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Technical and economic impact analysis of the demonstrations in task-forces TF2 - Deliverable D15.2

WP15. Economic impacts of the demonstrations, barriers towards scaling up and solutions

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Publication date:
2014

Document Version
Publisher's PDF, also known as Version of record

Citation (APA):
Bell, K., Houghton, T., Doquet, M., Denis, A-M., Despouys, O., Cutululis, N. A., ... García-González, J. (2014). Technical and economic impact analysis of the demonstrations in task-forces TF2 - Deliverable D15.2: WP15. Economic impacts of the demonstrations, barriers towards scaling up and solutions.

Technical and economic impact analysis of the demonstrations in TF2

Deliverable: D15.2

EC-GA nº 249812

Project full title: Transmission system operation with large penetration of Wind and other renewable Electricity sources in Networks by means of innovative Tools and Integrated Energy Solutions

Document info

Document Name	Technical and economic impact analysis of the demonstrations in task-forces TF2
Responsible Partner	RTE and DTU
Work Package	WP15. Economic impacts of the demonstrations, barriers towards scaling up and solutions
Deliverable nº :	D15.2
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Document history

Version	Date	Main modification	Author
01	10/10/2012	Preliminary TOC	Poul Sørensen (DTU)
04	26/03/2013 03/05/2013	Addition of Strathclyde and RTE material RTE review Updating of results tables	Keith Bell (Strathclyde) Michel Doquet, Anne-Marie Denis (RTE) Tom Houghton (Strathclyde)
05	26/06/2013	Addition of DTU and Energinet.dk material	Nicolaos A. Cutululis, Poul Sørensen (DTU)
06	31/07/2013	Minor revisions	Olivier Despouys, RTE
07	31/11/2013	Final review	Javier García González, (Comillas-IIT)

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1 Executive summary

This deliverable D15.2 is one of the outcomes of Work Package WP15 entitled "Economic impacts of the demonstrations, barriers towards scaling up and solutions". In particular, this deliverable presents the economic impact analysis of the demonstrations performed in task-force TF2 . The main findings of the analysis carried out can be summarized as follows:

- New offshore network capacity that interconnects national networks allows local surpluses of wind power to be used elsewhere, reserve power to be held, and potentially cheap, zero carbon power to be used instead of more expensive higher-carbon fossil fuel plants .
- It has not been possible to identify a clear preference in 2020 for an H-grid multi-terminal offshore network when compared with radial connections of wind power from offshore hubs to shore plus point-to-point interconnectors. However, the design of the H-grid has not been optimised in this study and the results for 2030 shown clear benefits if the costs of DC breakers are neglected.
- The CO_2 reduction benefits arising from a reversal of the merit order of fossil fuelled generation are significant when compared with those directly associated with the development of offshore wind capacity.
- The analysis of offshore wind farms in Denmark shows that thanks to the new 'High Wind Ride Through' controllers, the largest disturbance due to storms can be reduced notably. In particular, maximum ramp rates (in 15 min) are reduced from 1343 MW to 209 MW. Although the frequency stability should be assessed for complete synchronous areas, this result indicates that the traditional control (High Wind Shut Down) can be a threat to the frequency stability, and that this danger is significantly reduced using the new controller. In addition to that, the new controller implies a minor increase in the energy production during the storm event – between 2-4% in the analyzed case, and a minor reduction in the net balancing costs.

The methodology followed to perform the assessments, and the main results obtained for are summarized hereafter.

Offshore wind power development is on an early stage today. However, it will contribute massively to future European energy supply. The methodology used to perform the impact assessment of new HVDC configurations in off-shore wind generation is based on the model ANTARES, developed by the French System Operator, RTE. This tool makes use of detailed hourly wind speed series, loads and considers key generator parameters and technical characteristics. A particular feature of ANTARES is its capability to model multivariate stochastic processes such as wind speeds across a wide area. Despite this fact, simulations cannot hope to model all the multitudinous influences on fuel prices, generation development, system operation and imperfect market operation.

The results suggest that new offshore network capacity to allow increased exchange of power between different countries will be important to realising the full potential of new wind power developments. This new network capacity not only allows local surpluses of wind power to be used elsewhere but also facilitates reserve power to be held remote from a particular area and so minimise the total holding of reserve and increase the utilisation of renewable energy. However, it might also allow cheap high carbon generation in remote areas to be used instead of lower carbon fossil fuelled plant in a local area. It may thus be concluded that effective pricing of carbon emissions is crucial. Next table summarises the results of 2020 case with 27.1 GW and 2030 case with 61.3 GW (in brackets) of new offshore wind generation capacity

Table 1. Summary of results of 2020 and (*2030)*

	Case 0 – no new OWF	Case 1 – radial connection of new OWF	Case 2 – radial connection of new OWF + new point-to-point interconnectors	Case 3 – H-grid
TWh of new offshore wind production	0 (0)	74 (178)	74 (178)	75 (186)
Europe-wide CO_2 emissions from ‘forward’ merit order electricity production (million tonnes)	1201 (1507)	1150 (1406)	1157 (1417)	1157 (1415)
Europe-wide CO_2 emissions from ‘reverse’ merit order electricity production (million tonnes)	829 (1170)	779 (1043)	775 (1032)	771 (1025)
Total cost of ‘forward’ merit order electricity production and annualised offshore grid capital cost (million euros)	49713 (65580)	48775 (63379)	48666 (63283)	49855 (62170)
Total cost of ‘reverse’ merit order electricity production and annualised offshore grid capital cost (million euros)	60883 (75631)	60085 (74028)	60269 (74535)	61463 (73655)

Main conclusions are:

- It has not been possible to identify a clear preference in 2020 for an H-grid multi-terminal offshore network when compared with radial connections of wind power from offshore hubs to shore plus point-to-point interconnectors. However, the design of the H-grid has not been optimised, and the results for 2030 shown clear benefits if the costs of DC breakers are neglected.
- The CO2 reduction benefits arising from a reversal of the merit order of fossil fuelled generation are significant when compared with those directly associated with the development of offshore wind capacity.

Regarding the technical and economic impact of the storm controls, three simulation tools have been used in the analysis: WILMAR Joint Market Model (JMM), Simulation of Balancing (SimBa), and Correlated Wind (CorWind). The simulation of wind power production was done using a steady-state wind to power (wind2power) conversion model. The wind2power conversion model includes a power curve – the representation of the relation between wind speed and wind power, and the storm controller (High Wind Shut Down – HWSD and High

Wind Extended Production – HWEP, which is based on the new storm controller used in Demo 4).

A number of high wind speed periods were identified in the historical data covering the period 2001 – 2011. Each period was simulated with HWSD and HWEP. The results show very clearly that with the HWEP controller the total power dip is significantly lower than the one with HWSD, (around 0.5 p.u.).

The most remarkable impact is related to the maximum ramping which has been calculated for time windows relevant for the power system operation: 15, 30, 60 and 90 min. Next table shows obtained values for the 2020 base scenario:

Table 2. Maximum ramping in MW (base scenario 2020)

	Time horizon			
	15 min	30 min	60 min	90 min
HWSD	1343	1441	1516	1876
HWEP	209	247	430	542
Difference	1133	1194	1086	1334

From frequency stability point of view, the most interesting result is the 15 min window. It should be noted that the maximum ramping of 1343 MW in the HWSD case is higher than the dimensioning outage of 1200 MW in the Nordic system, while the 209 MW with the HWEP is well below that limit. Although the frequency stability should be assessed for complete synchronous areas, this result indicates that the HWSD control can be a threat to the frequency stability, and that this danger is significantly reduced using the HWEP control.

Regarding the impact on balancing, during the analyzed storm period, the TSO up-regulation expenses for hour-ahead balancing are increased and down regulation earnings are increased when the HWSD control is replaced by the HWEP control. However, these numbers are negligible compared to the annual net balancing costs.

2 Introduction

This document presents the deliverable D15.2, which is one of the three deliverables contained in WP15 as stated in the DoW:

Table 1.1 Description of deliverable in DoW WP15

Deliverables:			
D15.2	(RTE, DTU)	Report on the impact of: ▪ new HVDC configurations in off-shore penetration (RTE) ▪ coordinated storm control for off-shore wind generation in Denmark (DTU)	M34 (Jan-13)

3 Impact of new HVDC configurations in off-shore penetration

3.1 Expected outcomes of this analysis (RTE)

The Key Performance Indicators (KPIs) in respect of Task Force 2 of Work Package 15 were defined at the very beginning of the project in Deliverable 2.1 as shown in Table 2.1. Responsibility for quantifying these KPIs was delegated to RTE which worked along with the University of Strathclyde in performing an economic analysis of the anticipated benefits from an off-shore grid in the North Sea for WP5 in DEMO3 DCGRID. In addition, other activities within Demo 3 (comprising WP5 and WP11) contributed towards the development of knowledge in respect of DC grids for the facilitation of offshore wind power.

Table 2.1: Key Performance Indicators (KPIs) for Task Force 2 of Work Package 15

KPI.15.TF2.1	Amount of offshore renewable energy that could be securely transmitted by the new HVDC network, [GWh/year]
KPI.15.TF2.2	Ratio between the expected benefit to the system for integrating this energy from of offshore renewable power in the system, and the expected incurred cost to deploy the new components, [Euro / Euro]
KPI.15.TF2.3	CO_2 emissions that could be avoided in Europe 2020 due to this offshore renewable power, [tonne CO_2/year].

The analyses carried out in WP5 contributing towards the Task Force 2 section of WP15 had the objective of showing how, from both a technical and an economic perspective, different offshore HVDC network structures could assist in facilitating the integration of offshore wind generation into the European electricity transmission system. In particular, these analyses sought to identify the relative costs, taking into account both the operational and capital costs associated with different structures, as well as the CO_2 emissions.

In addition, other activities within Demo 3 of TWENTIES, comprising contributions from both WP5 and WP11, explored technical aspects of DC grids including control, protection and contributions of DC grids towards AC system ancillary and restoration services. Findings from these studies can be found in dedicated Demo 3 deliverables and are summarised in section 2.3 below.

3.2 Approach to economic analysis

The approach to quantifying values in respect of the three TF2 KPIs was centred on Europe-wide simulation studies for putative 2020 and 2030 generation and demand scenarios. These scenarios and the methodology used to explore them are described in section 2.4. The results are, among other things, sensitive to the following network characteristics:

1. the NTCs onshore within the three main regions of analysis: Continental Europe, Scandinavia and the British Isles;

2. the NTCs between the three regions, i.e. offshore, and the broad configuration in which the offshore NTCs are delivered;
3. the way of connecting new offshore wind farms.

The latter two respects are interrelated in that one option for connection of a single offshore wind farm, or a group of them whose outputs are collected together at a single hub, is via a radial link back to a single shore, usually within the same territory as that from which the wind farm development originated. However, another is via some form of offshore grid, e.g. in the form of an 'H' or a tree, offering two or more onshore entry points. It was considered reasonable to assume that the majority of the newer locations of offshore wind farms will be further out from shore than those that have been developed to date and will thus make use of HVDC voltage source converter technology; this, in turn, opens the possibility of developing DC grids and a choice of how much power to direct to which terminal. Moreover, onshore terminals may be within the same AC synchronous area or different ones. In the former case, there exists the possibility of using the offshore grid to transfer power from one part of the AC system to another and to bypass onshore constraints; in the latter, the DC grid may provide interconnection capacity between different AC systems.

In order to compare the impact of different forms of offshore HVDC network capacity, four different network cases were studied:

- Case 0, a reference case in which no new offshore wind farms (OWFs) were assumed to have been connected after 2011[1];
- Case 1 in which there were simple radial connections of new OWF capacity to the nearest shore;
- Case 2 in which there were simple radial connections of new OWF capacity to the nearest shore along with new point to point interconnectors between regions around the North Sea;
- Case 3 in which an 'H' / tree multi-terminal DC grid in the North Sea both gave OWFs access to shore and provided some power transfer capacity between different AC systems.

In each case, present day onshore net transfer capacities (NTCs) between regions of Europe were taken from the ENTSO-E historical data (https://www.entsoe.eu/resources/ntc-values/ntc-matrix/) along with existing offshore interconnectors.

Further background on how the different network cases were formed is given in section 2.5.5 below.

Energy produced by different generators and the associated CO_2 emissions and costs of production depend on conditions that arise throughout the course of a year of operation and are subject to the limits imposed by the NTCs, maximum and minimum generation limits, and the variation of demand, wind speed and the water stored for use in hydro power generation. Estimates of the total wind production, CO_2 emissions and electrical energy production cost were therefore made using a sequential Monte Carlo simulation provided via a software tool developed by RTE, ANTARES (this tool is described in sections 2.1 and 3 of deliverable 5.2-a issued by Demo 3). However, a simulation that takes account of all possible limitations of power system operation is not practical so the results obtained here must be regarded only as indicative and dependent on underlying assumptions. Moreover,

[1] 2011 is the year in which the analysis was first performed.

- using a sequential Monte Carlo simulation of all 8760 hours of year with the modelling of many possible years is computationally heavy;
- the tool is not designed to assess power system security in light of possible network failures;
- it was not the intention to optimise the designs of the offshore networks studied.

In simple terms, the expected benefit of integrating additional wind generation capacity into the European power system would arise from substitution of electrical energy derived from fossil fuels with that from wind. This would be highest if (a) wind production was not curtailed and (b) the replacement of fossil fuel derived energy by wind energy was 1:1. The benefit in terms of operational cost and CO_2 savings would also depend on exactly which types of fossil fuelled generation were replaced, the different technologies having different emissions characteristics. ANTARES is designed to dispatch generation on a least cost basis and the "optimal" utilisation of wind would result in a minimisation of cost and not necessarily of CO_2 emissions except to the extent to which carbon emissions are priced.

'Spillage' of wind power, i.e. restriction of the power output of wind farms to less than that available at a given time, can arise for any of the following reasons:

- the available power transfer capacity on the connection between a wind farm and the main interconnected system is less than the available wind power output;
- there is a constraint on the main interconnected AC system that prevents export of all available power;
- there is a surplus of the total power that could be generated relative either to demand or to limits imposed on utilisation of wind in order to ensure system frequency stability following a secured event;
- the scheduling of primary reserve at some minimum level prevents all the available wind power being fully utilised if total generation is not to exceed total demand.

That is, the replacement of fossil fuelled generation by wind is limited by the ability to always fully exploit the available wind power.

If the network branches for connection of offshore wind power also facilitate power exchanges between market areas, wind curtailment can be reduced by providing access to wider demand locations and eventually pumped storage facilities that allow the wind energy to displace fossil fuelled generation in low wind time periods. Additional point-to-point interconnectors can serve the same purpose.

Both offshore network branches and increases of onshore NTCs that permit power exchanges between areas can allow reserve to be shared, so minimising the costly running of fossil-fuelled plant. In addition, the same network branches can have an impact in low wind time periods by permitting higher merit (cheaper) generation to be used in particular areas than would otherwise have been the case. However, while this promises direct financial benefits, the CO_2 impact depends on the CO_2 emissions characteristics of the higher merit generation compared with the lower merit plant it is displacing.

A further benefit that might be expected from a grid structure as opposed to a simple radial connection back to a single AC system location arises from the redundancy among paths for the offshore wind power to reach shore and, hence greater robustness against network or converter failures. To quantify the benefit requires a specialist reliability analysis using suitable component failure and repair rate data. This was the aim of a separate WP5 deliverable

(deliverable D5.3-a entitled "Comparison of different network solutions in the North Sea offshore system" issued by Demo 3).

3.3 Main findings of the Demo 3

Demo 3 - DCGRID of TWENTIES has been broadly concerned with DC grids, in particular multi-terminal HVDC, as described briefly below:

1. in WP5, the operation and control of basic DC grid topologies, also a study of the drivers for development of DC grids as distinct from simple radial connections of offshore wind farms;
2. in WP11, the protection of DC grids, in particular the detection and location of DC faults and the feasibility of interruption of fault currents by means of DC circuit breakers (DCCB).

The main findings from WP5 in respect of the drivers for DC grids read across quite directly into KPIs 15.1, 15.2 and 15.3 and are discussed in sections 2.4 to 2.7 below.

In respect of operation and control, it can generally be concluded that, for the basic topologies under consideration in WP5 and WP11, there is no particular obstacle identified to the feasibility of such multi-terminal DC grids.

However, without DC circuit breakers, there are limits to the power that should be exported from a single, contiguous DC grid (one that is fully electrically connected on the DC side) into a single AC system synchronous area. This limit is given by the primary reserve carried within that AC synchronous area (3 GW for Continental Europe). Without DCCBs, a short circuit fault anywhere on that single, contiguous DC grid would require the interruption of fault current by the operation of AC circuits breakers at each of the terminals of that DC grid and so would cause all power generated on that DC grid or transferred by it to be lost. If a particular loss of infeed limit was to be exceeded, it is not always necessary to restrict generation on the DC grid[2]. Instead, the DC grid could be reconfigured pre-fault into a number of separate contiguous DC grids that are only connected via the AC side through at least two converters (that generally have circuit breakers on the AC side). This should be done in such a way that a fault on one of them, which would lead to the loss of that entire DC electrical island, would not cause any loss of infeed limit to be exceeded. Provided a fault on the DC side can be located, it can be cleared from the AC side and disconnectors on the DC side opened to isolate the fault. The DC grid can then be reconfigured to allow its operation to restart and as much power to be generated on it as possible.

DEMO 3 has found via simulation studies that, within certain configurations of DC grid, there is no necessity for fast communications between different terminals of the DC grid in order for their operation to be adequately coordinated, even when subject to the loss of a converter. This can be achieved via suitable droop controls and over-voltage and over-current limitations. However, the droop settings must be chosen in order to avoid any risk of small signal instability and communication facilities of some kind, albeit not necessarily fast, need to be provided in order to change the control settings so that particular steady state power flows between the different terminals can be achieved.

[2] The precise setting of the primary reserve level (generally determined by the 'loss of infeed' consequential to a single fault event) is dependent on a cost-benefit analysis in which the cost of increased primary reserve holdings is compared with the benefit of permitting a higher loss of infeed.

A further finding of Demo 3 has been that offshore wind farms operating on DC grids that are connected to separate main interconnected AC systems might enhance their income by being able to offer ancillary and system restoration services. Simulation studies in WP5 have demonstrated the feasibility of ancillary services and, to some extent, restoration services. However, certain contributions to AC system defence might depend on fast communications to provide control signals. In addition, the operation of voltage source converters can impact on the operation of AC system distance protection.

WP11 has investigated the protection of DC grids, both detection and location of DC faults and the clearance of faults by operation of DCCBs. The main performance requirements of DC protection have been investigated and illustrated on a low scale hybrid real time mock-up. A scale demonstration of a DC breaker has shown that it can be feasibly built and operated. However, scaling up to high powers and voltages still remains challenging.

A number of different designs of voltage source converter have been reviewed. These have differing levels of operational complexity, size and cost, but also have different impacts on the controllability of DC grids, particularly during faults and when re-starting after a fault. A major consideration will be the extent to which current feeding into a DC side short-circuit from the AC side can be blocked, thus affecting the required performance characteristics of a DC breaker.

Overall, the following, very simple conclusions might be drawn:

- multi-terminal DC grids based on voltage source converter technology are feasible;
- offshore wind farms connected via HVDC might offer ancillary or system restoration services and contribute to global AC/DC system control;
- operation of a multi-terminal DC grid with a capacity less than the primary reserve level of the AC area to which it is connected, does not depend on DC circuit breakers, though DC circuit breakers are likely to provide some operational benefits, such as, within a multi-terminal grid structure, permitting some level of continuity of supply;
- a medium-voltage DC circuit breaker has been demonstrated, but scaling up remains a challenge especially for some classes of fault currents, as does DC grid system protection;
- DC grid protection would appear to rely on fast, reliable communications. However, depending on the configuration of the grid, coordination of the normal operation of the different terminals of a DC grid and operation immediately after a number of credible disturbances does not require fast communications.

In addition, when designed well, DC grids may be expected to be cost competitive with radial connections plus point-to-point interconnections.

A more complete summary of the findings of Demo 3 can be found in TWENTIES deliverable D5.4 and the full details of the investigations conducted can be found in other deliverables of WP5 and WP11.

3.4 Description of the DC grid assessment methodology and problem setting

This section describes work aimed at quantifying the impact of different configurations of offshore network on wind energy production, CO_2 emissions and the cost of electrical energy, i.e. in relation to the KPIs. The main assessment methodology and scenarios are described below.

3.4.1 Modelling of generation and demand

Key to understanding the drivers for development of new interconnection capacity in Northern Europe and the benefits of coordinated development of one or more offshore grids is adequate modelling of the demand for electricity and how this interacts with the availability of generation the dispatch of which depends on their respective relative costs of operation. It has always been the case not only that demand at a particular time is somewhat uncertain (affected in the short-term largely by variations in weather) but also available generation. While particular thermal generating units might be out of service due to maintenance or forced outages, the availability of wind power is particularly uncertain due to variability of wind speeds. In turn, prudent utilisation of available hydro resources would take account of these uncertainties within the constraints imposed by water storage capacity, expected in-flows and maximum power output. However, a further constraint is imposed on the dispatch of generation to meet demand across a large area by the capacity of the network to transfer power within it. If the benefits of increased network capacity are to be fully understood, all these effects should be modelled.

The study reported here has used the ANTARES analysis tool developed by the French system operator, RTE, which has also been used in the production of the European 'Ten Year Network Development Plan' (TYNDP) on behalf of ENTSO-E, the European Network of Transmission System Operators of Electricity (www.entsoe.eu). ANTARES makes use of detailed hourly wind speed and loads and key generator parameters such as capacity, forced outage rates and operating cost. However, in order that credible hourly time series of dispatches can be produced, it also makes use of generator minimum on and off times, as well as main hydro characteristics such as typical monthly inflows within a unit commitment process based on heuristics and defined operating reserve requirements. The latter are defined at the level of an "ANTARES macro-node", the size of which may vary from a single substation to a whole country.

A particular feature of ANTARES is its capability to model multivariate stochastic processes such as wind speeds across a wide area, through a two-step process. In the first step, a statistical analysis function assesses various parameters characterizing the kernel of experimental time-series at hand (either historical or yielded by meteorological simulation tools). The assessed parameters describe the marginal probability distribution function for the variable (e.g. wind speed) measured on each site, the temporal auto-correlation function of this variable and the spatial correlations between the different variables related to the different sites. In the second step, a stochastic time-series generator makes use of these parameters to sample an arbitrarily large set of realistic time-series. When these generated time-series are wind speeds, a last (optional) step carries out a conversion to wind power using given speed to power curves (defined site by site).

3.5 Model Implementation

3.5.1 Network representation

One of the objectives in this study has been to understand the variability of power imbalances in different locations within a coherent representation of dispatches of power that takes into account inter-temporal constraints. This requires the simulation of a large number of years of operation in a Monte Carlo approach, typically thousands of them if a loss of load probability is to be estimated with any degree of confidence. However, the priority here has been metrics of predominant system behaviour such as the total energy produced by different classes of generation and carbon emissions which, in a typical study, can be estimated with a few hundreds of trials.

The approach taken for the main economic study has been to represent the European power system as a number of nodes each of which represents a single country having demand and generation capacity made up of individual generating units of different types. The operation of generation is modelled on a stochastic basis with a 1 hour time step. With network branches between nodes representing actual or proposed power flow paths, different study cases can be straightforwardly set up with different sets of NTCs on the various branches.

3.5.2 Basis of the case studies

A number of different cases have been modelled in order to explore the rationale for development of, in particular, offshore network capacity and quantified in terms of:

- annual CO_2 emissions;
- the annual energy production of different types of thermal generation;
- 'spilled energy', i.e. available wind energy that could not be utilised; and
- unsupplied energy.

The primary driver – reduction in carbon emissions – should clearly be articulated but this is dependent on precisely which generation resources would be used under different circumstances. In addition, to meet the demand for electricity remains the fundamental requirement of power systems and quantification of the 'spill' or curtailment of renewable energy will be important in determining limits to their utilisation.

The cases studied concern both different generation and demand scenarios and different levels of NTC between different regions. They are summarised below.

3.5.3 Generation capacity and demand scenarios

The study has seen a number of different 2020 and 2030 scenarios developed for potential generation capacity and load across the European Economic Area (EEA). However, the results reported here concern only the central case for 2020 and a case for 2030. Although described in terms of those years, the scenarios, summarised in Tables 2.2 and 2.3 below, should not be regarded as forecasts of what will be developed by then. Rather, they are intended to provide a reasonable basis for assessment of what levels of power transfer across Europe might be necessary to enable the 2020 targets broadly to be met with further increases in renewable energy thereafter, and what benefits might accrue from development of new offshore network capacity, delivered in different structures.

Table 2.2: Total generation capacities in 2020 scenario

	Continental Europe	British Isles	Scandinavia	**Total**
Coal (GW)	101.2	29.8	9.6	**140.6**
Lignite (GW)	52.5	0.3	1.2	**54.0**
CCGT (GW)	119.0	30.9	4.8	**154.7**
Other Dispatchable fossil fuelled (GW)	86.3	7.9	11.4	**105.7**

Nuclear (GW)	104.1	7.1	12.4	**123.6**
Other Non-Dispatchable Generation (GW)	19.8	2.2	8.0	**30.0**
Reservoir and run-of-river hydro (GW)	98.0	1.7	60.4	**160.1**
Pumped storage (GW - generation)	39.9	3.1	9.1	**52.1**
Onshore wind (GW)	166.0	18.0	9.3	**193.3**
Offshore wind (GW)	12.2	14.9	0.0	**27.1**
Solar (GW)	80.1	2.7	0.0	**82.8**
All generation (GW)	877.1	118.1	126.2	**1121.5**
Peak demand (GW)	*450.0*	*70.0*	*88.0*	
Annual electricity consumption (includes pumping (TWh)	*2779.0*	*396.0*	*493.0*	***3668.0***

Table 2.3: Total generation capacities in 2030 scenario

	Continental Europe	British Isles	Scandinavia	**Total**
Coal (GW)	101.2	29.8	9.6	**140.6**
Lignite (GW)	52.5	0.3	1.2	**54.0**
CCGT (GW)	119.0	30.9	44.8[1]	**194.7**
Other Dispatchable fossil fuelled (GW)	86.3	7.9	11.4	**105.6**
Nuclear (GW)	72.1	1.2	3.9	**77.2**
Other Non-Dispatchable Generation (GW)	19.8	2.2	8.0	**30.0**
Hydro (GW)	98.0	1.7	60.4	**160.1**
Pumped storage (GW)	39.9	3.1	9.1	**52.1**
Onshore wind (GW)	166.0	18.0	9.3	**193.3**
Offshore wind (GW)	20.1	39.5	1.7	**61.3**
Solar (GW)	160.2	5.4	0.0	**165.6**
All generation (GW)	935.1	140.0	119.4	**1234.5**
Peak demand (GW)	489.1	76.1	95.7	
Annual electricity consumption (includes pumping (TWh)	3020.7	430.4	535.9	**3987.0**

1. Includes an additional 40GW of CCGT capacity in Sweden

The scenarios used in TWENTIES WP5 have been based on a number of other published scenarios such as those produced by Eurelectric and the European Wind Energy Association (EWEA) informed by the European country 'Renewable Energy Action Plans' (REAPS). These all differ slightly from each other; from these starting points, the scenarios here have adopted the following conventions:

- no expansion of total fossil fuelled thermal generation capacity – implicit in this is that thermal plant which reaches the end of its economic life will be replaced by equivalent plant;
- nuclear closures are assumed to take place according to figures published by the World Nuclear Association including the programme of nuclear generation closures in Germany which will see all nuclear plants there shut by 2022;
- aside from that already under construction in 2011, no new nuclear generation is assumed to be built by 2030;
- levels of additional wind generation are postulated which would permit achievement of targets for total renewable energy production, broadly based around EWEA statistics;
- solar to be consistent with projections from the European Photovoltaic Industry Association;
- the combined total of renewable resources and annual demand being broadly sufficient to meet the 2020 renewable energy target given an assumed capacity factor for onshore wind of 25%, for offshore wind of 35%, for hydro of 50% and solar of 15%, which in the scenario would give an overall renewables production of around 1300TWh[3];
- some further demand growth and openings of wind farms are assumed by 2030. However, in addition, some new CCGT capacity is assumed to be added in areas that otherwise would experience a relatively high unsupplied energy.

Variants on the scenarios detailed in Tables 2.2 and 2.3 are those in which no new offshore wind capacity is connected, i.e. the total for offshore wind is the 2011 total of 2.5GW.

3.5.4 Determination of generation dispatch

In this study, historic hourly wind power time series, scaled up to future capacities, have been used for countries in which there is already a significant history of wind power performance and data accessible to the investigators, i.e. Germany, Spain, Italy, Portugal, Denmark (East and West), Austria, Switzerland, France, Belgium and the Netherlands. For other countries, wind power time series have been synthesised using statistical representations of wind based on 5 years of hourly 'backcast' data from Meteo France on a 50km grid and the same speed to power curves as used in the TradeWind study[4].

Within ANTARES, generation is dispatched on the following basis.

(a) For every day of each month, the monthly available hydro energy is broken into daily blocks, proportionally to the daily demand elevated at the power α, where α is an operational parameter heuristically fitted for every area of the system. For instance, if the value of α is very high then week-ends are allotted considerably less hydro energy than week-days.

(b) For every week of the year, an economic optimization is carried out with a time step of one hour, in which the overall generation cost (sum of 168 hourly values) is minimized while respecting minimum and maximum limits on the power output of each plant, as well as the interconnection capacity limits.

[3] The National REAPS suggest approximately 34% of all electricity demand must come from renewables if the 20% target for energy overall is to be met.

[4] http://www.trade-wind.eu/index.php?id=13

The costs used in determining the economic dispatch are set up to define a typical 'merit order' in respect of generating plant of different types in which, for example, subject to generator availability, the network and the unit commitment constraints, wind and nuclear power may be preferred to cheap lignite generation which, in turn, may be preferred to coal and combined cycle gas turbines. That is, in view of the uncertainties of actual present day and future costs, the costs of different technologies relative to each other are regarded as being most important in determining the dispatch. Moreover, in understanding the scope for enhanced network capacity to facilitate the meeting of European renewables targets, a coordinated, Europe-wide dispatch was assumed. Nonetheless, in order that some estimation of relative costs and benefits of different options could subsequently be carried out, some particular values were assumed. These were based on costs given by the UK government Department of Energy and Climate Change in 2010 and are shown in Table 2.4. In addition a sensitivity case for the merit order was also assessed in which CCGT is preferred to coal and lignite. This case is referred to as the 'reverse merit order' case and the costs used are also shown in Table 2.4. While a 'reverse merit order' in respect of fossil fuelled generation might come about simply as a result of changes to the prices of gas, coal or lignite, it was postulated here that such a merit order reversal might be achieved with the same fuel prices as in the initial case but with the addition of a carbon price of €100 per tonne. This gives the resulting prices shown on the right hand side in Table 2.4.

Table 2.4: Fuel costs in both 2020 and 2030 scenarios

	Cost in € / MWh	
Cost contributor	Forward Merit Order	Reverse Merit Order[5]
Nuclear	7	7
Lignite	15	130
Coal / Coal CHP	27	119
CCGT / Gas CHP	40	81
OCGT	62	123
Oil	121	184

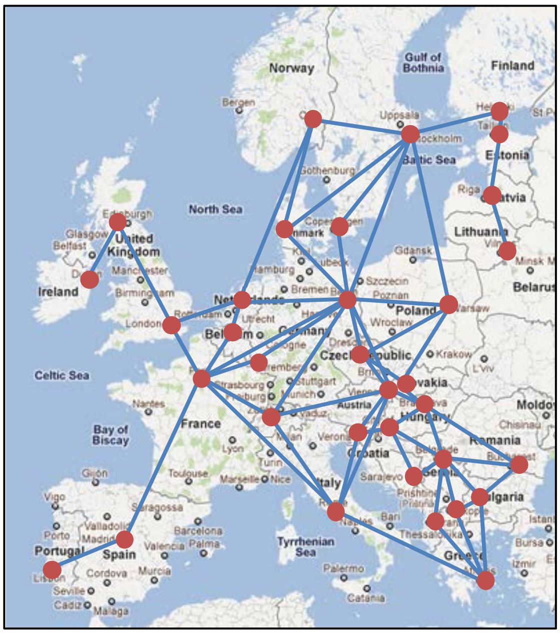
3.5.5 Network capacity cases

The study reported here has used single scenarios for 2020 and 2030 for generation capacity and demand but explored different network configurations. In determining these configurations, a significant degree of aggregation of wind farms around key 'hubs' has been assumed to take place within the wind sectors being considered. However, for offshore wind farm capacities in an area of a few GW or more, the present day scale of VSC HVDC and undersea cables suggests that there might not be much difference in the number of individual converters and cables between a hub approach and one in which each wind farm of around 1GW in size is connected independently to shore. Nonetheless, a hub approach is assumed.

A multi-terminal HVDC network offers the promise of both providing capacity to bring offshore wind power to shore and enhancing inter-region transfer capacity, and doing so either with greater benefits for a similar capital cost to network case 2 that was outlined in section 2.2 – radial plus separate interconnectors – or with similar benefits but at a lower capital cost.

[5] Based on underlying fuel price plus a carbon cost of €100 per tonne

The different network capacity cases were studied based on a common onshore network structure and capacity, taken as the present day set of NTCs published by ENTSO-E. This structure is shown in Figure 2.1. An example of a possible multi-terminal offshore H-grid structure that has been modelled in this study is shown in Figure 2.2.



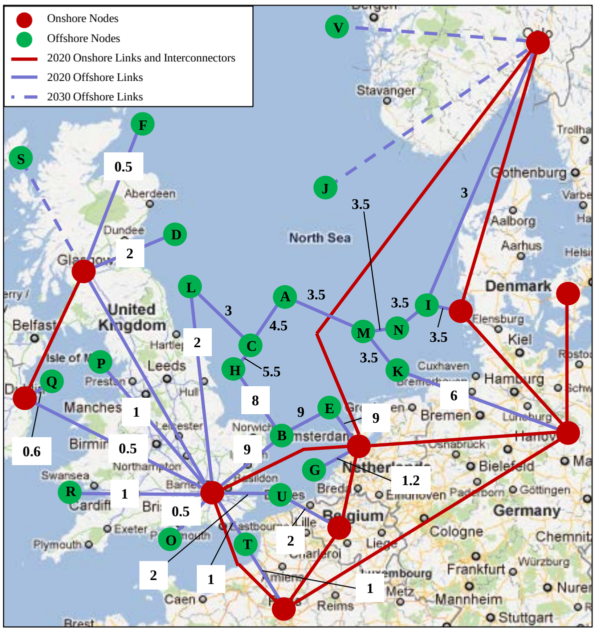


Figure 2.1: Initial network structure

Figure 2.2: Detail of the North Seas region showing offshore H-Grid

The radial network case – case 1 – is the most simple and consists in providing radial connections from each of the hubs identified to the node corresponding with the nearest land fall. In many cases this is the country of origin for the particular wind farm development. For example, the Dogger Bank wind farm (node A in the depiction of the 'H-grid' in figure 2.2) is only connected back to the UK in the radial case. It should be noted that the schematic representation in figure 2.2 does not provide any insight into where a connection is actually made into the existing AC network. In the cost benefit analysis reported below, estimates of actual distances to a likely point of connection to the AC system were used.

Instead of an H-grid, offshore interconnection capacity may be provided by more conventional 'point-to-point' means with offshore wind farms connected radially (network case 2). In the study, these are assumed to also be provided by HVDC (which need not be VSC) and the routes considered have been: Belgium – GB South; Germany – Norway; and Norway – GB North. In addition, the proposed 'embedded' HVDC link between GB North and GB South has been modelled.

The multi-terminal H-grid structure studied here and its associated branch capacities (network case 3) are based on engineering judgment to (a) provide sufficient capacity for offshore wind farms to access at least one shore and (b) provide some new inter-region interconnection capacity by adding 'bridges' between offshore hubs. As already noted, the design has not been the subject of repeated iterations to approximate an optimal solution. However, in terms of the total cost and aggregate GWkm of branch capacity, the structure is comparable to network case 2 (radial plus interconnectors).

Further details on all of the above can be found in TWENTIES deliverable D5.2a.

3.6 Results

The results reported in this section concern the future generation capacity and demand scenarios outlined above. These were simulated using ANTARES in which an attempt was made to respect the main limits on operation of both of the power system as a whole and of individual power stations. However, as was noted above, simulation that takes account of all possible limitations of power system operation is not practical so the results obtained must be regarded only as indicative. Nonetheless, using this approach, the impacts of three different designs of network capacity in the North Sea were studied as described in section 2.5.5.

In addition, a reference case, 'Case 0', was also studied in order to provide comparisons with a situation in which no new offshore wind farms are connected.

The main characteristics of the three network cases are as shown in Table 2.5. The aim of the study, as was noted in section 2.2, was not to optimise the designs of the offshore networks studied. This means that the total GWkm for the H-grid cannot be regarded as a final design that adequately balances cost of network infrastructure with the benefits that the infrastructure is expected to bring[6]. In addition, the total network cost is highly sensitive to the number of DC circuit breakers (DCCB) used. A simple assumption would be that each DC network branch has two DCCBs, one at each end, in a manner similar to that for onshore AC transmission circuits. At the other extreme, it could be assumed that no DCCBs are used meaning that short circuit faults on the DC network must be cleared by opening circuit breakers on the AC side of each and every terminal of the DC grid. However, this need not lead to a very large 'loss of infeed' every time a DC side fault occurs. The 'loss of infeed' for any one fault condition can be limited by judicious pre-fault partitioning of the DC network. In effect, this means operating the DC network infrastructure as a number of separate DC grids that are interconnected via the AC side. While this implies that any one DC side fault would still lead to *some* loss of infeed, once the fault has been cleared from the AC side, located and then isolated by the operation of simple disconnectors on the DC side, the DC network can be reconfigured, healthy branches returned to service and power transfer resumed. (In practice, there will be some intermediate options where DCCBs *are* installed but only a limited number of key locations).

[6] Ideally, a quantification of the relative benefits of a multi-terminal H-grid network structure would involve finding an H-grid that delivers at least the same benefit as radial connection of offshore wind farms plus point-to-point interconnectors but costs less, or delivers more services to the mainland grid. . This was not the question answered in our task, nonetheless, our results do serve to highlight some important issues.

Table 2.5: Main characteristics of the offshore network cases

Feature	Case 1 – simple radial connections of new OWFs	Case 2 – simple radial connections of new OWFs + new point-to-point interconnectors	Case 3 – H-grid
Cable total GWkm	2687	6393	9541
Number of offshore platforms	22	22	22
Number of new VSC	22	22	29
Number of new LCC	0	3	0
Possible number of DC circuit breakers	0	0	30

Although the design of the 'H-grid' was not optimized and makes its general characteristics similar to those achieved in case 2, results are provided below in respect of

- wind energy output;
- CO_2 emissions;
- Cost of electrical energy production.

Wind energy output for the generation and demand scenarios summarised in Tables 2.2 and 2.3, and for the network cases above, is as shown in Tables 2.6 to 2.9. More detail can be found in the deliverable 5.2a and a paper presented at the CIGRE 2012 Paris Session[7].

Table 2.6: Wind energy output and unsupplied energy for 2020 'forward' scenario

	Absolute energy (TWh)			
	Case 0 – no new OWF	Case 1 – radial connection of new OWF	Case 2 – radial connection of new OWF + new point-to-point interconnectors	Case 3 – H-grid
Energy Consumed (including pumping)	3668	3668	3668	3668
Onshore wind	341	340	340	340
New offshore wind	0	74	74	75
Total wind energy	341	414	414	415
Total spilled energy	11	14	13	12

[7] T. Houghton, K. Bell and M. Doquet, "The economic case for developing HVDC-based networks to maximise renewable energy utilisation across Europe: an advanced stochastic approach to determining the costs and benefits", 44th CIGRE Session, paper C1-117, Paris, August 2012

Spilled offshore wind energy	0	1	1	0
Unsupplied Energy[8]	6	6	1	1

Table 2.7 Wind energy output and unsupplied energy for 2020 'reverse' scenario

	Absolute energy (TWh)			
	Case 0 – no new OWF	Case 1 – radial connection of new OWF	Case 2 – radial connection of new OWF + new point-to-point interconnectors	Case 3 – H-grid
Energy Consumed (including pumping)	3668	3668	3668	3668
Onshore wind	341	340	340	340
New offshore wind	0	73	74	75
Total wind energy	341	413	413	415
Total spilled energy	11	14	14	12
Spilled offshore wind energy	0	2	2	0
Unsupplied Energy[7]	6	6	1	1

Table 2.8: Wind energy output for the 2030 'forward' scenario

	Absolute energy (TWh)			
	Case 0 – no new OWF	Case 1 – radial connection of new OWF	Case 2 – radial connection of new OWF + new point-to-point interconnectors	Case 3 – H-grid
Energy Consumed	3987	3987	3987	3987

[8] Note that the figures for unsupplied energy should be treated with caution given that ANTARES was used in its "economic" mode rather than the "adequacy" mode that would have required a significantly greater number of Monte Carlo simulation years in order to allow the loss of load probability to be estimated with any degree of confidence

Onshore wind	342	340	341	341
New offshore wind	0	178	178	186
Total wind energy	342	518	519	527
Total spilled energy	10	24	23	15
Spilled offshore wind energy	0	12	12	5
Unsupplied Energy[7]	10	5	4	3

Table 2.9: Wind energy output for the 2030 'reverse' scenario

	Absolute energy (TWh)			
	Case 0 – no new OWF	Case 1 – radial connection of new OWF	Case 2 – radial connection of new OWF + new point-to-point interconnectors	Case 3 – H-grid
Energy Consumed	3987	3987	3987	3987
Onshore wind	342	341	341	342
New offshore wind	0	178	179	186
Total wind energy	342	519	520	527
Total spilled energy	10	23	22	15
Spilled offshore wind energy	0	12	11	4
Unsupplied Energy[7]	10	5	4	3

It can be seen that the effect of increasing interconnection capacity (network cases 2 and 3) is to reduce both spilled energy and unsupplied energy as compared with networks cases 0 and 1.

As an illustration of the pattern of wind production through a year and its statistical variability from one year to the next as modelled by ANTARES, the monthly wind production and its standard deviation in the 2030 scenario is shown in Table 2.10 for the 'case 1' radial connection case. In addition, the monthly spilled wind for the same 2030 case is shown in Table 2.11.

Table 2.10: Monthly variation in offshore wind production in 2030 for H-grid

	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC
Mean energy production (TWh)	23.5	16.6	17.6	14.1	13.6	10.3	10.6	11.8	15.5	16.8	20.8	18.8
Standard deviation (TWh)	1.6	2.5	2.5	2.2	1.8	1.5	1.6	1.6	1.8	2.0	2.0	2.6

Table 2.11: Monthly variation in 'spilled' offshore wind production in 2030 for H-grid

	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC
Mean spilled energy (TWh)	0.7	0.4	0.6	0.3	0.3	0.2	0.2	0.1	0.3	0.4	0.5	0.5
Standard deviation (TWh)	0.1	0.1	0.2	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1

3.6.1 Contribution of a DC grid to reduction of CO_2 emissions

Provided grid capacity – both offshore and onshore – is sufficient, the energy produced by OWFs generally replaces an equivalent produced by fossil fuelled generation and hence reduces CO_2 emissions. However, under some circumstances and for power system operation reasons, not all the available wind energy can be utilised. Thus, as was discussed in section 2.1, at least some available wind power must be 'spilled'. This will require operation of alternative generation. Ideally, this would be flexible renewable generation such as hydro but it may be fossil fuelled.

A multi-terminal grid will, in general, interconnect different areas of an AC system or different synchronous systems. This will have a wider impact than that described above; this impact depends on the nature of AC system operation in those areas and on behaviour of the electricity market. In particular, within a competitive, single European electricity market, extra interconnection capacity reduces congestion and increases access to the cheapest generation. The impact of this depends on the relative CO_2 emissions characteristics of the generation thus facilitated, and which generators are cheapest in the short-run clearly depends on fuel and carbon prices.

For the main generation capacity characteristics summarised in Tables 2.2 and 2.3 and assumed fuel prices in Table 2.4, the 'merit orders' of generation were as shown in Table 2.12.

Table 2.12: Generation 'merit orders'

Rank	'Forward'	'Reverse'
1	Nuclear	Nuclear
2	Wind	Wind
3	Hydro	Hydro
4	Lignite	CCGT
5	Coal	Coal
6	CCGT	Lignite
7	OCGT	OCGT
8	Oil	Oil

In addition to the generation fuel costs shown in Table 2.4, imputed costs for unsupplied energy (€25000 / MWh) were used. The CO_2 emissions apparent in the 2020 and 2030 cases compared with the "no offshore wind" scenario are provided in Table 2.13. These results provide evidence of one of the potential unintended consequences of introducing more inter-regional interconnection capacity. Since ANTARES works on the basis of a Europe-wide least cost despatch of generation, the effect of increasing NTCs can be to provide cheaper but higher emissions coal and lignite fired power plants with greater access to market. It can be seen that in the forward merit order cases where coal and lignite are preferred to gas, network cases 2 and 3 offer *lower* CO_2 savings than network case 1. (Cases 1, 2 and 3 all reduce CO2 emissions relative to Case 0, the 'no new offshore wind' case). In the reverse merit order case, where a sufficiently high carbon price effectively increases the cost of coal and lignite relative to gas fired generation given the same fuel prices or where the price of gas reduces sufficiently, it can be seen that network cases 2 and 3 have improved carbon emissions when compared with the case 1.

Table 2.13 Total CO_2 emissions for 2020 and 2030 scenarios

Scenario	Absolute CO_2 emissions (million tonnes)	*Change from case 0 (million tonnes)*		
	Case 0 – no new OWF	Case 1 – radial connection of new OWF	Case 2 – radial connection of new OWF + new point-to-point interconnectors	Case 3 – H-grid
2020 'forward'	1201	*-50*	*-43*	*-44*
2020 'reverse'	829	*-50*	*-55*	*-58*
2030 'forward'	1507	*-101*	*-90*	*-92*
2030 'reverse'	1170	*-128*	*-138*	*-145*

3.6.2 Contribution of a DC grid to reduction of the cost of electrical energy

In order to contribute to a reduction in the overall cost of electrical energy, a DC grid should facilitate access to cheaper generation than would otherwise have been the case. However, the reduction in the cost of generation must be greater than the cost of the DC grid for there to be a net benefit.

The extent of the above economic impact depends not only on the design and capacity of the DC grid but also on general electricity market conditions and operational restrictions across the power system as whole. In particular, the economic impact depends on what generation capacity there is of different types, their locations relative to demand and available grid capacity (onshore as well as offshore) and the prices of fuel and carbon. Now that development and operation of generation is, in most of Europe, largely independent of that of the network, future generation capacity is highly uncertain and the identification and development of 'optimal' transmission network capacity not only extremely difficult but also highly dependent on the methods used to quantify risk. Fuel prices are also extremely uncertain.

While the simple fuel costs provided in Table 2.4 have been used to quantify the differences in production costs, they represented only a portion of the costs to which generators will be exposed. The additional costs include capital costs, operation and maintenance, tax, insurance and connection and use of system costs. Moreover, consumers of electrical energy will also have additional industry costs to bear. However, the fuel costs represent the main component of the marginal cost of production which is why it is of particular interest.

The assumed costs for components of the DC grids have been used to estimate the net benefits. The cost assumptions are shown in Table 2.14. They were each annuitised over 20 years at a discount rate of 10% and their costs are shown in Tables 2.15 and 2.16. The effects of the DC grid designs on total cost of generation are as shown in Tables 2.17 – 2.20.

Table 2.14: Capital costs of DC grid components

System Element	Capital cost (€m)[9]
3000MW line commutated converter	213
1000MW voltage source converter	135
Platform	70
HVDC 1000MW 500kV Cable per km	0.72
DC 1000MW Circuit Breaker	40

Table 2.15: Annuitised capital costs of DC grid cases 2020 (million euros)

	Case 0 – no new OWF	Case 1 – radial connection of new OWF	Case 2 – radial connection of new OWF + new point-to-point interconnectors	Case 3 – H-grid
Offshore network cost excluding DCCB	0	1177	1984	1954
Cost of DCCB	0	0	0	1149
Offshore	0	1177	1984	3117

[9] Based on data contained in ENTSO-E Offshore Transmission Technology Report https://www.entsoe.eu/publications/system-development-reports/north-seas-grid-development/

network cost including DCCB				

Table 2.16: Annuitised capital costs of DC grid cases 2030 (million euros)

	Case 0 – no new OWF	Case 1 – radial connection of new OWF	Case 2 – radial connection of new OWF + new point-to-point interconnectors	Case 3 – H-grid
Offshore network cost excluding DCCB	0	2832	3296	3395
Cost of DCCB	0	0	0	1149
Offshore network cost including DCCB	0	2832	3296	5023

Table 2.17: Total annual costs for 2020 'forward' merit order scenario

Cost item	Absolute cost (million euros)	*Change from case 0 (million euros)*		
	Case 0 – no new OWF	Case 1 – radial connection of new OWF	Case 2 – radial connection of new OWF + new point-to-point interconnectors	Case 3 – H-grid
Energy production cost excluding cost of carbon	48568	*-2330*	*-3222*	*-3054*
Spilled energy cost	1145	*214*	*191*	*79*
Carbon cost	25211	*-1056*	*-911*	*-914*
Annualised capital Cost (excl DCCB)	0	*1177*	*1984*	*1954*
Annualised Capital Cost of DCCB	0	*0*	*0*	*1163*
Total cost excluding DCCB	74924	*-1994*	*-1958*	*-1935*
Total cost including DCCB	74924	*-1994*	*-1958*	*-772*

Table 2.18: Total annual costs for 2020 'reverse' merit order scenario

Cost item	Absolute cost (million euros)	*Change from case 0 (million euros)*		
	Case 0 – no new OWF	Case 1 – radial connection of new OWF	Case 2 – radial connection of new OWF + new point-to-point interconnectors	Case 3 – H-grid
Energy production cost excluding cost of carbon	59758	-2276	-2872	-2621
Spilled energy cost	1126	301	274	84
Carbon cost	17416	-1052	-1145	-1225

Annualised capital Cost (excl DCCB)	0	1177	1984	1954
Annualised Capital Cost of DCCB	0	0	0	1163
Total cost excluding DCCB	78299	-1850	-1759	-1808
Total cost including DCCB	78299	-1850	-1759	-645

Table 2.19: Total annual costs for 2030 'forward' merit order scenario

Cost item	Absolute cost (million euros)	*Change from case 0 (million euros)*		
	Case 0 – no new OWF	Case 1 – radial connection of new OWF	Case 2 – radial connection of new OWF + new point-to-point interconnectors	Case 3 – H-grid
Energy production cost excluding cost of carbon	64556	-6417	-6874	-7276
Spilled energy cost	1024	1383	1282	471
Carbon cost	31643	-2120	-1886	-1929
Annualised capital Cost (excl DCCB)	0	2832	3296	3395
Annualised Capital Cost of DCCB	0	0	0	1628
Total cost excluding DCCB	97224	-4322	-4183	-5339
Total cost including DCCB	97224	-4322	-4183	-3711

Table 2.20: Total annual costs for 2030 'reverse' merit order scenario

Cost item	Absolute cost (million euros)	*Change from case 0 (million euros)*		
	Case 0 – no new OWF	Case 1 – radial connection of new OWF	Case 2 – radial connection of new OWF + new point-to-point interconnectors	Case 3 – H-grid
Energy production cost excluding cost of carbon	74635	-5729	-5593	-5834
Spilled energy cost	996	1294	1201	463
Carbon cost	24574	-2677	-2907	-3049
Capital Cost (excl DCCB	0	2832	3296	3395
Capital Cost DCCB	0	0	0	1628
Total excluding DCCB	100205	-4280	-4004	-5026
Total including DCCB	100225	-4280	-4004	-3398

3.7 Conclusions

The main metrics used to compare the different scenarios for WP15 have been total wind energy production, emissions of carbon dioxide and the cost of electrical energy.

It must be noted that, while an advanced modelling tool has been used, simulations cannot hope to model all the multitudinous influences on fuel prices, generation development, system operation and imperfect market operation. In addition, as exhibited by, for example, the recent history of transfers across the interconnectors between England and France and England and the Netherlands where power flows have been consistent with transfers from low spot price areas to high price areas only around 60% of the time, it is not practically possible to capture all influences on generation dispatch and power transfers in a simulation. For example, there are likely to be influences from local network constraints (not modelled in the studies reported here) and forward energy contracting.

The results suggest that new offshore network capacity to allow increased exchange of power between different countries will be important to realising the full potential of new wind power developments. This new network capacity not only allows local surpluses of wind power to be used elsewhere but also facilitates holding of reserve power remote from a particular area and so minimise the total reserve held and increase the utilisation of renewable energy. However, it might also allow cheap high carbon generation in remote areas to be used instead of lower carbon fossil fuelled plant in a local area. It may thus be concluded that not only are support for investment in very low carbon generation capacity such as wind and development of the transmission network important for reduction of carbon emissions associated with use of electricity, but so too is effective pricing of carbon emissions.

Some further observations can be made.

- It is expected that larger grid ratings than those of the scenarios studied (both on-shore and off-shore) would ensure a decrease in wind energy spilled.
- Optimized grid ratings (both on-shore and off-shore) would imply a small amount of residual wind spillage, the point of equilibrium being reached when the economic value of the last used MWh generated off-shore is equal to its marginal transmission cost.

Among the objectives of TWENTIES is the discovery of some answers to the question: "What should the network operators implement to allow for off-shore wind development?" This comes as part of a wider aim of "giving Europe a capability of responding to the increasing share of renewable in its energy mix by 2020 and beyond while keeping its present level of reliability performance." Some final remarks are therefore made in respect of the 'key performance indicators' (KPIs) defined in respect of Work Package (WP) 15, Task Force (TF) 2 at the outset of the project by TWENTIES Deliverable 2.1. These KPIs are reproduced in Table 2.21.

Table 2.21: Key Performance Indicators for work package 15, task force 2

KPI.15.TF2.1	Amount of offshore renewable energy that could be securely transmitted by the new HVDC network, [GWh/year]
KPI.15.TF2.2	Ratio between the expected benefit to the system for integrating this energy from of offshore renewable power in the system, and the expected incurred cost to deploy the new components, [Euro / Euro]
KPI.15.TF2.3	CO2 emissions that could be avoided in Europe 2020 due to this offshore renewable power, [tonne CO2/year].

Some indications of renewable energy production and CO_2 emissions have been given in Tables 2.6 to 2.9 and 2.13 above for some particular generation and demand scenarios. Moreover, a number of network cases are also shown in those tables that allow some form of cost-benefit analysis to be performed. The main outcomes of that analysis are shown in Tables 2.17 to 2.20. However, as has been noted above, it was not the intention to optimise the designs of the offshore networks studied. Optimisation of the offshore network design for a particular generation and demand background should be the subject of extensive further work. Still more work would be required to identify a design that is robust in light of uncertainty regarding the future generation and demand background.

The ability of any study to address some particular questions depends heavily on the data and tools that are available. As has been described above, questions related to the amount of offshore renewable energy that can be accommodated, the cost benefit of different options for doing so and the CO_2 impact depend on a large number of factors, among them:

- the installed renewable generation capacity;
- the power network capacity;
- the variability of the available renewable power and the demand for electricity and how that variability is managed, which depends on the power network capacity, the

characteristics of other generation and on market arrangements for the trading of energy and the provision of ancillary services;
- relative prices and availability of different generators.

To enable the most efficient use of the funds and time made available within TWENTIES WP5 from which the results described above have been drawn for WP15, TF 2, it was decided to make use of existing and already very powerful software – ANTARES – rather than to develop new software. However, this means that certain issues of interest cannot be addressed. These include 'secure transmission' in relation to KPI.15.TF2.1. To 'securely transmit' means that a credible contingency can occur without breach of system limits. In turn, this means either that corrective action must be taken sufficiently quickly following the occurrence of a contingency or that power transfers must be restricted before any contingency occurs such that there would be no adverse consequences following the event. Testing of 'secure transmission' involves the modelling of contingencies, which generally means the simulation of fault outages.

ANTARES does not have the capability to model contingencies directly. However, it does represent inter-area power transfers as part of a 'transport model' and allows the definition of 'net transfer capacities' (NTCs) that limit the transfer of power. The NTCs used in the study represent the existing system in Europe; the NTC values were taken from the ENTSO-E historical data. In reality, there is no single NTC value for any particular network boundary as the exact power transfer capability depends, in particular, on the precise dispatch of power and the ratings of lines (which, if dynamic ratings are not used, are seasonal). A single NTC can thus only be indicative. Nonetheless, it is possible for an NTC to be defined as the secure transfer under some particular, representative condition. If what is quoted by ENTSO-E as the NTC for a particular boundary is a secure NTC then the transfers modelled within ANTARES might, to some extent, be considered as 'secure'. However, it is not clear from the data how the NTCs are calculated, whether they are 'secure' or what precise definition of 'security' was applied.

The main results shown in Tables 2.6 to 2.9, 2.13 and 2.17 to 2.20 relevant to the above KPIs are summarised in Tables 2.22 and 2.23 below. From these, the following further conclusions are drawn:

- It has not been possible from these studies to identify a clear preference in 2020 for an H-grid multi-terminal offshore network when compared with radial connections of wind power from offshore hubs to shore plus point-to-point interconnectors. However, the design of the H-grid has not been optimised, and the results for 2030 show clear benefits if the costs of DC breakers are neglected.
- The CO_2 reduction benefits arising from a reversal of the merit order of fossil fuelled generation are significant when compared with those directly associated with the development of offshore wind capacity.

An issue not fully explored here has been the cost of DC breakers and the sensitivity of the overall cost-benefit of a multi-terminal grid to that cost and the number of DC breakers used. However, an initial analysis suggests that the cost of a DC breaker should be less than around €10m per unit if an H-grid in which they are widely deployed is not to become unduly expensive.

Table 2.22: Summary of results of 2020 case with 27.1 GW of new offshore wind generation capacity

	Case 0 – no new OWF	Case 1 – radial connection of new OWF	Case 2 – radial connection of new OWF + new point-to-point interconnectors	Case 3 – H-grid
TWh of new offshore wind production	0	74	74	75
Europe-wide CO_2 emissions from 'forward' merit order electricity production (million tonnes)	1201	1150	1157	1157
Europe-wide CO_2 emissions from 'reverse' merit order electricity production (million tonnes)	829	779	775	771
Total cost of 'forward' merit order electricity production and annualised offshore grid capital cost (million euros)	49713	48775	48666	49855
Total cost of 'reverse' merit order electricity production and annualised offshore grid capital cost (million euros)	60883	60085	60269	61463

Notes:

- Total CO_2 and costs depend on assumptions made about non-wind generation capacity, generation production costs, market arrangements and network capacity and costs of new offshore network capacity.
- Costs do not include costs of: networks within OWF or connecting OWF to offshore hubs; DC breakers; CO_2 costs; unsupplied energy; costs of financial support to renewables.
- Design of offshore network has not been optimised.

Table 2.23: Summary of results of 2030 case with 61.3 GW of new offshore wind generation capacity

	Case 0 – no new OWF	Case 1 – radial connection of new OWF	Case 2 – radial connection of new OWF + new point-to-point interconnectors	Case 3 – H-grid
TWh of new offshore wind production	0	178	178	186
Europe-wide CO_2 emissions from 'forward' merit order electricity production (million tonnes)	1507	1406	1417	1415
Europe-wide CO_2 emissions	1170	1043	1032	1025

from 'reverse' merit order electricity production (million tonnes)				
Total cost of 'forward' merit order electricity production and annualised capital cost of offshore grid (million euros)	65580	63379	63283	62170
Total cost of 'reverse' merit order electricity production and annualised capital cost of offshore grid (million euros)	75631	74028	74535	73655

Notes:

- Total CO_2 and costs depend on assumptions made about non-wind generation capacity, generation production costs, market arrangements and network capacity and costs of new offshore network capacity.
- Costs do not include costs of: networks within OWF or connecting OWF to offshore hubs; DC breakers; CO_2 costs; unsupplied energy; costs of financial support to renewables.
- Design of offshore network has not been optimised.

4 Impact of coordinated storm control for off-shore wind generation in Denmark

4.1 Expected outcomes of this analysis (DTU)

The KPI defined for the up-scaling of Demo 4 in WP15 – defined at the beginning of the project – aims at quantifying the impact that the actions demonstrated in Demo 4 will have on the need for reserves in the Danish power system

Table 3.1 Key performance indicator for Demo 4 in WP15

KPI.15.TF2.4	Reduced reserve requirement to operate the Danish 2020 and 2030 power system securely in storm situations [MW]. This will be calculated as the difference between the expected requirements with and without the actions demonstrated in Demo 4

4.2 Main findings of demo 4 (Energinet.dk)

Experience from very tough weather conditions in western Denmark during autumn 2012 demonstrated that if offshore wind turbines are equipped with new high wind ride through control, it is possible to run them for longer during periods with high wind speeds, which means there is less risk of turbine shut-down and less risk to the stability of the power system.

In addition, total output during these periods is higher from turbines equipped with the new high wind ride through control than in those with old control algorithm, which would abruptly shut down the wind farm when the wind speed went over 25 m/s. Measurements from Horns Rev II during stormy weather proved that the wind turbines equipped with the new high wind ride through control software could stay in operation in wind speeds of up to 32 m/s. The new high wind ride through controllers, developed by Siemens (installed on 91 wind turbines at Horns Rev II) leads to less abrupt changes in production for the wind farm as a whole. Wind farms with the new high wind ride through control options will in extreme weather situations experience gradual reductions in production and the mechanical parts of the individual turbine are, generally, less exposed.

In the autumn of 2012, several storms hit western Denmark. During these storms, power production at Horns Rev II hardly went down at all. Simulations show that if the old control algorithm had been in operation, the wind farm would have shut down completely (see Fig.1).

During the autumn 2012 and winter 2012/2013 storms, the extra power production with the new system was considerable. Moreover, if wind speeds are high enough to cause the power produced to decrease, the drop in output happens much more gradually than would have been the case with the old system. This was the case for the big storm on 30-31 January 2013. This is a huge advantage for balancing the electricity system.

The power system in western Denmark is operated as one area that needs to be in balance. Problems occur only rarely thanks to advanced operating systems. Everyone responsible for balancing in the power system in Denmark is obliged to update their detailed production and consumption schedules every five minutes. The detailed schedules provide Energinet.dk (the Danish TSO) with the opportunity to avoid larger imbalances by manually activating regulating power. Manual regulating power has an activation time of 15 minutes. This means that the automatic balancing system needs to be ready to handle the system imbalance that can arise within around 15 minutes. The potential of a more gradual decrease of production from a single offshore wind farm during 15 minutes allows the integration of more wind farms into the system.

Almost all power production is balanced through well-functioning Nordic power markets (both in the day-ahead and regulating power markets). Thanks to the Norwegian hydropower system, and the HVDC connection to Norway, a very high share of the wind power variability in western Denmark is balanced, today. With the new high wind ride through controller installed in offshore wind parks it is possible to integrate more offshore wind into the system without jeopardising system security at times of high winds.

The goal of doubling the share of wind power in final electricity consumption in Denmark (from approximately 25% to 50%) within seven years, along with increased growth in wind power capacity across Europe will significantly challenge the power system. Advanced controllers have been considered to effectively balance power variations between the Nordic Region and western Denmark so that power system balance restoration is possible in case of unforeseen large variations in (offshore) wind power generation.

4.3 Description of the assessment methodology and problem setting (DTU)

4.3.1 Definitions

Several metrics were used in assessing the results of the up-scaling work presented in this report. In order to have an overview of those metrics, their definitions are presented in this sub-chapter.

Ramp rates

The ramping is defined as the change in the mean value from a period to another:

$$P_{\text{ramp}}(n) = P_{\text{mean}}(n+1) - P_{\text{mean}}(n)$$

or graphically, in Figure 1.

The ramp rates are used as a measure of the variability induced by wind power and they represent the effort that the system needs to make in order to balance a system with varying wind power. In the definition used, positive values mean that decreasing wind power production, resulting in an increase of the production from other sources, i.e. conventional power plants.

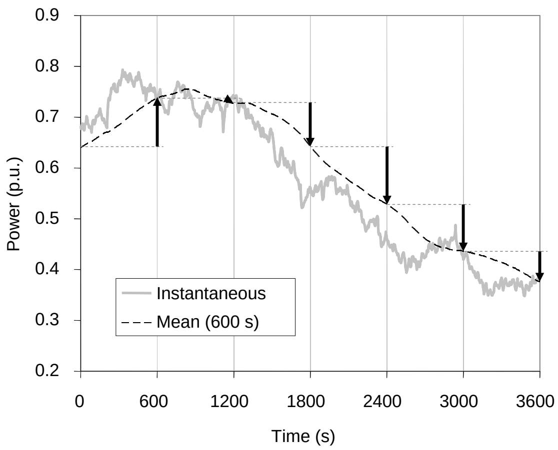


Figure 1 Definition of ramping

Maximum ramping

The definition of maximum ramping applied in this report is quite similar to the definition of regulation applied in [1] and used in [2]. The intention is to define a quantity which can be used to assess if the frequency stability is threatened due to sudden (or short term) loss of wind power generation.

The frequency stability in a synchronous power system area relies on the availability of sufficient online frequency containment reserves to handle unexpectedly lost generation in the first instance. In the Continental European synchronous area, the reference incident is defined as the loss of 3000 MW generation [3]. The corresponding dimensioning outage is 1200 MW in the Nordic Synchronous area [4].

In the second instance, the frequency containment reserves must be replaced by frequency replacement reserves, so that normal security level is re-established within a certain time. This reserve replacement usually takes up to 15 minutes, and additional loss of generation within this time period can cause frequency stability problems.

Normally, the need for frequency containment reserves is set so that the frequency remains stable after loss of the largest generation unit. However, the frequency stability can also be threatened if the wind power generation drops with more than the online frequency containment reserves within 15 minutes. This is normally not an issue because the total wind power changes relatively slow over large areas, but in case of a storm passage with massive scale offshore wind power concentrated in relatively small areas, the wind power generation can drop significantly within 15 minutes.

In order to quantify the short-term loss of wind power generation, the maximum ramping is defined as the difference between the present power and the minimum instantaneous power in the following time window Twin. Since the reserves must be allocated in advance, the positive reserve requirement is defined as the difference between the initial mean value and the minimum value in the next period. It has also been chosen to use a mean value of the present power rather than an instantaneous value with average periods T_{ave} , because the initial value is rather random. The assessment of maximum ramp rates is involving a statistical window time T_{win}, which reflects the time scale of interest. The time scales of interest will depend on the power system size, load behavior and specific requirements to response times of reserves in the system. In order to study the wind variability in different time scales, the analysis is performed for several time windows.

This definition of maximum ramping is illustrated for time windows T_{win} = 60 min and average periods T_{ave} = 15 min in Figure 2. The simulated (or measured) instantaneous power is shown in gray tone. The mean values for the latest 15 min are calculated and shown in black. For each 15 minute period, the reserve requirement is calculated as indicated by the arrows.

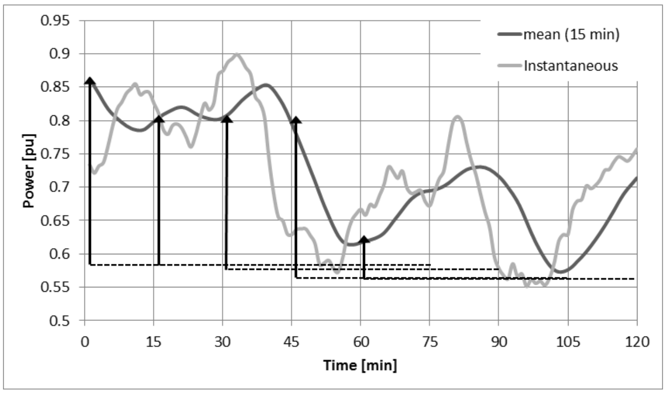


Figure 2 Definition of maximum ramping

$$P_{\text{res}}(n) = P_{\text{mean}}\left[t(n) - T_{ave}\ ; t(n)\right] - P_{\min}\left[t(n)\ ; t\ (n) + T_{win}\right]$$

Here, [t_{beg} ; t_{end}] denotes the time period from t_{beg} to t_{end}. Note that with this definition, positive ramping means decreasing wind power that requires positive ramping from other power plants.

4.3.2 Tools

CorWind

The CORrelated WIND power fluctuations (CorWind) model has been developed at DTU Wind Energy (former Risø) for over a decade now. It is a software tool that allows the simulation of wind power time series that have a realistic variability. Furthermore, CorWind can simulate wind power output in different locations, taking into account the spatial correlation between them.

CorWind is an extension of the linear and purely stochastic PARKSIMU model [5] which simulates stochastic wind speed time series for individual wind turbines in a wind farm, with fluctuations of each time series according to specified power spectral densities and with correlations between the different wind turbine time series according to specified coherence functions. The coherence functions depend on frequency and space, ensuring that the correlation between two wind speed time series will decrease with increasing distance between the points. Moreover, the slow wind speed fluctuations are more correlated than the fast fluctuations. Finally, the stochastic PARKSIMU model includes the phase shift between correlated waves in downstream points, ensuring that correlated wind speed variations will be delayed in time as they travel through the wind farm. These model properties ensure that the summed power from multiple wind turbines will have realistic fluctuations, which has been validated using measured time series of simultaneous wind speeds and power from individual wind turbines in two large wind farms in Denmark.

The CorWind extension of PARKSIMU is intended to allow simulations over large areas and long time periods. The linear approach applied in PARKSIMU assumes constant mean wind speeds and constant mean wind directions during a simulation period, which limits the geographical area as well as the simulation period significantly–typically to the area of a single wind farm and to a maximum period of two hours. CorWind uses reanalysis data from a climate model to provide the mean wind flow over a large region, and then adds a stochastic contribution using an adapted version of the PARKSIMU approach that allows the mean flow to vary in time and space.

The meteorological data was produced using a mesoscale reanalysis method, which is often used for obtaining high-resolution climate or climate change information from relatively coarse-resolution global general circulation models or reanalysis. The mesoscale reanalysis uses a limited-area, high-resolution model driven by boundary conditions from the reanalysis. The strength in using the models to fill the observation gaps is that the fields are dynamically consistent and they are defined on a regular grid. Additionally, the models respond to local forcing that adds information beyond what can be represented by the observations.

The mesoscale reanalysis used to generate the meteorological time series uses the National Center for Atmospheric Research (NCAR) Advanced Research Weather Research and Forecasting (ARW-WRF) model [6]. The version used is v3.2.1 that was released 18 August 2010. The model forecasts use 41 vertical levels from the surface to the top of the model located at 50 HPa; 12 of these levels are placed within 1000 m of the surface. The model setup uses standard physical parameterizations including the Mellor-Yamada (MYJ) PBL scheme [7].

The model was integrated within the domain shown in Figure 3. The model grid has a horizontal spacing of 30 km, on a polar stereographic projection with center at 52.2°N, 10°E. The domain has dimensions of 115 × 108. The simulation from which the meteorological time series are derived covers twelve years (2000–2011). Individual runs are re-initialized every 11 days. Each run overlaps the previous one by 24 h, to avoid using the time during which the model is spinning up mesoscale processes. A similar method was used and verified in [8]-[10]. Initial boundary and grids for nudging are supplied by the ERA Interim Reanalysis [11].

The model was validated against measurements from two largest – at the time – offshore wind farms in the world, namely Horns Rev 1 wind farm located in the North Sea in the west coast of Denmark and Nysted wind farm, located in the south coast of Denmark, in the Baltic sea.

The validation was done in terms of wind farm ramp rates. The measured wind farm power is calculated in p.u. as the average power of the available turbines in each 2 hour segment. Thus, the reduction of the wind farm power due to non availability of wind turbines is removed. This choice is justified because missing data from a turbine is not necessarily indicating that the turbine is not producing power, but can also be because of failures in the SCADA system.

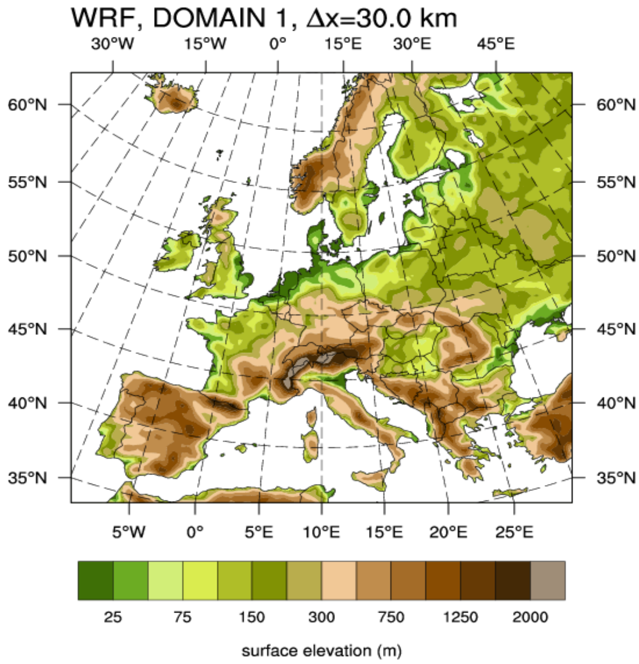


Figure 3 Domain configuration and terrain elevation used in the simulations for domain (30 km)

For each measured 2 hour segment, the average wind speed and wind direction is calculated, and a 2 hour wind farm power time series is simulated. The simulations are performed with the detailed model including low frequency fluctuations and wind farm generated turbulence.

When the ramp rates have been calculated for each set of neighbour periods n and n+1 for all segments, the ramp rates are binned according the corresponding initial power $P_{mean}(n)$. This is because the statistics of the ramping will depend strongly on the initial power. For instance, the power is not likely to increase very much when it is already close to rated. A power bins size 0.1 p.u. has been selected.

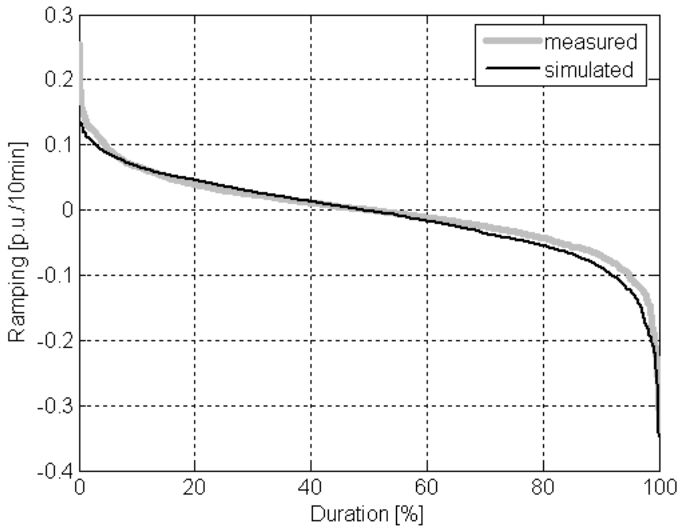


Figure 4 Duration curves of 10 minutes ramp rates in the initial power range from 0.8 to 0.9 p.u.

The ramping is sorted in each power bin, and a duration curve is obtained. This is done for the measurements and for the simulations. As an example, the duration curves for ten minute ramp rates in the initial power range between 0.8 - 0.9 p.u. is shown in Figure 4. There is a good agreement between the simulated and the measured duration curves.

The most interesting point of the duration curves is the highest wind farm negative ramp rate, i.e. around 100% on the duration curve, because this quantifies the highest requirement to the ramp rates of other power plants. The wind farm positive ramp rates are not so interesting here because they can be limited directly by the wind farm main controller.

In Figure 5, the 99% percentile of the 10 minutes ramp rates duration curve for all power ranges is shown. In order to assess the model performances, both Horns Rev and Nysted simulated and measured ramp rates are plotted.

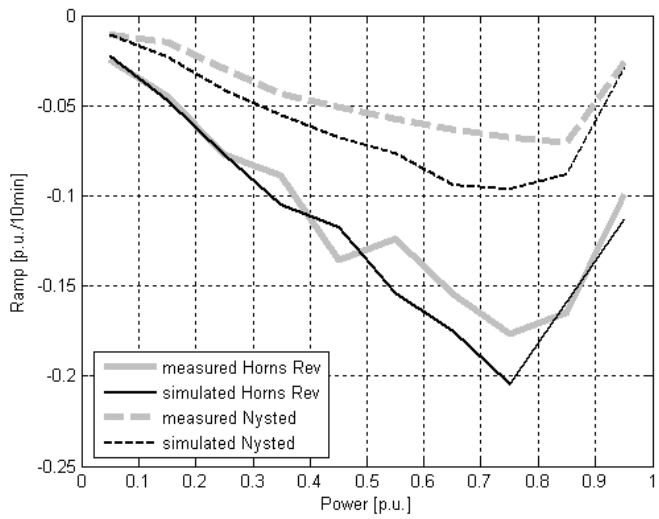


Figure 5 The 99% percentiles of 10 minutes ramp rates in all power ranges for Horns Rev 1 and Nysted wind farm

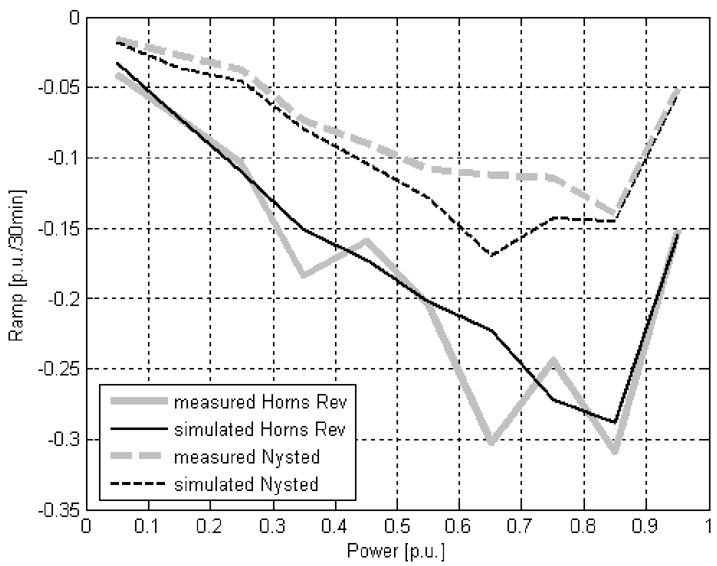


Figure 6 The 99% percentiles of 30 minutes ramp rates in all power ranges for Horns Rev and Nysted wind farms

The 99% percentile for 30 minutes period is shown in Figure 6. The match between simulated and measured power fluctuations is similar to the 10 minutes periods, with the simulated power fluctuations still being systematically bigger than the measured ones.

WILMAR

The WILMAR (Wind Power Integration in Liberalised Electricity Markets) model (reference) consists of two modules: the Scenario Tree Tool (STT) and the Joint Market Model (JMM). The STT is a tool for generating scenario trees for wind and demand. The scenario trees are subsequently used by the JMM to find the hourly economic unit commitment and dispatch of electricity generation with respect to uncertainty in wind and demand. In Wilmar, uncertainty is disregarded in the unit commitment and dispatch problem solution, and scenario trees are not needed for the JMM simulations. Therefore only the JMM is used in WILMAR.

The Joint Market Model (JMM) forms the economic dispatch of power generation, flows, and consumption given generation unit data, trading capacities, loads, fuel and emission prices, as well as, information on wind, hydro etc. JMM operates with a dynamic planning horizon of up to 36 hours and an hourly time resolution. JMM includes integrated optimisation of electricity storage units over the planning horizon (up to 36 hours). This makes it possible to model e.g. cold storage units and electric vehicles as described in [12]. Three modes are available: Perfect forecast, deterministic with forecast error, and stochastic. The three modes differ in the way stochasticity in wind and demand is treated. In this project JMM is run in perfect forecast mode, which assumes perfect information throughout the entire planning horizon.

Due to the nature of the wind forecasts used in this project, the hourly dispatch values can be interpreted as “Day-ahead” or “Spot-market” solution and serves as input to the SIMBA model.

SimBa

Simulation of Balancing (SIMBA) is a model developed by Energinet.dk and DTU Wind Energy, aiming at simulating the balancing of the Danish power system. It requires hourly energy values for scheduled production, consumption and exchange as input. In the operational set-up the values are expected to be the scheduled hourly values shortly before the power planning of the operating hour. This is usually seen as the output from a traditional Unit Commitment model (UC model) and therefore the output from an UC model is used as input to SIMBA. In the present setup, the UC model (WILMAR JMM) simulates the day-ahead spot market and returns time series for production, consumption, prices etc. in an hourly time resolution. Then SIMBA transforms these time series into a more detailed (5 minutes) time resolution and thus simulating hour-ahead operational schedules for production, exchanges etc. In the operational setup the sum of the day-ahead energy schedules will always be zero whereas the sum of all hour-ahead power schedules might not be zero for all detailed time steps. Market players will pay for deviations from energy schedules as well as deviations from their power schedules. The generation of power schedules in SIMBA differs for the different types of production, consumption and exchanges.

Hour-ahead power schedules for consumption are generated by smoothing the hourly energy values. In this first version of the model it is assumed that the consumption is perfectly forecasted which also can be interpreted as if the consumption were known one hour in advance.

Power schedules for exchanges via interconnectors are generated so that they respect ramping conditions. In the West Danish area transit from Nordic countries to Germany causes imbalance due to different ramping speeds.

Power schedules for traditional power plants are based on ramping from one hourly energy to the next using the ramping characteristics the user has given in the user interface.

Power schedules for wind production are based on wind power forecasts. The hourly wind power values from the UC model are not used by SIMBA, but replaced by simulations of the wind power forecast one hour prior to the operating hour with the detailed time resolution. Based on these values detailed power schedules are generated, including the intra-hour variability that is not modeled by most wind power forecast systems. In addition, detailed power time series are generated to model the actual wind power production.

Based on these detailed power schedules, a resulting system balance can be calculated. The schedules can be interpreted as the power schedules available to the operators prior to the operating hour.

SIMBA also calculates the available capacity in the system. This is based on knowledge about the technical characteristics of the units in the model. Based on this and the marginal costs of the units a merit order list of upward and downward regulation capacity is created. This simulates the NOIS list in the Nordic system.

Finally, when activating regulating power in the model, the rules applying to activation are obeyed. In this version of the model, the balancing is rather simple but obeys the existing rules for balancing in the Danish system. For each half hour the mean imbalance is calculated and this amount is activated. This simulates real-life operations at Energinet.dk although Energinet.dk continuously updates schedules and activates regulating power in real time. The results from SIMBA will therefore be able to provide an estimate of the amount of activated regulating power as well as a residual imbalance that needs to be balanced with real time schedule updates and automatic reserves.

4.3.3 Link between tools

There were three simulation tools used in the assessment of the technical and economic impact of the storm controls.

- WILMAR Joint Market Model (JMM)
- Simulation of Balancing (SimBa)
- Correlated Wind (CorWind)

The day-ahead (DA) unit commitment and dispatch is simulated using the WILMAR-JMM. It gives the DA schedule for both the wind and non-wind units for the power system in North Europe taken as Denmark, Norway, Sweden, Finland, UK, Germany, Holland, Belgium, France and Poland.

The hour-ahead balancing is simulated using SimBa. One of the inputs to SimBa is the DA schedule output of WILMAR for only Denmark, separated into the two synchronous areas, DK1 and DK2.

The DA wind power forecast $P_{w,DA}$[1h], which serves as an input to both WILMAR-JMM and SimBA, is simulated using CorWind. CorWind is also used to generate the time series for the possible power $P_{w,pos}$[5m] and hour-ahead (HA) forecasts $P_{w,HA}$[5m] that are consistent with the

DA forecast. The deviation between the $P_{w,HA}$[5m] and the $P_{w,DA}$[5m] provides the imbalance that SimBa will try to reduce through a simulation of the Danish power market.

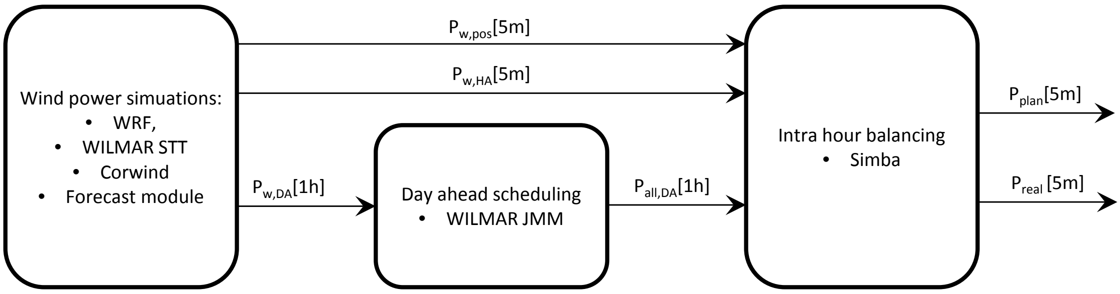


Figure 7 Overview of the tools and their linkages

4.4 Results

4.4.1 Wind power scenarios in Denmark

The wind power development scenarios considered in the project are presented in details in [13]. For Denmark, the scenario considers a total number of 24 offshore wind farms (existing and future ones), leading to a total installed capacity of around 3 GW.

Table 3.2 Onshore and Offshore wind power in 2020 and 2030 in Denmark

	2020		2030	
	Base (MW)	**High (MW)**	**Base (MW)**	**High (MW)**
ONSHORE	3700	4000	4869	5,381
OFFSHORE	2811	3211	4,611	5,811
TOTAL	6511	7211	9480	11192

The geographical distribution of those wind farms is shown in Figure 8. It should be mentioned here that Horns Rev 3 wind farm, initially estimated to have a capacity of 200 MW, was recently announced to have been approved for an installed capacity of 400 MW. Nevertheless, for consistency, we have decided to keep the original estimated installed capacity.

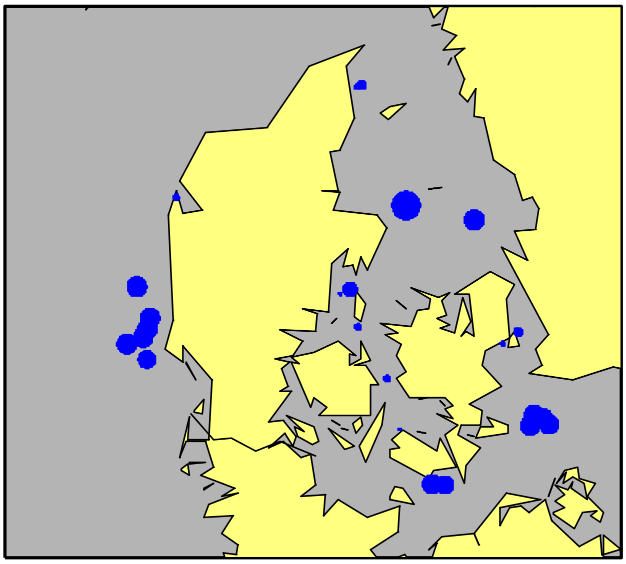


Figure 8 Offshore wind farms in Denmark in 2020

4.4.2 Aggregation of power curves

The simulation of wind power production was done using a steady-state wind to power (wind2power) conversion model. The wind2power conversion model includes a power curve – the representation of the relation between wind speed and wind power, and the storm controller (High Wind Shut Down – HWSD and High Wind Extended Production – HWEP, which is based on the new storm controller used in Demo 4 and described in [14]). Usually, the power curves are given for individual wind turbines.I In this study, aggregated wind power curves – able to map the relation between average wind speed and total power output for a whole wind farm was used. A more detailed description of the wind2power conversion module is given in [15]. The graphical representation of the wind2power conversion module, for both HWSD and HWEP, is given in Figure 9.

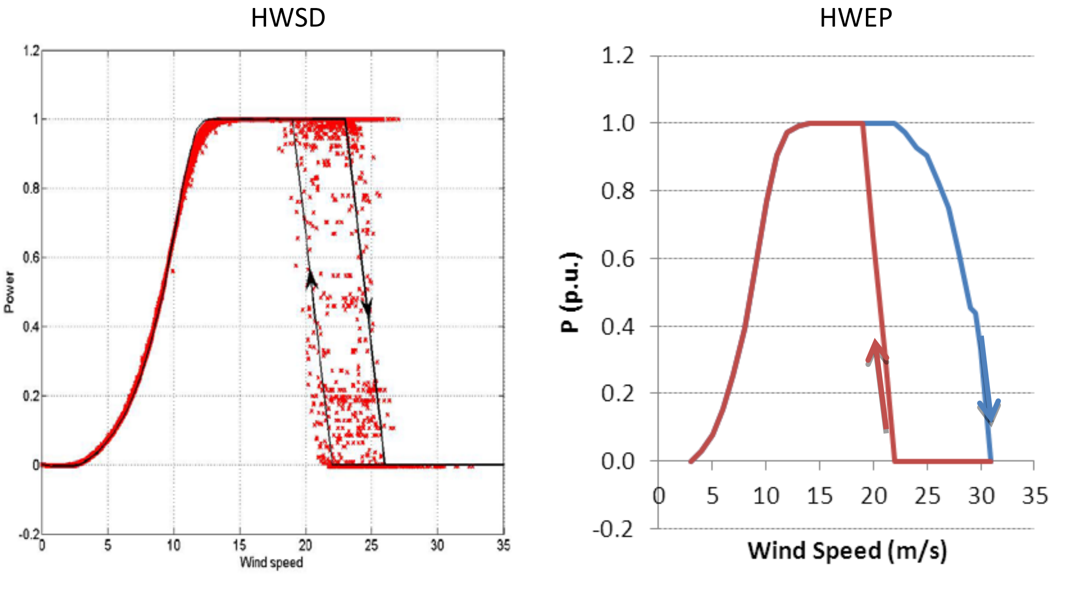


Figure 9 HWSD (left) and the HWEP (right) controls

4.4.3 Up-scaling of storm impact

A number of high wind speed periods were identified in the historical data covering the period 2001 – 2011. The list of those events is given in Table 3.3

Table 3.3 High wind speed periods

2001	01/01/2001	**2008**	21/03/2008
2005	02/01/2005		13/08/2008
2007	01/01/2007		08/11/2008
	08/01/2007	**2009**	11/06/2009
	18/03/2007		03/10/2009
	27/06/2007	**2010**	11/11/2010
	08/11/2007		07/02/2010
2008	25/01/2008	**2011**	10/03/2011
	27/02/2008		

Each period was simulated with HWSD and HWEP. An example of one of the results is given in Figure 10. For an easy comparison the mean wind speed is also plotted. The result shows very clearly that with the HWEP controller the total power dip is significantly lower than the one with HWSD, i.e. around 0.5 p.u..

The simulations were done using CorWind. In order to have a more significant statistical result, the simulations were done for several random seeds for the stochastic part. In total, each event was simulated with a number of 5 random seeds for each period.

The maximum ramping – as defined in section 3.3.1 – was calculated for time windows relevant for the power system operation: 15, 30, 60 and 90 min. The duration curves for both controllers are given in

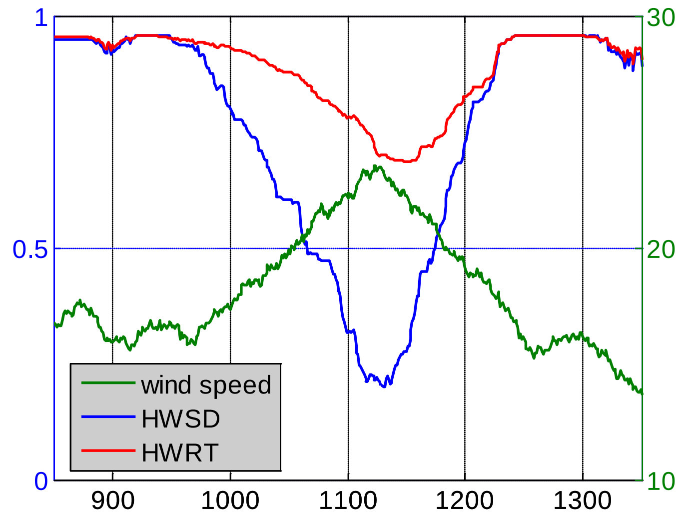


Figure 10 Offshore wind power production in Denmark, in 2020, during a storm event

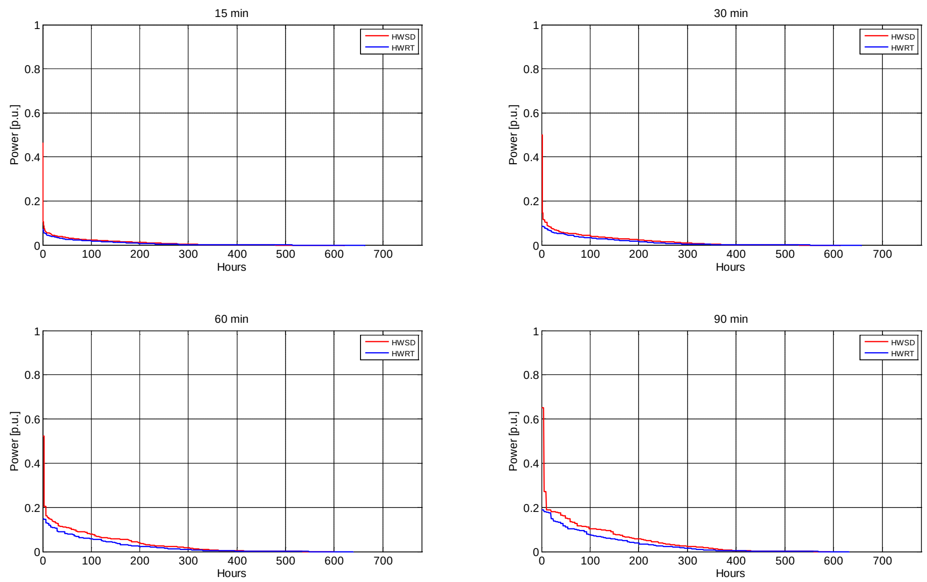


Figure 11 Offshore wind power maximum ramping duration curves

When looking at the maximum values of the distribution, the difference between the two controllers – for each time window – is given in Figure 12.

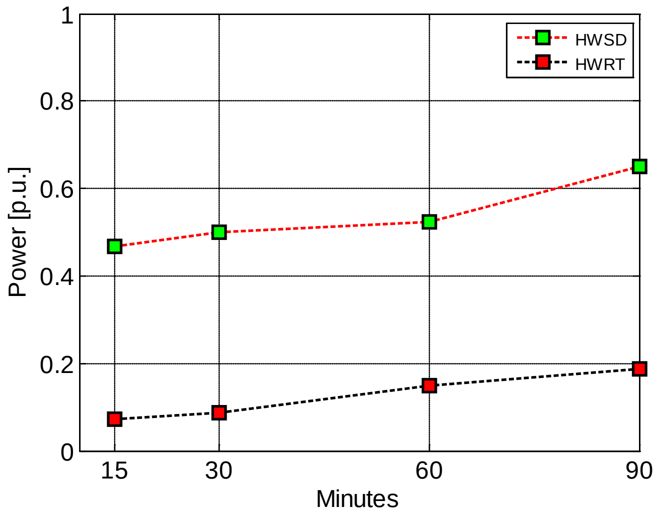


Figure 12 Maximum ramping values for each interval

The values of the maximum ramping are given – in per units in Table 3.4 and in MW for the 2020 base scenario in Table 3.5. The reduction in terms of maximum ramping is almost 40% of the installed capacity or around 1200 MW with time windows of 15 – 90 min.

Table 3.4 Maximum ramping in relative units

	Time horizon			
	15 min	30 min	60 min	90 min
HWSD	0.47	0.50	0.53	0.65
HWEP	0.07	0.09	0.15	0.19
Difference	**0.39**	**0.41**	**0.38**	**0.46**

Table 3.5 Maximum ramping in MW (base scenario 2020)

	Time horizon			
	15 min	30 min	60 min	90 min
HWSD	1343	1441	1516	1876
HWEP	209	247	430	542
Difference	**1133**	**1194**	**1086**	**1334**

From the frequency stability point of view, the most interesting result is the 15 min window. It should be noted that the maximum ramping of 1343 MW in the HWSD case is higher than the dimensioning outage of 1200 MW in the Nordic system, while the 209 MW with the HWEP is well below that limit. Although the frequency stability should be assessed for the complete synchronous areas, this result indicates that the HWSD control can be a threat to the frequency stability, and that this danger is significantly reduced using the HWEP control. The assessment in the synchronous areas will be reported in TWENTIES deliverable D16.6.

4.4.4 Simulation of balancing

The analysis of the balancing during storm for the Danish power system was done using SIMBA – together with CorWind and WILMAR – in the setup described in section 3.3.3. The simulation was done for the meteorological year 2009. During this year, there was only one event that triggered the storm control in a significant manner. This can be clearly seen in Figure 13, where the difference between the wind power with HWSD and HWEP control is shown.

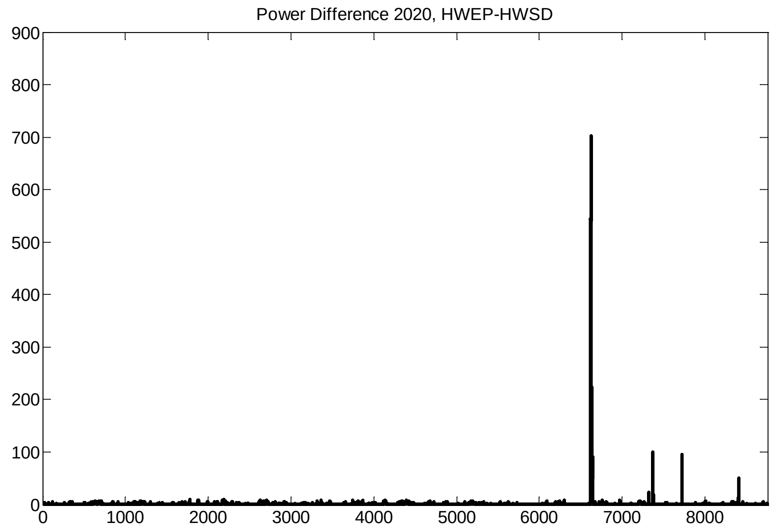


Figure 13 Wind power difference, 2020 scenario

The interest in this analysis lies in the period of storm events or, in other words, in the moments in time that there is difference in the wind power time series shown above. This is because the differences are due only to the storm controller. The period with significant differences in the wind power is around October 3rd, when a high wind speed front passed over Denmark. The wind power production for the 2020 scenario, for both HWSD and HWEP, during the storm event is shown in Figure 14.

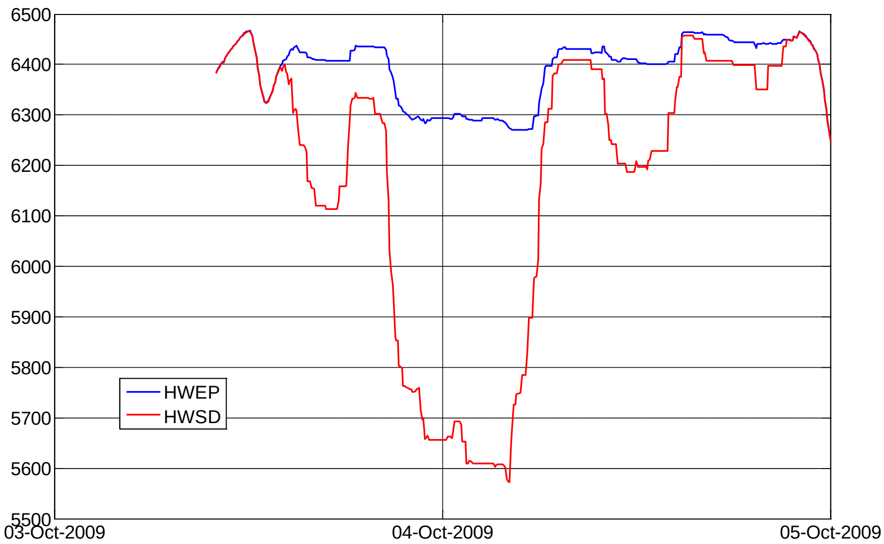


Figure 14 Wind power production for both controllers during the storm event, 2020 scenario

It is easily observable that the magnitude of the difference in the power production is not very large, thus the impact on the overall balancing is expected to be modest. Nevertheless, the results can illustrate if the trend is towards diminishing the need for reserves or not.

The hour-ahead balancing results, for 2020, are summarised in Table 3.6. One should notice that the results are compared only during the storm event, i.e. for a period of a little over a day.

Table 3.6 Hour-ahead balancing in Denmark during storm event in 2020

Year 2020	HWSD	HWRT	HWRT-HWSD	HWRT/HWSD
Up regulation volume [MWh]	1977	1651	326	84%
Down regulation volume [MWh]	-4376	-4520	144	103%
Up regulation expenses [€]	5228	4487	742	86%
Down regulation earnings [€]	3825	4600	775	120%

As expected, the difference in the regulation volumes is rather small. What is to be mentioned here is that even during an event with a small overall impact, TSO's expenses decreases and the down regulation earnings increase. When looking at the amounts only **during** the event, the difference in percentage show a decrease of the up regulation volume around 15% while the down regulation volume increases very little. In terms of earnings for the TSO, the increase is around 20%.

When looking at the 2030 scenario, one can observe the same storm event in the beginning of October – see Figure 15. This time, the magnitude of the power difference is larger, as expected

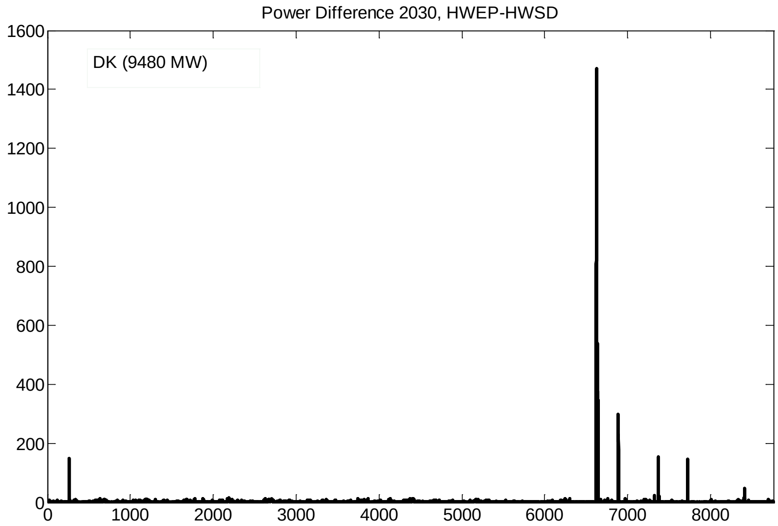


Figure 15 Wind power difference in Denmark, 2030 scenario

The wind power production for the 2030 scenario, for both HWSD and HWEP, during this storm is shown in Figure 16.

The hour-ahead balancing results, for 2030, are summarised in Table 3.6. One should notice that the results are compared only during the storm event, i.e. for a period of a little over a day.

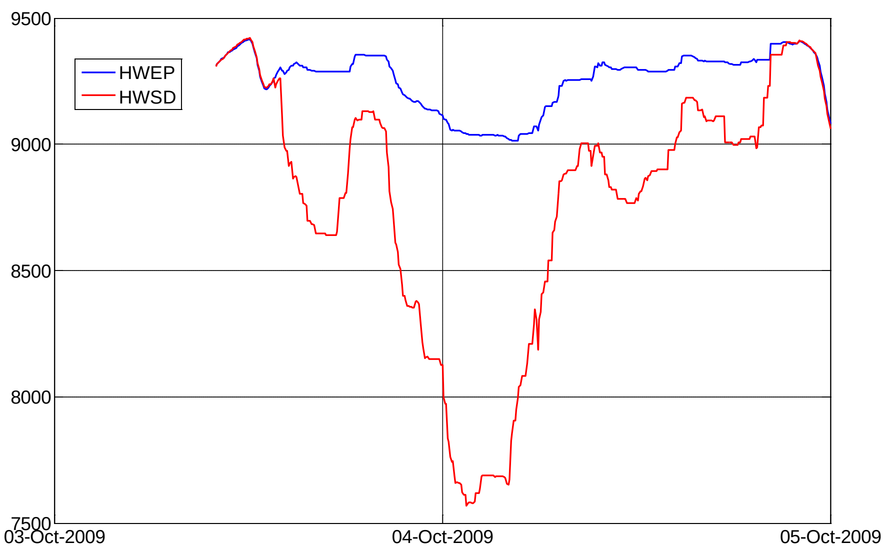


Figure 16 Wind power production for both controllers during the storm event, 2030 scenario

Table 3.7 Hour-ahead balancing in Denmark during storm event in 2030

Year 2030	HWSD	HWRT	HWRT-HWSD	HWRT/HWSD
Up regulation volume [MWh]	3368	3203	166	95.08%
Down regulation volume [MWh]	-8855	-10054	1199	113.54%
Up regulation expenses [€]	8620	8253	368	95.74%
Down regulation earnings [€]	796	846	50	106.23%

The conclusions are similar as in the 2020 case, with the new controller improving the system needs for balancing.

4.5 Conclusions (DTU)

The main conclusion arising from the study is that the HWSD control can be a threat to the frequency stability, and that this danger is significantly reduced using the HWEP control. In addition to that, the HWEP-type controller implies a minor increase in the energy production during the storm event – between 2-4% in the analyzed case, and a minor reduction in the net balancing costs.

From the analysis of the maximum ramp rates, it is found that the largest disturbance due to storms are reduced from 1343 MW to 209 MW considering only the offshore wind farms in Denmark. Although the frequency stability should be assessed for complete synchronous areas, this result indicates that the HWSD control can be a threat to the frequency stability, and that this danger is significantly reduced using the HWEP control.

During the analyzed storm period, the TSO up-regulation expenses for hour-ahead balancing are increased and down regulation earnings are increased when the HWSD control is replaced by the HWEP control. However, these numbers are negligible compared to the annual net balancing costs.

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