeq 0 \) is done by:

\[
\begin{bmatrix}
V_{r\,\text{new}} \\
\alpha_{\text{new}}
\end{bmatrix} = \begin{bmatrix}
V_{r\,\text{old}} \\
\alpha_{\text{old}}
\end{bmatrix} - J^{-1} \begin{bmatrix}
f_1 \\
f_2
\end{bmatrix} 
\]  
(3.24)

Using the data from Fig. 3.9, and rated wind \( V_r \), it can be seen that single values of \( P_e \) and \( Q_e \) solved separately have numerous solutions. By setting active power \( P_e \) equal to 1 and reactive power \( Q_e \) to 0, the iteration process will produce rotor voltage value \( V_r = 0.2191 \) p.u. with phase angle \( \alpha = 194.6911^\circ \) as a solution.

![Graph showing DFIG active \( P_e \) and reactive \( Q_e \) power generation as a function of rotor voltage magnitude \( V_r \) and its phase displacement with regard to stator voltage \( V_s \) - angle \( \alpha \); slip \( s = -0.2 \), \( V_s = 1 \), \( R_s = 0.01 \), \( X_s = 0.12 \), \( X_m = 5 \), \( R_r = 0.005 \), \( X_r = 0.2 \).](image)

Figure 3.9: DFIG active \( P_e \) and reactive \( Q_e \) power generation as a function of rotor voltage magnitude \( V_r \) and its phase displacement with regard to stator voltage \( V_s \) - angle \( \alpha \); slip \( s = -0.2 \), \( V_s = 1 \), \( R_s = 0.01 \), \( X_s = 0.12 \), \( X_m = 5 \), \( R_r = 0.005 \), \( X_r = 0.2 \).

Stator and rotor voltages after transformation to the \( dq0 \) axis —
\( V_{ds0} = V_s, V_{qs0} = 0, V_{os0} = 0, V_{dr0} = V_r \cos(\alpha), V_{qr0} = V_r \sin(\alpha), V_{0r0} = 0 \) — allow initial \( dq0 \) current computation. The 0-axis voltages equal to zero come from an assumption that in the initial stage, the wind farm and the grid are working in balanced and symmetrical three-phase conditions. The assumption that \( V_{qs0} = 0 \) is not that straightforward, as the stator voltage might have a \( q \) component (the proportion of \( d \) and \( q \) values depend on
reference system). This assumption is made to simplify RSC and GSC control by getting rid of the \( \alpha, \beta \) transformation. In order to set \( V_{qs0} = 0 \) on WECS terminals, an additional procedure is shown in Chapter 4.

With rotor and stator voltages known, initial values of the current can be found through

\[
I_{ds0} = \frac{P_s V_{ds0} + Q_s V_{qs0}}{V_{ds0}^2 + V_{qs0}^2}
\] (3.25)

\[
I_{qs0} = \frac{P_s V_{qs0} - Q_s V_{ds0}}{V_{ds0}^2 + V_{qs0}^2}
\] (3.26)

\[
I_{dr0} = \frac{P_r V_{dr0} + Q_r V_{qr0}}{V_{dr0}^2 + V_{qr0}^2}
\] (3.27)

\[
I_{qr0} = \frac{P_r V_{qr0} - Q_r V_{dr0}}{V_{dr0}^2 + V_{qr0}^2}
\] (3.28)

After computing the initial currents based on (3.14), initial fluxes values can be gathered. This ends the initialization stage and allows the dynamic simulation to start, according to (3.1)-(3.13). The last equation needed for dynamic simulation (for \( \omega_{\text{rotor}} \) computation) is the electrical torque, given by:

\[
T_e = \Psi_{qr} I_{dr} - \Psi_{dr} I_{qr}
\] (3.29)

### 3.1.4 Rotor-side converter (RSC) control

Rotor-side converter control has numerous implementations depending on turbine manufacturer, rated power and type. In recent years there have been many publications in academic and industrial societies regarding different schemes and concepts for DFIG control. The control model presented in this section is relatively simple, but widely used.

RSC control implemented in this model is based on proportional-integral (PI) controllers. The proportional part of the controller makes a change in PI output based on current error, \( e \) (difference between the set value of the tracked variable and its current value). The integral part output depends both on the current error value, and on past error values. In mathematical terms, PI controller output can be defined by:
$y(t) = k_p e(t) + k_i \int_0^t e(\tau) \, d\tau \quad (3.30)$

where $k_p$ is the proportional gain, $k_i$ is the integral gain and error $e(t) = u_{set}(t) - u(t)$. RSC control is based on two PI sets (Fig. 3.10). The first set controls the active power and the second the reactive power - such control is possible thanks to the $dq0$ reference frame that allows decoupled control of those values. Active power control consists primarily of three PI controllers. The first one controls the value of $I_{qr}$ by changing $V_{qr}$ and the second tries to keep the stator power $P_s$ equal to its set value $P_{s\, set}$ by influencing the set value of current $I_{qr\, set}$. The third controller used in the active power set has the goal of damping the turbine and rotor angular speed oscillations. This control is achieved by changing $P_{s\, set}$.

![Diagram of Rotor side converter active (upper one) and reactive (lower one) power control.](image)

Reactive power control consists of three PI controllers. The first one controls the value of $I_{dr}$ by changing $V_{dr}$. This PI controller (like the corresponding controller for active power) does not have integral part $k_{i\, I_{dr}} = 0$ ($k_{i\, I_{qr}} = 0$); thus, proportional gain is greater than the reactive (and active) power controller, $k_{p\, I_{dr}} > k_{p\, Q_s}$ ($k_{p\, I_{qr}} > k_{p\, P_s}$). This implies that keeping the correct value of the rotor current has priority over active and reactive power control. The last controller in the reactive power set tracks the stator voltage magnitude, $V_s$, error by changing the set value of reactive power $Q_{s\, set}$. As can be seen in Fig. 3.10, all the PI controllers need to be initialized. Initial values were computed in previous sections, and the PI controller gains are shown in Appendix A.
3.1.5 Pitch control

Similarly, as with RSC control, pitch control varies with turbine type. The main difference between various pitch controls is the input value that will eventually determine the pitch angle, $\beta$. The most common input values are $P_e$, $P_s$, $\omega_{gen}$, $V_w$ or a combination of those variables. In this model, $\omega_{gen}$ is chosen as an input (Fig. 3.11). The initial pitch angle, $\beta_0$, that was computed in Section 3.1.2 based on function $\beta(V_w)$ is the second input.

![Pitch control diagram](image)

Figure 3.11: Pitch control.

As can be seen in Fig. 3.11, the generator rotor-speed error is multiplied by gain $k_p$. For different implementations, this proportional gain works with different sampling times $T_s$. Usually this sampling-time frequency ranges from 0.33 Hz to 1 Hz for the proportional gain (as in this model) or has an inherited sampling time for PI controllers. Using a short sampling time is justified during normal working conditions. An increase in wind speed causes $\omega_{gen}$ to increase and limits the mechanical power by a change in $\beta$. Thanks to a low sampling rate, the blade servomotor will not work constantly, and short wind variations might be disregarded. A problem arises when a fault in the grid or voltage drop takes place. Then sampling of the $\omega_{gen}$ error leads to a different pitch-control output based on probability. When using pitch control with $T_s = 1 \text{ s}$ sampling time, a fault and any change in $\omega_{gen}$ (for fast post-fault recovery) might go unnoticed.

As this model is created for assessing the reliability framework that might require numerous simulations, $T_s$ is set to use the inherited sampling time (almost non-stop sampling). The main element of the second part of the pitch control scheme is an integrator, which simulates the mechanical blades motion. The gain, $1/T_{\text{servo}}$, represents the delay of the servomotors rotating the blades; the value of $T_{\text{servo}}$ is usually equal to a fraction of a second. This description of mechanical blade motion needs to have limitations in terms of a minimum and maximum value of the pitch angle $\beta$ and change of the pitch angle ($d\beta$). For most currently working WECS, the range of
$d\beta_{\text{max}}$ is $2^\circ/s$ to $10^\circ/s$ (with $d\beta_{\text{min}}$ equal to $d\beta_{\text{max}}$ or smaller), and the pitch angle range is limited from $\beta_{\text{min}} = 0^\circ$ to $\beta_{\text{min}} = 90^\circ$. All gains and parameter values in this pitch control model are presented in Appendix A.

3.1.6 Direct-current link model

The direct-current link connects the rotor-side converter and the grid-side converter. In order to keep the rated voltage value, a capacitor is included in dc-link (Fig. 3.8). The voltage on the capacitor changes during the dynamic simulation according to:

$$\frac{V_{\text{DC pu}}}{dt} = \frac{1}{C}(P_{\text{gsc}} - P_r)$$ (3.31)

where $P_{\text{gsc}}$ is the active power flowing between GSC and the dc-link, $C$ is the dc-link capacitor capacity, and $P_r$ is the active power between RSC and the dc-link defined as:

$$P_r = V_{dr}I_{dr} + V_{qr}I_{qr}$$ (3.32)

If losses in the dc-link are neglected, $P_r = P_{\text{gsc}}$. When assuming that $R_c \approx 0$, active power flowing through GSC is equal to the active power at the GSC terminal, $P_c$. Computation of $P_{\text{gsc}}$ is straightforward, as:

$$P_c = V_{ds}I_{cd} + V_{qs}I_{cq}$$ (3.33)

where $V_{ds,qs}$ are the $dq0$ components of the stator voltage, and $I_{cd,cq}$ are the $dq0$ components of the current flowing from the GSC terminals to the grid. Notation $I_{cd,cq}$ instead of $I_{dc,qc}$ is used to eliminate confusion with dc-link currents and voltages. Implementation of (3.31) into the model is done through the integrator block, which leads to the necessity of knowing $V_{\text{DC0 pu}}$. According to [42], $V_{\text{DC}}$ in steady-state operation is expressed by:

$$V_{\text{DC0 pu}} = \frac{2\sqrt{2}}{\sqrt{3}}V_s p_m$$ (3.34)

where $V_s$ is the grid voltage at the stator and GSC terminals, and $p_m$ is the modulation depth of GSC ($p_m \leq 1$). Based on $P_r$ and $P_{\text{gsc}}$, charging $J_1$ and discharging $J_2$ currents of the dc-link capacitor can be computed [42]:

36
\[ J_1 = \frac{P_r}{V_{DC}}, \quad J_2 = \frac{P_{gsc}}{V_{DC}} \]  

(3.35)

Two more values needed to initialize the dc-link model and GSC control are the voltage \( V_c \) and current \( I_c \) with their \( dq0 \) components. As can be inferred from Fig. 3.8, GSC current at the terminal is:

\[ I_c = \frac{V_c - V_s}{R_c + jX_c} \]  

(3.36)

where \( V_c \) is the voltage on the terminals of GSC, \( R_c \) is the circuit resistance between GSC and its grid terminals, and \( X_c \) is the GSC smoothing inductor. To solve this equation, another relationship between \( V_c \) and \( I_c \) is needed:

\[ P_c + jQ_c = V_s I_c^* \]  

(3.37)

where \( Q_c \) is the reactive power on the GSC terminals. In steady-state, \( Q_c \) is equal to zero; GSC works with a power coefficient equal to 1.

The dynamic part of the dc-link simulation is based on Equations (3.31)-(3.33) for dc-link voltage computation and on (3.36) for \( I_{cd,cq} \) computation. GSC currents will change following the stator voltage, \( V_s \). During a fault, GSC current changes might force injection or consumption of reactive power (\( Q_c \neq 0 \)). It is assumed that the dc-link voltage is sufficient to keep the voltage \( V_c \) constant or equal to values given by GSC control.

### 3.1.7 Grid side converter (GSC) control

GSC control consists of two sets of PI controllers (Fig. 3.12). The first one is based on active current control, \( I_{cd} \). For this set, the values, which are being controlled by the change of GSC voltage component \( V_{cd} \), are the dc-link capacitor voltage, \( V_{DC} \), and the GSC active current, \( I_{cd} \). The second set consists of one PI controller that reacts to change in the reactive current \( I_{cq} \) by changing the GSC voltage component, \( V_{cq} \). Specific values of PI controller gains are presented in Appendix A.
3.2 WECS Characteristics

WECS characteristics are an input to the created models. The data needed depends on the choice of WECS and particular manufacturer design characteristics. Most of the characteristics are set and remain constant during the reliability assessment process, but some parameters are treated as random variables.

The group of constant parameters is relatively large. Examples of those parameters are: rated power, $P_r$ [W]; cut-in, cut-off and rated wind speed, $V_{cut-in}, V_{cut-off}, V_r$ [p.u.]; maximum and minimal generator angular speed, $\omega_{gen\ max}, \omega_{gen\ min}$ [p.u.]; air density, $\rho$ [kg/m$^3$]; number of pole pairs, $P$; stator, rotor and grid-side converter impedances, $R_s, X_s, X_m, R_r, X_r, R_c, X_c$ [p.u.]; dc-link capacitor capacity, $C$ [F]; turbine-shaft inertia, $H_t$ [s]; generator rotor inertia, $H_g$ [s]; mechanical damping coefficient, $D$ [s p.u./el.rad]; shaft stiffness, $K_s$ [p.u./el.rad], or whole group of parameters defining WECS control (see Appendix A for all parameters, with assigned values).

An example of a parameter regarded as a random variable is the wind speed $V_w$. Wind speed defines numerous other parameters and sets up the steady-state work points. The assumption of just one wind speed for the process of reliability assessment would lead to results with little physical significance. For example, using a low wind speed may leave higher current reserves, such that rotor transients may not violate the limit or activate the relay, whereas working close to the rated wind speed may result in relay activation and eventually failure.
The Rayleigh distribution is one of the most commonly used wind speed distributions. Its advantage over the group of Weibull distributions is its simplicity; for Rayleigh computation, only the average value of gathered random variable samples is needed. The Weibull distribution with shape parameter \( k \) equal to 2 corresponds to the Rayleigh distribution. The equation below defines the Rayleigh distribution:

\[
f_{\text{Rayl}}(V_w) = \frac{V_w}{V_{\text{avr}}^2} e^{-\frac{V_w^2}{2V_{\text{avr}}}}
\]

where \( V_{\text{avr}} \) is the average wind speed. Figure 3.13 (same as Fig. 2.2) presents the Rayleigh probability density function for three different average wind speeds. The wind speeds chosen represent the average value of the three best wind class locations rated as “excellent,” “outstanding,” and “superb.”

![Rayleigh distribution function for three different average wind speeds](image)

Figure 3.13: Rayleigh probability distribution function for three different average wind speeds - \( V_w = 7.75, 8.4, 9.95 \text{ m/s} \).

Table 3.1 presents the average wind-power location classification of the U.S. Department of Energy - National Renewable Energy Laboratory. Wind powers and speeds used for that table were measured at 50 m above ground surface.

Reactive power generation set point \( Q_s \) is another example of a parameter that might be a random variable. A reactive-power set point is not a classical random variable, as it is set by the turbine manufacturer or by the grid operator. Its value depends on grid code and operator policy, which does not necessarily result in a constant \( Q_s \) value. For example, a grid operator who wants to cover his reactive power deficit might increase
Table 3.1: Wind power classification according to U.S. Department of Energy

<table>
<thead>
<tr>
<th>Wind power class</th>
<th>Resource potential</th>
<th>Annual average wind power density at 50 m in [W/m²]</th>
<th>Annual average wind speed at 50 m in [m/s]</th>
</tr>
</thead>
<tbody>
<tr>
<td>1</td>
<td>poor</td>
<td>&lt;200</td>
<td>&lt;5.6</td>
</tr>
<tr>
<td>2</td>
<td>marginal</td>
<td>200-300</td>
<td>5.6-6.4</td>
</tr>
<tr>
<td>3</td>
<td>fair</td>
<td>300-400</td>
<td>6.4-7</td>
</tr>
<tr>
<td>4</td>
<td>good</td>
<td>400-500</td>
<td>7-7.5</td>
</tr>
<tr>
<td>5</td>
<td>excellent</td>
<td>500-600</td>
<td>7.5-8</td>
</tr>
<tr>
<td>6</td>
<td>outstanding</td>
<td>600-800</td>
<td>8-8.8</td>
</tr>
<tr>
<td>7</td>
<td>superb</td>
<td>800-1600</td>
<td>8.8-11.1</td>
</tr>
</tbody>
</table>

the $Q_s$ value on wind farms in his system. Obtaining a $Q_s$ probability density function might be a very difficult task. It would require detailed data of system operator activity. But those data would give only results for one particular system. An operator with a small wind penetration might use only the synchronous generators excitation for reactive power balance. Another operator, whose grid has a high wind power penetration, will use the wind farms as a source of reactive power more often. An example of the proposed $Q_s$ probability density function is shown in Chapter 7.

Wind speed and reactive power set point are two key variables, which will take different values during the entire WECS operation, and will determine WECS working conditions. Thus it is necessary to include them in the assessment of WECS reliability.
4.1 Grid Model

The grid model used can be a detailed model of a particular grid where WECS will be connected, or it can be standardized. Standardized models allow reliability comparison between different WECSs. The best known are IEEE models or the infinite bus concept. In certain cases the grid model can be defined by grid requirements. For example, the Danish grid code defines a model with specified parameters, on which the WECS reaction for three-phase faults must be tested. This model is shown in Fig. 4.1.

![Figure 4.1](image)

Figure 4.1: Equivalent model of the power system used in stability analysis of symmetrical faults as defined by the Danish grid code [40].

The grid model used in this study is shown on Fig 4.2. It consists of a voltage source and a source impedance that represent the grid from the WECS perspective. The next elements are a \( \pi \) model of a line connecting the WECS with the system and the transformer. This changes the WECS voltage level (depending on the vendor: 0.5 – 1 kV) to the grid voltage level at the connection point. All parameters that define the elements of the grid model are shown in Appendix A.

The connection between the WECS model and the grid model is shown in Fig. 4.3. The WECS model works on the \( dq0 \) axis, while the grid model is a three-phase \( abc \) system. For this reason the \( dq0-abc \) and \( abc-dq0 \)
conversion blocks are used. As can be seen, the WECS model takes voltage on its terminals (bus B4) as an input, and outputs the total value of current flowing from the WECS. The value of injected current is the sum of currents flowing from the stator winding $I_{ds}, I_{qs}$ and through the grid-side converter $I_{cd}, I_{cq}$. Those currents are modeled as current sources determined by the WECS model.

Grid characteristics are inseparably connected to the chosen grid model. For the model from Fig. 4.2 the main parameters are system voltage level, $V_{sys}$, with the corresponding angle, $V_{sys\ angle}$; grid frequency, $f$; source
impedance, $Z_{sys}$, or system short-circuit power, $S_{syssc}$; source impedance $R/X$ ratio; line length, $l_{km}$; line positive and zero sequence resistance, inductance and capacitance in $\Omega/km$, $H/km$, $F/km$; transformer nominal power; transformer winding connection; high-voltage transformer winding parameters, resistance, $R_{w1}$, and inductance, $L_{w2}$; low-voltage transformer winding parameters, voltage, $V_{weecs}$, resistance, $R_{w2}$ and inductance, $L_{w2}$; and transformer magnetizing reactance, $R_m$.

In this study all grid characteristics are treated as constant parameters. That means that none of the random variable distributions, which are needed for reliability measure computation, originates from grid characteristics. But there are certain cases when some of those parameters might be random variables. For example, the system voltage, $V_{sys}$, could take a few values during the simulation process. For each voltage value, the grid model should be different. A physical interpretation would be reliability assessment, which includes various WECS connection points on different voltage levels.

4.3 Fault Characteristics

Fault characteristics are one of the key parameters defining the reliability measure. From a WECS perspective they can be divided into two groups: far and close faults. Of course, this division is somewhat artificial, as there is no clear border between them.

Close faults can be defined as faults which physically took place near the WECS or as faults whose short-circuit current is generated to a large degree from the WECS. These faults must be modeled on a detailed short-circuit model of the grid and WECS. Faults to be simulated are three-phase with ground (3K), phase-to-phase (2K), phase-to-phase with ground (2KE), phase-with-ground (1K) and loss-of-line without short-circuit. The point of fault injection depends on the chosen model. A detailed model should include more than one injection point. When assessing reliability of a group (farm) of WECS instead of just one, at least one injection point should be placed after the point of common coupling (PCC) that is on the connection between the WECS farm and the grid. PCC may be the most fragile point where a fault might occur.
It is important to establish the correct probability for each of the simulated faults. Three-phase faults may be more severe, but the probability of encountering them is much smaller than for one-phase faults. Because of that, parameters like “type of fault” or “fault duration” are, in this study, random variables with corresponding probability distributions. As an example, Fig. 4.4 illustrates the number of fault events per year per 100 km of lines as a function of the type of fault and the voltage level of the transmission line. Assuming that faults were aggregated into two groups, single-phase and poly-phase, those data might be used for reliability index computation, as they carry information about the probability of each of those events.

Figure 4.4: Fault statistics in the France’s transmission and sub-transmission level [40].

Far faults are defined as faults which physically took place far from the WECS or as faults whose short-circuit current is generated to a small degree from the WECS. Far faults are modeled as a voltage change in the voltage source, which represents the grid. If the wind penetration is small and the system is relatively strong, then the far-faults concept can be used for simulation of almost all faults with high accuracy. An example of using the far-fault concept is the infinite bus model, where the current flowing from the WECS does not change the voltage values imposed by the voltage source. Figure 4.5 presents the occurrences of voltage drop, as a function of duration and the voltage magnitude. Those data are sufficient for reliability measure computation.

The more accurate the grid fault data available, the more realistic the
Figure 4.5: Electric Power Research Institute data of voltage drop monitoring for substation with 5 min filter [40].

computed reliability measure will be.
CHAPTER 5

GRID REQUIREMENTS - FAILURE
DEFINITION

Grid requirements and grid codes are essential in reliability framework assessment. The event of the fault itself does not violate any grid codes, but the WECS reaction to this fault may. When WECS behavior for certain simulation conditions does not fulfill the grid code, then this particular simulation is marked as one with a failure.

At present, grid requirements for WECSs are mainly connected to low voltage ride-through (LVRT), also called fault ride-through (FRT), capability. There are also a series of other requirements that wind farms have to fulfill, such as active power regulation, reactive power regulation, voltage quality (harmonic, flickering), steady-state power production depending on voltage and frequency level, etc. For reliability analysis, these are of less important, as they are not technologically as challenging as LVRT.

LVRT is the ability of a wind turbine to withstand certain voltage drops without shutting down. Most of the grid codes specify one group of LVRT requirements, but there are certain exceptions, such as Denmark or Ireland, which define different LVRT requirements for transmission and distribution levels in the same grid. In the following subsections, Danish and US requirements for WECS connection are presented.

5.1 Elkraft and Eltra Systems (Danish) WECS Requirements

In this section some of the most important requirements imposed on new WECS (from a reliability framework assessment perspective) for Elkraft and Eltra grids are presented. These regulations apply to all wind farms connected to the grid after the year 2004 at voltage levels above 100 kV.
A wind turbine must not shut down under conditions specified in Table 5.1. These requirements must also be met for a sequence of at least two one-phase (also for two-phase and three-phase) short-circuits within a 2 min interval and at least six one-phase (also for one-phase and three-phase) short-circuits within a 5 min interval.

Table 5.1: Faults in Danish transmission grid for which a wind turbine must not trip

<table>
<thead>
<tr>
<th>Three-phase short circuit</th>
<th>Duration up to 100 ms</th>
</tr>
</thead>
<tbody>
<tr>
<td>Two-phase short circuit</td>
<td>Duration up to 100 ms followed by a second fault after 300 – 500 ms with duration up to 100 ms</td>
</tr>
<tr>
<td>with/without earth</td>
<td></td>
</tr>
<tr>
<td>Single-phase to earth</td>
<td>Duration up to 100 ms followed by a second fault after 300 – 500 ms with duration up to 100 ms</td>
</tr>
<tr>
<td>short circuit</td>
<td></td>
</tr>
</tbody>
</table>

For each newly connected wind turbine, the grid operator must receive results of simulations based on the model in Fig. 4.1. This simulation must be done with the voltage profile from Fig. 5.1. This voltage profile represents a three-phase fault with a slow voltage recovery. The short-circuit power is assumed to be equal to $10P_n$, where $P_n$ is the turbine nominal power, with phase angle equal to $84.4^\circ$ ($\frac{R}{X} = 0.1$). The value of the voltage source is multiplied by a factor, in order to achieve pre-fault voltage equal to 1 p.u. on PCC. The WECS is working with a rated wind speed, nominal rotor speed, and with neutral reactive power compensation in PCC.

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Figure 5.1: Voltage profile for simulating of symmetric three-phase faults in Elkraft and Eltra grids [43].

The WECS or a group of WECSs will meet the grid requirements if, for this simulation, the following four conditions are fulfilled [43]:

- The wind farm will produce the rated power no later than 10 s after the voltage is above 0.9 p.u.
During the voltage dip specified in Fig. 5.1, the active power in the PCC will meet the condition:

\[ P_{current} \geq k_p P_{t=0}(\frac{V_{current}}{V_{t=0}})^2 \]  \hspace{1cm} (5.1)

where \( P_{current} \) is the current active power measured in PCC, \( P_{t=0} \) is the power measured in the PCC just before fault, \( V_{t=0} \) is the voltage in the PCC just before the fault, \( V_{current} \) is the current voltage measured in the PCC, and \( k_p = 0.4 \) is the reduction factor considering any voltage dips to the generator terminals.

The value of the pre-fault reactive power exchange with the grid and control over this exchange (Fig. 5.2) is restored no later than 10 s after the voltage is above 0.9 p.u.. Also during the voltage dip, WECS reactive current in the PCC must not exceed the value of the nominal WECS current.

![Figure 5.2: Requirements for a wind farm exchange of reactive power in the PCC [43].](image)

During the voltage dip, the WECS reactive power control has to change from normal regulation to maximum voltage support. This regulation should not create the voltage overshoots.

Additionally, the WECS must withstand the impact of certain asymmetrical faults in the grid after one unsuccessful automatic reclosure. For two-phase and single-phase faults in the transmission grid, modeled as
voltage drops from Fig. 5.3, the turbine must not shut down. The code also specifies the number of fault repetitions and time intervals between those repetitions, which the WECS must survive with sufficient hydraulic, pneumatic and emergency power reserves such that the turbine can continue normal operation.

Figure 5.3: Voltage profile for two-phase (on left) and single-phase (on right) fault tests for Elkraft and Eltra grids [43].

A grid operator will demand that the WECS owner provide the results of these simulations along with the models used. In addition, the models should be suitable for simulation of root-mean-square (RMS) values. Electromagnetic transient (EMT) models would not be accepted by the grid operator.

5.2 USA WECS Requirements

USA WECS requirements are specified by Federal Energy Regulatory Commission (FERC). In [44] FERC sets requirements for new wind generator connections. These requirements for many cases can be seen as guidelines, and much of the final authority is left to local utilities. For example, in the primary version of this standard, a wind plant was required to meet the defined low voltage ride-through standard, only if the transmission provider shows that low voltage ride-through capability is needed to ensure system safety or reliability. That means that the local provider could decide not to require LVRT from new wind farms. After
pressure from the North American Electric Reliability Corporation, LVRT was made a general standard and no reliability survey is needed to demand it from WECS vendors. What is more, the transmission provider can adopt additional LVRT requirements that were not specified by [44]. In addition to LVRT, [44] specifies wind farm requirements to provide the system with reactive power, power factor design criteria, and supervisory control and data acquisition (SCADA) demanded capabilities.

Figure 5.4: Minimum required wind plant response to voltage dip [40]

According to [44], the WECS must not shut down during voltage drops corresponding to durations as seen on Fig. 5.4. For example, a WECS has to survive a voltage drop of 85% that lasts 625 ms. Additional requirements state, as can be seen from the curve in Fig. 5.4, that a WECS must operate continually at 90% of the rated voltage, measured at the high-voltage side of the wind farm substation transformer.

5.3 Performance Requirements Summary

As was stated at the beginning of this chapter, for contemporary WECS reliability analysis, the LVRT capability seems to be of highest importance. For this reason one of the LVRT national grid codes can be used to define grid requirements. Depending on the direction in which reliability analysis should lean, the number of requirements will change. If the analysis is broader, then the grid requirements should be detailed and include all the codes in which WECSs are mentioned. At the same time, if the analysis is concentrated on a specific feature, such as LVRT reactive current support, then only limited requirements from the LVRT code need be taken into account.

After a precise definition of what is expected from a WECS, numerous
dynamic simulations take place. Each simulation which violates the defined grid requirements is marked as one with a failure and is used for assessing WECS reliability.
6.1 Dynamic Simulation

This section shows an example of a dynamic simulation. Grid and WECS models used are the same as those defined in Chapters 3 and 4. To simplify the WECS model, the voltage source angle is adjusted in the iteration process so that the steady-state voltage on WECS terminals, \( V_q \), is equal to 0. Thus, the \( \alpha\beta \) transformation for control purposes is unnecessary.

The WECS controls used do not include typical LVRT features, such as additional reactive current generation, and are set to track initialized steady-state values. Then the model created represents a WECS without LVRT capability. During a fault, when the rotor current exceeds the maximum value set on the relay, the crowbar is activated. It is assumed that this leads to converter blocking and eventually to wind turbine shutdown. The simulations correspond to reality up to the point when the rotor current exceeds the maximum value. If FRT is regarded as the grid requirements, and the model presented above is used, then by computing the reliability measure, we would assess the capability an older wind turbine model with regard to certain new LVRT requirements.

The main parameters of the first simulation are: fault duration, \( t_{\text{fault}} = 300 \text{ ms} \); voltage drop during fault, \( V_{\text{drop}} = 40\% \); WECS rated power, \( P_e = 2 \text{ MW} \); WECS rated wind speed, \( V_{w_r} = 14 \text{ m/s} \); wind speed during simulation, \( V_w = V_{w_r} \); generator angular speed for wind \( V_w \), \( \omega_{g_{\text{pu}}} = 1.2 \); system frequency \( f = 60 \text{ Hz} \); and reactive power generation, \( Q_s = 0.1 \text{ p.u.} \). The rest of the parameters are presented in Appendix A. In this model motor notation is used; for example, if the power is generated by WECS, it will have a negative value.

Figure 6.1 presents the stator and rotor fluxes, and, as can be seen in
Figs. 6.2-6.11, most of the WECS variables display three different stages. The first stage (pre-fault) takes place between the simulation start, $t_0$, and the beginning of the fault, $t_{\text{fault start}}$, and represents steady-state. The second period (fault) is defined during the fault, from $t_{\text{fault start}}$ to $t_{\text{fault cleared}}$. The third period (post-fault) begins with the end of fault and lasts until the variable returns to its steady-state value.

It is important to note that not only the fault itself can cause extreme conditions, such as excessive currents. The moment of the fault’s clearing can cause the turbine to trip, as can be seen in Fig. 6.2, where the rotor...
current $I_{dr}$ reaches its maximum value immediately after the fault is cleared, but not during the fault. This phenomenon is mostly caused by reactive and active current control, which is trying to keep the set current and power values during the fault by changing the RSC voltage. When suddenly the fault is removed, overshoot occurs.

As can be seen in Fig. 6.3, the stator voltage is defined by the system source voltage (modeling the fault). The influence on it from the WECS is limited, and is represented only as a small flickering.

Figure 6.4: Turbine mechanical torque, rotor mechanical torque, electrical torque and pitch angle.

The sudden stator voltage decrease during the fault creates a situation in which the WECS cannot export the energy produced into the grid. That
can be seen in Fig. 6.4 by tracing the value of the electrical torque, $T_e$, which oscillates in the vicinity of 0.453 (smaller value than before the fault). This results in an imbalance between the mechanical torque generated by the wind ($T_{m,t}$, $T_{m,r}$) and the generator electrical torque ($T_e$), which leads to an increase of the rotor (and turbine) angular speed (Fig. 6.5). As a result, the wind turbine is forced to work with a non-optimal wind tip speed ratio, $\lambda_{opt}$, leading to decrease in turbine’s mechanical torque and in the generated power (following curves from Fig. 3.6-3.7).

![Figure 6.5: Rotor angular speed (upper), turbine angular speed (center) and shaft twist (lower).](image)

The mechanical torque decrease during a fault (from 500 ms to 800 ms) can be clearly seen in Fig. 6.4. Without pitch control, after the fault is cleared the turbine mechanical torque would return to steady state value, and second oscillation would not be observed. Pitch control uses the rotor angular speed as an input variable. Under normal working conditions (no fault), this control works well. When the wind speed increases, $V_w \uparrow$, the mechanical torque and rotor speed also increase, $T_m \uparrow$, and the pitch control changes the pitch angle, $\beta \uparrow$, such that that the mechanical torque is limited $T_m \downarrow$. Unfortunately, during the fault, the generator rotor speed can increase, while the mechanical torque decreases (because the electrical torque decreases even more). In this case the pitch control results in further decrease of $T_m$. This leads to the conclusion that for certain faults, pitch control (the one used in this study) will prolong the return of the WECS parameters to their steady-state values during the post-fault period. This
may be the reason why some WECS vendors use more complicated pitch control mechanisms with more than one input variable.

The shaft twist-angle change is defined as the difference between the turbine torque, generator rotor torque, and electrical torque (or in other words the difference between $\omega_{\text{turb pu}}$ and $\omega_{\text{rotor pu}}$), as in (3.9)-(3.11), where the generator torque $T_r = D(\omega_{\text{turb pu}} + \omega_{\text{rotor pu}}) - K_s \theta$. During the fault, $\omega_{\text{turb pu}}$ increases more slowly than $\omega_{\text{rotor pu}}$ (Fig. 6.5) for three reasons. First, the rotor speed is directly affected by the change in the grid (fault). Second, the rotor and turbine masses create a two-mass system, in which those masses are connected through a shaft with a limited stiffness ($K_s \neq \infty$). Any change in the torque of one of the masses will not to be completely transferred to the other side — some of the energy is stored as a change in the shift twist. Third, the turbine mass inertia, $H_t$, is one order of magnitude higher than the rotor inertia, $H_g$. For that reason, even if the torque change were transferred instantaneously and without losses ($K_s = \infty$), the $\omega_{\text{turb pu}}$ would still change more slowly than $\omega_{\text{rotor pu}}$. After the fault is cleared, $T_e$ oscillates around its steady-state value ($T_{e\text{aver}} \uparrow$).

The rotor torque, $T_r$, encounters a higher counter-torque ($T_e$) and the generator rotor speed decreases, $\omega_{\text{rotor}}$, while the turbine speed, $\omega_{\text{turb}}$, keeps increasing. That leads to the two-mass system shaft twisting into the opposite direction. After several consecutive oscillations, the shaft twist angle returns to its steady-state value (Fig. 6.5).

Figure 6.6: Rotor circuit abc phase currents created from dq0 values based on steady-state rotor excitation frequency.
Figure 6.6 illustrates the rotor-circuit phase-currents values, which were computed from the $dq0$ transformation with the steady-state value of the rotor pulsation ($\omega_{exc}$). The rotor currents and voltage pulsations superimposed on the generator electric-field angular speed, $\omega_{gen}$, have to produce the grid pulsation (synchronous speed), $\omega_{grid} - \omega_{gen} = \omega_{exc}$. Without fulfilling this condition, a wind turbine is unable to produce power at the nominal frequency. This condition is met by changing the rotor voltage frequency through proper control of the IGBT switching frequency. The control is based on the generator angular speed. Every change in the generator speed will cause a change in the RSC IGBT switching frequency. In this study switching frequency control was not implemented and no physical model of IGBT was used. Thus, the plot of rotor currents from Fig. 6.6 does not fully correspond with reality for the periods when $\omega_{gen} \neq \omega_{gen \text{ steady-state}}$. As long as the $\omega_{gen}$ does not diverge far from its steady point, current graphs shown are acceptably precise.

![Figure 6.7: Stator active power $P_s$, rotor active power $P_r$, grid side converter active power $P_c$ (motor notation).](image)

During the fault, the stator active power oscillates around $-0.45$ (a smaller value than pre-fault), because the total power is unavailable for transfer to the grid, and encounters high overshoot at the beginning of the post-fault period. As can be seen in Fig. 6.7, the rotor active power follows a similar pattern. Reactive power exchange at the GSC terminals is caused directly by the voltage drop. After the fault occurs, GSC control, by changing the GSC voltage, is able to slowly bring $P_c$ to its set value. Unfortunately, that change of voltage $V_{cd,cq}$ (and by this also current $I_{cd,cq}$)
leads to an overshoot when the fault is removed and the grid voltage returns to its pre-fault value.

\[ Q_s, Q_r, Q_c \text{ [p.u.]} \]

Figure 6.8: Stator reactive power \( Q_s \), rotor reactive power \( Q_r \), grid side converter reactive power \( Q_c \) (motor notation).

Stator and rotor reactive powers (Fig. 6.8) oscillate in the vicinity of their steady points (\( Q_{s \text{ set}} = 0.1 \) p.u.). Those variables are not as influenced as the active powers by the voltage drop, as their values are relatively small. GSC reactive power, \( Q_c \), should be kept as close to zero as possible (based on the concept of only active GSC power exchange). By trying to do that, GSC control is partly responsible for the high \( Q_c \) overshoot at the beginning of the post-fault stage.

Figure 6.9 illustrates the behavior of key dc-link parameters. The dc-link charging current follows the oscillations of \( P_r \) (3.35). \( P_r \) is the power produced (or consumed) in the rotor, which has to be injected (or extracted) to (or from) the dc-link. The situation is analogous with the dc-link discharging current, \( J_2 \), which follows \( P_c \), but encounters an even higher post-fault peak, because its value also depends on the dc-link voltage. The terms “charging” and “discharging” current may sometimes lead to confusion. They correspond with reality for sup-synchronous working conditions. Then the active power is sent from the rotor circuit to the dc-link (dc-link “charging”) and then from the dc-link through GSC to the grid (dc-link “discharging”). When working in sub-synchronous conditions the power flow direction changes and the current names theoretically could be swapped. For consistency, those names are kept as
The dc-link capacitor current is computed based on the charging and discharging current values, \( I_{DC\,cap} = J_1 - J_2 \). The same plot of current can be found using the equation \( I_{DC\,cap} = C \frac{dV_{DC\,cap}}{dt} \). During the fault period, the discharging current, \( J_2 \), is higher than the charging current, \( J_1 \). This forces \( I_{DC\,cap} \) to increase. The same phenomenon changes the capacitor voltage — the dominance of \( P_c \) over \( P_r \) causes power imbalance. Higher power ejection than injection into DC-link leads to \( V_{DC\,cap} \) decrease. The reason for the high \( P_c \) value is the assumption that GSC is able to keep \( V_{cd,cq} \) values, and when the \( V_{ds,qs} \) suddenly decreases, the current \( I_{cd,cq} \) increases rapidly (3.36). With \( V_{cd,cq} \) constant (only at the beginning of fault - when the control did not yet react) and \( I_{cd,cq} \) increasing, the active power extracted from the dc-link, \( P_c \), increases (as well as the reactive power \( Q_c \)).

In the post-fault period, after the initial \( J_2 \) and \( P_c \) overshoots, voltage and current on the dc-link capacitor slowly return to their steady-state values.

Figure 6.10 illustrates voltages and currents of busses \( B_1 \) and \( B_4 \) from Fig. 4.2. Currents flowing through those busses are identical. For this reason one plot is zoomed to present the fault period with more detail.

The last graphs that present one particular simulation are shown in Fig. 6.11. Powers shown are the overall WECS values that are seen from the grid perspective. Total active power was computed from \( S_t = V_s (I_{wecs\,dq})^* \),
where $I_{	ext{wecs} \ dq0}$ is the current flowing from the wind turbine into the grid.

Active and reactive WECS power are simply real and imaginary parts of $S_t$.

Figure 6.10: Bus $B_1$ (grid voltage source) and $B_4$ (WECS terminals) phase voltages and currents for different time periods.

Figure 6.11: WECS terminal voltage $V_s$, total power $S_t$, active power $P_t$ and reactive power $Q_t$.

6.2 Simulation Validation

Every model should comply with the process of validation. Validation of the WECS models presented in this chapter is not straightforward.
Although there are papers and articles that deal with DFIG modeling, the numerous assumptions done during the design phase and the values of parameters chosen for simulation differentiate models from each other. Still, many similarities in the variables behavior can be found.

Figure 6.12: Conventional DFIG dynamic response during voltage sag of 50% condition at super-synchronous speed [45].

In [45] a new series connection of the DFIG grid side converter was presented. For a new design performance evaluation, a comparison with conventional DFIG was made. Figure 6.12 illustrates the behavior of several DFIG parameters during a 0.5 p.u. voltage sag for 150 ms. The most important similarity between those plots and the plots shown in Section 6.1 is the oscillatory character of variable changes and three distinct phases that each variable encounters (pre-fault, fault and post-fault).

A new DFIG control model, called internal model control (IMC), is presented in [46]. In order to prove the superiority of the newly proposed
Figure 6.13: Comparison of d- and q- axis stator output active and reactive powers, implemented by IMC-based (1) and traditional (2) PI regulators, under voltage dip [46].

Control scheme, authors compare it with a traditional PI control. This comparison is made, as the authors state, on a “full” DFIG model. Figure 6.13 illustrates stator active and reactive power behavior during a voltage dip of 33% for 200 ms, with a steady-state rotor speed 1.2 p.u., and stator active power 1 p.u. As can be seen in curves 2, both $P_s$ and $Q_s$ encounter typical three-stage oscillatory behavior. What is more, the active power fault oscillation point is also smaller than the post-fault one. This resembles $P_s$ plots from Fig. 6.7.

The third source of partial model validation is based on [47], where modeling adequacy and a control tuning of DFIG are discussed. Figures 6.14-6.15 illustrate a response for a voltage drop of 0.5 p.u. for 100 ms. Terminal-voltage small fluctuations during the fault are very similar to that simulated in Fig. 6.11. The same can be noticed when it comes to active and reactive power plots. Certain power discrepancies can come from the aforementioned assumptions about GSC modeling, thanks to which $P_c$ highly influences $P_t$, and the fact that in [47] pitch control was not implemented.

Oscillations of rotor angular speed from Fig. 6.15 are comparable to those computed in this study, Fig. 6.5. They both match typical power-system generator’s oscillations, with a frequency range of $1 – 2$ Hz.
Figure 6.14: DFIG active power response to network disturbance for three models. 30M represents a third-order induction generator model with stator and rotor electrical transient neglected, 50M is a fifth-order model with stator transients neglected, while FOM is also a fifth-order model in which all transients are represented [47].

6.3 Reliability Assessment

This section presents a few practical examples to assess WECS reliability by computing reliability measure, $R_{wecs}$. The assessment is based on grid and WECS models presented in Chapters 3 and 4. Characteristics (parameters and variables) of those models are presented in Appendix A. In this case study there will be four random variables. Two are WECS characteristics: wind speed, $V_w$, and the set value of reactive power generation, $Q_s$. Two other random variables define the fault characteristics — voltage drop value, $V_{\text{drop}}$, and fault duration, $t_{\text{fault}}$. Voltage drop is the per unitized difference of the voltage root-mean-square value before the voltage dip and during the dip (neglecting transient flickering). Fault duration is the period between the fault occurrence and the fault clearance. In order to compute $R_{wecs}$, the probability distribution functions of those four random variables are needed.

In this example, wind speed distribution is based on Rayleigh pdf, with average wind speed of 8.6 m/s. This distribution is discretized to five values (Fig. 6.16, same as Fig. 2.4). Wind speeds below $V_{\text{cut-in}} = 4$ m/s and above $V_{\text{cut-off}} = 25$ m/s are not taken into account, and the remaining pdf is normalized such that $\sum_{i=1}^{5} P(V_{wi}) = 1$.

The probability distribution function of the set reactive power value used
Figure 6.15: DFIG response to network disturbance for 0.5 p.u. voltage drop at infinite bus with constant wind speed [47].

Figure 6.16: Discretized wind speed probability distribution.

in this example is shown in Fig. 6.17. It is discretized to three values with corresponding probabilities. Those probabilities are based on an assumption that this particular WECS operates close to zero reactive power exchange.
for 60% of its work time. The discretized values $Q_s = 0.1$ and $Q_s = 0.2$ will represent, with equal probability, the remaining part of the distribution.

The fault characteristics are based on EPRI data. From those data, a conclusion can be made that the fault duration, $t_{\text{fault}}$, and the voltage drop, $V_{\text{drop}}$, are not independent variables. For this reason, their pdf cannot be separated from their joint distribution pdf. In this example, voltage drop is represented by four values and fault duration by five values (Fig. 6.18). Based on these random variables and deterministic variables specified in
Appendix A, WECS reliability assessment is being done as shown in Chapter 2.

Table 6.1: WECS case-study design reliability measure as a function of rotor circuit resistance and reactance

<table>
<thead>
<tr>
<th>$R_r$ [p.u.]</th>
<th>$X_r$ [p.u.]</th>
<th>$R_{weecs}$</th>
</tr>
</thead>
<tbody>
<tr>
<td>0.005</td>
<td>0.2</td>
<td>0.8685</td>
</tr>
<tr>
<td>0.00575</td>
<td>0.23</td>
<td>0.8746</td>
</tr>
<tr>
<td>0.0065</td>
<td>0.26</td>
<td>0.8852</td>
</tr>
</tbody>
</table>

If the performance requirements specify that the current in the rotor circuits should not exceed the value of $1.5I_{r,n}$, then the overall reliability measure, $R_{weecs}$, equals 0.8685 for the tested WECS. After finding the WECS reliability measure, some changes in WECS control or design can be made. For example, if the rotor inductance, $X_r$, and resistance, $R_r$, are increased by 30%, the new reliability measure equals 0.8852 (Table 6.1). That result means that the increase of rotor inductance and resistance leads to the increase of WECS reliability with regard to faults in the grid. However, an increase in those parameters can also increase power losses in steady-state.

Table 6.2: WECS case-study design reliability measure as a function of the system short-circuit power

<table>
<thead>
<tr>
<th>$S_{sys,sc}$ [VA]</th>
<th>$R_{weecs}$</th>
</tr>
</thead>
<tbody>
<tr>
<td>$0.5 \cdot 10^7$</td>
<td>0.8441</td>
</tr>
<tr>
<td>$10^7$</td>
<td>0.8685</td>
</tr>
<tr>
<td>$2 \cdot 10^7$</td>
<td>0.9193</td>
</tr>
</tbody>
</table>

If the short-circuit power of the system were changed from $10^7$ VA to $0.5 \cdot 10^7$ VA, the reliability measure changed from 0.8685 to 0.8441. When the grid is strengthened to $2 \cdot 10^7$ VA, the reliability measure equals 0.9193 (Table 6.2). The stronger the grid, the easier it is for the WECS to fulfill set requirements.

Another set of WECS parameters that affect WECS reliability are active and reactive power control gains. The issue of setting correct PID gains is broad enough to be a separate study. What is more, the term “correct gains” may be misleading, as the value of the gains will change for different control objectives, such as minimization of either rotor shaft oscillations or
rotor current transients. Table 6.3 presents the reliability assessment results for three gain sets. The gains increase leads to an increase of WECS reliability. In order to find the best set of values that fulfill the particular performance requirements, a multi-variable optimization process based on the proposed reliability framework should be carried out.

Table 6.3: WECS case-study design reliability measure as a function of the system active power PI controllers gains

<table>
<thead>
<tr>
<th>$k_{pP}$</th>
<th>$k_{iP}$</th>
<th>$k_{pI}$</th>
<th>$k_{iI}$</th>
<th>$k_{p\omega}$</th>
<th>$k_{i\omega}$</th>
<th>$R_{\text{wecs}}$</th>
</tr>
</thead>
<tbody>
<tr>
<td>0.112</td>
<td>0.37</td>
<td>0.54</td>
<td>0</td>
<td>5</td>
<td>0</td>
<td>0.8685</td>
</tr>
<tr>
<td>1.25 \cdot 0.112</td>
<td>1.25 \cdot 0.37</td>
<td>1.25 \cdot 0.54</td>
<td>0</td>
<td>1.25 \cdot 5</td>
<td>0</td>
<td>0.8765</td>
</tr>
<tr>
<td>1.5 \cdot 0.112</td>
<td>1.5 \cdot 0.37</td>
<td>1.5 \cdot 0.54</td>
<td>0</td>
<td>1.5 \cdot 5</td>
<td>0</td>
<td>0.8764</td>
</tr>
</tbody>
</table>

The presented framework both allows one to find the key parameters that affect WECS reliability and to ascertain the significance of those parameters with respect to different WECS and grid characteristics. As can be seen in Table 6.4, the 30% increase of rotor circuit impedance in a system with $10^7$ VA short-circuit power gives a 1.92% increase in WECS reliability. But the same change in a system with $2 \cdot 10^7$ VA short-circuit power produces only a 0.96% reliability increase.

Table 6.4: WECS case-study design reliability measure as a function of the system short-circuit power and the rotor circuit resistance and reactance

<table>
<thead>
<tr>
<th>$R_r$ [p.u.]</th>
<th>$X_r$ [p.u.]</th>
<th>$S_{\text{sys_sc}}$ [VA]</th>
<th>$R_{\text{wecs}}$</th>
<th>$\Delta R_{\text{wecs}}$</th>
</tr>
</thead>
<tbody>
<tr>
<td>0.005</td>
<td>0.2</td>
<td>$10^7$</td>
<td>0.8685</td>
<td>0%</td>
</tr>
<tr>
<td>0.0065</td>
<td>0.26</td>
<td>$10^7$</td>
<td>0.8852</td>
<td>1.92%</td>
</tr>
<tr>
<td>0.005</td>
<td>0.2</td>
<td>$2 \cdot 10^7$</td>
<td>0.9193</td>
<td>0%</td>
</tr>
<tr>
<td>0.0065</td>
<td>0.26</td>
<td>$2 \cdot 10^7$</td>
<td>0.9281</td>
<td>0.96%</td>
</tr>
</tbody>
</table>

A similar analysis can be done with respect to the system short-circuit power and the active power PI controller gains (Table 6.5). For the $10^7$ VA system, the 25% and 50% PI gains change produce, respectively, a 1.92% and a 0.91% $R_{\text{wecs}}$ increase. For the $2 \cdot 10^7$ VA system, the same controller gains increase results in a $-1.2\%$ and a $-1.6\%$ $R_{\text{wecs}}$ decrease. This result proves the usefulness of the proposed reliability framework. When the WECS design is tested for only specific conditions (without the framework), the result can be biased. For example, in order to produce the optimal control, the value of the system impedance, to which WECS will be
connected, should be given. While this information may not be available
during the design phase, at least the range of the system impedance values
should be known. Then the proposed framework should be combined with
an optimization process to produce the desired control values.

Table 6.5: WECS case-study design reliability measure as a function of the
system short-circuit power and the active power PI controllers gains

<table>
<thead>
<tr>
<th>$S_{sys _sc}$</th>
<th>$k_p _P$</th>
<th>$k_i _P$</th>
<th>$k_p _I$</th>
<th>$k_i _I$</th>
<th>$k_p _\omega$</th>
<th>$k_i _\omega$</th>
<th>$R_{wecs}$</th>
<th>$\Delta R_{wecs}$</th>
</tr>
</thead>
<tbody>
<tr>
<td>$10^7$</td>
<td>0.112</td>
<td>0.37</td>
<td>0.54</td>
<td>0</td>
<td>5</td>
<td>0</td>
<td>0.8685</td>
<td>0%</td>
</tr>
<tr>
<td>$10^8$</td>
<td>1.25 · 0.112</td>
<td>1.25 · 0.37</td>
<td>1.25 · 0.54</td>
<td>0</td>
<td>1.25 · 5</td>
<td>0</td>
<td>0.8765</td>
<td>0.92%</td>
</tr>
<tr>
<td>$10^9$</td>
<td>1.5 · 0.112</td>
<td>1.5 · 0.37</td>
<td>1.5 · 0.54</td>
<td>0</td>
<td>1.5 · 5</td>
<td>0</td>
<td>0.8764</td>
<td>0.91%</td>
</tr>
<tr>
<td>$2 \cdot 10^7$</td>
<td>0.112</td>
<td>0.37</td>
<td>0.54</td>
<td>0</td>
<td>5</td>
<td>0</td>
<td>0.9193</td>
<td>0%</td>
</tr>
<tr>
<td>$2 \cdot 10^8$</td>
<td>1.25 · 0.112</td>
<td>1.25 · 0.37</td>
<td>1.25 · 0.54</td>
<td>0</td>
<td>1.25 · 5</td>
<td>0</td>
<td>0.9083</td>
<td>−1.2%</td>
</tr>
<tr>
<td>$2 \cdot 10^9$</td>
<td>1.5 · 0.112</td>
<td>1.5 · 0.37</td>
<td>1.5 · 0.54</td>
<td>0</td>
<td>1.5 · 5</td>
<td>0</td>
<td>0.9046</td>
<td>−1.6%</td>
</tr>
</tbody>
</table>
CHAPTER 7

CONCLUSIONS

The main motivation for the research presented in this thesis is the increased penetration of wind energy into the grid. This change requires development of an adequate framework that could assess the WECS reliability in the face of specified external disturbance, e.g., grid faults and internal component faults. In the past, design for reliability, with respect to external faults, of conventional (synchronous) generators was concerned mainly with the study of three phase-faults on their terminals. Based on the results of such study, the proper winding size was chosen along with the correct protection relay settings. But such an approach is inadequate for WECSs for two reasons. First, the control and operability of WECSs is a very complex issue. A single WECS consists of numerous control loops, whose control strategies may change as the external variables change. In addition, some of those controls are aggregated and can respond to the grid operator commands. Secondly, there are numerous WECS, grid and fault variables that have a large effect on the WECS operating conditions. In this study these “random” variables are distinguished (for reliability assessment purpose) from “deterministic” (constant) variables. This framework was showcased using a detailed model of type C WECSs with corresponding deterministic and random variables. Fault and grid variables essential to reliability measurements were included in the assessment.

The proposed framework allows a quantitative analysis of different WECS designs and control schemes. As presented in Chapter 6, each WECS design and control scheme can be given a measure $R_{\text{wecs}}$ from the range $0 \rightarrow 1$ that will describe its reliability with regard to specified requirements. This reliability assessment allows a comparison of different vendors’ WECS designs, when both designs are tested using the same framework for the same requirements. An analogous study can be done to compare different WECS control schemes within one WECS design.
concept. Within this framework, WECS reliability can also be computed with respect to different grid codes/performance requirements.

This framework can reveal the key parameters that influence overall WECS reliability. As shown in Chapter 6, one of the key parameters can be control gains, rotor circuit resistance or the short-circuit power of the system to which the WECS is connected. A 30% increase of rotor impedance led to 1.82% reliability increase, and doubling short-circuit power gave 5.85% increase. A 25% increase of the active power control gains produces a 0.92% reliability increase. Another advantage of this framework is the ability to discover the significance of key parameters with respect to different WECS and grid characteristics. For example, for the $10^7$ VA system, the 25% and 50% PI gains change produces, respectively, a 0.92% and a 0.91% $R_{wecs}$ increase, while for the $2 \cdot 10^7$ VA system, the same controller gains increase results in $-1.2\%$ and $-1.6\%$ $R_{wecs}$ change. Based on this result, WECS designers using the $10^7$ VA system would look for optimal PI gains in the region between 100% and 150% of the initial gain, while the results for the $2 \cdot 10^7$ VA system suggest that the most reliable point is below 100%. This shows the importance of correctly defining WECS working conditions. And if some parameter value (such as the system short-circuit power) is not known during the design stage, thanks to the presented framework, it can be treated as a random variable input (instead of a deterministic variable or parameter). What will result is a precise and more realistic WECS reliability assessment.
A.1 Case-Study Parameters and Variables Values

WECS, grid and simulation parameters and variables used for the case-study reliability assessment from Chapter 6 are presented in this section.

WECS parameters and variables: nominal power, \( P_n = 2 \cdot 10^6 \) W; nominal wind speed, \( V_{wn} = 14 \) m/s; cut-in wind speed, \( V_{wcutin} = 4 \) m/s; cut-off wind speed, \( V_{wcutoff} = 25 \) m/s; air density, \( \rho = 1.25 \) kg/m\(^3\); \( \omega_{g_{pu}} = 1.2 \); \( \omega_{g_{pu}} = 0.5 \); number of poles, \( P = 4 \); steady-state pitch angle control coefficient, \( K_b = 2.19 \); nominal voltage on WECS terminals, \( V_{weces_{pu}} = 1 \); stator resistance, \( R_s = 0.01 \) p.u.; stator reactance, \( X_s = 0.12 \) p.u.; mutual reactance, \( X_m = 5 \) p.u.; rotor resistance, \( R_r = 0.005 \) p.u., rotor reactance, \( X_r = 0.2 \) p.u., resistance between GSC and WECS grid terminals, \( R_c = 0.0001 \) p.u., reactance between GSC and WECS grid terminals (mainly from smoothing inductor), \( X_c = 0.3 \) p.u.; the dc-link capacitor capacity, \( C = 6 \cdot 10000 \cdot 10^{-6} \) F; generator inertia, \( H_g = 0.7 \) s; turbine inertia, \( H_t = 5 \) s; damping coefficient, \( D = 0.01 \) p.u.; stiffness coefficient, \( K_s = 0.3 \) p.u./el.rad; active power control PI gains: \( k_{p_P} = 0.112 \); \( k_{i_P} = 0.37 \); \( k_{p_I} = 0.54 \); \( k_{i_I} = 0 \); \( k_{p_\omega} = 5 \); \( k_{i_\omega} = 0 \); reactive power control PI gains: \( k_{p_Q} = 0.004 \); \( k_{i_Q} = 0.015 \); \( k_{p_I} = 0.54 \); \( k_{i_I} = 0 \); \( k_{p_V} = k_{p_Q} \); \( k_{i_V} = k_{i_Q} \); grid side converter PI gains: \( k_{p_I} = 0.54 \); \( k_{i_I} = 0 \); \( k_{p_V_{dc}} = k_{p_{I2}} = k_{p_I} \); \( k_{i_V_{dc}} = k_{i_{I2}} = k_{i_I} \); pitch angle control coefficients: \( K_p = 175 \); \( \beta_{max} = 60^\circ \); \( \beta_{min} = 0^\circ \); \( \frac{d\beta}{dt}_{max} = 10^\circ/s \); \( \frac{d\beta}{dt}_{min} = -10^\circ/s \); \( T_{servo} = 0.25 \) s.

Grid parameters and variables: grid frequency \( f = 60 \) Hz; grid pulsation, \( \omega_{e_{rps}} = 2\pi f \); system source voltage, \( V_{sys} = 25 \cdot 10^3 \) V; system source voltage angle, \( V_{sys_{angle}} = 0^\circ \); systems short-circuit power, \( S_{sys_{sc}} = 10^6 \) VA; system impedance ratio, \( \frac{X}{R}_{sys} = 10 \); system source-transformer line parameters:
\[ t_{km} = 10, \ R_1 = 0.1153 \, \Omega/km, \ R_0 = 0.413 \, \Omega/km, \ L_1 = 1.05 \cdot 10^{-3} \, H/km, \]
\[ L_0 = 3.32 \cdot 10^{-3} \, H/km, \ C_1 = 11.33 \cdot 10^{-9} \, F/km, \ C_0 = 5.01 \cdot 10^{-9} \, F/km; \]
transformer parameters: \( P_{nt} = 1.5 \cdot P_n, \ V_t = 575 \, V, \ L_{\text{winding}1 \text{pu}} = 0.025, \)
\[ R_{\text{winding}1 \text{pu}} = L_{\text{winding}1 \text{pu}}/30, \ L_{\text{winding}2 \text{pu}} = 0.025, \]
\[ R_{\text{winding}2 \text{pu}} = L_{\text{winding}2 \text{pu}}/30, \ R_{m \text{ pu}} = 500; \]
Simulation parameters: fault start, \( t_{\text{fault start}} = 0.2; \) fault clearing, \( t_{\text{fault cleared}} = 0.3; \)
base power, \( P_b = P_n; \) base WECS voltage, \( V_b = 575 \, V; \)
base WECS phase-to-ground voltage, \( V_{bph-g} = V_b/\sqrt{3}; \)
base current, \( I_b = P_b/(3V_{bph-g}); \)
base impedance, \( Z_b = V_{bph-g}/I_b; \)
base system voltage, \( V_{sysb} = V_{sys}; \)
simulation step size, \( h = 50 \cdot 10^{-6} \, s; \)
pitch angle control step size, \( T_s = h; \)
PI controllers step size, \( h_{PI} = h. \)

### A.2 Case-Study MATLAB Code

#### A.2.1 Main simulation

```matlab
clear all
clic
n_pdf_Vw=5;
Vw_cut_in=4; %m/s
Vw_cut_off=25; %m/s
s1=(Vw_cut_off-Vw_cut_in)/(2*n_pdf_Vw);
for nn=0:1:(n_pdf_Vw-1)
    VW(nn+1)=Vw_cut_in+s1+nn*s1*2;
end
for nn=0:1:(n_pdf_Vw-1)
    PVW(nn+1)= quad(@rayl,VW(nn+1)-s1,VW(nn+1)+s1);
end
su_n=1;
while abs(err) > 0.00001
    su=0;
    for nn=0:1:(n_pdf_Vw-1)
        PVW(nn+1)=PVW(nn+1)*su_n;
        su=su+PVW(nn+1);
    end
    su_n=2-su;
    err=1-su;
end
```

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figure(2)
bar1=bar(VW,PVW);
set(bar1,'BarWidth',0.1);
n_pdf_q=3;
Q=[0,0.1,0.2];
PQ=[0.6,0.2,0.2];
figure(3)
bar1=bar(Q,PQ);
set(bar1,'BarWidth',0.1);
n_pdf_Vdrop=4;
VDROP=[-0.15,-0.25,-0.4,-0.75];
n_pdf_fault_durat=5;
FAULT_DURAT=[0.0583,0.1333,0.25,0.5,1.5]
IRMAX=zeros(n_pdf_Vw,n_pdf_q,n_pdf_Vdrop,n_pdf_fault_durat);
simul_number=0;
for pP=1:1:n_pdf_Vw
Vw=VW(pP);
Vw_help=Vw;
for ppP=1:1:n_pdf_q
Qs_set=Q(ppP);
Qs_set_help=Qs_set;
for pppP=1:1:n_pdf_Vdrop
Vdrop=VDROP(pppP);
Vdrop=VDROP(pppP);
for ppppP=1:1:n_pdf_fault_durat
fault_durat=FAULT_DURAT(ppppP);
if (fault_durat==1.5),t_stop_sim=2,end
if (fault_durat==0.5),t_stop_sim=1,end
if (fault_durat==0.25),t_stop_sim=0.7,end
if (fault_durat==0.1333),t_stop_sim=0.5,end
if (fault_durat==0.0583),t_stop_sim=0.4,end
clear C C0_f_km C1_f_km D Hg Ht I_dc_cap I_dc_cap2 I_r_abc_max I_wecs_d_0 I_wecs_dq0 I_wecs_dq0_0 I_wecs_q_0 Iabc_B Iabc_B1 Iabc_B2 Iabc_B3 Iabc_B4 Iabc_B6 Ib Icd_0 Icq_0 Idr Idr_0 Ids Ids_0 Iqr Iqr_0 Iqs Iqs_0 Ira Irb Irc J1 J1_0 J2 J2_0 Kb Kp Kt er L0_h_km L0_sys_h L1_h_km L1_sys_h L_s_c_h L_s_c_p_h Lc_h Lm_h Lr_h Ls_h Lw1_pu Lw2_pu P Pb Pc Pc_0 Pe Pn Pn_t Pr Pr_0 Ps Ps_0 Psi_dr Psi_dr_0 Psi_ds Psi_ds_0 Psi_qr Psi_qr_0 Psi_qs Psi_qs_0 Pt Qc Qr_Qr Qs Qs_0 Qt R R0_ohm_km R0_sys R0_sys_ohm R1_ohm_km R1_sys R1_sys_ohm R_inf R_s_c R_s_c_ohm R_s_c_p R_s_c_p_ohm Rc Rc_ohm Rm_pu Rr Rr_ohm Rs Rs_ohm Rw1_pu Rw2_pu Ssys_sc St T_servo Te Te_0 Tm_0_no_corr_pu Tm_0_pu Tm_r_pu Tm_t_b Tm_t_pu Ts V V1 V_dc V_dc_0 Vabc Vabc_B Vabc_B1 Vabc_B2 Vabc_B3 Vabc_B4 Vabc_B6 Vb Vb_ph Vcd_0 Vcq_0 Vdr Vdr_0 Vds Vds_0 Vqr Vqr_0 Vqs Vqs_0 Vsys Vsys_angle Vsys_b Vt Vw_cut_in Vw_cut_off Vw_n
t_start_init=0;
t_stop_init=0.1;
t_start_sim=0;
%t_stop_sim=1;
t_fault_start=0.2;
t_fault_cleared=fault_durat+t_fault_start;
t_start_grid_init=0;
t_stop_grid_init=0.2;
Pn=2e6; %Watts
Vw_n=14; %m/s
Vw_cut_in=4; %m/s
Vw_cut_off=25; %m/s
ro=1.25; %kg/m^3
omega_g_n_pu=1.2;
omega_g_min_pu=0.5;
f=60; %Hz
omega_e_rps=2*pi*f; %rps
P=4;
Kb=2.19;
V1=1;
Vabc=V1;
%base values
Pb=Pn;
Vb=575; %V
Vb_ph_g=Vb/sqrt(3);
Ib=Pb/(3*Vb_ph_g); %A
Zb=Vb_ph_g/Ib; %Ohms
Rs=0.01;
Xs=0.12;
Xm=5;
Rr=0.005;
%Rr=0.0065
Xr=0.2;
%Xr=0.26
Rc=0.0001;
Xc=0.3;
C=6*10000*10^-6; %F
Rs_ohm=Rs*Zb;
Xs_s=Xs*Zb;
Ls_h=Xs_s/omega_e_rps;
Xm_s=Xm*Zb;
Lm_h=Xm_s/omega_e_rps;
Rr_ohm=Rr*Zb;
Xr_s=Xr*Zb;
Lr_h=Xr_s/omega_e_rps;
Rc_ohm=Rc*Zb;
Xc_s=Xc*Zb;
Lc_h=Xc_s/omega_e_rps;
%WECS parameters for SimPower
Z_s_c=(Rs+i*Xs)*(Rc+i*Xc)/(Rs+Rc+i*Xc+i*Xs);
R_s_c=real(Z_s_c);
R_s_c_ohm=R_s_c*Zb;
X_s_c=imag(Z_s_c);
L_s_c_h=X_s_c*Zb/omega_e_rps;
[x]=solve('X_s_c*x^2-(X_s_c^2+R_s_c^2)*x=0');
X_s_c_p=(X_s_c^2+R_s_c^2)/X_s_c;
R_s_c_p=X_s_c_p*X_s_c/R_s_c;
R_s_c_p_ohm=R_s_c_p*Zb;
L_s_c_p_h=X_s_c_p*Zb/omega_e_rps;
%system parameters
Vsys=25e3; %V
Vsys_angle=0; %deg
Vsys_b=Vsys;
%system impedance (positive sequence and negative sequence)
Ssys_sc=10e6; %VA
%Ssys_sc=2*10e6;
X_R_sys=10;
R_inf=1e10;
R1_sys=0.1;
R1_sys_ohm=R1_sys*Vsys^2/Ssys_sc;
X1_sys=1;
L1_sys_h=X1_sys/omega_e_rps*Vsys^2/Ssys_sc;
R0_sys=0.3;
R0_sys_ohm=R0_sys*Vsys^2/Ssys_sc;
X0_sys=3;
L0_sys_h=X0_sys/omega_e_rps*Vsys^2/Ssys_sc;
%system-transformer line parameters
l_km=10; % line length km
R1_ohm_km=0.1153;
R0_ohm_km=0.413;
L1_h_km=1.05e-3;
L0_h_km=3.32e-3;
C1_f_km=11.33e-009;
C0_f_km=5.01e-009;
%transformer parameters
Pn_t=1.5*Pn;
Vt=575; %V
Lw1_pu=0.025;
Rw1_pu=Lw1_pu/30;
Lw2_pu=0.025;
Rw2_pu=Lw2_pu/30;
Rm_pu=500;
%two mass model parameters
% Hg=0.5; %s
% Ht=5; %s
Hg=0.7; %s
Ht=7; %s
Ks=0.3; %pu/el.rad
D=0.01; %pu*s/el.rad
h=50*10^-6; %step size
%active power control
h_pi=h;
kp_act_p=0.112;
ki_act_p=0.37;
kp_act_i=0.54;
ki_act_i=0;
%kp_act_omega=kp_act_i;
%ki_act_omega=ki_act_i;
%kp_act_omega=5;
kp_act_omega=5;
ki_act_omega=0;
%reactive power control
kp_reac_i=0.54;
ki_reac_i=0;
kp_reac_q=0.004;
ki_reac_q=0.015;
kp_reac_v=kp_reac_q;
ki_reac_v=ki_reac_q;
%grid side converter control
kp_gsc_i=0.54;
k_i_gsc_i=0;
kp_gsc_Vdc=kp_gsc_i;
ki_gsc_Vdc=ki_gsc_i;
kp_gsc_i2=kp_gsc_i;
ki_gsc_i2=ki_gsc_i;

% pitch angle control
Kp=175;
% Ts=0.5
Ts=1; % s
T_s=-1;
beta_max=60;
beta_min=0;
dbeta_dt_max=10; % deg/s
dbeta_dt_min=-10; % deg/s
T_servo=0.25; % s

% vector time form of input data
Vw=[t_start_init,Vw;t_stop_init,Vw];
Pn=[t_start_init,Pn;t_stop_init,Pn];
Vw_n=[t_start_init,Vw_n;t_stop_init,Vw_n];
Vw_cut_in=[t_start_init,Vw_cut_in;t_stop_init,Vw_cut_in];
Vw_cut_off=[t_start_init,Vw_cut_off;t_stop_init,Vw_cut_off];
ro=[t_start_init,ro;t_stop_init,ro];
omega_g_n_pu=[t_start_init,omega_g_n_pu;t_stop_init,omega_g_n_pu];
omega_g_min_pu=[t_start_init,omega_g_min_pu;t_stop_init,omega_g_min_pu];
omega_e_rps=[t_start_init,omega_e_rps;t_stop_init,omega_e_rps];
P=[t_start_init,P;t_stop_init,P];
Kb=[t_start_init,Kb;t_stop_init,Kb];
Qs_set=[t_start_init,Qs_set;t_stop_init,Qs_set];
V1=[t_start_init,V1;t_stop_init,V1];
Rs=[t_start_init,Rs;t_stop_init,Rs];
Rr=[t_start_init,Rr;t_stop_init,Rr];
Xs=[t_start_init,Xs;t_stop_init,Xs];
Xr=[t_start_init,Xr;t_stop_init,Xr];
Xm=[t_start_init,Xm;t_stop_init,Xm];
C=[t_start_init,C;t_stop_init,C];
Rc=[t_start_init,Rc;t_stop_init,Rc];
Xc=[t_start_init,Xc;t_stop_init,Xc];
Hg=[t_start_init,Hg;t_stop_init,Hg];
Ht=[t_start_init,Ht;t_stop_init,Ht];
Ks=[t_start_init,Ks;t_stop_init,Ks];
D=[t_start_init,D;t_stop_init,D];

% simulink
sim('dfig5m_init')
%angle and magnitude corrections
for nn=0:1:20
    sim('grid_part_init')
    if(nn==0)
        Vsys_angle=-1.1*angle_corr2;
    end
    Vsys=Vsys*(2-magn_corr);
    Vsys_angle=Vsys_angle+nn*abs(angle_corr2)/20;
end
sim('dfig5m_sim')
I_r_abc_max=max(max(max(abs(Ira)),max(abs(Irb))),max(abs(Irc)));
IRMAX(ppP,pppP,ppppP)=I_r_abc_max;
clear Vw Qs_set
Vw=Vw_help;
Qs_set=Qs_set_help;
simul_number=simul_number+1;
X_simul_number=[0,1,2];
Y_simul_number=[0,simul_number,I_r_abc_max];
bar(X_simul_number,Y_simul_number);
end
end
end
end

A.2.2 Reliability measure computation

n_pdf_Vw=5;
n_pdf_q=3;
n_pdf_Vdrop=4;
n_pdf_fault_durat=5;
P_VW_Q_VDROP_FAULT_DURAT=zeros(n_pdf_Vw,n_pdf_q,n_pdf_Vdrop,n_pdf_fault_durat);
for pPp=1:1:n_pdf_Vw
    for ppPp=1:1:n_pdf_q
        P_VW_Q_VDROP_FAULT_DURAT(pPp,ppPp,1,1)=11.45/27.13*PQ(ppPp)*PVW(pPp)
        P_VW_Q_VDROP_FAULT_DURAT(pPp,ppPp,1,2)=2.4/27.13*PQ(ppPp)*PVW(pPp)
        P_VW_Q_VDROP_FAULT_DURAT(pPp,ppPp,1,3)=1.25/27.13*PQ(ppPp)*PVW(pPp)
        P_VW_Q_VDROP_FAULT_DURAT(pPp,ppPp,1,4)=1.35/27.13*PQ(ppPp)*PVW(pPp)
        P_VW_Q_VDROP_FAULT_DURAT(pPp,ppPp,1,5)=0.2/27.13*PQ(ppPp)*PVW(pPp)
        P_VW_Q_VDROP_FAULT_DURAT(pPp,ppPp,2,1)=3.2/27.13*PQ(ppPp)*PVW(pPp)
        P_VW_Q_VDROP_FAULT_DURAT(pPp,ppPp,2,2)=1.05/27.13*PQ(ppPp)*PVW(pPp)
    end
end
\[
P_{VW\_Q\_VDROP\_FAULT\_DURAT}(pp_{Pp}, pp_{Pp}, 2, 3) = \frac{0.5}{27.13} PQ(pp_{Pp}) PVW(pp_{Pp})
\]
\[
P_{VW\_Q\_VDROP\_FAULT\_DURAT}(pp_{Pp}, pp_{Pp}, 2, 4) = \frac{0.35}{27.13} PQ(pp_{Pp}) PVW(pp_{Pp})
\]
\[
P_{VW\_Q\_VDROP\_FAULT\_DURAT}(pp_{Pp}, pp_{Pp}, 2, 5) = \frac{0.05}{27.13} PQ(pp_{Pp}) PVW(pp_{Pp})
\]
\[
P_{VW\_Q\_VDROP\_FAULT\_DURAT}(pp_{Pp}, pp_{Pp}, 3, 1) = \frac{2.05}{27.13} PQ(pp_{Pp}) PVW(pp_{Pp})
\]
\[
P_{VW\_Q\_VDROP\_FAULT\_DURAT}(pp_{Pp}, pp_{Pp}, 3, 2) = \frac{0.6}{27.13} PQ(pp_{Pp}) PVW(pp_{Pp})
\]
\[
P_{VW\_Q\_VDROP\_FAULT\_DURAT}(pp_{Pp}, pp_{Pp}, 3, 3) = \frac{0.4}{27.13} PQ(pp_{Pp}) PVW(pp_{Pp})
\]
\[
P_{VW\_Q\_VDROP\_FAULT\_DURAT}(pp_{Pp}, pp_{Pp}, 3, 4) = \frac{0.2}{27.13} PQ(pp_{Pp}) PVW(pp_{Pp})
\]
\[
P_{VW\_Q\_VDROP\_FAULT\_DURAT}(pp_{Pp}, pp_{Pp}, 3, 5) = \frac{0.1}{27.13} PQ(pp_{Pp}) PVW(pp_{Pp})
\]
\[
P_{VW\_Q\_VDROP\_FAULT\_DURAT}(pp_{Pp}, pp_{Pp}, 4, 1) = \frac{0.6}{27.13} PQ(pp_{Pp}) PVW(pp_{Pp})
\]
\[
P_{VW\_Q\_VDROP\_FAULT\_DURAT}(pp_{Pp}, pp_{Pp}, 4, 2) = \frac{0.16}{27.13} PQ(pp_{Pp}) PVW(pp_{Pp})
\]
\[
P_{VW\_Q\_VDROP\_FAULT\_DURAT}(pp_{Pp}, pp_{Pp}, 4, 3) = \frac{0.35}{27.13} PQ(pp_{Pp}) PVW(pp_{Pp})
\]
\[
P_{VW\_Q\_VDROP\_FAULT\_DURAT}(pp_{Pp}, pp_{Pp}, 4, 4) = \frac{0.56}{27.13} PQ(pp_{Pp}) PVW(pp_{Pp})
\]
\[
P_{VW\_Q\_VDROP\_FAULT\_DURAT}(pp_{Pp}, pp_{Pp}, 4, 5) = \frac{0.31}{27.13} PQ(pp_{Pp}) PVW(pp_{Pp})
\]

\[
\text{sum\_tot}=0;
\]
\[
\text{for } pP_{p}=1:1:n\_pdf\_Vw
\]
\[
\text{for } ppP_{p}=1:1:n\_pdf\_q
\]
\[
\text{for } pppP_{p}=1:1:n\_pdf\_Vdrop
\]
\[
\text{for } ppppP_{p}=1:1:n\_pdf\_fault\_durat
\]
\[
\text{sum\_tot}=\text{sum\_tot}+P_{VW\_Q\_VDROP\_FAULT\_DURAT}(pp_{Pp}, pp_{Pp}, pppP_{p}, ppppP_{p})
\]
\end{verbatim}

\[
\text{end}
\end{verbatim}

\[
\text{end}
\end{verbatim}

\[
\text{end}
\end{verbatim}

\[
\text{end}
\end{verbatim}

\[
\text{reliab\_sum}=0;
\]
\[
\text{iter}=0;
\]
\[
\text{for } pP_{p}=1:1:n\_pdf\_Vw
\]
\[
\text{for } ppP_{p}=1:1:n\_pdf\_q
\]
\[
\text{for } pppP_{p}=1:1:n\_pdf\_Vdrop
\]
\[
\text{for } ppppP_{p}=1:1:n\_pdf\_fault\_durat
\]
\[
\text{if } (\text{IRMAX}(pP_{p}, pp_{Pp}, pppP_{p}, ppppP_{p})>=1.5)
\]
\[
\text{reliab\_sum}=\text{reliab\_sum}+P_{VW\_Q\_VDROP\_FAULT\_DURAT}(pp_{Pp}, pp_{Pp}, pppP_{p}, ppppP_{p})
\]
\[
\text{iter}=\text{iter}+1;
\]
\end{verbatim}

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A.2.3 Embedded M-file *power curves* from the *initialization* model

function \([Pe,s,Tm_0_pu,omega_g_0_rps,beta_0,omega_t_b_rps,R,Tm_t_b]=\)
\(\text{power\_curves}(Vw,Pn,Vw_n,Vw\_cut\_in,Vw\_cut\_off,ro,P,omega\_g\_n_pu,omega\_g\_min_pu,omega\_e\_rps,Kb)\)
\([Pe,s,Tm_0_pu,omega\_g\_0\_rps,beta_0,omega\_t\_b\_rps,R,Tm\_t\_b]=\text{create2}(Vw,Pn,Vw_n,Vw\_cut\_in,Vw\_cut\_off,ro,P,omega\_g\_n_pu,omega\_g\_min_pu,omega\_e\_rps,Kb)\);
function \([Pe,s,Tm_0_pu,omega\_g\_0\_rps,beta_0,omega\_t\_b\_rps,R,Tm\_t\_b]=\text{create2} (Vw,Pn,Vw_n,Vw\_cut\_in,Vw\_cut\_off,ro,P,omega\_g\_n_pu,omega\_g\_min_pu,omega\_e\_rps,Kb)\)
eml.extrinsic('if','fzero','while');
c1=0.73;
c2=151;
c3=0.58;
c4=0.002;
c5=2.14;
c6=13.2;
c7=18.4;
c8=-0.02;
c9=-0.003;

```
%\%Cp(lambdai,beta=0), computing Cp\_max and lambda\_opt by taking dCp/dlambda
%pd\_Cp\_pd\_lambdai=-c1*c2./(lambdai.^2).*exp(-c7./lambdai)
+c1*(c2./lambdai-c3*beta-c4*beta^c5-c6).*exp(-c7./lambdai)
./(lambdai.^2).*exp(-c7./lambdai)
%x=fzero(''-0.73*151/(x^2)*exp(-18.4/x)+0.73*(151/x-13.2)*18.4/(x^2)*exp(-18.4/x)',10,'TolFun',0.001,'ToX',0.001);
beta=0;
X=[2:.0001:15];
lambdai\_X=((1./(X+c8*beta))-(c9/(beta^3+1))).^-1;
Cp\_X=c1*(c2./lambdai\_X-c3*beta-c4*beta^c5-c6).*exp(-c7./lambdai\_X);
Cp\_max=max(Cp\_X);
i=1;
lambdai=10;
eps=0.0001
while (i<50)
f=c1*(c2/lambdai-c3*beta-c4*beta^c5-c6)*exp(-c7/lambdai)-Cp\_max;
df\_lambdai=-c1*c2/(lambdai^2)*exp(-c7/lambdai)
+c1*(c2/lambdai-c6)*c7/(lambdai^2)*exp(-c7/lambdai);
Xnew=lambdai-df\_lambdai^-1*f;
lambdai=Xnew(1);
i=i+1;
```
if (abs(f)<eps)
i=55;
end
if(i==50)
itEr=1;
end
end
lambda_opt=lambdai/(l+c9*lambdai);

% computing radius based on Pr,Vw_n,Cp_max this step is needed
% as Cp curves are general
R=sqrt(Pn/(0.5*ro*pi*Cp_max*Vw_n^3));

% omega_r is the angular speed of rotation of the rotor (gener. side)
% omega_g is the angular speed of rotation of the generator electrical field
omega_g_b_rps=omega_e_rps;
omega_g=omega_g_b_rps*2/P;
omega_r_n_rps=omega_g_n*omega_g_b_rps;
omega_r_min_rps=omega_g_min*omega_g_b_rps;

% omega_t is the angular speed of rotation of the turbine
% (shaft connected with blades)
omega_t_n_rps=lambda_opt*Vw_n/R;

% gearbox ratio
K=omega_r_n_rps/omega_t_n_rps;
omega_t_b_rps=omega_r_b_rps/K;

% relation between P and omega_opt below Vw_n
K_opt=0.5*ro*pi*R^5*P_max/(lambda_opt^3)/Pn*(omega_t_b_rps^3);

% computation of V_opt_min
V_opt_min=(omega_g_min*omega_t_b_rps)*R/lambda_opt;

% turbine base torque
Tm_r_b=Pn/omega_r_b_rps; %Nm
Tm_t_b=Pn/omega_t_b_rps; %Nm
if (Vw<Vw_cut_in)
Pe=0,s=1,omega_g_0_rps=0,Tm_0_pu=0;beta_0=0;
else if (Vw<V_opt_min)
beta=0;
lambda_V=(omega_g_min*omega_t_b_rps)*R/Vw;
lambdai_V=((1/(lambda_V+c8*beta))-(c9/(beta^3+1))^^-1;
Cp_V=c1*(c2/lambdai_V-c4*beta^c5-c6)*exp(-c7/lambdai_V);
P_e=(0.5*ro*pi*R^2*P*Vw^3)/Pn;
omega_g_0_rps=omega_g_min*omega_g_b_rps;
s=(omega_e_rps-omega_g_min*omega_g_b_rps)/omega_g_0;
beta_0=0;
Tm_0_pu=((0.5*ro*pi*R^2*P*Vw^3)/(omega_g_0_rps*2/P))/Tm_r_b
else if (Vw<=Vw_n)
\[ Pe = \frac{(0.5 \cdot \rho \cdot \pi \cdot R^2 \cdot Cp_{\text{max}} \cdot V_w^3)}{P_n}; \]
\[ \omega_{g_0 \ rps} = \lambda_{\text{opt}} \cdot V_w \cdot R / \omega_{\text{t \ b \ rps}} \cdot \omega_{g_b \ rps}; \]
\[ s = \frac{(\omega_{e \ rps} - \omega_{g_0 \ rps})}{\omega_{e \ rps}}; \]
\[ \beta_0 = 0; \]
\[ Tm_{0 \ pu} = \frac{(0.5 \cdot \rho \cdot \pi \cdot R^2 \cdot Cp_{\text{max}} \cdot V_w^3) / (\omega_{g_0 \ rps} \cdot 2 / P)}{Tm_{r \ b}}; \]
\[ \text{else if} (V_w < V_w_{\text{cut \ off}}) \]
\[ \omega_{g_0 \ rps} = \omega_{g_n \ pu} \cdot \omega_{g_b \ rps}; \]
\[ \beta = K_b \cdot (V_w - V_w_{\text{n}}); \]
\[ \lambda_{V} = \omega_{t \ n \ rps} \cdot R / V_w; \]
\[ \lambda_{\text{dai \ V}} = \frac{(1/(\lambda_{V} + c8 \cdot \beta)) - (c9/(\beta^3 + 1))^{-1}}{\lambda_{V} + c8 \cdot \beta}; \]
\[ C_{p \ V} = c1 \cdot (c2/(\lambda_{\text{dai \ V}} - c3 \cdot \beta \cdot c4 \cdot \beta \cdot c5 \cdot c6)^{-1} \cdot \exp(-c7/\lambda_{\text{dai \ V}}); \]
\[ Pe = \frac{(0.5 \cdot \rho \cdot \pi \cdot R^2 \cdot C_{p \ V} \cdot V_w^3)}{P_n}; \]
\[ \beta_0 = \beta; \]
\[ s = \frac{(\omega_{e \ rps} - \omega_{g_0 \ rps})}{\omega_{e \ rps}}; \]
\[ Tm_{0 \ pu} = \frac{(0.5 \cdot \rho \cdot \pi \cdot R^2 \cdot C_{p \ V} \cdot V_w^3) / (\omega_{g_0 \ rps} \cdot 2 / P)}{Tm_{r \ b}}; \]
\[ \text{else} \]
\[ Pe = 0, s = 1, \omega_{g_0 \ rps} = 0, Tm_{0 \ pu} = 0; \beta_0 = 90; \]
\[ \text{end} \]
\[ \text{end} \]
\[ \text{end} \]

A.2.4 Embedded M-file grid side converter and dc link initialization from the initialization model

function \[ [Vcd_0, Vcq_0, V_{dc \ 0}, Pc_0, Icd_0, Icq_0, J1_0, J2_0] = \]
\[ \text{initialization2(Pr_0, Vds_0, Vqs_0, Rc, Xc)} \] \#eml
\[ [Vcd_0, Vcq_0, V_{dc \ 0}, Pc_0, Icd_0, Icq_0, J1_0, J2_0] = \]
\[ \text{create3(Pr_0, Vds_0, Vqs_0, Rc, Xc)}; \]
function \[ [Vcd_0, Vcq_0, V_{dc \ 0}, Pc_0, Icd_0, Icq_0, J1_0, J2_0] = \]
\[ \text{create3(Pr_0, Vds_0, Vqs_0, Rc, Xc)}; \]
\[ \text{eml.extrinsic('if')} \];
\[ \text{Pc}_0 = \text{Pr}_0; \]
\[ \text{Vs}_0 = \sqrt{V_{ds \ 0} \cdot V_{qs \ 0} + V_{qs \ 0} \cdot V_{qs \ 0}}; \]
\[ \text{pm} = 1; \]
\[ \% \text{Pc}_0 = \text{abs}(\text{Sr}_0); \]
\[ \% \text{ang} = \text{angle}(\text{Sr}_0) / \pi \times 180; \]
\[ \% \text{if ( (ang <= -90) \&\& (ang >= -180) ) \| ( (ang >= 90) \&\& (ang <= 180) ) ) \]
\[ \% \quad \text{Pc}_0 = -\text{Pc}_0 \]
\[ \% \text{end} \]
A.2.5 Embedded M-file *rotor voltage initialization* from the *initialization* model

```matlab
function [V2, alfa, iter_er] = initialization(Rs, Rr, Xs, Xr, Xm, Pe, Qs, s, V1, V2_0, alfa_0) %#eml
    [V2, alfa, iter_er] = create(Rs, Rr, Xs, Xr, Xm, Pe, Qs, s, V1, V2_0, alfa_0);
end

function [V2, alfa, iter_er] = create(inp_Rs, inp_Rr, inp_Xs, inp_Xr, inp_Xm, inp_Pe, inp_Qs, inp_s, inp_V1, inp_V2_0, inp_alfa_0)
    eml.extrinsic('while', 'if');
    Rs = inp_Rs;
    Xs = inp_Xs;
    Xm = inp_Xm;
    Rr = inp_Rr;
    Xr = inp_Xr;
    Peset = inp_Pe;
    Qsset = inp_Qs;
    %Qrset = 0;
    s = inp_s;
    V1 = inp_V1;
    C1 = Rs*Rr/s - (Xs*Xr+Xm*Xs+Xr*Xm);
    C2 = Rs*Xr+Rr*Xs/s+Xm*Rs+Rr*Xm/s;
    C3 = C1*C1+C2*C2;
    V2 = inp_V2_0;
    alfa = inp_alfa_0;
    %V2 = 0.1;
    %alfa = 200/360*2*pi;
    eps = 0.001;
    i = 1;
    iter_er = 0;
    while (i<50)
        X = [V2; alfa];
    end
```

\[
\begin{align*}
I_{cd,0} &= \frac{P_c}{V_{ds,0}+V_{qs,0}V_{qs,0}/V_{ds,0}}; \\
I_{cq,0} &= \frac{V_{qs,0}I_{cd,0}}{V_{ds,0}}; \\
I_{c,0} &= I_{cd,0} + \text{i}I_{cq,0}; \\
V_{dc,0} &= \frac{V_s}{0.6124/\mu m}; \\
J_{1,0} &= \frac{P_r}{V_{dc,0}}; \\
J_{2,0} &= \frac{P_c}{V_{dc,0}}; \\
V_{c,0} &= I_{c,0}(R_c+\text{i}X_c)+V_s; \\
V_{cd,0} &= \text{real}(V_{c,0}); \\
V_{cq,0} &= \text{imag}(V_{c,0});
\end{align*}
\]
\[ f_1 = -(V_1 V_1/C_3 (R_s R_r R_r/s/s + R_s (X_r + X_m)^2 + X_m X_m R_r/s) + V_1 V_2 X_m/C_3/s (C_1 \sin(\alpha) - C_2 \cos(\alpha))) - (V_2 V_2/C_3/s (R_s R_s R_r/s + X_s (X_s + X_m) R_r/s + X_m (R_s X_m + R_r/s (X_s + X_m))) - V_1 V_2 C_3 X_m (C_1 \sin(\alpha) + C_2 \cos(\alpha))) - P_{e_{set}}; \]
\[ f_2 = -(V_1 V_1/C_3 ((X_r + X_m) (X_s X_r + X_m (X_s + X_r)) + R_r R_r/s/s (X_s + X_m)) + V_1 V_2/C_3/s X_m (C_1 \cos(\alpha) + C_2 \sin(\alpha))) - Q_{s_{set}}; \]
\[ f = [f_1; f_2]; \]
\[ df_1_dV_2 = -V_1 X_m/C_3/s (C_1 \sin(\alpha) - C_2 \cos(\alpha)) - 2 V_2/C_3/s (R_s R_s R_r/s + X_s (X_s + X_m) R_r/s + X_m (R_s X_m + R_r/s (X_s + X_m))) + V_1/C_3 X_m (C_1 \sin(\alpha) + C_2 \cos(\alpha)); \]
\[ df_1_dalpha = -V_1 V_2 X_m/C_3/s (C_1 \cos(\alpha) + C_2 \sin(\alpha)); \]
\[ df_2_dV_2 = -V_1/C_3/s X_m (C_1 \cos(\alpha) + C_2 \sin(\alpha)); \]
\[ df_2_dalpha = -V_1 V_2/C_3/s X_m (-C_1 \sin(\alpha) + C_2 \cos(\alpha)); \]
\[ J = [df_1_dV_2, df_1_dalpha; df_2_dV_2, df_2_dalpha]; \]
\[ X_{\text{new}} = X - \text{inv}(J) * f; \]
\[ V_2 = X_{\text{new}}(1); \]
\[ \alpha = X_{\text{new}}(2); \]
\[ i = i + 1; \]
\[ \text{if (abs}(f_1) < \text{eps} \& \& \text{abs}(f_2) < \text{eps}) \]
\[ i = 55; \]
\[ \text{end} \]
\[ \text{if (i = 50)} \]
\[ \text{iter}_{\text{err}} = 1; \]
\[ \text{end} \]
\[ \text{end} \]

A.2.6 Embedded M-file *power curves2* from the *dynamic* model

```matlab
function Tm_pu=power_curves2(beta_deg,Vw,omega_t_pu,omega_t_b_rps,R,Tm_t_b,P,ro) %#eml
[Tm_pu]=create4(beta_deg,Vw,omega_t_pu,omega_t_b_rps,R,Tm_t_b,P,ro);
function [Tm_pu]=create4(beta_deg,Vw,omega_t_pu,omega_t_b_rps,R,Tm_t_b,P,ro)
eml.extrinsic('if');
c1=0.73;
c2=151;
c3=0.58;
c4=0.002;
c5=2.14;
c6=13.2;
```

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c7 = 18.4;
c8 = -0.02;
c9 = -0.003;

\[ \omega_{t_{\text{rps}}} = (\omega_{t_{\text{pu}}} \omega_{t_{\text{b{rps}}}}) \]

\[ \lambda = (\omega_{t_{\text{rps}}}) R / V_w; \]

\[ \lambda_i = \left( \frac{1}{\lambda + c8 \beta_{\text{deg}}} \right) - \left( \frac{c9}{\beta_{\text{deg}}^3 + 1} \right)^{-1}; \]

\[ C_p = c1 \left( \frac{c2}{\lambda_i} - c3 \beta_{\text{deg}} - c4 \beta_{\text{deg}}^c5 - c6 \right) \exp \left( -\frac{c7}{\lambda_i} \right); \]

\[ T_{m_{\text{pu}}} = \left( \frac{0.5 \rho \pi R^2 C_p V_w^3}{\omega_{t_{\text{rps}}}} \right) / T_{m_{\text{t_b}}}; \]
APPENDIX B

RELIABILITY ASSESSMENT MODELS

B.1 Initialization Stage Model

Figure B.1 presents the initialization stage model. The steady-state values computed in the initialization model serve as inputs to the dynamic model. Both models were created in Simulink.

B.2 Dynamic Simulation Model

The Figure B.2 presents the dynamic simulation model divided into subsections. Each subsection is presented, respectively, in Fig. B.3-Fig. B.7.
Figure B.1: Initialization stage model.
Figure B.2: Dynamic simulation model divided into subsections.
Figure B.3: Submodel 1.
Figure B.5: Submodel 3.
Figure B.6: Submodel 4.
Figure B.7: Submodel 5.
REFERENCES


