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System Requirements for Wind Power Plants

John Olav Tande, Giuseppe Di Marzio, Kjetil Uhlen

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SINTEF Energy Research

Address: NO-7465 Trondheim, NORWAY
Reception: Sem Sælands vei 11
Telephone: +47 73 59 72 00
Telefax: +47 73 59 72 50

www.energy.sintef.no

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CONTRIBUTOR(S)

John Olav Tande, Giuseppe Di Marzio, Kjetil Uhlen

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RESULT (summary)

This report considers grid codes for connecting wind farms to the electricity grid, and may be used as a background document when considering technical requirements for connecting new wind farms.

The focus point of this report is on the grid code specified by the Norwegian TSO (Statnett) by end 2005. This code, being strictly a guideline, includes amongst others requirements to reactive power capabilities and low-voltage fault ride-through, and these requirements are assessed in this report.

The requirement on reactive power capability is basically saying that wind farms shall be able to assist in maintaining a stable grid voltage. Assessing typical grid conditions for connecting large wind farms the analysis concludes that it is reasonable to require that wind farms shall be able to contribute with reactive power corresponding to a power factor between unity and 0.95 (capacitive and inductive).

The requirement on fault ride-through is assessed considering the ability of various wind farm technologies to meet the requirement, and the likelihood of the given voltage dip and slow recovery to appear as a consequence of a short-circuit fault in the up-stream regional or transmission network. It is concluded that is reasonable to require fault ride-through of a dip with a duration of 0.4 s, going down to 0.25 pu (or possibly 0.15 pu though depending on the wind farm technology this may pose a challenge for connecting wind farms to (very) weak grids, and must be judged also on the likelihood of such deep dips occurring). The requirement of 0.7 pu voltage for 9 s seems not well justified. Instead it is suggested that the voltage after the dip can return to 0.9 pu within a half second or thereabout.

This report also includes a brief on wind turbine technology, power control and impact on frequency stability, and some issues on international grid codes.

KEYWORDS

SELECTED BY AUTHOR(S)		
	Wind power	Grid codes
	Reactive contribution	Fault ride-through

TABLE OF CONTENTS

Page

PREFACE

This report considers technical requirements for connecting wind farms to the electricity grid. The analysis presented in the report applies as starting point the recommendations by Statnett given in their grid code “Veiledende systemkrav til anlegg tilknyttet regional- og sentralnettet i Norge (VtA)” dated 16.12.2005, hereunder is the relevant recommendations to wind farms considered.

The report is prepared by SINTEF Energy Research according to contract with EBL Kompetanse AS, and with the active involvement of the project reference group:

Hans Magne Ådland, EBL
Hans Olav Ween, EBL
Espen Hagstrøm, Statkraft
Rune Mork, Statnett
Kjetil Ryen, NVE
Lars Olav Hoset, TrønderEnergi Kraft
Terje Lauvdal, Hydro
John Olav Tande, SEfAS
Kjetil Uhlen, SEfAS
Giuseppe Di Marzio, NTNU/SEfAS

The report gives analysis results as prepared by SINTEF Energy Research, and is not binding in any way about which recommendations that shall be applied in any future version of the VtA.

1 INTRODUCTION

Grid codes basically contain the rules for connecting generators to the grid. They are typically developed by the Transmission System Operator (TSO) to facilitate rules fitted to system needs; hence they may vary in items covered, level of detail and requirements to generator technology. Detailed requirements to wind power technology is a fairly new addition to grid codes, reflecting that wind farms until the end of the nineties generally were fairly small and had little impact on the system operation. The large wind farms being built and operated today may however have a significant impact, thus it is rational to include requirements to these in grid codes.

Statnett (the Norwegian TSO) has recently (December 2005) included requirements to wind farms in their grid code [1]. The requirements are for wind farms > 10 MVA connected to the regional or main transmission grid. This code is strictly a guideline that gives recommendations, though Statnett has the right and obligation to assess new installations and based on this decide whether the installation can be permitted to operate or not. Statnett's recommendations to wind farms include the following aspects:

1. Operation at varying grid frequency (normal 49.0-50.5 Hz, limited 47.0-51 Hz)
2. Operation at varying grid voltage (normal +/- 10 %, reactive capability cosφ = +/- 0.91 ref wind farm point of grid connection)
3. Active power control (remote control of maximum production, system for ramp-rate limitation and participation in frequency control)
4. Reactive power control (system to operate at two modes: a) set-point cosφ, b) active voltage control with droop)
5. Operation in case of grid faults or abnormal grid voltages (fault ride-through for voltages at the grid connection point of the wind farm down to 0.15 pu and with a slow recovery)
6. Verification of characteristic properties (analyze impact on system using simulation model and make numerical wind farm model available for Statnett for simulation using PSS/E or similar)

Statnett highlights the importance of dialogue in the planning process of wind farms, and through this achieve at fitted technical requirements for new installations. In general, it is so that grid codes for wind farms are a rather new issue, hence it must be expected that these will be adjusted over time, possibly harmonized between countries, also illustrated by the big number of international papers dealing with the subject of grid codes for wind farms, e.g. [2-6].

This present report may be used as a background document when considering technical requirements for connecting new wind farms. A brief on alternative wind technology in terms of power quality characteristics is given in section 2. The report puts emphasis on reactive power capabilities (section 3, item 2 and 4 in the above list) and wind farm response to voltage dips (section 4, item 5 in the above list). Examples of grid faults giving voltage dips are given in section 5, hereunder grid faults at various distances from a wind farm. Section 6 gives a brief on power control and impact on frequency stability, and in section 7 some issues on international grid codes are summarized. The report findings are summarized in section 8. The Appendices include a nomenclature (Appendix A), a detailed data listings (Appendix B), more on the response of wind turbines on voltage dips (Appendix C), and a general brief on calculation of voltage increment due to power in-feed (Appendix D).

2 WIND TURBINE TECHNOLOGY

2.1 General

This section gives an overview of alternative wind technology in terms of power quality characteristics. Hence the focus is on control and generator technologies. Figure 1 gives an overview of the main concepts that are discussed in some more detail in the following subsections, based largely on [17], though updated and extended to fit the purpose of this report. The description is divided into fixed speed wind turbines (type A) and variable speed wind turbines (type B, C and D).

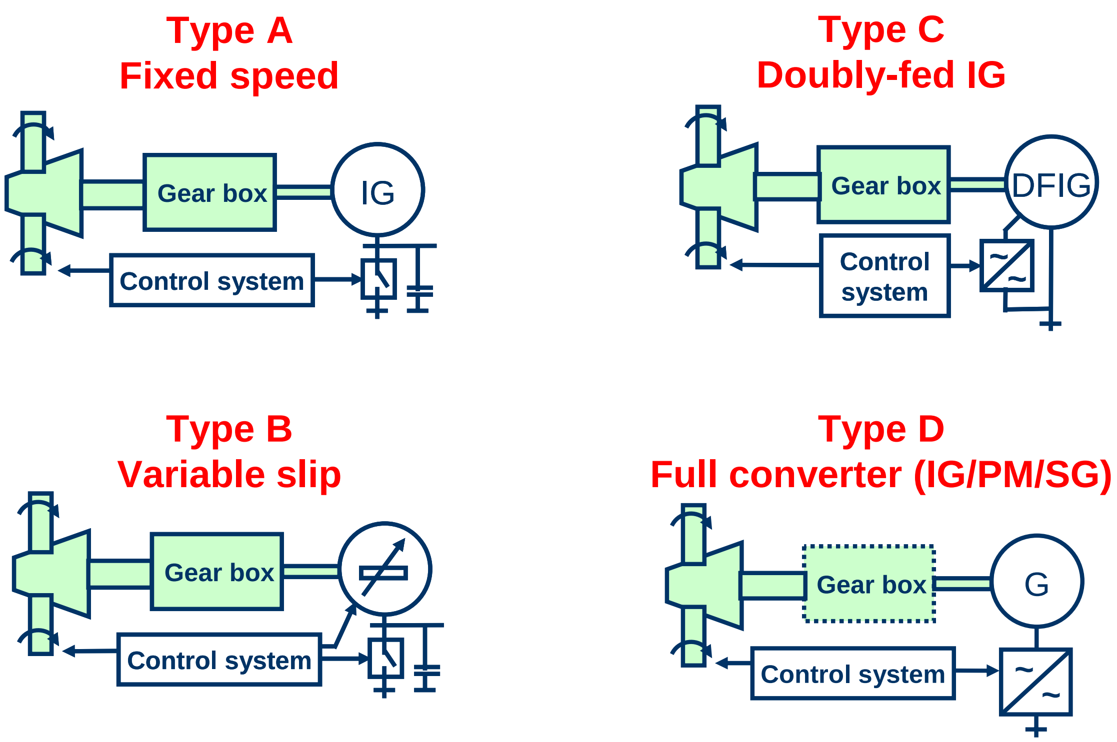


Figure 1. Overview of wind turbine concepts.

2.2 Fixed speed wind turbines

A fixed speed wind turbine commonly employs a three-phase squirrel-cage induction generator (SCIG) that is driven by the turbine via a gearbox and directly connected to the grid, i.e. without an intervening power electronic frequency converter. Thus, the induction generator will provide an almost constant rotational speed, i.e. only varying by the slip of the generator (typically about 1 %). The reactive consumption of the induction generator is compensated by application of capacitors, whereas a soft-starter limits the in-rush current to the induction generator during start-up. At wind speeds above rated, the output power is limited either by natural aerodynamic stall or by active pitching of the blades before the wind turbine is stopped at cut-out wind speed, commonly 25 m/s.

Start-up normally takes place at low wind speed, i.e. cut-in wind speed about 4-5 m/s, and then the soft-starter can effectively limit the in-rush current. Connection after a grid or wind turbine fault may however take place at high wind speeds. In this case the in-rush current may be significantly higher if the wind-induced torque is not limited by pitching the blades.

The capacitors may be connected in one or more steps. Capacitors for connection in one step commonly provide about zero reactive consumption at zero active power measured at the wind turbine terminals, and then an increasing reactive consumption to yield a power factor at rated active power of about 0,9 (inductive) depending on the induction generator characteristics. Modern fixed speed wind turbines are commonly equipped with more capacitors that are connected in steps, and using transistor based switches for fast control of the reactive compensation. This provides for capabilities ala a Static Var Compensator (SVC) and can be applied either for controlling the reactive exchange to a certain set value (e.g. zero for unity power factor) or for contributing to voltage control with droop settings just as any other utility scale power plant.

Siemens is the only of the top five wind turbine suppliers (Vestas (DK), Enercon (DE), Gamesa (ES), GE (USA) and Siemens (DE)) that manufacture large fixed speed wind turbines. The nacelle of a Siemens 2.3 MW fixed speed wind turbine is shown in Figure 2. The transformer, capacitors and controls are located at the bottom of the tower.

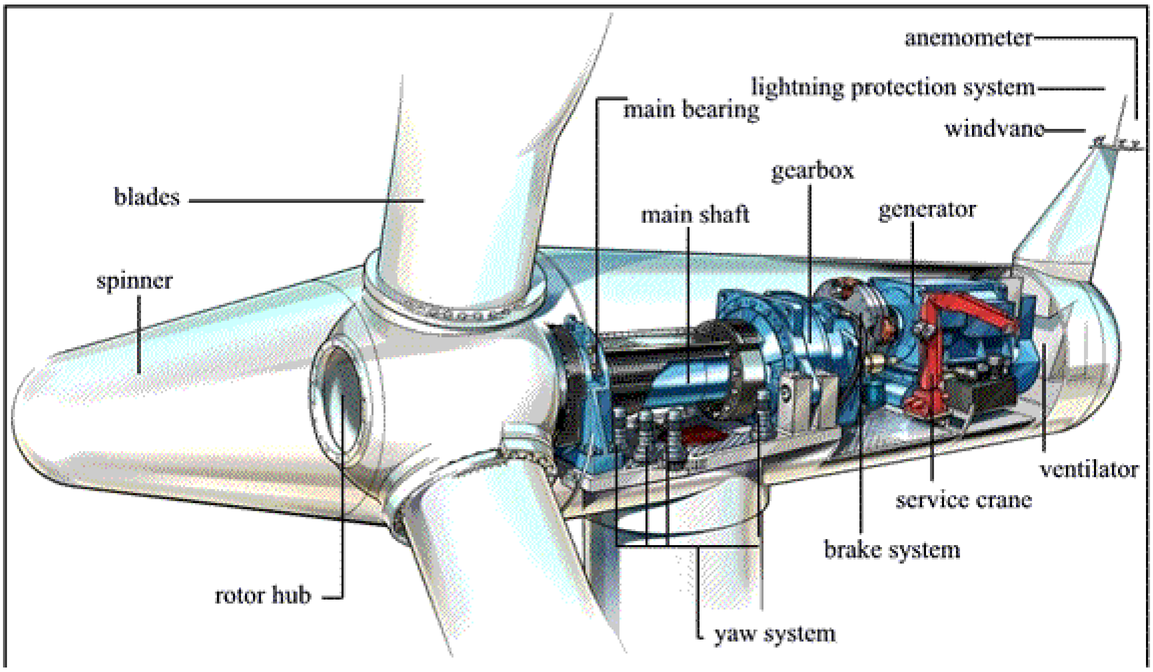


Figure 2: Schematic of Siemens 2.3 MW fixed speed wind turbine.

2.3 Variable speed wind turbines

Most variable speed wind turbines employ pitch control, and in the following description only such wind turbines are considered.

Variable speed operation opens for increased efficiency and enhanced control. The variable speed operation is commonly achieved either by controlling the rotor resistance of the induction generator, i.e. slip control (Type B in Figure 1), or by a power electronic frequency converter between the generator and the grid (Type C or D in Figure 1). Slip control is offered by Vestas only in what they call OptiSlip, and is mainly marketed in the USA where foreign sales of wind turbines with frequency converters are hindered by patent issues. The variable slip concept (OptiSlip) yields a speed range of about 10 %, whereas application of a frequency converter opens for larger speed variations. All variable speed concepts are expected to yield quite small power fluctuations and especially during operation above rated wind speed. They are also expected to offer smooth start-up. Hence, the basic difference between the three variable speed concepts in relation to power quality is that Type B does not have a power electronic converter and thus have reactive capabilities as a fixed speed wind turbine, whereas Type C and D has a converter that offers dynamic reactive power control. The reactive capabilities of Type C and D may differ as the Doubly-Fed Induction Generator (DFIG) concept of Type C uses a converter rated typically about 30 % of the generator and not 100 % (or more) as the case is for the Type D concepts. The grid side of the converters of all major wind turbine suppliers offering Type C or D concepts are all based on fast switching transistors and is hence not expected to emit over-harmonic currents that may significantly distort the voltage waveform. The converters are also full bridge meaning that the reactive power can be controlled independently of the active power output (within the apparent rating of the converter).

Vestas, Gamesa and GE all offer wind turbines with the Type C (DFIG) concept.

Enercon has been the pioneer of the top five manufacturers in developing the type D (full rated converter) concept. Their system employs a multi-pole (slow rotating) wound synchronous generator directly fixed to the turbine hub as illustrated in Figure 3. The system is often referred to as a “direct-drive generator system” as the generator is directly driven by the turbine, i.e. not using a gearbox.

Figure 3: Schematic of Enercon 2 MW wind turbine. Copy from www.enercon.de.

GE markets an alternative design in their 2.5 MW wind turbines. Here they use a multistage gearbox and a permanent magnet (high speed) generator connected to the grid via a full rated power converter. Siemens has a similar system in their SWT-2.3-82 VS (2.3 MW) wind turbine and in their SWT-3.6-107 (3.6 MW) wind turbine, but applies a standard SCIG connected to the grid via a full rated power converter.

The ScanWind turbines are also of Type D. The ScanWind 3.5 MW wind turbine uses a direct driven permanent magnet generator connected to the grid via a full rated frequency converter. The generator and converter are from Arctic Windpower, a Finland-based electrical consortium of Rotatek Finland Ltd, Verteco Ltd and Vaasa Engineering Ltd.

The existence of the gearbox or not in the Type D system may not significantly influence the power quality characteristics of the wind turbine. Actually, it is so that wind turbines applying different combinations of power electronic converters and generators may all yield similar power quality characteristics described in qualitative terms, though measurements on actual wind turbines may reveal distinct variations e.g. due to differences in the overall control system or the detailed design of the power electronic converter.

2.4 Quantification of characteristics

As it appears from section 2.2 and 2.3, it is evident that the power quality characteristics may vary considerable from one wind turbine type to another, and are manufacturer specific.

Seeing the need for consistent and replicable documentation of the power quality characteristics of wind turbines, the International Electrotechnical Commission (IEC) started work to facilitate this in 1996. As a result, IEC 61400-21 [14] was developed and adopted by CENELEC to constitute a European Norm. This standard is now under revision and a second edition is under preparation. This new version [15] suggests that the following parameters are relevant for characterising the power quality of a wind turbine:

- Wind turbine data (Rated data)
- Flicker (Continuous operation, Switching operations)
- Harmonics, *Interharmonics and Current Distortions (<9 kHz)*
- *Response to voltage dips*
- *Active Power Characteristics (maximum output, ramp rate limitation and set-point control)*
- *Reactive Power Characteristics (reactive power capabilities and set-point control)*
- *Grid Protection (tripping levels of over/under voltage magnitude and frequency)*
- *Reconnection time*

In the above list new topics compared to edition 1 of the standard are written in italics.

The additions to the standard are much related to the recent development of grid code requirements to large wind farms. The revised standard will still be for testing of single wind turbines, though it may contain information that will be useful for testing of wind farms.

3 REACTIVE POWER AND VOLTAGE CONTROL

3.1 General

This section considers reactive power and voltage control of wind farms. Reactive power control of wind farms has traditionally been limited to keeping the power factor (cosφ) to unity, or to allowing a small reactive consumption. In most new grid codes however, there are requirements for wind farms to be able to produce or consume certain amounts of reactive power, and also to be able to automatically control the reactive power for contributing to a stable grid voltage. This seems rational as wind farms can then add to voltage control in the same manner as other utility scale power plants and allow for connecting more wind power to the grid. The question is rather if the reactive power capacity of a wind farm shall be cosφ = 0.91 (capacitive and inductive) as suggested in [1], or something else. The basic reasoning is that reactive capacity comes at a cost, and a rational requirement should strike a balance between that and the value of having such capacity. To assess this, the impact of active and reactive power in-feed on the steady-state voltage is first presented (section 3.2), and secondly the amount of reactive power required for maintaining a stable steady-state voltage is determined (section 3.3). A similar analysis to the one presented in section 3.2 and 3.3 is reported in [7], but less detailed and with a scope to illustrate basic relations only and not assessing reactive power requirements as done here.

The analysis is kept on a general basis representing the grid by a Thevenin equivalent and the wind farm as a source of active and reactive power. This approach is taken to make the results representative for any type of wind turbine technology as characterised by its P and Q feed-in and any grid as characterised by its Thevenin equivalent. The system is shown in Figure 4. The Thevenin equivalent is simply an ideal voltage source (U_{eq}) behind an impedance ($Z_{eq}e^{j\psi}$) representing the grid as seen from the point of connection of the wind farm (BUS A in Figure 4). The Thevenin equivalent can also be described by the system fault level, i.e. the short-circuit apparent power (S_k) and the network impedance phase angle (ψ), see also eq. 1-3.

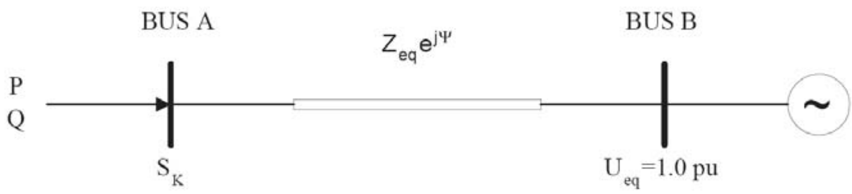


Figure 4: Thevenin equivalent of grid with wind farm feed-in of P and Q at BUS A.

$$\tan(\psi) = \frac{X_{eq}}{R_{eq}} \tag{1}$$

$$S_k = \frac{U_{eq}^2}{\sqrt{R_{eq}^2 + X_{eq}^2}} \tag{2}$$

$$\overline{Z}_{eq} = R_{eq} + j \cdot X_{eq} = Z_{eq} e^{j\psi} \tag{3}$$

3.2 Steady state voltage level

The impact of in-feed wind power on the steady-state voltage at the point of connection is assessed. The grid is represented by its Thevenin equivalent, and the analysis is carried out for various grid characteristics (S_k and ψ) and in-feed of power (P and Q). The grid characteristics are selected as to represent anything from strong to weak grids expressed by the short-circuit ratio (S_k/P_n), and for inductive to resistive grids expressed by the network impedance phase angle (ψ).

A grid is generally said to be "weak" when changes in the real and reactive power flows into or out of the network will cause significant changes in the voltage amplitude at that point, and at neighbouring points on the network. Networks in rural areas are generally weaker than in urban or industrial areas. Weak networks can also be referred to as having a "low short-circuit level" or "low fault level". Expressed in terms of the short-circuit ratio a network may be said to be weak for $S_k/P_n < 25$ and strong for $S_k/P_n > 25$. Most large wind farms in Norway are planned in areas with relatively weak networks, in the extreme all down to S_k/P_n close to 2.

Large wind farms are generally connected to transmission grids and these are mostly inductive with a network impedance angle ψ typically somewhere between 55 and 85 degrees. Smaller wind farms may be connected to distribution grids that are more resistive with ψ ranging typically between 25 and 55 degrees.

The analysis is carried out for three cases of wind farm reactive power compensation, i.e. a power factor equal to 0.95 (inductive), unity and 0.95 (capacitive). The results are given in Figure 5, Figure 6 and Figure 7. It is seen from the figures that the wind power gives less voltage deviations the higher the short circuit ratio (S_k/P_n). Further, the figures show that for the same short circuit ratio, the same injection of wind power may give an increment or a decrement in the voltage level depending on the network impedance phase angle (ψ) and the power factor of the wind farm.

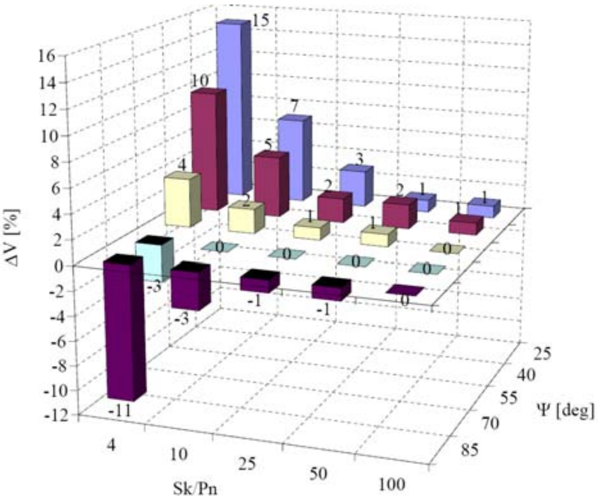


Figure 5: Voltage increment due to injection of wind power P_n with a power factor equal to 0.95 (inductive).

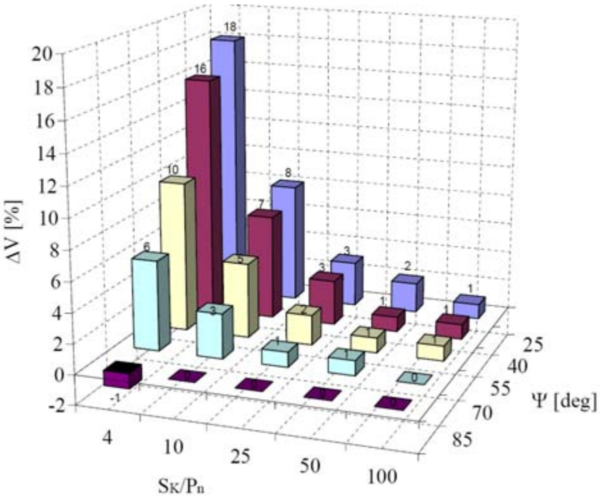


Figure 6: Voltage increment due to injection of wind power P_n with a power factor equal to 1.0.

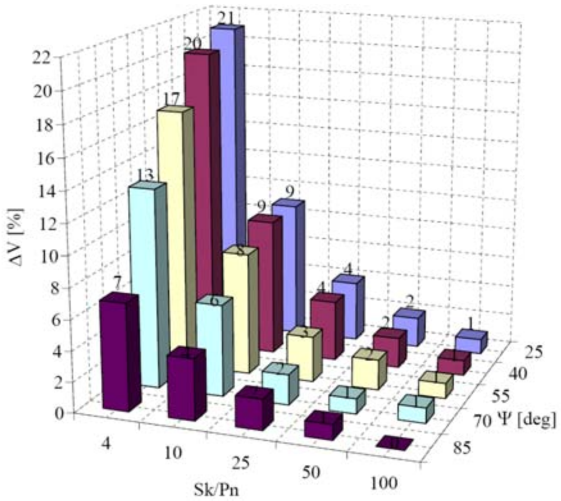


Figure 7: Voltage increment due to injection of wind power P_n with a power factor equal to 0.95 (capacitive).

3.3 Regulation of reactive power

As illustrated in section 3.2, a large injection of power may cause significant voltage deviations. To counteract on these and maintain the steady-state voltage within its acceptable limits[1], control of reactive power may be effective. The effectiveness of reactive power feed-in for maintaining a stable voltage is however depending on the network characteristics (S_k and ψ). This is assessed by assuming the same system as in section 3.2, and then calculating the amount of reactive power feed-in that is needed to maintain zero voltage deviation at the point of connecting the wind farm (BUS A in Figure 4). The calculated normalized reactive power feed-in (Q/P_n) is shown in Figure 8 for a wide range of short-circuit ratios (S_k/P_n) and network impedance phase angles (ψ). Figure 9 is as Figure 8, but with more details on low S_k/P_n ratios. Figure 10 shows instead of Q/P_n the needed power factor (cosφ) of the wind farm for maintaining zero voltage deviation at the point of connection.

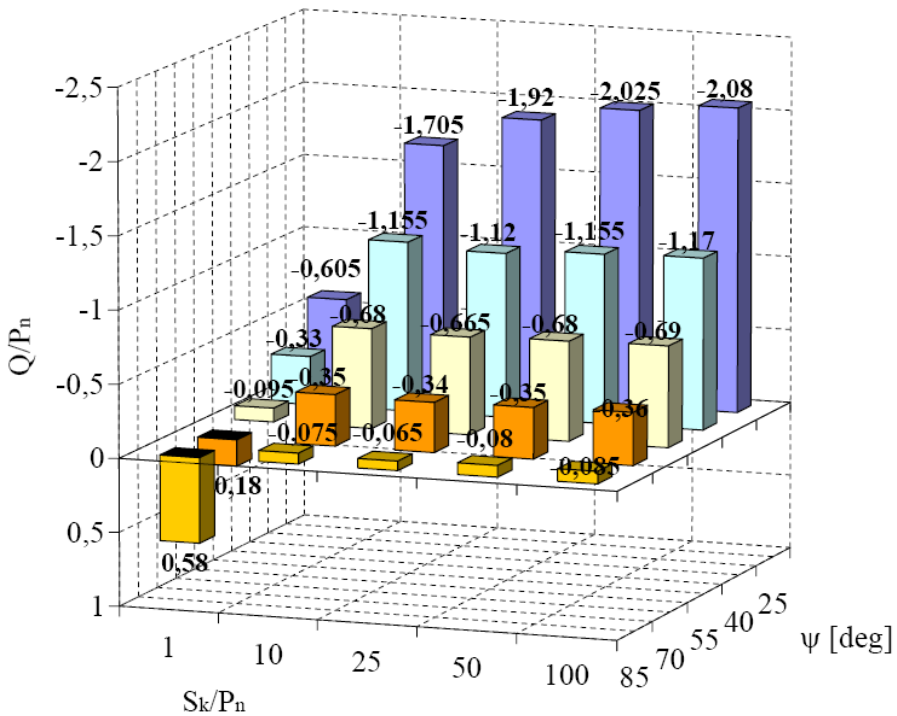
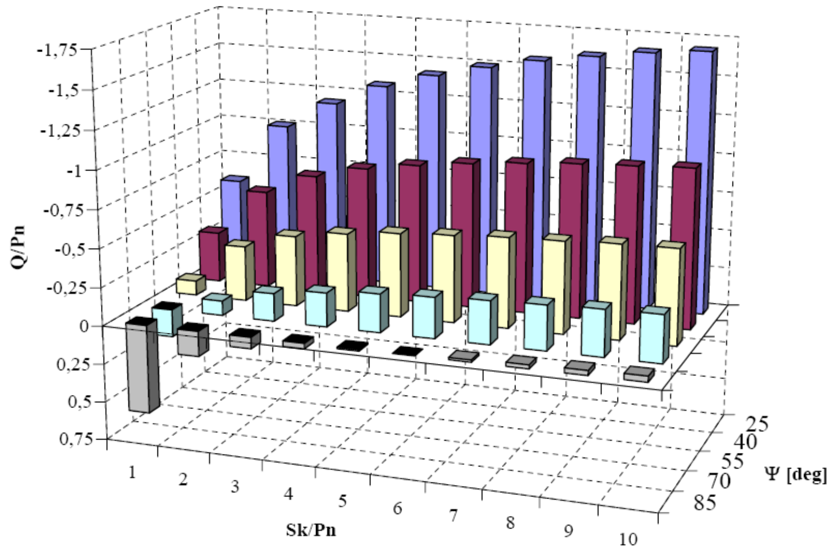


Figure 8: Reactive power feed-in (Q/P_n) for maintaining zero voltage increment as a function of the short-circuit ratio (S_k/P_n) and the network impedance phase angle (ψ).

[1] The acceptable limits for voltage deviations are system specific, though the steady-state voltage is typically required to be within +/- 10 % of its the nominal value at consumers, and generally within stricter limits at the transmission level.



	1	2	3	4	5	6	7	8	9	10
25	-0,605	-1,01	-1,19	-1,33	-1,425	-1,5	-1,565	-1,615	-1,66	-1,69
40	-0,33	-0,64	-0,775	-0,855	-0,905	-0,945	-0,975	-1	-1,015	-1,03
55	-0,095	-0,36	-0,46	-0,51	-0,545	-0,565	-0,585	-0,595	-0,61	-0,615
70	0,18	-0,095	-0,18	-0,22	-0,25	-0,265	-0,28	-0,29	-0,3	-0,305
85	0,58	0,165	0,075	0,035	0,01	0	-0,015	-0,025	-0,032	-0,038

Figure 9: Reactive power feed-in (Q/P_n) for maintaining zero voltage increment as a function of the short-circuit ratio (S_k/P_n) and the network impedance phase angle (ψ).

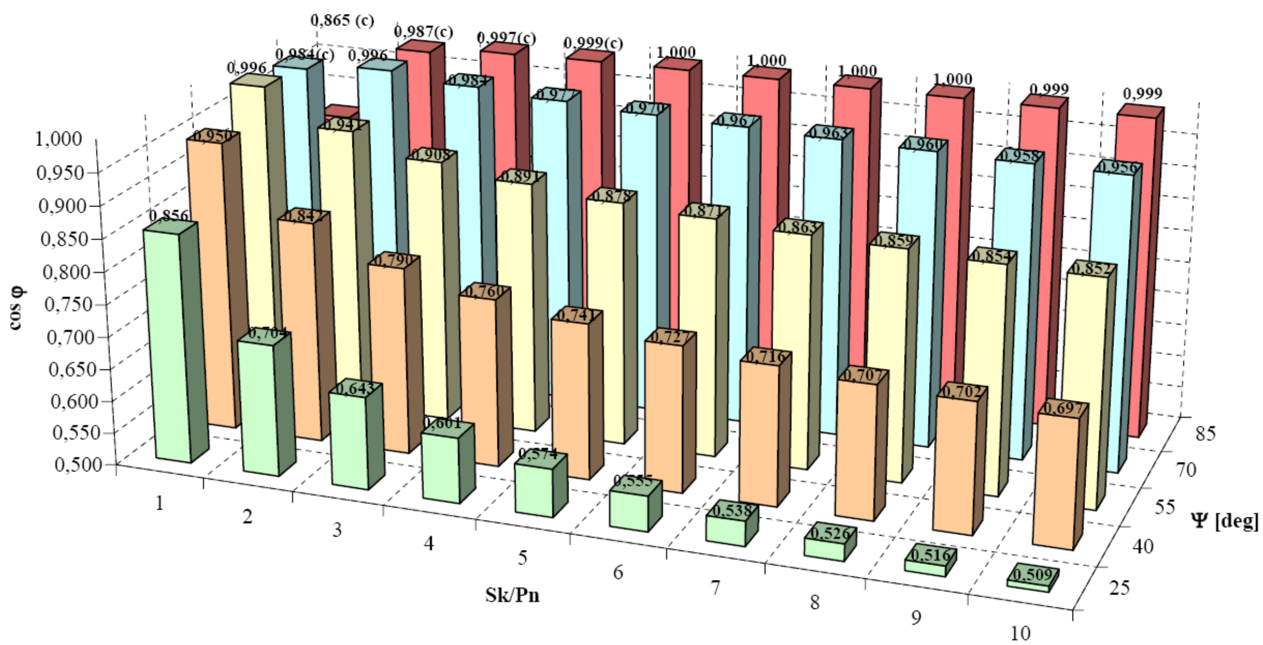


Figure 10: Power factor (cosφ) of wind farm for maintaining zero voltage increment as a function of the short-circuit ratio (S_k/P_n) and the network impedance phase angle (ψ). Note that the power factor shifts between being inductive and capacitive. In the figure a capacitive power factor is indicated by "(c)".

The following can be observed from the figures:

- For network impedance phase angles up to 55 degrees, a relatively high consumption of reactive power is required to maintain zero voltage deviation. Hence, in resistive grids (i.e. distribution grids), reactive power feed-in is a less effective measure to control the voltage.
- At bigger network impedance phase angles (70 and 85 degrees), quite smaller amounts of reactive power is required to maintain zero voltage deviation. The exception is the extreme case of S_k/P_n = 1 and ψ = 85 deg, where a power factor of 0.865 (capacitive) is required. Otherwise, the power factor required is between unity and 0.95.

At high S_k/P_n, say above 25, the voltage deviation can be reasonable approximated by the following relation:

$$\Delta U \approx \frac{P \cdot R_{eq} + Q \cdot X_{eq}}{U_{eq}} \tag{4}$$

The reactive requirement for maintaining zero voltage deviation is thus for $S_k/P_n > 25$ approximately independent of the network strength and simply given by the R/X ratio of the network:

$$\frac{Q}{P_n} \approx -\frac{R_{eq}}{X_{eq}} = \frac{-1}{\tan\psi} \tag{5}$$

Application of this approximate relation (eq. 5) gives the results as shown in Table 1. As can be seen the results are fair for $S_k/P_n > 25$, but should not be used at weaker networks ($S_k/P_n < 25$).

Table 1: Approximate calculation of reactive power for maintaining zero voltage increment.

ψ (deg)	**85**	**70**	**55**	**40**	**25**
tanψ	11.4	2.75	1.43	0.84	0.47
Q/P_n	-0.09	-0.36	-0.70	-1.19	-2.14

At weaker networks ($S_k/P_n < 25$) the voltage deviation and the required reactive power for maintaining a specific voltage deviation should be determined from accurate simulations or by using the following accurate analytic expressions (see also Appendix D):

Voltage deviation:

$$|U| = \sqrt{\frac{U_{eq}^2 + 2 \cdot (R_{eq} \cdot P + Q \cdot X_{eq}) + \sqrt{U_{eq}^4 + 4 \cdot (R_{eq} \cdot P + Q \cdot X_{eq}) \cdot U_{eq}^2 - 4 \cdot \left(X_{eq} \cdot P - R_{eq} \cdot Q\right)^2}}{2}} \tag{6}$$

$$\Delta U = \frac{|U| - |U_{eq}|}{|U_{eq}|} \cdot 100 \tag{7}$$

Required reactive power for maintaining a specific voltage |U|:

$$Q = \frac{1}{R_{eq}^2 + X_{eq}^2}\left(|U|^2 X_{eq} - \sqrt{|U|^2 (2R_{eq}P + U_{eq}^2)(R_{eq}^2 + X_{eq}^2) - |U|^4 R_{eq}^2 - P^2 (R_{eq}^2 + X_{eq}^2)^2} \right) \qquad (8)$$

Application of eq. 8 gives the results as shown in Figure 11. It is seen that the required reactive power (and power factor) varies with the required voltage deviation (zero, +/- 5 % or +/- 10 %), the short-circuit ratio (S_k/P_n) and the network impedance phase angle (85, 80, 75 and 70^o). Excluding the extreme case of $S_k/P_n = 1$, the required power factor is always between 0.95 and unity for obtaining zero voltage deviation. Changing the voltage by reactive power feed-in is more demanding the stiffer the grid, i.e. as shown in Figure 11 the amount of reactive power required for getting at a +/- 5 % or +/- 10 % voltage deviation is rapidly increasing the higher the short-circuit ratio. Indeed, this is normally not critical as the active power feed-in at high short-circuit ratios will anyhow not cause any large voltage deviation, see also section 3.2.

Summing up the results of this section it seems reasonable to require that wind farms shall be able to contribute with reactive power corresponding to a power factor between unity and 0.95 (capacitive and inductive). The reasoning behind this is that reactive power is mainly needed from large wind farms (i.e. connected to an inductive grid) to help maintain an acceptable voltage level at the connection point of the wind farm. In strong grids the voltage is expected not to be changed very significantly by the wind farm, and hence this will not be setting any particular requirement to the reactive contribution from wind farms (except maybe saying that the power factor shall be close to unity as to minimize grid losses). In weak grids the voltage may deviate significantly due to in-feed power from a wind farm (or any other generator for that matter), and hence this may set requirements to the reactive contribution from the wind farm (or other generator). The analysis shows that in such weak grids, and excluding the extreme case of $S_k/P_n = 1$, an amount of reactive power corresponding to a power factor between unity and 0.95 (capacitive and inductive) is sufficient for maintaining a stable voltage.

Indeed, the analysis presented here is not a substitute for any detailed grid study that should be prepared as part of planning a large wind farm, and such detailed assessment may come up with suggesting different reactive power requirements. This may be due to special grid conditions not taken into account in this report. Such requirements should however then be the exception and not the general rule.

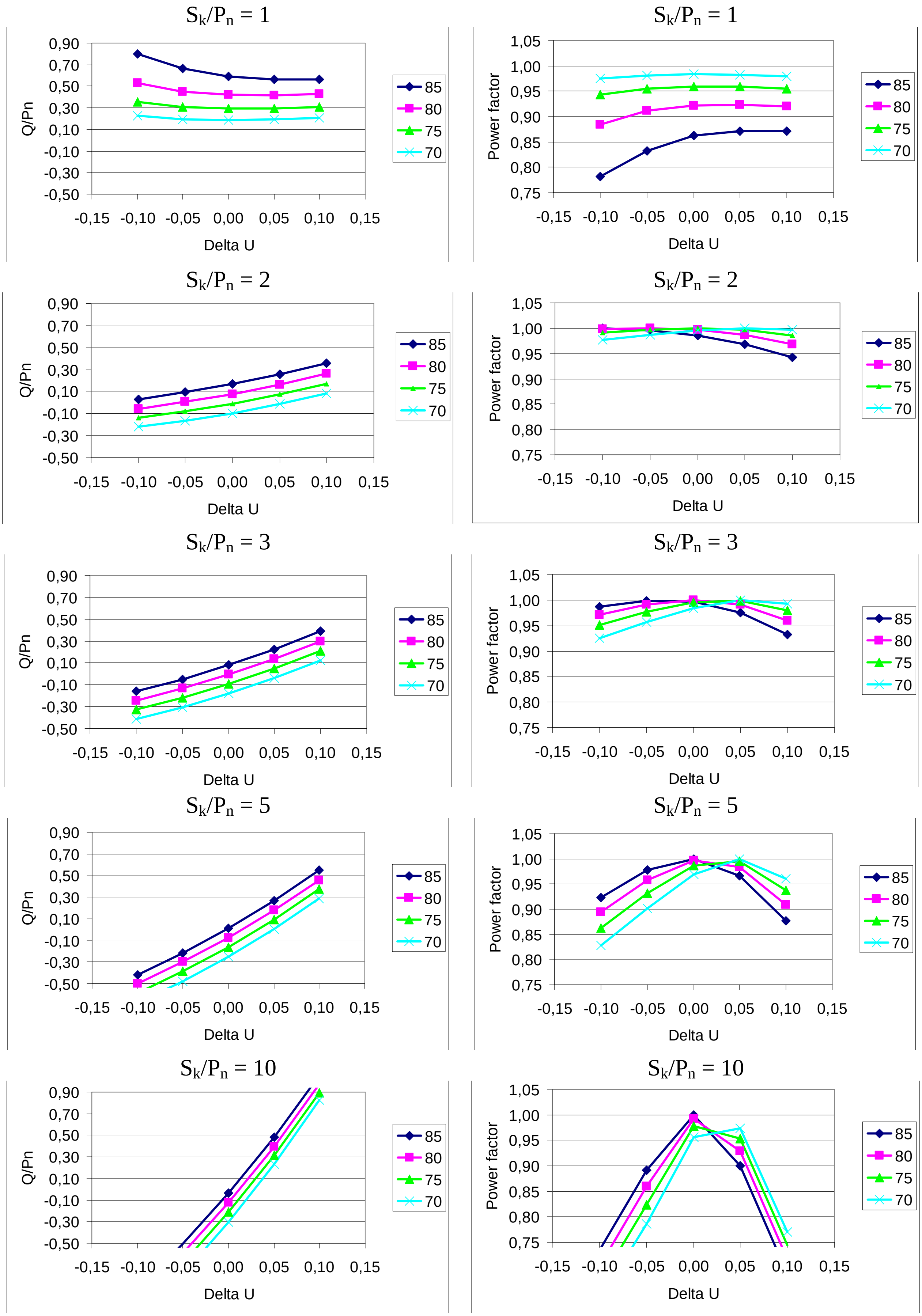


Figure 11: Reactive power Q/P_n (left graphs) and power factor (right graphs) as a function of voltage deviation (Delta U) for five cases of S_k/P_n and four cases of ψ (85, 80, 75 and 70^o).

4 WIND FARM RESPONSE TO VOLTAGE DIPS

4.1 General

Until a few years back the rule was that wind farms should disconnect in case of grid disturbances, e.g. voltage dips. The idea was to protect the wind turbines as low voltage could cause over-speed and mechanical failures, but also that tripping of some small generation would anyhow not have any significant impact on system stability. The development of large wind farms changed this as tripping of such can possibly lead to local deficit of generation, line overloading and system instability. It is worthwhile to notice that implicit in this new way of thinking is also a recognition of wind farms as a source of firm power, i.e. the system is operated relying on the wind power generation.

Low-voltage fault ride-through capabilities of wind farms can be achieved in a variety of ways. The challenge is basically that as the voltage drops the current output must increase or else the turbines will accelerate to over-speed. Blade pitching can be activated to limit the aerodynamic power, and by this reduce current and acceleration, but not immediately. Hence, the lower the voltage the wind farm shall be able to ride-through, the bigger the challenge.

The purpose of this section is to analyse and present some basic properties of wind farms with respect to transient stability and response to voltage dips. To do this, a numerical test grid as described in section 4.2 is applied, and the response on grid faults (voltage dips) of various wind farm technologies are assessed by simulation. The simulations are carried out for three different wind farm technologies:

- Wind farm consisting of wind turbines with squirrel cage induction generators (SCIG) and fixed (no-load) reactive compensation (section 4.3).
- Wind farm consisting of wind turbines with SCIG and a static var compensator (SVC)[2] for reactive compensation (section 4.4).
- Wind farm consisting of wind turbines with doubly-fed induction generators (DFIGs) (section 4.5).

Simulations of wind turbines with full rated converters (ala Enercon and ScanWind) are not included in this report. The reason for this is that the behaviour of such wind turbines is very dependent on the applied control system being manufacturer specific and considered of competitive value. Indeed, manufacturers of such wind turbines generally claim that an advantage of their technology is excellent performance under grid faults, and this seems realistic. Their actual performance must however be verified by measurements as simulations performed without knowing the actual control strategy can be misleading. This is also discussed as part of assessing wind turbines with DFIGs (section 4.5) that also has a performance influenced by the implemented control system, though not to such full domination as the case is for wind turbines with full scale converters.

[2] An alternative means for dynamic reactive compensation could be application of a STATCOM, or it could be by capacitors being connected in steps, and using transistor based switches for fast control of the reactive compensation.

The simulations in section 4.3 to 4.5 consider a short-circuit in the grid followed shortly after by tripping of the faulted line. The results indicate the ability of wind farms to ride-through voltage dips, but also that this ability depends not only on the wind farm technology, but also on the grid and dip characteristics. The ability of wind farms to ride-through a dip followed by a slow voltage recovery as specified in [1] is assessed in section 4.6.

The simulations are performed in SIMPOW [11] applying phasor-type models (also denoted RMS-type models), i.e. ala as in PSS/E and other power system simulation tools.

4.2 Test grid

A numerical model of a test system including grid, generation and load has been implemented for carrying out the analyses. This test system is shown in Figure 37. The wind farm is connected through a single 25 km radial to a regional network (145 kV). A local synchronous generation (50 MVA) and local load (50 MW, 10 MVAr) are connected in the regional network. The regional network is connected to the main grid via a double 145 kV line.

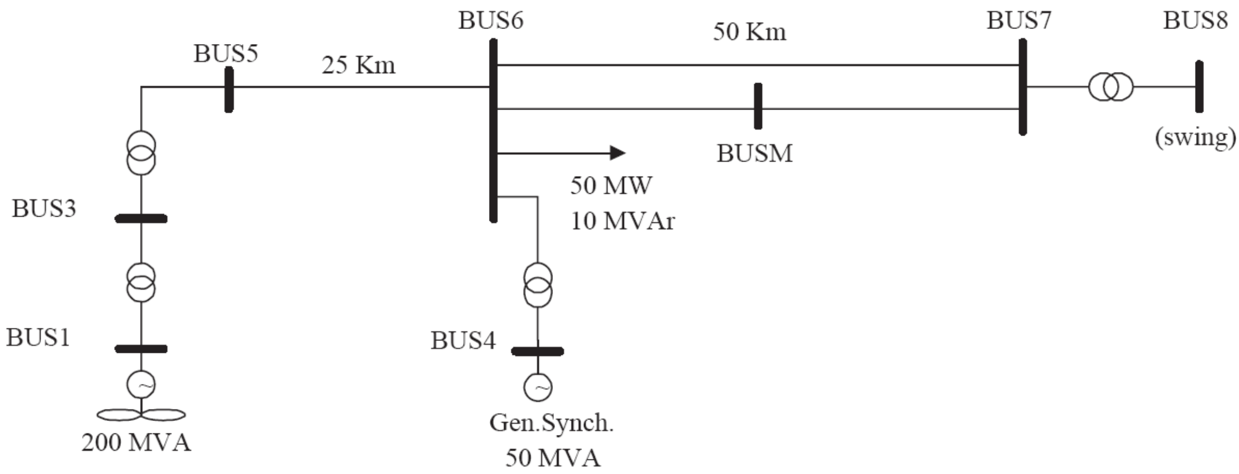


Figure 12: Single line diagram of the test system

The motivation behind the choice of the test system is that most existing and planned wind farms in Norway are located in areas where the likely grid connection is within regional transmission networks at 132-145 kV voltage level. A typical wind farm has an internal network at 22 kV and generator transformers at each wind turbine. In the test system the entire wind farm is modelled as one equivalent generator and one 0.69/22 kV transformer (BUS1-BUS3). The main wind farm substation (BUS3-BUS5) is usually connected radially to the regional grid (BUS5-BUS6). The regional 132 kV networks are normally operated as meshed grids with one or more connections to the main transmission network (here represented by the two lines connecting BUS6 and BUS7). Within the regional network there are substations and feeders to distribution networks and very often some other local generation. In the test system model all loads and local generation are connected to BUS6. The main transmission grid (BUS8) can be modelled in further detail depending on the type of studies to be performed on the test system.

The data of the lines are selected as to achieve a fairly weak and highly inductive grid. The connection point of the wind farm (BUS 5) has a short-circuit power of 605 MVA and a network impedance phase angle of 84 degrees.

A complete description of the test grid is given in Appendix B. Main issues of the wind farm modelling are given in the subsequent sections. A joint condition is that the wind induced torque is assumed to be constant, i.e. a common assumption when simulating wind farm response on voltage dips. Appendix C includes more simulations of wind farms subject to voltage dips.

4.3 Wind farm with SCIG and no-load reactive power compensation

The wind farm is here modelled applying a standard SCIG model, a two-mass model of the mechanical drive train and a standard capacitor model. The wind farm is rated 200 MW with a fixed capacitor bank rated 50 Mvar. This supplies sufficient reactive power for magnetizing the SCIG at zero power output, i.e. no-load reactive power compensation. The assumed data of the two-mass model resembles that of a real wind turbine and are given in Table 2.

Table 2: Assumed data of the two-mass model

Shaft stiffness	K=0.29 p.u./el.rad
Turbine intertia	H_T=4.7 sec
Generator inertia	H_G = 0.3 sec

The model is run for different levels of wind generation and simulating a three-phase short-circuit[3] at BUS M (Figure 12) and subsequent fault clearance by tripping the faulted line. By varying the time delay before the line tripping (here denoted Fault Clearing Time, FCT) it is possible to identify the maximum FCT before the system becomes unstable. This maximum time delay is denoted Critical Clearing Time (CCT) and is commonly used as an indicator on transient stability. The results are shown in Table 3. Note that it was not possible to run the simulation at rated wind generation (200 MW) as this lead to an unstable operation even prior to applying any fault on the system, i.e. simply due to lack of reactive compensation of the wind farm (see also Appendix B).

Table 3: CCT as determined by simulation

Wind power P (MW)	S_k/P	CCT (ms)
50	12.1	500
100	6.05	250
150	4.03	100
180	3.36	0

The system response on the fault with a FCT = 100 ms is shown in Figure 13 for the indicated levels of wind generation.

[3] A three phase fault represents the worst condition compared to other types of faults as far as the system stability is concerned.

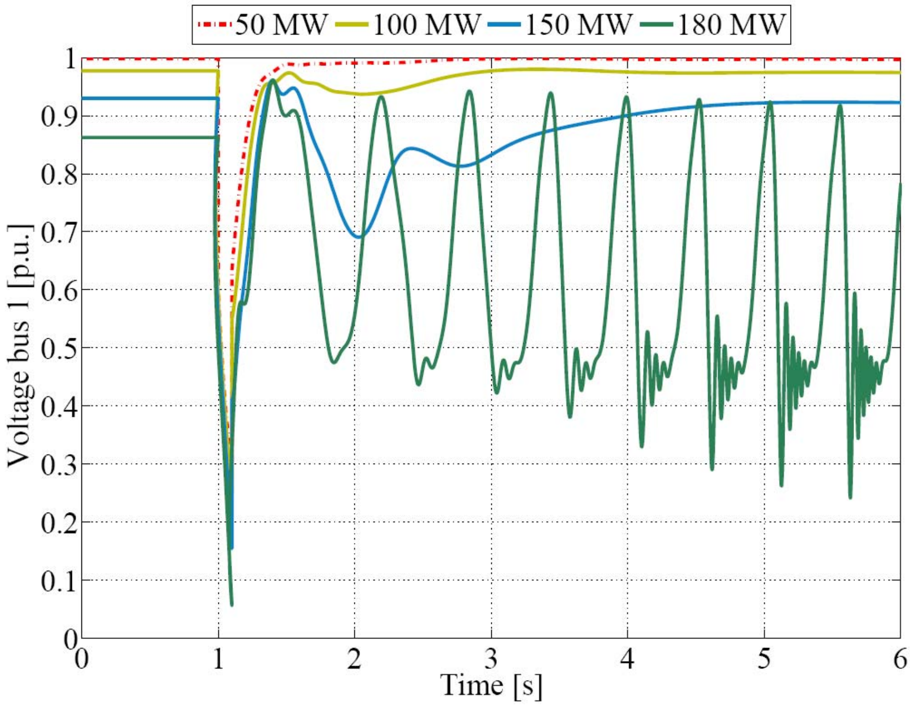


Figure 13: Simulation of wind farm with SCIG and no-load reactive compensation. FCT is 100 ms.

4.4 Wind farm with SCIG and SVC

The wind farm is modelled as in section 4.3, but rated 250 MW, and instead of a standard capacitor model of 50 Mvar, a standard model of an SVC rated 200 Mvar is applied. The SVC is assumed connected at the generator terminals (BUS 1) and operated in voltage control mode.

The model is run for different levels of wind generation and simulating a three-phase short-circuit with subsequent fault clearance as in section 4.3. The results are summarised in Table 4.

Table 4: CCT as determined by simulation

Wind power P (MW)	S_k/P	CCT (ms)
50	12.1	500
100	6.05	350
150	4.03	250
200	3.03	50
250	2.42	10

The system response on the fault with a FCT = 100 ms is shown in Figure 14 for the indicated levels of wind generation.

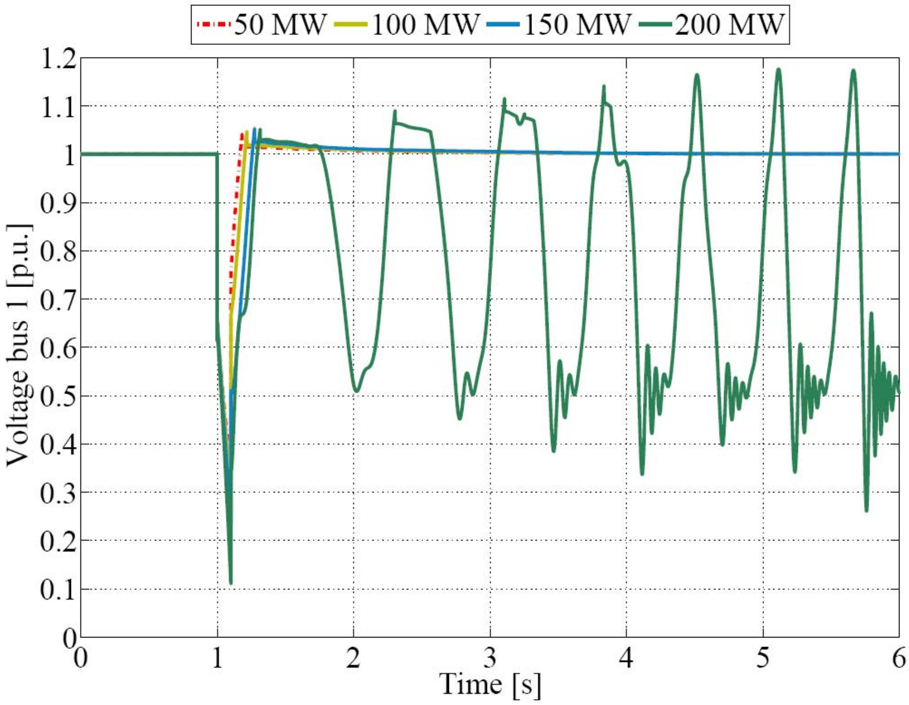


Figure 14: Simulation of wind farm with SCIG and SVC. SVC is rated 200 MVA. FCT is 100 ms.

4.5 Wind farm with DFIG

The wind farm is here modelled applying a user-built DFIG model with a lumped representation of the mechanical drive train, i.e. the inertia of the turbine is lumped together with generator (H_G = 5 s). The power electronic converter (voltage source frequency converter) of the DFIG is assumed rated 35% of the nominal capacity of the generator. The assumed control strategy is to switch from power to rotor current control during the fault and by this limit the current during the fault to an acceptable level. In real life a crowbar protection[4] would probably also be operated, but assumed here only to be connected for very short time periods (fractions of a period to limit transients) and therefore not included in this RMS-type simulation.

The model is run for different levels of wind generation (by changing the rating of the wind farm) and simulating a three-phase short-circuit with subsequent fault clearance as in section 4.3. The results are summarised in Table 5.

Table 5: CCT as determined by simulation

Wind power P (MW)	S_k/P_n	CCT (ms)
50	12.1	500
100	6.05	500
150	4.03	350
200	3.03	No convergence

[4] A crowbar protection is basically a resistor that short-circuits the rotor windings and by this protects the power electronic converter. A "dynamic" crowbar may be switched on and off within fractions of a period.

The system response on the fault with a FCT = 100 ms is shown in Figure 15 for the indicated levels of wind generation.

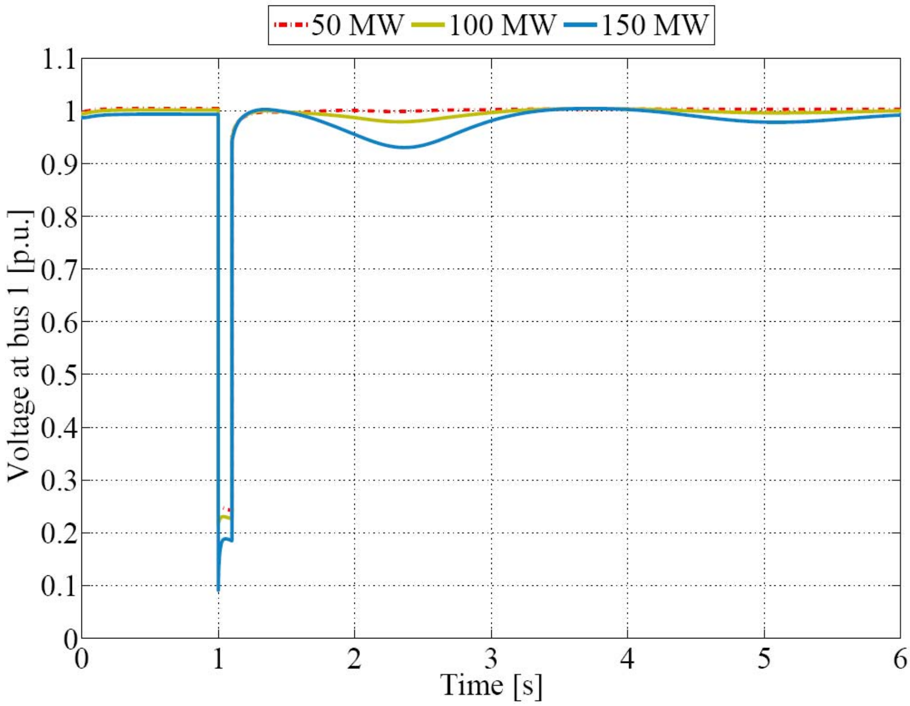


Figure 15: Simulation of DFIG with rotor current control. FCT is 100 ms.

The simulation results are sensitive to the assumed control strategy of the DFIG. This is illustrated by the following alternative simulations using a “standard” DFIG model (beta version) as provided by SIMPOW. Here, the control is assumed to short-circuit the rotor windings through a crowbar resistor during the fault. This effectively protects the power electronic converter against over-currents and over-voltage on the dc-link, but as can be seen from the simulation results in Figure 16, this “static” crowbar protection gives poorer fault ride-through capabilities. The term “static” crowbar protection is applied as to indicate that the crowbar remains connected during the fault and until the effect of the fault has abated, i.e. in Figure 16 the distinct voltage change at about 4 and 5 seconds after the fault is due to the disconnection of the crowbar. This DFIG model includes also a two-mass representation of the mechanical drive train, and applied here with data as in Table 2. However, the effect of including the two-mass representation with regards to voltage dip response is not significant compared to that of the assumed “static” crowbar protection.

Without having measurements to compare with simulation results it is obviously difficult to say that one simulation gives a correct representation of a given system and one other is wrong. Comparing the results of Figure 15 and Figure 16, however, and knowing that modern DFIG wind turbines are generally capable of fault-ride through, it seems likely that the results shown in Figure 15 gives a better representation of the modern DFIG technology than the results shown in Figure 16. One other observation is that the applied control strategy will dominate the simulation result. Hence, as long as the actual control strategy of DFIG wind turbines are kept as a business secret by the wind turbine manufacturers and measurements are not available for comparison with simulations, the result of simulations can not be said to accurately represent any DFIG turbine. This goes not only for DFIG turbines, but also for wind turbines with full scale power electronic converters – the response of such turbines will be totally dominated by the applied control system. Simulations can still be useful, though results must be applied with care.

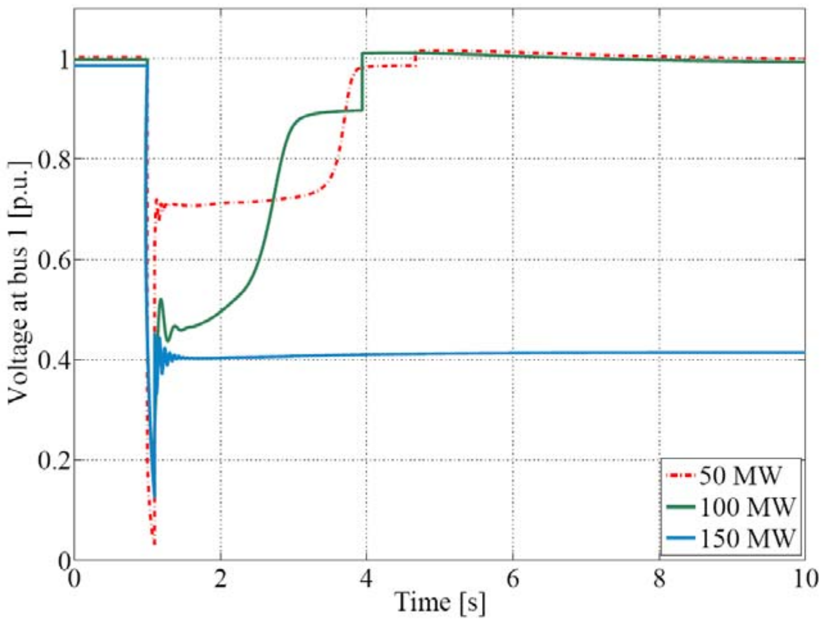


Figure 16: Simulation of DFIG with "static" crowbar protection. FCT is 100 ms.

4.6 Wind farm response to voltage dip with slow recovery

The ability of wind farms to ride-through a voltage dip followed by a slow voltage recovery as specified in Figure 17, and in accordance with [1], is assessed. The dip goes down to 0.15 pu and remains at this level for 0.4 s, thereafter it increases during 0.6 s to 0.7 pu and remains at this level for 9 s, before increasing to 0.9 pu. The reasoning behind the duration of the dip being 0.4 s is basically that this is the time it normally will take to trip a faulted line (according to the response time of the first and second zone protection systems being used in Norway). The reasoning behind the voltage at 0.7 pu for 9 s is not clear. The understanding of the authors is that in a grid operated according to the N-1 criterion (as is common practice), the tripping of a line after a fault should result in recovering to an acceptable voltage, i.e. minimum 0.9 pu, within a half second or thereabout, and not to 0.7 pu. Obviously, it is possible to think up situations that could result in such low voltage after a tripping, but such unlikely events should hardly be the dimensioning case for setting fault ride-through requirements to wind farms, at least not if this impose a significant technical issue (and hence cost) for wind farms.

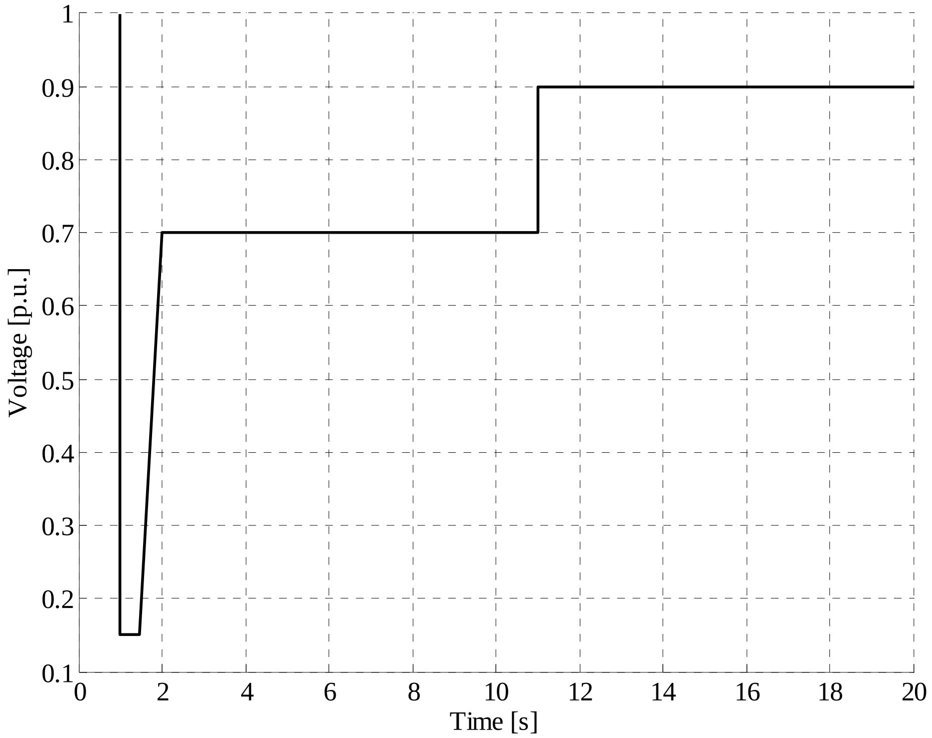


Figure 17: Voltage profile according to [1].

It is not easy to implement a meaningful simulation of a fault case that gives a voltage profile according to Figure 17. One possibility could be to simply impose such voltage profile on the connection point of the wind farm (BUS 5), but this would hardly reflect any real-life situation. One critical issue is that this would not reflect the change of the voltage angle during the fault, i.e. being a main challenge for fault ride-through of wind farms (or any other generators for that matter); hence the option of imposing the voltage profile is not any further considered here. Rather, for assessing if it is the voltage dip down to 0.15 pu that is the challenge, or if it is the 0.7 pu voltage for 9 s, the results of sections 4.3 to 4.5 are revisited. To this, Figure 18 shows a summary of the results obtained from sections 4.3 to 4.5.

It is seen that the critical clearing time (CCT) of the fault is depending on the short-circuit ratio S_k/P_n and on the applied wind farm technology. At a clearing time of 400 ms (as in accordance with the voltage profile in Figure 17 and the fault ride-through requirements given in [1]), the short-circuit ratio should be above 4.7 (DFIG), 8.0 (SCIG with SVC) and 9.6 (SCIG with no-load compensation). Indeed, these results are for the specific model grid and fault location, and quite different results may be obtained if another grid structure is applied (e.g. less inductive) and if the fault gave a smaller voltage dip. The point is that according to the simulation results, any modern wind farm is likely to be able to cope with a fault resembling that of the 0.15 pu requirement, though more challenging at weak grids. A less deep dip would obviously be easier to handle, and hence, then wind farms could be operated at weaker grids. The 0.7 pu requirement is more demanding. This appears from observing the simulated system responses in Figure 13 to Figure 15. If the voltage is not brought back up to closer to nominal after the dip, it is obviously harder to get back to stable operation.

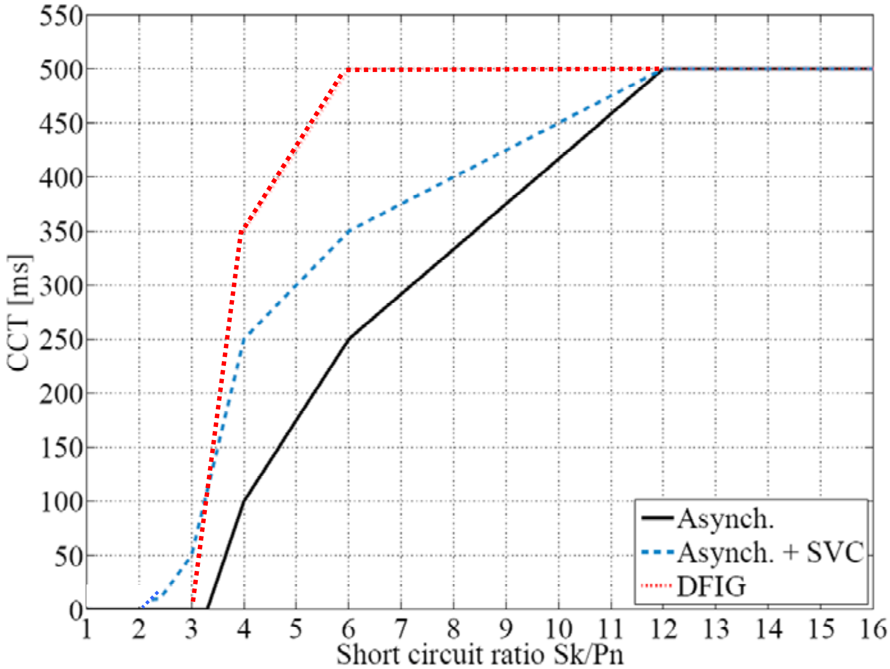


Figure 18: Critical clearing time (CCT) of fault according to simulation as a function of the short-circuit ratio.

Summing up on the assessment it seems reasonable to require fault ride-through of a dip with a duration of 0.4 s, i.e. in accordance with the response time for protection equipment to trip a faulted line. The dip going down to 0.15 pu may pose a challenge for connecting wind farms to (very) weak grids, e.g. $S_k/P_n < 10$ *depending on the wind farm technology, though must be judged also on the likelihood of such deep dips occurring. This is assessed in section 5. The requirement of 0.7 pu voltage for 9 s seems not well justified. Instead it is suggested that the voltage after the dip can return to 0.9 pu within a half second or thereabout.*

5 PROPAGATION OF VOLTAGE DIPS

This section summarizes some results based on a previous project [8] where the aim has been to assess how deep voltage dips can be expected at the wind generator terminals (as well as in other places in the network) depending on the location of a fault (three-phase short circuit). This is of main interest when specifying requirements for how deep voltage dips a wind turbine must be able to ride through.

It is obvious that a wind farm (or any generator) must <u>not</u> be designed to ride through a lasting fault on its own feeder or point of connection. The primary objective here is to illustrate the likely consequence of faults somewhat further out in the regional and transmission network.

The simulation model refers to the wind farm at Smøla (Smøla I and II, 148 MW). The wind farm has been modelled such that each radial (groups of 4-7 turbines) constitutes an equivalent wind turbine generator connected to the main substation transformer (point of connection) through a 22 kV cable and 0.69/22 kV transformer (Figure 19).

The wind farm model has been included within in the existing Nordel transmission system model.

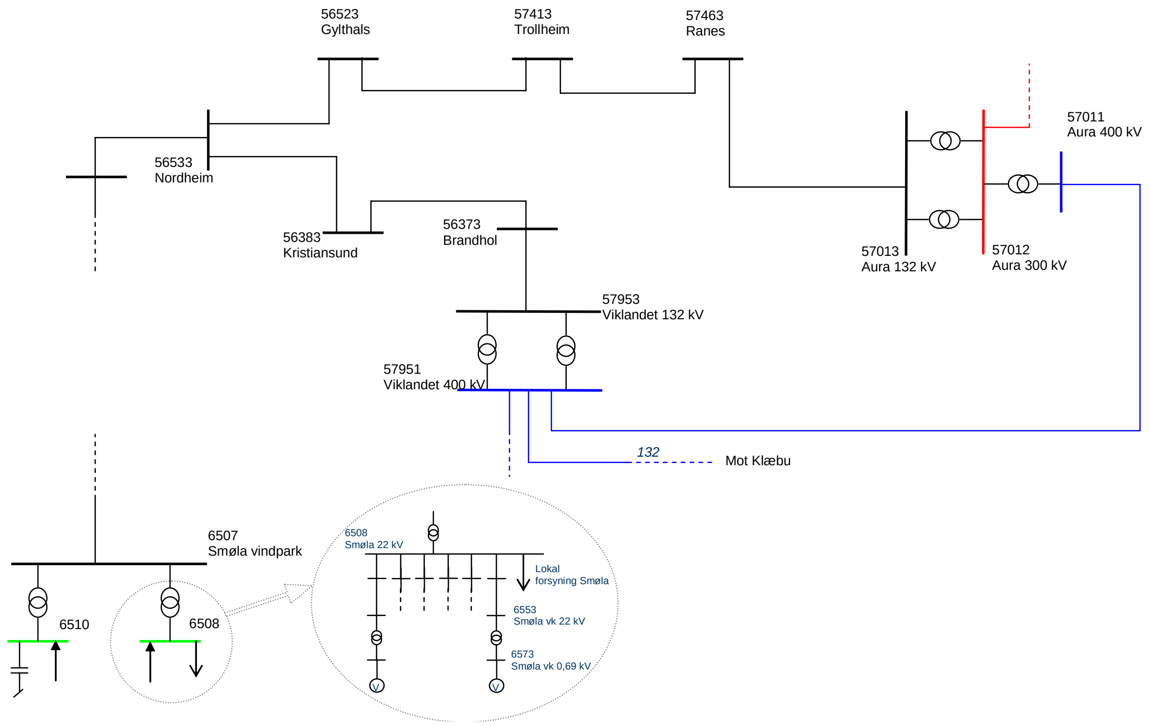


Figure 19: Single line diagram of Smøla wind farm‘s connection point to the 132 kV network and further to the central transmission network (300 kV and 400 kV).

5.1 Analyses

Dynamic analyses have been performed simulating the system responses to a temporary (100 ms) three-phase short circuit applied at different nodes and voltage levels in the network. The purpose is to map how large voltage dips can be expected at various nodes in the network, including the wind generators' terminals, depending on fault location.

Short circuit faults are simulated at the following nodes:

- Aura/Viklandet 400 kV
- Aura 132 kV
- Nordheim 132 kV
- Smøla 132 kV (connection point of wind farm at 132 kV)
- Smøla 22 kV (22 kV bus bar at 22/132 kV transformer)
- Smøla vk 22 kV (at 22 kV side of one of the wind turbine's transformer)
- Smøla vk 0.69 kV (at 0.69 kV side of one of the wind turbine's transformer).

See Figure 19 for more details about the network.

The analyses are performed assuming two different wind farm technologies. The first is based on fixed speed wind turbines with induction generators (equivalent to the actual installation) and fixed reactive compensation. The second set of analyses assumes variable speed wind turbines with doubly-fed induction generators. These are equipped with voltage source frequency converters rated 35% of nominal capacity of the generators.

The simulations are performed with the same type of wind power technology for Smøla stage 1 and stage 2, i.e. the units in the park are assumed to consist of either standard asynchronous generators or DFIGs. In reality the wind turbines at Smøla II consist of standard asynchronous generators with fast reactive power compensation. This reactive power compensation regulates the power factor within ± 0.98 (ref. 22 kV side). A simplified model for such reactive compensation is included in the simulation model to provide for a power factor $\cos\varphi = 1.0$ (ref. 22 kV side of the wind turbine transformer). It is reasonable to assume that a more accurate modelling of the compensation device will give somewhat more favourable results for the cases with standard asynchronous generators, but no significant differences are expected.

In both cases it is used a two-mass model of the wind turbine drive trains, i.e. a separate model for the turbine itself which is connected to the generator model through the mechanical shaft.

5.2 Discussion of results

The main results are summarised in Table 6 and 7 in the next sub-sections and further illustrated in Figure 20 through Figure 33. As an example it is seen that the voltage of a generator terminal does not go below 30% of nominal when the fault is applied near 132 kV Nordheim, which is the substation closest to Smøla (see Figure 22).

The low-voltage fault ride-through (FRT) capability of a power plant is closely related to transient stability, but it is a somewhat more general property. Possible control actions and protection during and after a fault should also be taken into account in the assessment.

In the discussion of FRT it is useful to remind about the motivation behind such requirements from a system perspective, which is to maintain operational security by avoiding cascading outages when faults occur in the network. Relating to wind power this is first of all important when the forecasted wind generation is taken into account when operational security limits are determined.

This is e.g. relevant with regard to determination of power import limits to mid-Norway. A higher limit is possible if the contribution from wind power (that could be up to 200 MW for Hitra/Smøla) can be taken into account. If the wind power contribution can not be relied upon an additional safety margin must be included to fulfil the standard n-1 security criterion.

In practice the operational risk depends on the faults/contingencies to be taken into account:

- Fault within or near the wind farm is normally not critical from a system perspective. Loss of the wind farm can then be regarded as an n-1 event and should always be within the security limit.
- Loss of a main transmission line to the area is usually the most critical contingency, and it is thus definitely important that such events do not lead to cascading outages.
- Faults and outages within the area of concern and within the regional transmission network can be more or less critical, and there is a need to assess whether cascading outages of wind farms have adverse consequences.

Based on the above, the main challenge regarding FRT is to enforce requirements to ensure that wind farms (and other generation) do not trip when the critical faults (from a system point of view) occur. This suggests the following considerations and conclusions for the case analysed in this section:

- The Smøla wind farm must be able to ride through a fault in the transmission grid (i.e. near Aura or Viklandet). In this case a faults at Aura leads to a voltage dips of less than 5% within the wind farm. This is clearly within the present requirement and should neither pose any technical problems.
- A fault near Smøla or within the wind farm may lead to voltage dips (down to 100% close to the fault location). However, this should not be critical from a system point of view, and there is no reason to require FRT in such cases.
- Faults in the regional transmission grid (between Aura 132 kV and Nordheim 132 kV) are the most interesting as a cascading trip of the wind farm could have adverse consequences for customers in a larger area. The results show that the wind farm may experience voltage dips down to 25-30% of nominal voltage in such cases.

By comparing the results in Table 6 with the case assuming wind turbines with doubly-fed induction generators (Table 7), we observe minor differences only in the initial voltage dips following a short circuit fault.

Thus, a reasonable requirement in these cases is that the wind farm should be able to ride through short voltage dips down to at least 25% of nominal voltage at the point of common connection (in this case at Smøla 132 kV).

It is furthermore interesting to note that the (apparently) most critical fault at 132 kV Nordheim does not lead to very significant voltage dips at the individual wind generators’ 0.69 kV terminals, even though the voltage at 132 kV is down to 10% of nominal. This is very much due to the short circuit current contribution from the induction generators themselves. Similar contribution to short circuit currents can not be expected if wind turbines are grid connected by full scale frequency converters, which highlights the need for separate models and separate analyses for the various wind turbine technologies.

5.3 Results

5.3.1 Standard asynchronous generator

Table 6 shows the retained voltage at different nodes with a three phase short circuit at different nodes. The voltage is reported for two time instants; when the fault occurs (t = 0+ s) and when it is cleared (t = 0,1 s).

Table 6: Retained voltage at different nodes with a three phase short circuit. Wind turbine with constant rotational speed. Standard asynchronous generator.

Node where 3ph SC is applied:		Retained voltage [pu] at each node, when fault occurs (t = 0+ s) and after 100 ms (t = 0,1 s)													
		Aura 400		Aura 132		Nordheim 132		Smøla 132		Smøla 22		Smøla vk 22		Smøla vk 0,69	
Node name	Node number[1)]	t = 0+ s	t = 0,1 s	t = 0+ s	t = 0,1 s	t = 0+ s	t = 0,1 s	t = 0+ s	t = 0,1 s	t = 0+ s	t = 0,1 s	t = 0+ s	t = 0,1 s	t = 0+ s	t = 0,1 s
Aura 400	57011	0.0	0.0	0.31	0.26	0.70	0.58	0.74	0.61	0.82	0.67	0.82	0.67	0.85	0.70
Aura 132	57013	0.45	0.44	0.0	0.0	0.63	0.51	0.68	0.54	0.78	0.61	0.78	0.61	0.82	0.64
Nordheim 132	56533	0.94	0.94	0.91	0.90	0.0	0.0	0.14	0.09	0.40	0.24	0.40	0.23	0.51	0.30
Smøla 132	6507	0.96	0.95	0.93	0.93	0.30	0.28	0.0	0.0	0.30	0.17	0.30	0.16	0.43	0.23
Smøla 22	6508	0.98	0.98	0.97	0.97	0.70	0.65	0.56	0.51	0.0	0.0	0.69	0.55	0.75	0.58
Smøla vk 22	6553	0.98	0.98	0.98	0.98	0.81	0.76	0.73	0.66	0.80	0.70	0.0	0.0	0.19	0.08
Smøla vk 0.69	6573	0.99	0.99	0.99	0.99	0.92	0.88	0.88	0.84	0.92	0.86	0.59	0.53	0.0	0.0

[1)] See single line diagram in Figure 19

Figure 20 – Figure 26 show the retained voltage at different nodes for a short circuit faults applied to a defined node (i.e. rows in Table 6).

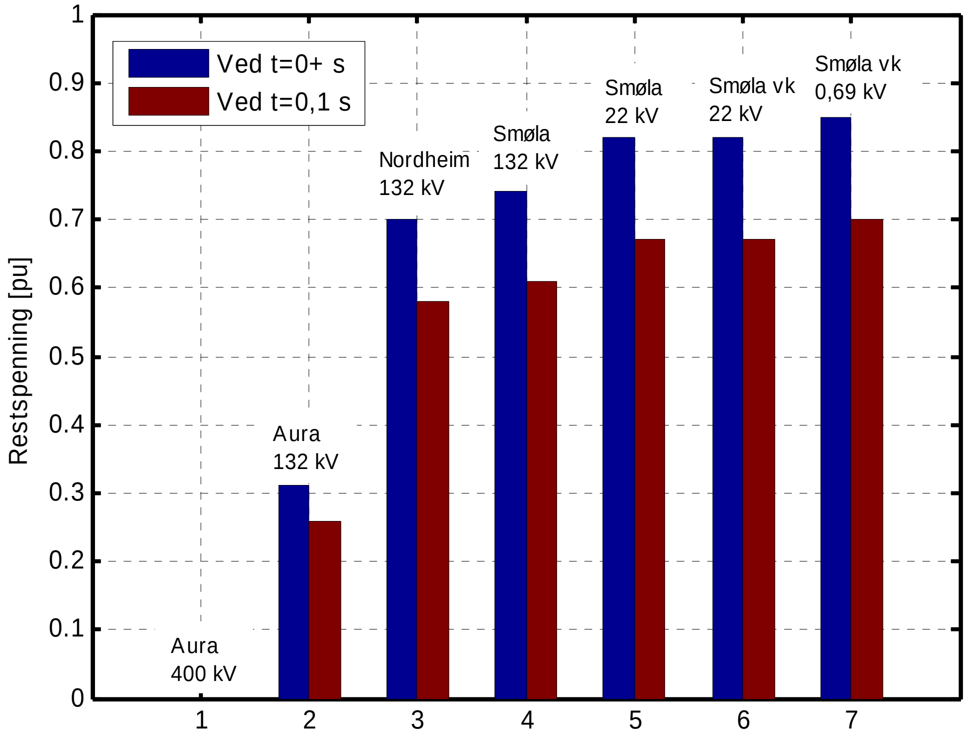


Figure 20: Retained voltage at different nodes with a short circuit applied at Aura 400 kV.

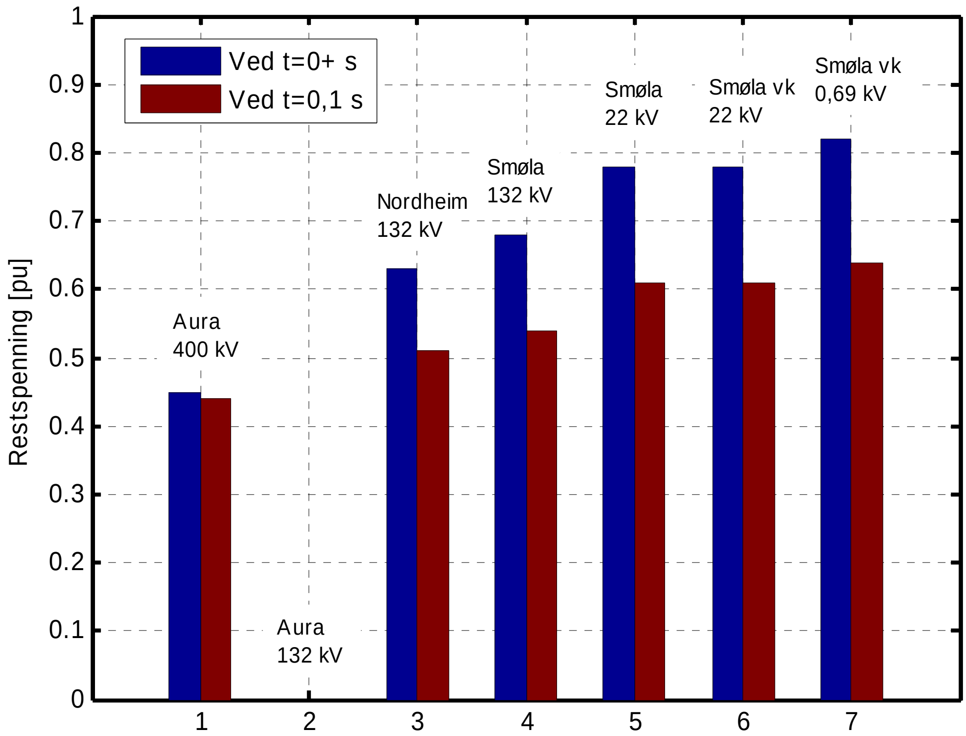


Figure 21: Retained voltage at different nodes with a short circuit applied at Aura 132 kV.

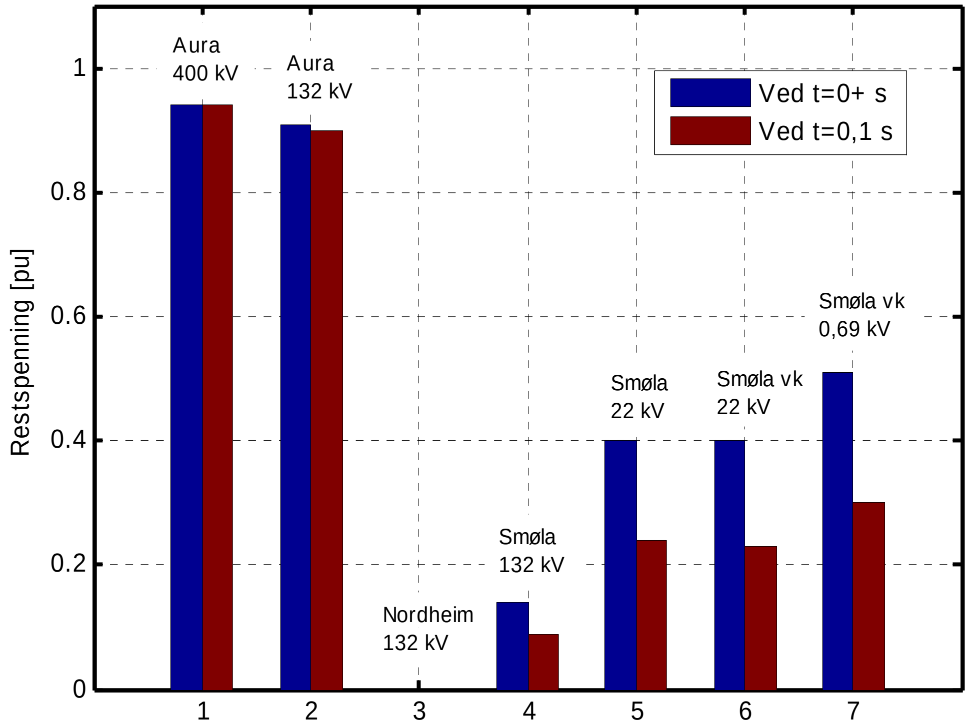


Figure 22: Retained voltage at different nodes with a short circuit applied at i Nordheim 132 kV.

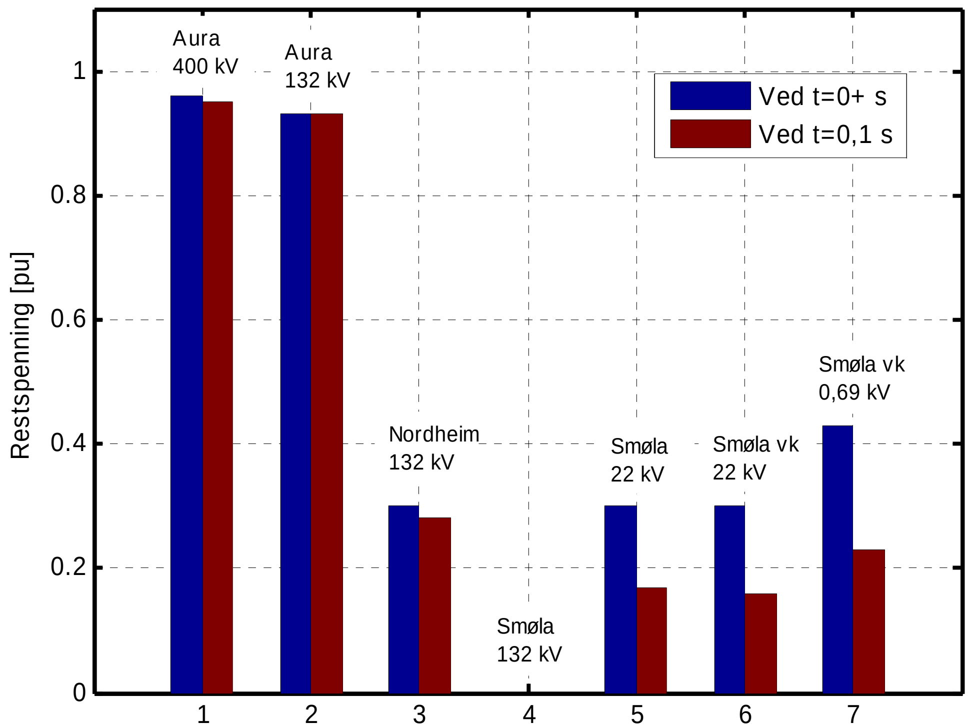


Figure 23: Retained voltage at different nodes with a short circuit applied at Smøla 132 kV.

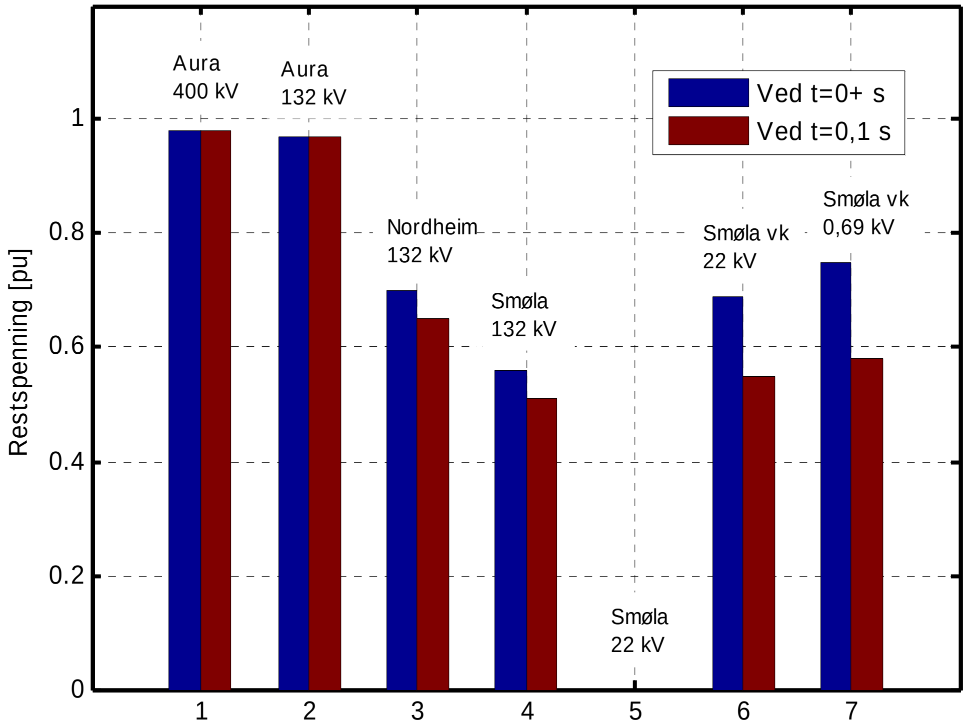


Figure 24: Retained voltage at different nodes with a short circuit applied at Smøla 22 kV.

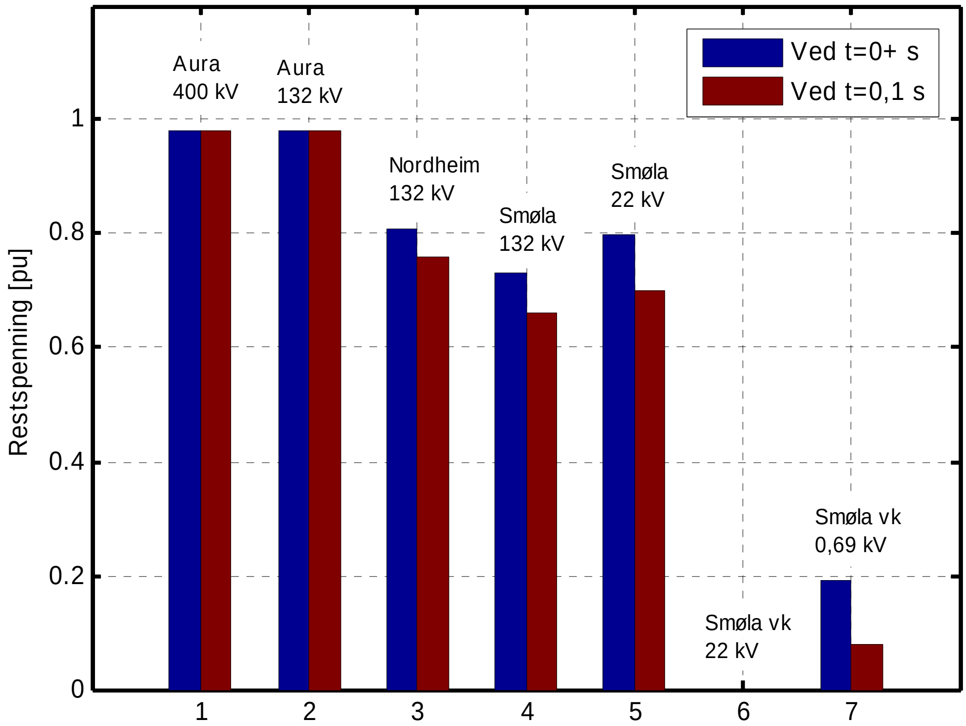


Figure 25: Retained voltage at different nodes with a short circuit applied at Smøla vk 22 kV.

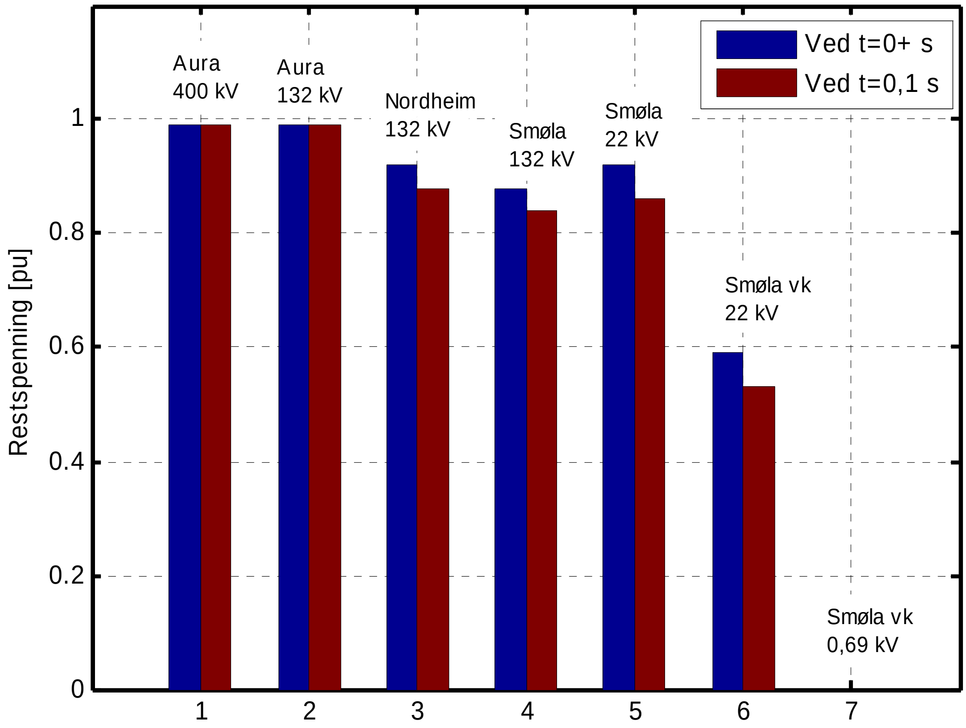


Figure 26: Retained voltage at different nodes with a short circuit applied at Smøla vk 0.69 kV.

5.3.2 Doubly-fed induction generator DFIG

Table 7 shows the retained voltage at different nodes with a three phase short circuit at different nodes. The voltage is reported for two moments; when the fault occurs (t = 0+ s) and when it is cleared (t = 0.1 s).

Table 7: Retained voltage at different nodes with three phase short circuit. Wind turbines with DFIG.

Node where 3ph SC is applied:		Retained voltage [pu] at each node, when fault occurs (t = 0+ s) and after 100 ms (t = 0,1 s)													
		Aura 400		Aura 132		Nordheim 132		Smøla 132		Smøla 22		Smøla vk 22		Smøla vk 0,69	
Node name:	Node number:[1)]	t = 0+ s	t = 0,1 s	t = 0+ s	t = 0,1 s	t = 0+ s	t = 0,1 s	t = 0+ s	t = 0,1 s	t = 0+ s	t = 0,1 s	t = 0+ s	t = 0,1 s	t = 0+ s	t = 0,1 s
Aura 400	57011	0.0	0.0	0.31	0.26	0.70	0.58	0.75	0.60	0.82	0.65	0.82	0.63	0.86	0.65
Aura 132	57013	0.45	0.44	0.0	0.0	0.63	0.51	0.69	0.53	0.78	0.59	0.78	0.57	0.82	0.59
Nordheim 132	56533	0.94	0.97	0.90	0.90	0.0	0.0	0.15	0.07	0.41	0.18	0.40	0.18	0.53	0.24
Smøla 132	6507	0.95	0.95	0.93	0.93	0.30	0.28	0.0	0.0	0.28	0.14	0.28	0.13	0.44	0.20
Smøla 22	6508	0.98	0.98	0.97	0.97	0.69	0.65	0.56	0.50	0.0	0.0	0.69	0.52	0.76	0.54
Smøla vk 22	6553	0.98	0.98	0.98	0.97	0.81	0.76	0.73	0.66	0.80	0.70	0.0	0.0	0.20	0.10
Smøla vk 0.69	6573	0.99	0.99	0.99	0.99	0.92	0.89	0.88	0.84	0.92	0.86	0.59	0.53	0.0	0.0

1) See single line diagram in Figure 19.

Figure 27 – Figure 33 show the retained voltage at different nodes for a short circuit faults applied to a defined node (i.e. rows in Table 7).

Comment Statnett comment Ch5.

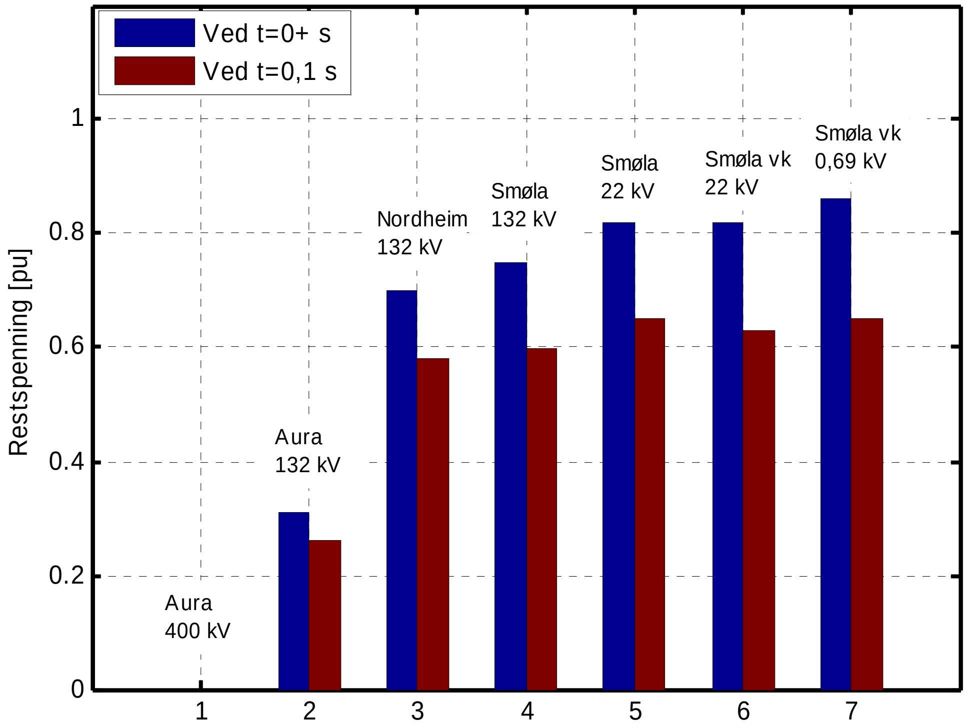


Figure 27: Retained voltage at different nodes with a short circuit applied at Aura 400 kV.

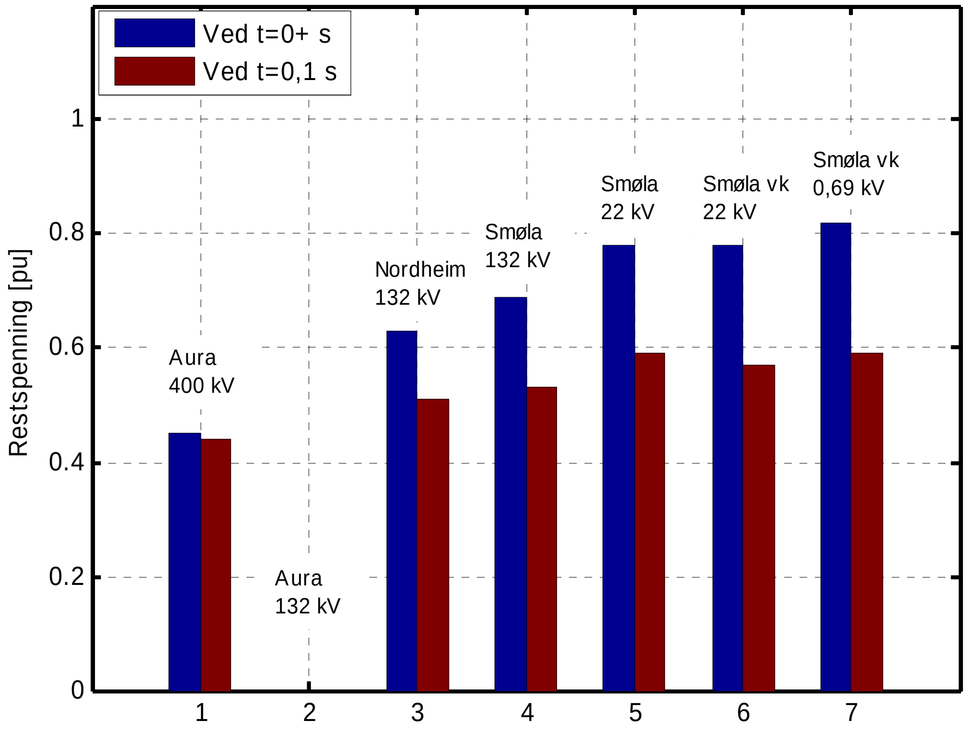


Figure 28: Retained voltage at different nodes with a short circuit applied at Aura 132 kV.

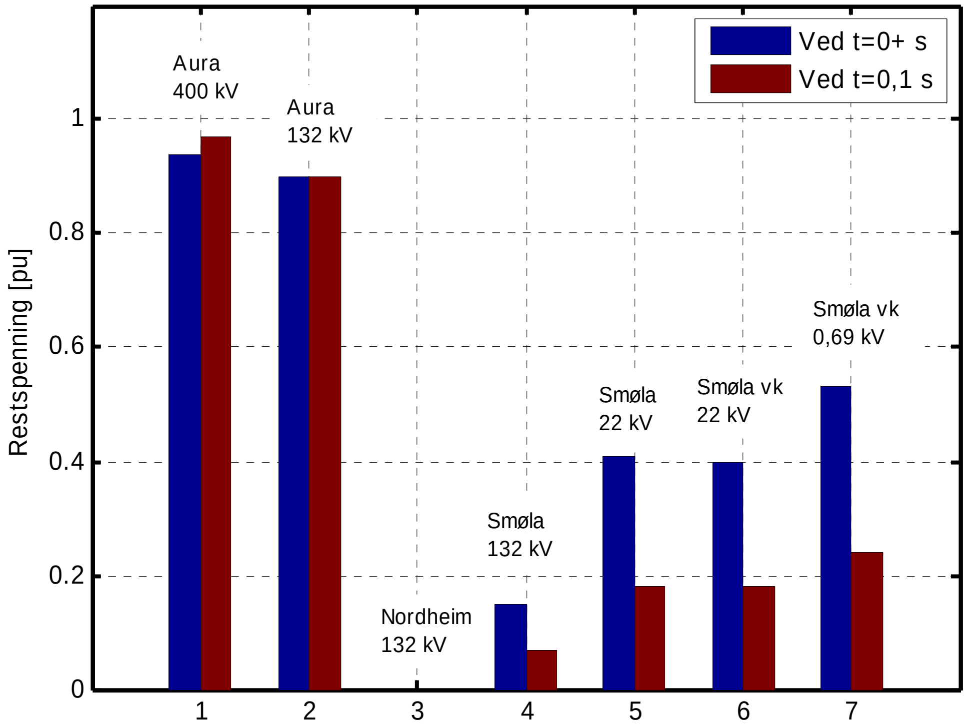


Figure 29: Retained voltage at different nodes with a short circuit applied at Nordheim 132 kV.

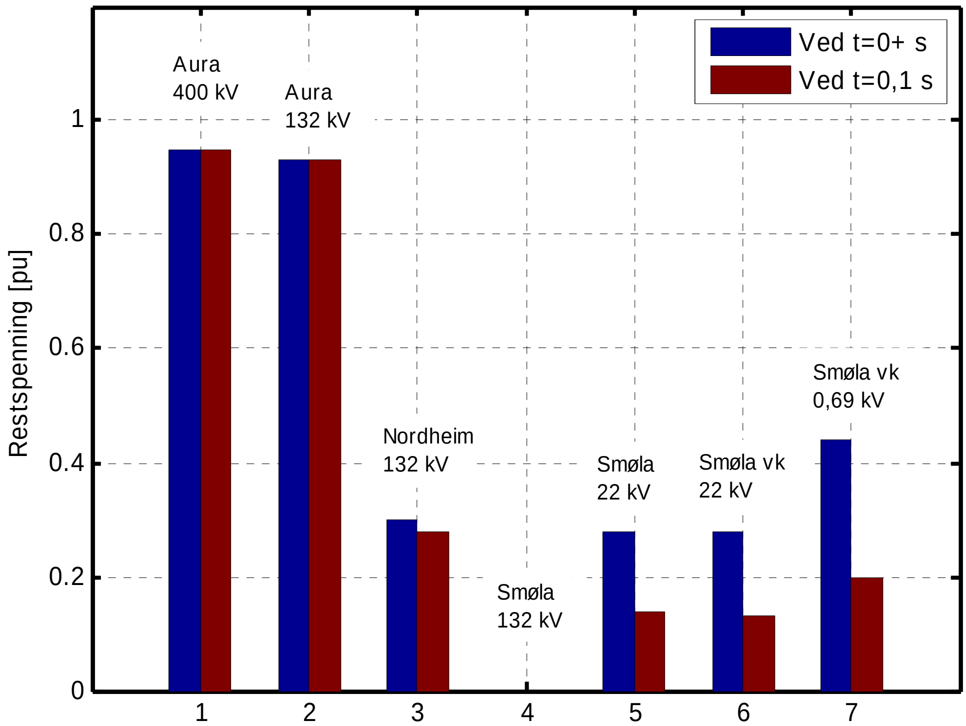


Figure 30: Retained voltage at different nodes with a short circuit applied at Smøla 132 kV.

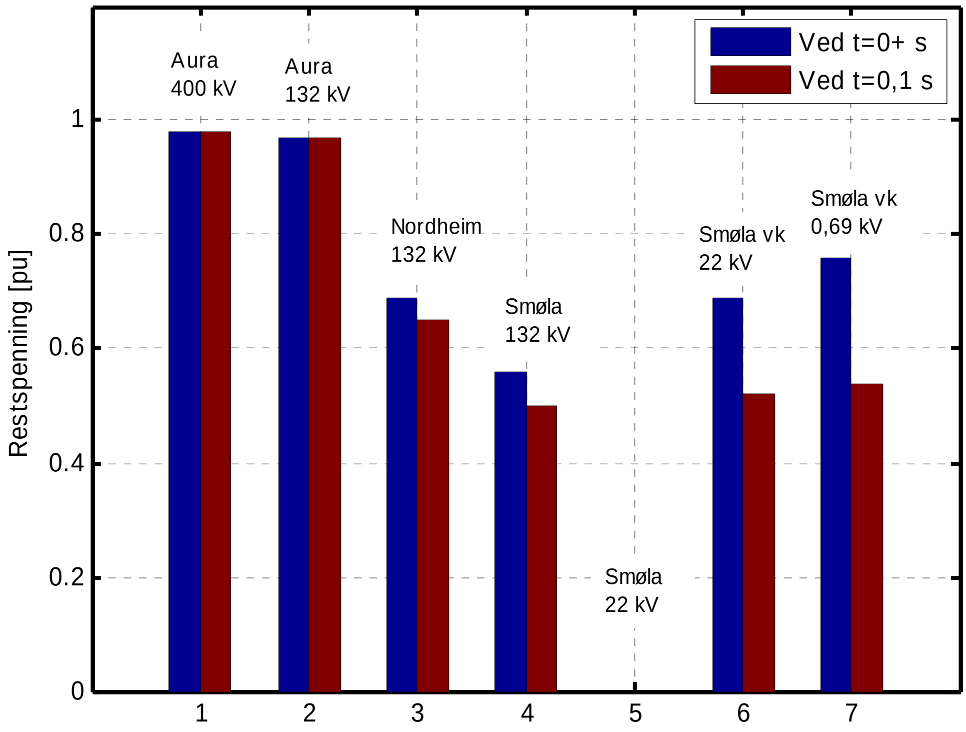


Figure 31: Retained voltage at different nodes with a short circuit applied at Smøla 22 kV.

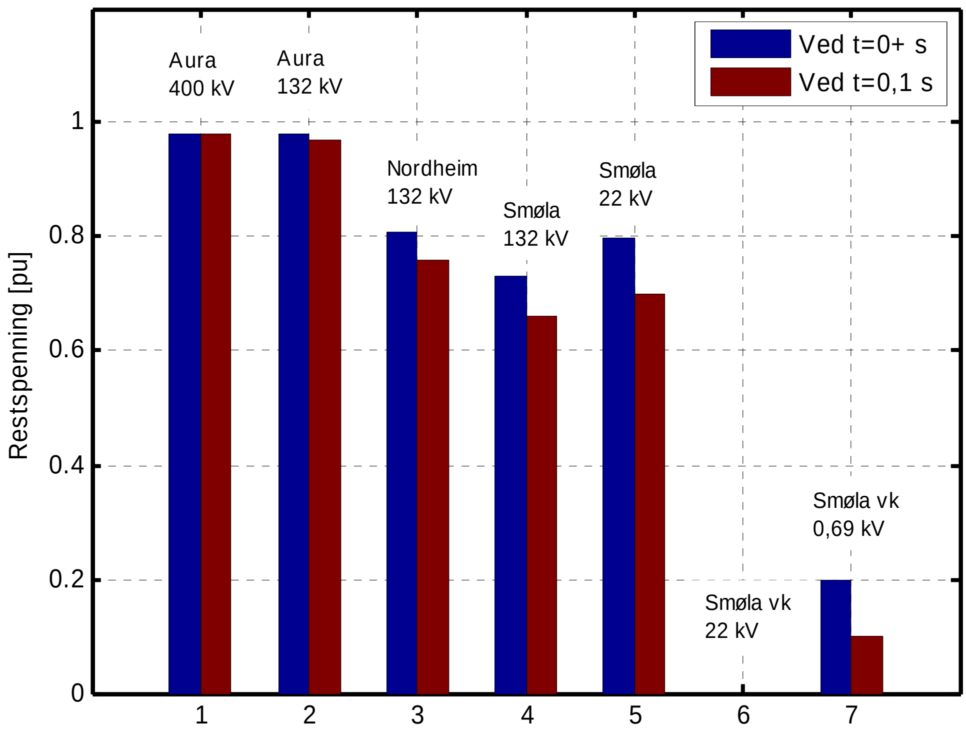


Figure 32: Retained voltage at different nodes with a short circuit applied at Smøla vk 22 kV.

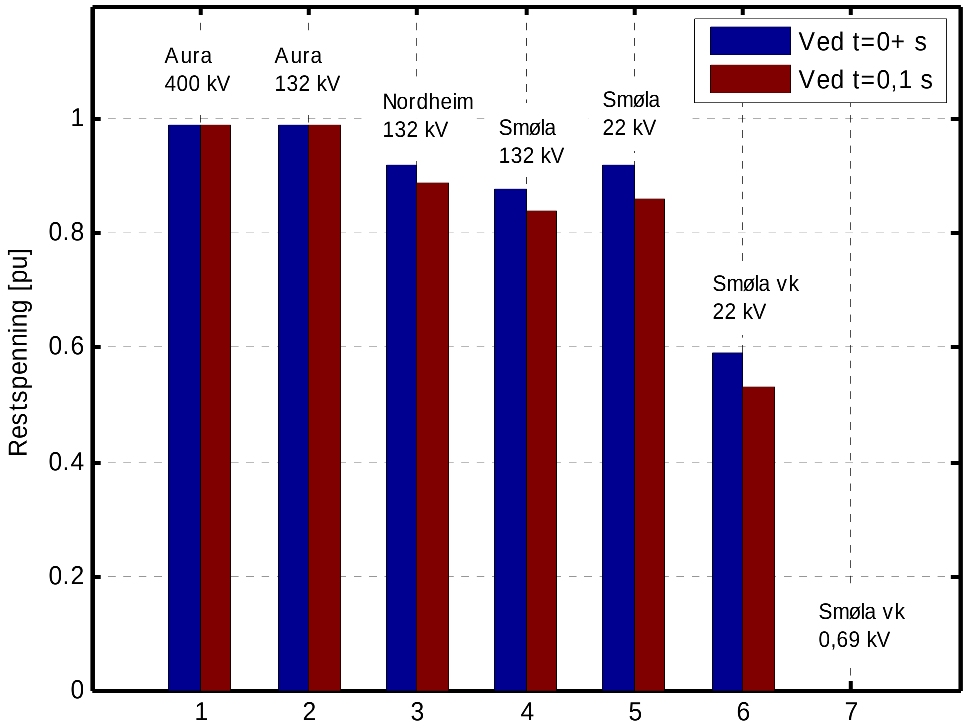


Figure 33: Retained voltage at different nodes with a short circuit applied at Smøla vk 0,69 kV.

6 POWER CONTROL AND IMPACT ON FREQUENCY STABILITY

It is important to distinguish grid codes from the actual requirements in system operation. One example concerns the provision of primary active power reserves. Although grid codes states that wind farms shall be *able* to operate at a limited power output, this is not the same as saying that the wind farm shall actually operate in this mode. Limitation of wind farm power output to facilitate an active power reserve will mean loss of energy, and probably active power reserves can be obtained at less cost from other generation. The ability of wind farms to limit their active power output according to a remote set-point value can still be useful, e.g. in case of temporary grid congestions.

All generating equipment in an electric system is designed to operate within a certain frequency range, but usually optimised to run normally within a narrow frequency band around 50 (or 60) Hz.

The frequency range where all generating plants are required to operate continuously is specified in the grid codes. Commonly this is between 49.5 and 50.5 Hz in Europe. Another wider frequency range are normally also specified where generators must be able to operate for different periods of time, possibly at reduced power output. This range may be between 47–47.5 Hz (minimum) and 52 Hz (maximum) [6], and is a requirement to ensure that generation remain connected in critical contingency situation and not leading to cascading outages.

The relatively small size of the test system model (section 4.2) makes it less suited to study frequency stability and primary reserves unless the transmission system is modelled in some more details. However some general conclusions can be made based on previous studies done on the topic. In general terms the frequency deviation depends very much on the share of wind power replacing conventional generation and the wind farm control strategy. As the share of wind power increases, so do also the expected frequency variations.

Choices of technology and control functionality make some difference. Variable speed wind turbines, including wind turbines with DFIGs are coupled to the grid via frequency converters. The decoupling of the machines from the grid by the converter results in the decoupling of the mechanical speed of the wind power generators from the grid frequency. In other words the variable speed wind turbines do not by themselves contribute significantly to the overall system's inertia. This will normally lead to an initial steeper drop in frequency with these technologies.

The behaviour after the transient, however, is mainly determined by the control strategy of the wind farms. This implies that variable speed wind turbines have a much greater potential to be able to contribute positively to primary frequency control, as described in several papers, e.g. [9] and [10].

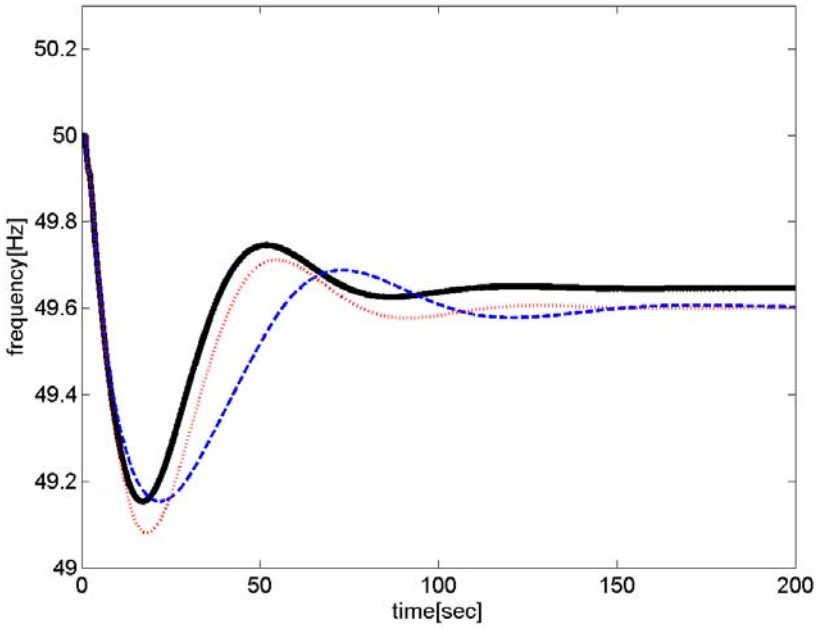
A study more relevant for the Norwegian power system is described in [12]:

It is clear that a wind farm must be controlled to limit their power output below the available energy optimal point if they shall be able to supply sustained primary control action as spinning reserves. This is, however, normally considered less cost effective than utilizing the existing (hydro) generators for primary frequency control response, thus allowing the wind turbine to extract maximum energy from the wind operation at their operational optimum.

The objective of this investigation [12] was to determine if optimal controlled wind turbines (variable or fixed speed) were able to contribute to the dynamic primary frequency response for a shorter period of time. A Nordic grid model was used and adjusted to simulate a case where a maximum capacity of 3000 MW wind power was installed in the western and mid-parts of Norway. The turbines were equipped with frequency control functions to actively contribute to the frequency response. The results showed that fixed speed machines were successfully able to contribute when operated at maximum power (above rated wind speeds) if they where allowed to overload for a shorter period of time. The variable speed wind turbines were able to contribute positively with spinning reserves at both partial load (by actively controlling the inertial response of the variable speed turbines), and at maximum power if they were allowed to overload.

A simulation study was performed to investigate the system (and frequency) response to major loss of generation. **Figure 34** illustrates that even though the total installed capacity of hydro generators with normal frequency droop control is significantly reduced in the two cases with 3000 MW installed wind power, the frequency response is only slightly better in the case without wind power. It is also noted that the initial frequency drop is about the same in all three cases. This is due to the natural (in the case of fixed speed turbines) or controlled (in the case of variable speed turbines) inertia response of the wind farms.

Wind farm operated at partial load (below rated power output)



Wind farm operated at full load (at rated power output)

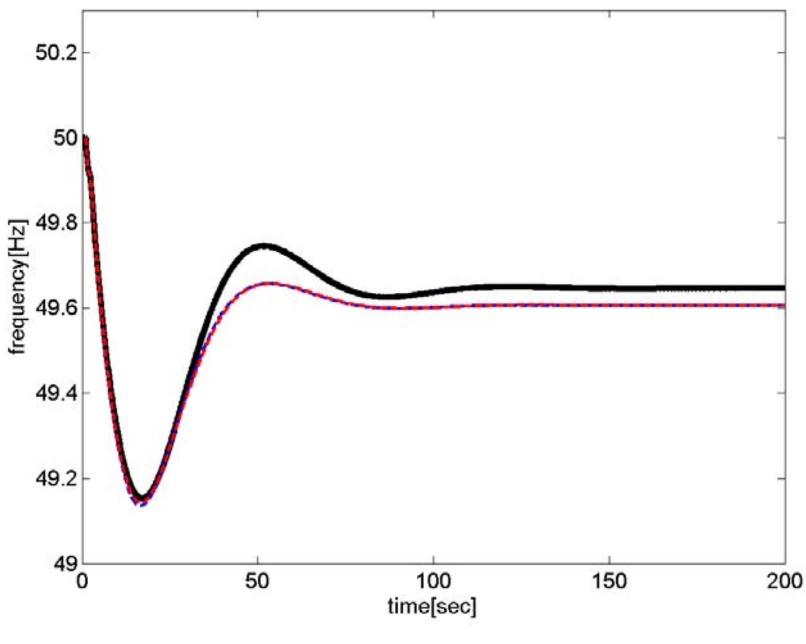


Figure 34: Frequency responses for case without wind power (solid curve, black), fixed speed wind turbines (dotted curve, red) and variable speed wind turbines (dashed curves, blue). Partial load is on upper graph and full on lower graph.

7 INTERNATIONAL GRID CODES

In this report the focus is on the most important and relevant requirements from a Norwegian point of view, namely reactive power compensation, voltage control and wind farm response to voltage dips (fault ride-through).

The various requirements that are included in grid codes are more or less important depending on the power system characteristics and network topologies where they apply. In this section we briefly discuss some of these requirements and under what conditions they may be of interest.

The details of the grid codes naturally depend on the needs in various countries. In the very large UCTE interconnection with strong and highly meshed transmission networks low-voltage fault ride-through capabilities is very important in order to avoid cascading outages that could lead to blackouts. One other important issue is frequency disturbances as was clearly illustrated by the 4. November 2006 disturbance [16] when the UCTE network was split in three separate islands resulting from grid faults originated in Germany. The separation of the south-western parts of Europe having at that time a deficit of power generation led to an under-frequency situation and loss of load. As a consequence of the under-frequency 2800 MW of wind power generation in Spain also tripped because of the under-frequency relay settings and thereby contributing to worsen the frequency drop.

In Ireland (including Northern Ireland) the situation different, having a power system that is not synchronously interconnected to other countries. In the much smaller power system frequency control and primary reserves becomes more important issues. A high share of wind power replacing conventional generation is a potential concern regarding frequency stability. Therefore the Irish grid code was early in specifying requirements for wind farm to be able to provide primary (frequency controlled) reserves.

Figure 35 illustrates how requirements for power control as a function of grid frequency are specified in various countries. All countries specify that it must be possible to reduce power output at over-frequency, but only the Irish code specify as a default the requirement to provide active reserves (additional power output) in under-frequency situations.

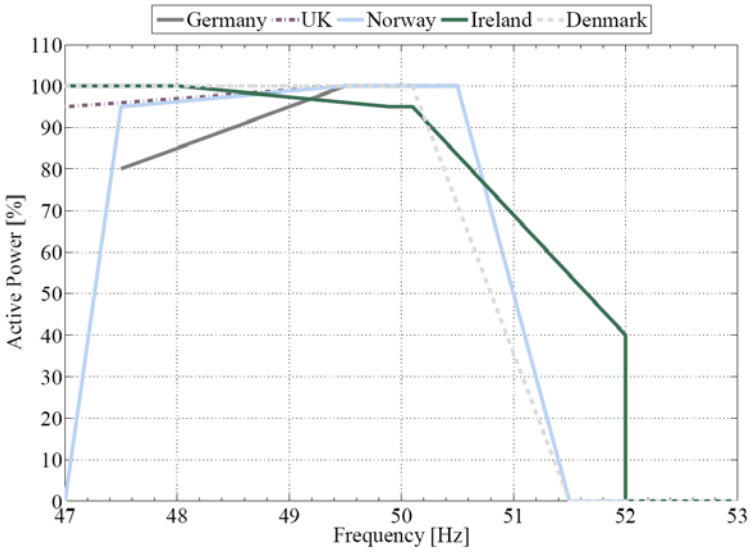


Figure 35: Frequency response required in Germany, UK, Denmark, Ireland and Norway

Western Denmark has a very high penetration of wind power, but unlike Ireland, Western Denmark is connected synchronously to the UCTE system, so frequency control and primary reserves are not necessarily the largest problem. On the other hand, secondary control and balancing is a real issue of concern.

In order to cope with the large penetration of wind, additional power control strategies may be necessary. Therefore, the grid code by Energinet.dk specify requirements for various power control functionalities, as illustrated in Figure 36 and further explained below.

1. Absolute power limitation: In this type of power control, the power output of the wind farm will never exceed a preset maximum, even if more power can be extracted from the wind. Below that maximum power, the wind farm power can be controlled to extract maximum power. The main reason for this requirement is primarily to ensure operational security, but there can also be economic motivations. In a situation when the demand is low and wind power is higher than forecasted, the system operator must acquire balancing power (down-regulation) to handle the situation. Limiting the power output from the wind farms may be the cheapest alternative, depending on the available offers in the balancing markets. This is e.g. a relevant problem in West-Denmark.

2. Ramp rates limitation: This type of control is in principle similar to active power limitation, in this case with time-variable set points for both ramping up and down. The latter is a critical issue for power system security. Abrupt wind power reductions can be limited by forecasting the periods with expected high negative gradients. In such cases, wind farm output is reduced in advance to limit the power gradient to a value which can safely be accommodated by the power system.

3. Delta production constraint: The power production is limited below the available power by a fixed amount. This type of power control allows the wind farm to take part in the primary frequency control. If there is a drop in the frequency, the wind farm is able to increase the power and help maintain the frequency.

4. Balance Regulation: In this case, the wind farm must be able to reduce/increase rapidly its power output, partly as an absolute power limitation and partly as a desired power gradient MW/min. This functionality is first of all needed if wind farms, due to e.g. local network constraints, must be able to contribute in balancing production and consumption of active power in the grid.

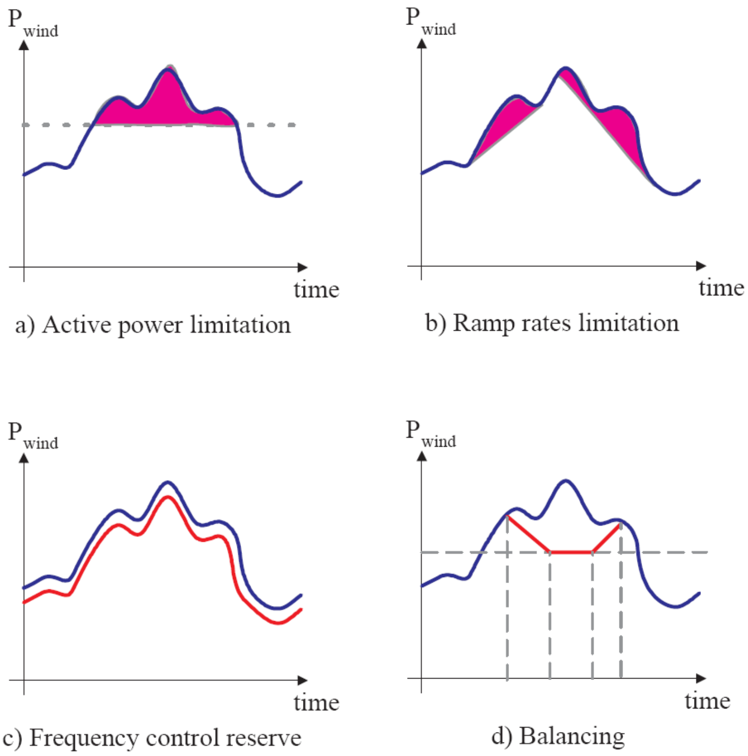


Figure 36: Different modes of advanced control of wind farms. The blue line shows the unrestricted wind farm power output (determined by wind conditions). The red line or area shows the controlled mode of operation (Ref: Energinet.dk).

8 SUMMARY AND CONCLUSIONS

This report considers grid codes for connecting wind farms to the electricity grid, and may be used as a background document when considering technical requirements for connecting new wind farms.

Basically, grid codes specify technical requirements for how a wind farm shall be able to operate and are typically developed by the Transmission System Operator (TSO) to facilitate rules fitted to system needs. Grid codes are hence system specific and may vary in the items covered, level of detail and stated requirements. The focus point of this report is on the grid code specified by the Norwegian TSO (Statnett) by end 2005. This code, being strictly a guideline, includes the following items for wind farms bigger than 10 MVA and connected to the regional or main transmission grid:

1. Operation at varying grid frequency (normal 49.0-50.5 Hz, limited 47.0-51 Hz)
2. Operation at varying grid voltage (normal +/- 10 %, reactive capability cosφ = +/- 0.91 ref wind farm point of grid connection)
3. Active power control (remote control of maximum production, system for ramp-rate limitation and participation in frequency control)
4. Reactive power control (system to operate at two modes: a) set-point cosφ, b) active voltage control with droop)
5. Operation in case of grid faults or abnormal grid voltages (fault ride-through for voltages at the grid connection point of the wind farm down to 0.15 pu and with a slow recovery)
6. Verification of characteristic properties (analyze impact on system using simulation model and make numerical wind farm model available for Statnett for simulation using PSS/E or similar)

The specification of requirements to wind farms in terms of grid codes is generally found to be rational. The question is rather exactly what the requirements shall be, and of those suggested by Statnett, the following two have been up for debate:

- reactive power capabilities (cosφ = +/- 0.91)
- fault ride-through for voltages down to 0.15 pu with a slow recovery

In this report these two requirements are assessed by numerical simulations.

The requirement on reactive power capability is viewed as a means to say that wind farms shall generally be able to assist in maintaining a stable grid voltage. Assessing typical grid conditions for connecting large wind farms the analysis prepared in this report concludes that it is reasonable to require that wind farms shall be able to contribute with reactive power corresponding to a power factor between unity and 0.95 (capacitive and inductive). The reasoning behind this is that reactive power from wind farms is mainly needed to help maintain an acceptable voltage level at the connection point of the wind farm. In strong grids the voltage is expected not be changed very significant by the wind farm, and hence this will not be setting any particular requirement to the reactive contribution from wind farms (except maybe saying that the power factor shall be close to unity as to minimize grid losses). In weak grids the voltage may deviate significantly due to in-feed power from a wind farm (or any other generator for that matter), and hence this may set requirements to the reactive contribution from the wind farm (or other generator). The analysis shows that in such weak grids, and excluding the extreme case of $S_k/P_n = 1$, an amount of reactive power corresponding to a power factor between unity and 0.95 (capacitive and inductive) is sufficient for maintaining a stable voltage. Indeed, the analysis presented in this report is not a substitute for any detailed grid study that should be prepared as part of planning a large wind farm, and such detailed assessment may come up with suggesting different reactive power requirements. This may be due to special grid conditions not taken into account in this report. Such requirements should however then be the exception and not the general rule.

The requirement on fault ride-through is assessed considering the ability of various wind farm technologies to meet the requirement, and the likelihood of the given voltage dip and slow recovery to appear as a consequence of a short-circuit fault in the up-stream regional or transmission network. Summing up on the assessment it seems reasonable to require fault ride-through of a dip with a duration of 0.4 s, i.e. in accordance with the response time for protection equipment to trip a faulted line. The dip going down to 0.15 pu may pose a challenge for connecting wind farms to (very) weak grids, e.g. $S_k/P_n < 10$ depending on the wind farm technology, though must be judged also on the likelihood of such deep dips occurring. Possibly, a reasonable requirement could be a dip down to 0.25 pu. The requirement of 0.7 pu voltage for 9 s seems not well justified. Instead it is suggested that the voltage after the dip can return to 0.9 pu within a half second or thereabout.

This report also includes a brief on wind turbine technology, power control and impact on frequency stability, and some issues on international grid codes.

In general, it is so that grid codes for wind farms are a rather new issue, hence it must be expected that these will be adjusted over time, possibly harmonized between countries, also illustrated by the big number of international papers dealing with the subject of grid codes for wind farms.

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APPENDIX A: NOMENCLATURE

ψ	network impedance phase angle (rad)
$cos\varphi$	power factor = P/S
H_g	generator inertia (s)
H_t	turbine inertia (s)
k	shaft stiffness (pu torque/electrical rad)
Q	reactive power (var)
P	active power (w)
R	resistance (ohm)
X	inductance (ohm)
S_k	short-circuit apparent power (VA)
S	apparent power (VA)
U	voltage (V)
Z	impedance (ohm)

CCT	Critical clearing time (s)
DFIG	Doubly-fed induction generator
FCT	Fault clearing time (s)
FRT	(low-voltage) fault ride-through
SCIG	Squirrel cage induction generator
SVC	Static var compensator
TSO	Transmission System Operator

APPENDIX B: TEST SYSTEM AND NUMERICAL MODEL DATA

Test system

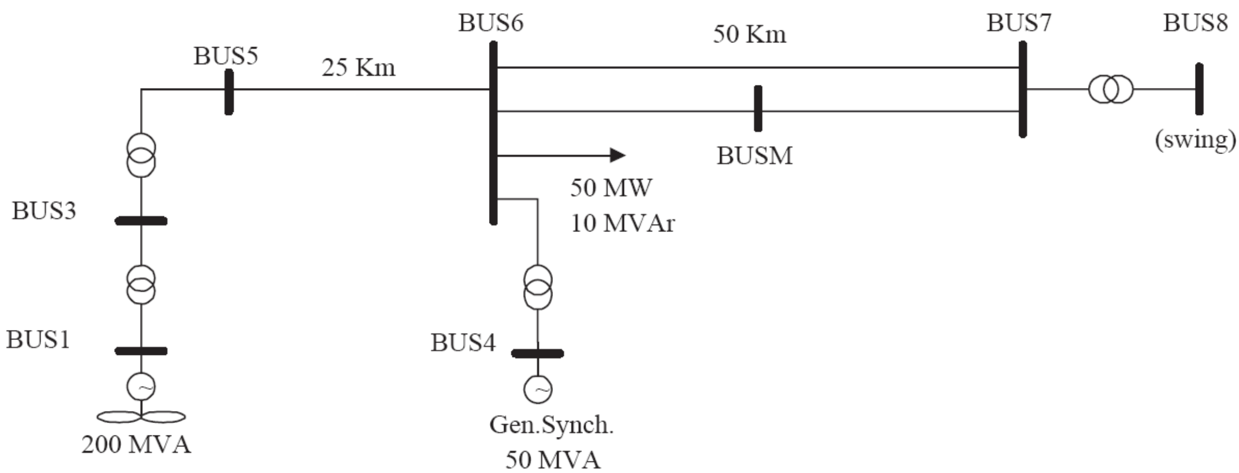

Figure 37: Single line diagram of the test system

Table 8: Main components of test system. The line data are according to [18], pp. 813.

Component	**Node(s)**	**Capacity / rating**	**Comments**
Radial line connecting the wind farm	BUS5-BUS6	145 kV R=0.021 Ω/km X=0.210 Ω/km C_d =26.52 nF/km	25 km
Regional transmission network, parallel lines	BUS6-BUS7	Each line: 145 kV R=0.021 Ω/km X=0.210 Ω/km C_d =26.52 nF/km	Each line assumed: 50 km
Local generator	BUS6	50 MW / 20 kV (PV-node in power flow)	Hydro power plant with synchronous generator
Local load	BUS6	P = 50 MW, Q = 10 Mvar	
Wind farm	BUS3	Various	Aggregated wind farm models. Various technologies.

The system is modelled in SIMPOW. Here the lines are modelled as TYPE 12 with R, X and B values given in per unit. The parameters of the line in per unit on 100 MVA, 145 kV base are:

$$Z_{BASE} = \frac{U_{BASE}^2}{S_{BASE}} = \frac{\left(145 \cdot 10^3\right)^2}{100 \cdot 10^6} = 210$$

$$R_{p.u.} = \frac{R}{Z_{BASE}} = \frac{0.021}{210} = 0.0001 pu / km$$

$$X_{p.u.} = \frac{X}{Z_{BASE}} = \frac{0.210}{210} = 0.001 pu / km$$

$$B_{p.u.} = \omega \cdot C_d \cdot \frac{1}{Y_{Base}} = 2 \cdot \pi \cdot f \cdot C_d \cdot Z_{BASE} = 2 \cdot \pi \cdot 50 \cdot 26.52 \cdot 10^{-9} \cdot 210 = 0.00175 pu / km$$

SIMPOW optpow file of the test network

```
        VtA network model

30/01/2007
**  vta.optpow  **

GENERAL
 SN=100
 LBASE=100
END

NODES
 BUS1  UB=0.69  AREA=1
 BUS3  UB=20.0  AREA=1
 BUSM  UB=145   AREA=1
 BUS4  UB=20    AREA=1
 BUS5  UB=145   AREA=1
 BUS6  UB=145   AREA=1
 BUS7  UB=145   AREA=2
 BUS8  UB=300   AREA=2
END
TRANSFORMERS
 BUS1  BUS3  SN=200   UN1=0.69  UN2=20.0 ER12=0.0090  EX12=0.0550  FI=0.0 NCON=0
 BUS3  BUS5  SN=250   UN1=20    UN2=145  ER12=0       EX12=0.15    NCON=0
 BUS4  BUS6  SN=250   UN1=20    UN2=145  ER12=0       EX12=0.15    NCON=0
 BUS7  BUS8  SN=800   UN1=145   UN2=300  ER12=0       EX12=0.15    NCON=0
END

LINES
 BUS5  BUS6   TYPE=12  R=0.0001   X=0.001    B=0.00175   L=25   NCON=0
 BUS6  BUS7   TYPE=12  R=0.0001   X=0.001    B=0.00175   L=50   NCON=0
 BUS6  BUSM   TYPE=12  R=0.0001   X=0.001    B=0.00175   L=25   NCON=0
 BUSM  BUS7   TYPE=12  R=0.0001   X=0.001    B=0.00175   L=25   NCON=0
END

ASYNCHRONOUS
 WT1 BUS1 TYPE=1A SN=200 UN=0.69 H=0.3
    R1=0.00619 X1S=0.135952 X2S=0.112143
    XM=3.904762 RTAB=7 RM=0.088095 NCON=0

!!! DFIG Model
! WT1 BUS1   TYPE=DSLS/MACHOPT/
!     SN=200     PG=195
!     UN=0.69    RS=0.01   RR=0.009
!     XS=0.18    XR=0.07   XM=4.4
!     A2=-0.631  A1=1.379  A0=0.524
END

LOADS
 BUS6  P=50   Q=10  MP=0  MQ=0 NCON=0
```

```
END

SHUNT
 BUS1 Q=-50
END
```

```
POWER CONTROL
  WT1    TYPE=ASYN  RTYP=P    P=180

!  BUS1   TYPE=NODE  RTYP=PQ   P=100.0     Q=0.0

! BUS1   TYPE=NODE  RTYP=UP   U=0.69   P=0.0
!                  CNODE=BUS1 QMIN=-200 QMAX=200  NAME=SVC3  NCON=0

! BUS5   TYPE=NODE  RTYP=UP   U=145    P=0.0
!       CNODE=BUS5 QMIN=-200 QMAX=200  NAME=SVC5  NCON=0

 BUS4   TYPE=NODE  RTYP=UP   U=20     P=50     NCON=0  NAME=G4

 BUS8   TYPE=NODE  RTYP=SW   U=300    FI=0       NAME=STIFF
END

TABLES
!ROTOR RESISTENCE
 7 TYPE=2  F=-1 0.02
            1 0.02
END

END
```

Assessment of test system

The impact on wind power generation technology on voltage stability is analysed for the test network depicted in Figure 37. Different load flows with increasing wind power generation are simulated for different generator technologies:

1. Wind turbines equipped with SCIG and no-load reactive power compensation;
2. Wind turbines equipped with SCIG and SVC;
3. Wind turbines equipped with DFIG generators

The reactive power compensation devices (capacitor banks and SVC) are connected at the generator terminals (BUS1). The (radial) line connecting the wind farm to the regional grid has been dimensioned with a maximum thermal capacity of 300 MVA. The results are shown in Figure 38. It is seen that the voltage at wind farm terminal’s (Bus 1) is kept above 0.9 p.u. for all three cases for wind farm output below 160 MW, and at well acceptable voltages (above 0.95 p.u.) for wind farm output below 130 MW (rated power of the assumed wind farm).

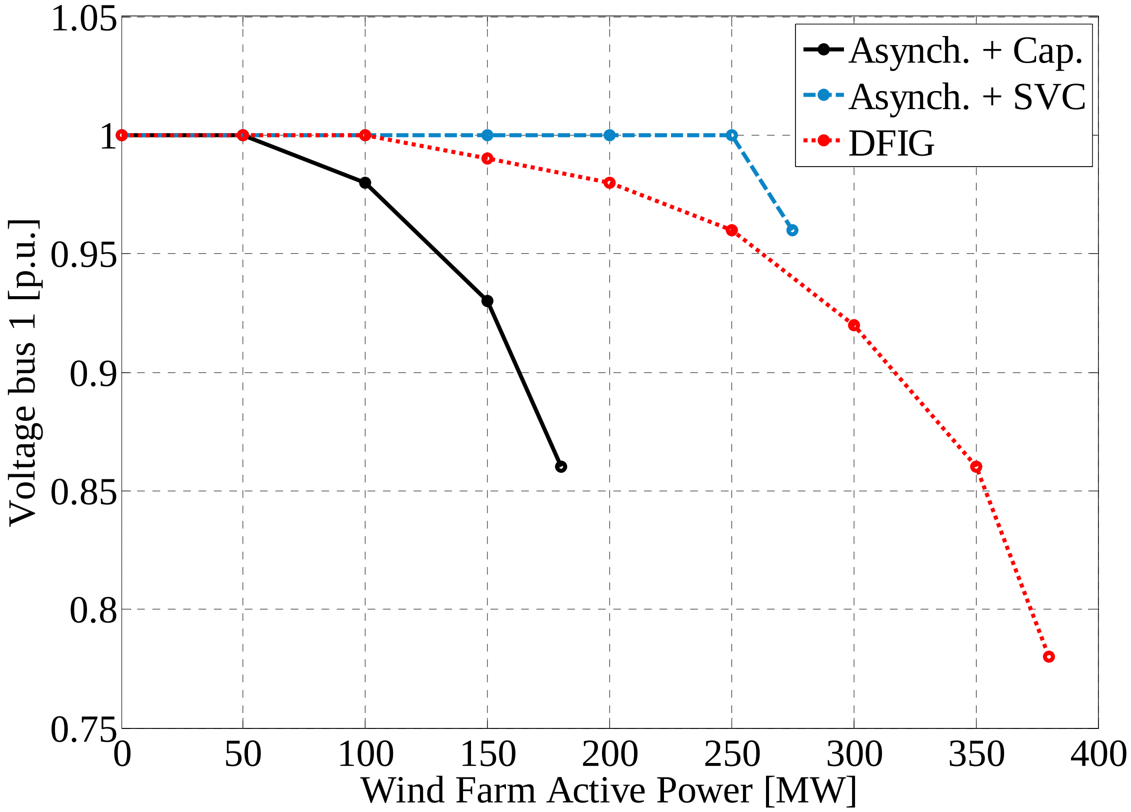

Figure 38: P-V curves for fixed speed wind generator with no load reactive power compensation, fixed speed wind generator with SVC and doubly fed induction generator.

APPENDIX C: MORE ON WIND FARM VOLTAGE DIP RESPONSE

In this section a comparison between wind generator's models is given, based upon time response of the voltage at generator's terminals when a short circuit is applied on one tie line.

Three models of wind generators using standard asynchronous machines with no load reactive power compensation and a power generation level of 150 MW are compared in Figure 39.

1. Lumped mass model of the generator and turbine with $H_G + H_T = 5$ s;
2. Two-mass model of the generator and turbine with H_G=0.3 s, H_T = 4.7 s and K = 0.29 p.u./el.rad;
3. Two-mass model of the generator and turbine with H_G = 0.3 s, H_T = 2.35 s and K= 0.29 p.u./el.rad.

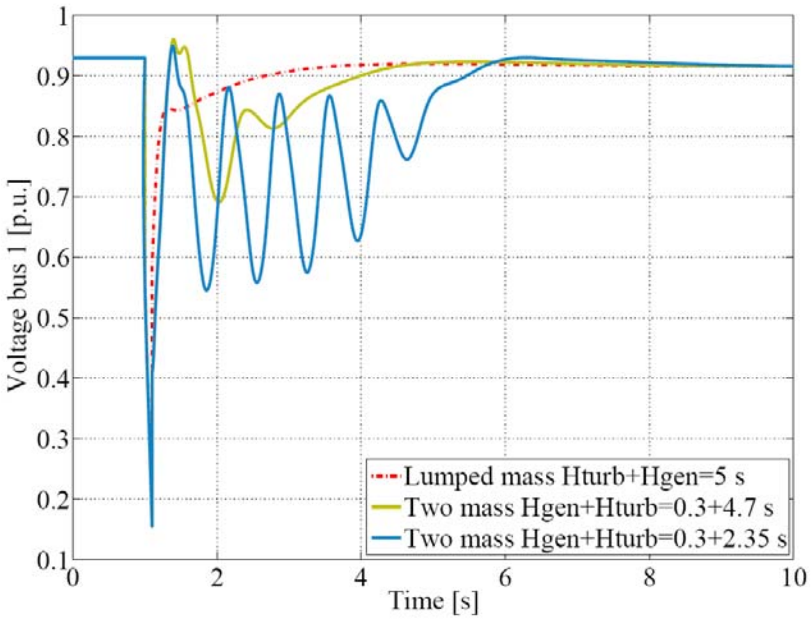

Figure 39: Voltage response of asynchronous generator models. The solid lines refer to the two-mass models, and the dashed line refers to the lumped mass model.

As show in Figure 39 a lumped mass model hides the voltage oscillations due two the different inertias of the generator and the turbine coupled through a shaft. In a two-mass model indeed the influence of the inertia constant of turbine and generator is clearly illustrated. The model with high turbine inertia (4.7 sec) recovers faster than the model with lower turbine inertia (2.35 sec). The results clearly illustrates that a two-mass model should be used for modelling a fixed speed wind turbine with a SCIG.

For simulation of variable speed wind turbines it is likely not as critical to use a two-mass model, i.e. at least not for assessing the response to voltage dips. This is because of the frequency converter that effectively “disconnects” mechanical and electrical oscillations. A verification of this is done as part of [13] as shown in Figure 40 and Figure 41.

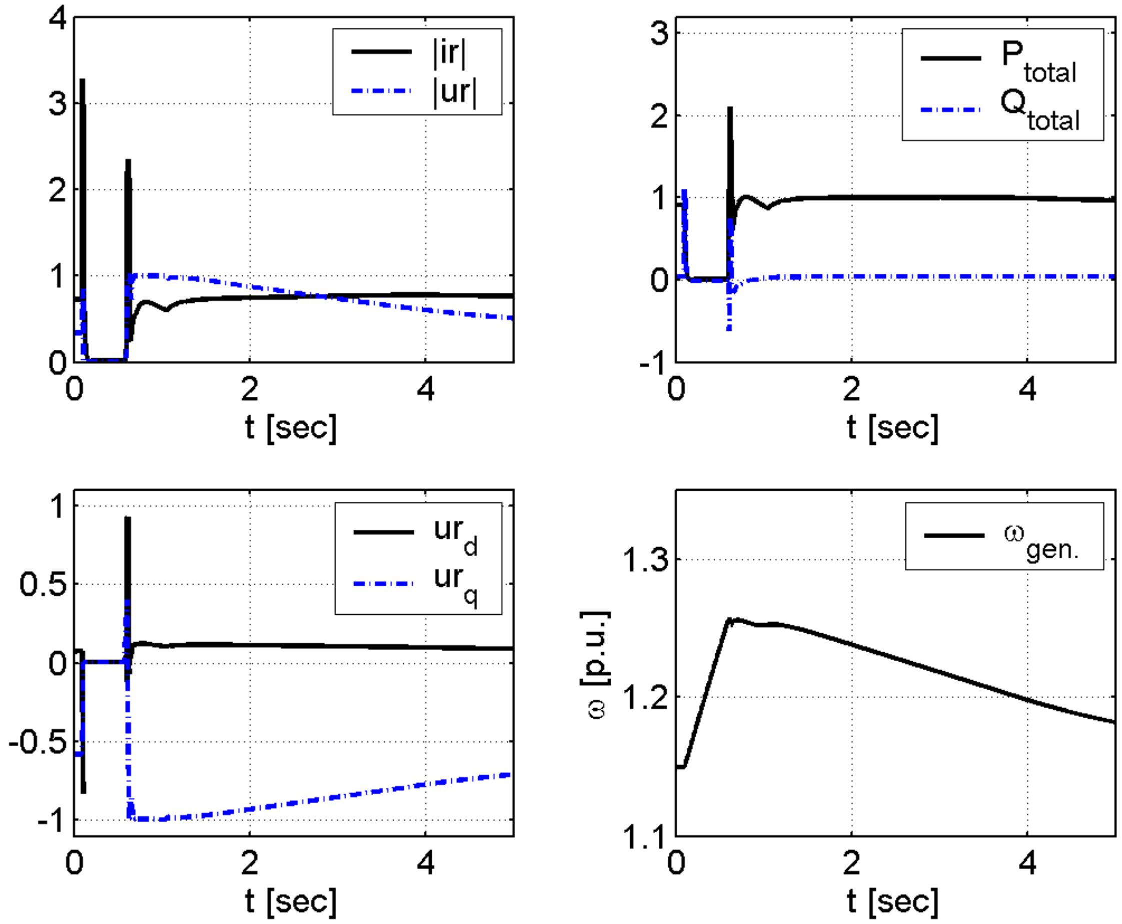

Figure 40: Simulation of 160 MW wind farm with DFIG lumped mass model. Copy from [13].

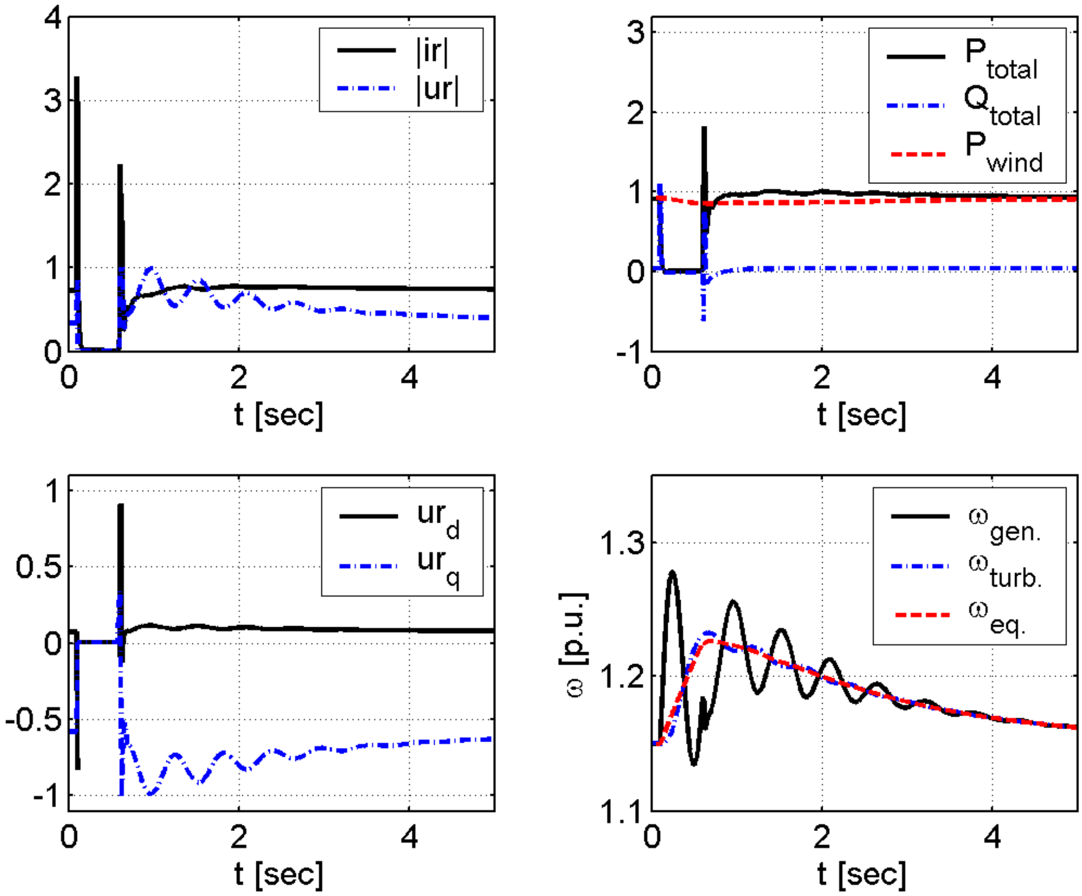

Figure 41: Simulation of 160 MW wind farm with DFIG two-mass model. Copy from [13].

APPENDIX D: VOLTAGE INCREMENT

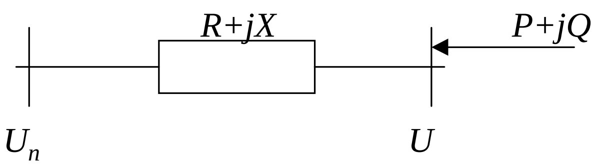

Figure 42: System with single line between two busses.

Consider the system given in Figure 42 consisting of a single line between two busses. Assuming that we know the voltage U_n, the line impedance R and X and the production P and Q, we may find an analytic expression of the voltage U as deduced here.

We start with:

$$U = U_n + (R + jX) \cdot I \tag{9}$$

Remember that:

$$S = U \cdot I^* \Rightarrow I = \frac{S^*}{U^*} = \frac{P - jQ}{U^*} \tag{10}$$

Combining **(9)** and **(10)** gives:

$$U \cdot U^* = U_n \cdot U^* + (R + jX) \cdot (P - jQ) \tag{11}$$

Remember that:

$$U = |U| \cdot e^{j\delta} = |U| \cdot (\cos\delta + j\sin\delta) \tag{12}$$

Combining **(11)** and **(12)** gives:

$$|U|^2 = U_n \cdot |U| \cdot \cos\delta + R \cdot P + Q \cdot X + j(X \cdot P - R \cdot Q - U_n \cdot |U| \cdot \sin\delta) \tag{13}$$

As $|U|$ per definition is real, and we chose U_n to be real:

$$X \cdot P - R \cdot Q - U_n \cdot |U| \cdot \sin\delta = 0 \Rightarrow \cos\delta = \frac{\sqrt{(U_n \cdot |U|)^2 - (X \cdot P - R \cdot Q)^2}}{U_n \cdot |U|} \tag{14}$$

Combining **(13)** and **(14)** gives:

$$|U|^2 = \sqrt{(U_n \cdot |U|)^2 - (X \cdot P - R \cdot Q)^2} + R \cdot P + Q \cdot X \tag{15}$$

$$|U|^4 - |U|^2 \cdot (2 \cdot (R \cdot P + Q \cdot X) + U_n^2) + (R \cdot P + Q \cdot X)^2 + (X \cdot P - R \cdot Q)^2 = 0 \tag{16}$$

Remember that:

$$x^2 + b \cdot x + c = 0 \Rightarrow x = \frac{-b \pm \sqrt{b^2 - 4c}}{2} \tag{17}$$

The voltage is given by:

$$|U| = \sqrt{\frac{U_n^2 + 2\cdot(R\cdot P + Q\cdot X) + \sqrt{U_n^4 + 4\cdot(R\cdot P + Q\cdot X)\cdot U_n^2 - 4\cdot\left(X\cdot P - R\cdot Q\right)^2}}{2}} \quad (18)$$

From this the relative voltage increment may be calculated according to its definition:

$$\Delta U = \frac{|U| - |U_n|}{|U_n|}\cdot 100 \quad (19)$$

Figure 43 shows the voltage increment as a function of the network impedance phase angle:

$$\tan\psi_k = \frac{X}{R} \quad (20)$$

and the short-circuit ratio:

$$\frac{S_k}{S} = \frac{U_n^2}{\sqrt{R^2 + X^2}}\cdot\frac{1}{\sqrt{P^2 + Q^2}} \quad (21)$$

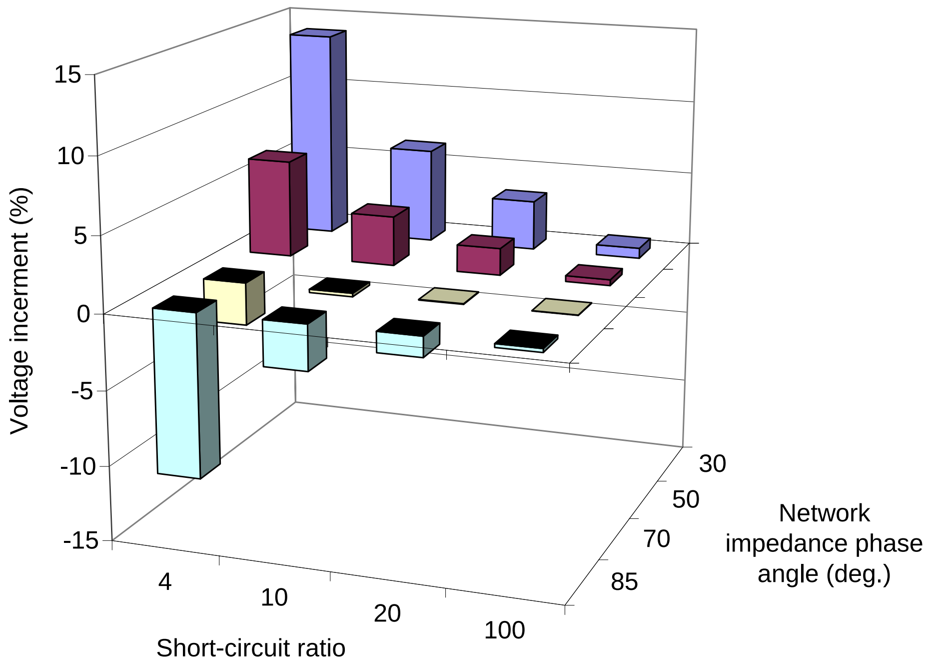

Figure 43: Voltage increment for cosφ = 0.95 (inductive).

Often the following approximate relation is applied:

$$\Delta U = \frac{R\cdot P + X\cdot Q}{U_n^2}\cdot 100 \quad (22)$$

Figure 44 shows a comparison between the accurate and the approximate formula. As can be seen, the approximation is fair for strong grids, say short-circuit ratio bigger than 20, whereas for weaker grids the approximate relation should be used with caution.

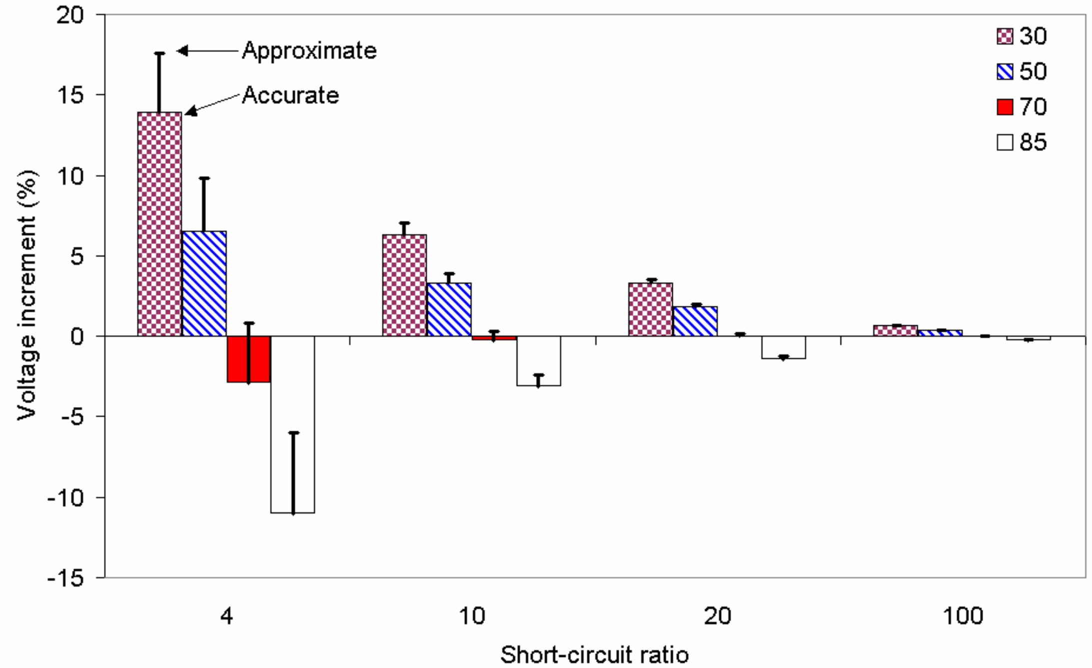

Figure 44: Comparison between accurate and approximate calculation of voltage increment for cosφ=0.95 (inductive).

SINTEF Energiforskning AS
Adresse: 7465 Trondheim
Telefon: 73 59 72 00

SINTEF Energy Research
Address: NO 7465 Trondheim
Phone: + 47 73 59 72 00