Stability and control of wind farms in power systems

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Stability and Control of Wind Farms in Power Systems

Clemens Jauch
Abstract (max. 2000 char.): The Ph.D. project ‘Stability and Control of Wind Farms in Power Systems’ deals with some selected problems related to wind power in power systems. With increasing wind power penetration, wind turbines substitute the power production of conventional power plants. Therefore, wind turbines also have to take over the power system stabilisation and control tasks, that were traditionally carried out by conventional power plants. Out of the many aspects related to this problem, this project focuses on transient fault ride-through and power system stabilisation. The selection of turbine types considered in this project is limited to active-stall turbines and variable speed, variable pitch turbines with gearboxes and full-scale converter-connected synchronous generators.

As a basis for the project, a study into the state of the art is conducted at the beginning of the project. Grid connection requirements that were in force, or published as drafts, at the time, and scientific literature related to the topic, are studied.

The project is based on simulations of wind turbines in a power system simulations tool. Some of the models used in this project were readily available prior to the project; the development of others is part of the project. The most extensive modelling work deals with the design of the electrical part of the variable speed turbine and its controls.

To simulate realistic grid operation the wind turbine models are connected to an aggregated model of the Nordic power system. For that purpose the Nordic power system model, which was available prior to the project, is extended with a realistic feeder configuration.

It is commonly demanded from modern wind turbines, that they must not disconnect in case of transient faults. Therefore, controllers are designed that enable the two turbine types to ride through transient faults. With these transient fault controllers the wind turbines can stay connected to the grid, such that their generation capacity is sustained, and normal grid operation can resume, after the fault is cleared.

Transient faults in the transmission system often cause power system oscillations. To further support the grid, a situation is assumed, where in future, wind turbines will be required to contribute to the damping of these power system oscillations. Power system oscillations are counteracted with a controlled injection of oscillating active power.

With an active-stall turbine oscillating power injection can only be realised by controlling the pitch angle. Hence the power system stabiliser of an active-stall turbine is a pitch angle controller. Two different approaches are chosen for designing such a power system stabiliser: a conventional PID controller, and a fuzzy logic controller.

For a variable speed turbine power system stabilisation is an easier task, as it varies its electrical power with power electronics. Hence, large and rapid power variations are easily possible. The negative side effect of ambitious power system stabilisation with variable speed turbines is torsional drive train oscillations. These drive train oscillations are addressed specifically, so the turbine stays stable when it performs power system stabilisation.

It is concluded that the controllers designed in this project enable active-stall turbines, and variable speed turbines with full-scale converter-connected synchronous generators, to support the grid in case of transient events.
Abstract

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It is concluded that the controllers designed in this project enable active-stall turbines, and variable speed turbines with full-scale converter-connected synchronous generators, to support the grid in case of transient events.
**Dansk Resumé**


Som basis for projektet udføres der et litteraturstudie. Nettillutningsbetingelser for vindmøller, såvel som videnskabelig litteratur, der er relateret til emnet, er studeret.


For at kunne simulere vindmølledrift realistisk, er det nødvendigt at have en realistisk el-systemmodel. Derfor er der valgt en model af det Nordiske el-system. Modellen er udvidet på en måde, der tillader at introducere vindkraft i systemet på en realistisk måde.

Efterhånden er det et almindeligt krav, at vindmøller skal være i stand til at kunne fortsætte driften under og efter en transient netfejl. Derfor er der udviklet nogle regulatorer, der gør, at de to betrægtede mølletyper er i stand til dette.

På transmissionssystemniveauet fører en transient fejl ofte til systemsvingninger. Derfor antages en situation, hvor det kræves af vindmøller, at de kan bidrage til dæmpningen af disse svingninger. El-systemsvingninger kan modvirkes og dermed dæmpes ved at føde en oscillerede aktiv effekt ind i systemet.

For en variabelhastighedsmølle er systemstabilisering en meget nemmere opgave, fordi den styrer den aktive effekt med konverteren. Derfor er store og hurtige effektvariationer nemme at realisere. Ulempen ved det er, at møllen så bliver udsat for torsionssvingninger. Disse svingninger dæmpes dog aktivt, sådan at møllen forbliver i stabil drift, og at den kan udføre systemstabilisering.

Konklusionen er, at de regulatorer, der er udviklet i løbet af projektet, gør active-stall vindmøller og variabelhastighedsmøller med gearkasser og synkrongeneratorer bag fuldskalakonvertere, klar til at støtte el-systemet, hvis der opstår en transient fejl i nettet.
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This Ph.D. project has been generously funded by Risø National Laboratory. Risø provided me with everything that was necessary for carrying out this work: the workplace, the work environment, the simulation models, the software and all the other resources, without which I would not have been able to complete this project.

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List of Publications

This thesis is based on the work contained in the following, published, or submitted peer-reviewed journal articles. These articles were written during the period of this Ph.D. project. In this thesis the problem definition, which is the premise of the project, the methodology, the single steps leading to the solutions of the problems, and finally the results are presented in a brief and self-contained manner. Hence reading this thesis provides the reader with the most important information necessary to comprehend the project and its results. For more details references to the articles are placed in the text in the style of e.g. ‘Publication 1’. The articles, i.e. ‘Publication 1’ to ‘Publication 8’ are listed below and can be found in the appendix of this thesis.

Publication 1

Publication 2

Publication 3

Publication 4
Publication 5
Jauch, C., Cronin, T., Sørensen, P., and Bak-Jensen, B. *A Fuzzy Logic Pitch Angle Controller for Power System Stabilisation*. Wind Energy, accepted for publication, 2006

Publication 6

Publication 7

Publication 8
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1 Introduction

In many countries of the world wind power expands, and covers a steadily increasing part of these countries’ power demand. From an environmental point of view this is a favourable development, but there are some technical problems that need to be addressed. Growing wind power has impacts on the power systems into which the wind turbines feed their power. Increasing wind power penetration in a power system means, that wind turbines substitute the conventional power plants that traditionally control and stabilise the power system.

Conventional power plants comprise synchronous generators, which are driven by steam, gas or running water turbines. Their characteristics and their controllability, of both the generator and the prime movers, are well understood and facilitated to their full potential. With such conventional power plants the voltage and the frequency of large interconnected AC power systems, can be controlled and held stable, in steady state, as well as in transient operating conditions. A control task of prime importance is the re-establishing of stable grid conditions after a transient fault, i.e. recovering the grid voltage and damping power system oscillations caused by the fault. Power plants with synchronous generators and conventional prime movers are very suitable for this task.

As wind power penetration in power systems increases, and hence more and more conventional power plants are replaced, the respective power system operators are concerned about the stability and reliability of their power systems. Therefore, more and more power system operators revise their grid connection requirements, and issue grid connection requirements specifically made for wind turbines and wind farms. Until recently, wind turbines were treated by and large as embedded generators, which were not to contribute to power system control. Hence wind turbines were required not to actively attempt to control voltage or frequency. In addition, wind turbines were required to disconnect from the grid when abnormal operating conditions occurred. If, however, wind power substitutes conventional power plants, it also has to take over the power system control and stabilisation tasks, which the substituted conventional power plants were carrying out.
One of these control tasks is to ride through transient disturbances in power systems. This means that generation must not be lost due to temporary excursions in voltage or frequency.

An AC power system is a complex system, which is vulnerable to disturbances. When the voltage or the frequency deviates considerably from its rated operating point, the system might break down, unless the parts of the system, which are the cause of the problem, are disconnected. Voltage and frequency need to be monitored carefully, and controlled accurately at any time, to prevent contingencies with severe consequences.

A transient short circuit fault is a very common disturbance in a power system. It suppresses the grid voltage, and upsets the rotating machines in the vicinity of the fault, causing the speeds of these machines, and the power flows in the network to oscillate. Such sub-synchronous system oscillations have to be damped, to avoid that the system becomes unstable. Traditionally such oscillations are damped by conventional power plants with synchronous generators, which are equipped with power system stabilisers.

Hence, with increasing wind power penetration wind turbines are getting involved in the task of controlling voltage and frequency in steady state as well as transient operation. Although there is a host of aspects related to this problem, in this project the focus is limited to the following:

- **Transient fault ride-through:** Wind turbines have to be able to ride through transient voltage dips. When the voltage at the terminals of the wind turbine gets suppressed, by e.g. a transient short-circuit, the turbine must not disconnect, and must resume operation as soon as the voltage has recovered.
  
  The following aspects are considered:

  o Voltage recovery at the wind turbine terminals
  o Reactive power demand of the wind turbine
  o Active power behaviour of the wind turbine after the fault is cleared
  o Prevention of excessive speed excursions of the wind turbine generator
  o Damping of torsional drive train oscillations caused by the fault.

- **Power system stabilisation:** Wind turbines have to be able to dampen power system oscillations, which are caused by e.g. transient faults or switching
events. Power system oscillations caused by a transient fault in the vicinity of a wind turbine is the worst case scenario, as the wind turbine has to ride through the fault, before it can contribute to power system stabilisation. In this project the following aspects are considered:

- Transition from transient fault ride-through to power system stabilisation operation
- Controlled oscillating active power production to counteract power system oscillations
- Optimal control of the relatively slow pitch system
- Damping of drive train oscillations caused by oscillating power extraction
- Evaluation of the impact of wind turbine control on the power system oscillations.

The wind turbine types considered are active-stall turbines and variable speed, variable pitch turbines. The variable speed, variable pitch turbine is one with a conventional drive train, i.e. a gearbox, and a full-scale converter-connected synchronous generator. Although the majority of variable speed turbines operate with doubly fed induction generators, a full-scale converter-connected synchronous generator turbine with gearbox is chosen, as this type currently gains relevance on the market, and as much research has been carried out on doubly fed induction generator turbines already [1,2,3].

The project is based on simulations in the power system simulation tool PowerFactory from DIgSILENT. Different wind turbine controllers and control strategies are developed to enable the two turbine types to ride through transient faults, and to perform power system stabilisation. The controllers developed are of different types, depending on what best suits the control problem at hand. A realistic power system model allows simulating different transient fault situations, and assessing the mutual impacts between the power system and the wind turbines.
2 State of the Art

In this chapter the basis for the project is established. First it is investigated what power system operators require from wind turbines in order to connect to their grids. These requirements are documented in grid connection requirements (GCR), which are issued by the power system operators. The GCR that are already in force constitute a state of the art of the current wind turbine technology. All wind turbines that are to connect to a power system have to comply with the GCR of the respective power system operator.

Further a literature study investigates what other research work has been carried out on this topic. Finally, from the GCR and the literature studied, it is concluded what work has been done in this project.

2.1 Grid Connection Requirements

2.1.1 Introduction

In the past there was usually no wind power connected to the power system, or the level of wind power penetration was extremely low compared to the power production from conventional power plants. Therefore, GCR for wind turbines or wind farms were originally not necessary. As wind power started to be developed more actively at the end of the 1980s, network companies that faced increasing numbers of wind turbines in their systems elaborated their own connection rules. During the 1990s, those connection rules were harmonized on national levels, e.g. in Germany and Denmark. This harmonization process often involved national network associations, as well as national wind energy associations, which represented the interests of wind turbine manufacturers, as well as wind farm developers and owners.

While other authors, like e.g. Santjer and Klosse [4] have analysed single GCR, here a comparison of different relevant GCR is conducted.

Since GCR are subject to frequent revision, it is difficult to make a comparison that is always up to date. Hence in this thesis the state of GCR in force, or published as proposals, in the beginning of 2004, i.e. the time when this study was carried out, is considered. Changes that happened in the meantime are not taken into account. It has
to be noted that it is not the intention of this comparison to present a status of current GCR. It has to be acknowledged that the GCR discussed in this thesis are outdated at the time this thesis is written (spring 2006). The comparison presented in this thesis is relevant nonetheless, as it provided the basis for this project.

In this thesis GCR of several countries which are proactively meeting the challenge of considerable wind power penetration are analysed. The countries considered are Denmark [5,6], Germany [7], Ireland [8], Sweden [9] and Scotland [10]. For the sake of comprehensibility the selection of countries is not complete. Equally, the selection of power system operators in the respective countries is not complete either.

As discussed above, this thesis deals with transient fault ride-through and power system stabilisation. Therefore only the relevant parts of the GCR are taken into account here. Requirements that deal with unrelated aspects like power quality, modelling and verification, communication etc. are beyond the scope of this work.

The following discussion shall not reproduce specific numbers from the individual GCR, but intends to give a general idea of the content and background of GCR. More details are given in Publication 1.

### 2.1.2 Active Power Control

From a power system operator’s point of view, the ability to control active power is important for two reasons: during normal operation to avoid frequency excursions; and during transient fault situations to obtain transient and voltage stability. The analysed GCR do generally not distinguish between active power control for normal operation and for transient fault operation.

Power control is especially important for transient stability and voltage stability in case of faults. If the power can be reduced efficiently as soon as a fault occurs, the turbine can be prevented from going into overspeed [11]. Considering turbines with directly grid-connected induction generators, the reactive power demand is less after the fault is cleared, if the power can be reduced effectively, which helps re-establishing the grid voltage [12]. Another concern, from the viewpoint of the power system operators, is the rate at which power is ramped up after a fault is cleared. The requirement for ramp rates is made to avoid power surges on the one hand, and to avoid that generation is missing, because generators ramp up too slowly on the other
hand. Both cases would mean power imbalance, which could lead to instability, even though the initial fault has been cleared.

Power control is required in all considered GCR. The requirements vary greatly and depend, among other factors, mainly on the short-circuit power of the system considered. The lower the short-circuit power, the more demanding is the power control necessary for keeping the system stable during and after a fault.

2.1.3 Frequency Operating Range

Wind turbines need to tolerate frequency deviations during steady state operation. Some GCR even require the participation in primary and secondary frequency control. More interesting in this project, are the frequency requirements related to transient events. A transient fault in an interconnected power system can lead to oscillations in the system frequency. It is desirable that the frequency tolerance of wind turbines is as wide as possible; to avoid that under such post-fault conditions the situation gets worse, because wind turbines disconnect and hence generation is lost. Extensive frequency operating ranges, however, have effects on the operation of wind turbines. The speed of fixed speed wind turbines depends directly on the grid frequency. The aerodynamic properties of wind turbine blades is non-linearly dependent on the tip speed ratio, and hence on the speed of the turbine [13]. The operation of variable speed turbines with doubly fed induction generators, is to a large extend independent of the grid frequency, while the operation of variable speed turbines with full-scale converters is fully independent of the grid frequency.

2.1.4 Voltage Control and Reactive Power Compensation

Utility and customer equipment is designed to operate at a certain voltage rating. Voltage regulators and control of reactive power at the generator and consumer connection points are used in order to keep the voltage within the required limits, and to avoid voltage stability problems. In some GCR also wind turbines are required to contribute to voltage control. In Figure 1 the reactive power requirements are compared in terms of power factor. Note that ‘lagging’ refers to production of reactive power, and ‘leading’ to absorption of reactive power. In Figure 1, only the operating limits are considered, i.e. it is not taken into account under which voltage conditions the respective amount of reactive power is demanded. In Figure 1 the requirements for
the Danish transmission system [6] and the Swedish system [9] are not shown, as they were relatively slack. They only demanded a neutral power factor (power factor = 1) over the whole range of active power.

The main reason for reactive power requirements is that generators can actively control the voltage at their terminals, by controlling the reactive power exchange with the grid. Especially during transient faults the voltage has to be supported, since the reactive power demand of induction generators increases when the voltage drops [14,15]. Generators with voltage source inverters can support the system voltage at their terminals by exporting reactive power [16]. By doing so they boost their active power export during the fault, and hence mitigate the problem of acceleration.

2.1.5 Transient Fault and Voltage Operating Range Requirements

In this section the voltage operating ranges and the corresponding trip times are compared. The comparison considers the requirements in terms of ‘wind turbines have to stay connected to the grid’. The comparison of the different voltage operating ranges, and their corresponding trip times in Figure 2, shows only the outermost operating limits. This means that no correlation with active or reactive power, as specified in the GCR, is considered here.

Since no specific voltage/trip time characteristic was given in the GCR for the Danish transmission system [6], this has to remain missing in this comparison.

Figure 1 Comparison of power factor ranges as required by the different power system operators (status beginning 2004).

“E.ON > 100 MW” = German GCR applicable to wind farms > 100 MW [7], “E.ON < 100 MW” = German GCR applicable to wind farms < 100 MW [7], “Scottish” = [10], “ELTRA distri.” = [5], “ESBNG” = [8].
In the two Danish [5,6], the Scottish [10] and the German [7] GCR not only voltage operating limits were specified, but ride-through of transient faults to sustain generation was also specifically mentioned.

When a voltage dip occurs during normal operation of the wind turbine, the current rises in order to export the same amount of power as before the voltage dip. This implies that the whole wind farm must be designed for currents larger than rated current.

When a short-circuit fault occurs in the system, the voltage at the generator terminals drops to a level depending on the location of the fault. Hence the wind turbines might not be able to export as much power as is input by the wind [14]. If a wind farm is connected by a radial feeder only, and a three-phase short-circuit occurs on this feeder, the wind farm can only export as much power as is dissipated in the resistances of the generators, transformers, lines and the fault. Only in the GCR for

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**Figure 2** Comparison of voltage operating ranges and corresponding trip times as required by the different power system operators (status beginning 2004).

“E.ON, small f current” = German GCR applicable to generators with small fault current contribution [7], “E.ON, large f current” = German GCR applicable to generators with large fault current contribution [7], “Svk < 100 MW” = Swedish GCR applicable to wind farms < 100 MW [9], “Svk > 100 MW” = Swedish GCR applicable to wind farms > 100 MW [9], “Scottish” = [10], “Danish” = Danish GCR for wind turbines connected at < 100 kV [5], “ESBNG” = [8].
the Danish transmission system, wind farms were exempted from having to ride through such a fault [6].

2.1.6 Conclusion

This section presents a comparison of regulations for the connection of wind power to power systems. The comparison reveals that the requirements differ significantly among the countries considered. The requirements reflect the properties of each power system, as well as the experience, knowledge and policies of the power system operators at the time the GCR were published.

From this comparison it becomes clear, that fault ride-through has been a requirement that wind turbines have been fulfilling for quite some time already. Hence it can be assumed that wind turbines, which are currently sold on the marked, are capable of riding through the different types of specified transient faults, and possess the necessary active and reactive power control capabilities for doing so.

From the GCR analysed it can also be seen that power system stabilisation was only mentioned in the Scottish GCR [10], which was still a draft version. The British Wind Energy Association, however, pointed out in its official response to this draft, that wind turbines are currently not yet capable of performing power system stabilisation. The British Wind Energy Association also states that more research is necessary before this requirement can be fulfilled [17]. State of the art is however, that wind turbine operation is not upset by post-fault frequency oscillations in the grid.

2.2 Literature Review

This literature review summarises work done related to large scale integration of wind power in general and transient fault ride-through and power system stabilisation with wind turbines in particular.

To become accepted on a large scale, renewable energy sources are required to behave like power plants. The capabilities of wind farms to take over power plant tasks have been investigated on a general basis [18]. The offshore wind farm Horns Rev in Denmark is equipped with a control system that allows power plant behaviour to some extend [19]. An alternative approach to achieve conventional power plant behaviour, is to combine different types of renewable energy sources, among them
wind power, to virtual power plants [20]. Since virtual power plants are not yet commercially available, but wind power penetration grows rapidly, power system operators are concerned about the consequences of high wind power penetrations, like e.g. in Germany [21], in India [22], and in Spain [23]. In a general manner different electrical solutions for fulfilling GCR have been discussed [24], but more detailed analysis is required for finding practical solutions.

It is discussed in many publications that wind turbines impact on the operation of power systems. The impact on voltage quality, power characteristic and grid frequency is dependent on the turbine type considered [25]. Such findings are not only based on theoretical considerations, but have been confirmed by measurements [26]. The inherent variability of wind power causes wind turbines to exhibit power fluctuations and cause flicker in the grid [27]. In more critical operating conditions wind turbines can even compromise voltage stability in the grid [28]. It has been found though, that the operation of wind turbines itself is also affected by variations in grid voltage, voltage imbalance, variation in system frequency and voltage distortion [29].

Since this project is based on simulations of wind turbines in a power system simulation tool, the aspect of modelling wind turbines is of great importance. Part of this project deals with variable speed turbines, as this type of turbine has become more and more important, due to its many advantages compared to fixed speed turbines [30]. There are several different variable speed concepts possible, but the two most widespread realise speed variability with (i) doubly fed induction generators and (ii) full-scale converter-connected synchronous generators. As this project only deals with variable speed turbines that have full-scale converter-connected synchronous generators, doubly fed induction generators shall be neglected in this literature review.

Some simple models of variable speed turbines neglect the aerodynamics and the mechanical dynamics of the wind turbine [31]. This might be justifiable when operation with small signal disturbances is considered. However, if large disturbances in the grid upset the wind turbine, a detailed model of the wind turbine system is essential, even if its generator is connected to the grid via a full-scale converter. A detailed wind turbine model is even more important for fixed speed wind turbines...
with directly grid-connected squirrel cage induction generators. There the turbine
dynamics are directly reproduced in the grid as variations in power and voltage.

More advanced models of wind turbine systems include an aerodynamic model with
the dynamic stall effect, a mechanical model which represents the turbine drive train
as a two-masses, stiffness and damping system, and a detailed wind model [32,33,34].

For dynamic simulations it is essential that the simulation model is initialised
properly, otherwise fictive transients occur at the beginning of the simulation. The
initialisation of a wind turbine model can either be unidirectional from the grid to the
wind [35], or bidirectional from the grid to the rotor and from the wind to the rotor
[36]. The latter method has the advantage that imprecisions in the initialisation lead to
transients, which to a large extend get absorbed by the huge inertia of the turbine
rotor.

For simulating larger systems, an aggregation of several wind turbines and wind
farms is favoured, to increase simulation speed and to reduce computation resources.
Such aggregations can be done on the electrical level only, neglecting the dynamics of
the single turbines [37], or considering the whole wind turbine model and the spacial
variation of the wind speed [38].

Model validation is an important issue, since the validity of models is essential for
realistic simulations. The validation of a passive stall turbine model is conducted by
means of an islanding experiment, where the turbine got islanded during normal
operation. This allowed comparing the measured signals with simulated signals [39].
In a similar investigation an active-stall turbine was islanded, and there the model was
not only validated against measured electrical signals, but also against measured
mechanical signals of the drive train [40]. Following the demand of continued
operation even in case of transient grid disturbances, as stated in different GCR,
model validation was conducted in an experiment, where a squirrel cage induction
generator was islanded, and subsequently reconnected to the grid [41].

A number of authors have investigated how wind turbines can fulfil the requirements
demanded by power system operators. Also the possible consequences that the GCR
might have on the operation of wind turbines are considered. Here too, only the
literature is considered that deals with GCR aspects related to transient events in the
grid.
The frequency in a power system is controlled by controlling the active power of the generators. Large offshore wind farms can, and from a power system operator’s point of view have to, contribute to frequency control, if the wind turbines are capable of controlling their pitch angles [42]. Frequency deviations from nominal can happen not only under normal operation, but also in the wake of transient faults. To sustain generation after transient faults, power system operators require wind turbines to be able to operate in a wide range of frequencies, which can be problematic for fixed speed turbines [29].

When subject to a transient fault, the clearance time and the short circuit power of the system, determine whether a squirrel cage induction generator reaches its stability limit. If the stability limit is exceeded, overspeeding causes an increased reactive power demand, which disturbs voltage recovery [12]. The stability limit is even more critical in wind turbines, since wind turbine drive trains are flexible and tend to perform torsional oscillations when excited by a transient fault [14,43,27]. To enhance transient stability of fixed speed wind farms different mechanical and electrical design parameters of the turbines are suggested to vary [15]. The transient stability limit of fixed speed turbines can also be pushed with braking resistors that dissipate power during the fault, and hence prevent acceleration of the turbine [44].

Different wind turbine types have different impacts on the transient fault behaviour of power systems. There are particularly big differences between fixed speed wind turbines, and full-scale converter-connected variable speed turbines. While squirrel cage induction generators of fixed speed wind farms provide damping of power system oscillations, inverters of variable speed turbines enhance transient stability and voltage stability of the power system [45].

Investigations were conducted where, in transient fault situations, offshore wind farms with the size of conventional power plants, are demanded the same performance as conventional power plants [46].

2.3 Conclusion

From the analysed GCR it can be concluded, that transient fault ride-through is a common requirement for grid connected wind turbines. Wind turbines need to be able to sustain operation in case of voltage dips of a certain depth (in some cases down to 0
p.u.) and a certain length (typically a few hundred milliseconds). The reactive power requirements, for helping to re-establish the grid voltage after a fault, vary greatly, and range from mere neutral power factor at the grid connection point to onerous voltage support.

The studied literature reveals that a lot of research has been done on the mutual effects of transient fault ride-through of different wind turbines and the power system. Most of the work, however, deals with the electrical effects of and on the wind turbines. The wind turbine types considered are mostly passive stall or variable speed with doubly fed induction generators. Variable speed turbines with conventional drive trains (gearbox) and full-scale converter-connected synchronous generators are hardly considered; although this concept has some relevance on today’s marked. In general little attention has been paid to concrete control strategies that allow wind turbines to ride through transient faults; and in particular active-stall turbines were hardly considered. Many authors identified that large signal disturbance operation, like transient fault ride-through, poses a need for refining simulation models. There however most of the attention is drawn to the electrical models, and some attention to the mechanical models; the aerodynamic models are often neglected.

The studied GCR reveal that wind turbines are required to sustain operation, even in case of frequency deviations, which might be caused by transient events in the grid. No requirement is made for damping of grid frequency oscillations, or in general power system oscillations. The studied literature reveals that some effort has been made on analysing the effects that power system oscillations have on the operation of wind turbines. But there is not indication for that much work has been done on how wind turbines could actively stabilise power systems, by damping power system oscillations. However, as wind power penetration progresses, it is most likely that wind turbines will be demanded to participate in the damping of power system oscillations.

This state of the art review is carried out in a manner that takes the project’s goals, as listed in chapter 1, as basis. Hence it can be concluded from this review, that for achieving these goals, the following problems need to be addressed in this project.

- Considering not only variable speed, variable pitch turbines, but also active-stall turbines for transient operation
• Refining the aerodynamic model of the active-stall turbine
• Developing the controls for a variable speed turbine with gearbox and converter-connected synchronous generator
• Concrete control strategies for transient fault ride-through and power system stabilisation operation
• Investigation into mutual effect between different wind turbines types and the power system

With the goal of the project clearly identified in chapter 1, and further specified in this chapter, the description of how the problems are addressed starts with an introduction of the simulation models in the following chapter.

3 Description of the Simulation Models

Research of the kind carried out in this project almost invariably needs to be based on simulations. The equipment involved, i.e. wind turbines and power systems are very expensive and affect a lot of people. It is therefore not possible to base a project like this, which deals with the initial design of wind turbine controllers, on experiments only. Computer simulations are an appropriate alternative, as computation speed has reached levels that allow simulating wind turbines and power systems realistically, with reasonable time consumption. Computer simulations have a practical relevance, since power system operators simulate the influence of wind turbines on their grids. For this purpose, wind turbine manufacturers are demanded to supply simulation models of their wind turbines in different power system simulation tools. Hence, this project is based on the simulation of wind turbines in the power system simulation tool PowerFactory from DIgSILENT [47]. The different models used in this project are introduced briefly in this chapter. More details on these simulations models can be found in the publications referred to in the text.
3.1 Wind Turbine Models

The wind turbine models for power system simulations, developed at Risø National Laboratory, represent those components of a wind turbine, which have the most visible impacts on power system operation. As these models are documented extensively in a number of publications, which are cited in this text, here only a brief introduction is given. A more detailed description is only provided for the models that were developed during this Ph.D. project, and which are described fully in the publications appended to this thesis. These models are: (i) the electric part of the variable speed wind turbine model, and (ii) the controls of the generator of the variable speed wind turbine model. Controller models that serve the purpose of transient fault ride-through and power system stabilisation, are discussed in chapter 4 and 5 respectively.

![Diagram of wind turbine simulation model]

Figure 3 Layout of the simulation model of an active-stall wind turbine.

In Figure 3 the layout of a wind turbine simulation model (here of an active-stall wind turbine) is shown. The general layout of a wind turbine simulation model is the same, irrespective of what wind turbine type is considered. The difference between the active-stall and the variable speed turbine model is inside the blocks “control system” and “generator & compensation”, as well as the signals exchanged between these blocks in Figure 3. Hence, since the wind model, the aerodynamics model and the drive train model are the same, they will be introduced in the following sections, followed by one section for each, the active-stall turbine and the variable speed turbine. The power system model is discussed in section 0.
3.1.1 Wind Model and Aerodynamics Model

The wind that hits the rotor of a wind turbine varies with time and space. It varies with time, due to natural wind speed variations; and at one fixed point in time, it is not the same in every location on the rotor plane, due to the tower shadow and other spatial effects. The wind speed, seen by a rotor blade on a rotating rotor, hence varies with time, depending on the position of the rotor blade. The wind model, in the block “wind speed” in Figure 3, calculates a single signal, $w$, from the integration of wind speeds over the whole rotor plane. Hence it takes the spatial variations of wind speed in time into account, and yet allows the aerodynamic model to be simple [34].

Depending on what simulations are conducted, the wind model can be adapted to facilitate simulations and to make them as realistic as possible. When situations are simulated that only last a few seconds, like transient fault ride-through and power system stabilisation, the natural wind speed variations can be neglected. When a whole wind farm is simulated, as opposed to a single wind turbine, the spatial wind speed variations that a rotor blade experiences during one revolution can be neglected. These variations cancel each other out when several wind turbines are aggregated [34].

The aerodynamic properties of the wind turbine rotor are represented in a lookup table. The aerodynamic torque coefficient, $C_q(\lambda, \theta)$, is looked up depending on the tip speed ratio ($\lambda = v_{tip}/w$) and the pitch angle, $\theta_{pitch}$ [32,33]. From Figure 3 it can be seen that the aerodynamics model generates an aerodynamic torque, $T_{ae}$, from the input variables $w$, $\theta_{pitch}$ and the rotor speed, $\omega_{WTR}$. $T_{ae}$ is the input variable to the mechanical model of the wind turbine drive train.

3.1.2 Mechanical Model

The mechanical model consists of the wind turbine drive train, as this is the mechanical component that has the most bearing on the power system behaviour of a wind turbine. The structural dynamics of other mechanical components, like the tower or the rotor blades, are neglected.

The model of the mechanical drive train of the wind turbine is a two masses, stiffness and damping model. It represents the large inertia of the turbine rotor, the small
inertia of the generator rotor, and the flexible drive train with the gearbox in between [48], see Figure 4.

![Figure 4 Wind turbine drive train model.](image)

### 3.1.3 Active-Stall Wind Turbine

The simulation model for fault-free operation of a 2 MW active-stall turbine was readily available at Risø National Laboratory at the beginning of this Ph.D. project. Its electrical part and its controller are briefly introduced in the following section.

#### 3.1.3.1 Electrical Model and Active-Stall Controller for Normal Operation

An active-stall turbine has a directly grid-connected squirrel cage induction generator, whose reactive power demand is compensated for by switchable shunt capacitors. The capacitors are connected and disconnected depending on either the power factor, or the voltage at the wind farm terminals, or the grid connection point.

As can be seen in Figure 3, the generator in the wind turbine is driven by the wind turbine drive train, which transmits the mechanical power from the turbine rotor to the generator. In an active-stall turbine, the active power can only be controlled by controlling the pitch angle of the rotor blades. A controller for normal, fault-free operation adjusts the pitch angle such that the active power production is maximised below rated wind speed, and that it is limited to rated power for above rated wind speeds [49]. To limit the power from the wind the controller pitches the blades to negative pitch angles (Figure 5), causing the rotor blades to stall. The stall effect can be explained in a simplified approach, as a separation of the airflow from the surface of the downwind side of the blade. Figure 5 shows that the apparent wind, which is the wind seen by the rotor blade, comprises two components. One perpendicular to the rotor plane (ambient wind) and one parallel to the rotor plane (caused by the
rotation of the blade). The apparent wind has a certain angle of attack, i.e. a certain angle at which it hits the leading edge of the blade. The angle of attack depends on the ratio between the wind speeds perpendicular and parallel to the rotor plane, and the pitch angle of the blade. If the angle of attack becomes too large, the flow around the airfoil of the blade does not manage to stay laminar and attached to the downwind side of the surface of the airfoil, but becomes separated and turbulent. The consequent stall effect reduces the aerodynamic power of the blade, since optimal power extraction requires laminar flow around the blade.

The investigation into transient fault ride-through of active-stall turbines (Publication 2) showed, that during and after a transient fault, the pitch angle needs to be changed drastically, and that the rotor speed oscillates. Both effects cause the angle of attack to vary considerably in short intervals. This indicates that the dynamics of the stall effect might have a noticeable relevance in such situations. Hence in Publication 3 the dynamics of the stall effect are analysed, as is described in the following section.

### 3.1.3.2 Dynamic Stall

The stall effect is, among other factors, a function of the angle of attack. Hence, when the angle of attack changes, also the degree to which a blade stalls changes. This change in stall does, however, not happen instantaneously, since the airflow around the blades cannot change instantaneously. It is therefore called dynamic stall effect [50].

The model of the dynamic stall effect used in this project, is incorporated in the $C_q(\lambda, \theta)$ model (aerodynamics block in Figure 3) [32]. It is a further development of the original dynamic stall model, which was based on the aerodynamic lift coefficient in sections of the blade [50]. Details about the dynamic stall effect and its

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**Figure 5** Cross-section of a wind turbine blade with the apparent wind comprising the rotating wind and the ambient wind; pitch angle and the resulting angle of attack.
implementation in the $C_q(\lambda, \theta)$ model can be found in Publication 3. Its influence on the transient fault operation of an active-stall turbine is discussed in chapter 4.

### 3.1.4 Variable Speed Wind Turbine

The model for fault-free operation of a 2 MW variable speed, variable pitch wind turbine was available at Risø National Laboratory too. However, it comprised a doubly fed induction generator. Hence the electrical part of this model needed to be replaced by a synchronous generator (SG) with a full-scale converter and the controls of the SG. In the following sections the electrical model and the control strategy for normal operation are described. Since the electrical part of the model has substantial influence on the operation of a variable speed turbine, the simulation of different operating conditions is presented in the last section.

#### 3.1.4.1 Electrical Model

The electrical connection of the SG to the grid via a full-scale converter is shown in Figure 6. The AC voltage of the SG, $V_{AC}$ as shown in Figure 6, is rectified by a simple diode rectifier and inverted to AC voltage with the grid frequency by an IGBT inverter. In the DC circuit between the AC/DC rectifier and the DC/AC inverter is a capacitor, $C$, which stores electrical energy to smooth $V_{DC}$. In the DC circuit as well as in the AC connection from the inverter to the grid are inductors that smooth the current from the power electronics. $V_{DC}$ is controlled by the SG with its electrical excitation system.

![Figure 6 Electrical Connection of the variable speed wind turbine with SG and full-scale converter.](image)
3.1.4.2 Variable Speed Controller for Normal Operation

The control strategy for fault-free operation, which is introduced briefly in the following, could be adapted from the previously existing variable speed, variable pitch model with doubly fed induction generator [51].

At wind speeds below rated, the controller keeps the pitch angle constant at the value where the aerodynamic efficiency is maximal. The inverter controller, which controls how much power is extracted from the generator, indirectly controls the speed of the wind turbine, and by doing so tracks the tip speed ratio \( \lambda = v_{\text{tip}} / w \) at which the rotor blades exhibit their highest practicable aerodynamic efficiency. In wind speeds close to rated, the tip speed, \( v_{\text{tip}} \), of the rotor reaches the maximum tolerable limit for steady state operation. Therefore, the speed is limited by the pitch system, while the inverter extracts as much power as possible at the given tip speed ratio. At above rated wind speeds the inverter controller holds the electrical power constant at rated power, and the pitch controller controls the speed of the wind turbine. Gusts in the wind are absorbed by the rotating mass of the turbine rotor, which means that transient wind speed variations are not reproduced as transient electric power variations in the grid. Allowing gusts to be absorbed in acceleration of the rotor, instead of feeding them through to the grid as electrical power peaks, minimises stress in the wind turbine drive train, and improves electrical power quality in the grid.

Since variable speed is realised by decoupling the generator from the stiff grid frequency, the strong torsional damping characteristic, which is inherent to AC-connected generators, is invariably lost. Due to the torsional spring characteristic of the wind turbine drive train (Figure 4) the speed of the generator in the wind turbine is prone to oscillations, whenever the system gets excited by changes in the wind speed, the pitch angle or the terminal voltage. It is therefore crucial that torsional drive train oscillations are actively damped by the wind turbine controller. Otherwise the principle advantage of mechanical stress mitigation in the variable speed concept would be negated by damaging drive train oscillations [52].

3.1.4.3 Drive Train Stabilisation

A more detailed introduction to the problem of speed oscillations in different generator types is provided in Publication 7. There it is also discussed that in a wind turbine, a SG behind a full-scale converter is an unstable system.
To counteract the speed oscillations of the SG in the wind turbine, either the mechanical input power at the shaft of the SG, or the electrical output power at the terminals of the SG, have to be controlled. Inherent to wind turbines is that the mechanical power can only be varied by pitching the blades. This is a comparably indirect way of impacting on the mechanical power at the generator shaft, since the pitch system is slow and the pitch angle acts on the aerodynamic power of the turbine rotor. The generator shaft, however, is connected to the turbine rotor via the drive train. This means that the pitch control system has to consider the dynamics of the drive train, if it is to control the mechanical power at the generator shaft. A much more direct means of damping the speed oscillations in the SG is to control the electrical power that is extracted from the SG at its terminals. A straightforward way of doing this is to control the power that the DC/AC inverter sends into the grid. This, however, means that drive train oscillations become visible as power fluctuations in the grid, even under normal operation [53]. Also, as is described in chapter 5, a variable speed turbine can perform much better in power system stabilisation, when the inverter controller can be solely applied to damping power system oscillations. Hence, the alternative that remains is to use the excitation system of the SG, to temporarily control the electrical power that is extracted from the SG. In this project this approach is pursued. The resulting generator controller is a novel solution to the problem of unstable drive train oscillations in variable speed wind turbines. The whole design is discussed in detail in Publication 7, while in this thesis only a brief introduction to the general concept is given.

The basic idea behind this concept is that the DC link capacitor (Figure 6) is used as short term energy storage. By periodically changing the level of charge of the capacitor, energy is stored and released in a manner that damps oscillations in the generator speed. The power flowing from the inverter into the AC grid is independent of $V_{DC}$, hence the damping of drive train oscillations can be achieved without impacting on the power that is injected into the grid.

Figure 8 shows the simplified control circuit of the voltage control loop of the SG. The voltage controller (VCO) controls the DC voltage, $V_{DC}$, with the excitation system of the SG. The speed, $\omega$, of the SG is filtered with a bandpass filter (BP), and is input into the drive train stabiliser (DTS), which generates a voltage setpoint that is added to the steady state voltage setpoint $V_{DC \text{ set}}$. 

\[ V_{DC \text{ set}} \]
Since the DTS shall only act on the oscillations with the resonance frequency of the drive train, and shall not interfere with the speed control of normal operation, $\omega$ needs to be filtered by a bandpass filter. The characteristic of this bandpass filter, and the frequency to which its passband is tuned, is discussed in detail in Publication 7.

Figure 7: Overview of the controller of the variable speed, variable pitch turbine with full-scale converter-connected SG.

The DTS works similarly to a power system stabiliser (PSS) in an AC-connected SG. There the excitation voltage of the SG is varied, to transiently vary the power that is extracted from the generator and injected into the grid, to counteract speed oscillations. A DTS impacts on the control of the DC link voltage, and by doing so controls the energy, which is transiently extracted from the SG and stored in the DC capacitor. By controlling the DC voltage the VCO determines to which degree the capacitor in the DC link gets charged, i.e. how much energy it stores.

Figure 8: Voltage control loop of synchronous generator (SG) with voltage controller (VCO), bandpass filter (BP) and drive train stabiliser (DTS).
Figure 7 shows a drawing of the general design of the variable speed, variable pitch controller and how the DTS is embedded in the system.

It has to be noted that the described method of drive train stabilisation, would also be applicable if the generator were not an electrically excited SG, and hence the DC voltage were controlled by e.g. a chopper.

### 3.1.4.4 Simulation of Variable Speed Wind Turbine Operation

With the electrical model in place normal operation of the variable speed wind turbine is simulated. Figure 9 shows the wind speed, the wind turbine generator speed and the electrical power the wind turbine injects into the grid. The wind speed is chosen such that it varies around rated (12 m/s), since simulations have shown, that this is the region where the turbine is most prone to oscillations. Note that in this simulation, both the spacial variation of wind speed in time, and the natural wind speed variations are taken into account. The slow variations in the wind speed signal in Figure 9 are the natural variations in the wind. The periodical component in the wind speed signal is the spacial variation.

The simulations in Figure 9 show that the turbine is stable, and that no excessive speed oscillations occur. It is also visible that the power, which is injected into the grid, is held at exactly 1 pu whenever the wind speed allows rated operation.

In the following simulations the performance of the DTS is assessed under unrealistically harsh conditions. The system is subject to wind speed step changes with a step width of 2 m/s. Figure 10 shows the steps in the wind speed and the speed of the wind turbine generator. It can be seen that the speed overshoots at every step in wind speed, absorbing the excess energy in the rotating mass of the drive train. While excess energy is absorbed in acceleration, the pitch system has time to dissipate aerodynamic power. The electrical power fed into the grid is always constantly 1 pu, as soon as the wind speed exceeds 12 m/s, which is the rated wind speed. Figure 10 reveals that the steps in wind speed excite the system to perform torsional drive train oscillations, which get damped effectively by the DTS.
The DC capacitor is a crucial part of the DTS system, as it is used as energy storage when drive train oscillations are damped. To show the impact of the size of the DC capacitor, Figure 10 also shows the speed of the wind turbine generator when the DC capacitor has three times its initial rating. In Figure 10 ‘normal C’ refers to the rating the DC capacitor needs to have to reduce ripples in the DC voltage to an acceptable level [1], and ‘large C’ refers to three times ‘normal C’. Comparing the two graphs in Figure 10 makes clear that a larger C enhances the performance of the DTS. It has to be noted that the overshoot in speed, caused by the wind speed steps, is not influenced by the rating of the DC capacitor. Due to the sharp filtration of the speed signal by the BP, this overshoot is not visible to the DTS. The overshoot in speed contains the extra energy that is injected to the wind turbine by the suddenly increasing wind speed, and is therefore solely dealt with by the pitch system.

Figure 9 Wind speed, generator speed and electrical power in the grid under normal operation of the variable speed turbine.

It can be concluded that the DTS, whose design is described in Publication 7, performs well, and keeps the variable speed wind turbine stable under any operating condition. Since the concept of the DTS distinguishes clearly between the stabilisation
of the drive train speed, and the overall control of the turbine, negative impacts of the turbine on the grid are minimised. As is shown in chapter 5, this clear distinction is also advantageous when the turbine is engaged in power system stabilisation.

![Graph of wind speed and speed response of the variable speed turbine.](image)

**Figure 10** Step changes in wind speed and speed response of the variable speed turbine.

### 3.2 Nordic Power System Model

#### 3.2.1 Nordic Transmission System Model

For the simulations shown in Figure 9 and Figure 10 the wind turbine model is connected to a simple grid model, as the purpose of these simulations is to show the behaviour of the wind turbine. But since in this project also the influence of wind turbines on the dynamic behaviour of power systems is to be investigated, a realistic power system model is required.

In this project a model of the interconnected Nordic power system, which is the power system of the countries Norway, Sweden, Finland and Denmark is chosen. This system is divided into two synchronous 50 Hz areas. The largest part of the system, comprising the grid in Norway, Sweden, Finland and the eastern part of Denmark is one interconnected, synchronous AC system. The small rest of the Nordic power
system, i.e. western Denmark, is AC connected to the large UCTE system, which is the interconnected AC system of central Europe. In this study the UCTE system is not of interest, hence, for simplicity, the term “Nordic power system” in the following refers to the Nordic synchronous system of the countries Norway, Sweden, Finland and eastern Denmark.

The model of the Nordic power system is an aggregation, which means that the generators, lines and loads in the model are lumped representations of several generators lines and loads in reality. It comprises 35 nodes and 20 synchronous generators. It is a model of the transmission system, comprising high voltage levels only. More details about the Nordic power system model can be found in Publication 6 and in the References [54] and [55].

3.2.2 Model of the Grid in Eastern Denmark

In the location of eastern Denmark, the model is extended with a simplified model of the transmission and distribution system to represent the connection of wind power in eastern Denmark. This grid, which is shown in Figure 11 comprises all voltage levels from transmission system voltage down to generator terminal voltage.

The south of eastern Denmark is a remote location in the system, which is why the grid is relatively weak there. The majority of the wind turbines in eastern Denmark are connected to this weak grid in the south.

It is assumed that the wind power in eastern Denmark is the only wind power that has to be considered in the Nordic system. This is a sound assumption, as only faults in eastern Denmark are simulated. Any wind power that is installed in other parts of the system would hardly be affected by faults in eastern Denmark.

Inherent to wind power is that its resources are far away from load centres, and hence almost invariable far away from strong transmission systems. This is even more applicable for offshore wind farms. The largest part of the wind power that will be installed in eastern Denmark in future will be offshore.

The amount of wind power that is introduced, substitutes power from synchronous generators. Hence the total amount of active power transmitted through the system remains the same, apart from the losses of the extra components.
In the extension as shown in Figure 11 three wind farms in the south of eastern Denmark are considered. One wind farm represents all the land-based wind turbines, which are distributed over the southern islands of eastern Denmark. These turbines are aggregated to one single induction generator. Another aggregated wind farm represents the Nysted offshore wind farm. This is one of the world’s largest offshore wind farms and has been connected to the system since 2003 [56]. The third wind farm is an offshore wind farm, that is currently in the planning stage, and that will probably be installed in the foreseeable future [57]. This future offshore wind farm is in Figure 11 shown as an active-stall wind farm, as active-stall is the wind farm type considered in the investigation into the transient fault behaviour of the Nordic power system in Publication 6. However, in chapter 4 and 5 the behaviour of the Nordic
power system is also tested with the future offshore wind farm consisting of variable speed turbines. In either case the future offshore wind farm is aggregated to one single generator, driven by one single wind turbine model. The aggregation of the whole wind farm to one wind turbine is justifiable, since all turbines in the wind farm are equal. Also the wind speed considered is above rated wind speed, i.e. even with shadowing effects in a wind farm all turbines have sufficient wind for rated power production. Besides, small variations can be neglected, since the disturbance simulated (transient short-circuit) is a large signal disturbance.

In Publication 6 more details about the extension of the power system model can be found. Also presented in Publication 6 are simulations, where the Nordic power system model is used to investigate the mutual effects between wind power and the power system in transient fault situations. It is shown that the Nordic power system responds sensitively to wind power. Transient fault ride-through and power system stabilisation performed by wind turbines have a visible impact on the entire system.

3.3 Summary

The simulation models of the active-stall and the variable speed, variable pitch turbine as described in this chapter allow simulation of normal, i.e. fault-free operation. As will be shown in the following chapters, these models are further developed to make them able to ride through transient faults, and to contribute actively to the damping of power system oscillations.

For simulation of power system stabilisation to be realistic, a realistic power system model is of major importance. Therefore the model of the Nordic power system is chosen, and is extended to realistically represent the wind power connected in eastern Denmark. The investigations presented in Publication 6 show that the Nordic power system is a very suitable case for the kind of study carried out in this project.

4 Transient Fault Ride-Through

Transient faults are very common disturbances in power systems, and as discussed in chapter 2, wind turbines are demanded to ride through transient faults, in order to
sustain operation. If a fault happens close to a wind turbine, the voltage at the generator terminals of the wind turbine drops, and hence also the active power drops. If a wind turbine controller does not attempt to reduce the mechanical power input, the turbine accelerates during the fault. The drive train also gets excited to torsional oscillations, since it acts like a torsion spring that gets untwisted during the fault [40]. Under normal operation this spring is twisted by the aerodynamic torque from the rotor, acting on one end of the drive train, and the electrical torque from the generator, acting on the other end. During the fault, the electrical torque drops to close to zero, which unloads the spring instantly and allows it to untwist.

By the time the fault is cleared, the generator has accelerated considerably beyond its rated speed, and has started oscillating with the resonance frequency of the drive train. If a wind turbine has no means of controlling its power, the critical fault clearance time (the maximum fault duration that still allows the turbine to return to normal operation after the fault is cleared) is very short. Therefore, in the following sections controllers are presented that allow the active-stall turbine and the variable speed, variable pitch turbines, introduced in the previous chapter, to ride through transient faults.

### 4.1 Active-Stall Wind Turbine

For an active-stall turbine, the transient fault situation described above, would mean that the increase in generator speed, would imply an increase in reactive power demand of the generator, since active-stall turbines are equipped with squirrel cage induction generators [12]. The reactive power demand of the generator lets the voltage recover only slowly. The drive train speed oscillations are reproduced as active and reactive power oscillations, and are consequently visible as voltage oscillations in the grid.

In the following a controller is presented that enables an active-stall turbine with conventional hardware to ride through transient faults. It prevents the turbine from going into overspeed, and by doing so, assists in voltage recovery. At the same time it helps damping drive train oscillations.

Since an active-stall turbine has only its pitch system to control the power of the turbine, the transient fault controller is a pitch angle controller. As described in
Publication 2 it is an open-loop power controller, which reduces the aerodynamic power of the rotor, as soon as a grid fault is detected. The sequence of a transient fault operation is as follows:

1. detection of fault
2. pitch angle is ramped with the maximum pitch rate of the pitch system to the value where the aerodynamic power of the rotor is zero
3. check whether pitch angle has reached this value
4. check whether grid voltage has recovered and generator speed is in normal range
5. pitch angle is ramped back to value prior to the fault
6. resume of normal operation

In Publication 2 this control sequence is described in more detail. There also the behaviour of the controller is described for abnormal situations, like when the grid voltage does not recover immediately after the fault is cleared. Here, however, only the simulation of a 3-phase fault is discussed as an example. The grid configuration for this simulation is, as described in Publication 2, a simple feeder that connects the wind turbine to a simple grid equivalent.

Figure 12 shows the behaviour of the active-stall turbine with the transient fault controller when riding through a transient 3-phase fault.

As described above, and as shown in Figure 12, riding through a transient fault means that an active-stall wind turbine has to change the pitch angle as quickly as possible (maximum pitch rate), and that the speed of the turbine rotor oscillates. Both effects are effectively changes in the angle of attack (see section 3.1.3.1). If the angle of attack changes also the degree, to which the blades stall changes. Since this does not happen instantaneously, as mentioned in section 3.1.3.2, the influence of the dynamic stall effect is investigated.

Therefore, Figure 12 shows the voltage and the active power at the terminals of the active-stall turbine for the cases with and without the dynamic stall effect. In the simulation with dynamic stall, any intended decrease and increase of power is delayed. The reason for this is the delayed aerodynamic power response caused by dynamic stall. After the pitch angle becomes stationary again, the power still varies,
because the drive train speed still oscillates. Also these power variations, which are caused by speed oscillations, are affected by the dynamic stall effect.

In a squirrel cage induction generator, the reactive power demand depends on the active power operating point. Hence, if the active power varies, as shown in Figure 12, also the reactive power consumption varies, which in turn becomes visible in the voltage. It can be concluded that the dynamic stall effect has a visible impact on the transient fault operation of the active-stall turbine, even after the transient fault operation has finished, and the pitch angle is stationary again. Therefore, the impact of the dynamic stall effect, as discussed analytically in Publication 3, must not be neglected.

Figure 12 Voltage, active power and pitch angle of the active-stall turbine subject to a transient 3-phase fault, with and without dynamic stall.
4.2 Variable Speed Wind Turbine

For a variable speed wind turbine transient fault ride-through is a very different problem compared to an active-stall turbine. Since the generator speed is not linked to the stiff grid frequency, the wind turbine drive train can accelerate, and thereby accumulate kinetic energy during the fault, without serious consequences. This missing link to the stiff grid frequency means on the other hand, that the drive train oscillations are not inherently damped, but that they need to be damped actively by the wind turbine controller.

Under normal operation the wind turbine controller controls the slow variations in speed with the pitch system [51]. The speed oscillations with the resonance frequency of the drive train are damped by controlling the excitation of the SG, as discussed in Publication 7. Under a transient fault though, the electric power export gets disrupted instantly. This also instantly unloads the drive train of the turbine, causing the generator to accelerate steeply and to perform strong torsional oscillations. Since the wind turbine cannot export electrical power during the voltage dip, the drive train stabiliser (DTS), which would normally dampen torsional oscillations, does not succeed in stabilising the generator speed. Once the grid voltage has recovered and power export resumed, the DTS could in principle resume with drive train stabilisation. However, since by then the generator speed is oscillating considerably more than under normal operation, the DTS would require a much larger DC circuit capacitor, to be able to dampen oscillations with such large amplitudes. Therefore, during and just after the fault, the speed of the generator is stabilised by the transient fault controller, which acts on the inverter, as discussed in detail in Publication 8.

As discussed in chapter 3, the VCO of the SG controls the DC voltage under normal operation. Also during a voltage dip, caused by a fault close to the wind turbine, the DC voltage can be controlled by the VCO. If, however, this fault causes power swings in the power system, the voltage at the wind turbine terminals can rise in the wake of the fault, causing the voltage source inverter to unintentionally allow reverse power flow. Reverse power flow charges the DC capacitor, which cannot be discharged by the VCO, but only by the inverter. Hence the transient fault controller has to control the DC voltage during and just after a fault too. How the transient fault controller controls the inverter is described in more detail in Publication 8. There also the
transition from transient fault operation to normal operation is discussed. This transition needs to be smooth to avoid transients. Therefore, the control signals from the transient fault controller and the controller for normal operation are phased in and out using ramp functions.

In the following section simulations of the variable speed wind turbine, and the active-stall wind turbine, riding through a transient fault are shown and compared.

4.3 Comparison and Conclusion

For the simulation and comparison of the fault ride-through behaviour of the two wind turbine types, they are connected to the Nordic power system, as opposed to the simple grid used for the simulation in Figure 12. They are, however, not connected as single wind turbines, but as aggregated 198 MW wind farms. Their transient fault ride-through operation is simulated under equal conditions, to allow them to be compared. Note that these conditions are not the same as in the Publications where fault ride-through of the active-stall turbine is simulated. Hence a direct comparison to the simulations shown there is not possible. Note also that the different wind turbines are not connected and performing fault ride-through at the same time, hence there are no mutual effects between the two wind farms. The fault simulated is a 300 ms 3-phase fault at the busbar Spanager on Zealand (DK) in Figure 11. The other wind farms shown in Figure 11 are not connected, hence they do not have an influence on the simulations either.

Figure 13 shows the simulated transient fault responses of the two wind turbine types. It can be seen, that after the clearance of the fault, the voltage at the wind turbine terminals recovers faster in case of the variable speed turbine. In case of the active-stall turbine, the reactive power demand of the generator delays the voltage recovery slightly. The inverter in the variable speed turbine causes rapid voltage fluctuations just after the clearance of the fault.

Figure 13 also shows the power that the two turbine types inject into the grid. The large and relatively long lasting power variations of the active-stall turbine are caused by the squirrel cage induction generator, which passively dampens the oscillations in the turbine drive train. The fluctuating power, injected by the variable speed turbine,
is the result of the transient fault controller, which controls the inverter such that the
generator speed oscillations are damped and the DC voltage stabilised.

Finally Figure 13 also shows the pitch angle of the two turbines. From this it becomes
obvious that the mechanical structure of an active-stall turbine, particularly the pitch
system, has to work much harder during transient fault operation. In the case of a
variable speed turbine the pitch system only performs slow and modest pitch angle
variations to control the overall speed of the drive train. All the fast power variations
required for damping the drive train oscillations and for stabilising the DC voltage are
solely performed by the inverter.

It can be concluded that the transient fault controllers of both turbine types allow the
turbines to ride through transient faults successfully.
However, the transient fault itself, as well as the transient fault behaviour of the wind turbines, has an impact on the operation of the power system.

The transient fault at busbar Spanager not only causes a voltage dip at the terminals of the wind turbines, but it also suppresses the voltage at busbar Zealand. Hence it also demands SG Zealand to ride through a voltage dip. The fault ride-through behaviour of SG Zealand is affected by the fault ride-through behaviour of the wind turbines. To compare the impact of the two different turbine types, Figure 14 shows the speed of SG Zealand for the two cases: (i) the active-stall turbines riding through the fault, and (ii) the variable speed turbines riding through the fault.

Figure 14 Speed of SG Zealand when the active-stall and the variable speed wind turbines ride through the transient fault at busbar Spanager.

Figure 14 shows clearly that the variable speed turbine has a negative effect on the power system. The active-stall turbine adds damping to the system, since the inertia of the wind turbine drive train is added to the system through the directly grid connected squirrel cage induction generator. The inertia of the variable speed turbine is completely decoupled by the full-scale converter, and does hence not add any damping to the system.

With increasing wind power penetration it becomes more and more important, that wind turbines are involved in the stabilisation of the power system. This is even more the case, since it is to be expected, that the majority of wind turbines installed in future will be variable speed turbines. As Figure 14 suggests, and as is confirmed in literature [58], increasing levels of variable speed wind power penetration have negative effects on the dynamic behaviour of power systems. The reason for this is that the drive train inertia of variable speed turbines is not inherently added to the
power system [59]. Therefore, in the following chapter the active-stall and the variable speed turbines are equipped with controllers that enable them to actively dampen power system oscillations.

5 Power System Stabilisation

In the previous chapter it was already indicated that a fault in the vicinity of an AC-connected SG, of e.g. a conventional power plant, prevents this SG from exporting electrical power, as long as the voltage is suppressed. Hence, during this fault the SG has to accumulate the mechanical energy, which is input by its prime mover. A rotating machine can only accumulate energy by accelerating. If the fault is transient, the generator accelerates during the fault, and, after the fault is cleared, it tries to export as much electrical power as possible to decelerate again. As a result, the rotor speed of this generator oscillates (see Figure 14).

In an interconnected AC power system a fault in one area, and the subsequent rotor speed oscillations of the SG in this area, lead to power swings between different areas in the whole system (inter-area oscillations). Considering the Nordic power system, a fault in eastern Denmark causes inter-area oscillations as far away in the system as in the inter-area link between northern Sweden and Finland. The frequencies of inter-area oscillations in different locations in the Nordic power system, are in the range of 0.1 to 1 Hz [60], and are hence in the same range as the frequency oscillations in eastern Denmark (Figure 14).

In an AC power system the speed of a SG is the electrical frequency. If the frequency, i.e. the speed of a SG, is low, it can be increased by injecting extra power into the system. If the frequency, i.e. the speed of a SG, is high, it can be decreased by extracting extra power from the system. Inter-area oscillations are power oscillations in inter-area links, and are of a similar nature as grid frequency oscillations. Hence, grid frequency oscillations, as well as inter-area oscillations, can be counteracted with a controlled active power injection into the grid.

If a wind turbine is to counteract such power system oscillations, i.e. inject controlled oscillating power into the grid, it needs to have a very effective means of controlling
It has to be capable of injecting power, oscillating with the frequency of the power system oscillations. To have the biggest possible damping effect, these power oscillations should have the largest possible amplitude. Ideally the wind turbine would be able to vary its power between zero and rated power.

If the power system oscillations are caused by a transient fault in the vicinity of the wind turbine, this wind turbine has to first ride through the fault, before it can contribute to power system stabilisation. Since power system stabilisation following fault ride-through is the worst case scenario, in this chapter this scenario is considered only. The fault type, fault duration and fault location are the same as in the previous chapter. Also the grid configurations are equal, allowing the power system stabilisation of the different turbine types to be compared. It has to be noted again that this grid configuration is not the same as in the Publications where power system stabilisation with active-stall turbines is discussed.

In the following sections controllers are present, that enable the active-stall turbine and the variable speed, variable pitch turbine to perform power system stabilisation. The transient fault ride-through operation is as described in the previous chapter. The power system stabilisers, described in this chapter, take over from the transient fault controllers, described in the previous chapter, as soon as the fault is cleared, and the wind turbines are stable. The power system signal, whose oscillations the wind turbines have to dampen, is the speed of the SG connected to busbar Zealand in eastern Denmark, (Figure 11), i.e. the electrical frequency.

5.1 Active-Stall Wind Turbine

Since an active-stall turbine only has its pitch system to control its active power, the oscillating power variations, as described above, are difficult to accomplish. Nevertheless are the power system stabilisation capabilities of active-stall turbines of major interest. Many active-stall turbines have been erected in the past, and many active-stall turbines are still being sold due to their competitive price and robust technology.

In the following sections two different controllers for power system stabilisation are presented. First a classical PID controller is described and its performance discussed.
Building on the experience gained from this approach, a novel fuzzy logic controller is developed, which is presented in the subsequent section.

### 5.1.1 PID Controller

The power system stabiliser in an active-stall turbine controls the pitch angle such that the generator injects oscillating power into the grid. These power oscillations need to be in the right phase angle, so they counteract the power system oscillations.

![Control circuit of the PID power system stabiliser in the active-stall turbine.](image)

Figure 15 shows the control circuit, from which it can be seen that the turbine power is controlled in a closed loop. If the frequency of the power system, $f_{\text{MEAS}}$ (speed of SG Zealand), deviates from the setpoint, $f_{\text{SET}}$, the frequency error $f_{\text{ERR}}$ causes a power signal $P_{\text{DIFF}}$, which acts as setpoint on the closed power control loop, contributing to the power error signal $P_{\text{ERR}}$. The PID controller tries to eliminate this power error by generating a pitch angle setpoint, $\theta$, which is input to the wind turbine, i.e. the pitch system.

The PID controller is designed with the root locus method. To be able to apply this method, the plant to be controlled has to be described in terms of its transfer function. The full transfer function of the wind turbine is of very high order, and contains a number of nonlinearities. To facilitate the design process, a reduced order representation is yielded from the wind turbine’s step response, such that the root locus method can be applied.

When the transfer function of the wind turbine is to be found from the turbine’s step response, the nonlinearities of the turbine system must be considered, as discussed in Publication 4. The most relevant of these are the nonlinear aerodynamic characteristic of the rotor blades ($C_q(\lambda, \theta)$), and the nonlinearily limited pitch rate of the pitch system. The nonlinear aerodynamics are basically a variation in power sensitivity, i.e. how sensitively the power responds to pitch angle changes ($dP/d\theta$) [51]. Hence this nonlinearity can be addressed with gain scheduling. The nonlinearly limited pitch rate
of the pitch system is a more difficult problem to solve, and therefore the pitch system is often considered a linear system.

Since it is favourable to use simple and robust PI and PID controllers, in previous work different authors have suggested a number of approaches for modelling and controlling pitch systems. For normal operating conditions it is often assumed, that the pitch angle only needs to change moderately, i.e. without reaching the maximum pitch rate of the pitch system [61]. A step change in the pitch angle setpoint leads to a response of the pitch angle, which allows representing the pitch system with a linear approximation, e.g. a first order transfer function [62]. The pitch system response is crucial for response sensitive control tasks. For that purpose pitch systems have been represented with second order transfer functions, and without an acceleration limiter [63]. In control situations where the maximum allowed pitch rate is desired, e.g. to avoid large speed excursions, a switched controller can be applied. It interrupts the continuous pitch control to feather the blades with the maximum pitch rate, and resumes continuous pitch control once the speed is below a threshold. This method circumvents the problem of having the nonlinearity of the pitch system in the linear control system for continuous operation [64].

![Figure 16](image.jpg)

Figure 16 The active power the wind farm injects into the grid to dampen the power system oscillations. Grid frequency oscillations caused by the transient fault, with and without the wind farm actively damping them. For comparison also the wind farm power when only riding through the fault is shown.
Since power system stabilisation requires continuous pitching, often with the maximum pitch rate, in this project the following approach is chosen: the transfer function of the wind turbine as a whole, i.e. including the pitch system, with its limitation in pitch rate, is found. To take the nonlinear aerodynamics into account, a number of second order transfer functions are yielded from the step responses of the entire wind turbine, with the pitch system, in the different operating regions.

With these reduced order transfer functions the PID controller in Figure 15 is designed, as described in Publication 4.

Figure 16 shows the effect of the active-stall wind turbines with the PID power system stabiliser. It shows the power the wind turbines inject, and the effect this has on the grid frequency for two cases: (i) the wind turbines merely riding through the transient fault (as described in the previous chapter); and (ii) the wind turbines applying their power system stabilisers to dampen the grid frequency oscillations. The simulation shown in Figure 16 is conducted at a wind speed of 14 m/s. It can be seen, that the active-stall turbines with the PID power system stabiliser add extra damping to the system at this wind speed. The same scenario has also been simulated for all other wind speeds, from cut-in wind speed (4 m/s) to shut-down wind speed (25 m/s). These simulations reveal that the controller performs well in most, but not in all wind speeds. The limited performance of the active-stall turbine with the PID power system stabiliser is caused by the aerodynamic properties of the rotor blades, in combination with the limited pitch rate of the pitch system.

To vary the power, an active-stall turbine can at the most pitch the blades between the pitch angle of normal operation, and the pitch angle where the aerodynamic power is zero. From Figure 17, which shows these two pitch angle values, it becomes obvious, that the region between 7 m/s and 11 m/s is most demanding for the pitch controller. There the difference between these pitch angles values is largest. For the controller to perform satisfactorily, it has to be able to sweep between the upper and the lower pitch angle limit in reasonably short time. Since the pitch system has a limited pitch rate, the larger the gap between the limits (i.e. the larger the value in the right-hand diagram in Figure 17), the slower the response of the controller. This explains why the controller does not perform satisfactorily in wind speeds between 7 m/s and 11 m/s.
It can be concluded that in case of large signal control, like the power system stabilisation operation shown here, the numerous nonlinearities in the wind turbine are difficult to address with conventional controllers. Therefore an alternative approach has been chosen, which is discussed in the following section.

5.1.2 Fuzzy Logic Controller

Since the many nonlinearities of a wind turbine make linear controllers difficult to use in power system stabilisation, fuzzy logic control is applied in this project. Previously fuzzy logic has not been used much in wind turbine control. One of the main reasons for this is that most of the wind turbine control tasks have been in the small signal range, where linear PI and PID controllers perform well. However, as discussed above, power system stabilisation is by no means a small signal control task. This is especially the case if the wind turbine has to ride through a deep voltage dip, before power system stabilisation can start. In such an operating condition the numerous nonlinearities of a wind turbine become a severe constraint, which a fuzzy logic controller can handle very well. Systems that are difficult to describe mathematically, that are nonlinear, and whose properties are likely to change with time, are the prime area of application of fuzzy logic control [65].

Conventional controllers, like PI and PID controllers, require a mathematical description of the system to be controlled, for their parameters to be tuned. For the design of a fuzzy logic controller, such a description is not necessary; as it is replaced by common sense knowledge of the system’s behaviour. This knowledge is reflected in a series of rules, which the controller uses to derive its output signal from the input signals.

The design of the PID controller described in the previous section, provides the necessary insight into the task of using an active-stall wind turbine for power system...
stabilisation. The process of designing a fuzzy logic controller consists of the following steps: (i) determining the inputs and designing the fuzzy sets for these inputs, (ii) setting up the rules, and (iii) designing a method to convert the fuzzy result of the rules into a crisp output signal, known as defuzzification. While in Publication 5 a detailed description of the design of the fuzzy logic controller is given, here a brief introduction shall suffice.

From the inputs electrical power and grid frequency, the derivatives are generated. The crisp values of frequency, power, derivative of frequency, derivative of power, and turbine speed, are expressed in terms of degrees of membership of fuzzy sets. Rules suggest what pitching actions should be taken, based on all conceivable combinations of memberships. In the defuzzification a crisp pitch angle setpoint is derived from the results of the different rules.

Figure 18 shows how the fuzzy logic pitch angle controller is embedded in the wind turbine model. The pitch angle setpoint, $\theta$, is input to the pitch system of the wind turbine, and controls the electric power, which is injected into the power system.

Figure 18 Wind turbine control circuit with fuzzy logic power system stabiliser.

Figure 19 shows the active power, which the fuzzy logic power system stabiliser causes the active-stall wind turbines to inject into the grid at a wind speed of 14 m/s. The effect this has on the grid frequency oscillations is also shown in Figure 19. It can be seen that the fuzzy logic power system stabiliser adds extra damping to the system. Despite the fact that the limited pitch rate causes the pitch system to have a response time, which is a function of the wind speed (Figure 17), the fuzzy logic controller performs also well in all other wind speeds, from cut-in to shut-down wind speed. Therefore, the fuzzy logic controller is found to be more suitable than the PID controller described in the previous section.
To show that the fuzzy logic controller also works if applied to a system behaving somewhat differently from the system it has been designed for, in Publication 5, the performance of the power system stabiliser is simulated with a reduced maximum pitch rate in the pitch system. There it is shown that the performance hardly varies, when a less powerful pitch system is applied.

In Publication 6 the effect of the fuzzy logic power system stabiliser on the Nordic power system is analysed. There the situation is simulated, where the future offshore wind farm in eastern Denmark consist of active-stall turbines, which are equipped with the fuzzy logic power system stabiliser described here. It is found that the stabiliser helps damping power system oscillations, caused by a fault close to the wind turbines, and that its effect is visible throughout the entire system.

In section 5.3 the performance of the fuzzy logic power system stabiliser is further discussed and compared to the power system stabiliser of the variable speed wind turbine.
5.2 Variable Speed Wind Turbine

Already today the majority of installed wind turbines are variable speed, variable pitch turbines. In future it is expected that the market share of variable speed turbines will increase even further. Therefore, in this section a controller is presented that enables the variable speed turbine, introduced in chapter 3, to perform power system stabilisation.

The variable speed turbine controls the power it injects into the grid solely with its inverter. Hence rapid and large power variations are easily possible, which is advantages for power system stabilisation.

The active power the inverter of the wind turbine injects into the grid is extracted from the generator of the wind turbine. The mechanical power, which drives the generator, cannot be controlled equally fast as the electrical power, since it is controlled by the pitch system. Hence the power variations caused by the inverter, have to be catered for by the kinetic energy, stored in the inertia of the rotating wind turbine rotor. Therefore, the generator accelerates if less power is extracted, and it decelerates if more power is extracted, than is input by the turbine rotor. The pitch system only counteracts the slow variations in the generator speed, and it does not attempt to counteract short-term speed excursions. Instead, the speed is allowed to fluctuate around its steady state value. This way the speed of the generator is kept within tolerable limits, while at the same time the pitch system is not burdened with drastic pitching actions.

Figure 20 shows the simplified control circuit of the power system stabiliser. A full description of the system is given in Publication 7 and Publication 8.

The power system signal, whose oscillations are damped, is the measured grid frequency, \( f_{\text{meas}} \). If \( f_{\text{meas}} \) is different from the frequency setpoint, \( f_{\text{set}} \), a frequency error, \( \Delta f \), occurs, which is transformed into a power error, \( \Delta P \), by a droop characteristic. Hence \( \Delta P \) is the power that is made available for power system stabilisation. Since this power depends on the energy stored in the rotating mass of the wind turbine rotor, the slope of the droop factor that translates \( \Delta f \) into \( \Delta P \), has to be dependent on the overall speed of the wind turbine rotor.
Figure 21 shows the general concept of the $f$ versus $P$ droop characteristic, and how the droop characteristic varies depending on the overall rotor speed of the wind turbine. It can be seen, that the slope of the droop becomes steeper, the slower the wind turbine rotor spins. This means, that the amplitude of the power variations decreases, the less kinetic energy is stored in the rotating mass of the wind turbine. Figure 20 shows that the wind turbine generator speed, $\omega$, is filtered by a low pass filter (LP-block), to avoid that short term speed variations have an impact on the slope of the droop characteristic.

Figure 21 Droop characteristic: a) general concept of $\Delta f / \Delta P$; b) droop characteristic as function of rotor speed.

Figure 22 shows the power system stabilisation performance of the variable speed wind turbines. The inverter allows the power system stabiliser to realise large power variations. These variations add strong damping to the system, which has the effect that the grid frequency oscillations subside quickly.

In the following section, the consequences of the power system stabilisation operation of the variable speed wind turbine is further discussed, and compared to the operation of the fuzzy logic power system stabiliser of the active-stall turbine.
Comparison and Conclusion

The previous sections made it clear, that power system stabilisation requires a wind turbine to inject oscillating power into the grid. If the cause of the power system oscillations is a fault, which requires the wind turbine to ride through a deep voltage dip, the turbine has to deal with two problems: (i) the increased and oscillating drive train speed of the wind turbine, and (ii) the power system oscillations.

From a power system stabilisation point of view, the fundamental difference between the active-stall turbine and the variable speed turbine is the generator type, and the means of controlling the electric power. In the active-stall turbine the squirrel cage induction generator is AC-connected, since it is not designed to operate with variable speed. The steep torque versus slip characteristic of squirrel cage induction generators [66], provides inherent damping to the power system. Any oscillation in grid frequency means oscillation in slip, and therewith in torque. Hence the large inertia of the wind turbine drive train, which is connected to the shaft of the induction generator, becomes visible as inertia in the system. Therefore, the oscillations in Figure 14 are more damped in case of the active-stall wind farm. At the same time

Figure 22 The active power the wind farm injects into the grid to dampen the power system oscillations. Grid frequency oscillations caused by the transient fault, with and without the wind farm actively damping them. For comparison also the wind farm power when only riding through the fault is shown.

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this torque versus slip characteristic also provides inherent damping to the rotor of the induction generator in the wind turbine. Figure 23 shows the wind turbine generator speed of the two turbine types. It can be seen that the initial oscillations of the induction generator in the active-stall turbine are quickly damped.

The full-scale converter-connected SG in the variable speed turbine neither adds inherent damping to the power system, nor is its speed inherently damped by the power system. The power that the inverter injects into the grid is completely independent of both, the grid frequency, and the SG speed. Hence the full-scale converter of the variable speed turbine does not add inherent, i.e. passive damping to the system, which can be seen in Figure 14. Figure 23 shows that the generator speed in the variable speed turbine oscillates much longer than in the active-stall turbine. These oscillations need to be counteracted actively; first by the transient fault controller, and subsequently by the DTS. The quicker the transient fault controller passes the control of the inverter on to the power system stabiliser, the more damping the variable speed turbine adds to the power system. However, this means at the same time, that the generator speed oscillates stronger and that the DTS has a more difficult task in damping these oscillations. Hence the transition is chosen such that the DTS manages to dampen these oscillations.

The power variations that actively dampen the power system oscillations are in the active-stall turbine controlled aerodynamically. The pitch system is a relatively slow means of controlling power. And the aerodynamic power, which is controlled by the pitch system, has to go through the flexible drive train first, before it has an effect on the electrical power.

The variable speed turbine has the clear advantage, that it does not engage the pitch system in power system stabilisation. The power variations for power system stabilisation operation.
stabilisation are exclusively realised by the inverter, which allows much faster and larger power variations than the pitch system. Also, the inverter acts directly on the generator, and does not require the power variations to go through the drive train first. Hence the variable speed turbine is capable of varying its electrical power between zero and rated in short intervals.

Figure 24 shows the pitch angles of the active-stall and the variable speed turbine. From this it becomes clear, that the pitch system in the active-stall turbine has to work hard, to achieve the desired electrical power variations. It also becomes obvious, that the large and fast pitch angle variations demand a realistic mechanical and aerodynamic model of the active-stall turbine, for the simulations to be realistic. The pitch system of the variable speed turbine, however, only performs slow and modest pitching actions, as this is sufficient for keeping the overall speed of the turbine within its band of normal speed variations.

**Figure 24 Pitch angle of the active-stall turbine with fuzzy logic controller, and the variable speed turbine.**

It can be concluded that the active-stall turbine and the variable speed turbine are capable of performing power system stabilisation. The active-stall turbine, with its AC-connected squirrel cage induction generator, adds passive damping to the system, and active power system stabilisation is possible too. The variable speed turbine, with its full-scale converter does not add any passive damping to the power system at all. It is, however, capable of adding substantial controlled damping, since it is capable of varying its electric power between zero and rated, in short intervals. This ability to perform very well in power system stabilisation, however, comes at the expense of poorly damped drive train oscillations. Hence power system stabilisation has to be traded off, at least to a certain extend, against drive train stabilisation.
6 Conclusions and Future Work

In this Ph.D. project it is investigated how wind turbines can support the grid in transient fault situations. Within this rather broad topic, the project only covers areas where little research has been done before. Therefore the selection of turbines is limited to types that are relevant on the marked on the one hand, and that have attracted little attention in science on the other hand. Hence, the turbine types considered are active-stall turbines and variable speed, variable pitch turbines with full-scale converter-connected synchronous generators. The latter one is a representative for the class of variable speed, variable pitch turbines, which have gearboxes and full-scale converter-connected generators in general.

Since no such variable speed turbine model was readily available at the beginning of this project, the electrical model and its control needed to be designed, and are hence also presented in this thesis. It is a novel design that allows the turbine to inject active power into the grid, independent of drive train oscillations. Therefore the power control of the inverter can be fully made available for power system stabilisation. The drive train oscillations, which are inherent to variable speed turbines with gearboxes and full-scale converter-connected generators, are damped by using the DC link capacitor as short terms energy storage.

From a power system’s point of view the aspects that this project focuses on, are transient fault ride-through, and power system stabilisation. In the following sections it is summarised and concluded what these two aspects mean for the two turbine types considered. Finally, in the last section future work is suggested, based on the findings of this project.

6.1 Transient Fault Ride-Through

Transient fault ride-through is common practice for modern wind turbines. A lot of research has gone into how transient faults affect wind turbines, but little attention has been drawn to specific control strategies. How fault ride-through is realised is usually kept confidential by the wind turbine manufacturers. Hence, in this thesis concrete solutions are presented, that allow the considered turbine types to ride through transient faults.
It is shown that none of the turbine types experiences excessive speed excursions, and that they are able to ride through faults, without burdening the grid by retarding voltage recovery, or exciting power swings.

The transient fault controller in the active-stall turbine mitigates the inherent reactive power demand of the induction generator by controlling the generator speed, and hence enhances voltage recovery. At the same time, the active power surge, which is inevitable after the clearance of the fault, is also limited. The drive train oscillations, which are excited by the fault, are damped quickly by the AC-connected induction generator.

These drive train oscillations are much more difficult to deal with in the variable speed turbine, where the generator is fully decoupled from the grid by a full-scale converter. However, there the transient fault controller manages to actively dampen these oscillations. The full-scale converter, on the other hand, has the advantage that the speed of the generator is free to vary, independent of the grid frequency. Therefore, speed oscillations do not cause power surges in the grid, which means that the turbine has a less visible effect on the grid voltage recovery. With its full-scale converter the variable speed turbine has further the ability, to actively support the grid voltage recovery with reactive power injection.

It can be concluded, that with the presented controllers, active-stall and variable speed, variable pitch turbines are capable of riding through transient faults. By doing so they prevent that the fault causes an imbalance between generation and consumption.

6.2 Power System Stabilisation

A transient fault often excites the power system to perform oscillations in the grid frequency and in inter-area links. Traditionally power system oscillations have been damped by conventional power plants. Wind turbines have, so far, not been considered for active power system stabilisation. However, research has been carried out to investigate, how different wind turbine types impact passively on power system oscillations. It has been identified, that fixed speed turbines with squirrel cage induction generators, inherently, i.e. without active control, add damping to the
system. Variable speed turbines with full-scale converters, however, add no damping to the system. In some cases such turbines can even reduce the damping in the system.

In this work controllers are designed that enhance the two considered turbine types to actively dampen power system oscillations. To test the controllers under worst case conditions, the fault, which excites the power system oscillations, is simulated close to the wind turbines. Hence the turbines have to ride through this fault, before they can perform power system stabilisation. This poses the problem that the transition from transient fault operation to power system stabilisation operation, has to happen as quickly as possible on one hand, and as smoothly as possible on the other hand. The controllers presented in this thesis achieve a good compromise between these two constraints. For an active-stall turbine this is generally not too difficult, as the generator speed oscillations are damped naturally by the grid. In the variable speed turbine a compromise is found, that allows the transient fault controller to dampen drive train oscillations to a level that can be handled by the drive train stabiliser. At the same time, the power system stabiliser cuts in early enough, to have a strong damping impact on the power system oscillations.

The power system stabilisers strive for injecting oscillating power into the grid that counteracts the power system oscillations. In case of the active-stall turbine it is found, that controlling the pitch system to achieve this goal is a difficult task. Due to the nonlinearities in the wind turbine, and the limited performance of the pitch system, oscillating power with the right frequency and phase angle is hard to achieve. However, two different pitch controllers are presented that achieve this goal: a conventional PID controller, and a novel fuzzy logic controller. The latter one enhances the active-stall turbine to add controlled damping to the system at any operating point.

Since in a variable speed turbine the electric power is solely controlled by the inverter, the power system stabiliser can make 100% of the turbine’s power available for system stabilisation. Hence the variable speed turbine is capable of adding substantial damping to the system, provided that the aerodynamic power is sufficient for replenishing the kinetic energy stored in the drive train.

It can be concluded that the power system stabilisers, presented in this thesis, allow the respective wind turbines to add to the damping of power system oscillations. It
can further be concluded, that the variable speed turbine is clearly more suitable for this task than the active-stall turbine.

6.3 Future Work

To further utilise the results of this project, the author suggests that in future the following work should be carried out.

The simulation models used in this project should be refined according to the findings made in this project. To further pursue power system stabilisation with active-stall turbines, more attention has to be drawn to the models that are involved in the control of the aerodynamic power.

- Since the active-stall turbine needs to pitch a lot, and often with the maximum pitch rate, the structural dynamics of the rotor blades might have a noticeable impact on the aerodynamic power. Only minor twisting of the blades can lead to large differences in power. Figure 17 shows, that for the largest part of the wind turbine’s operating range, the difference between the pitch angle of full power and of zero power is less than 8 degrees. Hence, if there are torsional oscillations in the blades, these might have a visible effect on the aerodynamic power.

- Dynamic inflow might have an impact on large and fast pitch angle variations of active-stall turbines. It is expected that dynamic inflow has a positive impact on intended quick power variations, as it acts differentiating [62].

- The pitch system has been identified as the main limitation in the active-stall turbine. It is pushed hard during transient operations, and therefore it would be advantageous to have it represented by a more detailed model.

Transient operations, as described in this thesis, are expected to cause considerable mechanical loads for wind turbines. Transient fault ride-through has been demanded from wind turbines for only a few years yet. Therefore, its impact on the mechanical loads, and on the turbines’ lifetime, is by and large unknown. Power system stabilisation with wind turbines is completely new, hence the mechanical loads it causes, are completely unknown. Therefore, research should be conducted on the possible consequences for the turbines’ lifetime.
Finally the designed controllers have to be used for power system analysis. In previous research the impact of increasing levels of wind power penetration has been investigated. Such studies have to be repeated, this time with wind turbines that are equipped with the transient fault controllers and the power system stabilisers presented in this thesis.
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International Comparison of Requirements for Connection of Wind Turbines to Power Systems

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International Comparison of Requirements for Connection of Wind Turbines to Power Systems

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Power production from wind turbines has increased considerably during the last decade. Therefore today’s wind turbines, which are typically set up in wind farms, have a significant influence on the operation of power systems. The efficient and secure operation of power systems is supported by grid codes, which are sets of requirements for all network users (suppliers, customers, etc.). In Europe, several transmission network operators have introduced special grid connection requirements for wind farms. These requirements are mainly based on existing grid codes, initially written for conventional power plants usually equipped with synchronous generators. This article presents a comparison of grid connection requirements for wind farms issued, or proposed as a draft, by transmission network operators in Denmark, Sweden, Germany, Scotland and Ireland. Copyright © 2005 John Wiley & Sons, Ltd.

Introduction

The relationship of transmission system operators (TSOs) with all users of the transmission system (generators, consumers, etc.) is outlined in grid codes. The objectives of the grid codes are to secure efficient and reliable power generation and transmission, to regulate rights and responsibilities of the entities acting in the electricity sector.

In the past there was usually no wind power connected to the power system, or the percentage of wind power penetration was extremely small compared with total power production. Therefore grid connection requirements (GCRs) for wind turbines (WTs) or wind farms (WFs) were originally not included in the grid codes. As wind power started to be developed more actively at the end of the 1980s, each network company that was facing an increasing number of WFs elaborated its own connection rules.

During the 1990s, those connection rules were harmonized at national level, e.g. in Germany and Denmark. This harmonization process often involved national network associations as well as national wind energy associations, which represented the interests of WF developers and owners.

In recent years rapid development of wind turbine technology and increasing wind power penetration, as shown in Figure 1 and Table I, have resulted in continuous reformulation of the GCRs and creation of requirements for wind power even at transmission level. Some TSOs still have unified requirements for all production units, which makes it very difficult for WT producers and WF developers to fulfil these GCRs. Other TSOs

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have defined special GCRs for wind power based on existing requirements for conventional production units.

Unfortunately, the continuously changing GCRs make a comparison or evaluation of the already very complex GCRs very difficult, and only a small amount of literature exists.\(^1\)\(^2\) A comparison of existing GCRs can help:

- to solve or reduce controversies between WF developers and network operators regarding connection requirements;\(^3\)\(^4\)
- WT producers to gain a better understanding about the existing requirements, which may help to develop new hardware and control strategies;
- to provide an understanding of the relevant issues for those countries, regions or utilities that are still in the process of developing GCRs for WFs;

Since GCRs, especially those newly and specifically developed for WFs, are subject to frequent revision, it is difficult to make a comparison that is always up to date. In this article the state of GCRs in force, or published as proposals, in spring 2004 is considered. Changes that the GCRs have undergone in the meantime could not be taken into account.

### Selection of Countries and System Operators

In this article, GCRs of several countries which are proactively meeting the challenge of considerable wind power penetration are analysed. The countries considered are Denmark, Germany, Ireland, Sweden and Scotland. The selection of countries is not complete, for the sake of comprehensibility. Equally, the selection of TSOs in the respective countries is not complete either.
Denmark has two TSOs, Eltra and Elkraft, which both use the same GCRs (referred to as Eltra further in the text). These GCRs are the first worldwide which were specifically made for WTs connected to the transmission system, and they are currently under revision. Offshore WFs of considerable size (>150 MW) are already today directly connected to the transmission system (voltage > 100 kV), and larger WFs are expected. Eltra states on its homepage (www.eltra.dk) that its GCRs for WFs are a preparation of the power system for the large offshore WFs to come.

The GCRs for the Danish distribution system (referred to as Eltra&Elkraft further in the text) are still in draft form but are expected to affect WTs connected after 1 July 2004. In Denmark an ever-increasing part of the electrical power comes from distributed generators connected to the distribution system (voltage < 100 kV). Therefore the Danish TSOs also have to issue GCRs for generators connected to the distribution system, to ensure reliable operation of the whole power system.

It is anticipated that the Scottish transmission system will have to accommodate a lot of wind power in the near future. To facilitate a high level of wind power penetration, the Scottish TSO has issued a guidance note for the connection of wind farms (referred to as Scot further in the text). WFs will in future be required to ride through any disturbances (without tripping) as successfully as the conventional power plants they replace. The requirements will be applicable to WFs of at least 5 MW, irrespective of the voltage level to which they are connected. This guidance note is still a draft version and is in discussion with the wind power industry, which is represented by the British Wind Energy Association (BWEA). BWEA has published its comments on the guidance note. Some of the requirements will be phased in over the next 3 years. Here, phasing-in dates are not considered, only the final state of the requirements is deemed important.

The connection requirements of the Swedish TSO Svenska Kraftnät (referred to as SvK further in the text) concern all WTs or WFs with rated power > 0.3 MW. It should be pointed out that SvK states requirements for all types of generators, although with regards to some aspects, e.g. frequency control, special requirements are stated for wind power. This document is still a draft version and is currently under revision.

Different companies run the interconnected German transmission system. Here only the GCRs of E.ON Netz (referred to as E.ON further in the text) are considered, since E.ON has issued new GCRs on the basis of increasing penetration of sustainable energy generators (mainly WTs). They apply to WFs connected to high-voltage networks (60 and 110 kV) and extra-high-voltage networks (220 and 380 kV).

Finally, the Electricity Supply Board National Grid in Ireland (ESBNG) has elaborated a draft proposal for requirements for connection of wind farms (referred to as ESBNG further in the text). The document is intended to apply to WFs connected to the transmission system (110, 220 and 400 kV) with a registered capacity of 30 MW and more. This is mainly a clarification of how the existing grid code should be interpreted for connection of WFs, although some requirements are specially adapted to make it easier for WFs to comply with them.

Comparison of Connection Requirements

Active power control

From a power system operator’s point of view the ability to control active power is important for two reasons: during normal operation to avoid frequency excursions; during transient fault situations to guarantee transient and voltage stability. In this article both aspects are covered in one section, since the GCRs generally do not distinguish between active power control for normal operation and for transient fault operation.

To secure stable power system operation, the exchange of power in the grid has to be in balance. Changes in power supply or demand can lead to a temporary imbalance in the system and thereby affect operating conditions of power plants as well as consumers. To avoid long-term unbalanced conditions, the power demand is forecast and power plants adjust their power production accordingly. The requirements for active power control are thus stated in order to ensure stable frequency in the system, prevent overloading of transmission lines, ensure that power quality standards are fulfilled and avoid large voltage steps and inrush currents at start-up and shutdown of WTs.
Power control is also important for transient and voltage stability during faults. If the power can be reduced efficiently as soon as a fault occurs, the turbine can be prevented from going into overspeed.\(^{13}\) Considering turbines with directly grid-connected induction generators, the reactive power demand is less after the fault is cleared, which helps in re-establishing the grid voltage.\(^{14}\) Another concern from the viewpoint of the power system operator is the rate at which power is ramped up after a fault has been cleared. The requirement for ramp rates is made to avoid power surges on the one hand and to avoid that generation is missing because generators ramp up too slowly on the other hand. Both cases would mean power imbalance, which could lead to instability even though the initial fault has been cleared.

Power control is required in all considered GCRs. The requirements vary greatly and depend, among other factors, mainly on the short-circuit power of the system considered. The lower the short-circuit power, the more demanding is the power control necessary for keeping the system stable during and after a fault.

*Eltra* and *Eltra&Elkraft* requirements for active power control state that the 1 min average of active power should not exceed the setpoint by more than 5\% of maximum power of the WF. *E.ON* and *ESBNG* require the WF’s active power to be less than registered capacity at any time. *Scot* states that registered capacity should not be exceeded over an appropriate averaging period.

In addition, *Eltra* and *SvK* require the technical possibility to reduce active power to <20\% of maximum power in 2 s (*Eltra*) or 5 s (*SvK*) by individual control of each WT, when demanded.

According to *Eltra&Elkraft*, the rate of change in active power should be adjustable within a range of 10\%–100\% of registered capacity per minute.

*E.ON* requires active power reduction of minimum 10\% of registered capacity per minute. In the wake of loss of grid voltage, power has to be ramped up with a gradient of not more than 10\% of rated power per minute. This ramp can be realized in steps (reconnection of single WTs) if the step size does not exceed 10\% of rated power per minute.

*ESBNG* requires that, in any 15 min period, active power output change is limited as follows: 5\% of registered capacity per minute for WFs < 100 MW, 4\% for WFs < 200 MW and 2\% for WFs > 200 MW.

In *Scot* the maximum power change is defined as four times registered capacity of the WF per hour, for WFs under 15 MW the limit is 60 MW h\(^{-1}\), while for WFs above 150 MW the limit is 600 MW h\(^{-1}\), which is the normal loading and unloading rate of Scottish thermal units. This is the average change in power output measured over any 10 min period. However, the rate of change in the 1 min average should not exceed three times the rate of change in the 10 min average.

In some regulations there are also requirements regarding start-up and shutdown of WFs. *Eltra* requires WFs to have a signal documenting the cause of past WF shutdowns. This signal should be a part of logic managing start up of WTs for operation. *Scot*, *Eltra* and *E.ON* state that WF operation at start-up and shutdown should comply with voltage quality requirements. In addition, *Scot* requires WFs to comply with maximum power change rates as described above. *SvK* states that high wind speed must not cause simultaneous stop of all WTs within WFs, maximum permissible power reduction is 30 MW min\(^{-1}\). Similarly, in *Scot* it says that no more than 25\% of registered capacity may be tripped; instead a controlled reduction in output should be achieved over a 30 min period.

**Frequency range and control**

Frequency in the power system is an indicator of the balance between production and consumption. For normal power system operation the frequency should be stable and close to its rated value. In Europe the frequency is usually 50 ± 0.1 Hz and falls out of the 49–50.3 Hz range very seldom.

The imbalance has to be catered for by the generation, since load is usually not controllable. For this purpose, primary and secondary frequency control is used. The primary control units increase or decrease their generation until the balance between production and consumption is restored and frequency has stabilized. The frequency is then not necessarily stabilized on its rated value, and primary control reserves are partly engaged. The time span for this control is 1–30 s. In order to restore the frequency to its rated value and to release engaged primary reserves, the secondary control is employed with a time span of 10–15 min. The secondary
control thus results in a slower increase/decrease in generation. In some countries, automatic generation control is used, in other countries the secondary control is accomplished manually by request from the system operator.

At normal operation the power output of a WF can vary by 10%–15% of installed capacity within 15 min. This could lead to additional imbalances between production and consumption in the system. Considerably larger variations in power production may occur during and after extreme wind conditions.

When comparing the frequency operating ranges, the stiffness of the grids considered has to be borne in mind. Small systems are more prone than large systems to deviate from rated frequency in the case of imbalance between load and generation. The Danish system and the Scottish system become small when their few connections to their neighbouring systems are lost. In addition, the Danish system is weakened owing to the many small, dispersed generators; and the Scottish system is embedded in the British system, which is inherently small compared with the system in continental Europe.

Figure 2 illustrates the requirements for frequency range tolerance and frequency control in the considered countries. ESBNNG requires WFs to include primary frequency control in the WF control system. For this purpose it has to be possible to dispatch 3%–5% of rated capacity for primary frequency control (as required for thermal power plants). ESBNNG and some other regulations also require WFs to be able to participate in secondary frequency control. This can be achieved at overfrequencies by shutting down some WTs within WFs or by pitch control. Since wind cannot be controlled, power production at normal frequency would be intentionally kept lower than possible so that the WF is able to provide secondary control at underfrequencies. SvK
specifically notes that generators are not obliged to fulfil the requirements given in Figure 2 in the case of insufficient wind speed.

A transient fault in an interconnected power system can lead to swings in the system frequency. It is desirable that the frequency tolerance of generators is as wide as possible to avoid that under such post-fault conditions the situation gets worse because generation is lost.

Extensive frequency operating ranges have effects on the operation of turbines. The speed of constant speed WTs depends directly on the grid frequency. The aerodynamic properties of the WT blades is non-linearly dependent on the tip speed ratio and hence on the speed of the turbine. In the case of the Scottish system, constant speed stall WTs are practically ruled out by the new requirements. The power of constant speed stall turbines at higher wind speeds drops more than *pro rata* with frequency, which is not allowed according to Scot. Variable speed turbines, on the other hand, can run at the desired speed irrespective of the grid frequency.

**Voltage control**

*Reactive Power Compensation*

Utility and customer equipment is designed to operate at a certain voltage rating. Voltage regulators and control of reactive power at the generator and consumer connection points are used in order to keep the voltage within the required limits and to avoid voltage stability problems. WTs are also required to contribute to voltage control in the power system.

In Figure 3 the reactive power requirements are compared in terms of power factor. Note that ‘lagging’ refers to production of reactive power and ‘leading’ to absorption of reactive power. In generator sign convention the current lags the voltage when reactive and active currents are positive. In Figure 3, only the operating limits are considered, i.e. it is not taken into account under which voltage conditions the respective amount of reactive power is demanded.

Reactive power is in the first instance required to compensate for the reactive power demand of the generator, transformer and other inductive equipment, such that the wind power installation does not burden the power system with reactive power demand. If the wind power installation absorbs reactive power, the thermal capacity of the conductors connecting the installation with the power system is to a lesser extent available for active power transfer. In addition, the voltage at the generator terminals is suppressed owing to the voltage drop caused by the reactive current flowing into the wind power installation.

The second reason for reactive power requirements is that generators can actively control the voltage at their terminals by controlling reactive power exchange with the grid. Especially during transient faults the voltage,
has to be supported, since the reactive power demand of induction generators increases when the voltage drops.\textsuperscript{17,18} Generators with voltage source inverters can support the system voltage at their terminals by exporting reactive power,\textsuperscript{19} in order to boost their active power export during the fault and hence mitigate the problem of acceleration.

The reason why generators are also required to absorb reactive power (leading power factor), as illustrated in Figure 3, is operating conditions such as lightly loaded system conductors.

Comparing the reactive power requirements, it becomes clear that the more the WFs equal power plants (big capacity and connected to a high voltage level), the wider is the power factor range demanded. In Scot, exactly the same performance is demanded from WFs as from comparable conventional power plants. Scot may perhaps be relaxed before being brought into force, since it is specifically made for WFs and is still in discussion with BWEA.\textsuperscript{8}

\textit{Eltra} and \textit{SvK} are comparably slack, demanding only a neutral power factor over the whole range of active power. Therefore these two reactive power compensation requirements are not illustrated in Figure 3.

\textit{E.ON} requires that the steps in reactive power compensation are $\leq 0.5\%$ of registered capacity. Steps smaller than 25 kVAr are not required though. The purpose of this regulation is to avoid high inrush currents due to switching transients and to comply with permissible voltage steps. It has to be possible to operate WFs with a rated power of less than 100 MW with a power factor between 0.95 lagging and 0.95 leading. The required power factor values always apply at the grid connection point. WFs rated at 100 MW or more have to be able to operate at a power factor between 0.925 lagging and 0.95 leading. The power factor range is, however, limited depending on the grid voltage to avoid a leading power factor at grid voltages below rated. It has to be possible to run repeatedly through the whole applicable range of power factor within a few minutes.

In \textit{E.ON}, generators with small fault current contribution are required to support grid voltage in the case of faults by supplying reactive power proportional to the voltage drop. Between 10\% and 50\% voltage drop the generators have to supply reactive current between 10\% and 100\% of rated current, linearly proportional to the voltage. Generators with big fault current contribution, on the other hand, are not required to contribute to voltage support during transient faults.

\textit{Tap Changers}

Tap-changing transformers are used to maintain predetermined voltage levels. The voltage in the WF can be maintained within a certain range irrespective of the system voltage and the operating point of the WF.

In \textit{E.ON} it is recommended to equip WFs with a tap-changing grid transformer so that the transformer ratio can be varied and the voltage at the point of connection to the network can be controlled.

Similarly, \textit{Scot} states that WFs rated at 100 MW or more should have manually controlled tap-changing transformers to allow the grid operator to dispatch the desired reactive power output. WFs rated at between 5 and 100 MW may use this method if they have their own transformer, or may use other methods of controlling reactive power agreed with Scottish Power at the application stage.

\textit{ESBNG} requires that each transformer connecting a WF to the network should have an on-load tap changer. The tap step should not alter the voltage ratio at the HV terminals by more than 2.5\% on the 110 kV system or 1.6\% on the 220–400 kV systems.

\textit{Transient fault and voltage operating range requirements}

In this section the voltage operating ranges and the corresponding trip times are compared. The comparison considers the requirements in terms of ‘WTs have to stay connected to the grid’. Requirements stating delay times after which WTs have to disconnect once they no longer need to stay connected are not deemed important. This is done because, from the viewpoint of WTs, the time during which severe operating conditions have to be tolerated is most relevant. The comparison of the different voltage operating ranges and their corresponding trip times in Figure 4 shows only the outermost operating limits. This means that no correlation with active or reactive power, as specified in the GCRs, is considered here. In the case of \textit{Scot}, only the limits for
the 132 kV grid are shown, as these are the most onerous. For the same reason, only the limits for the 110 kV grid are shown for ESBNG.

Since no specific voltage/trip time characteristic is given in Eltra, this has to remain missing in this comparison. Simulations with specific WF and grid topologies have to be carried out to assess the stability requirements for the Eltra transmission grid, as outlined later in this section.

Eltra, Eltra&Elkraft, Scot and E.ON specify not only voltage operating limits, but also mention specifically ride-through of transient faults to sustain generation.

When a voltage dip occurs during normal operation of the WT, the current rises in order to export the same amount of power as before the voltage dip. This implies that the whole WF must be designed for currents bigger than rated current.

When a three-phase short-circuit fault occurs in the system, the voltage at the generator terminals drops to a level depending on the location of the fault, and the WT might not be able to export as much power as is input by the wind.17 If a WF is connected by a radial feeder only, and a three-phase short-circuit occurs on this feeder, the WF can only export as much power as is dissipated in the resistances of the generators, transformers, lines and the fault. Only in Eltra are WFs exempted from having to attempt to ride through transient faults that open-circuit the WF terminals. The amount of power dissipated during such a fault is, depending on the operation point of the WF, often only a fraction of the mechanical input power. As soon as the circuit breakers open to isolate and clear the fault, the WF is isolated and cannot export any power. Hence during the fault, and even more during the clearance of the fault, the WTs can only store the mechanical input power by accelerating. As long as the WTs are freely accelerating, the slip in the generators (assuming induction generators) is zero. However, acceleration implies that the slip after the clearance of the fault is bigger than prior to the fault. The bigger the slip, the bigger is the reactive power demand of the generator, and this implies that it is much more difficult for the voltage at the WF terminals to recover after the fault has been cleared. The longer it takes for the voltage to recover, the longer is the period during which the WT is in imbalance between mechanical input power and electrical output power, i.e. the WT accelerates, or at least draws more reactive power.14,20,21

Figure 4. Requirements for voltage operating range
In the case of a two-phase fault the imbalance between input and output power, as well as the speed and reactive power demand problem as described above, is less serious. However, with this type of fault the voltage becomes unbalanced and this implies that the current becomes unproportionally more unbalanced, again assuming induction generators. This can be explained by means of the equivalent circuit of induction machines where the rotor resistance is divided by slip. Under normal operation, slip is small (<0.1), i.e. the rotor resistance is big. If the voltage at the generator is unbalanced, it contains a negative phase sequence (NPS) component. This NPS voltage rotates in the opposite direction to the grid voltage; hence, considering this NPS voltage, slip is very big (approximately 2), i.e. the rotor has a small resistance. This implies that the NPS component of the grid voltage drives a large NPS current, which might trip the protection equipment and hence prevent the turbine from riding through the fault.

For the sake of comprehensibility the requirements for fault ride-through are further discussed below in separate subsections for each GCR.

**Eltra**

No specific voltage operating ranges and respective trip times in transient fault situations are specified in *Eltra*. Simulations of specific grid topologies and WFs have to be carried out in order to determine voltage values likely to occur at the WT terminals. It is stated, however, that the requirements do not apply to radially connected WFs, where a fault would isolate the WF, i.e. WFs do not need to ride through faults whose clearance would open-circuit the WF terminals. Under such circumstances the WF may disconnect.

WFs have to stay connected and stable under a permanent three-phase fault on any arbitrary line or transformer and under a transient two-phase fault (unsuccessful auto-reclosure) on any arbitrary line.

In the wake of a fault the voltage can be down to 70% of the initial voltage for a duration of up to 10 s, which must not lead to instability of the WF.

The controllability of the WF must be sustained for up to three faults within 2 min or for up to six faults if the delay between the faults is 5 min, each fault occurring during steady state operation. This requirement makes sure that the turbines are fitted with sufficient auxiliary power supplies.

When the voltage directly after a fault falls below 60%–80% for longer than 2–10 s, it is likely that the turbines have accelerated so much that the grid cannot get them back to normal speed. In such a case a fast reduction in active power and a fast increase in reactive power have to be conducted. If this does not successfully re-establish the grid voltage, the WF has to be disconnected.

**Eltra&Elkraft**

According to *Eltra&Elkraft*, WTs have to stay connected to the grid in the case of three-phase faults for 100 ms. Two-phase faults with or without involvement of ground have to be coped with for 100 ms, followed by an auto-reclosure after 300–500 ms, which leads to a new short-circuit (unsuccessful auto-reclosure) for a duration of another 100 ms.

The WTs have to be able to sustain operation during at least six such faults in a 5 min interval. The protection relays in the turbines must not trip from the currents occurring during such grid faults.

In *Eltra&Elkraft* it is specifically stated that turbines may disconnect for their own protection if the voltage drops below the limit depicted in Figure 4. If, however, this limit is not exceeded, the turbines must not disconnect in order to sustain generation.

**E.ON**

E.ON’s requirements for transient fault behaviour are split into two categories: one for generators with big fault current contribution at the grid connection point, i.e. the fault current is at least twice the rated current for at least 150 ms, and one for generators where the fault current contribution is less than that. Simulations of WFs with specific turbine types and farm layouts have to be conducted to determine to which category the farms belong.
In *E.ON* it is stated that if the grid voltage at the connection point of the WF falls in a quasi-stationary manner (i.e. the voltage does not change faster than 5% min$^{-1}$) below 80% of the value before the voltage dip, disconnection must occur at the earliest after 3 s and at the latest after 5 s.

**Generators with Big Fault Current Contribution.** A three-phase short-circuit in the transmission system close to the connection point, with a fault clearance time of 150 ms, must not lead to instability or disconnection of the generator, provided that the short-circuit ratio of the grid is bigger than 6 after the fault clearance. If the short-circuit ratio is less, a shorter fault clearance time can be agreed. This requirement applies irrespective of the operating point prior to the fault. Furthermore, it is required that dynamic effects in the wake of transient faults, which might cause longer lasting voltage dips, must not lead to disconnection of the generator.

**Generators with Small Fault Current Contribution.** In addition to the voltage tolerance shown in Figure 4, generators with small fault current contribution also have to fulfil requirements concerning power ramp rates after faults. It generally applies that, after fault clearance, power output has to be ramped up with at least 20% rated power per second, unless the voltage recovers only slowly. If the conditions for slow voltage recovery (which will not be outlined in detail here) are fulfilled, power output may be ramped up with 5% rated power per second.

It can be agreed that the generator may briefly disconnect if the voltage behaves such that a power ramp of 5% rated power per second would be justified. In this case the generator has to resynchronize no later than 2 s after the fault clearance and power output has to ramp up with at least 10% rated power per second.

**Scot**

In *Scot* it is stated that during transient faults the system voltage can go down to zero for the duration of the fault clearance time. Including back-up protection trip times, the clearance time can extend to a maximum of 300 ms.

The acceleration of the turbines caused by imbalance between input and output power during the fault must not compromise the turbines’ ability to supply reactive power and to ride through transient faults.

Figure 4 illustrates the voltage limits and the corresponding trip times that apply at the closest point in the transmission system, i.e. the grid side of the grid connection transformer.

The upper limit of the voltage tolerance is chosen to avoid tripping of protection equipment as a result of transient voltage peaks caused by switching operations in the grid.

**Application at Horns Rev**

In the following example the control system for the newly installed Horns Rev offshore WF is briefly presented. This WF is the first that had to fulfil the requirements outlined in *Eltra*. The control system is currently being implemented, so practical experiences do not yet exist. The following information is based on Reference 22.

The offshore WF Horns Rev is located in the North Sea, approximately 15 km west of Denmark. The installed power is 160 MW, divided into 80 WTs laid out in a square pattern. The turbines are arranged in 10 columns with eight turbines in each. Two columns make a cluster of 32 MW where the WTs are connected through radial feeders. Each cluster is connected to the offshore transformer substation where the 34–165 kV transformer is located.

From an electrical point of view, new specifications and requirements for connecting large-scale WFs to the transmission network had to be met in the project. As mentioned before, the TSO (Eltra) has formulated requirements for power control, frequency, voltage, protection, communication, verification, transient fault ride through and tests. According to those requirements, the WF must be able to participate in the control tasks on the same level as conventional power plants, constrained only by the limitations imposed by the existing wind conditions. For example, during periods with reduced transmission capacity in the grid (e.g. due to service or replacement of components in the main grid) the WF might be required to operate at reduced power levels with all turbines running. Another aspect is that the WF must be able to participate in the regional balance control (secondary control).
The general control principle of the WF has to consider that the control range of the WF depends on the actual wind speed. Furthermore, as the wind speed cannot be controlled, the power output of the WF can only be throttled. For instance, if the wind speed is around 11 m s$^{-1}$, the power output from the WF can be controlled to any value between 0 and approximately 125 MW.

Some of the key elements of the overall control strategy are illustrated in Figure 5 and briefly described below.

- The *absolute power constraint* control approach limits the total power output of the WF to a predefined setpoint.
- The *balance control* approach allows one to reduce the power production of the overall WF at a predefined rate and later to increase the overall power output, also at a predefined ramp rate.
- The *power rate limitation* control approach limits the increase in power production to a predefined setpoint, e.g. maximum increase in power production 2 MW min$^{-1}$. It is important to emphasize that this approach does not limit the speed of power reduction, as the decrease in wind cannot be controlled. In some cases, however, this can be achieved when combined with the *delta control* approach.
- *Delta control* reduces the amount of total power production of the WF by a predefined setpoint, e.g. 50 MW. Hence, if *delta control* is now combined with a *balance control* approach, the production of the WF can be briefly increased or decreased according to the power system requirements. A WF equipped with such a control approach can be used to supply automatic secondary control for the power system.
- Eltra also requires that a WF must be able to participate in the secondary frequency control. This is achieved by combining *delta control* with a frequency controller implemented directly in each individual turbine in the WF.
- A control feature for fault ride-through is implemented in the control system of each WT. By applying pitch control, the turbine speed is kept close to nominal speed during and after a fault. By controlling the reactive power demand during and after the fault, the risk of a voltage collapse due to excessive reactive power demand is avoided. The turbines can stay connected to the grid for voltage drops to even 0 V for up to 200 ms. To ensure that the control system works even under such conditions, a UPS back-up system supplies the essential units of the turbine.\(^2\)

### Conclusions

This article presents a comparison of regulations for the interconnection of WFs with the power system. The regulations considered are those in force, or published as proposals, in spring 2004. Most of the analysed documents are still under revision and have perhaps undergone some changes, or probably will undergo some changes in future.

The comparison reveals that the requirements differ significantly among the countries considered. This depends on the properties of each power system as well as on the experience, knowledge and policies of the TSO.

The requirements are based on existing grid codes written for conventional power plants with synchronous generators, and most requirements are therefore well defined only for rated operation of WFs (i.e. only a few
It is necessary to define the requirements for the whole operating range of WFs. To make it easier for WT manufacturers to comply with the GCRs, a more harmonized approach would be useful.

References


Simulation Model of a Transient Fault Controller for an Active-Stall Wind Turbine

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Simulation Model of a Transient Fault Controller for an Active-Stall Wind Turbine

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ABSTRACT
This paper describes the simulation model of a controller that enables an active-stall wind turbine to ride through transient faults. The simulated wind turbine is connected to a simple model of a power system. Certain fault scenarios are specified and the turbine shall be able to sustain operation in case of such faults. The design of the controller is described and its performance assessed by simulations. The control strategies are explained and the behaviour of the turbine discussed.

Keywords: active-stall, wind turbine, controller, simulation model, transient fault, fault ride through, DlgSILENT, PowerFactory.

1 INTRODUCTION
In many countries of the world wind power is expanding and covers a steadily increasing part of these countries’ power demand. However, if wind turbines are to substitute for conventional power plants they have to take over many of the control tasks that keep the power system stable [1]. One of these control tasks is ‘to ride through’ transient faults in power systems. This means that generation must not be lost due to voltage excursions caused by transient faults. As wind power penetration increases, the respective power system operators are concerned about the stability and reliability of their networks. This is why many power system operators issue grid connection requirements that specifically address wind turbines and demand them to ride through transient faults. The first grid connection requirement of this kind was issued by the Danish transmission system operators [2]. These requirements have been in effect for several years and are applicable to wind farms connected to the transmission system.

One of the standard turbine types, which can be subject to these grid connection requirements are fixed-speed active-stall turbines. Therefore the author developed a controller that enables active-stall turbines, with conventional hardware, to fulfil these requirements. This controller is presented and its performance discussed in this article, which is a direct continuation of Jauch et al. [3], describing an active-stall controller for
continuous, fault free operation. The wind turbine model and the controller model described in Jauch et al. [3] are the basis for the controller presented here. The underlying idea for the development of the transient fault controller is that no hardware modifications in the turbine should be required. The goal is to develop a control strategy that is capable of making a standard active-stall wind turbine fit for transient fault ride through.

The simulation environment in which this transient fault controller is developed is the power system simulation tool PowerFactory from DlgSILENT [4]. The wind turbine considered is connected to a transmission system with a feeder configuration, to which the Danish grid connection requirements apply. Several fault scenarios are simulated and the performance of the controller discussed.

2 POWER SYSTEM MODEL

As stated in ELTRA [2] these requirements consider wind farms that are connected to the transmission system, i.e. the grid with a system voltage higher than 100 kV. Wind farms are considered connected to the transmission system if there is no load connected between the wind farm and the transmission system.

It is also stated that wind farms are required to have sufficient reactive power compensation to be neutral in reactive power at any operating point. This requirement applies at the connection point to the transmission system.

In this work a single wind turbine, instead of a wind farm comprising many wind turbines is considered. The ratings of all power system components, i.e. cables, transformers and the compensation unit, are chosen accordingly.

The power system model as used in these simulations is illustrated in Figure 1, which shows a compensation unit connected to the wind turbine terminal. This compensation unit, comprising a capacitance and a variable reactance, controls the reactive power flow on the HV side of the 33/132 kV transformer to be zero under normal operation. During a transient fault the compensation unit stays connected to the system.

As described in ELTRA [2], in case of short circuit faults, operation only has to be sustained if the clearance of the fault does not isolate the wind turbine. This is the case if (i) the fault happens somewhere remote in the transmission system, or (ii) if the wind farm is connected through a ring feeder, the fault happens on one of the two legs of the ring feeder. To simulate the biggest possible impact, faults on a leg of the ring feeder have been chosen. Therefore one of the two parallel 132 kV feeders is split up into two sections with a bus between the sections. The fault happens on this bus (called Fault Bus in Figure 1) and the clearance of the fault happens by isolating this bus.

![Figure 1: Grid Diagram.](image-url)
3 WIND AND WIND TURBINE MODELS

The wind and wind turbine models are the same as described in Jauch et al. [3], hence they will be described only very briefly here.

The wind model is a single wind speed signal model. It takes natural wind speed variations and the 3p effect caused by the tower shadow into account. The long-term average of this wind speed signal is a parameter that is called $v_{mean}$ in the parameter list in section 6.3. For a detailed description of the wind model see Sørensen P. et al. [5].

The aerodynamic model, which represents the aerodynamic properties of the turbine rotor is described in a $C_q$ table. Input to this table is (i) the tip speed ratio, comprising the wind speed signal and the rotational speed of the rotor, and (ii) the pitch angle.

The mechanical structure of the turbine is represented by a two masses, with a spring and damping model of the drive train.

A detailed description of the mechanical and aerodynamic model can be found in Sørensen P. et al. [6] and Hansen A.D. et al. [7].

Details about the implementation of the wind and wind turbine model into the simulation tool PowerFactory are given in Hansen A.D. et al. [8].

The generator is a squirrel cage induction machine, which is a standard model in the PowerFactory library.

4 TRANSIENT FAULTS

In this section, the fault scenarios specified in ELTRA [2] are outlined. Successful ride through of these faults is the benchmark for the controller.

Wind farms have to stay connected and stable under the following fault situations:

- 3-phase fault with permanent isolation of the fault
- 2-phase fault with unsuccessful auto-reclosure.

These requirements, however do not apply to faults on radial feeders connecting wind farms, i.e. feeders where the clearance of a fault would isolate the wind farm.

Generally no auto-reclosure is to be expected in case of a 3-phase fault. For 3-phase faults the typical fault clearance time is 100 ms.

For 2-phase faults where auto-reclosure is attempted, the typical clearance time is also 100 ms, a typical auto-reclosure time is 300 ms and a typical final clearance time is 100 ms to 500 ms.

In the wake of a fault, the voltage can drop to 70% of the unperturbed voltage, for a duration of up to 10 seconds. Even under these conditions, the turbines must be able to carry out the control actions required to re-establish stable operation.

Furthermore it is stated in ELTRA [2] that wind turbines have to be capable of controlling their output power. As a measure for sufficient controllability, wind turbines are required to be able to reduce their output power to 20% rated power within two seconds, starting from any operating point. In a transient fault situation, the full power decrease and the subsequent power increase must be possible within approximately 30 seconds.

Here the assumption is made that the turbine is equipped with sufficient auxiliary power supply for the turbine’s own power demand to be covered during these 30 seconds.

5 CONSEQUENCES OF A SHORT CIRCUIT FAULT FOR A WIND TURBINE

To introduce the problem Figure 2 shows the response of an ordinary active-stall turbine without a transient fault controller, when subject to a 3-phase fault as described above.
During the fault the voltage at the generator terminals drops and hence also the active power drops to close to zero. Since the wind turbine controller does not attempt to reduce the mechanical power input, the turbine accelerates. This can be seen from the generator speed, which increases steeply. The generator accelerates for two reasons: One reason is that the rotor accumulates rotating energy during the fault, since there is still mechanical power input, although no power can be exported during the fault. The second reason is that the drive train acts like a torsion spring that gets untwisted during the fault [9]. During normal operation, the aerodynamic torque from the rotor acting on one end of the drive train and the electrical torque from the generator acting on the other end, twist this spring. During the fault, the electrical torque drops to zero, which untwists the spring.

By the time the fault is cleared, the generator has accelerated considerably beyond its rated speed. This implies that the reactive power demand of the generator has also risen considerably [10]. The reactive power demand of the generator lets the voltage recover only slowly. Due to the torsion spring characteristic of the turbine drive train, the generator speed oscillates. This oscillation leads to oscillations in active and reactive power, which in turn leads to oscillations in voltage. The oscillations are too lightly dampened and so they increase. A recovery of voltage and speed is not possible. It has to be noted that the situation depicted in Figure 2 is only possible in theory. In practice the overspeed protection system of the turbine would stop the turbine to prevent damages. The mechanical structure of the turbine would ultimately suffer severe damage from such extensive speed oscillations.

The short circuit power of the transmission system (see Figure 1) is chosen such that this kind of fault leads to instability, i.e. the grid cannot supply enough reactive power to let the voltage recover quickly and hence suppress the oscillations.
6 TRANSIENT FAULT CONTROL

Based on the findings of the previous section, a controller has been developed that enables an active-stall turbine to cope with the transient faults described in section 4. In this section the control strategy and the implementation of this strategy are described.

6.1 Controller layout

Figure 3 shows the control diagram of the wind turbine controller. In Figure 3, the section called “normal pitch controller”, is the pitch controller for normal, fault free operation. The normal pitch controller as well as the “pitch logic” and the “pitch system” are described in detail in Jauch et al. [3].

In addition to the description in Jauch et al. [3], the pitch logic has been supplemented with a bypass switch. The pitch logic avoids unnecessary pitching during normal operation, to avoid mechanical wear in the pitch system. However during a transient fault, pitch control is essential and the prevention of mechanical wear of the pitch system is of low priority. Hence a bypass switch has been added to the section pitch logic (see Figure 3), to feed the pitch angle setpoint directly through to the pitch system in case of a transient fault.

The generator speed, the active power of the generator (P_{\text{generator}}) and the voltage at the generator terminals (V_{\text{generator}}) are used to monitor the condition of the grid.

A transient fault is detected when the active power of the generator drops very steeply. A drop in the voltage at the generator terminals also indicates a fault. After a fault, the voltage is monitored to check whether the system has recovered.

The generator speed is monitored to detect if the generator goes into overspeed. If no abnormality is detected in either the active power, or the voltage, overspeed is an indicator of islanding operation. If a wind turbine becomes isolated from the rest of the system, the voltage will not drop, since the compensation unit of the turbine will keep the generator excited. Instead the turbine is likely to run into overspeed, because the power dissipated in this part of the system is most likely less than the power produced by the turbine. As a result of this imbalance, the turbine accelerates. The active power of the generator might not clearly indicate an islanding incidence, since a steep drop in active power will only be observed if the dissipated power in the system is much less than the generator power. This however depends on the size of the island and the operating point of the turbine. After the clearance of a fault, the actions of the transient fault controller must have brought the speed back to its normal range, before the controller attempts to resume normal operation.

Figure 3: Transient fault controller embedded in wind turbine pitch control system.
The transient fault controller is essentially an open-loop feed-forward controller. When a grid fault is detected, the transient fault controller (in Figure 3, the block “pitch angle ramp”) puts the pitch angle setpoint in a step change to a value where the aerodynamic power is zero. After the fault is cleared, the pitch angle setpoint is ramped up again to its initial value.

For each wind speed there is one particular pitch angle where the power is zero. Since the turbine on hand is an active-stall turbine, this pitch angle is in the negative range, i.e. where the power limiting effect is the stall effect [3]. In Figure 3 the block “zero power θ” contains a two-dimensional lookup table. This table comprises pitch angles at which the turbine generates and absorbs zero power. The graph called “0.0 MW pitch” in Figure 4 shows the content of the zero power pitch angle table. For comparison, the graph “normal operation pitch” shows the pitch angle under normal, fault free operation. The difference between these two graphs is the way the pitch system has to go in case of a transient fault (from normal operation pitch to 0.0 MW pitch and subsequently back again).

6.2 Control sequence
The basic principle of the transient fault controller is to reduce the aerodynamic power of the rotor as soon as a grid fault is detected. The general sequence of the transient fault control strategy is as follows:
1. detection of fault
2. pitch angle setpoint is stepped to angle of zero power
3. check whether pitch system has reached this angle
4. check whether grid voltage has recovered and generator speed is in normal range
5. ramp up of pitch angle to value prior to fault
6. resume of normal operation

If at least one of the conditions for a grid fault is given (steep drop in power, undervoltage or overspeed) the controller steps the pitch angle setpoint to the value of no power (see Figure 4). When the transient fault controller steps the pitch angle setpoint to this value, the pitch system ramps the pitch angle with its maximum pitch rate to the new setpoint.

Figure 4: Pitch angles as a function of wind speed, (i) when the turbine power is zero, and (ii) at normal operation, from start-up to shutdown wind speed.
Once this pitch angle is reached, the fault has to be cleared by the grid protection system, and the grid has to have recovered from the fault, i.e. the voltage returned to its normal range. In addition, the speed of the turbine must have returned to a value below its maximum allowed value.

If the grid has not recovered, or the generator speed is still beyond its limit by the time the pitch angle of zero power is reached, the pitch angle setpoint remains there until the block "grid condition" in Figure 3 sets the flag `grid_OK`, indicating that the turbine can return to normal operation.

Once this flag is flying, the block "pitch angle ramp" ramps the pitch angle setpoint up to the value prior to the fault.

If a new fault condition occurs while the pitch angle is ramped up again, the whole sequence starts from the beginning, i.e. the pitch angle setpoint is immediately stepped to the angle of zero power, and so on.

### 6.3 Parametric design

The controller is designed in a parametric way so its performance can be adjusted to specific wind turbines dimensions and grid characteristics. The parameter settings used for the simulations in this article are designed for a 2 MW turbine as described in detail in Jauch et al. [3]. The parameters of the transient fault controller used in the simulations here are as listed in Table 1, unless stated otherwise.

The maximum pitch rate, $r$, is the physical limitation of the pitch system. It cannot pitch faster than $\frac{8}{s}$, which is a typical value for an active-stall turbine.

$v_{\text{mean}}$ is the long term average wind speed around which the actual wind speed varies. 14 m/s is a wind speed at which the turbine at hand produces rated power, i.e. 2 MW. Rated power operation has been chosen since this is the most demanding operating point for the grid.

$SL_{\text{gen}}$ is the highest allowed generator speed. If this speed is exceeded, the turbine is either in islanding operation or it has not yet recovered from a transient short circuit fault.

$V_{\text{lower}}$ is the lowest possible voltage for normal operation. The value of 0.7 p.u. is specified in ELTRA [2]. If the grid voltage is less than this value this can be an indication of a short circuit fault. In the wake of a short circuit fault it indicates that the grid has not yet recovered.

d$P$/dt is the derivative, i.e. the slope of the active power signal. This parameter has to be set to a value that does not occur under normal operation on the one hand, and makes the controller sensitive enough to detect faults on the other hand reliably.

$T_{\text{ramp}}$ is the time the controller takes to ramp the pitch angle down to the pitch angle of zero power output and immediately after that up again. Hence, with this parameter indirectly the slope, with which the pitch angle is ramped up, can be set. The reason why this indirect method has been chosen is that the time from the onset of the fault to resuming of normal operation is specified in ELTRA [2]. Here a very short time has been chosen. This time is

### Table 1: Parameter settings of wind turbine and transient fault control system.

<table>
<thead>
<tr>
<th>Name</th>
<th>Short description</th>
<th>Value</th>
</tr>
</thead>
<tbody>
<tr>
<td>$r$</td>
<td>Maximum Pitch Rate [°/s]</td>
<td>8</td>
</tr>
<tr>
<td>$v_{\text{mean}}$</td>
<td>Mean wind speed [m/s]</td>
<td>14</td>
</tr>
<tr>
<td>$SL_{\text{gen}}$</td>
<td>Maximum allowed generator speed [p.u.]</td>
<td>1.04</td>
</tr>
<tr>
<td>$V_{\text{lower}}$</td>
<td>Lower voltage limit [p.u.]</td>
<td>0.7</td>
</tr>
<tr>
<td>d$P$/dt</td>
<td>Slope of active power drop [MW/s]</td>
<td>$-200$</td>
</tr>
<tr>
<td>$T_{\text{ramp}}$</td>
<td>Time for pitch angle ramp down and back up [s]</td>
<td>1.6</td>
</tr>
</tbody>
</table>
in practice, too short for the pitch system, since the pitch rate forces the whole time to be longer than specified by this parameter. As will be discussed in the simulations section, the best results were achieved when after the clearance of a fault the pitch angle is ramped up as fast as possible. Allowing 30 seconds for the whole transient fault operation, as stated in ELTRA [2], would lead to a worse dynamic response of the turbine.

In the simulations section some of the parameters will be varied and the consequences of these variations discussed.

7 SIMULATIONS

In this section, the fault scenarios as described in section 4 are simulated and the performance of the transient fault controller assessed. The benchmark for the performance is compliance with the Danish grid connection requirements [2].

Following that, simulations, which describe the function of the transient fault controller, are shown and discussed, and possible improvements to achieve better performance suggested.

7.1 Three phase short circuit

A 3-phase short circuit fault on the Fault Bus (Figure 1) that lasts for 100 ms and gets cleared by permanent isolation of the Fault Bus is simulated in Figure 5. After the clearance of the fault, the drive train is excited into torsional oscillations. These oscillations can be seen in the speed and the active power signal. Two frequency components can be observed: A high frequency, which is the natural frequency of the small inertia on the high-speed shaft of the drive train. The superimposed low frequency component is the natural oscillation frequency of the wind turbine rotor with its large inertia on the low-speed shaft of the drive train.

Figure 5: Wind turbine subject to a 3-phase short circuit fault on the Fault Bus with permanent isolation after 100 ms. Ordinate, proportional change in named variable. Abscissa, time in seconds.
Directly after the fault, the oscillations of the high-speed shaft of the drive train are most visible. These oscillations become dampened quickly because the generator is then again connected to the recovered grid voltage.

In Figure 6 the control signals are plotted. As soon as the fault is detected, the digital flag Fault Operation is set ‘high’ and stays high until the whole fault operation has finished. When fault operation starts, the pitch angle setpoint Transient Theta is immediately stepped to the pitch angle of zero power ($\Theta_z_P$ in Figure 6). As soon as the fault is cleared, indicated by the signal grid_OK being high, the transient fault controller waits for the pitch angle ($\Theta$ in Figure 6) to reach $\Theta_z_P$, before it is ramped up again.

There are two reasons why the pitch angle is driven completely down to $\Theta_z_P$, although the fault has been cleared already before this angle is reached. The first reason is that this way the power surge after the clearance of the fault can be minimised. The energy accumulated during the fault is, at least partially, dissipated aerodynamically by the turbine rotor. The second reason is that speed oscillations, excited by the untwisting of the drive train, are dampened much faster (see Figure 5). A drawback of this strategy is however that the active power dips slightly into the negative region (164 kW power absorption) for a short period of time. This problem does not occur with a faster acting pitch system, i.e. a pitch system that is capable of doing a higher pitch rate. This will be shown and discussed in section 7.6.

Once the pitch angle of zero power is reached, the pitch system ramps the pitch angle setpoint up again to its initial value. When the initial value is reached the transient fault operation is over and normal operation resumes. In Figure 3, the switch in the section “pitch logic” switches

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Figure 6: Controller signals during a 3-phase short circuit fault on the Fault Bus with permanent isolation after 100 ms. Ordinate, proportional change in named variable. Abscissa, time in seconds.
back to its normal position, to transmit the pitch angle setpoint from the pitch controller for normal operation.

7.2 Two phase short circuit with unsuccessful auto-reclosure

A short circuit between the phases a and b is simulated on the Fault Bus. The Fault Bus is isolated after 100 ms and an auto-reclosure is attempted after another 200 ms. The fault is then cleared by permanently isolating the Fault Bus after yet another 300 ms.

The control strategy is the same as during a 3-phase fault. As soon as the fault is detected, the transient fault controller takes over the control of the pitch angle and drives it to the value where the turbine ceases to produce power (see Figure 8).

Due to one phase still being intact, the initial surge in speed (see Figure 7) is not as large as it is during a 3-phase fault, because the drive train does not become untwisted completely. By the time the fault is cleared permanently, the pitch angle has almost reached its new setpoint. When this setpoint is reached, the signal grid_OK in Figure 8 indicates the grid has recovered and that the pitch angle \( \Theta \) can be driven to the value of normal operation again.

The unsuccessful auto-reclosure upsets the recovery of the speed; see Figure 7, where the speed surge during the auto-reclosure is larger than during the initial fault. Although this leads to longer lasting speed oscillations, the magnitude of the oscillations is still less than in case of a 3-phase fault. Therefore, the active power neither oscillates so much in the wake of the fault, nor dips into the negative region (which it does in the wake of the 3-phase fault).

It can be concluded that a 2-phase fault, even with unsuccessful auto-reclosure, is a less demanding task for the transient fault controller than a 3-phase fault without auto-reclosure.

![Figure 7: Wind turbine subject to a 2-phase short circuit fault on the Fault Bus with an unsuccessful auto-reclosures and final disconnection. Ordinate, proportional change in named variable. Abscissa, time in seconds.](image-url)
7.3 Three phase short circuit with subsequent voltage sag

Here the situation is simulated where the voltage does not recover immediately in the wake of a fault, but stays below the lower limit for turbine operation (0.7 p.u., see Table 1) for some time. In the simulations, this voltage depression is provoked by temporarily connecting a reactive power sink on the high voltage side of the 33/132 kV transformer at the same time as the fault is cleared.

As can be seen in Figure 9, the voltage stays below 0.7 p.u. until the simulation time of 5 seconds. At simulation time 5 seconds, the reactive power sink is disconnected and the grid voltage recovers.

Since the signal 'grid_OK' in Figure 10 indicates that the turbine cannot return to normal operation (grid voltage has not yet recovered beyond 0.7 p.u.), so at the time when the pitch angle of zero power has been reached, the controller holds the pitch angle at this value.

The controller holds it there until the voltage has recovered. It does not matter for how long the voltage sag lasts. In theory, the turbine can idle for an arbitrarily long period of time, not producing power and awaiting grid recovery. It has to be noted however that in practice the auxiliary power supply (e.g. UPS) of the turbine is the limiting factor in such a situation. The turbine consumes substantial power for the control system (e.g. controller, pitch system, yaw system, fans, pumps and the like), which during a deep voltage sag cannot be extracted from the grid.

As can be seen in Figure 9, the low frequency power oscillations, caused by speed oscillations of the turbine rotor with its high inertia, lead to a brief dip of the active power into the negative region (56 kW power consumption). This cannot be avoided with such a simple controller, since it only feeds a setpoint signal forward. To actively dampen these oscillations and hence avoid power consumption, a feedback control system would be required.
Figure 9: Wind turbine subject to a 3-phase short circuit fault on the Fault Bus with permanent isolation after 100 ms and temporary deep voltage sag. Ordinate, proportional change in named variable. Abscissa, time in seconds.

Figure 10: Controller signals during a 3-phase short circuit fault on the Fault Bus with permanent isolation after 100 ms and temporary deep voltage sag. Ordinate, proportional change in named variable. Abscissa, time in seconds.
7.4 Three phase short circuit with temporarily weak grid
To assess the performance of the controller in a situation where the grid is weak after a fault, a reactive power sink is connected at clearance of the fault, and disconnected at simulation time 5 seconds, as in the previous simulation. Here however the sink has a lower rating, i.e. it suppresses the voltage less, so it can recover as long as the turbine does not feed in any power. The voltage returns beyond the lower limit but cannot sustain more power being fed into the system.

When the voltage recovers and exceeds 0.7 p.u., the transient fault controller starts ramping up the pitch angle. As the pitch angle increases, power from the generator increases as well. The more power is produced the higher is the reactive power demand of the generator, hence the more the voltage is suppressed. As the voltage under-runs 0.7 p.u. again, a new transient fault operation starts: the pitch angle setpoint is stepped down, voltage recovery is waited, and, subsequently, a new pitch angle increase attempted. At simulation time 5 seconds, the reactive power sink is disconnected, allowing the voltage to recover and hence the turbine to feed in full power.

7.5 Three phase short circuit at 9 m/s wind speed
So far all simulations have been conducted at 14 m/s wind speed, as this implies rated power production, which is the most demanding burden for the power system. However the most demanding for the pitch system is 9 m/s wind speed, where the difference between the pitch angle of normal operation and zero power production is greatest (13.4 degrees, see Figure 4).

The turbine behaves as in section 7.1. However, the magnitude of the speed oscillations is much smaller, and the voltage recovers much faster, since the lower wind speed involves a much lower reactive power extracted from the power system.

![Figure 11: Wind turbine subject to a 3-phase short circuit fault on the Fault Bus with permanent isolation after 100 ms and temporarily weak grid. Ordinate, proportional change in named variable. Abscissa, time in seconds.](image-url)
It takes the pitch system 1.6 seconds to ramp the pitch angle down to the value of zero power production, and also it takes 1.6 seconds to ramp it up again, because in this case the pitch system has to pitch farthest. At the point in time, when the low frequency oscillation of the turbine rotor force the power into negative direction (power consumption) the pitch angle is in a position, where it cannot counteract this power dip. Therefore, the power of the generator drops below zero (max. 218 kW power consumption). The generator consumes power only for 424 ms, which neither upsets neither the turbine operation nor the grid voltage.

7.6 Possible improvements
The situation described in the previous section could be circumvented with a faster acting pitch system. As an example, a pitch rate of 15 degrees per second is chosen, as this is a value deemed technically possible. The scenario simulated is again a 3-phase fault. The average wind speed is set to 9 m/s as it has been shown before that this is a demanding situation.

The larger pitch rate allows the pitch system to run through the whole transient fault operation in a much shorter time compared to the simulations in the previous section. Here the pitch angle is already well on its way towards the pitch angle of normal operation by the time the low frequency power oscillation is at its minimum. Therefore the active power does not drop below zero.

8 CONCLUSION
The controller presented in this article enables an active-stall turbine to ride through transient faults as demanded by the grid connection requirements issued by the Danish transmission system operators.
Even with standard hardware, the turbine performs well. It does not burden the power system such that the voltage cannot recover after a transient fault. The turbine itself is also protected against mechanical damage caused by excessive speed excursions. The transient fault controller manages to keep the turbine stable and in safe conditions.

Although the performance of the controller and hence the behaviour of the wind turbine is satisfactory, it can be improved even further if the pitch system is capable of a pitch rate of 15 degrees per second.

In future, the transient fault controller could be improved further by developing it into a feedback controller so speed oscillations can be tackled actively.

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by

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The Relevance of the Dynamic Stall Effect for Transient Fault Operations of Active-stall Wind Turbines

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ABSTRACT
This article describes a methodology to quantify the influence of dynamic stall on transient fault operations of active-stall turbines. The model of the dynamic stall effect is introduced briefly. The behaviour of the dynamic stall model during a transient fault operation is described mathematically, and from this its effect quantified. Two quantities are chosen to describe the influence of the dynamic stall effect: one is active power and the other is time delay. Subsequently a transient fault scenario is simulated with and without the dynamic stall effect and the differences discussed. From this comparison, the conclusion is drawn that the dynamic stall effect has some influence on the post-fault behaviour of the wind turbine, and it is hence suggested that the dynamic stall effect is considered if an active-stall wind turbine is to be modelled realistically.

Keywords: active-stall, dynamic stall, transient fault, wind turbine

I. INTRODUCTION
The stall effect at wind turbine blades is the separation of the airflow on the down-wind side of the blades. When a wind turbine blade stalls, its aerodynamic power is reduced in proportion to the extent of the stall effect. The apparent wind, which is the wind seen by the blades, has two components: These are perpendicular to the rotor plane (real wind) and parallel to the rotor plane (caused by the rotation of the blades). The apparent wind has a certain angle of attack, i.e. a certain angle at which it hits the leading edge of the blade. The angle of attack depends on the ratio between the wind speed components perpendicular and parallel to the rotor plane, and the pitch angle of the blade. If the angle of attack becomes too big, the flow around the airfoil of the blade does not manage to stay laminar and attached to the surface of the airfoil, but becomes separated and turbulent. The consequent stall effect reduces the aerodynamic power of the blade, since optimal power extraction requires laminar flow around the blade.

An active-stall turbine provokes stall deliberately, in order to control the aerodynamic power of the blades. This is done by pitching the blades in a negative direction [1], such that the angle of attack is increased and the stall effect reduces power to the desired power setpoint.

The transition from one operating point to another requires not only that the blades turn from one pitch angle to another, but also that the stall effect changes from one extent to another. This transition in stall effect cannot happen instantaneously, but involves a time delay, since the airflow around the blades does not change instantaneously.
When a wind turbine has to ride through a transient fault in the grid, it has to reduce its aerodynamic power quickly to tackle the inherent imbalance between the aerodynamic input power and the drastically reduced electrical output power. A possible control strategy for an active-stall turbine subject to such a situation is presented and discussed in Jauch et al. (2005) [2].

2. DYNAMIC STALL EFFECT

The model of the dynamic stall effect used here was developed by Sørensen [3]. It describes the dynamic stall effect in terms of the aerodynamic torque coefficient $C_q$, based on Øye’s model of dynamic stall in terms of the aerodynamic lift coefficient $C_l$ in sections of the blades [4]. In Sørensen’s $C_q$-based model, the dynamic stall effect is taken into account by creating a time dependent $C_q^\text{dynamic}$, which is a composition of three different aerodynamic torque coefficients: one for attached flow, one for separated flow and one for steady state flow. The three different aerodynamic torque coefficients are calculated using standard blade element methods with the corresponding lift coefficients.

In the simulation model of the wind turbine, the aerodynamic properties of the wind turbine rotor are implemented as $C_q$-lookup tables. In the model considered here, where the dynamic stall effect is considered, three $C_q$-lookup tables are implemented [5].

In Figure 1, the three $C_q$ values are plotted over a range of pitch angles, exemplified for a wind speed of 24 m/s. In transient fault simulations, the ambient wind speed can be considered constant. The operation of a wind turbine under a transient fault situation involves sweeping over a certain range of pitch angles. Therefore, it is realistic to consider $C_q$ values of one particular wind speed over a relevant range of pitch angles, as shown in Figure 1.

The $C_q^\text{dynamic}$, which is the combination of these three values, is described by Equation 1, where $\tau$ is the attachment factor, which will be discussed in the following section.

\[
C_q^\text{dynamic} = \tau \cdot C_q^\text{attached} + (1 - \tau) \cdot C_q^\text{separated}
\]  

(1)

Figure 1: $C_q^\text{static}$, $C_q^\text{attached}$ and $C_q^\text{separated}$ over pitch angle $\theta$ for a wind speed of 24 m/s.
2.1 The Attachment Factor $f$

The attachment factor $f$ determines to what degree $C_q^{\text{dynamic}}$ consists of $C_q^{\text{attached}}$ (the $C_q$ value belonging to attached airflow around the airfoil), and of $C_q^{\text{separated}}$ (the $C_q$ value belonging to the airflow, which is separated from the surface of the airfoil). Equation 2 shows the attachment factor $f_{\text{static}}$ for steady state condition.

$$f_{\text{static}} = \frac{C_q^{\text{static}}}{C_q^{\text{attached}}} - \frac{C_q^{\text{separated}}}{C_q^{\text{separated}}}$$

(2)

Figure 2 shows $f$ over a range of pitch angles at certain wind speeds. The pitch angle at which a turbine runs under normal operation at a given wind speed, and the pitch angle to which it pitches at a transient fault, are both known [2]. Hence from Figure 2 the values of $f$, before and after the pitching action, can be found.

The time delay in the dynamic stall effect is introduced in the attachment factor. When a pitching action forces $f$ to change (see Figure 2), it cannot do so instantaneously. A time delay is implied, which will be explained in the following section.

2.2 Time Dependency of the Attachment Factor $f$

The attachment factor $f$ has to go through a first-order low-pass filter before it enters into the calculation of $C_q^{\text{dynamic}}$. Hence, a time delay constrains $C_q^{\text{dynamic}}$ whenever a change in $f$ is involved. It also has to be said that if $f$ changes less than from zero to one, or vice versa, only a part of $C_q^{\text{dynamic}}$ is constrained by the first-order characteristic. The remaining part follows the input without delay. The dynamic representation of $f$ is given in Equation 3.

$$f = \frac{C_q^{\text{static}}}{C_q^{\text{attached}}} - \frac{C_q^{\text{separated}}}{C_q^{\text{separated}}} \left(1 + \frac{1}{1 + s \cdot \tau}\right)$$

(3)

The time constant $\tau$ is an inverse function of the wind speed $v$ (Equation 4), making the time dependency of the attachment factor, and hence of the dynamic stall effect, less relevant the larger the wind speed. As shown in Equation 4, large wind speeds lead to short time constants, $\tau$, minimising the effect of the low-pass filter. The constant $C$ in Equation 4 is the weighted average chord length of the airfoil of the blade. The aerodynamic data used here
are of a generic 2 MW wind turbine blade. The cord length of this blade varies along the blade. To get one single value it is averaged and weighted with the distance to the centre of the rotor, which leads to $C = 1.91 \text{ m}$. 

$$\tau = \frac{4 \cdot C}{v} \quad (4)$$

From Equation 3 and Equation 4 it can be seen that there is always a time delay in reaching a new operating point, i.e. a new $C_q$ (unless $f$ in the new operating point is the same as $f$ in the initial operating point). Considering transient fault operation, where there is a transition from normal operation to the operating point where the turbine does not produce any power [2], there is usually a change in $f$.

Looking at Figure 2, it can be seen that at large wind speeds (20 to 25 m/s) and negative values of $\theta$, the $f$-curves become flatter and are close to zero between $\theta$ of normal operation ($\theta_{norm}$) and $\theta$ of zero power operation ($\theta_{P=0}$), which is $-5$ and $-10$ degrees respectively. The small change in $f$, and the fact that the time constant of the first-order low pass filter is very short at these wind speeds, means that there will be little time delay changing from the old $C_q^{\text{dynamic}}$ to the new $C_q^{\text{dynamic}}$. Hence, the dynamic stall effect becomes less important for transient fault operations at very large wind speeds.

3. PITCH ANGLE RAMP AS INPUT SIGNAL

The time delay caused by the first-order low pass filter could be easily quantified if the input were a step change. This is however not the case. The input is the pitch angle controlled by the pitch system. Due to the physical constraints of the pitch system, the pitch angle cannot be changed rapidly as a step, but is ramped. Under transient fault operation, the pitch controller tries to reach the pitch angle of zero power ($\theta_{P=0}$) as quickly as possible, hence the slope with which the pitch angle is ramped is the maximal pitch rate of the pitch system.

Analysing the response of a first-order system, when subject to a ramp signal at the input, can easily be done in the Laplace domain. The Laplace transform of a ramp function with a slope $r$ is shown in Equation 5.

$$f(t) \xrightarrow{L} R(s)$$

$$r \cdot t \xrightarrow{L} \frac{r}{s}$$

The transfer function of a first-order system, with input $R(s)$, output $C(s)$ and time constant $\frac{1}{a}$ is

$$G(s) = \frac{C(s)}{R(s)} = \frac{a}{s + a} \quad (6)$$

The response when subject to a ramp is hence

$$C(s) = \frac{r \cdot a}{s(s + a)}$$

$$\xrightarrow{L^{-1}} c(t)$$

$$C(s) = \frac{L^2}{s} \rightarrow c(t)$$

$$c(t) = \frac{r \cdot (a^{-a \cdot t} + a \cdot t - 1)}{a} \quad (7)$$

Since the ramp signal, i.e. the pitch angle slope, is only a finite ramp, Equation 7 only produces correct results for $t \leq t_{\text{end, ramp}}$, i.e. until the time the pitch angle stops ramping.
can be calculated from the difference in pitch angle (\(\Delta \theta\)), between the pitch angle of normal operation (\(\theta_{\text{norm}}\)), the pitch angle where the aerodynamic power is zero (\(\theta_{P=0}\)), and the maximum pitching rate \(r\) of the pitch system.

\[
\begin{align*}
\Delta \theta &= \theta_{\text{norm}} - \theta_{P=0} \\
t_{\text{end ramp}} &= \frac{\Delta \theta}{r}
\end{align*}
\] (8)

Setting \(t_{\text{end ramp}}\) into Equation 7 yields the value that represents the position at the end of the pitch angle ramp. This value is a relative pitch angle with the unit of degrees. With the initial pitch angle (\(\theta_{\text{norm}}\)), a pitch angle that corresponds to the output of the first-order system at the end of the ramp can be calculated (Equation 9).

\[
\theta_{\text{end ramp}} = \theta_{\text{norm}} - c(t)
\] (9)

As mentioned in section 3.2, the change in \(f\) indicates how much of \(C_q\) can follow the input without time delay, and how much has to follow the first-order characteristic. The new value of \(C_{q,\text{dynamic}}\) that can be reached instantaneously, i.e. without being constrained by the first-order characteristic is \(C_{q,\text{dynamic},q(\text{init})}\). This can be calculated when inserting Equation 2 into Equation 1, which is shown in Equation 10, where the index “old” refers to “before the pitching started” and the index “new” refers to “after the pitch angle has reached its final value”.

\[
\begin{align*}
\frac{C_{q(\text{old})}}{C_{q(\text{new})}} &= \frac{C_{\text{sep}}(q(\text{old}))}{C_{\text{sep}}(q(\text{new}))} \cdot \frac{C_{\text{att}}(q(\text{old}))}{C_{\text{att}}(q(\text{new}))} \cdot \left(1 - \frac{C_{\text{sep}}(q(\text{old}))}{C_{\text{sep}}(q(\text{old}))} \cdot \frac{C_{\text{att}}(q(\text{old}))}{C_{\text{att}}(q(\text{old}))}ight) = C_{q,\text{dynamic},q(\text{init})} \\
f_{\text{old}} \cdot C_{\text{att}}(q(\text{new})) + \left(1 - f_{\text{old}}\right) \cdot C_{\text{sep}}(q(\text{new})) &= C_{q,\text{dynamic},q(\text{init})}
\end{align*}
\] (10)

Equation 11 quantifies the fraction of \(\Delta C_q\) that can be accomplished without causing a time delay, as a fraction of the total difference in \(C_q\) that has to be swept.

\[
\Delta C_{q,\text{dynamic}} = C_{q(\text{old})} - C_{q,\text{dynamic},q(\text{init})}
\]

\[
\Delta C_{q,\text{dynamic},q(\text{relative})} = \frac{\Delta C_{q,\text{dynamic}}}{C_{q(\text{old})} - C_{q(\text{new})}}
\] (11)

Note that \(\Delta C_{q,\text{dynamic},q(\text{relative})}\) as defined is a ratio with no units, therefore it can be used further to calculate the overall response of the system as a non-dimensional scale factor.

As pointed out earlier, the input is a finite ramp. The overall response of the system can be described as a combination of the first-order response and as a fraction of a linear function with the slop \(r\). Figure 3 shows, in principal, the difference between a first-order system responding to a finite ramp and a transfer function, comprising a first-order characteristic and a direct gain characteristic responding to a finite ramp. In Figure 3, the mixed transfer function is as an example represented by a 36% first order and a 64% direct gain characteristic.

Equation 12 describes the overall response (partially first-order characteristic, partially direct gain, i.e. ramp) for \(t \leq t_{\text{end ramp}}\).

\[
\epsilon_{\text{overall}} = \epsilon(t) \cdot (1 - \Delta C_{q,\text{dynamic},q(\text{relative})}) + \Delta C_{q,\text{dynamic},q(\text{relative})} \cdot r \cdot t
\] (12)
For $t = t_{end\_ramp}$, Equation 12 yields the overall response of the system after the pitch angle ramp. This is still a pitch angle value in degrees, which can be made per unit by dividing the total difference in pitch angle, as in equation 13.

$$c_{overall\_relative} = \frac{c_{overall}}{\Delta \theta} \tag{13}$$

This dimensionless overall value can be turned into a $C_q$ value when combining it with the $C_q^{static}$ that belongs to the final pitch angle $(C_q^{static\_new})$:

$$C_q^{dynamic\_end\_ramp} = (1 - c_{overall\_relative}) C_q^{static\_old} + c_{overall\_relative} C_q^{static\_new} \tag{14}$$

$C_q^{static}$ is used for this purpose because, for $t \to \infty$, $C_q^{dynamic}$ always converges to $C_q^{static}$. This can be shown when inserting Equation 2 into Equation 1 and setting $C_q^{dynamic} = C_q^{static}$.

$$C_q^{static} = C_q^{static}$$

Now that the delay caused by the dynamic stall effect can be quantified in terms of the aerodynamic torque coefficient $C_q$, it is interesting to know what the consequences are for a transient fault operation of an active-stall turbine. In the following section,
the effect of dynamic stall is verified in terms of power and in terms of time delay for transient fault operations in the wind speeds regions, where dynamic stall has a visible effect.

4. EVALUATION OF THE DYNAMIC STALL EFFECT

As described in Jauch et al. (2005) [2], transient-fault ride-through of a wind turbine poses the problem of abrupt imbalance between aerodynamic input power and electrical output power causing oscillations and acceleration of the wind turbine’s drive train. The acceleration can be mitigated and the oscillations dampened, by drastically reducing the aerodynamic input power. For an active-stall turbine, this can be done by pitching the blades so they stall. Ideally the blades are pitched sufficiently for the stall effect to remove all the aerodynamic power, i.e. the rotor produces zero power. If there were no dynamic stall effect, the aerodynamic power of the rotor would be zero immediately when the pitch angle for zero power is reached. In this case, $C_{q(\text{end ramp})}$ would be $C_{\text{q(static)}}$. However this is not true, as has been shown in section 4, hence the power is not zero either.

Note that $\theta_{p=0}$ is not a constant value but is subject to variations due to speed oscillations. As long as the rotor speed oscillates, also $\lambda$ oscillates, which in turn leads to oscillations in $\theta_{p=0}$.

There are two ways of expressing the consequence of the dynamic stall effect. One is the residual power that is caused by the residual $C_{q}$, the other is the time taken for the first-order low pass filter to settle to its final value after the ramp has reached its final value.

4.1 Residual Power

The absolute residual torque coefficient $C_{q}$

$$C_{q(\text{residual})} = C_{q(\text{end ramp})} - C_{q(\text{new})}$$

(17)

can be transformed into the power coefficient $C_{p}$

$$C_{p} = C_{q} \cdot \lambda$$

(18)

through the tip speed ratio $\lambda$.

$$\lambda = \frac{v_{tip}}{v_{wind}} = \frac{R \cdot 2 \cdot \pi \cdot n_{rotor}}{v_{wind}}$$

(19)
Knowing $C_q$, the power of the turbine can be calculated as:

$$P = \frac{1}{2} \cdot \rho \cdot \pi \cdot R^2 \cdot v_{wind} \cdot C_p$$

(20)

In Equation 20, $\rho$ is the air density and $R$ is the radius of the rotor.

Keeping in mind that the aerodynamic power at the end of the pitch angle ramp should be zero, Figure 5 shows that for some wind speeds quite substantial power is still being generated due to the residual $C_q$.

### 4.2 Settling Time

The other way of expressing the impact of the dynamic stall effect is the time for $C_q$ to settle to its final value. Here the 2% settling time $T_s$ is chosen to quantify the delay. In control engineering $T_s$ is usually used for expressing the time it takes a first-order system to reach 98% of a step-change setpoint. Here however, it is used to express the time for $C_q^{\text{dynamic}}$ to reach 98% of $C_q^{\text{static}}$, after the pitch angle ramp reached its final value.

A first-order system that is subject to a finite input ramp responds as described in section 4, until the ramp comes to a halt. After that, it behaves as subject to a step change. The magnitude of this step change is the difference between the current value at $t = t_{\text{end_ramp}}$ and the final value of the ramp. Equation 21 expresses this value in terms of pitch angle in degrees.

$$\theta_1 = \Delta \theta - c(t)$$

(21)

The pitch angle value that corresponds to 98% of the input signal (not only the final step but the whole ramp) is

$$\theta_2 = \theta_1 - 0.02 \cdot \Delta \theta$$

(22)

Hence, the time it takes for the first-order system to reach $\theta_2$ can be calculated with Equation 23:

$$T_s = -\frac{\ln\left(1 - \frac{\theta_2}{\theta_1}\right)}{a}$$

(23)

Since the pitch system, with its limited pitching rate, is the main cause of the delay, $T_s$ can also be expressed as a fraction of the overall settling time. It is also important to note, that the difference between $\theta_{\text{norm}}$ and $\theta_{\text{P-0}}$, and hence the duration of the pitch angle ramp $T_{\text{ramp}}$, is...
varies with the wind speed. Hence $T_{d(\text{relative})}$ allows a better evaluation of the impact of dynamic stall.

$$T_{x(\text{relative})} = \frac{T_s}{T_r + T_{\text{ramp}}}$$  \hspace{1cm} (24)

In Figure 6, $T_s$ as well as $T_{d(\text{relative})}$ are plotted over the relevant wind speed range. This diagram shows that the dynamic stall requires 58% of the whole time needed to reach $\theta = \theta_0$. This constitutes a significant impact, since the turbine will be producing its rated power in the wind speed region for which the delay is largest. Here also the residual power is large (Figure 5) and exceeds 16% of the turbine’s rated power at 13 m/s. Beyond 15 m/s, the impact subsides gradually with increasing wind speed, and becomes irrelevant at very large wind speeds.

5. TRANSIENT FAULT OPERATIONS

The same transient fault scenarios as in Jauch et al. (2005) [2] have been simulated, this time with a model of the dynamic stall effect. The simulation results are compared and conclusions drawn from this comparison. The simulations in Jauch et al. (2005) [2] were conducted with 14 m/s wind speed. As can be seen from Figure 5 and Figure 6, 14 m/s is a wind speed that makes sense also for the investigation into the impact of the dynamic stall effect. The simulation results of a transient 3-phase fault, with and without dynamic stall, are plotted in Figure 7, which allows direct comparison.

Here only a 3-phase fault is simulated and compared. While in Jauch et al. (2005) also three other transient fault scenarios were simulated, here it is deemed sufficient to only show and discuss the simulation results of a 3-phase fault. The qualitative difference with and without dynamic stall is always the same.

In the simulation with dynamic stall, while the pitch angle ramps down, the active power becomes larger than in the simulation without dynamic stall. The reason for this is the delayed aerodynamic power reduction caused by dynamic stall. Immediately after $\theta_{r-0}$ is reached, the pitch system ramps up again. This intended increase in power however is also delayed, hence the power increase is dampened.

The dynamic stall effect causes the power to change, even well beyond the time when the pitch angle becomes stationary again. The low frequency oscillations are oscillations of the turbine rotor that has large inertia [2]. As these speed oscillations cause oscillations in the apparent wind, i.e. the wind seen by the rotor blades, also the angle of attack oscillates.
Figure 7: Voltage, active power, reactive power, speed and pitch angle of an active-stall turbine subject to a transient 3-phase fault, with and without dynamic stall; wind speed = 14 m/s.
Variations in the angle of attack are effectively the same as pitch angle variations. Hence the dynamic stall affects the turbine power even when the pitch system does not attempt to control the power. This leads to the positive effect that the overshoot in power, caused by the low frequency oscillations of the drive train, is not as large as would have been without dynamic stall.

In Figure 7, at simulation time 1.97 seconds, when $\theta_{P \rightarrow 0}$ is reached (i.e. ideally no aerodynamic power), the electrical power output of the turbine is far from zero. This electrical power is caused by the kinetic energy that is fed into the grid in order to decelerate the mass of the rotor. The effect of dynamic stall is the difference between the two power graphs. Comparing this difference to the total power at this time, shows that dynamic stall makes a minor difference, which nevertheless is not negligible.

Note that the time delay of the dynamic stall effect causes a time delay in the overall response of the turbine. The oscillations of the turbine drive train are clearly delayed due to dynamic stall.

The reduced magnitude of the oscillations in active power, lead to a smaller amplitude in speed oscillations, which in turn leads to less reactive power and, hence, smaller voltage oscillations.

6. CONCLUSION
The analysis shows that dynamic stall has a visible effect on the transient fault behaviour of an active-stall turbine. The simulations show that the dynamic stall effect has no major impact on the control strategy of active-stall turbines under transient fault situations. However, the dynamic behaviour of the turbine changes, because the extra time delay increases the time constant of the overall wind turbine system.

Dynamic stall slightly dampens drive train oscillations excited by a transient fault. Hence dynamic stall can be considered a positive effect in terms of transient stability. After a transient fault, dynamic stall reduces the amplitude of the low frequency oscillations in the power, speed and, hence, the voltage variation.

Considering the transient-fault ride-through of an active-stall turbine, it can be concluded that the dynamic stall effect makes this a slightly less onerous task for an active-stall wind turbine. This is because the transient fault control strategy, as described in Jauch et al. (2005) [2], is an open loop feed forward control.

The increased time constant of the system might become a disadvantage when more direct grid control tasks are attempted with an active-stall turbine. One such task could be to actively dampen power oscillations in the wake of a transient fault in the power system. To perform such a control task, a closed-loop feedback control system would be necessary, for which the increased time constant might be significant.

The overall conclusion is that the dynamic stall effect has a minor impact on the transient fault operation of an active-stall wind turbine. However, if an active-stall turbine is to be modelled realistically, the dynamic stall effect should not be neglected.

In future it could be investigated what influence dynamic inflow has on the transient fault operation of active-stall turbines. Dynamic inflow is another phenomenon that adds time dependencies to the aerodynamics of a wind turbine. Especially during transient fault operation, where the aerodynamic power is reduced quickly, such dynamics might be important.

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Design of a Wind Turbine Pitch Angle Controller for Power System Stabilisation

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Design of a Wind Turbine Pitch Angle Controller for Power System Stabilisation

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Abstract
The design of a PID pitch angle controller for a fixed speed active-stall wind turbine, using the root locus method is described in this paper. The purpose of this controller is to enable an active-stall wind turbine to perform power system stabilisation. For the purpose of controller design the transfer function of the wind turbine is derived from the wind turbine’s step response. The performance of this controller is tested by simulation, where the wind turbine model with its pitch angle controller is connected to a power system model. The power system model employed here is a realistic model of the North European power system. A short circuit fault on a busbar close to the wind turbine generator is simulated, and the dynamic responses of the system with and without the power system stabilisation of the wind turbines are presented. Simulations show that in most operating points the pitch controller can effectively contribute to power system stabilisation.

Keywords: PID controller, pitch controller, power system oscillations, wind turbine

1 Introduction
In many countries of the world wind power expands and covers a steadily increasing part of these countries’ power demand. Growing wind power has impacts on the power systems into which the wind turbines feed their power. As wind power penetration increases, the respective power system operators are concerned about the stability and reliability of their power systems [1]. Therefore more and more power system operators revise their grid connection requirements and issue grid connection requirements specifically made for wind turbines and wind farms [2].
Increasing wind power penetration in a power system means that wind turbines substitute the conventional power plants that traditionally control and stabilise the power system. If wind power penetration exceeds a certain level, wind turbines have to be involved in performing these control tasks [3]. This is even more important since it has been recognized that wind turbines themselves have an influence on the dynamic behaviour of the power system to which they are connected [4]. A stable power system is also of great importance for wind turbines, as variations in grid voltage and frequency have considerable impacts on the operation of wind turbines [5].

A transient short circuit fault is a very common disturbance in a power system. Such a short circuit fault leads to sub-synchronous system oscillations that have to be damped before the system becomes unstable. Traditionally such oscillations are damped by conventional power plants with synchronous generators, which are equipped with power system stabilisers. Power system stabilisation with synchronous generators is an established technology, which is applied all over the world [6].

If wind turbines are to take over such damping tasks they have to have a very effective means of controlling their electrical output power. A common wind turbine type is the fixed speed active-stall wind turbine, which has a pitch system that allows the turbine to vary the pitch angle of the blades. If an active-stall turbine is to limit its power, it pitches its blades to an angle where the airflow around the blades gets detached from the surface of the blades and becomes turbulent, i.e. the blade stalls [7]. Active-stall turbines have directly grid connected squirrel cage induction generators and the reactive power demand of this type of generator is usually compensated by capacitor banks. For a description of the active-stall concept see [8]. The pitch system of active-stall turbines has previously been tested and used in practice for various dynamic operating situations [9]. In this article a controller is presented that enables an active-stall turbine to use its pitch system to perform power system stabilisation similar to conventional power plants.

For simulations of grid frequency oscillations to be realistic, a realistic grid model is required. One approach is to consider a model of a power system, which could possibly exist in reality [10]; another approach is to use a model of a real system. In this project the latter approach has been chosen to ensure the validity of the findings. The power system model used here is an aggregated model of the interconnected power system of the countries Norway, Sweden, Finland and eastern Denmark.

To introduce the problem to be dealt with a brief introduction to the phenomenon of power system oscillations and the general concept of power system stabilisation is given in the beginning of this article. A simplified transfer function of the wind turbine is found from the turbine’s step response. With this transfer function a PID controller for grid frequency stabilisation is designed, using the root locus method. The performance of the wind turbine with the designed controller is assessed in simulations and the results are discussed.
2 Power System Oscillations and Stabilisation

The frequency in an AC power system is stable when the electrical demand plus the electrical losses equal the electrical generation in the system. An imbalance between generation and demand leads to rising grid frequency if the generation exceeds demand, and to dropping grid frequency if the demand exceeds the generation. The grid frequency finds a new equilibrium if there is either sufficient frequency sensitive load in the system, or if the generators are equipped with governors that adjust the prime mover power so the generators pull the frequency back to its rated value. Governor controllers, which control the mechanical power of the prime mover are used to control the steady state frequency of the system in all modern power systems.

If a change in load or in generation happens gradually, the frequency will deviate gradually. If a step change happens, the frequency will experience transient oscillations before it settles to its new equilibrium.

A transient short circuit fault can be considered a step change, as the short circuit current constitutes a step in load. If the short circuit happens close to a generator, the voltage at the generator terminals will be suppressed so the generator cannot export active power, hence a step change in generation occurs. In any case, a short circuit upsets the balance between load and generation in a step change.

If, as described above, a synchronous generator (SG) cannot export electrical power during a short circuit fault it has to accumulate the mechanical energy, with which the prime mover drives the generator. A rotating machine can only accumulate energy by accelerating. Hence the generator accelerates during the fault, and, after the fault is cleared, it tries to export as much electrical power as possible to decelerate again. As a result, the rotor speed of the generator oscillates.

In an interconnected AC power system a fault in one area and the subsequent rotor speed oscillations of the synchronous generators in this area lead to power swings (inter-area oscillations) between different areas in the whole system. Considering the Nordic power system, which is the system at hand in this project, a fault in eastern Denmark causes inter-area oscillations as far away in the system as in the inter-area link between northern Sweden and Finland.

Since the rotor in a SG rotates synchronously with the stator field, the rotor speed is the same as the electrical frequency. Hence, rotor speed oscillations are grid frequency oscillations, which have to be dampened before the whole system becomes unstable. In a conventional power plant, SG equipped with power system stabilisers dampen these oscillations. If future wind farms substitute a considerable amount of conventional power plants, these wind farms have to be involved in the damping of grid frequency and inter-area oscillations.

As described above, frequency oscillations are caused by an imbalance between generated power and consumed power. Hence, grid frequency oscillations (as well as inter-area oscillations) can be counteracted with a controlled active power injection into the grid. Since the wind turbine type considered here is an active-stall turbine, which is equipped
with a squirrel-cage induction generator, the only means of controlling its output power is the pitch system that controls the aerodynamic power, which drives the generator.

3 Description of the System

In this section the system to be controlled is described. This is effectively the wind turbine, whose electric power has to counteract the power system oscillations, and the grid to which the wind turbine is connected. The wind turbine model and the power system model are implemented in the power system simulation tool PowerFactory from DIgSILENT [11].

3.1 Power System Model

A realistic power system model is of major importance when assessing the system stabilising capabilities of the wind turbine controller to be developed. For this purpose a model of the Nordic power system, which is the power system of the countries Norway, Sweden, Finland and eastern Denmark has been chosen. Characteristic for the Nordic power system is that although it is geographically large, it is of relatively small capacity, since Norway, Sweden, Finland and Denmark are only lightly populated countries. The model of the Nordic power system is an aggregated model, comprising 35 nodes and 20 SG. It has been developed at SINTEF in Norway [12], [13].

For the purpose of this research work the power system model has been extended with a feeder that connects a wind farm to the Nordic system at the busbar Zealand, in eastern Denmark. A 2000 MVA SG, with a dispatched power of 765 MW is also connected to this busbar. The total dispatched power of the whole Nordic power system is 43000 MW.

The system setup is shown in Figure 1, where the induction generator (IG) of the wind farm is connected through a realistic feeder configuration to the busbar Zealand in the Nordic power system.

As can be seen in Figure 1, a short circuit fault is simulated at one of the 132 kV busbars. This fault is a three-phase short circuit that lasts for 300 ms.

During the fault the voltage at the busbar Zealand (Figure 1) is depressed, which means that
the SG cannot export as much power as is imported by its prime mover. Hence SG Zealand accelerates during the fault, and after the fault is cleared SG Zealand tries to export as much power as possible to decelerate to its rated speed. As a result of this the rotor speed of SG Zealand oscillates (Figure 12). These oscillations excite the whole system to perform oscillations, which can be sensed as grid frequency oscillations and inter-area oscillations throughout the entire system. The frequencies of inter-area oscillations in different locations in the Nordic power system are in the range of 0.1 to 1 Hz [4] and are hence in the same range as the frequency oscillations in eastern Denmark (Figure 12). If the wind farm were connected in a different location in the system such inter-area oscillations could have been chosen as the signal to be damped by the wind farm. However, the wind farm is located in eastern Denmark because this best represents the current wind power situation in the Nordic power system. Therefore this dictates that the power system signal to be damped by the wind farm is the frequency, i.e. the speed of the SG Zealand.

The fault location has been chosen because it (i) upsets the power system and excites it to perform oscillations that the wind farm has to act on, and (ii) it challenges the wind farm as it has to ride through a deep voltage dip. It is therefore a worst case scenario, which is most demanding for the wind turbine controller.

3.2 Wind Farm Model

Compared to the size of the whole Nordic power system, or even of the SG at busbar Zealand, the wind farm is relatively small. It has a rated active power of 198 MW, which is a realistic size for a wind farm nowadays. However, it will be shown in section 6 that even with such a modest rating the wind farm is capable of contributing to the stabilisation of the grid frequency.

The wind farm is aggregated to one single generator, driven by one single wind turbine model. The turbine considered in these investigations is an active-stall turbine. A detailed description of the mechanical and aerodynamic model of the wind turbine can be found in [14], [15] and [16]. The model used here reflects reality quite well, which has been proven in an islanding experiment of a real 2 MW turbine [17]. A detailed description of the control strategy implemented in this active-stall turbine model can be found in [8].

The aggregation of the whole wind farm to one wind turbine is justifiable since all turbines in the wind farm are equal. Also the wind speed considered is above rated wind speed, i.e. even with shadowing effects in a wind farm all turbines have sufficient wind for rated power production. Besides small variations are negligible since the type of control considered here is large signal control.

In order to dampen grid frequency oscillations the wind turbine controller strives for increasing its electrical power output when the grid frequency is low and reducing its power output when the grid frequency is high.

Figure 2 shows the control circuit, from which it can be seen that the turbine power is controlled in a closed loop. If the frequency of the power system, $f_{\text{MEAS}}$, deviates from the setpoint, $f_{\text{SET}}$, the frequency error $f_{\text{ERR}}$ causes a power signal $P_{\text{DIFF}}$, which acts as setpoint on the closed power control loop, contributing to the power error signal $P_{\text{ERR}}$. 

Transfer Function of Wind Turbine

To design a PID controller using the root locus method, the plant to be controlled has to be described in terms of its transfer function. The plant to be controlled is, as can be seen in Figure 2, the wind turbine with its generator. When a grid frequency deviation occurs a bias power setpoint, $P_{DIFF}$, which is added to the power setpoint for normal operation, $P_{SET}$, is generated; this causes an error signal, $P_{ERR}$, which the wind turbine has to eliminate. Hence the transfer function required is the transfer function from frequency error to electrical power.

The full transfer function of the wind turbine is of very high order and contains a number of nonlinearities as described in the next section. It can be shown, however, that the wind turbine can actually be described with a set of second order equivalent transfer functions. Such second order transfer functions can be found via the step response of the wind turbine. Due to the nonlinear nature of the wind turbine, step responses have to be conducted in different operating regions, leading to different transfer functions in the respective operating regions.

The application of linear controllers in wind turbines is common practice, although wind turbines are nonlinear systems. From an industrial point of view it is favourable to use simple and robust controllers in wind turbines; however, the nonlinearities need to be taken into account when the controllers are designed. In the following section the nonlinearities are identified.

4.1 Nonlinearities in the Wind Turbine

The wind turbine system contains several nonlinearities, which must be considered when the transfer function of the wind turbine is to be found from the turbine’s step response.

- When a wind turbine is to use its pitch controller to counteract power system oscillations, it can vary its output power between maximum, or rated power, and zero power. The pitch angle values corresponding to these power values are shown in Figure 3. Hence the pitch angle setpoint is non-linearly limited by these boundaries.

- The pitch system, which turns the pitch angle setpoint into a real pitch angle has a maximum pitch rate and hence introduces a non-linearity. The pitch rate considered in these simulations is 15 deg/sec, which is realistic for modern turbines [18].
The aerodynamic properties of the rotor blades are implemented into the simulation model as a lookup table of the aerodynamic torque coefficient $C_q(\lambda, \theta)$ [8]. Figure 4 shows $C_q$ versus the tip speed, $\lambda = \frac{v_{tip}}{v_{wind}} = \frac{R \cdot \omega}{v_{wind}}$, and the pitch angle, $\theta$. From Figure 4, which shows the relevant ranges of $\lambda$ and $\theta$, it can be seen clearly that the aerodynamic properties of the blades are nonlinear.

The dynamic stall effect adds another nonlinearity to the system [19]. In any operating condition where the degree to which the blades stall changes, which is at any notable change in pitch angle, the dynamic stall effect describes the transition to the new operating point. The dynamic stall effect adds a first order low pass and a nonlinearity to the system.

For finding the transfer function of the wind turbine via its step response these nonlinearities have to be taken into account. The boundaries of the pitch angle (upper and lower) can be avoided by applying a step change that does not cause the pitch angle to hit any of these boundaries. The nonlinearly limited pitch rate of the pitch system cannot be avoided. The nonlinear $C_q$ characteristic of the rotor blades can be taken into account by applying step changes that lead to changes in $C_q$ only in regions where the $C_q$ characteristic can be considered linear. The nonlinearity in $C_q$ is basically a variation in
power sensitivity, i.e. how sensitively the power responds to pitch angle changes \( \frac{dP}{d\theta} \) [20]. The dynamic stall effect cannot be avoided, but its nonlinearity plays only a minor role [19].

### 4.2 Step Response of the Wind Turbine System

With the step response the transfer function of the open loop system has to be found. Earlier it has been identified that the system to be controlled is the power control loop of the wind turbine. The open loop system is, as depicted in Figure 5, the system from frequency error, \( f_{ERR} \), to electrical power, \( P_e \). The controller in Figure 5 is a pure P controller with unity gain, i.e. the step response yielded consists of the wind turbine dynamics only.

For this exercise the power system, to which the wind turbine generator is connected, has to be an infinite busbar. I.e. any changes in power from the turbine must not lead to noticeable variations in grid voltage or frequency. This means that for the purpose of controller design the power system dynamics must be absent. Later when the wind turbine controller is tested the turbine model is connected to the realistic power system model.

The step changes in \( f_{ERR} \) have to be chosen such that the constraints caused by the nonlinearities, as described in section 4.1 are taken into account. Hence different transfer functions are found for different operating regions. These transfer functions are then used to generate different sets of controller parameters for the respective operating regions.

![Figure 5](image1.png)

Figure 5 Power control loop of the wind turbine in open loop operation for finding its step response.

![Figure 6](image2.png)

Figure 6 Step change in frequency error and step response of the wind turbine power.
As an example the step response from $f_{ERR.}$ to $P_{el}$ is depicted in Figure 6, where $f_{ERR.}$ steps from 0 Hz to 0.1 Hz while the wind turbine operates at a wind speed of 24 m/s.

### 4.3 Transfer Function from the Step Response

The shape of the wind turbine’s response, depicted in Figure 6, indicates that the wind turbine can be approximated as an underdamped second order system. Hence second order transfer functions can be found from the wind turbine’s step responses [21]. This means that the open loop system in Figure 5 is simplified to the system shown in Figure 7.

![Figure 7 Open loop power control system simplified to a second order system.](image)

The general form of a second order transfer function is:

$$G(s) = \frac{Kb}{s^2 + cs + b}$$

(1)

Since the system response in Figure 6 shows that the system is underdamped the poles of the transfer function must be conjugate complex and in the left half of the complex number plane (s-plane). The location of these poles can be determined from the system’s time response.

The parameters that describe the time response of an underdamped second order system are the damping ratio, $\zeta$, and the natural frequency, $\omega_n$. The transfer function of a second order system in terms of $\zeta$ and $\omega_n$ is given in Equation (2), where $K$ is the open loop forward gain.

$$G(s) = \frac{K\omega_n^2}{s^2 + 2\zeta\omega_n s + \omega_n^2}$$

(2)

In order to obtain the transfer function, the step response has to be analyzed and $\zeta$ and $\omega_n$ calculated. The parameters that can be measured from the time response and that allow calculating $\zeta$ and $\omega_n$ are the peak time, $T_p$, and the percent overshoot, $\%OS$. $T_p$ is the time it takes the signal to reach its peak value, and $\%OS$, is the percentage by which the first overshoot exceeds the steady state value:

$$\%OS = \frac{c_{max} - c_{final}}{c_{final}} \cdot 100$$

(3)

Where $c_{max}$ is the highest value in the overshoot and $c_{final}$ is the steady state value after the transient oscillations have subsided. With this definition $\%OS$ can be measured in the system’s time response.

The damping ratio, $\zeta$, is only a function of $\%OS$:
With the knowledge of $\zeta$ from Equation (4) the natural frequency, $\omega_n$, can be calculated:

$$\omega_n = \frac{\pi}{T_p \sqrt{1 - \zeta^2}}$$

The open loop forward gain, $K$, of the system can be found from the initial and final value at the input ($f_{\text{initial}}$ and $f_{\text{final}}$ respectively), and the initial and final response of the system ($c_{\text{initial}}$ and $c_{\text{final}}$ respectively).

$$K = \frac{c_{\text{initial}} - c_{\text{final}}}{f_{\text{initial}} - f_{\text{final}}}$$

With the parameters $\zeta$, $\omega_n$ and $K$ the system’s transfer function can be set up as in Equation (2).

The method described here yields simplified transfer functions of the system, which can be used for developing a controller.

The nonlinearities of the system are taken into account such that the yielded set of second order transfer functions represents the system as accurately as possible with a system complexity which is as low as possible. Although the nonlinearly limited pitch rate has an impact on the dynamics of the system, this impact can be offset by the controller to be designed. The response of the pitch system is reflected in an underestimation of $\omega_n$, which can be compensated for by speeding up the system by adjusting the derivative gain of the PID controller.

Instead of more sophisticated methods for dealing with the nonlinearly limited pitch rate this method has been chosen as it yields satisfactory results without increasing the system complexity. From an industrial point of view low complexity of the control system is of high importance, since in the PLC control systems in real wind turbines simplicity and robustness are paramount.

### 5 PID Controller Design

In this section the design of a PID pitch angle controller, based on the transfer functions derived above, is presented using the root locus method [21].

First the desired performance of the closed loop system, when subject to a step change at the input, is determined. Then a PID controller, that compensates the system such that it fulfils the desired performance, can be designed. Here the requirement is made that the
compensated closed loop system should exhibit 20 % overshoot and that the peak time of
the compensated system should be 10 % of the uncompensated peak time.

From the open loop transfer function of the plant (Equation (2)) the closed loop transfer
function can be generated:

\[ T(s) = \frac{G(s)}{1 + G(s)} \]  

(7)

Applying a step change to the uncompensated closed loop system yields the uncompensated
system response. The desired system response, which is the response the system shall
exhibit when it is equipped with an appropriate controller, can be expressed in terms of pole
locations on the s-plane.

The dynamic response of the system can be defined as a combination of %OS and peak
time.

On the s-plane %OS is defined by the damping ratio line, which is a straight line starting
from the origin going into the negative half-plane. A system that exhibits a certain %OS has
a pole somewhere on the damping ratio line that corresponds to this %OS. Figure 8 shows
the damping ratio line for 20 %OS. To fulfil the requirement of 20 %OS the system has to
have a pole on the damping ratio line in Figure 8.

A pole consists of a real and an imaginary part:

\[ \text{pole} = (\sigma + j\omega_d) \]  

(8)

Equation (8) and (9) show that the imaginary part of a pole is described by the peak time of
the system.

\[ \omega_d = \frac{\pi}{T_p} \]  

(9)

Since the imaginary part of the pole is known its real part can be calculated, since it is also
know that the pole has to lie on the previously specified damping ratio line.

Now that the location of the desired pole is found on the s-plane the root locus of the
system has to be manipulated such that it actually goes through this location. This can be
achieved by adding a zero to the open loop transfer function of the system. Since a zero is a
differentiator, adding a zero to the transfer function means adding a D-controller to the
system. With the D-controller the desired dynamic response of the system is achieved.

Under steady state condition the system is required not to have a control error. A steady
state error can be avoided by adding an integrator to the system. An integrator eliminates
the steady state error because it integrates the control error over time; leading to an
increasing control signal as long as the control error exists. In a transfer function an
integrator can be realized by adding a pole at the origin of the s-plane, i.e. \( 1/s \). Since
adding a pole at the origin would distort the root locus such that it would no longer go
through the point previously found for the dynamic response, a zero has to be added too.
Hence the transfer function of an I-controller looks like Equation (10).
The closer the zero, $z_I$, is to the origin, the more it compensates for the effect of the pole, hence the less the effect of the integrator. The farther the zero is away from the origin, the more the integrator has an effect, not only on the steady state response, but also on the dynamic response of the system. But since the dynamic response should be affected as little as possible a compromise has to be found for the location of the zero $z_I$.

Plotting the root locus of the PID-compensated system yields the gain, $K_{PID}$, at which the root locus crosses the desired damping ratio line (Figure 8).

The transfer function of the whole PID controller in serial form is given in Equation (11).

$$PID(s) = K_{PID} \cdot (s + z_D) \cdot \frac{(s + z_I)}{s}$$  \hspace{1cm} (11)

Since PID controllers in wind turbine PLCs are usually implemented in additive form, the controller gains of the P-, the I-, and the D-controller can be yielded when comparing Equation (11) with the standard transfer function of a PID controller:

$$PID(s) = \frac{K_D \left( s^2 + \frac{K_p}{K_D} s + \frac{K_I}{K_D} \right)}{s}$$  \hspace{1cm} (12)

This method for developing the PID controller has been applied for every transfer function found from the step responses in the different operating regions (as discussed in section 4.1). Figure 9 shows the gains for the P-, the I-, and the D-controller in the different operating regions.
To compensate the underestimated $\omega_n$ as discussed in section 4.3 the gain of the derivative controller, $K_d$, has been increased by testing. In this non-analytical way the disadvantage of the nonlinearly limited pitch rate can be circumvented, while at the same time the system remains simple.

The controller gains are implemented into the simulation model as lookup tables, so that the model works with the right gains in every operating point.

![Figure 9 The PID controller gains for the different operating regions.](image)

### 6 Results and Discussions

In this section the controller is tested by simulating a 300 ms short circuit at the 132 kV busbars as shown in Figure 1. This short circuit upsets the Nordic power system and can be sensed throughout the entire system. It has the biggest impact on the generator Zealand, since this one is closest to the fault location. The power system stabilising pitch angle controller developed above uses the speed signal of the SG Zealand as input and controls the active power of the wind farm so the oscillations in the SG speed get damped.

![Figure 10 Voltage at the wind farm terminals.](image)
In Figure 10 the effect of the short circuit is visualized in terms of voltage at the wind farm’s terminals.

Figure 11 shows the speed of SG Zealand, and the active power of the wind farm. Comparing the oscillations in the SG speed and the wind farm power, it can be seen, that there is a 180 degrees phase shift between these oscillations. This causes the damping effect, since the wind farm reduces its active power when the SG speed is above its rated value, and it increases its power when the SG speed is below its rated value.

To quantify the damping effect of the wind turbine controller Figure 12 shows the speed of the SG in three different situations: (i) without any wind farm, (ii) with the wind farm, but without the grid frequency stabiliser, and (iii) with the wind farm employing its grid frequency stabiliser. Figure 12 shows clearly that without the wind farm, the short circuit fault has the worst effect on the rotor speed of the SG. When the wind farm is connected, but its grid frequency stabiliser is disabled, it performs merely transient fault ride through control as described in [22]. Even this has a big damping effect on the SG, since the wind farm can be considered as a rotating machine with a large inertia [4]. Besides the wind farm acts as breaking resistor in the moment when the fault is cleared. As can be seen in Figure 11, the active power dips into negative region, which means that the wind farm absorbs power from the grid in an instant when the SG speed is well above its rated value. The effect of power absorption is caused by the torsion spring characteristic of the drive train of the wind turbines [22]. When the wind turbines employ their grid frequency stabilisers, another noticeable damping is added, which is especially visible between simulation time 3 and 6 seconds.

When quantifying the wind farm’s contribution to the damping of the speed oscillations of SG Zealand it has to be kept in mind that the rating of the wind farm (198 MW) is only a
fraction of the rating of SG Zealand (2000 MVA). In future larger wind farms might become realistic. A wind farm with a larger rating will also have a bigger damping effect. If the fault location was chosen differently, such that the voltage at the wind farm terminals would not be affected, i.e. the wind farm would not need to ride through a voltage dip, the wind farm would even be able to dampen the first swing of the speed of the SG.

All the simulations shown above have been conducted at 14 m/s wind speed. All the other wind speeds from cut-in wind speed (4 m/s) to shut-down wind speed (25 m/s) have been simulated as well. The grid frequency stabiliser works well between the rated wind speed (12 m/s) and shut-down wind speed of the wind turbine. Between 7 m/s and 11 m/s it does not show satisfying results, as the pitch system has an insufficient pitch rate for these wind speeds. Figure 13 shows the difference between pitch angle of full power and zero power (Figure 3) plotted versus wind speed.

From Figure 13 it becomes obvious that the region between 7 m/s and 11 m/s is most demanding for the pitch controller, since there the difference between these pitch angle values is biggest. For the controller to perform satisfactorily, it has to be able to sweep between the upper and the lower pitch angle limit in reasonably short time. Since the pitch system has a limited pitch rate, the bigger the gap between the limits (i.e. the bigger the value in Figure 13), the slower the response of the controller.

Below 7 m/s the controller works well. Closer to the cut-in wind speed, however, the wind farm produces only very little power since there is only very little energy in the wind, hence the damping effect on the rotor speed of the SG is hardly noticeable. In below rated wind speed situations the shadowing effect of a wind farm should be taken into account when considering an aggregated wind farm, as different wind speeds at different locations in a wind farm lead to different power values of the turbines.

![Figure 12 Speed of the SG at busbar Zealand, when subject to a transient short circuit on the 132 kV level. (i) Without any wind farm connected, (ii) with wind farm only riding through transient fault, and (iii) with wind farm actively stabilising the rotor speed of the SG.](image-url)
7 Conclusion

It is shown in this paper that a fixed speed active-stall wind turbine, which has only its pitch system to control its output power, is capable of contributing to the damping of power system oscillations. In the example simulated here the power system oscillations to be damped are grid frequency oscillations. It is found that damping of grid frequency oscillations is possible in most of the wind speeds of the wind turbine’s operating range, but not in all. Throughout this study the pitch system has been identified as the main limitation. With its limited pitch rate it affects the whole system. The PID controller designed here enhances the wind turbine to high performance despite the limitations imposed by the pitch system.

A dramatic increase in pitch rate is not to be expected in future, as with increasing pitch system performance, also the size of the blades will increase. Therefore it seems unrealistic to assume a pitch rate higher than 15 deg/sec.

Although variable speed, variable pitch turbines would be more suitable for damping power system oscillations, the power system support capabilities of active-stall turbines, as investigated in this work, are of major interest. Many active-stall turbines have been erected in the past and many active-stall turbines are still being sold due to their competitive price and robust technology. Even for offshore applications active-stall is still an attractive type of turbine, as the robustness of the active-stall concept is of high value in an inaccessible environment like an offshore wind farm.

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A Fuzzy Logic Pitch Angle Controller for Power System Stabilisation

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A Fuzzy Logic Pitch Angle Controller for Power System Stabilisation

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Abstract - In this paper the design of a fuzzy logic pitch angle controller for a fixed speed active-stall wind turbine, which is used for power system stabilisation, is presented. The system to be controlled, which is the wind turbine and the power system to which the turbine is connected, is described. The advantages of fuzzy logic control, when applied to large signal control of active-stall wind turbines, are outlined. The general steps of the design process for a fuzzy logic controller including definition of the controller inputs, setup of the fuzzy rules and the method of defuzzification are described. The performance of the controller is assessed by simulation, where the wind turbine's task is to dampen power system oscillations. In the scenario simulated for this work the wind turbine has to ride through a transient short-circuit fault and subsequently contribute to the damping of the grid frequency oscillations that are caused by the transient fault. It is concluded that the fuzzy logic controller enables the wind turbine to dampen power system oscillations. It is also concluded that due to the inherent nonlinearities in a wind turbine and the unpredictability of the whole system the fuzzy logic controller is very suitable for this application.

Key words: fuzzy logic, pitch controller, power system stabilisation, transient fault, wind turbine

1 Introduction

Until recently, the relatively small capacity of wind farms has meant that they were mainly considered as sources of power injection into a stable grid. In case of any abnormalities in the grid, wind turbines were simply disconnected only to be reconnected when normal grid operation has resumed. However, with increasing levels of wind power penetration and with increasing wind farm capacities, wind farms will have to take over more of the grid control tasks that are performed by conventional power plants.

Power system stabilisation, e.g. damping of grid frequency oscillations and of power swings are common control tasks undertaken by conventional power plants.

A transient short-circuit fault is a very common disturbance in a power system. Such a short-circuit fault suppresses the grid voltage only locally, but causes grid frequency oscillations and power swings like inter-area oscillations that can be sensed far away in the system.

If a short-circuit is close to a generator it suppresses the voltage at the generator terminals and prevents the generator from exporting active power, while its prime mover still imports mechanical power. This results in an acceleration of the rotor. After the fault is cleared the rotor is decelerated again and experiences transient oscillations.
before it settles to its steady state speed. In a synchronous generator, which is invariably the type of generator used in conventional bulk power plants, the rotor rotates synchronously with the stator field. Hence the rotor speed equals the electrical frequency.

In an interconnected AC power system a fault in one area and the subsequent rotor speed oscillations of the synchronous generators in this area lead to power swings (inter-area oscillations) between different areas in the whole system.

In many conventional power plants the synchronous generators are equipped with power system stabilisers that dampen rotor speed oscillations [1]. If wind farms are to replace a considerable amount of conventional power generation in the future, then they will have to assist in the damping of power system oscillations such as grid frequency oscillations and inter-area oscillations. This can be achieved by a variation in output power of the wind farm. The oscillating power system signal (frequency or power) has to be counteracted and damped by injecting oscillating active power into the grid. Considering oscillations in grid frequency this means: high grid frequency requires a reduction in wind farm power and a low grid frequency requires an increase in wind farm power. Power swings like inter-area oscillations have to be counteracted similarly. The implication of this is that, if wind turbines are to take over power system stabilisation tasks, they need to have a very effective means of regulating their electrical output power.

A common wind turbine type is the active-stall wind turbine, which has a directly grid-connected squirrel cage induction generator and a pitch system for varying the pitch angle of the rotor blades. An active-stall turbine, therefore, has only its pitch system to use for controlling the output power. The pitch system of active-stall turbines has previously been tested and used in practice for various dynamic operating situations [2].

Fuzzy logic has not been applied much to wind turbine control. It has been used for the purposes of energy extraction optimisation [3] and speed and voltage control of wind turbines under normal operation [4]. One of the main reasons as to why fuzzy logic has not yet been applied widely is that most of the wind turbine control tasks have been in the small signal range, where linear PI and PID controllers perform well. Power system stabilisation, however, is by no means a small signal control task, as the wind turbine power has to be varied between zero and full power in very short intervals. This is especially the case if the stabilisation has to be carried out in the wake of a short-circuit fault that is close to the wind turbine and hence the wind turbine is required to ride through a deep voltage dip. In such operating conditions the numerous nonlinearities of a wind turbine become a severe constraint, which a fuzzy logic controller can handle very well.

In this article a fuzzy logic pitch angle controller is described that enables an active-stall wind turbine to perform power system stabilisation. In the case simulated here the wind turbine has to ride through a transient short-circuit fault and subsequently contribute to the damping of grid frequency oscillations. It is possible to consider other power system oscillations but grid frequency oscillations have been chosen for reasons outlined later in section 2.1.
2 System description

In this section the system to be controlled is described. This comprises the wind turbine, whose electric power has to counteract the power system oscillations, and the power system to which the wind turbine is connected. The wind turbine model and the power system model are implemented in the power system simulation tool PowerFactory from DIgSILENT [5].

2.1 Power System Model

For simulations of power system oscillations to be realistic, a realistic power system model is required. The power system model used in this project is a model of the interconnected power system of the countries Norway, Sweden, Finland and eastern Denmark. The model has been developed at SINTEF in Norway [6] and is an aggregation of a fully detailed model of the Nordic transmission system.

Characteristic for the Nordic power system is that although it is geographically large, it is of relatively small capacity, since Norway, Sweden, Finland and Denmark are only sparsely populated countries.

The model covers the high voltage system and comprises 35 nodes and 20 synchronous generators.

For the purpose of this research work the model as developed by SINTEF has been extended with a wind farm feeder that connects a 198 MW wind farm to the Nordic system at the busbar “Zealand”, in eastern Denmark. A 2000 MVA synchronous generator (SG), with a dispatched power 765 MW is also connected to this busbar. The total dispatched power of the whole Nordic power system is 43000 MW.

The system setup is shown in Figure 1, where the induction generator (IG) of the wind farm is connected through a realistic feeder configuration to the busbar “Zealand” in the Nordic power system.

As can be seen in Figure 1, a short-circuit is simulated at one of the 132 kV busbars. This short-circuit is a three-phase short-circuit that lasts for 300 ms. This duration of the short-circuit is chosen, since some power system operators specify it as a worst case scenario that some wind farms have to be able to cope with [7]. When this short-circuit occurs the Nordic power system temporarily loses the power generated by the wind farm, and at the same time the remaining generation, mainly the SG at busbar Zealand, has to supply part of the fault current flowing into the short-circuit fault. The fault current constitutes a load as (i) every short-circuit has an active power component, and (ii) the fault current flowing towards the fault location causes losses in the conductors of the system. During the fault the voltage at the busbar Zealand is depressed, which
means that the SG cannot export as much power as is imported by its prime mover. Hence SG Zealand accelerates during the fault, and after the fault is cleared SG Zealand tries to export as much power as possible to decelerate to its rated speed. As a result of this the rotor speed of SG Zealand oscillates (Figure 8).

Due to the topology of the Nordic power system the fault in eastern Denmark causes inter-area oscillations as far away in the system as in the inter-area link between northern Sweden and Finland. Disturbances in different locations of the system lead to inter-area oscillations between different areas in the entire system. The frequencies of these inter-area oscillations in the different locations of the Nordic power system are in the range of 0.1 - 1 Hz [8], and are hence in the same range as the frequency oscillations in eastern Denmark. If the wind farm were connected in a different location in the system such inter-area oscillations could have been chosen as the signal to be damped by the wind farm. However, the wind farm was located in eastern Denmark because this best represents the current wind power situation in the Nordic power system. Therefore this dictates that the power system signal to be damped by the wind farm is the frequency, i.e. the speed of the SG Zealand. By damping the speed oscillations of SG Zealand the wind farm does, however, indirectly act damping on the inter-area oscillations too.

The fault location has been chosen because it (i) upsets the power system and excites it to perform oscillations that the wind farm has to act on, and (ii) it challenges the wind farm as it has to ride through a deep voltage dip.

2.2 Wind Farm Model

Compared to the size of the whole Nordic power system, or even of SG Zealand, the wind farm is relatively small. It has a rated active power of 198 MW, which is a realistic size for a possible offshore wind farm in Eastern Denmark.

The wind farm is aggregated to one single squirrel cage induction generator, driven by one single wind turbine model. The turbine type considered in this work is active-stall. A detailed description of the mechanical and aerodynamic model of the wind turbine can be found in [9], [10] and [11]. The model used here reflects reality quite well, which has been proven in an islanding experiment of a real 2 MW turbine [12]. The aggregation of the whole wind farm to one wind turbine is valid as all turbines in the wind farm are equal. Also the wind speed considered is above rated wind speed, i.e. even with shadowing effects in a wind farm all turbines have sufficient wind for rated power production. Besides, small variations are negligible since the type of control considered here is large signal control. It should be noted that in below rated wind speeds the wind turbines in a wind farm would not produce the same power; hence the aggregation would need to take these differences into account.

If the wind farm were to be modelled as individual wind turbines the stabiliser would be realised as a controller in each turbine. The power system signal to be stabilised (frequency in this example) would however, still be measured centrally.

Power system stabilisation is a very response-time sensitive control task, which is why the highest possible pitch rate is assumed. The pitch rate chosen here is 15 deg/s, which is a possible pitch rate for a modern multi-megawatt turbine [13]. It has to be acknowledged though that in the wind turbine simulation model used here no structural
dynamics of the rotor blades are included. High pitch rates cause the blades to twist and consequently to exhibit torsional oscillations. Therefore in section 4 the fuzzy logic controller will also be tested for a pitch rate of only 10 deg/s.

In order to dampen grid frequency oscillations the wind turbine controller strives for increasing its electrical power output when the grid frequency is low and reducing its power output when the grid frequency is high.

Figure 2 shows how the fuzzy logic pitch angle controller is embedded in the wind turbine model.

Figure 2 Wind turbine control circuit with fuzzy logic power system stabiliser.

### 3 Fuzzy logic controller

A detailed review of fuzzy logic is outside the scope of this paper but some background will clarify the reasons for considering its use. Conventional linear controllers like PI and PID controllers need a mathematical description (e.g. transfer function) of the system to be controlled in order to tune their parameters. For the design of a fuzzy logic controller a precise mathematical description of the system is not necessary, as such a mathematical description is replaced by common sense knowledge of the system’s behaviour. This knowledge is reflected in a series of rules, which the controller uses to derive its output signal from its input signals. Fuzzy logic controllers apply reasoning, similar to how human beings make decisions, and thus the controller rules contain the expert’s knowledge of the system. Hence it is systems that are difficult to describe mathematically that are the prime area of application for fuzzy logic control.

So, the big advantages of fuzzy logic control when applied to a wind turbine are that the turbine system neither needs to be accurately described, nor does it need to be linear. Although the system simulated here is a realistic simulation model described in terms of transfer functions, it does not describe a wind turbine to its full extent. When designing a linear controller using such a simulation model, it is probable that the linear controller would need further modification before application in a real wind turbine. A real wind turbine contains several dynamics that are not fully known and therefore cannot be described in a simulation model. A fuzzy logic controller on the other hand does not require a completely accurate description of the system; hence it would also work if applied in a system behaving somewhat differently from the system it has been designed for. This will be shown in section 4 where the performance of the fuzzy logic controller is simulated with a pitch rate lower than the one the fuzzy logic controller has been designed for. In addition to the unknown dynamics there are also numerous
nonlinearities in the wind turbine, the most evident of which is the nonlinearly limited pitch rate of the pitch system.

Another part of the system to be controlled is the power system to which the turbine is connected. Characteristic for power systems is that their properties and hence their mathematical description vary with the system configuration. As loads and feeders might connect and disconnect without notice, the configuration is not predictable.

In order to design a fuzzy logic controller the essential premise is not an accurate description of the system, but expert knowledge about the likely behaviour of the system. The design of the PID controller described in [14] provided an insight into the task of using wind turbines for power system stabilisation and the problems encountered. This knowledge is now applied in the design of the fuzzy logic controller. The design process for a fuzzy logic controller consists of: (i) determining the inputs, (ii) setting up the rules, and (iii) designing a method to convert the fuzzy result of the rules into a crisp output signal, known as defuzzification. These steps are described in the following subsections.

As mentioned in the previous section the wind turbine can counteract grid frequency oscillations by increasing its output power when the frequency is low and reducing its output power when the frequency is high. (Note that the same would apply if the input signal from the power system were the power in an inter-area link.) As in an active-stall turbine the pitch angle is the only means of controlling the electric power from the turbine, the control signal from the fuzzy logic controller is a pitch angle setpoint.

The grid frequency stabiliser is normally not active, but is activated only if the measured grid frequency leaves a band of tolerable frequency variations. Once the grid frequency has settled in this band and remains there, the grid frequency stabiliser is deactivated and normal operation resumes.

3.1 Input Signals

The input signals required are:

- Electrical frequency, $f$, as this is the chosen signal to be stabilised.
- Rate of change of the electrical frequency, $df/dt$, which provides insight to what the frequency will be.
- Electrical power of the wind farm, $P$, as the electrical power of the wind farm has to counteract the frequency deviations.
- Rate of change of the electrical power of the wind farm, $dP/dt$, which indicates in which direction $P$ changes. This is important, as the power of the wind farm cannot be controlled very quickly. Due to the long time constants in the wind turbine a quick power variation is not possible, therefore a prediction of the power development is needed to control the power efficiently.
- Speed of the wind turbine generator, $n$, which is required for preventing the turbine from overspeeding. It is not needed for power system stabilising operation. However, during a transient fault the wind turbine generator accelerates; hence after the fault overspeed is likely to occur and has to be prevented.
• Magnitude of grid frequency oscillations, $mag$, which is used for adjusting the weight of the inputs to allow effective control also when the magnitude of the frequency oscillations becomes small.

### 3.2 Fuzzy Sets for the Inputs

A fuzzy logic controller cannot handle crisp input signals, but needs them described in fuzzy terms. Therefore the crisp input signals have to be expressed in terms of membership of fuzzy sets. The shapes of the fuzzy sets ‘low $f$’, ‘OK $f$’ and ‘high $f$’ for the input $f$ are depicted in Figure 3. The shapes of the fuzzy sets ‘negative $df/dt$’, ‘zero $df/dt$’ and ‘positive $df/dt$’ for the input $df/dt$ are also shown in Figure 3. The shape of the fuzzy sets for $P$ and $dP/dt$ look the same.

![Figure 3 Fuzzy sets for the input signal electrical frequency $f$ and rate of change of electrical frequency $df/dt$.](image)

Depending on the crisp value of the input variable considered it can be expressed in terms of degree of membership of the fuzzy sets. The shape of the fuzzy sets has been determined by using expert knowledge of the system.

![Figure 4 Fuzzy set for the input signal wind turbine generator speed $n$.](image)

In the case of the input signal $n$ there is only one fuzzy set, ‘high $n$’, as this is only a safety measure to prevent the turbine from overspeeding (see Figure 4). Whenever the speed of the wind turbine generator is above the value $n_{\text{set}}$ it is assigned a degree of membership of the fuzzy set “high $n$”.

Similarly there is only one fuzzy set for the magnitude of the frequency oscillations, $mag$, (Figure 5). The magnitude of the frequency oscillations determines the degree of membership of the fuzzy set ‘ratio’. How ‘ratio’ is used in the controller will be explained in more detail in the following section.
3.3 Fuzzy Rules

The degrees of membership of the fuzzy sets described in the previous section are used further in rules that are based on the expert knowledge of the control problem to be dealt with. These rules describe what actions are required for all conceivable combinations of memberships; i.e. they cover all possible operating points.

As mentioned above the output signal of the controller is a pitch angle setpoint, hence the actions described in the rules are increasing, decreasing, or keeping the pitch angle the same. The rules are sorted in groups depending on which signals they deal with. The rules are listed in Table 1.

<table>
<thead>
<tr>
<th>Group f</th>
<th>Group P</th>
<th>Group n</th>
</tr>
</thead>
<tbody>
<tr>
<td>increase $\theta$ if</td>
<td>low $f$ AND zero $df/dt$</td>
<td>low $P$ AND zero $dP/dt$</td>
</tr>
<tr>
<td></td>
<td>low $f$ AND negative $df/dt$</td>
<td>low $P$ AND negative $dP/dt$</td>
</tr>
<tr>
<td></td>
<td>OK $f$ AND negative $df/dt$</td>
<td>OK $P$ AND negative $dP/dt$</td>
</tr>
<tr>
<td>decrease $\theta$ if</td>
<td>high $f$ AND zero $df/dt$</td>
<td>high $P$ AND zero $dP/dt$</td>
</tr>
<tr>
<td></td>
<td>high $f$ AND positive $df/dt$</td>
<td>high $P$ AND positive $dP/dt$</td>
</tr>
<tr>
<td></td>
<td>OK $f$ AND positive $df/dt$</td>
<td>OK $P$ AND positive $dP/dt$</td>
</tr>
<tr>
<td>keep $\theta$ if</td>
<td>high $f$ AND negative $df/dt$</td>
<td>high $P$ AND negative $dP/dt$</td>
</tr>
<tr>
<td></td>
<td>OK $f$ AND zero $df/dt$</td>
<td>OK $P$ AND zero $dP/dt$</td>
</tr>
<tr>
<td></td>
<td>low $f$ AND positive $df/dt$</td>
<td>low $P$ AND positive $dP/dt$</td>
</tr>
</tbody>
</table>

Table 1 If-Then rules of the fuzzy logic controller.

3.4 Defuzzification

Under any condition several rules will fire, each making a suggestion as to how the pitch angle setpoint should be changed. To address the complexity of the control task at hand every rule has to be considered at any point in time. The output signal of the fuzzy logic controller is a pitch angle setpoint that is sent to the pitch system. The pitch system needs a crisp setpoint. Therefore the results of the rules, being “increase $\theta$”, “decrease $\theta$” and “keep $\theta$”, have to be transformed into a crisp $\theta$-value. Hence the defuzzification has to combine the results of all the rules and find a crisp result value.

To define the vague terms “increase $\theta$”, “decrease $\theta$” and “keep $\theta$”, which are the outcome of the rules, the following definitions are made:

- “increase $\theta$” refers to the pitch angle where the turbine produces full power, i.e.
the pitch angle for normal operation: $\theta_{\text{normal}}$

- “decrease $\theta$” refers to the pitch angle where the turbine produces zero power: $\theta_{\text{zP}}$
- “keep $\theta$” refers to the pitch angle that corresponds to the power setpoint during power system stabilisation operation: $\theta_{\text{mid}}$

The values of the pitch angles $\theta_{\text{normal}}$, $\theta_{\text{mid}}$ and $\theta_{\text{zP}}$ are known values from the aerodynamic characteristic of the rotor blades.

In the defuzzification process the crisp pitch angle setpoint is found by determining the centre of gravity as shown in Figure 6, where the “increase $\theta$”, “decrease $\theta$” and “keep $\theta$” are depicted as columns on the pitch angle values $\theta_{\text{normal}}$, $\theta_{\text{zP}}$ and $\theta_{\text{mid}}$ respectively.

The height of the columns of Group $f$ and Group $P$ are in the first instance determined by the results of the rules that have fired. The degrees of membership of the signals considered in each firing rule determines the result of that rule, by applying the AND operation. The height of the columns of Group $f$ and Group $P$ are further adjusted by weighting with the degree of the membership ‘ratio’:

- $\text{height } \text{Group } f = (1 - \text{ratio}) \cdot \text{Group } f$
- $\text{height } \text{Group } P = \text{ratio} \cdot \text{Group } P$

This makes the columns of Group $f$ weigh heavier the smaller the magnitude of the frequency oscillations.

From Figure 6 it can also be seen that Group $n$ has only one column on the pitch angle $\theta_{\text{zP}}$. The height of this column depends on the degree of membership of ‘high $n$’. The length of this column is much longer than the other columns, since the rule “decrease $\theta$ if ‘high $n$’” is only a safety measure. If the speed is so high that it causes this rule to fire the reduction of power for limitation of the turbine speed is paramount.
4 Results and discussions

With the controller in place a short-circuit fault as described in section 2.1 is simulated. The wind speed during the simulation is a constant 14 m/s, which is sufficient for the turbine to produce rated power. Figure 7 shows the voltage at the wind farm terminals, the speed of the synchronous generator SG Zealand and the power of the wind farm during and after the fault. The power from the wind farm counteracts the oscillations in the speed of SG Zealand. The oscillations in the wind farm power are caused by controlled pitch angle variations from the fuzzy logic controller.

At the instant the fault is cleared the active power of the wind farm dips into negative region, i.e. the wind farm absorbs power. This phenomenon is caused by the torsion spring characteristic of the drive train of the wind turbine [15]. When a fault suddenly prevents electrical power production the drive train is unloaded, which causes the speed of the drive train to oscillate. Power absorption occurs just after the clearance of the fault due to the oscillation frequency of the drive train and the fault duration.

The effect of the power system stabilisation of the wind farm can be seen best when comparing the speed of SG Zealand with the fuzzy logic stabiliser being active and inactive, which can be seen in Figure 8. To further compare the effect of the fuzzy logic grid frequency stabiliser Figure 8 also shows the speed of SG Zealand when damped with a previously designed PID grid frequency stabiliser in the wind farm [14]. In the case where the grid frequency stabiliser is inactive the wind farm merely rides through
the fault. This means that the wind farm performs only the pitching actions necessary to be able to stay connected to the grid without experiencing excessive overspeed [15].

Figure 8 shows that the wind farm contributes noticeably to the damping of the speed oscillations of SG Zealand when it is equipped with the PID grid frequency stabiliser, and even more so when it is equipped with the fuzzy logic stabiliser. When quantifying this contribution it has to be kept in mind that the rating of the wind farm is only about a tenth of the rating of SG Zealand.

Since the situation simulated here causes the wind turbine to ride through a deep voltage dip the fuzzy logic stabiliser first needs to dampen the drive train oscillations of the wind turbine that are caused by the voltage dip [15]. Hence in the first period of the grid frequency oscillation the wind farm cannot contribute to the damping of the grid frequency oscillations. If a different fault location were chosen, such that the wind farm would not experience a voltage dip it could already act damping on the first period of the oscillation and even enhance transient stability of the SG. However the fault location is chosen because it constitutes a worst case scenario, as the fuzzy logic controller needs to respond to two oscillations at the same time: the drive train oscillations of the wind turbine and the frequency oscillations in the power system. Figure 9 shows how the controller varies the pitch angle to control the two oscillations.

One of the advantages of fuzzy logic controllers is that a precise description of the
system to be controlled is not crucial for the design of the controller. Therefore, without any adjustments to the fuzzy logic stabiliser, its performance is tested when the maximum pitch rate of the pitch system is limited to 10 deg/s. From Figure 10, which shows the speed of SG Zealand for the two cases (fuzzy logic stabiliser with 10 deg/s and with 15 deg/s), it can be seen that the performance hardly varies when a less powerful pitch system is applied. This proves that (i) the fuzzy logic controller also works well for a system it has not specifically been designed for and (ii) the fuzzy logic controller manages to produce good results even with lower pitch system duty.

The fuzzy logic stabiliser has been tested for all wind speeds from cut-in wind speed (4 m/s) to shut-down wind speed (25 m/s). The pitch angle controller can vary the pitch angle in the range from pitch angle of maximum or rated power, to the pitch angle of zero power. From Figure 11, which shows these pitch angles as a function of wind speed, it can be seen that there is a large difference in pitch angles for these two power values between wind speeds of 7 to 11 m/s.

Despite the fact that the limited pitch rate causes a response time which is dependent on the size of the difference in Figure 11, i.e. which is a function of wind speed, the fuzzy logic controller has been found to perform well at any wind speed. Close to the cut-in wind speed, however, the wind farm produces very little power since there is only a small amount of energy in the wind. The power it can inject into the grid for damping oscillations is therefore hardly noticeable. At below rated wind speed the shadowing effect should be taken into account when considering an aggregated wind farm, as
different wind speeds at different locations in a wind farm lead to different power values of the turbines.

When wind power is to contribute to the stability of an interconnected power system it is important that the wind turbine controllers do not disturb other controllers. Although any controller might work well on its own, in combination their control result might be worse. A wind turbine controller striving for damping grid frequency oscillations must not, for example, interfere with power system stabilisers (PSS) in synchronous generators, and by doing so lead to less damping of grid frequency oscillations. To prove that the fuzzy logic stabiliser also works well in conjunction with a PSS, the same fault situation has been simulated as before, this time (i) with the fuzzy logic stabiliser and (ii) without the fuzzy logic stabiliser (wind farm only riding through the fault), but in both cases with a PSS in SG Zealand. These simulations revealed that the fuzzy logic stabiliser works well together with the PSS in SG Zealand. The oscillations in the speed of SG Zealand are more damped and it returns quicker to its rated value.

5 Conclusion

The general build-up and functions of a wind turbine pitch angle controller that enables the wind turbine to dampen and stabilise oscillations in the power system has been described. The performance of the fuzzy logic stabiliser has been assessed by means of simulations of different maximum pitch rates, different wind speeds, as well as with and without PSS in the SG whose speed is to be stabilised.

The advantage of fuzzy logic control is that an accurate description of the system is not necessary. An accurate description of the power system to which the wind farm is connected is usually unknown, as its configuration is subject to changes during operation. A description of the wind turbine system, which is valid for any conceivable operating point, is difficult to obtain partly due to the many nonlinearities, among which is the nonlinearly limited pitch rate of the pitch system. Therefore, for the task of large signal control of wind turbines fuzzy logic is an attractive type of control.

The rules in the fuzzy logic controller allow the designer to provide the controller with foresight so it can initiate its response to situations that can be expected to arise. This leads to moderate controller actions. In the case of a fixed speed active-stall wind turbine this means pitching actions, which are not very sensitive to the maximum pitch rate of the pitch system. This is particularly advantageous as fast pitching actions mean wear in the pitch system and stress for the rotor blades. In addition, simulations that include fast pitching actions are potentially unrealistic, as the structural dynamics of large rotor blades, like the blades of the 2 MW turbine considered here, are likely to exhibit noticeable dynamic behaviour.

It can be concluded that the fuzzy logic stabiliser, described in this article, enables an active-stall wind turbine to contribute actively to the stability of the power system. Wind turbines behaving like this are not passively relying on a stable power system as a premise for their operation, but actively support the system.
References


Simulation of the Impact of Wind Power on the Transient Fault Behavior of the Nordic Power System

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Simulation of the impact of wind power on the transient fault behavior of the Nordic power system

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Abstract
In this paper the effect of wind power on the transient fault behavior of the Nordic power system is investigated. The Nordic power system is the interconnected power system of the countries Norway, Sweden, Finland and Denmark. For the purpose of these investigations the wind turbines installed and connected in eastern Denmark are taken as study case. The current and future wind power situation in eastern Denmark is modeled and short circuit faults in the system simulated. The simulations yield information on (i) how the faults impact on the wind turbines and (ii) how the response of the wind turbines influences the post-fault behavior of the Nordic power system.

It is concluded that an increasing level of wind power penetration leads to stronger system oscillations in case of fixed speed wind turbines. It is found that fixed speed wind turbines that merely ride through transient faults have negative impacts on the dynamic response of the system. These negative impacts can be mitigated though, if sophisticated wind turbine control is applied.

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Keywords: Fault ride through, Nordic power system, Wind power, Transient fault

1. Introduction
The study of the effects of growing wind power penetration on the stability and reliability of power systems is of interest in many countries in the world. Wherever wind power will be installed on a large scale such studies are carried out to prevent severe consequences for the power system considered [1]. Besides the commonly discussed impacts of and on the system voltage, also the system frequency plays an important role. When wind power penetration increases, wind turbines have to be involved in the control of the grid frequency. This is a relatively straightforward task for normal operation, where load changes cause the system frequency to deviate [2]. Frequency control is a much more demanding task for wind turbines in the wake of transient faults [3]. Under transient fault situations both the voltage and frequency have to be considered to assess the impact of wind power on the system stability [4].

This paper considers the mutual effects of wind power in power systems under transient fault situations. As study case the Nordic power system is taken. It is analyzed (i) how the wind turbines behave in the system when it experiences a transient fault and (ii) what impact the wind turbines have on the dynamic behavior of the system after a fault.

The Nordic power system stretches the countries Norway, Sweden, Denmark and Finland. Not only is substantial amount of wind power already today installed in the Nordic power system, a lot more is expected to come due to the promising wind conditions in northern Europe. Characteristic for the Nordic power system is that it is geographically large, but at the same time it is of comparably small capacity, due to Norway, Sweden, Denmark and Finland being only sparsely populated countries. This makes it more vulnerable to high levels of wind power penetration if the installed turbines are uncontrolled distributed generators.

Until recently wind turbines connected to the Nordic power system were not engaged in the control and support of the
system. If transient faults in the system lead to considerable excursions in voltage and/or frequency the wind turbines were to disconnect and to reconnect only once the system has returned to stable operation. Increasing wind power penetration leads to the problem that considerable amount of generation might disconnect in case of a transient fault in the system, causing the system to become unstable from an otherwise harmless fault situation. To prevent such situations newly installed wind turbines have to comply with new grid connection requirements that demand wind turbines to ride through transient faults.

Elkraft, which is the operator of the transmission system in eastern Denmark has already today one of the world’s largest offshore wind farms connected to its system, and more even larger offshore wind farms are expected in the near future. Therefore, Elkraft along with the other system operators in the Nordic power system, is interested in the possible consequences of local high wind power penetration. The model of the Nordic power system used in these investigations has been developed at SINTEF in Norway [6], and is an aggregation of a fully detailed transmission system model, whose validity has been proven with measurements. It is a model of the transmission system comprising aggregations of conventional power plants only; no wind farms have been included at SINTEF.

At Risø National Laboratory a model of the wind power connected to the Nordic power system in eastern Denmark has been added to SINTEF’s Nordic power system model. This additional model has been developed in cooperation with Elkraft. The simulation tool used in these investigations is the power system simulation tool PowerFactory from DiGSIbENT [7].

This article presents the results of joint efforts of Risø National Laboratory, SINTEF and Elkraft on the field of transient stability of wind power in the Nordic power system.

2. The Nordic power system model

The Nordic power system stretches the countries Norway, Sweden, Denmark and Finland, and has a nominal system frequency of 50 Hz. It is divided into two synchronous areas. The biggest part of the system, comprising Norway, Sweden, Finland and the eastern part of Denmark are one interconnected, synchronous AC system. The small rest of the Nordic power system, i.e. western Denmark, is AC connected to the big UCTE system, which is the interconnected AC system of central Europe. Several HVDC links connect the Nordic synchronous system with the central European system. There are, among others, HVDC links between Norway and western Denmark, between eastern Denmark and Germany and between southern Sweden and Germany.

Since in transient fault situations the HVDC links can be considered uncontrolled voltage dependent sources and sinks, the central European part of the system is of no relevance for transient fault simulations. Hence for simplicity the term “Nordic power system” will in the following refer to the Nordic synchronous system.

The model of the Nordic power system is an aggregation, which means that the generators, lines and loads in the model are lumped representations of several generators lines and loads in reality. It comprises 35 nodes and 20 synchronous generators. It is a model of the transmission system only; comprising the voltage levels 420, 300, 150 and 135 kV. In the location of eastern Denmark, the model is extended with a simplified grid to represent the connection of wind power. This simplified grid comprises all voltage levels from transmission system voltage down to generator terminal voltage. This extension is described in the following section.

3. Model of wind power installations in the Nordic power system

As mentioned earlier the purpose of the extension of the Nordic power system model is that wind power can be implemented realistically into the model. The extension considers the transmission and distribution system in eastern Denmark. Eastern Denmark is a remote location in the system. In the south of eastern Denmark, which is where the majority of the wind turbines are connected, the grid is relatively weak. Denmark is the country in the Nordic power system that has by far the highest level of wind power penetration. Therefore, it is only natural to model the wind power connected there. It is assumed that wind power in eastern Denmark is the only wind power that has to be considered in the Nordic system.

Inherent for wind power is that its resources are far away from load centers and hence almost invariant far away from strong transmission systems. This is even more applicable for offshore wind farms. The largest part of wind power that will be installed in eastern Denmark in future will be offshore.

The amount of wind power that is introduced, substitutes power of synchronous generators. Hence the total amount of active power transmitted through the system remains the same, apart from the losses of the extra components.

3.1. Topology of the grid in eastern Denmark

In the original model as developed by SINTEF eastern Denmark is represented by a single busbar with a synchronous generator and a load. This busbar is called Zealand, as can be seen in Fig. 1, which shows the topology of the whole power system extension. The synchronous generator at busbar Zealand (SG Zealand) is rated 2000 MVA and represents all the conventional power plants in eastern Denmark. The load connected to Zealand represents the load in the northern part of eastern Denmark.

In the extension (Fig. 1) three wind farms in the south of eastern Denmark are considered. One wind farm represents all the land-based wind turbines, which are distributed over the southern islands of eastern Denmark. These turbines are aggregated to one single induction generator. Another wind farm represents the Nysted offshore wind farm. This is one of the world’s largest...
offshore wind farms and has been connected to the system since 2003 [8]. The third wind farm is an offshore wind farm that is likely to be installed in future.

The connection between the 420 kV busbar and the wind farms is modeled in a more detailed manner than the rest of the Nordic system. It considers all voltage levels from 420 kV down to generator terminal voltages.

3.2. Model of wind farm feeders

The wind farms in the south of eastern Denmark are connected to the transmission system of the Nordic power system through the relatively weak grid of eastern Denmark. Therefore, the power system in eastern Denmark has to be modeled in more detail than the transmission system.

Between the busbars Zealand and Spanager (see Fig. 1) is one transformer that steps the voltage down from 420 kV to 132 kV. From Spanager, which is situated on the island of Zealand, close to Copenhagen, to the busbar Radsted, which is situated in the south, on the island of Lolland, are several parallel 132 kV lines. The number of parallel lines is varied depending on the level of wind power penetration simulated. (Different cases are simulated as will be seen in Section 4.) The distance between Spanager and Radsted is approximately 100 km.
Connected to Radsted is a load that represents the load in the south of eastern Denmark. The wind farms are connected to Radsted through 132 kV feeders and medium voltage cables, representing the cable network in the wind farms. The 132 kV feeder connecting the distributed land-based wind turbines is assumed to be 25 km long. This length is an approximate value found by considering the distance from Radsted to a central location between all the land-based turbines [9]. From this central location 24 parallel 11 kV cables, of 20 km length, represents the medium voltage cable network to the turbines. The length of the 11 kV cable is an average distance from the turbines to the central location mentioned above. Since the distributed land-based turbines are all connected to the distribution system, three transformers are chosen to step the voltage down from the transmission system voltage to the generator terminal voltage.

The wind farm is modeled with a 29 km long 132 kV line. The cable network inside the wind farm is represented by three parallel, 3.2 km long, 33 kV cables. The distance of 3.2 km is the average distance from the turbines to the transformer platform [10]. The 132 kV feeder connecting the future offshore wind farm with Radsted is assumed to be 30 km long. Just like in the case of the Nysted offshore wind farm, also here the internal farm cable network is represented by three parallel 3.2 km long, 33 kV cables.

With these feeders the generators of the wind turbines are connected to the Nordic power system. The generators and their prime movers, i.e., the wind turbines are described in the following section.

### 3.3. The wind farm models

#### 3.3.1. Wind model

In this article only transient fault simulations are considered. The simulated events last up to a few seconds, therefore, natural wind variations need not be taken into account. Rotating wind speed variations like 3 pu (the tower shadow effect) [11] can be neglected as well, because the wind power plants considered are aggregations of many single wind turbines. If many turbines are connected together their rotating wind speed variations cancel each other out.

The wind speed is set to a constant 18 m/s, which is a wind speed that allows all turbines to produce rated power. A rated power operating point is chosen, as this is most burdening for the power system.

#### 3.3.2. Model of the distributed land-based wind turbines

Substantial amount of wind power is distributed over the islands in the south of eastern Denmark. These distributed land-based wind turbines are aggregated and modeled by one squirrel cage induction generator. The prime mover is modeled by a constant mechanical torque that acts on a two masses spring and friction model, which then drives the generator (Fig. 2). Aerodynamics and control schemes of these turbines are neglected. They are not relevant for transient fault studies as the grid connection requirements that were applicable when these turbines were installed demand them to disconnect in case of a grid fault.

The capacity of the induction generator representing the aggregation of all the distributed land-based wind turbines is 235 MW. This is a value that can be worked out from the wind turbine data register of the Danish Energy Authority [9]. The protection system that disconnects the land-based turbines in case of a fault is implemented in the form of under-voltage, overspeed and overcurrent protection. The protection scheme implemented in this model disconnects the generator and its compensation unit, when:

- the voltage at the generator terminals drops below 0.85 pu for 100 ms;
- the speed of the generator exceeds 104% of its rated speed (when the generator cannot export as much power as is imported through the wind, it accelerates);
- the current exceeds 200% rated current for 100 ms.

It is assumed that the reactive power compensation is implemented in such a way that only the no load reactive power demand of the generator is compensated. This is in accordance with the applicable grid connection requirements.

#### 3.3.3. Model of Nysted offshore wind farm

The Nysted offshore wind farm consists of 72 identical active-stall wind turbines, each rated 2.3 MW [8]. Therefore, this wind farm is modeled with 72 parallel 2.3 MW induction generators, driven by a wind turbine model with full mechanical (Fig. 2) and aerodynamic representation [12]. A similar wind turbine model has been verified in an islanding experiment of a real multi-megawatt active-stall turbine. This experiment proved that the model represents the behavior of the real turbine well [13]. Fig. 3 shows the topology of the wind turbine model.

An active-stall controller that finds the right pitch angle during normal, fault-free operation is implemented. It optimizes the active power production at wind speeds below rated wind speed. Above rated wind speeds it limits the active power output of the
The Nysted offshore wind farm has to fulfill grid connection requirements that require certain fault ride through capabilities [5]. Therefore, also a transient fault controller is implemented that allows the turbines to ride through transient faults without experiencing damaging speed excursions [15].

In accordance with the applicable grid connection requirements, a reactive power compensation unit has to keep the wind farm neutral in reactive power demand at the grid connection point. A shunt capacitor bank is implemented at the generator busbar, and a controller controls the number of connected capacitors, \( n_C \), such that the steady state power factor is one at the high voltage side of the 132/33 kV transformer.

### 3.3.4. Model of future offshore wind farm

The future offshore wind farm considered is also made of active-stall wind turbines. It consists of 99 identical 2 MW turbines. Hence the wind farm is modeled with 99 parallel induction generators driven by a wind turbine model similar to the one used in the Nysted wind farm (Fig. 3). The control of the wind turbines in the future offshore wind farm is more sophisticated as these turbines are not only required to ride through transient faults, but also to contribute to the damping of grid frequency oscillations in the wake of transient faults [3]. This is not demanded in current grid connection requirements, but if wind power penetration increases this will probably become a requirement.

Also here it is assumed that the wind farm controls its steady state reactive power production such that it is neutral in reactive power demand at the high voltage side of the 132/33 kV transformer. For that purpose also here a shunt capacitor bank is implemented. The switching frequency of the capacitor contacts is assumed to be somewhat higher than in the Nysted wind farm, emulating more sophisticated technology.

### 4. Simulations, results and discussions

Different scenarios are simulated to assess the impact of wind power in the current and the future situation. The faults simulated are 100 ms, zero impedance, three-phase short circuits on one of the lines between Spanager and Radsted, close to Radsted (see Fig. 1). The fault gets cleared by permanent disconnection of the faulted line. This is a fault situation described in Elkraft’s grid connection requirements for wind farms connected to the transmission system [5].

#### 4.1. Case 1

The current situation is simulated, i.e. only the land-based turbines and the Nysted offshore wind farm are connected. The feeder for the future offshore wind farm, as shown in Fig. 1 is not existent in this simulation.

Fig. 4 shows that the voltage at busbar Radsted drops to zero, as Radsted is closest to the fault location. Zealand is hardly affected by this fault as the relatively weak connection between Radsted and Zealand causes a substantial voltage drop. The voltage at the terminals of the land-based turbines gets suppressed in the beginning of the fault and after a few ms it drops to zero as the protection system of these turbines disconnects them. The voltage at Radsted recovers quickly after the clearance of the fault because the land-based turbines have disconnected, which means that they do not consume reactive power any more. In addition to that the now unloaded cables in the feeder to the land-based turbines act as capacitors generating noticeable amount of reactive power (Fig. 7). The voltage at Nysted recovers also relatively quickly because of the reduced reactive power demand of the Nysted generator in the first seconds.

The fault excites the inherently flexible drive train of the Nysted wind turbines (Fig. 2) to oscillations, which in the first instances after the clearance of the fault leads to a strongly reduced active power production [15]. At the same time the compensation capacitors stay connected helping the voltage to recover.

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**Fig. 4.** Case 1: voltage at different locations in the system.
Fig. 5 shows the speed of the generator of the Nysted offshore wind farm. During the fault the speed of the generator accelerates steeply. Just after the clearance of the fault it exhibits oscillations with the resonance frequency of the small inertia of the generator rotor (Fig. 2). While these oscillations subside within the first 2 s after the fault, the underlying low resonance frequency of the turbine rotor with its large inertia becomes dominant. At simulation time 3 s these low frequency oscillations cause a noticeable increase in generator speed, which in turn means that the generator requires more reactive power. Increasing speed in a squirrel cage induction generator means increasing slip, \( s \). From Fig. 6, which shows the equivalent circuit diagram of such a squirrel cage induction generator, it can be seen that with increasing slip, \( s \), the overall rotor resistance decreases \( R_{\text{rotor}} = R_\Omega / s \). Lower resistance leads to more current flowing through the mainly inductive circuit of the generator, causing higher reactive power demand. For these considerations it is sufficient to use the steady state equivalent circuit of the generator as shown in Fig. 6. The wind turbine drive train, which causes the speed oscillations, has considerably larger time constants than the electrical circuit of the generator.

Fig. 7 shows that this reactive power demand has to be covered by SG Zealand, which produces reactive power to be transferred to Sweden (line DK-S). This reactive power surge causes a voltage drop between Zealand and Rudsted, which can be seen in Fig. 4 around the simulation time 3 s. Eventually the voltages in eastern Denmark settle to a slightly higher value because of the extra reactive power being generated in the cables of the land-based turbines feeder.

4.2. Case 2.0

Here the situation is simulated that the future offshore wind farm has been connected and that the turbines in this wind farm have the same control capabilities as the Nysted turbines, i.e. only fault ride through as demanded by the current grid connection requirements. The rating of the 420/132 kV transformer and the number of lines between Spanager and Rudstad are increased to suit the extra power installed in the new wind farm. In addition the dispatched power of SG Zealand is reduced by 200 MW and its rated power is reduced by 200 MVA to reflect the situation that future installed wind power will substitute conventional power plants.

In Fig. 8 the voltage of the land-based turbines is not shown as this drops to zero like in the previous case. From Fig. 8 it can be seen that the voltage at Rudsted, and consequently at the terminals of the wind farms, is under considerably more strain than in the previous case. The drive trains of the turbines in the two offshore wind farms oscillate similarly causing the speed of the generators to oscillate (Fig. 2), which causes the reactive power demand to oscillate (Fig. 6), and this in turn causes the voltage to oscillate strongly too.

Due to the stronger connection between Zealand and Rudsted the voltage at Zealand is slightly lower than in case 1. This
is of no consequence for the voltage in the rest of the Nordic system.

The fault does however upset the grid frequency, because SG Zealand exhibits strong rotor speed oscillations, which is visible in strong active power oscillations as shown in Fig. 9. These power oscillations can only propagate through the line between Zealand and Sweden (called ‘line DK-S’ in Fig. 9) into the rest of the Nordic power system and be absorbed by other bulk power plants.

4.3. Case 2.1

In the case simulated here the future offshore wind farm employs its grid frequency stabilizer to counteract the frequency oscillations caused by the short circuit [3]. This emulates the situation that in future wind turbines will be involved in the stabilization of the power system.

In the first instance these turbines have to tackle their own drive train oscillations before they can contribute to grid frequency stabilization. Therefore, the rise in voltage (Fig. 10) just after the clearance of the fault is similar to that in the previous case. The voltage dip after simulation time 3 s is much less severe, which is due to the pitching actions of the grid frequency stabilizer. Consequently also the power oscillations as plotted in Fig. 11 are less severe than in the previous case.

For better comparability of the cases 2.0 and 2.1 the active power of SG Zealand and in line DK-S are plotted in one graph in Fig. 12. From Fig. 12 it becomes visible that the oscillations in the rotor speed and hence the active power of SG Zealand and in line DK-S, are noticeably dampened by the control actions of the grid frequency stabilizer in the future offshore wind farm.

4.4. Comparison of the grid frequency response of cases 1, 2.0 and 2.1

As noted above, the voltage variations caused by the faults, simulated in the different cases, has a negligible impact on the Nordic power system. The frequency and hence the active power flow through the system gets affected though. An effective means of comparing the consequence of the different scenarios on the Nordic power system is comparing the speed responses of SG Zealand, i.e. the grid frequency.

Fig. 13 shows the speed of SG Zealand for the cases 1, 2.0 and 2.1. The comparison of cases 1 and 2.0, which both do not include any active frequency damping by the installed wind turbines, shows that in the case of larger wind power installation the speed of SG Zealand gets more upset. As shown...
in Figs. 4 and 8 this is not caused by the stronger connection between the fault location and Zealand. The voltage at Zealand dips during the fault almost equally low in both cases. Instead it is the power that the wind farms have to inject into the Nordic system to dampen their drive train oscillations. While in case 1 most of the installed wind power disconnects during the fault, hence does not contribute to the excitation of oscillations, in case 2.0 there are two wind farms that stay connected. The turbines of both wind farms exhibit only relatively lightly damped drive train oscillations, which cause corresponding power oscillations that excite rotor speed oscillations in SG Zealand.

The comparison of cases 2.0 and 2.1 in Fig. 13 shows how the future offshore wind farm can contribute to the damping of such oscillations when it employs its pitch angle grid frequency stabilizer [3].

As described above, the rotor speed oscillations in SG Zealand cause power fluctuations that propagate through the entire Nordic power system. Hence the other synchronous generators in the system experience rotor speed oscillations too, as they have to absorb the power fluctuations. Fig. 14 shows the speed of three arbitrarily chosen synchronous generators, which are in different, relatively remote locations in the system. Also here the three cases are compared with each other. The same observations that have been made with the speed of SG Zealand can be made here too. The most important observation is that
higher levels of wind power penetration lead to increased excita-
tions of the power system. Also here it can be observed that the
future offshore wind farm with its grid frequency stabilizer is
capable of impacting positively on the damping of system-wide
oscillations.

When quantifying the damping effect of the future offshore
wind farm it has to be kept in mind that its rating is only
about a tenth of the rating of 5 GW Zealand, and much less com-
pared to the total active power transmitted through the system
(43,000 MW).

5. Conclusion

Due to the location of wind resources wind farms are mostly
connected to weak parts of the power system. A transient fault
happening in such a weak part (comparably low short circuit
power) has only a local impact on the system voltage. The local
voltage depression can hardly be noticed in other parts of the
transmission system. It does however upset the wind turbines
in the vicinity and cause their flexible drive trains to exhibit
torsional oscillations. These oscillations manifest themselves in
power fluctuations. Such power fluctuations are not only local
effects but propagate through the system causing synchronous
generators to exhibit speed oscillations, which are effectively
frequency oscillations. It is shown that these frequency oscilla-
tions are visible in the entire system.

It has been proven that a high level of wind power penetration
with fixed speed turbines leads to stronger grid frequency oscilla-
tions, and hence to stronger grid frequency oscilla-
tions are visible in the entire system.

Recently issued grid connection requirements demand wind
turbines to ride through transient faults. This requirement has
been made to avoid that substantial amount of generation is
lost in the wake of otherwise harmless transient faults. The
simulations show that the goal of keeping turbines operational
can be achieved. However, the simulations presented here show
also, that these requirements have an immediate disadvantage.

Demanding fixed speed turbines to only ride through transient
faults leads to system-wide oscillations. It has been proven
though, that wind turbines, when equipped with sufficient con-
trol mechanisms can actively contribute to the damping of these
oscillations.

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Publication 7

Transient and Dynamic Control of a Variable Speed Wind Turbine With Synchronous Generator,
Part 1: Drive Train Stabilisation

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Abstract - In this article a controller is presented that dampens torsional drive train oscillations in a variable speed wind turbine with a full-scale converter-connected synchronous generator. First the general problem of torsional oscillations and their damping in generators is explained. This leads to the general concept of drive train stabilisation in a wind turbine with a full-scale converter-connected synchronous generator. To be able to develop a controller that dampens drive train oscillations (drive train stabiliser) the relevant parts of the wind turbine system and their interactions are discussed. From these results the design of the drive train stabiliser is explained and its performance is tested by means of simulations in the power system simulation tool PowerFactory. It is concluded that the presented drive train stabiliser is performing well. It dampens torsional drive train oscillations even under unrealistically harsh operating conditions.

Key words: damping, drive train, synchronous generator, torsional oscillations, wind turbine

1 Introduction

The majority of multi-megawatt wind turbines are variable speed turbines, as the variable speed concept has many advantages compared to the fixed speed concept [1].

A variable speed turbine can adjust its rotor speed to track the tip speed ratio at which the rotor blades exhibit their highest aerodynamic efficiency. Hence variable speed turbines yield more energy than fixed speed turbines.

Another advantage is that gusts in the wind can be absorbed by the rotating mass of the turbine rotor, which means that transient wind speed variations are not reproduced as transient electric power variations in the grid. During short-term gusts the controller of the turbine can choose to keep the power of the generator constant [2]. Constant electrical power is not only advantageous for the electric power quality in the grid, but it also mitigates stress for the mechanical structure of the drive train of the wind turbine. Due to the large inertia of a wind turbine drive train power peaks caused by gusts are mainly transformed to torque peaks. Especially gearboxes suffer stress and premature failure when operated under regularly occurring torque peaks. When the wind turbine controller manages to minimise torque peaks, the drive train with its bearings and the gearbox can be designed lighter and cheaper [1].
Nowadays practically all variable speed turbines are able to vary the rotor speed because the generator of the turbine is either partially or fully decoupled from the fixed grid frequency. (There do exist mechanical concepts for variable speed but they are practically of no relevance for commercial turbines.) While the historical development of variable speed turbines has shown that this is the most efficient and easiest way of achieving variable speed, there is also a downside to this concept. If power electronics decouple the generator from the stiff grid frequency the strong torsional damping characteristics, which are inherent to AC-connected generators is invariably lost. It is therefore crucial that torsional drive train oscillations are actively damped by the wind turbine controller. Otherwise the principle advantage of mechanical stress mitigation in the variable speed concept would be negated by damaging drive train oscillations [3]. When the wind turbine controller dampens drive train oscillations it controls the inverter and by doing so generates an oscillating damping torque, which is reproduced as oscillating power variations in the grid [4].

In this article a controller is presented that dampens torsional drive train oscillations in a variable speed turbine without causing oscillating power variations in the grid. The turbine considered is a variable speed turbine with a full-scale converter-connected synchronous generator. The wind turbine with its controller is implemented in the power system simulation tool PowerFactory from DIgSILENT. The function and performance of the controller is assessed by means of simulations in PowerFactory.

2 System Description

The wind turbine considered is a 2 MW variable speed, variable pitch turbine, whose general pitch and speed control strategy is described in detail in Hansen et al. [5]. Hence here only a brief overview of the normal pitch and speed control strategy shall be given.

Above rated wind speed the pitch system strives to limit the speed of the turbine rotor to the tolerable maximum. It does, however, allow speed excursion to make the rotating mass of the drive train absorb gusts in the wind. This allows the inverter controller to inject constant power into the grid.

Below rated wind speed the speed controller adjusts the rotor speed according to the wind speed. The controller strives for keeping the tip speed ratio \( \frac{v_{\text{tip}}}{v_{\text{wind}}} \) as close as possible to the value at which the aerodynamic efficiency of the blades is maximal. In this operating region the pitch angle is held constant at a value where the aerodynamic efficiency of the rotor blades peaks, while the inverter controller (power controller) controls the speed [6].

The drive train of the wind turbine is described with a two masses spring and damping model [6], representing the torsional spring characteristic of a wind turbine drive train including a gearbox (Figure 8). Due to this torsional spring characteristic the speed of the generator in the wind turbine is prone to oscillations whenever the system gets excited by changes in the wind speed, the pitch angle or the terminal voltage. Also the spacial variations of wind speed in time excite the system to oscillations [7]. In case of a three bladed wind turbine, this excitation has a frequency of three times the rotational frequency of the rotor (3p effect). The most obvious of these wind speed variations is
the tower shadow, i.e. the sudden change in wind speed a rotor blade experiences when it passes in front of the tower of the wind turbine.

The generator type considered here is an electrically excited synchronous generator (SG). To get variability in the rotor speed a SG needs to be connected to the grid via a full-scale converter. Figure 1 shows the setup of such a system. The AC voltage of the SG is rectified by a simple diode rectifier, and inverted to AC voltage with the grid frequency by an IGBT inverter. In the DC circuit between the AC/DC rectifier and the DC/AC inverter is a capacitor, $C$, which stores electrical energy to smooth the DC voltage, $V_{DC}$. In the DC circuit, as well as in the AC connection from the inverter to the grid, are inductors that smooth the current from the power electronics.

**Figure 1** Electrical Connection of variable speed wind turbine with SG and full-scale converter.

### 3 Damping Mechanisms of Generators

To introduce the problem of undamped speed oscillations in wind turbine generators the damping mechanisms of generators are discussed briefly in this section.

In fixed speed wind turbines squirrel cage induction generators (SCIG) are employed. In this case torsional drive train oscillations subside very quickly, since the stator windings of SCIG can always be AC-connected to the grid. When operating below the break-down torque SCIG have relatively steep torque versus slip characteristics with positive slopes. Hence, already small speed excursions cause the generator to generate a strong counter-torque. When the generator accelerates the slip increases, since the grid frequency can be considered constant, i.e. the stator field rotates with a constant speed. Increased slip causes more current to be induced in the rotor, which causes a stronger decelerating torque. When the generator decelerates the slip decreases, causing less induction in the rotor and hence less torque. Hence, speed oscillations are not a problem for turbines with SCIG under normal operation.

The majority of variable speed turbines employ doubly-fed induction generators (DFIG), where the stator windings are AC-connected to the grid. The rotor windings of a DFIG are not short-circuited like in SCIG but connected to the grid via an inverter. In such a configuration the torque versus slip characteristic of the generator can still be used to dampen drive train oscillation. But here the inverter in the rotor circuit has to be controlled to actively manipulate the torque versus slip characteristic accordingly.
Since in this article variable speed turbines with SG are considered, the damping mechanisms of SG are discussed in the following subsections. For the sake of comprehensibility first the AC-connected SG, and then the SG behind a full-scale converter, as can be found in wind turbines, is discussed.

### 3.1 Damping of Speed Oscillations in AC-Connected SG

In a SG the rotor rotates with the same speed as the stator field, i.e. they are in synchronism. There is also synchronism between the stator field and the rotor field if the SG is loaded. In this case, however, there is an angle between the two fields, the so-called load angle, which is a function of the generator loading. In a simplified approach the connection between the rotor field and the stator field can be considered an elastic magnetic band, which gets elongated the more the generator gets loaded.

When an AC-connected SG experiences load changes, the load angle, or in other words the length of the elastic magnetic band, changes. This change, however, does not happen instantaneously, but the load angle performs oscillations that settle to the new value. Oscillations in load angle are effectively rotor speed oscillations, since the speed with which the stator field rotates, is determined by the grid frequency, which in turn can be considered constant. Hence there is a relative movement between the stator field and the rotor field.

AC-connected SG are usually equipped with damper windings. These damper windings work comparably to induction generators as described in the previous section. If there is a relative movement between the stator field and the rotor field a current is induced in these damper windings, which causes a torque counteracting the rotor speed oscillations [8].

To enhance transient stability of AC-connected SG with electrical excitation systems, power system stabilisers (PSS) are employed [9]. A configuration in which a SG is equipped with a PSS looks like depicted in Figure 2.

![Figure 2: SG with voltage controller (VCO) and PSS](image)

The PSS senses speed oscillations and offsets the voltage setpoint such, that the active power that is sent into the grid counteracts these oscillations. I.e. the PSS has to cause a torque which is in phase with the speed oscillations. The voltage setpoint plus the output of the PSS are compared to the generator voltage, which leads to a voltage error that the voltage controller (VCO in Figure 2) eliminates by changing the excitation of the SG.

Increasing the excitation of the SG causes more reactive power to flow into the grid, which causes the voltage at the generator terminals to rise. A higher voltage allows more active power to flow from the SG into the grid. The active power that can be extracted continuously from the SG is determined by the mechanical power that is input at the generator’s shaft. An increase in terminal voltage can hence only cause a
temporary increase in electrical power, which extracts kinetic energy from the rotating mass of the generator rotor, and by doing so decelerates it.

3.2 Damping of Speed Oscillations in Full-Scale Converter-Connected SG

As discussed earlier a SG in a wind turbine has to be connected via a full-scale converter. The frequency at the terminals of the SG in such a configuration is floating freely with the speed of the generator rotor. Hence even in case of transient load changes there is no relative movement between the rotor field and the stator field that could induce a current into the damper windings. Since the damper windings cannot provide a damping torque a wind turbine with a SG behind a full-scale converter is an unstable system.

Figure 3 shows how the speed of a SG in a wind turbine oscillates with gradually increasing oscillation amplitude, causing the system to break down eventually. To counteract these oscillations either the mechanical input power at the shaft of the SG, or the electrical output power at the terminals of the SG can be controlled.

Inherent for a wind turbine is that the mechanical power can only be varied by pitching the blades. This is a very inefficient way of impacting on the mechanical power at the generator shaft, since the pitch angle acts on the aerodynamic power of the turbine rotor. The generator shaft is connected to the turbine rotor via the drive train. This means that the pitch control system has to consider the dynamics of the drive train if it is to control the mechanical power at the generator shaft.

A much more direct means of damping the speed oscillations in the SG is to control the electrical power that is extracted from the SG at its terminals. A straightforward way of doing this is to control the power that the inverter sends into the grid. This, however, means that drive train oscillations become visible as power fluctuations in the grid even under normal operation [4]. As will be discussed in Part 2 of this article [10] it is especially disadvantageous to use the inverter to dampen drive train oscillations when the wind turbine is to contribute to the damping of grid frequency oscillations.

The alternative that remains is to use the excitation system of the SG to temporarily control the electrical power that is extracted from the SG. In this case the capacitor in the DC circuit between the rectifier and the inverter is used as short term energy storage. By periodically charging and discharging this capacitor, energy is stored in the

Figure 3 Speed of a SG in a wind turbine running at rated power, and without active drive train stabilisation.
capacitor, which allows damping the oscillations in the generator speed. The power flowing from the inverter into the AC grid is independent of the DC voltage; hence the damping of drive train oscillations can be achieved without impacting on the power that is sent into the grid.

Similar to a PSS in an AC-connected SG the excitation voltage of the SG can be used to transiently control the electrical power which is stored in the DC capacitor. By controlling the DC voltage the voltage controller (VCO) at the SG determines to which degree the capacitor in the DC link gets charged, i.e. how much energy it stores. The device, which works similarly to a PSS, and by doing so stabilises the drive train speed of the wind turbine is called drive train stabiliser (DTS). From Figure 4, which shows the general setup of such a system, the similarity to a PSS (Figure 2) becomes obvious.

![Figure 4 SG with VCO and DTS](image)

**4 Description of Synchronous Generator System**

In the previous section the general concept of drive train stabilisation, using the VCO of the SG, to control the transiently stored energy in the DC link capacitor is introduced. In the following the SG and DC circuit system of a variable speed wind turbine, as shown in Figure 1, as well as the drive train are described mathematically. This provides the basis for the DTS design, which is described in section 5.

![Figure 5 Block diagram of the SG with VCO, DC voltage loop and mechanical drive train of wind turbine printed in black. The DTS loop is printed in grey.](image)
Figure 5 shows a simplified block diagram of the system. It shows the voltage control loop, the DTS loop, the DC circuit, the influence of the electrical power, $P_{el}$, and the mechanical power, $P_{mech}$, on the mechanical speed, $\omega$, of the generator rotor, and the dynamics of the wind turbine drive train. The DTS loop is shown in grey as it is not dealt with in this section. The DTS is discussed in detail in section 5.

In this description the emphasis is on the dynamics of the generator rotor speed. Therefore, the dynamics of the electrical components, with their comparably short time constants are neglected.

In the following sub-sections the signal flow in Figure 5 (except the DTS loop) is explained.

### 4.1 Electrical Power, $P_{el}$

In the variable speed wind turbine configuration, as shown in Figure 1, the active power that is sent into the grid is not determined by the mechanical power that drives the SG, like it is the case with AC-connected SG. Instead the active power and hence the electrical energy that flows into the utility grid, is set by the wind turbine controller, and is controlled by the DC/AC inverter. In Figure 5 the block $P(\omega)$ represents the active power control strategy of the wind turbine controller, where the active power, $P_{inv}$, is determined by the speed of the generator [5]. Before $\omega$ enters into the power control strategy, $P(\omega)$, it is filtered with a low pass filter (block LP in Figure 5) in order to avoid that high frequency components in speed variations are reproduced as power variations in the grid. Integrating $P_{inv}$ over time leads to the energy, $E_{inv}$, which the inverter injects into the grid. The electrical power, $P_{el}$, that can flow from the generator into the DC circuit is dependent on the voltage drop, $V_{drop}$, between the internal source voltage of the SG, $V_S$, and the DC voltage, $V_{DC}$. Figure 6 shows a simplified equivalent circuit diagram of the system. The inductance $X_d$ in Figure 6 is the synchronous reactance of the SG, while $L_{DC}$ is the inductor in the DC circuit (see Figure 1).

$$V_{drop} = V_S - V_{DC}$$  \text{Equation 1}

The voltage drop, $V_{drop}$, mainly consists of the voltage drop along the synchronous reactance, $X_d$ in the SG. A minor fraction of $V_{drop}$ is caused by the diodes in the rectifier. The inductor $L_{DC}$ only contributes to $V_{drop}$ when the DC current changes, since $L_{DC}$ has negligible resistance.

Under steady state operation the VCO keeps $V_{DC}$ constant, irrespective of the power that is extracted from the DC circuit. Figure 7 shows the internal source voltage of the SG necessary for keeping $V_{DC}$ constantly at 1 pu at any operating point.
If electrical power is to be extracted from the SG continuously, mechanical power has to be fed into the SG.

4.2 Mechanical Power, $P_{\text{mech}}$

In Figure 5 the mechanical power, $P_{\text{mech}}$, which drives the SG comprises the torque, $T_{sh}$, of the high speed shaft of the wind turbine drive train and the rotor speed, $\omega$, of the SG.

$$P_{\text{mech}} = T_{sh} \cdot \omega$$  \hspace{1cm} \text{Equation 2}$$

The drive train of the wind turbine can be described as a torsional spring with a damping [11]. On one end of this spring is the large inertia of the turbine rotor, $J_{\text{rot}}$, and on the other end is the small inertia of the generator rotor, $J$, as depicted in Figure 8.

$$\omega_{\text{rot}} \cdot n = \omega_{\text{rot}}'$$  \hspace{1cm} \text{Equation 3}$$

The speed of the turbine rotor, $\omega_{\text{rot}}$, can be transformed to the high speed side of the gearbox with its ratio $n$, yielding $\omega_{\text{rot}}'$. If the two ends of the torsional spring do not rotate with the same speed there is a difference in speed that causes the torsional spring to twist (Figure 8).

$$\Delta \omega_{k} = \omega - \omega_{\text{rot}}'$$  \hspace{1cm} \text{Equation 4}$$
Integrating $\Delta \omega_k$ over time leads to the angle, $\theta$, by which the torsional spring is twisted.

$$\theta = \int \Delta \omega_k \, dt$$ \hspace{1cm} \text{Equation 5}

$T_{sh}$ is the sum of two torque components: one comprising the stiffness of the torsional spring, $k$, the other comprising the damping coefficient, $c$.

$$T_{sh} = \theta \cdot k + \Delta \omega_k \cdot c$$ \hspace{1cm} \text{Equation 6}

If $P_{mech}$ does not match the electrical power, $P_{el}$, the mechanical speed of the SG varies.

### 4.3 Mechanical Speed, $\omega$

Considering normal operation, an imbalance between $P_{el}$ and $P_{mech}$ leads to a change in $\omega$ of the SG rotor with its inertia $J$.

The difference between $P_{el}$ and $P_{mech}$ is

$$\Delta P = P_{mech} - P_{el}$$ \hspace{1cm} \text{Equation 7}

Integrating power over time yields the energy which is fed into, or extracted from the rotating mass.

$$E_{rot} = \int \Delta P \, dt$$ \hspace{1cm} \text{Equation 8}

Since the rotating energy can also be expressed as a function of speed and inertia,

$$E_{rot} = \frac{1}{2} \cdot J \cdot \omega^2$$ \hspace{1cm} \text{Equation 9}

the speed can be calculated too (referring to block $\omega(E)$ in Figure 5):

$$\omega = \sqrt{\frac{2 \cdot E_{rot}}{J}}$$ \hspace{1cm} \text{Equation 10}

Due to the torsional spring characteristic of the drive train any imbalance between $P_{el}$ and $P_{mech}$ also leads to oscillations of the generator speed.

The frequency of these oscillations (visible in Figure 3) is the free-free frequency, $f_{f/f}$, of the wind turbine drive train. $f_{f/f}$ is the frequency with which the small inertia, $J$, of the generator rotor oscillates when the drive train gets excited to torsional oscillations [11]. For calculating $f_{f/f}$ the two masses model of the drive train (Figure 8) has to be reduced to a one mass model with the equivalent inertia $J_{eq}$.

$$J_{eq} = \frac{J_{rot} \cdot n^2 \cdot J}{J_{rot} + n^2 \cdot J}$$ \hspace{1cm} \text{Equation 11}

With the equivalent inertia, $J_{eq}$ and the stiffness, $k$, of the drive train $f_{f/f}$ can be calculated:
Now the frequency with which the drive train speed oscillates, and which needs to be damped, is known.

As has been shown in Equation 7 to Equation 10 an imbalance between $P_{el}$ and $P_{mech}$ leads to a variation in $\omega$. Therefore, it is also possible to deliberately provoke such an imbalance to counteract oscillations in $\omega$ with the frequency $f_{f-f}$. As discussed above a DTS does this by impacting on the excitation voltage of the SG to store energy in the DC circuit capacitor. Therefore, the relation between the DC voltage and the energy stored in the DC capacitor is explained in the following.

### 4.4 Energy in DC Capacitor and in Rotating Mass

As can be seen in Figure 5 the energy stored in the DC capacitor, $E_C$, is the difference between the electrical energy input by the wind turbine, $E_{WT}$, and the electrical energy extracted by the DC/AC inverter, $E_{inv}$, which is determined by the wind turbine control strategy.

$$E_C = E_{WT} - E_{inv}.$$  
**Equation 14**

$E_C$ can also be expressed as a function of the DC voltage, $V_{DC}$, which is applied to the DC capacitor with its capacity $C$.

$$E_C = \frac{1}{2} C \cdot V_{DC}^2.$$  
**Equation 15**

Equation 15, which refers to the block $V(E)$ in Figure 5, shows that when the VCO in Figure 5 controls $V_{DC}$, it indirectly controls the energy stored in the DC capacitor.

To counteract drive train oscillations kinetic energy from the rotating mass of the generator rotor has to be transformed to electrical energy and has to be stored in the DC capacitor. The kinetic energy, $E_{rot}$, is a function of the inertia, $J$, and the rotational speed, $\omega$.

$$E_{rot} = \frac{1}{2} J \cdot \omega^2.$$  
**Equation 16**

Equation 16 refers to the block $\omega(E)$ in Figure 5. $C$ in Equation 15 and $J$ in Equation 16 are constants determined by the design of the wind turbine. Hence, storing the energy of a given speed excursion, $\Delta \omega$, demands a difference in DC voltage, $\Delta V_{DC}$, as described by Equation 17.

$$\Delta V_{DC} = \sqrt{\frac{J}{C}} \cdot \Delta \omega.$$  
**Equation 17**

Now that the relation between mechanical and electrical power and their impact on the generator speed, as well as the frequency of the critical oscillations are known, the DTS can be designed.
5 Drive Train Stabiliser

The objective of the design of the DTS is that drive train oscillations with a frequency of $f_{df}$ have to be damped, such that the system stays stable under any conceivable operating condition. In Figure 5 the DTS loop is printed in grey blocks and lines, and shows how the DTS is embedded in the SG system.

From Equation 12 it is known which frequency the DTS needs to tackle. To avoid that the DTS interferes with the speed control of the wind turbine for normal operation the speed signal needs to be filtered before it enters into the DTS. Figure 9 shows the setup of the SG with VCO and DTS. In comparison to Figure 4, which already showed the general setup, now a bandpass (BP) filter is added.

![Figure 9 SG with VCO, BP filter and DTS](image)

5.1 Design of Bandpass Filter

The task of the BP filter is to only let oscillations of the critical frequency $f_{df}$ through and to block all other frequencies.

![Figure 10 Bode Plot of BP filter tuned to the $f_{df}$](image)
By choosing a narrow bandwidth the BP filter allows the DTS to act exclusively on oscillations with $f_{ff}$. From Figure 10, which shows the bode plot of the BP filter; the sharp distinction of the critical frequency becomes visible.

The design of the BP filter is done in Matlab [12], where the desired cut-off frequency and bandwidth have to be specified.

### 5.2 Design of DTS

The DTS has to produce a signal, which offsets the voltage setpoint, $V_{DC \text{ set}}$, in Figure 9 such that $V_{DC}$ varies in a way that kinetic energy from the rotor speed oscillations is stored in the DC capacitor. In other words the measured speed oscillations have to be translated to an oscillating voltage offset with the right phase angle, which generates a torque that damps the speed oscillations.

To find the required angular contribution of the DTS the system is operated without the DTS loop, and a sinusoidal disturbance signal that has the frequency $f_{ff}$ is superimposed on $V_{DC \text{ set}}$. The angle $\phi$ by which $V_{DC}$ lags the disturbance signal is measured. (NB: $V_{DC}$ is still a DC voltage, but it has a sinusoidal offset such that $V_{DC}$ oscillates around its mean value; without changing polarity. See also Figure 15.)

In a rotating mechanical system that exhibits speed oscillations, damping can be achieved with a torque which is in phase with the speed oscillations. In case of a generator this damping torque has to be achieved electrically, i.e. the power that is generated from the damping torque is to be dissipated electrically. In an AC-connected SG $\varphi$ is the angular contribution of the PSS, i.e. the angle by which the PSS has to advance the phase in order to generate a torque, which is in phase with the speed oscillations.

Also in a full-scale converter-connected SG the damping torque has to be in phase with the speed oscillations. However, since the DTS uses the capacitor in the DC circuit to store the energy required for generating this damping torque, the phase angle is different by 90 degrees: The mechanical power generated by the damping torque has to be transformed to electrical power, which is stored in the DC capacitor. Hence there has to be a current in the DC capacitor, which is in phase with the speed oscillations. In order to drive a current in a DC capacitor the applied voltage at the capacitor has to change:

$$i_c = C \cdot \frac{dV_{DC}}{dt}$$ \hspace{1cm} \text{Equation 18}

The differentiation in Equation 18 implies that the torque caused by a sinusoidal DTS-signal leads $V_{DC}$ by 90 degrees. Hence the signal in the DTS path has to be delayed in order for the torque to be in phase with the speed. Since the BP filter does not cause any change in phase angle at $f_{ff}$ (Figure 10) the angular contribution, $\beta$, of the DTS is

$$\beta = -90 + \varphi$$ \hspace{1cm} \text{Equation 19}

This leads to the conclusion that the DTS can be realised with a first order lag element (PT1), which delays the phase by $\beta$ at $f_{ff}$.

Equation 20 shows the transfer function of a PT1 [13].
The angular contribution of a PT1 is
\[ \beta(\omega) = -\arctan(\omega T) \]

Hence the time constant, \( T \), of the PT1 can be calculated with the required angular contribution \( \beta \) it has to provide at \( f_{\text{ref}} \).
\[ T = -\frac{\tan \beta}{\omega_0} \text{ with } \omega_0 = 2 \cdot \pi \cdot f_{\text{ref}} \]

The gain, \( K_P \), of a PT1 can be tuned by testing, since the gain has no bearing on the angular contribution of the DTS loop. Increasing \( K_P \) increases the damping of the DTS; however, \( K_P \) has to be tuned such that the voltages, which occur in the DC circuit are within tolerable limits.

In the following section the system is operated under different operating conditions and the performance of the DTS is assessed.

6 Simulation Results

The performance of the DTS is tested in all possible wind speed conditions. To assess normal operation Figure 11 shows the simulated generator speed and active power in the grid under the given wind speed condition. It is deemed most interesting to show operation in wind speeds around rated, as there the system is most prone to oscillations and as frequent transitions between the two control strategies (for above and below rated operation) occur.

The simulations in Figure 11 show that the turbine is stable and that no excessive speed oscillations occur. It is also visible that the power, which is injected into the grid, is held at exactly 1 pu whenever the wind speed allows rated operation.

In the following simulations the performance of the DTS is assessed under more demanding, albeit unrealistic conditions. The system is subject to wind speed step changes as shown in Figure 12. To show the need for a DTS the system is first operated without the DTS. Figure 13 shows that the system is unstable, since the speed of the wind turbine generator exhibits oscillations with increasing magnitude.

Therefore, in the following the system is simulated with DTS as designed above. Also the capacity of the DC capacitor is varied to show the impact of the capacitor rating on the performance of the DTS.

The DC capacitor is a crucial part of the DTS system as it is used as energy storage when drive train oscillations are damped. Considering the relation of Equation 17 to the design of a real wind turbine it can be stated that the inertia of the SG rotor is difficult to alter, hence \( J \) in Equation 17 has to be taken as a given constant. The other parameter in Equation 17 is the capacity \( C \) of the DC capacitor. Altering the rating of the DC capacitor is technically easily possible, constrained only by economic considerations.
As an initial approach a minimal rating of the DC capacitor is chosen. A minimum requirement that a capacitor in a DC link has to fulfil, is to reduce ripples in the DC voltage to an acceptable level [14]. Applying this approach leads to a certain DC capacitor rating. To assess the impact of the size of C, the system is also tested with a three times larger capacitor. In the following the capacitor with a minimum size is called ‘normal C’, while the three times larger capacitor is called ‘large C’. It is expected that the performance of the DTS increases when employing the large C. (Note that the simulations shown in Figure 11 are performed with normal C.)

Figure 14 shows $\omega$ of the wind turbine generator. The speed overshoots at every step in wind speed, absorbing the excess energy in the rotating mass of the drive train. While excess energy is absorbed in acceleration the pitch system has time to dissipate aerodynamic power. The electrical power fed into the grid is always constantly 1 pu as soon as the wind speed exceeds 12 m/s, which is the rated wind speed. Figure 14 reveals that the steps in wind speed excite the system to perform torsional drive train oscillations, which get damped effectively by the DTS. Comparing the two graphs in Figure 14 makes clear that a larger C enhances the performance of the DTS. This becomes even more visible when looking at Figure 15, which shows how $V_{DC}$ has to be varied in order to damp the drive train oscillations. (In these simulations $V_{DC\,\text{set}}$ is 1.1 pu.)
A very important aspect of drive train oscillations in wind turbines is the angle $\theta$ with which the drive train gets twisted under load (see Figure 5 and Figure 8). The value that $\theta$ gets when the drive train is loaded to a certain extend is dependent on the stiffness of the drive train, and is hence determined by its design. The fact that the drive train gets twisted under load is not damaging as such, but periodical changes in $\theta$ lead to stress and undue wear, especially in the gearbox [3]. $\theta$ is a measure for torque in the drive train. Especially damaging for gearboxes is when the torque reverses its sign.
Figure 16 shows that $\theta$ and hence the torque varies only in a narrow band around the value of steady state operation. The drive train oscillations do not cause excessive $\theta$ oscillations, which shows that the DTS also has a positive effect on the gearbox. Here too, the finding that a bigger C enhances the performance of the DTS can be confirmed.

![Figure 15 Voltage in DC circuit.](image1)

![Figure 16 Drive train twist angle $\theta$](image2)

### 7 Conclusion

In this article a drive train stabiliser is described that enables a wind turbine with a full-scale inverter-connected synchronous generator to stay stable in any operating condition. Even the simulation of unrealistically harsh operating conditions confirms the applicability of the concept and the particular design of the DTS described in this article.

It can be concluded that by controlling the voltage in the DC circuit between the rectifier and the inverter drive train oscillations can be damped without impacting negatively on the power quality in the grid.
Since this concept distinguishes clearly between the stabilisation of the drive train speed and the overall control of the turbine, negative impacts of the turbine on the grid are minimised. In Part II of this article [10] it will be shown how this concept can be extended to allow the wind turbine to actively contribute to the damping of power system oscillations.

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Transient and Dynamic Control of a Variable Speed Wind Turbine With Synchronous Generator,  
Part 2: Power System Stabilisation

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Transient and Dynamic Control of a Variable Speed Wind Turbine with Synchronous Generator

Part 2: Power System Stabilisation

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Abstract - In this article a variable speed wind turbine is equipped with a controller that allows the turbine to ride through transient voltage dips and perform damping of power system oscillations. The general concept of damping power system oscillations with variable speed turbines is briefly introduced. A controller is described that allows the wind turbine to ride through a transient voltage dip and subsequently perform power system stabilisation. The performance of the controller is tested by means of simulations in the power system simulations tool PowerFactory. Two situations are simulated: the wind turbine rides through a transient fault only; and the wind turbine first rides through a transient fault and subsequently dampens the power system oscillations that are caused by the fault. It can be concluded that the wind turbine can contribute considerably to power system stabilisation.

Key words: power system oscillations, power system stabilisation, transient fault, ride-through, wind turbine

1 Introduction

Ever increasing wind power penetration makes an increasing amount of conventional generation redundant in many countries. Although this is a favourable development from an environmental point of view, power system operators view this as a potential risk for the stability of their power system. Therefore more and more power system operators revise their grid connection requirements and issue grid connection requirements specifically made for wind turbines and wind farms [1]. The bottom line of these grid connection requirements is that wind power substituting conventional generation needs to be involved in power system control and stabilisation. If wind turbines substitute the generation capacity of conventional power plants they also need to substitute the regulating capacity of conventional power plants. While currently these requirements mainly demand uninterrupted operation also in case of transient power system disruptions, in future it is to be expected that also sophisticated regulating tasks will be transferred to wind turbines.

Riding through transient faults constitute a burden for wind turbines, as the transient disruption of electric power export upsets the turbine, and causes torsional oscillations in the wind turbine drive train. For a power system transient faults usually lead to different kinds of power system oscillations [2].
If in future wind turbines are required to take over more of the power system control and stabilising tasks, which traditionally are carried out by conventional generators, also the task of damping power system oscillations will become applicable.

Slootweg and Kling have found that variable speed wind turbines have more favourable impacts on transient stability of power systems than fixed speed turbines [3]. They also found though, that variable speed turbines can have a negative impact on power system oscillations [4].

Previous work has shown how fixed speed, variable pitch wind turbines can be employed to actively contribute to damping of power system oscillations [2]. Simulations have shown that this type of turbine can contribute noticeably to the damping of oscillations in the Nordic power system [5]. Due to the flexible power control inherent to variable speed, variable pitch wind turbines, it is expected however, that these turbines are more suitable for this type of control task. A variable speed wind turbine can use the kinetic energy stored in the rotating mass of the turbine rotor to transiently vary its power output. Since the power output of variable speed turbines is controlled by power electronics, the pitch system of the turbine is exercised much less, and at the same time larger power variations are possible than with fixed speed, variable pitch turbines.

In part 1 of this article [6] a variable speed turbine with a full-scale converter-connected synchronous generator is introduced. Characteristic for this turbine is that the damping of rotor speed oscillations in the turbine are fully decoupled from the power which is fed into the grid. Such turbines can contribute to grid support if their inverter is used for voltage control [7]. In future more active contribution to the stabilisation of power systems, like damping of power system oscillations, will be required from wind turbines. Damping of power system oscillations requires controlled active power injection into the grid. Therefore in this article a controller is described that allows a variable speed turbine with a full-scale converter-connected synchronous generator, as introduced in part 1 of this article [6], to perform power system stabilisation.

### 2 Concept of Power System Stabilisation with Variable Speed, Variable Pitch Turbines

Stabilisation of power systems, i.e. damping of power system oscillations can be achieved with a controlled injection of active power into the grid. Conventional power plants with synchronous generators (SG) are damping power system oscillations with so called power system stabilisers (PSS). In an AC power system the speed of a directly connected SG equals the electrical frequency, since the rotor of a SG rotates synchronously with the stator field. A PSS in a SG dampens oscillations in the electrical frequency, i.e. the speed of the SG, by generating a damping torque that is in phase with the frequency oscillations. By doing so the PSS causes the SG to inject oscillating active power into the grid [8]. Other types of power system oscillations, like inter-area oscillations can be counteracted similarly.

Hence if wind turbines are to participate in the damping of power system oscillations like grid frequency oscillations and inter-area oscillations, they have to be able to inject oscillating active power into the system. Considering oscillations in grid
frequency this means: high grid frequency requires a reduction in wind farm power and a low grid frequency requires an increase in wind farm power. Power swings like inter-area oscillations have to be counteracted similarly. Since in variable speed wind turbines the power injected into the grid is controlled by an inverter made of power electronics rapid and large power variations are easily possible from an electrical point of view. The active power the inverter injects into the grid is extracted from the generator of the wind turbine. The mechanical power that drives the generator cannot be controlled equally fast, since it is controlled by the comparably slow pitch system. Hence the power variations caused by the inverter have to be catered for by the kinetic energy stored in the inertia of the rotating wind turbine rotor. Therefore the generator accelerates if less power is extracted and it decelerates if more power is extracted. The pitch system only counteracts the slow variations in the generator speed, and it does not attempt to counteract short-term speed excursions. Instead the speed is allowed to fluctuate around its steady state value. This way the speed of the generator is kept within tolerable limits, while at the same time the pitch system is not burdened with drastic pitching actions.

In the following sections first the simulation model used in this study is introduced. Then a controller is described that enables a variable speed turbine to ride through a transient fault and to subsequently perform power system stabilisation.

### 3 System Description

The system that is involved in the control of the variable speed wind turbine is the wind turbine itself and the power system to which the wind turbine is connected. The wind turbine model and the power system model are implemented in the power system simulation tool PowerFactory from DgSILENT [9].

#### 3.1 Power System Model

For simulations of power system oscillations to be realistic, a realistic power system model is required. The power system model used in this project is a model of the interconnected power system of the countries Norway, Sweden, Finland and eastern Denmark. The model has been developed at SINTEF in Norway [10] [11] and is an aggregation of a fully detailed model of the Nordic transmission system.

![Figure 1](image.png)  
*Figure 1 Connection of the variable speed wind farm connected to the Nordic power system.*
Characteristic for the Nordic power system is that although it is geographically large, it is of relatively small capacity, since Norway, Sweden, Finland and Denmark are only sparsely populated countries.

The model covers the transmission system and comprises 35 nodes and 20 SG.

For the purpose of this research work the model as developed by SINTEF has been extended with a feeder that connects a 198 MW wind farm to the Nordic system at the busbar Zealand, in eastern Denmark. In the simulated case a 2000 MVA SG, with a simulated dispatched power of 765 MW is also connected to this busbar. The total simulated dispatched power of the whole Nordic power system is 43000 MW.

The system setup is shown in Figure 1, where the SG of the wind farm is connected via a diode rectifier, a DC circuit, a voltage source inverter and a realistic feeder configuration to the busbar “Zealand” in the Nordic power system.

A 300 ms, three-phase short-circuit is simulated at the HV busbar in Figure 1. This short-circuit temporarily isolates the wind farm from the Nordic grid and at the same time upsets the operation of the SG at busbar Zealand. The short-circuit suppresses the voltage at busbar Zealand causing SG Zealand to accelerate, and after the fault is cleared to perform rotor speed oscillations. These oscillations propagate through the entire Nordic power system, causing rotors in other SG and power flows in inter-area links to oscillate too.

It is desired that the wind farm contributes to the damping of the oscillations in the speed of SG Zealand, and consequently of the other oscillations in the system.

The short-circuit has the worst impact on the operation of the wind farm, since its terminal voltage gets depressed most, and since it is temporarily isolated by the fault. Hence the wind farm needs to ride through a deep voltage dip before it can contribute to the damping of the rotor speed oscillations in SG Zealand.

3.2 Wind Farm Model

Compared to the size of the whole Nordic power system, or even of SG Zealand, the wind farm is relatively small. It has a rated active power of 198 MW, which is a realistic size for a possible offshore wind farm in Eastern Denmark. (Currently the tendering process for a 200 MW wind farm in this area is running [12].) Even with such a modest rating the wind farm is capable of contributing to damping of power system oscillations as will be shown in section 5.

The wind farm is aggregated to one single synchronous generator and one single full-scale converter, driven by a single wind turbine model. The electrical part of the turbine and its control is discussed in detail in part 1 of this article [6]. A detailed description of the mechanical and aerodynamic models of the wind turbine can be found in [13], [14] and [15]. The mechanical and aerodynamic models used here reflect reality quite well, which has been proven in an islanding experiment of a real 2 MW turbine [16].

The aggregation of the whole wind farm to one wind turbine is valid as all turbines in the wind farm are equal. Also the wind speed considered is above rated wind speed, i.e. even with shadowing effects in a wind farm all turbines have sufficient wind for rated power production. Besides, small wind speed variations are negligible since they do not have an impact on the power the inverter transiently extracts the drive train for power system stabilisation. Only if the wind speed drops permanently below rated
wind speed the permanently lower aerodynamic power has an impact on power system stabilisation operation. How the system behaves at wind speeds below rated will be discussed in the following section. There the transient fault controller, i.e. the controller that enables the turbine to ride through a transient voltage dip; and the power system stabiliser, i.e. the controller that allows the turbine to dampen power system oscillations are described.

4 Transient Fault Controller and Power System Stabiliser

In part 1 of this article [6] the block diagram of the wind turbine system with generator, drive train, DC circuit, drive train stabiliser (DTS) and power control for normal operation has been shown. Now the control circuit for transient fault operation and power system stabilisation operation, as shown in Figure 2, shall be discussed. All the blocks and the signal flows that were discussed in part 1 of this article shall not be shown here again for the sake of comprehensibility. All these blocks and signals are in the block called Gen. in Figure 2. The only blocks, which are repeated here, are the blocks of the power controller for normal operation (these are the blocks LP and \( P(\omega) \)), since the power control modes and the interaction between these modes is the topic of this article.

As can be seen in Figure 2 the inverter can get its active power setpoint, \( P_{set} \), from three different controllers: (i) from the wind turbine controller (\( P(\omega) \)-block) for normal operation (\( P_{norm} \)), (ii) from the fault controller (signal \( P_f \)) or (iii) from the power system stabiliser (signal \( P_{st} \)).

\( P_f \) is only required if the voltage at the wind turbine terminals dips deeply. In the trans.-block in Figure 2 the decision is made whether or not \( P_f \) is required, depending on the terminal voltage of the wind turbine. Subsection 4.2 describes how the transition to and from \( P_f \) is done.

In the select-block in Figure 2 the decision is made whether power system stabilisation operation is required, depending on the measured power system signal, here the frequency, \( f_{meas} \). If the frequency is outside the band of tolerable frequency variations the power system stabiliser control is selected, i.e. \( P_{sel} = P_{st} \). Note that the purpose of the power system stabiliser is not to counteract small signal variations, but power system oscillations, which cause a potential risk for the stability of the system. If \( f_{meas} \) is within its tolerable limits the wind turbine resumes normal operation, i.e. \( P_{sel} = P_{norm} \).

4.1 Transient Fault Controller

Under normal operation the wind turbine controller controls the slow variations in speed with the pitch system [17], and dampens the speed oscillations with the resonance frequency of the drive train (\( f_{r} \)) by controlling the excitation of the synchronous generator [6]. Under a transient fault though, the electric power export gets disrupted instantly. This also unloads instantly the drive train of the turbine, which can be described as a torsional spring, causing the generator to accelerate steeply and to perform strong torsional oscillations. Since the wind turbine cannot export electrical power during the voltage dip the drive train stabiliser (DTS), which would normally dampen torsional oscillations [6] does not succeed in stabilising the
generator speed in case of a fault. Once the grid voltage has recovered the DTS could in principle resume with drive train stabilisation. However, since by then the generator speed is oscillating considerably more than under normal operation the DTS would require a much larger DC circuit capacitor to be able to dampen oscillations with such large amplitudes. Therefore during and just after the fault the speed of the generator is stabilised by the inverter controller as shown in the upper control loop in Figure 2, which is labelled “fault controller”. The PID controller in the fault controller gets the speed error, \( \omega_{\text{err}} \), as input and tries to eliminate it.

As can also be seen from Figure 2 the voltage of the DC circuit between the rectifier and the inverter (Figure 1) is also controlled by the fault controller in case of a fault. The voltage error, \( V_{DC\, \text{err}} \), is input to a P controller trying to keep the DC voltage within tolerable limits. Normally the DC voltage is controlled by the voltage controller (VCO) of the synchronous generator [6]. Also during a voltage dip caused by a fault close to the wind turbine the DC voltage can be controlled by the VCO. If, however, this fault causes power swings the voltage at the wind turbine terminals can rise in the wake of the fault, causing the voltage source inverter to unintentionally allow reverse power flow. Reverse power flow charges the DC capacitor, which cannot be discharged by the VCO, but only by the inverter. Hence the fault controller that controls the inverter has to take the DC voltage into account too.

As soon as the fault is cleared the transient fault controller is needed for a very short time only. Therefore \( P_f \) is phased out and at the same time \( P_{sel} \) is phased in once the fault is cleared, as described in the following subsection.

### 4.2 Transition from Pf to Psel

In Figure 2 the block \( \text{trans.} \) determines what power setpoint, \( P_{\text{sets}} \), is fed through to the inverter. As soon as the voltage at the terminals of the wind turbine, \( V_{\text{grid}} \) in Figure 2, drops below a certain level the \( \text{trans.}-\) block switches from \( P_{\text{sel}} \) to \( P_f \). Figure 3 shows the weighting factors \( a \) and \( b \) when a fault occurs, i.e. when \( V_{\text{grid}} \) drops below a

![Figure 2 Control circuit of transient fault controller and power system stabiliser.](image-url)
certain limit, and Equation 1 shows that the output signal of the trans.-block, \( P_{\text{set}} \), is the sum of the weighted inputs \( P_f \) and \( P_{\text{sel}} \).

It can be seen that when a fault occurs \( P_{\text{set}} \) instantly becomes \( P_f \) and stays \( P_f \) for as long as the fault persists. Once the fault is cleared the generator speed is stabilised by \( P_f \), which is then gradually phased out.

\[
P_{\text{set}} = a \cdot P_f + b \cdot P_{\text{sel}}
\]

Equation 1

To avoid an abrupt transition from \( P_f \) back to \( P_{\text{sel}} \) the weighting factors \( a \) and \( b \) in Equation 1 are ramp signals as shown in Figure 3. A smooth transition is especially important if the operation following the transient fault operation is power system stabilisation, since there the power setpoint, \( P_{\text{st}} \), is likely to vary strongly.

![Figure 3 Weighting factors a and b for phasing in and out of power setpoints in a transient fault situation.](image)

The ramp time, i.e. the duration of the ramps in Figure 3, determines how quickly the turbine can contribute noticeably to power system stabilisation, or how quickly it resumes normal operation after a fault. If the fault upsets the power system and calls for the turbine to perform power system stabilisation the ramp time has to be in the range of several hundred milliseconds to allow the turbine to contribute to power system stability quickly after the fault. If the fault only requires the turbine to ride through a deep voltage dip, but does not require power system stabilisation operation, the ramp time may be in the order of a few seconds. In this situation the drive train oscillations that were excited by the fault are calmed down before normal operation resumes.

### 4.3 Power System Stabiliser

Under normal operation the power, which the inverter extracts from the wind turbine generator, and which it injects into the grid, is determined by the \( P(\omega) \) controller (\( P(\omega) \)-block in Figure 2) [17]. If, however, the power system is subject to a disturbance, which causes power system oscillations, the wind turbine has to control its power not only depending on its rotor speed, \( \omega \), but also depending on what is needed for damping these power system oscillations. In Figure 2 the power system signal, which is damped is the measured grid frequency, \( f_{\text{meas}} \). If, as can be seen from Figure 2 \( f_{\text{meas}} \) is different from the desired frequency, \( f_{\text{set}} \), a frequency error, \( \Delta f \), occurs, which is transformed into a power error, \( \Delta P \), by a droop characteristic.
As has been discussed in the introduction, and as can be seen from Figure 2 the wind turbine injects oscillating power when the considered power system signal, here $f_{\text{meas}}$, oscillates. Since the possible amplitude of these power oscillations, depends on the energy stored in the rotating mass of the wind turbine rotor, the slope of the droop factor that translates $\Delta f$ into $\Delta P$ has to be dependent on the overall speed of the wind turbine rotor. Figure 4 shows the general concept of the $f$ versus $P$ droop characteristic, and how the droop characteristic varies depending on the overall rotor speed of the wind turbine. It can be seen that the slope of the droop becomes steeper the slower the wind turbine rotor spins, i.e. the amplitude of the power variations decreases the less kinetic energy is stored in the rotating mass of the wind turbine. Figure 2 shows that the generator speed, $\omega$, is filtered by a low pass filter (LP-block) to avoid that short term speed variations have an impact on the slope of the droop characteristic.

$\Delta P$ is compared with the measured power the inverter injects into the grid, and the resulting power error, $P_{\text{err}}$ is compensated by a P-controller.

In the following section the function of the transient fault controller and the power system stabiliser is shown and discussed by means of simulations.

5 Simulations and Discussions

The controller as described above is implemented in the variable speed wind turbine model in the Nordic power system model, and a 300 ms short circuit fault is simulated at the location shown in Figure 1. The wind turbine operates at 14 m/s wind speed, which allows rated power operation.

5.1 Fault Ride-Through

To introduce the problem the case is simulated where the wind farm only rides through the transient fault, i.e. the power system stabiliser is not in operation. This means that when the fault is detected the transient fault controller ($P_f$) becomes active, and when the fault is cleared $P_f$ is phased out and $P_{\text{set}} = P_{\text{norm}}$ is phased in.

Figure 5 shows the voltage at the different locations along the feeder which connects the wind farm to the Nordic power system. It can be seen that the fault causes a substantial voltage dip at the terminals of the wind farm.
Figure 6 shows the voltage at the wind farm terminals and the power the transient fault controller causes the inverter to inject into the grid in order to allow fault ride-through. It can be seen that the transient fault controller needs to perform drastic control actions just after the fault is cleared. It can also be seen that it is then phased out quickly to let the wind turbine controller for normal operation take over.

As can be seen in Figure 5 the fault also has an impact on the voltage at busbar Zealand. There the voltage gets depressed considerably such that SG Zealand cannot export as much electrical power as mechanical power is input by its prime mover. Hence the speed of SG Zealand rises during the fault, and after the fault is cleared it oscillates as depicted in Figure 7. In the following subsection it is shown how the power system stabiliser in the wind farm contributes to the damping of these oscillations.
5.2 Power System Stabilisation

The same fault situation as in the previous subsection is simulated; this time the wind farm employs its power system stabiliser to dampen the oscillations in the speed of SG Zealand. Until the fault is cleared the wind turbine behaves like in the previous case. After the fault is cleared $P_f$ is phased out and $P_{sel} = P_{st}$ is phased in. Figure 8 shows the wind farm terminal voltage and the power injected into the grid. The power oscillations shown counteract the speed oscillations in SG Zealand.

To assess the damping effect of the power system stabiliser in the wind farm, Figure 9 shows the speed of SG Zealand for the case (i) when the wind farm merely rides through the transient fault (Figure 7) and (ii) when the wind farm power system stabiliser is employed. From Figure 9 it can be seen that the wind farm contributes considerably to the damping of the power system oscillations. However, looking at Figure 8 it becomes obvious that the wind farm is pushed very hard to achieve this result. The power is varied by over 1 pu within a few hundred milliseconds. Since the power of the wind turbine is exclusively controlled by the inverter, such electrical power variations are possible. However, the short transition time that barely stabilise the wind turbine, but quickly proceeds to power system stabilisation allows the transient fault to upset the drive train of the wind turbine and cause strong torsional oscillations, which can be seen in Figure 10. For comparison, Figure 10 also shows the wind turbine generator speed for the case where the turbine only rides through the
fault. In this situation a longer ramping time helps stabilising the drive train making it easier for the DTS to handle the drive train oscillations.

Even in the case of power system stabilisation the oscillations in the wind turbine generator speed do not cause the wind turbine to become unstable, as they are damped by the DTS. However, they mean stress for the mechanical structure of the wind turbine.

When assessing the damping effect of the wind farm on the power system oscillations as shown in Figure 9, it has to be kept in mind that the rating of the wind farm is not even a tenth of the rating of SG Zealand. In this study the wind farm is pushed to its electrical limits, which means that the power is varied between zero and a tolerable overpower for a short period of time. The consequences of such drastic electrical control actions on the mechanical structure of the wind turbine are beyond the scope of this article, but it shall be pointed out that they need to be studied too.

From a power system’s point of view the performed control actions mean that the wind farm contributes with 100 % of its rating to power system stabilisation. However, even conventional power plants are only demanded to provide a fraction of their rating for power system stabilisation. Hence in a realistic application a power system operator would require wind turbines to perform power system stabilisations to a much lesser extend. This would allow the controller to contribute partly to the damping of the power systems oscillations and partly to the stabilisation of the drive train oscillations. The result of which would be less mechanical stress for the wind turbine drive train.

If a different fault location were chosen, such that the wind farm would not experience a voltage dip it could already act damping on the first period of the
oscillation and even enhance transient stability of the SG (first swing stability). However, the fault location is chosen because it constitutes a worst case scenario for the wind turbine controller.

6 Conclusion

In this article a controller is described that allows a variable speed wind turbine to perform power system stabilisation, i.e. dampen oscillations in the power system. Since power system oscillations are often caused by short circuit faults, also a controller is presented that allows the variable speed turbine to ride through a transient fault before it can perform power system stabilisation.

This study shows that the variable speed concept is favourable for power system stabilisation tasks. The clear distinction between the control of the power, which is injected into the grid and the speed of the wind turbine drive train, allows extensive power system stabilisation control actions. It is concluded that from an electrical point of view a variable speed wind turbine as described here can employ 100 % of its rating to perform power system stabilisation. In a real application the contribution demanded of a wind turbine is, however, likely to be considerably less.

To assess the performance of the developed wind turbine controller the damping effect on one particular power system signal is studied in this article. In their study on the impact of different levels of wind power penetration with variable speed wind turbines on power system oscillations, Slootweg and Kling observed the movement of eigenvalues through the complex plane. [4]. They concluded that under certain conditions variable speed turbines can have a negative effect on the damping of power system oscillations. A possible future task would be to perform such a study when the considered variable speed wind turbines are equipped with the power system stabiliser as described in this article.

References


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