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Technology, market and economic aspects of wind energy in Europe

Roberto Lacal Arántegui

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Cover picture: Offshore wind farm. © Jos Beurskens.

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ABBREVIATIONS AND ACRONYMS:

Throughout this report 2-letter country codes are used as for the International Organization for Standardization: http://www.iso.org/iso/country_names_and_code_elements. Other abbreviations and acronyms are:

bn	Billion (1 000 million)
CapEx	Capital expenditure, or capital cost
CF	Cohesion Fund
CoE	Cost of energy
DD	Direct-drive
DFIG	Doubly-fed induction electricity generator, also called DFAG (A for asynchronous)
EEA	European Economic Area, includes the EU plus Iceland, Liechtenstein and Norway.
EMG	Electromagnet generator
FP	Framework Programme for Research and Technological Innovation
EIB	European Investment Bank
EPO	European Patent Office
EBRD	European Bank for Reconstruction and Development
ERDF	European Regional Development Fund
EU	European Union
GW	Gigawatt (= 1 000 000 000 Watts)
HTS	High-temperature superconductor
IEE	Intelligent Energy Europe programme of the European Commission
IRR	Internal rate of return
IGBT	Insulated-gate bipolar transistor
JRC	Joint Research Centre, a directorate general of the European Commission
JTI	Joint Technology Initiative
kW	Kilowatt (= 1 000 Watts)
LCoE	Levelised cost of energy
m	Million
MW	Megawatt (= 1 000 000 Watts)
NPV	Net present value
OEM	Original equipment manufacturer, in the context of this report OEM is the wind turbine manufacturer.
OpEx	Operational expenditure or O&M cost
O&M	Operations and maintenance
PM	Permanent magnet (s)
PMG	Permanent magnet generator (s)
RD&D	Research, development and demonstration
RoI	Return on investment
RPM	Revolutions per minute
R&D	Research and development
SCIG	Squirrel-cage induction (or asynchronous) electricity generator
SET-Plan	(European) Strategic Energy Technology Plan (EC, 2007)
WIPO	World Intellectual Patent Organization
WRIG	Wound-rotor induction (or asynchronous) electricity generator

EXECUTIVE SUMMARY

During 2012 the wind energy sector saw a new record in actual installations and also a negative record year for the economics of its manufacturing sector. 2013, by contrast, saw a reduction in turbine installations but a better perspective for the economics of the sector.

The global market reached 45 GW of installed capacity in 2012 of which 1.4 GW offshore, whereas in Europe 11.9 GW installed beat the 2009 record of 10.2 GW, with the offshore market also marking a new record with 1.275 GW. Global cumulative installed capacity reached 285 GW at the end of 2012 and, according to preliminary reports, it reached around 320 GW by the end of 2013. The installed capacity at the end of 2012 in the EU produces 203 TWh of electricity on an average year.

The 2012 manufacturers market saw, for the first time in many years, the traditional leader Vestas unseated by GE Energy from the US (BTM, 2013). As in 2010 and 2011, four Chinese firms were included among the top-ten. However, the changes in the Chinese market are very significant as its 2010 market leader (and 2nd worldwide), Sinovel, became 9th worldwide. European firms Vestas, Gamesa and Siemens, General Electric from the US and Suzlon/Senvion (India/Germany) have a truly international reach whereas Chinese firms just started to seriously expand beyond the Chinese market, led by Goldwind.

From a technology point of view in 2013 the outstanding results of the TWENTIES project for wind integration deserves credit. They showed e.g. that up to 15% more electricity can be transported in existing lines with minimum operational and technological improvements, and up to 25% more in newly-designed lines using new but within-reach technologies.

In 2012 both turbine and project prices onshore dropped, and 2013 showed the first indications that a 40% reduction in offshore cost is within reach by 2020[1].

The analysis of data from IEAWind (2013) suggests that the average “Western” (i.e. without Chinese or Indian project data) wind project capital investment was ***1510 €/kW*** in 2012, a reduction of 4% over the 1 580 €/kW of 2011, and the average turbine cost was ***940 €/kW*** in 2012, a 6% reduction over the 998 €/kW of 2011. Calculations based on different sources suggest a significant reduction for 2013 to perhaps €1 410/kW.

Operational costs (OpEx) were also very different onshore (12 - 16 €/MWh) from offshore (22 - 53 €/MWh), figures depend on assumptions such as capacity factors.

There is a trend to lower prices in both CapEx and OpEx, possibly steeper in offshore than onshore OpEx and with significant potential for the reduction of offshore CapEx.

Evidence showed a reduction in the time needed for installing offshore foundations by means of expensive installation vessels, and that this learning effect was not mirrored by turbine installation. The data also showed that there is a significant gap between monopile foundation installation and other types of foundations.

This report discusses the technology, economics and market aspects of wind energy in Europe and beyond – because the wind sector is a global sector. Its intended audience include policy-making and support officers in the European institutions and Member States and the wind sector from developers through manufacturers to academia.

[1] For projects with final investment decision made in that year

1. Introduction

Figure 1: wind turbines at dawn. © Jos Beurskens.

This is the second issue of an annual report with which the Energy Systems Evaluation Unit of the Institute for Energy and Transport[2] supports policy-making related to the wind energy sector, by presenting its technology, market and economics with a focus on the European Union.

Wind power has seen an impressing deployment over the last two decades, from 3.5 GW in 1994 to around 320 GW of cumulative global capacity expected at the end of 2013. In Europe, the 100-GW mark was surpassed in September 2012, a year when four countries (Denmark, Portugal, Ireland and Spain) obtained between 15 and 30 % of their electricity from wind, and seven others more than 5 %. Wind energy will provide at least 12 % of European electricity by 2020, which is a very significant contribution to the 20/20/20 goals of the European energy and climate policy.

This report focuses on the wind sector in Europe but, because this sector is a global industry, some sections have a global scope. The report is based on industry annual reports and other declarations; on the JRC research work in wind technology; on JRC databases of wind turbines and installations, models and other internal research; on research by key players from industry and academia; and on direct industry consultation.

The report is made of regular sections and of ad-hoc research chapters focusing on specific technology issues. Section 2 investigates the technological situation: state-of-the-art of wind turbines and of their main components, research and innovations, and its possible future evolution, with a focus on technological changes brought about during 2013, or those hinted by industry and research institutions as the possible future. Section 3 analyses the market situation, what happened in 2012 plus the longer-term trends that emerge; proposes some deployment scenarios and analyses industrial strategies as made public by manufacturers and developers. Section 4 focuses on the economics of wind projects and their main elements thereof: project and turbine capital expenditure (CapEx), operational expenditure (OpEx), and cost of energy (CoE). Other socio-economic aspects touched upon include the amount of energy produced, the value of wind to the society and employment. Section 5 presents ad-hoc research on the learning-by-doing effect in the installation of the main elements of an offshore wind farm, the turbine and their foundations.

[2] One of the seven institutes of the Joint Research Centre of the European Commission, see http://ec.europa.eu/dgs/jrc/index.cfm

2. TECHNOLOGY STATUS

A wind turbine starts to capture energy at the cut-in speeds of around 3 m/s (11 km/h) and the energy produced increases initially in relation to wind speed in proportion to the wind speed cubed. Then, at higher wind speeds, it increases roughly proportionately to the wind speed until levelling off at the turbine rated power of around 12 m/s (43 km/h), then remaining constant until strong winds force the turbine to stop at the cut-out speeds of around 25 – 28 m/s (90 - 100 km/h) in order to avoid putting at risk its mechanical stability. Once stopped and secured, turbines are designed to withstand wind speeds of up to 70 m/s (252 km/h)[3]. Generally, utility-scale wind farms require minimum average wind speeds of 5.5 m/s for a profitable operation.

Current onshore wind energy technology is mature although it certainly has room for further improvement, e.g. better efficiency and improved drive trains; computer models to optimise site selection of turbines in a wind farm area –esp. when the terrain is not flat- and minimise wake losses. Offshore wind, however, still faces many challenges because of e.g. the demanding marine environment, the substructure and connection costs, which all together result in a high cost of the technology, logistics and installation processes, and it needs system optimisation.

The main components of a modern wind turbine are: rotor, composed of rotor blades, hub and pitch system; drive train composed of main shaft, gearbox (depending on configuration, see (Llorente-Iglesias et al., 2011)), low-, medium-, or high-speed electricity generator; control system; full or partial power electronics converter; yaw system made of drive and bearing; cooling system; and concrete, steel or hybrid towers. More and more, the control system is becoming a key element ensuring reliability, safety and optimum turbine output.

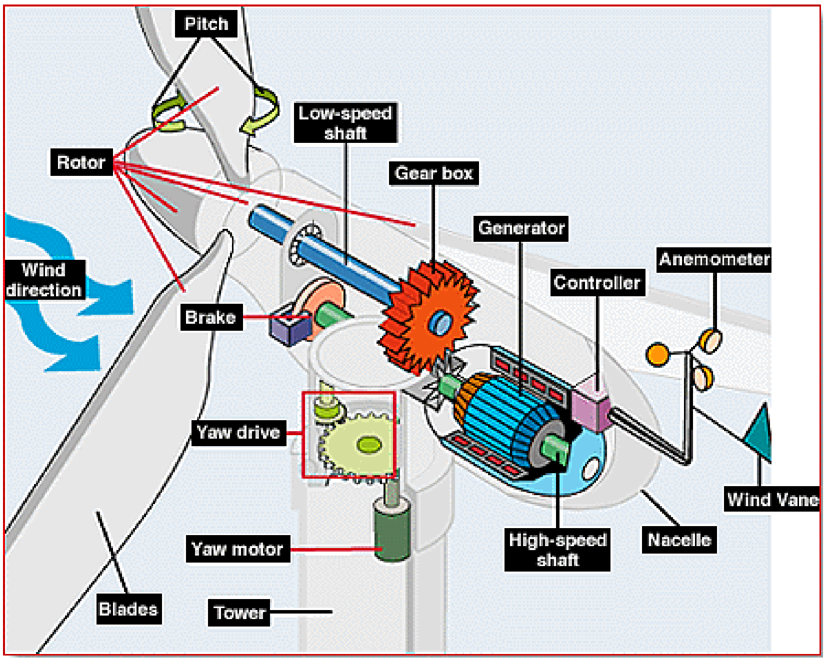


Figure 2: Main elements of a wind turbine. Courtesy of Gamesa

2.1. Wind energy state-of-the-art

2.1.1. Wind turbine design

Out of a wide variety of wind turbines, in the 1980s the Danish three bladed, single fixed speed, stall-regulated turbine became the dominant model in the market at rated power

[3] The exact values are set by the wind class, the wind turbines are designed for.

levels of less than 200 kW. Since then, turbine dimensions, both in terms of generator capacity and of rotor diameter, have grown steadily and by 2006, 2-MW turbines were commonly installed in onshore projects. Recently, the average size of turbines installed in 2012 in most western countries is 2 MW or above (BTM, 2013).

The main technological characteristics of current turbines are:

- Steel, concrete or hybrid towers reaching 150m of height.
- An upwind rotor with three blades, active yaw system, preserving alignment with the wind direction. Rotor efficiency, acoustic noise, costs and visual impact are important design factors. Some turbine designs have only two blades.
- High-wind-speed control. Pitch regulation, an active control where the blades are pitched along their axis to regulate the extracted power and reduce loads.
- Variable rotor speed. It was introduced to allow the rotor and wind speed to be matched more efficiently in particular at lower wind speeds, and to facilitate an output more according with the needs of the electricity grid.
- A drive train system, where a gearbox adapts the slow-rotating rotor to the needs of a fast-rotating electricity generator. However, more and more low-speed generators are used directly coupled to the turbine rotor, i.e. without a gearbox.

Although older, simpler designs are cheaper - in terms of both up-front investment and maintenance costs-, new technology increases energy extraction from wind, allows higher power outputs and –a crucial issue- provides electricity better adapted to the quality demanded by grid operations, eventually reducing the cost of energy.

The main wind turbine design driving goal is to minimise the costs of energy through lower capital costs and increased reliability, which translate into: specific designs for low and high wind sites, grid compatibility; low noise, good aerodynamic performance and redundancy of systems in offshore machines. Technical considerations that cover several of these goals include low-mass nacelle arrangements[4], large rotor technology and advanced composite engineering and design for offshore foundations, erection and maintenance.

Box 1: wind turbine configurations

Type A Fixed-speed rotor, no power converter - the "Danish model".

Type B Slightly variable speed rotor, no power converter – the "advanced Danish model".

Type C Variable speed rotor, doubly-fed induction generators (DFIG) with a partially-rated power converter (around 30% of rated power)

Type D Variable speed, direct drive, and full-scale power converter with either electromagnet or permanent magnet electricity generators.

A sketch of types C and D is included in section 2.2

Increasingly-demanding grid codes have an impact on turbine design. The type C turbine configuration (see box 1) is currently the most popular design (Llorente-Iglesias et al., 2011), but type D and hybrid designs (see Table 2) offer more flexibility thanks to a full power converter (FC)[5], thus allowing easier compliance with the most demanding grid "fault ride-through" capabilities required by recent grid codes. The transition from type C to type D or hybrid designs is accelerating as power electronics become increasingly more affordable

[4] For example, Acciona's 2013 version of the model AW300 claims nacelle weight (without the rotor) of 111.4 t, versus 118 t of the previous version.

[5] For a full explanation of why and how a full converter offers flexibility see e.g. (Llorente-Iglesias el al., 2011)

and reduce the importance of one of the key cost arguments against using them – the other being a high failure rate of power electronics.

2.1.2. Drive train design

Even when new turbine designs keep appearing in the megawatt range using permanent magnet generators (PMGs), the majority of those introduced in the last 12 months are for onshore use and contain a doubly-fed induction generator (DFIG).

Generator	Wind turbine model	Converter
DFIG	Vestas V110-2.0; Senvion 6.2M152; Acciona AW125/3000; Gamesa G114-2.0 and G114-2.5; Nordex N100/3300, N117/3000 and N131/3000	Partial
Squirrel-cage	Siemens SWT-4.0-120, SWT-4.0-130	Full
HS-PMG	Vestas V112-3.3, V117-3.3 and V126-3.3	Full
MS-PMG	Gamesa G128-5.0, G132-5.0	Full
LS-PMG	Siemens SWT-3.0-108, SWT-3.0-113; Enercon E115-3.0	Full
Undisclosed	GE 3.2-103, GE 2.5-120	Undisclosed

Table 1: Most wind turbines presented in the last 12 months include DFIG technology. Key: DFIG is the conventional doubly-fed induction generator; permanent magnet generators (PMG) are classified here as medium speed (MS) or high speed (HS)

On the other hand, the largest wind turbine designs (listed in Table 3), those mostly addressing the offshore market, with the main exception of Enercon and Senvion models, are based in permanent magnet generators. This finding suggests that the DFIG design retains the flavour of the onshore market –possibly thanks to the significant investment in the last years into improving the reliability of this type of energy conversion. They also suggest that offshore machines are more wary of reliability issues.

Table 2 shows a comparison of key drive-train elements in the type C and D configurations as well as in a hybrid configuration.

Item	Type C	Type D	Hybrid
Gearbox	3-4 stages, high speed	None	1-2 stages, medium speed
Generator	DFIG (1200 – 1800 RPM)	Electromagnet or PM, low speed (8–20 RPM)	PM (60 – 600 RPM)
Rare earth use	None	(if PMG) 160-200 kg/MW	40 - 60 kg/MW
Converter	Partial	Full	Full

Table 2: Comparison of the key elements for type C, type D and hybrid drive trains. Rare earth use is approximate for a 3-MW turbine. See Janssen et al. (2012) for an analysis on rare earths use in PMG.

The exact details of what constitutes each type are subject to debate between different authors. In general, turbine designs under configuration types A, B and C always use high-speed electricity generators, whereas low-speed generators are part of a type D design and medium-speed generators are considered a hybrid configuration.

Because the lower the speed of an electricity generator the larger its size, a medium-speed generator has a larger diameter than a high-speed one[6] - but induction (asynchronous) machines are generally less attractive at low speeds and large diameters (Jamieson, 2011). Therefore only synchronous machines, especially PMGs, are considered at medium and low speeds.

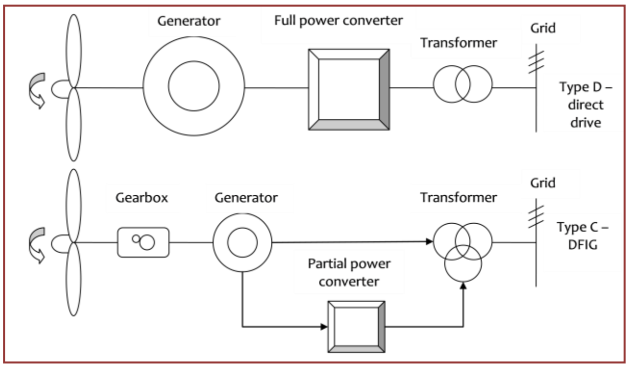


Figure 3: Sketch of drivetrain differences between turbine configurations types C and D.

The options for electrical power conversion depend on the turbine configuration (see box 1 and Figure 3). By default, types A and B do not include power conversion, although a hybrid configuration including, e.g. a simple squirrel-cage induction generator, could use full conversion to optimise output quality[7]. Type C can only use a partial converter whereas type D can only use a full converter. Table 1 shows that full converters are slightly more popular than PMG in new turbine designs. A more complete description can be found in the 2012 issue of this report.

2.1.3. Offshore design and foundations

Technology developments are also occurring in the growing offshore wind industry, where the design of foundations, installation systems, O&M strategies and cable connection is as important as that of turbines. The most popular foundations are monopiles and, to a lesser extent, gravity-based foundations for shallow-to-medium water depths. Figure 4 shows the split of installed foundations per type. Jacket foundations are more expensive than monopiles and, possibly more importantly, its installation takes longer. Still, they are expected to become more common because they absorb better the higher loads due to increasingly larger rotors and at depths of 30 – 60 m (by the way, a depth at which tripod and tripile designs have been consolidated during 2012-2013) and have significantly higher cost reduction potential (Lynderup, 2014).

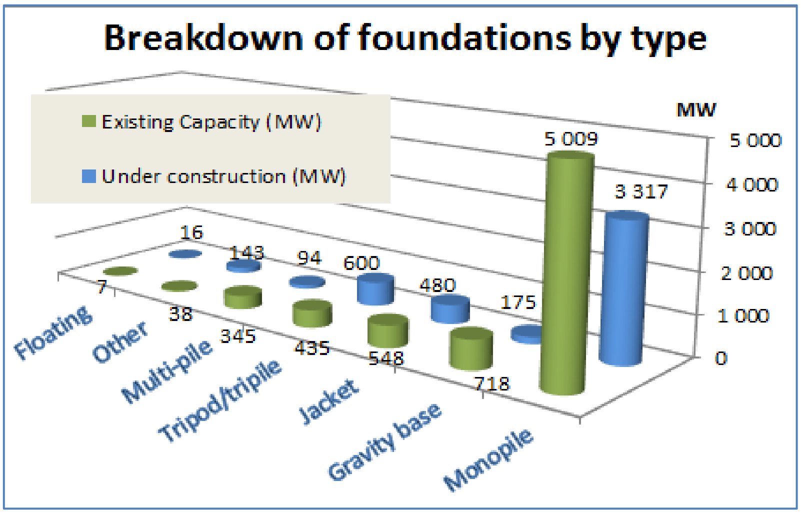


Figure 4: Split of foundations by type, both for existing wind farms and for wind farms under construction at the end of 2013. Source: JRC database.

[6] For example, a 6-MW low-speed PMG can have a diameter of 8 m whereas a medium speed PMG of slightly lower rating (3.3 MW) can have a 2.6 m diameter.

[7] Siemens' flagship configuration for the last six years is the NetConverter® concept which combines a high-speed, "simple" squirrel-cage induction generator, which generates at variable frequency and voltage, with a full converter that transforms the electricity to cover the most-demanding grid codes. Machines with this configuration included SWT-2.3-82 VS, SWT-2.3-93, SWT-2.3-101, SWT-2.3-108, SWT-3.6-107, and SWT-3.6-120.

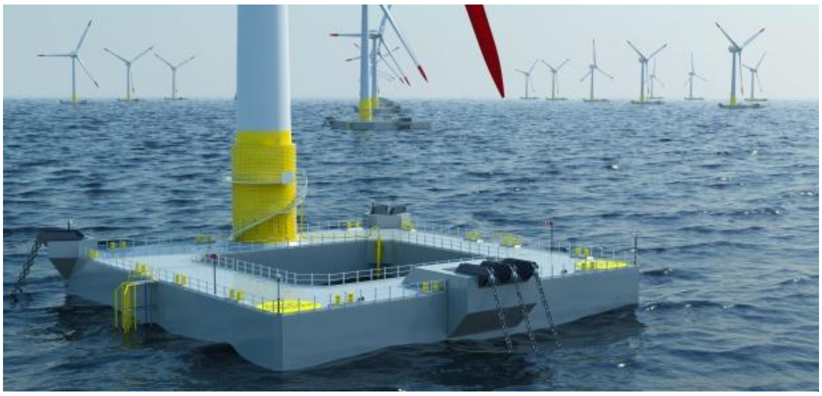


Figure 5: Vision of IDEOL's foundation design in a future floating wind farm. Courtesy IDEOL

A number of designs have reached the prototype stage including some supported by the UK Carbon Trust through the Offshore Wind Accelerator (Carbon Trust, 2014): suction bucket monopiles and jackets, twisted jackets, and floating gravity foundations. Much less common and, in fact, mainly experimental, are and the diverse designs of floating foundations, being explored in order to capture the very large resource available in deep-water areas. At the end of 2013 three prototypes with floating foundations were being tested in the world, one in Norway, one in Portugal and one in Japan (near Fukushima). The first deep-water demonstration wind farms in Europe will likely be the NER300-supported WindFloat and VertiMED projects[8].

Also on floating structures, the EU-supported project FLOATGEN will build two prototypes of multi-megawatt floating turbines in Southern Europe. The two floaters are IDEOL's (France) square ring-shaped concrete (pictured in Figure 5) and OO Star Wind Floater from Olav Olsen (Norway).

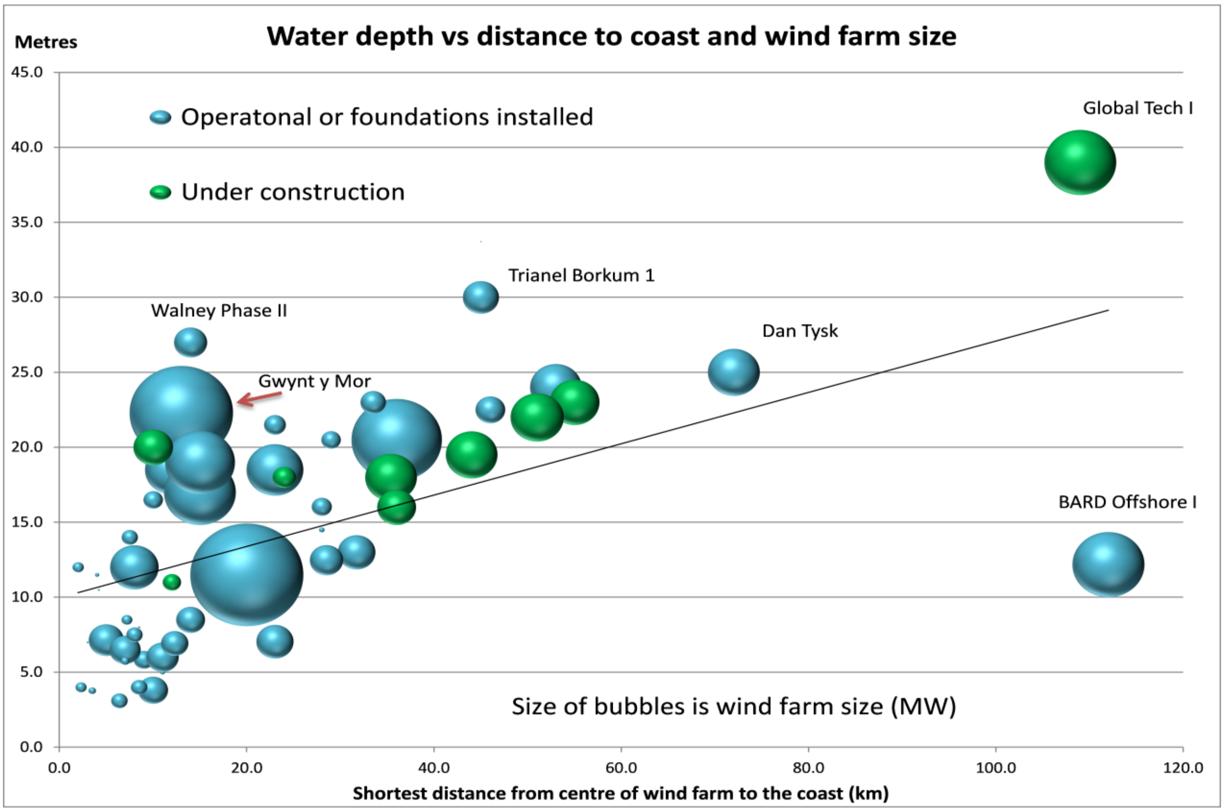


Figure 6: Mean depth (metres) versus distance to coast (km) of European OWF grouped by operational/ in advanced construction (i.e. foundations already installed) and under construction stages. Source: JRC data

[8] NER300 is a funding mechanism of the European Union which will provide 30 and 34 m EUR respectively to the WindFloat and VertiMED projects

2.1.4. Offshore wind: farther and deeper

Figure 6 shows the mean depth[9] of existing and under construction[10] European wind farms based on the JRC wind farms database. The graph shows clearly that of all wind farms under construction the ones farther from the coast and in deeper waters are located in German waters.

2.2. Technological developments and associated research

The main driver for developing wind technology further is to minimise the cost of energy (CoE) production, for which efforts focus on minimising capital and operation and maintenance costs and maximising reliability and energy production.

Manufacturer	Model	Size: MW/m	Technology	Status	S.P. W/m²
Enercon	E126-7.5	7.58/127	LS-EMG	Commercially available (2010)	***598***
Senvion	6.2M126	6.15/126	HS-DFIG	Commercially available (2009)	***493***
XEMC-Darwind	XD115	5.0/115	LS-PMG	Prototype installed (2011)	***481***
Areva	M5000/116	5.0/116	MS-PMG	Commercially available (2009)	***473***
Sinovel	SL6000	6.0/128	HS-SCIG	Commercially available (2011)	***466***
BARD	BARD 6.5	6.5/122	2 MS-PMG	Prototype installed (2011)	***454***
Ming Yang	6.5MW SCD	6.5/140	MS-PMSG	Prototype was expected for late 2013	***422***
Guodian UP	UP6000	6.0/136	HS-DFIG	Prototype installed (2012)	***413***
Gamesa	G128/5.0	5.0/128	MS-PMG	Prototype installed (2013)	***389***
Vestas	V164-8.0	8.0/164	MS-PMG	Prototype installed (2014)	***379***
Areva	M5000/135	5.0/135	MS-PMG	Prototype installed (2013)	***349***
Alstom	Haliade 150	6.0/150	LS-PMG	Prototype installed (2012)	***340***
Goldwind	GW6000	6.0/150	LS-PMG	Prototype installed (2014)	***340***
Senvion	6.2M152	6.15/152	HS-DFIG	Presented at EWEA Offshore 2013	***339***
Siemens	SWT-6.0-154	6.0/154	LS-PMG	Prototype installed (2012)	***322***
Mitsubishi	SeaAngel	7.0/167	Hydraulic transmission	Prototype expected (early 2014)	***320***
Samsung	S7.0	7.0/171	PMG	Prototype installed (2013)	***305***
Haizhuang CSIC	HZ-5MW	5.0/154	HS-PMSG	Prototype installed (2012)	***268***

Table 3: A sample of large wind turbines in the market or being introduced sorted according to specific power. Acronyms used: PMG = permanent magnet generator; EMG = electromagnet generator; DFIG = doubly-fed induction generator, a type of EMG. LS/MS/HS=low/medium/high speed; LS is necessarily a direct-drive machine, HS involves a 3-stage, conventional gearbox and MS involves 1- or 2-stage gearbox. Size included rated capacity in MW and rotor diameter in metres

The trend towards ever larger wind turbines continued during 2013 with two new shoreline-installed prototypes (Gamesa G128/5.0 and Areva M5000/135) and one offshore (Haliade 150). The largest, in terms of electricity power rating, wind turbine now in commercial operation has a capacity of 7.58 MW, and most manufacturers have introduced designs of turbines in the 4 – 8 MW range. Manufacturers are increasing the rotor swept area per rated power unit for offshore machines in what is an important trend, thus reducing their specific power (W/m^2) and reducing cost in other wind farm elements, notably in the

[9] Mean depth as declared by the developer or as calculated from the minimum and maximum depths estimated from nautical charts by 4COffshore (4COffshore, 2012).

[10] The distinction has been taken regarding to the level of construction carried out: in blue either the wind farm is finished or the foundations were completed by the end of 2013, in green the wind farm is at an earlier stage of construction but this had already started.

electrical equipment. This means that despite an increase in the installed cost per kW, the COE will decrease, this effect will be more noticeable offshore.

Table 3 includes a sample of commercial or recently-presented or announced large turbines sorted according to their specific power. The table shows that the six turbines with highest specific power are the oldest, suggesting the trend towards lower specific power.

2.2.1. Blades

Blade technology has become at the leading edge of technology development in wind energy, driven by the trend towards larger rotors and lower specific powers mentioned above, in a quest to reduce weight relative to length.

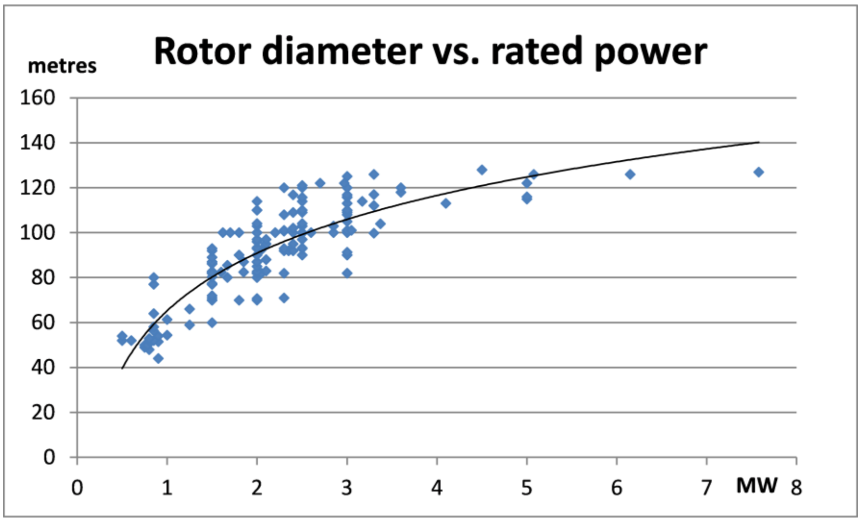


Figure 7: Comparison of rotor size with turbine rated capacity for turbines currently being commercialised. Source JRC data

The last three years have seen a technological leap forward in the manufacture of large blades. Rotor diameters which in general stabilised since 2004 at around 100 m, have, during the last three years, grown significantly longer. Turbines currently in the market for low-wind onshore sites have diameters from 100 to 131 m for a rated power between 2 and 3.5 MW, whereas several offshore prototypes have rotors between 164 and 171 m, as shown in Table 3. Figure 7 shows, for 202 turbines currently being commercialised, a comparison of rotor diameters (m) with the electricity generator rated power (MW).

Blade manufacture and design techniques have evolved towards resin injection moulding, e.g. Gamesa (2013) estimates a 25% reduction in cost because of this process); structural shell blade design (an improved carbon fibre technology) that, along a new aerofoil design, makes Vestas estimate weight reduction of 20% (Vestas, 2013). This is a similar reduction to what Siemens estimate thanks to a process that eliminates the use of adhesive joints (Siemens, 2013).

Figure 7 shows one consequence of the different sitting policies and wind regimes, namely that a given rotor diameter is used in turbines with a wide range of power ratings. For example, rotors with a 115-130 m diameter are used in turbines rated from 2 to 7.58 MW.

A standard blade is made of three main kinds of materials: glass, carbon or wood fibres (55%) epoxy, polyester or thermoplastic resins (30%); balsa wood, polyester foam and/or steel (8%) for the structural role; and coatings and adhesives (7%) (see Figure 8).

As shown later in Table 13 (in section 4.2.1), the cost of blades is about 15 – 23 % of the total cost of the turbine[11], the upper range is increasingly common due to new turbine models with larger rotors.

[11] A detailed cost breakdown is included as Table 13

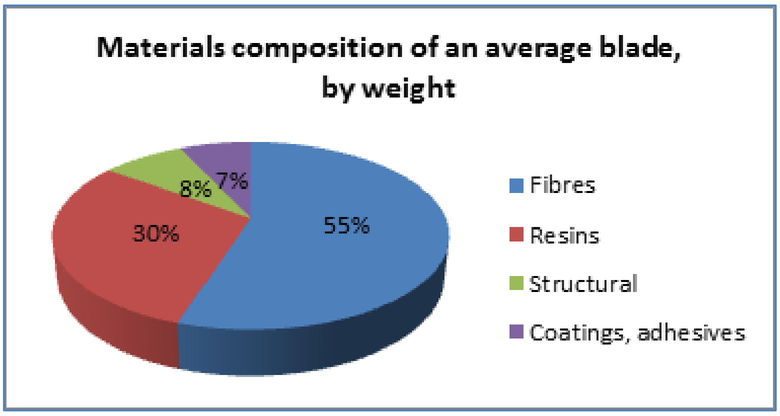


Figure 8: Average composition of wind turbine blades.

Blades are the key element in the development of turbines adapted to cold climates. The needs include anti- and de-icing devices and materials.

Ongoing RD&D projects

The British Energy Technologies Institute is partly financing the development of a 80-m (ish) long, split-blade technology based on lighter carbon fibre by Blade Dynamics (ETI, 2013b), designed for a future enhancement to the Siemens SWT-6.0 turbine. The company claims that their D49 blade (48.6m) weighs only 6.15t; this can be compared with Siemens' 2009 B49 IntegralBlade® which weights 10.3t.

The European Union is supporting several projects in this field through the 7th Framework Programme for research and technological innovation:

- WALiD combines design, material and process developments using recyclable thermoplastic materials to replace thermoset-based materials in the root, tip and shear web of blades to reduce their cost and weight.

- HIPPOCAMP, which develops a process to generate a light-weight, carbon-based nano-composite with both high static stiffness and high damping properties at a broad operating temperature and frequency range, applicable to blades.

- INNWIND.EU is an ambitious project aiming at developing the innovations needed for a 10-20MW wind turbine. In the area of blades, INNWIND.EU aims at developing aerodynamic concepts for high speed, low solidity offshore (including 2-bladed) rotors; defining and assessing innovative structural concepts for achieving lightweight rotor blades with adequate stiffness and strength; and improving the technology of distributed load control by developing (parts of) rotor blades with sensors, actuators, control devices and power supply, supported by laboratory experiments and subsequent testing of concepts on medium sized wind turbines.

- AVATAR aims at tackling the radical innovations needed for scaling up wind turbine designs towards 10-20 MW in the areas of aerodynamics. In particular, AVATAR will evaluate, validate and improve aerodynamic and aero-elastic tools to ensure applicability for large wind turbines, thus demonstrating the capability of these models to produce valid load calculations at all modelling complexity levels.

2.2.2. Gearboxes

Research shows that gearbox failures are most often due to unexpected loads originating somewhere else, e.g. in the turbine rotor or in its control system as a consequence of wind gusts, emergency stops, grid instability or of forcing the generator to maintain grid frequency. More detailed data are needed to improve the designs.

New gearbox designs aim at lighter gearboxes, more reliability and more efficiency to reduce both CapEx and OpEx. For example, bearings that are reinforced at the exact points where they support the highest loads and better transfer of loads to the tower (thus by-passing the gearbox), also help in improving gearbox reliability.

Ongoing projects

The European Union is supporting the following projects in this field:

- WINDRIVE aims at developing a 3-MW medium-speed, brushless DFIG wind turbine drivetrain (WTDT) with a 2-stage gearbox.

- Within INNWIND.EU's work package 3 (Electromechanical Conversion), Task 3.2 has as main objective the design and analysis of magnetic pseudo direct-drive generators, which consist of a mechanical and magnetic integration of a multi-pole permanent magnet machine and a magnetic gearbox. This combination is expected to be smaller than a conventional generator system, and the magnetic gear is also expected to be much more reliable than a conventional gear because there is no mechanical contact and wear between the teeth.

2.2.3. Electricity generators

Last year's report highlighted that the main problem faced by a PMG is the high variability in the price of its basic raw materials, namely the rare earths (RE) needed to manufacture permanent magnets, mostly neodymium and dysprosium. However, perhaps a similarly significant problem is the uncertainty of future supply.

Prices of rare earth metals increased in 2011 to reach nearly 100 times the prices of 2002/03, and the industry was alarmed, to say the least. Figure 9 shows this evolution for four significant metals, dysprosium (Dy), terbium (Tb) neodymium (Nd) and praseodymium (Pr). But the price crisis was short-lived: already one year after the peaks, prices had been reduced to between a half (Dy, Tb) and a quarter (Nd, Pr), and they continued to descend to stabilise between four and eight times the pre-crisis average.

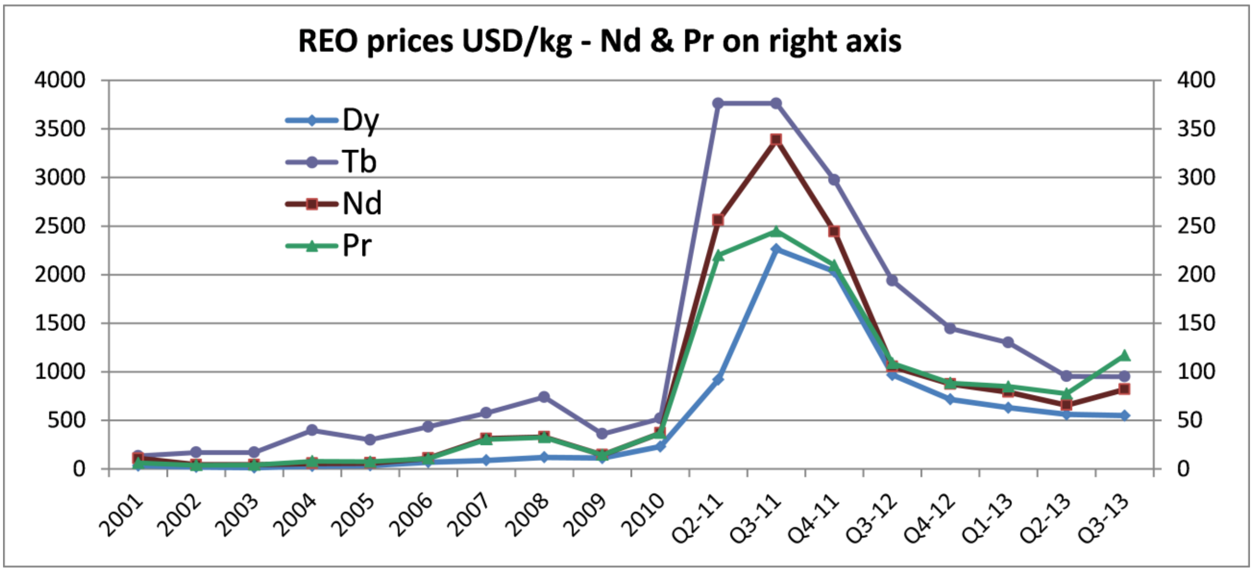


Figure 9: Evolution of prices of four rare earths metals. Source: quarterly and annual reports of Lynas Corp.

However, something has changed: whereas the price of Dy, an element which is key to stabilise the temperature and achieve high magnet specifications, was before the crisis consistently at around 3 times the price of Nd (the other key element in magnets), since late 2011 Dy costs around eight times the price of Nd. This difference is the result of the scarcity of Dy relative to other rare earths and of the high market demand.

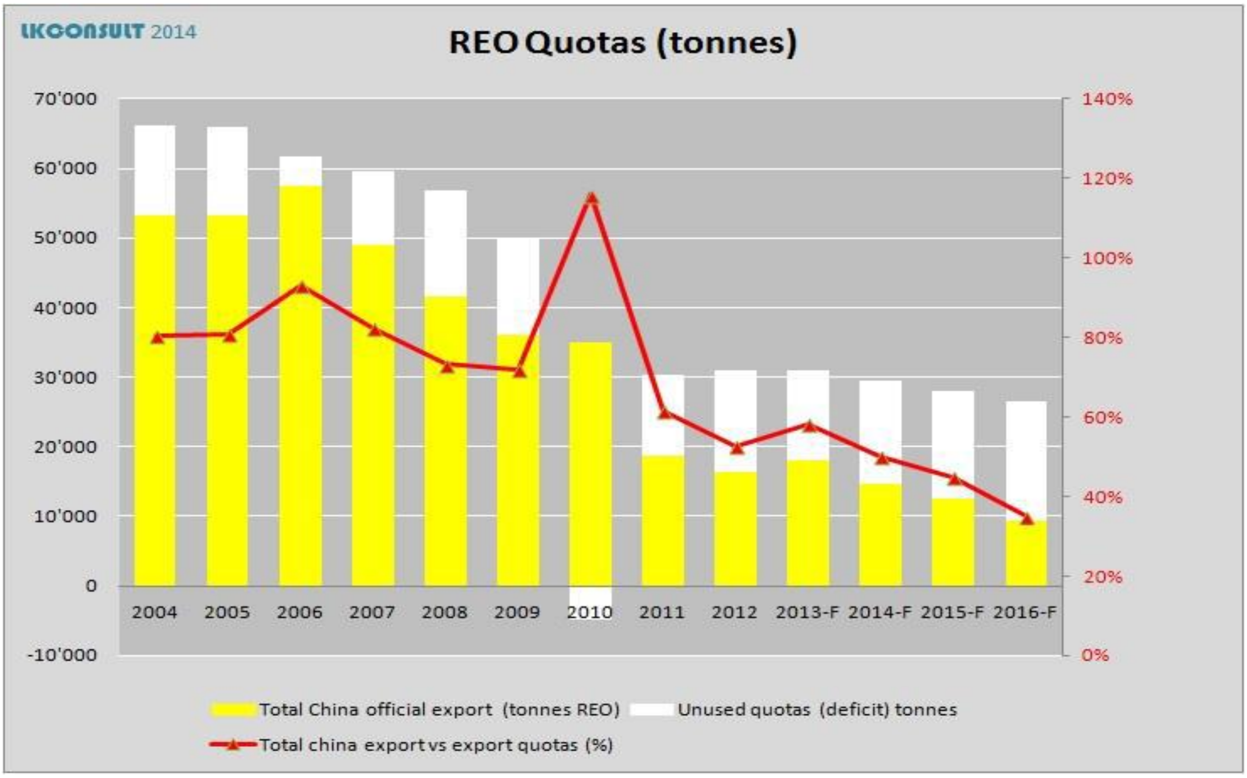


Figure 10: Chinese export quotas and actual official exports. Source: (REEFund, 2013). Note: smugling is estimated by different sources to add 15-25 000 t to official Chinese exports.

The problem of uncertain supply might end up being more important though, and it is due to the high geographical concentration of the supply of rare earth oxides with about 80-85% of them produced in China (Kingsnorth, 2013). Two risks are associated here: supplier market power and limited expertise in certain manufacturing steps outside Chinese companies. RE oxides are produced outside China, but most of their market is for transformation into metal or alloy, which is mostly done in China. "However, once transformed into a semi-finished or finished alloy or compound (e.g. NdFeB) then it would not be subject to export quotas (though there would still be duties payable when exported)" (Hatch, 2013).

Wind turbines with electromagnet generators are still predominant onshore even when key suppliers such as Vestas and Siemens are selling more of their PMG-based turbine models.

Ongoing projects

The European Union's FP7 is supporting several research projects in this field, possibly the most significant of which is ROMEO. ROMEO will research and develop several microstructural-engineering strategies to improve the properties of magnets based purely on light rare earths elements, especially the coercivity[12]. ROMEO also aims at developing a

[12] Coercivity is a property of a ferromagnetic material that measures its resistance to becoming demagnetised (Wikipedia)

totally rare-earth-free magnet. Another project supported by FP7 is SUPRAPOWER, aiming at developing a new compact superconductor-based generator.

2.2.4. Complex environments

Complex environments define mostly the design of turbines for severe operating conditions: extremely cold or hot climates, standing extreme winds, and sitting in complex terrain.

Ongoing projects

The Swedish project *Windpower in cold climates* (Vindforsk V-313, Swedish Energy Agency), the European projects *WINDHEAT* and *ICE²* (FP7), and the NER3008-supported *Blaiken wind farm* focus on basic research, innovative ice sensors and other smart measurement systems, de-icing and control systems. The Finnish project IcedBlades has as goals identifying if iced rotor causes increased loads and vibrations to key components (blades, tower, gearbox…).

- The DeICE-UT aims at developing an innovative dual de-icing system combining both high power ultrasonic guided waves and low frequency vibrations to both prevent ice accumulation and remove already formed ice.

- HYDROBOND aims at developing a new nanostructured, superhydrophobic coatings with anti-icing properties and enhanced bond strength, and new processes for application onto large blades for offshore use in order to reduce power losses and mechanical failures.

- WINDHEAT has as objective to develop understanding of ice formation on wind turbine blades and to build and demonstrate an accurate ice detection system based on a multiwavelength interdigital frequency wavenumber dielectrometry sensor, as well as a low power localized heating system based on graphite coatings.

Task 19 of the International Energy Agency Wind Technology Implementing Agreement (IEAWind), with the participation of Austria, Denmark, Norway, Switzerland, Sweden, Germany and Finland, focuses on cold climate issues and includes risk analysis (e.g. power losses because of ice, ice thrown), blade heating systems (with the participation of Enercon and Siemens), and the development of ice sensors and power supply systems for wind measurements (Krenn, A, 2013).

2.2.5. Offshore installation

One of the problems restricting the development of offshore wind farms, and increasing their cost, is the noise generated by existing methods of installing monopiles, and the impact that this noise has in particular on marine mammals. Different methods are being explored to reduce this noise including vibro-driving, bubbles curtains and others:

- DONG Energy tested the vibro-driving process in the installation of two of the monopiles in the Anholt wind farm, instead of hammering. The results suggest that vibro-driving, a procedure yielding significant lower installation noise, can be safely used in dense sands (Thilsted, Liingaard, Shajarati, Kallehave, & Gretlund, 2013).

- RWE Innogy, supported by the Carbon Trust (UK) will assess the applicability of standard design procedures to vibro-driving in a 6-pile experiment where 3 will be rammed and three vibrated into place.

- In the Netherlands, and supported by the FLOW R&D programme, Ballast Nedam will install three drilled, three driven and three vibrated piles under a DNV-defined test protocol.

- Fistuca proposes the BLUE Piling Technology which uses a large water column inside a steel tube supported by a horizontal steel plate where a combustion chamber is placed. A gas mixture is injected into the combustion chamber and then ignited, causing an increase in pressure that pushes the water upwards and simultaneously drives the pile downwards, into the soil. When the water falls down again on the support plate, it creates a second force pulse, driving the pile even deeper (Winkes & Genuit, 2013)

- The FP7 project LEANWIND attempts to apply lean principles to the critical project stages of offshore wind farm project development: "logistical processes, shore-based transport links, port and staging facilities, vessels, lifting equipment, safety and O&M".

Installing the tower offshore. Siemens seeks to use automated tack lines to control the rotation of the tower for future turbines (6MW model), whereas nowadays the rotation is controlled manually.

2.2.6. Castings and forgings: why size matters

For larger turbines, different types of the current ductile iron are gaining use, for example the 500-14 grade, where the primary difference is the silicon content. This allows for cheaper materials when casting the item. However, it is believed that this change does not involve any significant materials price increase.

The aspect of size itself contributes significantly to the increase in the price of castings for large turbines because:

- The larger items tie up more production space, square metres and this makes production less efficient so either the foundry reduces profits or tries to increase its mark-up by pushing prices up. Considering the size of large offshore hubs, bedframes, etc. then they tie up considerably more space in production and the cooling time is longer thus reducing the effective production area that is critical in a foundry.
- Transport price increases significantly when standard trucks for transport can no longer be used. This seems to have triggered plans for offshore foundries situated with direct access to harbours to minimize transport costs.
- The same issue applies to machining: at large sizes they require special suppliers with special computer numerical control machines and this increases costs.
- Again the challenges moving these items in regards to weight (cranes) and buildings limits the amount of suppliers and this could probably increase prices additionally.
- Finally storage of the items also becomes less cost effective as manufacturers need more inventory or are able to utilise storage capacity less with these large items.

Source: (Johansen, 2014).

2.2.7. Grid connection: the results of the TWENTIES FP7 project

TWENTIES is a large FP7–supported project looking at issues that are important for the large-scale integration of wind power. With a budget of 56.8 M€, of which 31.8 M€ is EU contribution, it ran from 1/4/2010 to 31/3/2013 covering 3 areas, 6 full-scale demonstration projects of new technologies and system management approaches.

A first area explored was how wind farms could provide ancillary services. Two demonstrations in Spain (SYSERWIND) and Denmark (DERINT) showed ways to do this: aggregated wind farms to provide voltage and frequency control, and virtual power plant with other generation technologies and with loads.

A second area explored was how to increase the flexibility of the transmission networks. For this, two demonstrations proved how dynamic line rating (DLR) and power flow control (PFC) technologies could enhance the energy transmitted with minimum additional expenditure. They showed e.g. that up to 15% more electricity can be transported in existing lines with minimum operational and technological improvements, and up to 25% more in newly-designed lines using new but within-reach technologies.

Finally, possible offshore HVDC meshed network technologies were explored with two further demonstrations: two different HVDC circuit breaker technologies and turbine resistance to high-winds (storms).

Detailed reports of the results of the TWENTIES project are available from its web site: http://www.twenties-project.eu/node/1.

"The outcomes of TWENTIES have far-reaching implications for the development of the future power system" (BNEF, 2013e)

2.3. Other challenges and responses

The 2012 JRC wind status report discussed some of the challenges that wind energy technology faces, challenges in the areas of technology development, project management and the context.

This subsection exposes the responses that the European wind sector, including public players, has given to these challenges during 2013.

2.3.1. Materials

The overall challenges for the materials used in wind energy that need to be addressed through research and development are (Janssen, et al., 2012):

- Life cycle management, from ore processing until waste reuse and recycling. This needs to be done by means of environmentally-friendly production technologies. In many cases existing processes need to be adapted.
- Resource management: Europe being a continent with few raw material resources should assure its strategic access to these products and/or develop alternatives for the critical materials,
- New materials (e.g. nanomaterials, fibres and polymers for blades, lubricants, permanent magnets) which make innovative solutions technically feasible,
- Materials for extreme conditions of exploitation, such as offshore, hot and abrasive, and cold climate conditions,
- Materials which allow and/or facilitate the automation of component manufacture.

2.3.2. Installation vessels

The old installation vessels, basically modified existing jack-up vessels, will not be able to install the next-generation wind turbines (farther offshore and in deeper waters) at a rate that can significantly reduce the cost of energy. The first generation of specialised (wind-only) installation vessels that came into play during 2010-2013 are much more capable for the installation at the current distances to shore and water depth, but they will show their limitations with the next generation of offshore turbines (take as "next generation turbine" the prototypes in Table 3), and with extra-large (XL) monopiles. Table 4 shows some of the technical specification of recently-commissioned or ordered installation vessels.

Vessel	*Transport capacity (MP/TP/WTG)* *Cargo area/Deadweight*	*Transit speed (knots)*	*Crane capacity*	*Jacking wave limits*	*Delivery year*
MPI Adventure *MPI Discovery*	*3600m2, 6415t*	*11.7*	*1000t @ 25m*	*2.8m (0º-45º)*	*2011*
Seajacks Zaratan	*2000m2, 3350t*	*9.1*	*800t at 24m*	*2.0m*	*2012*
Victoria Mathias/ Friedrich Ernestine	*, 4200t*	*7.5*	*1000t @ 21m*	*2.5m*	*2012*
Seafox 5	*3750m2, 6500t*	*10*	*1200t € 25 m*	*2 m*	*2012*
Pacific Orca/ Osprey	*4300m2, 8400t*	*13*	*1200t @ 31 m*	*2.5m*	*2013*
Sea Challenger	*3350m2, 5000t*	*12*	*900 t @ 24 m*	*2.0m Hs*	*2014*

Table 4: Examples of key technical specifications of new installation vessels. Source: company brochures and (Douglas-Westwood, 2013). Note: the knot (ISO standard kn) is the marine unit of speed, one knot equals one marine mille (1852 m) per hour.

A significant part of the approximately 15 – 25 GW of offshore wind farms that will be installed during 2015 – 2023 may use XL monopiles and turbines whose nacelle (weighting 350 – 450t) has to be lifted to above 100 metres - higher than nearly any turbine installed offshore so far. Ideally, next-generation installation vessels must be capable of covering those specifications, and to carry 7 – 9 new turbines per trip at a high transit speed (e.g. 15 knot). However, already a good improvement would be the constructions of new vessels designed for installing these larger, heavier foundations that will be necessary for the 7 – 8 MW turbines, because in this case the current multi-purpose vessels could be dedicated exclusively to installing turbines for which they would provide sufficient capacity (Lynderup, 2014).

The most important parameters defining the time required for the installation of wind turbines and foundations are possibly the performance of the vessels and the tools and processes delivered by the operator (Lynderup, 2014). The following list includes some key specifications for next-generation:

- number of wind turbines and/or foundations that can be transported,
- transit speed, positioning and pre-load time,
- wave limits for jacking,
- optimum layout of components on board (which increases the wind limit for installation),
- jacking time, and
- crane capacity and height.

Sources: (Forman, Bager, & Hoonings, 2014), (Lynderup, 2014)

2.3.3. Other research, development and demonstration in Europe

The UK's ETI granted Alstom and others 4 M GBP for developing a tension leg platform (TLP) concept of floating technology called Pelastar. A prototype might be built by 2015 using Alstom's Haliade 150-6MW offshore wind turbine (ETI, 2013a).

European projects that investigate resource measurements issues include SEEWIND, testing SODAR/LIDAR in complex terrain; SWIP (1/10/2013 to 31/5/2017) tackling wind resource assessment in urban areas for small turbines;

Condition monitoring; PHASEMASTER is a FP7-supported project trying to improve the inspection of blades on-site through shearography techniques, including the building of a prototype device.

The very important issue of damage to existing cable from new cable laying and other activities is being explored e.g. in the Netherlands by a *joint industry practice* guideline being negotiated.

3. Wind energy market status

2012 marked a new record in wind installations with some 44.8 GW (BTM, 2013), (GWEC, 2013) of new wind turbine capacity, bringing the worldwide total installed wind capacity to 284 GW, see Figure 11. This capacity can produce about 650 TWh[13] of electricity in an average year, or approximately 3 % of global electricity demand.

With 13 GW of new installations and a market share of 28% each, China and the US led the wind market in 2012, followed by Germany and India with around 2.4 GW each (5.5 %). European Union Member States added in total 11 896 MW (26 %), with Germany followed by the UK (1 897 MW), Italy (1 273 MW) and Spain (1 122 MW) as main contributors. Another four EU countries added 500 or more MW: Romania (923 MW), Poland (880 MW), Sweden (846 MW), and France (757 MW). Other European countries and Turkey added 2 665 MW. Of the rest of the world, Brazil with 1 077 MW, Canada (935 MW) and Mexico (801 MW) also exceeded the 500-MW mark.

The EU was still leading cumulative installed capacity with 106 GW at the end of 2012, whereas China maintained a 15-MW lead over the United States (75.3 vs. 60 GW, see Figure 11) although an estimated 15 GW of non-grid-connected wind turbines in China puts both countries on a par in terms of operational capacity. They were followed by Germany (31.3 GW), Spain (22.8 GW) and India (18.4 GW).

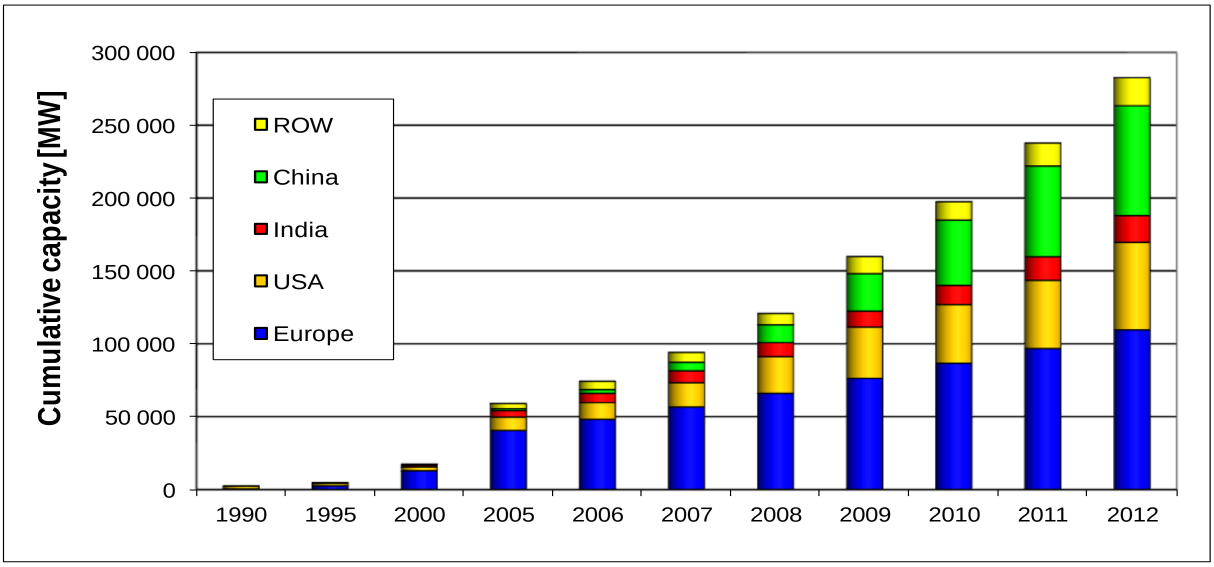


Figure 11: Cumulative worldwide installed wind power capacity from 1990 to 2012. Sources: (GWEC, 2013) and similar reports of previous years.

Although 2012 was a year of balance between Europe, China and the United states, with 28% of installations each, the overall shift in market weight towards Asia is still the trend. After Europe led the world market in 2004 with 75 % of new installations, it took only five years for Europe, North America and Asia to reach an almost even distribution of annual market shares. In 2012, Asia and North America dominated installations with 34 % and 33 % respectively, leaving Europe with 29 %. Despite the prospects for growth in Brazil and South Africa, other continents had a marginal contribution at 4%.

[13] Assuming an average capacity factor of 2200 hours or 25 %.

In terms of percentage annual growth, in 2012, the EU's wind capacity grew by 12.7 %, well below the global average of 18.8 %. The total EU capacity of 106 GW constitutes 11.4 % of its electricity generation capacity (EWEA, 2013a) and is capable of producing, approximately 203 TWh[14] of electricity or roughly 7.3 % of the EU electricity consumption.

Figures for offshore wind installations vary widely depending on the source, due to the different methodologies used. Based on the date that individual turbines started producing electricity, 2012 saw a 73 % increase in installed capacity from 824 to 1425 MW (including intertidal plant), and 2013 looks even more promising with 1496 MW of commissioned wind turbines by November, see Table 5.

Country	<2003	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	Total
Belgium								30	165		185	117	496
China						1.5		65	275	61.1	163		565
Denmark	210	193.2						238	207	3.6	50.4	349	1268
Finland	0.5					15	9		2.3				27
Germany			4.5		2.5		5	60	40	88.3	80	240	520
Ireland			25.2										25
Japan			11.3						14		0.12	18.4	44
Netherlands	19				108		120						247
Norway								2.3					2
Portugal										2			2
South Korea										2	3		5
Sweden	23.25					110		30			4.1	48	216
UK	4	60	60	90	95	95		382	556	667	940	708	3656
Vietnam												16	16
Total	256.5	253	101	90	206	222	134	806	1258	824	1425	1496	7089

Table 5: Annual installations offshore in MW. 2013 data does not include partly-operational wind farms at the end of the year. Unlike last year's table, intertidal and shoreline (i.e. physically connected to the shore) wind farms are included in this table. Source: JRC database.

3.1. Global market status

3.1.1. The European Union and beyond in Europe

The German market represented 20 % of the 2012 EU market, presenting a year-on-year (y-o-y) growth of 16 %, while the other traditional leader, the Spanish market, fell further to fourth position with 9.4 % of the EU market despite a slight y-o-y increase, after the United Kingdom's 16 % share (y-o-y +46 %) and Italy with 10.7 % (y-o-y +34 %). France, with 6.4 % share (y-o-y -9 %) completes this group of five EU countries with more than 5 GW cumulative installed capacity at the end of 2012. Other European markets that grew include Poland with 102% year-on-year, Romania 77% and Sweden 26%.

Over the last few years new European installations have remained at between 9 and 12 GW. Overall stability is therefore the norm in Europe, with offshore wind and new onshore

[14] Assuming a capacity factor of 1918 hours (21.9%), equal to the European average for the years 2002-2011. Source: author's calculations based on the historical wind energy capacity factor (CF) from Eurostat data on generation and installed capacity.

markets (countries) likely to push up annual figures to around 10-12 GW per year for the next 4 to 6 years, despite a reduction in installations expected in current leading markets.

Germany (31.3 GW) and Spain (22.8 GW) led the cumulative capacity at the end of 2012 followed by three countries in the 7.5 – 8.5 GW range: the UK (8.4 GW), Italy (8.2 GW) and France (7.6 GW). Portugal (4.2 GW) and Denmark (4.1 GW) followed, then Sweden (3.8 GW), Poland (2.5 GW) and the Netherlands (2.4 GW). Poland is considered an emerging wind market, as it is Romania (1.9 GW) and Turkey (2.3 GW): they are reaching a considerable cumulative capacity. The European overall situation is shown in Figure 12.

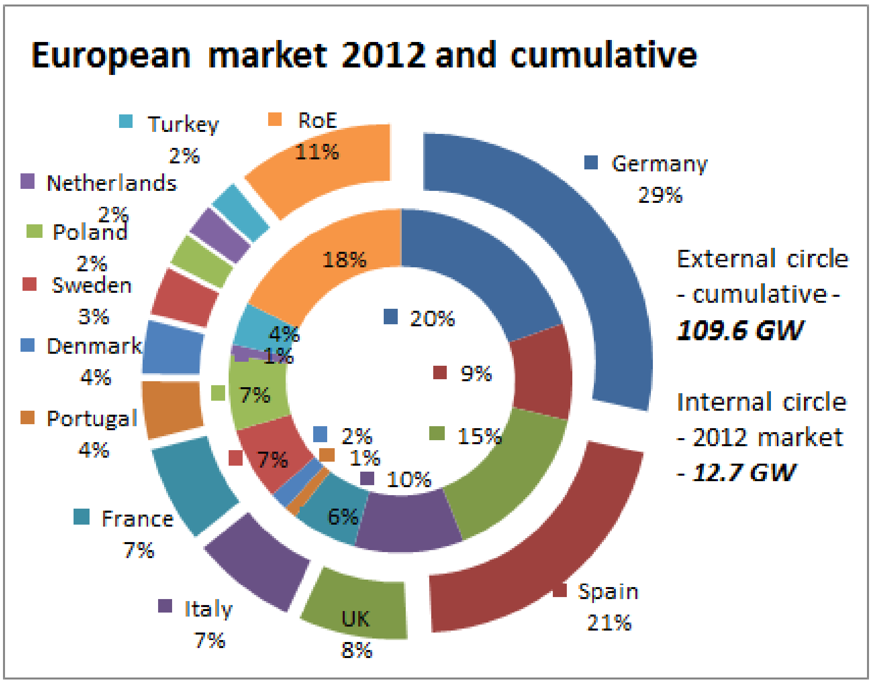


Figure 12: Installed capacity in Europe during 2012 and cumulative, for the main markets, in MW. Source EWEA (2013b)

3.1.2. China

The Chinese market markedly contracted in 2012 from 17.6 to 13 GW (-26% year-on-year). Still, it has to be noted that for the last four years China added capacity at a very high level, been the world market leader with 13.8, 18.9, 17.6, and 13 GW respectively (CWEA, 2013)[15] to reach 75.4 GW accumulated capacity at the end of 2012. Accumulated capacity grew by 20% during 2012.

The installed capacity that was not connected to the grid reached 15 GW at the end of 2012, a 20% of the total. This is an improvement over the 26% of the end of 2011.

3.1.3. North America

The record growth of the US market (13 GW, +90% y-o-y) contrasted with the extremely low growth expected for 2013 of some 1.2 GW. Canada saw a reduction in its annual market from 1.3 GW in 2011 to 935 MW, minus 28% y-o-y, for a cumulative capacity of 6.2 GW. Mexico showed the highest relative growth among emerging markets as its 800 MW more than doubled its cumulated capacity to 1 369 MW.

3.1.4. Rest of the world

The Indian market dipped to 2010 levels, from 3 to 2.3 GW (-23%) for a total cumulative capacity of 18.4 GW. Brazil is the other outstanding market, it nearly doubled cumulative

[15] CWEA statistics from previous years were consulted as well.

capacity from 1.5 to 2.6 GW with a 1 080-MW annual growth (+85% y-o-y). Australia, even with a significant y-o-y growth of 53% (358 MW) is far away from Brazil in annual market terms, although both markets tie at 2.6 GW cumulative capacity at the end of 2012. Growth in Africa is nearly nil although with two interesting events: the first African wind farm by a Chinese manufacturer (Goldwind in Ethiopia), and the 120-MW Bizerte wind farm in Tunisia by Gamesa. In addition, South Africa, although with no significant new capacity in 2012, gave very solid steps to becoming the most important African market from 2013 onwards through capacity auctioning.

3.1.5. The offshore market

The offshore market is the only one with a certain perspective of growth. One of the reasons is that projects offshore take much longer to realise, and investment decisions are taken early -thus requiring institutional and legal stability-, and generally governments have reacted to this need by setting up adequate legal frameworks. Still, permit-process, export cabling connections and other related issues regularly delay project expected commissioning dates and thus the overall market. Thus, BTM (2013) expects a global annual market of around 10.5 GW by 2017.

3.2. Analysis and projections

Annual market projections are now a little less optimistic than three years ago, with different sources expecting a strong reduction in 2013 installations, before continuing a moderate growth line in 2014 and successive years. However, even when the very optimistic figures, proposed three years ago for 2015 of 81 GW (BTM, 2011), are no longer thought possible, the continuous cost reductions shown in the last three years might completely change the picture for good.

Table 6 shows that global annual market projections expect a reduction of installations in 2013 and a rebound in subsequent years. Perhaps more interesting is the difficulty to predict 2013 installations: for example Bloomberg New Energy Finance (BNEF) in two reports of the same series only 10 months apart, shown in bold in the table, estimated a reduction from 38.6 to 33.7 (-13%) in 2013 installations.

Source	2013	2014	2015	2016	2017
BTM (2013)	40.4	47.6	45.1	50.9	57.7
GWEC (2013)	39.6	45.3	51.0	56.2	61.2
BNEF (2013a)	***38.6***	***45.8***	***44.9***	***48.4***	
BNEF (2013c)	***33.7***	***46.2***	***49.6***	***50.9***	
MAKE (2013a)	45.0	52.5	52.5	52.5	
JRC projections	43.8	47.5	50.0	54.0	57.0

Table 6: Annual market projections for different consulting and sector companies, in GW. Chinese figures are included here and correspond to newly installed capacity but not necessarily grid connected.

For the period 2014-2016, Table 6 shows the various sources that estimate a global annual market of between 45 and 56 GW, increasing afterwards mainly due to increased offshore installations. The JRC's longer-term projections include 215 GW installed for the EU by 2020, of which 27 GW offshore, and 715 GW globally, of which 44 GW offshore.

Factors that influence current projections include the recovery of the Chinese market to between 15 and 17 GW per year; stability in Europe; a slow initial increase in India getting steeper towards 2015-2016; a stronger pipeline of projects in Brazil and South-Africa; and strong growth in Mexico, Canada, Australia and other emerging markets.

In North America, the US market will explode again in 2014/2015 due to the change introduced in the extension to their main support mechanism, the Production Tax Credit (PTC), for which qualifying projects need to commit 5% of funds by end 2013 but can be finished in the following two years. Canada will continue to grow based in the tenders organised by regional governments, the latest of which are Ontario's 600 MW and Quebec's 450 MW in December 2013. Mexico government's *Secretaría de Energía* expects exponential grow from 1.5 GW at the end of 2012 to 9 GW at the end of 2018 (SENER, 2013) and projects are fast being built with the most significant commissioning expected for 2014.

In Central and South-America, Uruguay could be by 2016 the country with the highest wind energy penetration in the world (Montautti, 2013), whereas Brazil's auctioning system should yield some 7-8 GW more from 2014 to 2017. Chile also presents a very positive outlook in particular with the decrease of the cost of wind turbines.

Projects in Ethiopia and elsewhere in Africa (beyond South Africa) suggests that this continent could be the positive surprise of the near future, in particular under the push of Chinese developers and manufacturers.

The predictions of Japan to become an exploding market have not been realised in 2013 but it is likely in the next few years, supported by its generous feed-in-tariff of 22 000 JPY/MWh (€191/MWh) (Kogaki & Matsumiya, 2013). Problems specific to Japan include very demanding environmental impact assessment requirements, and a special manifestation of corrosion issues, but despite problems Japan expects the doubling of capacity by 2020. Vietnam, Philippines, and Thailand have a significant pipeline of wind projects, although the track record suggests that it is Thailand the country most likely to deliver in the medium term. Pakistan, with gifted resources in the Gharo – Keti Bandur wind corridor, has a pipeline of some 1500 MW to 2017 and a potential for 350 GW (Ali, 2013).

Australia is host to 3 GW of wind energy and has a development pipeline of 17 GW, including very large wind farms such as Hornsdale (315 MW) or Stockyard Hill (547 MW).

3.2.1. Progress towards the European Union 2020 goals

EU Member States and Norway have drawn objectives of wind installed capacity for 2020 within the context of the EU Climate and Energy policy. Table 7 shows these projections as well as the progress at the end of 2012. The colour assessment of the last three columns is as follows: green if already achieved 70% of the 2020 target, yellow if between 30% and 70% and red if less than 30%. This opinion is influenced as well on whether building of wind capacity has accelerated during the last years, whether policy instruments have been put in place recently or are expected to be put in place in the near term so that reaching the

2020 objectives seems reasonable, and on the turbine purchasing contracts in place by 1st December 2013 as reported by (Campbell, S (WPM), 2013).

Country	**Target capacity 2020 (MW)**			**Installed 2012 and progress outlook**		
	Onshore	Offshore	Total	Onshore	Offshore	Total
Austria	2 578	0	2 578	***1 378***		***1 378***
Belgium	2 320	2 000	4 320	***996***	***379***	***1 375***
Bulgaria	1 440		1 440	***684***		***684***
Cyprus	300		300	***147***		***147***
Czech R.	743		743	***261***		***261***
Denmark	2 621	1 339	3 960	***3 169***	***919***	***4 088***
Estonia	400	250	650	***270***	***0***	***270***
Finland	1 600	900	2 500	***261***	***27***	***288***
France	19 000	6 000	25 000	***7 557***	***0***	***7 557***
Germany	35 750	6 500*	42 250	***31 026***	***280***	***31 306***
Greece	7 200	300	7 500	***1 751***	***0***	***1 751***
Hungary	750		750	***329***		***329***
Ireland	4 094	555	4 649	***1 731***	***25***	***1 756***
Italy	12 000	680	12 680	***8 151***	***0***	***8 151***
Latvia	236	180	416	***52***	***0***	***52***
Lithuania	500		500	***225***		***225***
Luxemburg	131		131	***44***		***44***
Malta	15	95	110	***0***	***0***	***0***
Netherlands	6 000	5 178	11 178	***2 200***	***247***	***2 447***
Poland	5 600	500	6 100	***2 496***	***0***	***2 496***
Portugal	6 800	75	6 875	***4 226***	***2***	***4 228***
Romania	4 000		4 000	***1 905***		***1 905***
Slovakia	350		350	***3***		***3***
Slovenia	106		106	***0***		***0***
Spain	35 000	750	35 750	***22 795***	***0***	***22 795***
Sweden	4 365	182	4 547	***3 585***	***168***	***3 753***
UK	14 890	12 990	27 880	***5 490***	***2 948***	***8 438***
EU27	168 788	41 974	210 762	***100 732***	***4 995***	***105 727***
Norway	3 535	0	3 535	***703***	***2***	***705***

Table 7: Assessment of progress towards the 2020 objectives. Source: JRC. The progress outlook views expressed are purely those of the author and may not in any circumstances be regarded as stating an official position of the European Commission.

*After the 2013 elections offshore targets were reduced from 10 GW to 6.5 GW by 2020, this new target is included here instead of the NREAP.

3.2.2. EU Member State analysis

Policy initiatives are shaping the future of wind energy in the largest countries. Germany, due to its policy to abolish nuclear energy, will likely continue increasing wind capacity to perhaps 45 GW by 2020. The UK, with a new Contract-for-Difference (CfD, a kind of feed-in tariff premium) will consolidate its offshore leadership but will also see onshore installations grow due to the increasing number of approved projects. France, with a policy to increase renewables and thus counterbalance its nuclear supply, will see the first offshore wind farms by 2019 and could see extensive onshore development once the current administrative risks linked to its support legislation have been cleared. On the negative side Spain, second-biggest European market, had near-zero growth in 2013 and will see zero growth in 2014 and beyond, unless current policies change.

The following statements contribute to the summaries in Table 7:

- ***Austria***: mid-way to the target; project execution skyrocketed after a 2011 increase of the FiT and thanks to a favourable policy framework.
- ***Belgium***: only 32% of the target by end 2012, thus there is a significant gap.
- ***Bulgaria***: although mid-way to the target, a large base of turbine purchasing agreements in place initially suggests that reaching the target would be possible. However, retroactive policy changes could prevent reaching the targets, e.g. a new grid-connection fee for renewables equivalent to 39% of the feed-in-tariff income was introduced (Cojocaru & Piuk, 2013).
- ***Cyprus***: mid-way to the target; installations started recently (2010), thus it should not have problems to reach it.
- ***Czech*** Republic: only 35% of the target by the end of 2012, not the right policy context to reach the target.
- ***Denmark***: having already reached the 2020 target, Denmark has drawn more ambitious decarbonisation objectives that include 50% of electricity from wind.
- ***Estonia***: with a favourable policy context it should reach the target.
- ***Finland***: there is a significant gap (only 18% of the target was achieved by 2012) and although the political context improved, it will be very difficult to reach the target.
- ***France***: only 30% of the target was achieved by 2012. Even though a more favourable policy framework is now in place, it will be difficult to reach the target.
- ***Germany***: strong policy and public support means the target will be reached. Note, though, that after the 2013 elections the offshore targets were reduced from 10 GW to 6.5 GW by 2020 and from 25 GW to 15 GW by 2030.
- ***Greece***: not the favourable policy context necessary to reach the target, partly because of the economic problems in the country.
- ***Hungary***: not the favourable policy context necessary to reach the target.
- ***Ireland***: there is a significant gap but with the potential to reach the target once a favourable policy framework is in place.
- ***Italy***: although there is still a significant gap, Italy published new legislation improving the support scheme for renewables at the end of 2013.
- ***Latvia***: even though the gap is very significant, it is possible to reach such a low figure (in MW) once the necessary policy context is in place.
- ***Lithuania***: a strong pipeline of announced projects means the target should be reached.
- ***Luxemburg***: neither the necessary policy context to reach the target nor is the country very gifted in wind resources.
- ***Malta***: not the favourable policy context to reach the target.
- ***Netherlands***: there is a very significant gap still there. A new political consensus and tools put in place suggest that it will increase installations, but the gap to reach the target is too large.
- ***Poland***: a high volume of turbine purchasing agreements suggests that the target will be reached, but retroactive policy changes could prevent this. A new renewable energy law is expected.
- ***Portugal***: a significant gap still there, but the target can be reached.

- ***Romania***: legal changes with retroactive effect (deferred one of the two green certificates per MWh from 1/07/2013 to 1/01/2018) puts investment trust in jeopardy. In addition, the renewable energy law will be changed (Cojocaru & Piuk, 2013).
- ***Slovakia***: despite the large gap to the target, the total figure (350MW) is small and given a favourable policy framework the target might be reached.
- ***Slovenia***: a similar situation to Slovakia's.
- ***Spain***: regulatory changes with retroactive effect affecting FiT, and lack of policy will means the target will not be reached.
- ***Sweden***: a strong pipeline of announced projects means the target will be reached.
- ***UK***: a significant gap is still there, there might be difficulties in reaching the target.
- ***EU27***: although there is a significant gap still there, the EU as a whole will probably reach the 2020 target.
- ***Norway***: a significant gap means that there will be difficulties to reach the target.

The situation has become confused in several other EU countries as well, namely Romania, Bulgaria and Poland. In 2013 several large developers have abandoned some of these countries: Iberdrola left Romania and Poland, and DONG Energy left Poland, and these company reorganisations seems to be influenced by retroactive changes in support schemes of the markets concerned. In particular, changes to remuneration-related laws with retroactive effect strongly deny the basis for a safe investment environment as they affect already executed investment for which the investor has acquired financial liabilities.

3.3. Turbine manufacture market

The turbine manufacturers market share (Figure 13) revealed by BTM (2013) and MAKE (2013b) show a tie at the lead and suggests that the long-term leader Vestas (DK) was unseated by GE Wind of the US. This would be the natural consequence of GE being the market leader in a market, the US, which saw record installations after growing 90 % year-on-year. Three European companies follow (Siemens, Enercon and Gamesa), then Suzlon of India (two third of whose installations belong to its European subsidiary Senvion –formerly called REpower), then four manufacturers from China: Goldwind, Guodian United Power, Sinovel and Ming Yang.

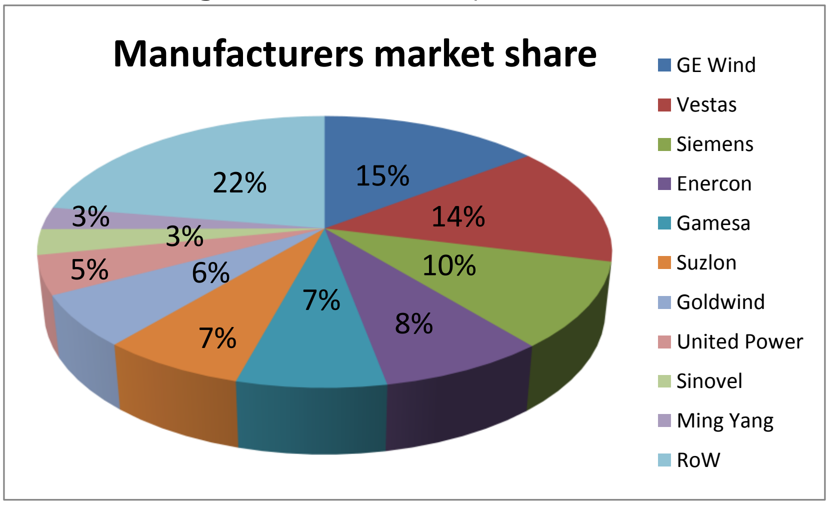


Figure 13: Manufacturer market share 2012 over 43.14 GW of installations. Elaborated with data from BTM (2013) and MAKE (2013b). Suzlon data includes its subsidiary Senvion (Germany)

The five largest firms together covered 54.6 % of the market (BTM, 2013), showing higher market concentration than in 2011 (47.2 %). However, the share of the top-ten suppliers remained stable at 77.3 % of the market versus 78.5 % in 2011. European manufacturers[16] increased their market share from 37.3 % in 2011 to 42.8 % in 2012, partly as a result of significantly lower installations in China –which resulted in lower share for Chinese manufacturers[17].

Historically the market has tended towards more competition, with more small suppliers gaining a market share, according to (BTM, 2013) and similar reports from previous years. Table 8 shows the top-10 manufacturer position from 2005 to 2012, and the shares of the top-five, top-10 and EU manufacturers in the top-10.

This reduction of the share of top tier-1 manufacturers is even clearer in the case of the market leader, Vestas, which has seen its share reduced from 27% in 2005 to 13% in 2011. Note that a significant cause of the evolution of market share is the growth of the Chinese market since 2008, its much larger size regarding any other market, and the absolute prominence that Chinese OEMs have had in their market.

Ranking	2012	2011	2010	2009	2008	2007	2006	2005
1	GE	Vestas	Vestas	Vestas	Vestas	Vestas	Vestas	Vestas
2	Vestas	Goldwind	Sinovel	GE	GE	GE	Gamesa	GE
3	Siemens	GE	GE	Sinovel	Gamesa	Gamesa	GE	Enercon
4	Enercon	Gamesa	Goldwind	Enercon	Enercon	Enercon	Enercon	Gamesa
5	Gamesa	Enercon	Enercon	Goldwind	Suzlon	Suzlon	Suzlon	Suzlon
6	Suzlon	Suzlon	Suzlon	Gamesa	Siemens	Siemens	Siemens	Siemens
7	Goldwind	Sinovel	Dongfang	Dongfang	Sinovel	Acciona	Nordex	REpower
8	Guodian UP	Guodian UP	Gamesa	Suzlon	Acciona	Goldwind	REpower	Ecotècnia
9	Sinovel	Siemens	Siemens	Siemens	Goldwind	Nordex	Acciona	Nordex
10	Ming Yang	Ming Yang	Guodian UP	REpower	Nordex	Sinovel	Goldwind	Mitsubishi
Top-5	54%	47.2%	52.2%	49.8%	62.3%	67.9%	75.8%	76.4%
Top-10	78%	78.5%	82.5%	78.7%	84.2%	87.2%	93.8%	93.2%
EU	45%	35.3%	34.5%	37.0%	51.3%	57.5%	70.0%	66.2%
Market	43.1 GW	41.7 GW	39.4 GW	38.1 GW	28.2 GW	19.8 GW	15 GW	11.5 GW

Table 8: Market share of the top-10 manufacturers 2005 – 2012. Source: JRC analysis based on (BTM, 2013) and on similar reports from previous years. Orange background reflects EU companies, and the share of EU companies in the top-10 is shown in the "EU" row. Global market figures (in GW) from BTM (see above). EU share includes Senvion, formerly called REpower, which is part of the Suzlon group.

The total share of European manufacturers reached 48% of world installations in 2012 when smaller manufacturers are included (BTM, 2013; JRC data).

The evolution of the annual manufacturers ranking shows that there are one or two truly global suppliers, Vestas and probably Gamesa, in the sense of having balanced presence in the different markets. Chinese manufacturers descended from positions 2, 6, 7 and 10 to positions 7 to 10 because of their dependence on a Chinese market which shrunk by 27 % in 2012, and their limited expansion beyond China. The US firm GE Wind climbed to number one because of its exposure to its home market, where it held 38.5 % share in 2012 (5 014

[16] Including Senvion (the European subsidiary of Suzlon), which according to (BTM, 2013) installed 2 122 MW out of the 3 177 MW installed by the Suzlon group.
[17] Figures for the Chinese market correspond to installed turbines whereas those elsewhere correspond to fully commissioned and grid-connected turbines.

MW (AWEA, 2013)), and the large growth of this market. Had not it been for its home market GE would be a minor market actor with 1 682 MW installed outside the US.

Siemens claimed third place thanks to its exposure to the US and offshore markets with 2 638 (AWEA, 2013) and 988 MW (JRC data) respectively out of a total 4 114 MW (BTM, 2013). But perhaps the most significant performance is that of Enercon which, at 3 538 MW, ranks fourth in 2012 installations despite not being present in markets covering 64.5 % of the market (US, China, India and offshore). Still, Enercon was aided by a high exposure to its home market (57 %, (BTM, 2013))

Chinese firms' dominance of their national market increase slightly from 91 % in 2011 to 92 % in 2012, but sold only 3.5 % of their turbines abroad, 431 MW (JRC data). This figure is significantly more than the 1.2 % of the total 17 600 MW of 2011 and shows a continuous grow in Chinese exports, from 213 to 431 MW[18]. Four foreign firms (Vestas, Gamesa, GE and Siemens) installed 1018 MW in China in 2012, 7.8 % of the Chinese market, but a significant reduction over the 1 626 MW installed in 2011 and the 2 000 MW installed in 2010.

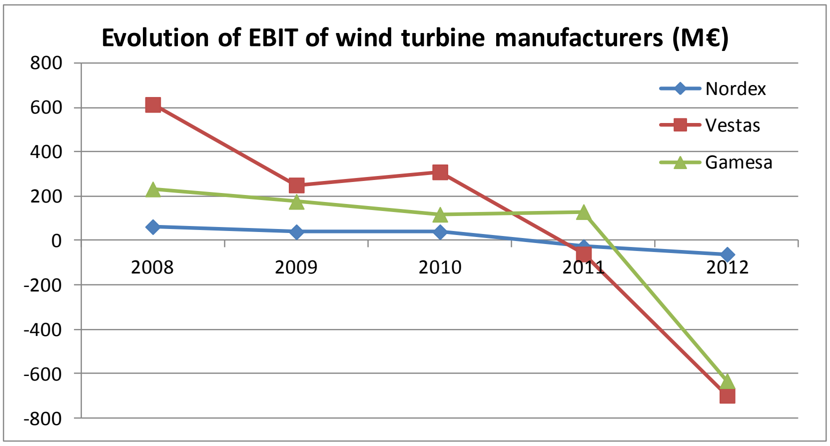


Figure 14: Evolution of the EBIT of wind turbine manufacturers, 2008 - 2012, for selected European companies. Source: company annual reports

Turbine manufacturers are under very high pressure and do not have financial strength. Figure 14 shows a sample of the business evolution of selected European wind turbine manufacturers as reflected in their annual EBIT (earnings before interest and tax). 2012 figures for Vestas and Gamesa include restructuring costs (one-off items such as write-downs of assets). Production overcapacity and fierce competition are two of the causes of these problems, but the sector is damaged by inconsistent support policies e.g. changing remuneration with retroactive effect – that affect investor confidence in some specific markets, with the danger of propagating the "me too" effect to healthy ones.

Other companies than those included in Figure 14 suffered a bad 2012 in the wind sector. Some companies went into bankruptcy or filed for insolvency, e.g. turbine manufacturer Fuhrländer of Germany, and offshore foundations manufacturers Smulders (Netherlands) and SIAG Nordseewerke (Germany). Other companies reported profit reduction.

However, the good news is that ***nearly all wind turbine manufacturers have experienced a significantly better 2013***, despite the lower sales, expecting positive EBIT figures at the end of the year.

[18] Methodologies on Chinese exports might not be comparable to installed data. In effect, at least until 2011 annual wind turbine data reported by CWEA was installed capacity for Chinese installation but exports reflected turbines sent abroad and not necessarily installed nor commissioned in the same year of export.

In this context, it is interesting to note some of the different strategies that manufacturers have defined for survival. Some of them downsized, partly aiming at the reduction of working capital, through outsourcing, e.g. Vestas and Gamesa. This could also result in strengthening design collaboration with key component suppliers and using standard components more often. This opens a door for non-European suppliers to raise its share of the turbine value added, e.g. Siemens "has localised the purchase of wind turbine hulls, principal axis and gearboxes in China" since 2008, and Gamesa manufactures components in their own Chinese plants that are then used in all markets.

Company annual reports show two other trends. Manufacturers claim that cost reductions are possible: Nordex expects to reduce turbine product costs "by 4% in 2013 and by 15% by 2015 relative to 2012"; Vestas has implemented "more than 100 product cost-out initiatives"; Gamesa "has launched new manufacturing processes with the goal of optimising costs" and claims positive results. This is very interesting: if these companies can reduce costs to that extent, then others probably can do it too, thus forming the basis for future reductions in the cost of turbines and therefore in the cost of energy.

A second trend is the increasingly aggressive policies towards capturing the operation and maintenance (O&M) market. Most turbine manufacturers are proud to show an increase in income share from this service and the reason is that O&M guarantees income for several years. As a consequence –possibly backed by lower O&M needs of newer, more reliable turbines, the O&M market is becoming more competitive, and prices offered to developers go down even below 10€/MWh (in variable terms).

3.4. Repowering old wind farms

The repowering of old wind farms with new turbines presents a number of interesting advantages:

- New turbines produce more energy per square metre of swept area, and suffer less maintenance stops. In extreme cases comparison for 2010-2012 generation, the pioneering 1991 offshore wind farm Vindeby generates at a 20-22% capacity factor, compared with the 2009 Horns Rev II which generates at 47-52% capacity factor.
- New turbines are fully compliant with new grid codes, thus offering better grid support and quality of electricity.
- Because new turbines with larger rotors run slower (10-20 RPM vs. 40-60 RPM), the risk for birds and bats is significantly lower.
- Repowering offers the opportunity of better landscape integration.
- Old machines can generally be sold in the international market, thus partly offsetting decommissioning costs.
- There are fewer objections to repowering than to a new project.

However, planning a repowered wind farm "is nearly the same as planning a new project and has comparable risks" (Christian Schnibbe, Manager PR & Marketing at developer WPD, quoted in (Lawson, 2013)). And a new planning permit is needed for the taller turbines, and this can be problematic depending on the country.

Repowering can be supported with an income premium (as in Denmark during 2001-2003 and 2008-2011), and the design of this scheme heavily influences the age at which turbines are replaces. In the case of Denmark's first scheme 850 turbines installed between

1985 and 1988 were replaced in 2002, giving an average age of 15.5 years, whereas the second scheme saw an average 19-21 years (Source: JRC based in data from (Danish Energy Agency, 2013)).

A rule of thumb is that repowering an old wind farm requires half the number of turbines resulting in double the installed capacity and tripled electricity generation (Bundestverband WindEnergie).

Wind turbines number (no.) and capacity (MW)	< 2006	2006	2007	2008	2009	2010	2011	2012	Cumulative
Decommissioned (no.)	147	79	108	26	76	140	170	252	998
Replacement (no.)	107	55	45	18	55	90	95	161	626
Decommissioned (MW)	155	26.19	41.29	9.74	36.7	55.7	123	179	627
Replacement (MW)	190	136.4	102.9	23.94	136.2	183.4	238	432	1443
Percentage of total market		6,1	6,2	1,4	7,1	12,3	11,3	17,9	

Table 9: Repowering activity in Germany 2006 - 2012. Source: BWE annual reports

By the end of 2000, 13 GW of wind turbines were installed in the EU of which an estimated 9 GW correspond to turbines with a rated power of 1 MW or lower. These pioneering installations are located in sites often gifted with better wind resources than what is available in today's greenfield projects. There is, therefore a large potential for repowering.

3.5. Industrial strategies

Increasing international competition imposes production reorganisation of the European wind technology manufacturers with one objective: reducing costs. Manufacturers may focus on two different cost concepts: levelised cost of energy (LCoE) or capital expense (CapEx). Reductions in CapEx have more limited range and sometimes cause unwanted effects such as higher operation and maintenance (O&M) costs. Searching for new business opportunities and energy solutions, turbine manufacturers are developing and analysing new technologies and markets, diversifying their activities.

"AWP has embarked on an ambitious cost-cutting program that will enhance ACCIONA's WTG specialist's competitiveness. 2014 is set to be a key year for these ambitions." (Acciona Windpower, 2013)

Box 2: Policy measures that can distort international competition include:

- Domestic incentive measures with possible implications for trade and international investment, such as subsidies and granting preferential access to financing (e.g. via preferential loans as in Brazil or loan guarantees);
- Imposing local content requirements (LCR) as a precondition to benefit from a feed-in tariff or to win a public tender);
- Trade measures such as improving export performance of components through targeted measures; restricting exports of materials and components so that more value-added products have to be manufactured locally (the case of China rare-earth export restrictions); dumping subsidies; or restricting imports (e.g. through tariffs and other trade barriers);
- Regulatory restrictions on foreign direct investment (FDI) such as limits to foreign ownership or limited access to land acquisition.

Sources: (OECD, 2013), own elaboration.

It has to be noted that a widespread form of government support to industry, tax relief for R&D funding or for building new manufacturing facilities, can also be widely used to support local manufacturing or R&D in the wind sector.

Industrial strategies are also a response of companies to a growing trend for governments to support domestic manufacture, which can distort trade. Box 2 shows different ways in which government policy implement this policy.

Vertical integration in the manufacturing sector has started to change. Vertical integration was a response to the problems caused by excessive demand in the years 2007/2009, including the lack of quality control of component suppliers. However, in a context of oversupply, vertical integration is seen as an undesirable locking of working capital. Vertical integration does take place increasingly from manufacturers into the development and O&M subsectors, the former as an additional way to sell their turbines and the latter as a lucrative business area based in increasingly-developed condition monitoring systems.

3.6. Deployment scenarios

The European Wind Industry Energy Association has defined targets of 230 GW installed in Europe by 2020, of which 40 GW offshore and 400 GW installed by 2030, of which 150 GW offshore.

The construction of deployment scenarios is supported on an assessment of players that have a say in future deployment as much as in the technology, global and sectoral economic situation. The following points formed the basis of our assessment:

- Wind energy is a local resource widely distributed. Its use makes countries independent from fuel imports from unstable countries, improves security of supply and does not have negative environmental impacts.
- Human-induced climate change is a reality asserted by scientific effort. The society generally understands the dangers of climate change and supports doing something about it. Political objectives generally include short-, medium- and long-term reductions of fossil fuel use.
- Current policies translate this societal need into plans and support for renewable energies including wind. Politicians have broadly stated their will to support renewables as necessary to tackle climate change.
- Wind energy technology continues to improve its reach and to reduce its cost. This is resulting in the opening of new markets (Brazil, South Africa…) and more will be created as costs reduce further. However, offshore wind is taking longer to reduce its cost significantly.
- Some bottlenecks need to be considered, e.g. installation of export cables for offshore wind farms.
- The Fukushima nuclear plant accident, which exposed the weaknesses of nuclear installations to certain natural phenomena, has triggered in some countries an energy policy switch towards renewables. Germany and Japan have made strong policy statements to increase their support for renewables and, although not with the same level of commitment, other countries follow track.

In Europe, the 2020 projections from the National Renewable Energy Action Plans (NREAPS, see Table 7) suggest that offshore installations will increase from 5 to 42 GW (37 GW or an 8-fold increase from 2012), significantly more than onshore, from 100 to 169 GW (69 GW or less than an 2-fold increase).

At the time of writing the scenario is grim for 2020 offshore wind installed capacity and both EWEA and NREAP projections seem very unlikely, and a figure between 25 and 33 GW seems more likely to be achieved. Therefore we suggest the following deployment scenarios for the European Union and the whole world, in gigawatts (GW):

	European Union			World		
	Total	Onshore	Offshore	Total	Onshore	Offshore
Cumulative capacity end 2012	106	101	5	283	278	5.4
Installed 2013-2015	40	34.5	5.5	129	121	8
Annual installation rate	13	11	1.8	43	40	2.7
Cumulative by 2015	146	135	10	412	399	13
Installations 2016-2020	70	48	17	300	266	31
Annual installation rate	14	9.6	3.4	60	53.2	6
Cumulative by 2020	216	183	27	715	665	44
Installations 2021-2030	135	50	85	750	550	200
Annual installation rate	13.5	5	8.5	75	55	20
Cumulative by 2030	351	233	112	1465	1215	250
Installations 2031-2050	150	40	110	1025	725	300
Annual installation rate	8	2	6	51	36	15
Cumulative by 2050	501	273	222	2490	1940	550

Table 10: Estimated installed capacity in GW, 2012 - 2050. Sources: GWEC (2013) (for 2012 data) and JRC analysis.

The European share of world cumulative capacity will continue to shrink from the current 40 % to 30 %, 24 % by 2030 and 22 % by 2050. In 2006 this share was 69 %.

We expect the onshore market to dominate in Europe until 2020 and sometime before 2030 to pass the baton to the offshore sector. Repowering (see section 3.4) will play a significant role, in terms of annual installations, possibly from 2015 in Germany, Denmark, the Netherlands and Spain, and will be followed by other countries. After 2030 new installed power is likely to correspond only to repowering of current wind farms.

In the rest of the world onshore installations will probably dominate all the way to 2050, despite the cost reductions that will materialise much earlier.

Both in Europe sometime after 2030 and in the world after 2050, the pace of installations will slow down to the level of replacement of obsolete equipment. New technologies will still allow cumulative capacity to increase regarding the decommissioned capacity (repowering).

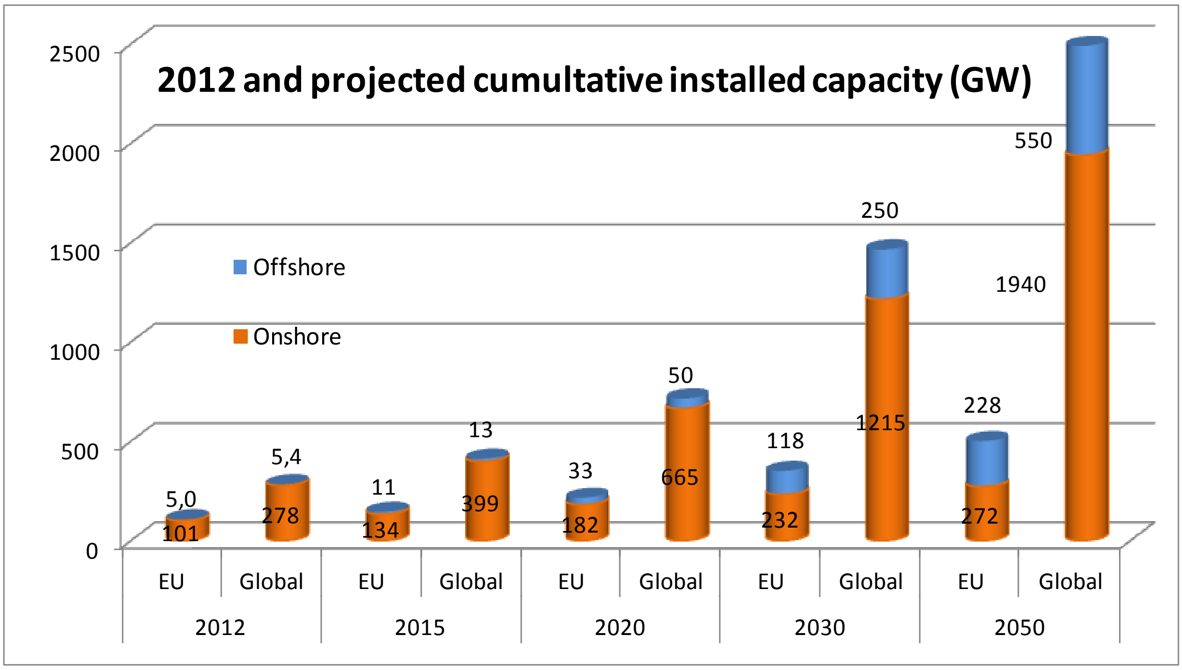


Figure 15: Projected cumulative installed capacity (GW). Source: JRC

4. ECONOMIC IMPACTS OF WIND ENERGY

The cost of wind energy depends on the cost of raw materials; on technology selection; installation costs (including grid-connection/extension); operation and maintenance costs; supply bottlenecks (e.g. limited competition in offshore export cable supply); market supply/demand balance; non-technical barriers (administrative, permitting, social acceptance, etc., including those caused by NIMBYism); the mode and level of remunerating wind electricity, e.g. feed-in tariffs (FiT); and on risks and uncertainties impacting on the investors and lenders and creating a need for technical and price contingencies[19].

4.1. Economic indicators

The indicator currently generally accepted to assess of the cost of wind is the levelised cost of energy (LCoE)[20], a standard for all energy-generating technology. However, this was not always the case as years ago, when capital investment (CapEx) was used as main indicator thus disregarding financial and operations and maintenance (O&M) costs.

The impact of wind in the society reaches much beyond its costs and into social (e.g. employment, well-being, emotional issues), environmental (e.g. supporting the fight against climate change but also having local environmental issues), taxes, employment created (and/or replaced from other generation technologies), etc.

Lastly, the indicator generally used at project level is the return on investment (RoI) with any of its similar definitions, e.g. internal rate of return (IRR) or the net present value (NPV). Interestingly, the RoI is used with two very different purposes i.e. by developers when assessing the expected profitability of a wind farm project, and by public authorities when defining the correct level of economic support for the technology.

In this context, we see that in the future developers and public authorities will continue using IRR for the same purposes, but we think that public authorities will gradually move to the value of wind for the society when taking high-level decisions e.g. on the future composition of the electricity mix, on large infrastructure investment, etc.

4.2. Economic figures

4.2.1. Evolution of turbine prices

Turbine prices declined until 2004 influenced by technology learning and the increasing volumes of production, then supply/demand imbalances and the increase of raw material and component prices pushed up global onshore turbine prices -related to the generator capacity- (other than in China) to around 1 200 EUR/kW in late 2007 for delivery in 2009. Then, manufacturing overcapacity, the reduction in raw materials costs caused by the financial crisis and increasing competition pushed down prices to around 890 €/kW for contracts signed by mid-2013 (BNEF, 2013b). In the US, the Department of Energy estimated 2012 turbine prices between 680 and 930 EUR/kW (at 1 EUR = 1.392 USD) (Tegen, et al., 2013) and China bidding turbine prices[18] averaged 480 - 600 EUR/kW (at

[19] Badiola (2014) reported contingency budgets are highest in the foundations and installations vessels up to 35%

[20] A summary definition of the levelised cost of energy (LCoE) indicator is included in the previous issue of this report (Lacal Arántegui, Corsatea, & Sumalinen, 2013)

1 EUR = 8.22 CNY). Offshore turbine prices at the port are in the range of 1 320 – 1 540 EUR/kW (Fichtner-prognos, 2013a), (BVG, 2012), (Badiola, 2014).

Figure 16 shows the evolution of average world turbine prices excluding Chinese installations, from a different source than IEAWind, from BNEF (2013b). The graph shows prices both by contract signature date (PCSD) and by turbine delivery date ("past/median", “old/new technology”). Comparing the time a price is picked in both PCSD and “past/median” shows the evolution of the time gap between signature of the contract and the installation of the turbines. Thus, projects with turbine supply contract signed in 2007/2008 took much longer to commission, around two years on average, than contracts signed in 2011/2012, around one year. From 2012 onwards the graph shows price differentiation between new and old technology as described above.

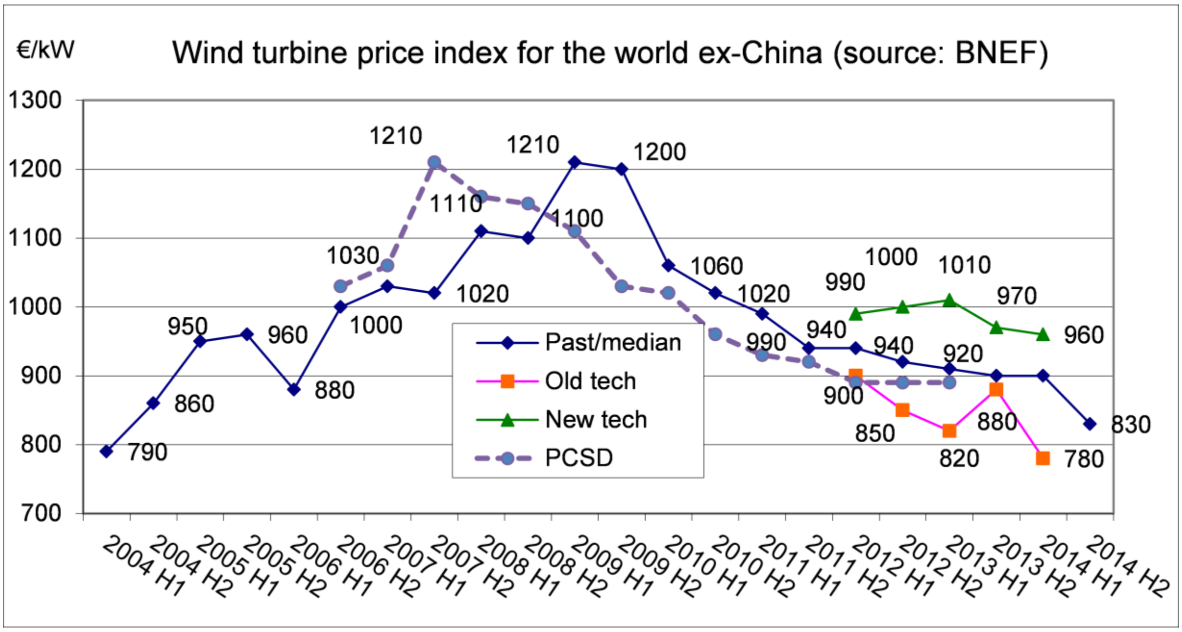


Figure 16: Evolution of wind turbine prices based on the year of delivery, except China. Source BNEF (2013b)

Average turbine prices trended down in 2012 allegedly because of the smaller (expected) market and higher competition. New technology continues to be more expensive and this technology split is likely to be a key cause of price differentiation between markets: in Europe Spain, Italy, the UK and France markets show the lowest prices, and the Scandinavian markets the highest (BNEF, 2013b).

It is interesting to see the contrast between 2011 and 2012 from one angle: whereas in 2011/12 higher price of turbines did not turn into high profits for their manufacturers in 2012/13, thanks to the painful cost-cutting and restructuring, lower turbine price levels still permitted manufacturers to achieve positive EBIT levels –as discussed in section 3.3.

The large differences between the prices of turbines for onshore and offshore applications are partly explained in terms of exponential size increases due to physics fundamentals. As an example, section 2.2.6 details these effects in the case of the castings and forgings of the wind turbine, and similar principles can be applied to towers, foundations, etc., e.g. the amount of material needed for monopiles grows exponentially with the monopile diameter.

Other reasons that explain those price differences include:

- a more complicated manufacturing process for large components;

- additional redundancy in particular of electrical components, sensors and measurement, remote control and condition monitoring;

- coatings for protection against the corrosive offshore environment;

- (perhaps) little competition with one manufacturer having a clear lead;

Sources: JRC; Badiola (2014).

4.2.2. Capital expenditure (CapEx)

The cost of the wind turbine is the main cost of onshore wind projects, but its share has been slowly reducing from around 70% to around 62% in a few years. Offshore, the share of turbine costs in total CapEx is lower at 30 – 40%, see Table 13.

Figure 17, with information from Table 14 and from last year's report, shows the different share of the cost of the turbine in the total CapEx for selected countries. Chinese data has slightly different components (see footnote 23) and it is therefore not comparable with the rest, and its presence in the graph shows these differences. The figures for Mexico, Austria and Sweden seem high, and Austria shows a clear reduction from 2011 to 2012.

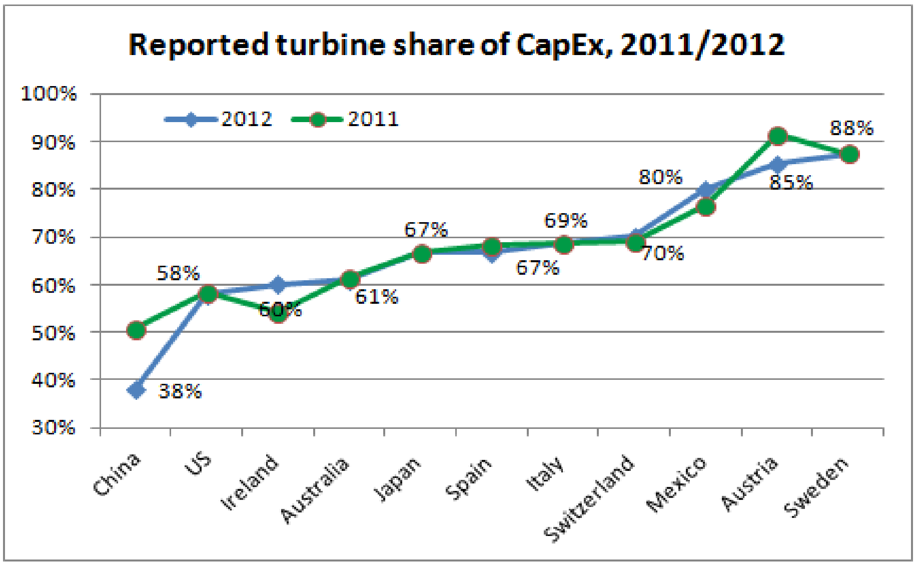


Figure 17: Turbine share of CapEx, 2011 and 2012. Source: IEAWind (2012, 2013)

From IEAWind (2013) the world weighted-average CapEx, (without China) for onshore projects in 2012 was €1 513/kW, and calculations based on different sources suggest a significant reduction for 2013 to perhaps €1 413/kW. If Chinese data are included[21], the world weighted average would be €1 395/kW for 2012. (Wiser & Bolinger, 2013) suggest a CapEx level around $2 190/kW (€1 651/kW) in 2010 reducing to $2 100/kW (€1 510/kW) in 2011 and $1 940/kW (€1 510/kW[22]) in 2012.

Offshore wind costs are subject to a lot of scrutiny because of the important effort to reduce it, not least by governments that are ready to pay the current high LCoE in order to achieve significant future price reductions. Different estimates put the offshore wind CapEx at €3 000 – 4 200/kW in 2011 with the upper end covered by farther offshore, deep-water wind farms (JRC, 2012). Two main sources have provided with additional information in the

[21] As discussed earlier, Chinese data cannot be compared with the rest of the world because they might not include towers or foundations, nor significant electrical equipment (e.g. transformers), nor certain ancillary (e.g. health & safety) equipment.

[22] The reduction in USD did not translate into a EUR reduction because of the exchange rate, which averaged 1.392 USD/EUR in 2011 and 1.2848 USD/EUR in 2012 (European Central Bank)

last eighteen months, BVG (2012) and Fichtner-prognos (2013a), and both sources based their work in the methodology set up by BVG (2012).

Source	**€/kW**	**Data yr**	**Scope**
EWI (JRC)	3 500	2010	EU average from different sources
BVG associates	2 854	2012	UK, modelled for the Crown Estate, minimum CapEx
Cpower	3 800	2011	Belgium, Thornton Bank II & III project
Navigant Consulting	4 705	2012	US, modelled for a DoE working group
Fichtner-prognos	3 753	2012	Germany, modelled for BWE, minimum CapEx, no grid connection costs

Table 11: Different offshore wind CapEx figures from different reliable sources, periods 2010-2012

It is important to note the variability of CapEx figures between countries and over time. In addition to Table 14, which represents somehow an official view of the countries contributing to the joint international effort IEAWind, there is the vision of industry analysts. Table 11 shows the range of variation in reported CapEx for offshore wind projects from some very reliable sources.

CapEx wind farms commissioned in year	MW (2011) in the sample	€/kW 2011	€/kW 2012	MW (2012) in the sample	Trend
Canada	852	1 915	2 117	540	↗
China	10 869	1 168	1 116	7 740	↘
India	1 422	1 058	904	767	↘
Ireland	46	1 694	1 612	69	↘
Japan	47	***1 663***	2 476	22	↗
Korea (Republic)	25	1 788	1 752	50	↘
Lithuania	6	1 710	1 562	14	↘
Romania	16	1 697	1 542	253	↘
United Kingdom	610	1 843	1 874	693	↗
United States	2 712	1 682	***1 698***	5 034	↗
For the following countries the sample of data did not reach 25% of the annual installation or there was a slight reliability issue with some of the data					
Brazil	91	1 530	***2 094***	229	↗
France	135	1 494	1 467	110	↘
Italy	244	2 023	1 822	165	↘
Norway	85	2 267	***1 105***	102	↘
Spain	128	1 496	1 431	150	↘
Sweden	39	1 872	1 468	128	↘
Mexico	374	1 623	1 689	673	↗

Table 12: Average country CapEx for projects commissioned in 2011 and 2012. Data from the first group of countries is considered representative at above 25% of the annual installation (2012). Data for the lower part does not reach the 25% of annual installations in any of those countries, but it is still interesting. Still, there are some remarks about part of the data, e.g. a halving of CapEx in Norway in one year is not reliable. Source: JRC analysis based on data from Bloomberg New Energy Finance renewable projects database.

Table 12 shows some country average CapEx from a commercial database containing 389 projects commissioned in 2011 and 335 projects in 2012. The figures, converted to

EUR_{2012}/kW, correspond to projects for the stated (sample) installed capacity in MW. Data in bold/italics suggest methodological differences with GWEC (2012) or data inconsistencies.

Table 13 shows the breakdown of offshore wind CapEx among the key elements of turbine, foundations, electrical connections and installation.

System or subsystem /Source	GL-GH [1]	Siemens [2]	Navigant [3]		Fichtner/ prognos [4]
			[3a]	[3b]	
Turbine	43%	44%	33%	38%	36%
Foundations	21%	23%	22%	25%	17%
Electrical infrastructure	21%	19%	12%	13%	
(Substation)					2%
(Export cable)					6%
Installation			19%	22%	15%
Construction finance		8%	12%		
Contingency		5%			13%
Others	14%		2%	2%	10%

Table 13: Breakdown of offshore wind farm costs as percentages, according to: [1] Germanische Lloyd – Garrad Hassan; [2] Siemens, [3] (Navigant Consulting, 2013), with two different figures depending on whether construction finance is considered a separate item, and [4] (Fichtner-prognos, 2013a). [1] and [2] declared those figures at a WindpowerMonthly webinar on 16.07.13. The assumptions under [4] include a model wind farm of 80 turbines of 4MW, some 40 km to shore and at 30 m water depth.

The previous issue of this report (Lacal Arántegui et al., 2013) discussed a few areas in which CoE could be reduced.

Irrespective of data issues the table shows one definite conclusion: there are huge differences between countries. In order to find out more about reducing the cost of energy these differences should be analysed and a model built which should show the impact in CoE of technology advancement and other factors acting it, whether legislative, materials, design, etc. (see subsection 4.2.7 below). This is the objective of a new European Commission study "*Support to EU wind energy technology development and demonstration, with a focus on cost competitiveness and smart integration*".

4.2.3. Capital investment versus turbine costs

The economic indicators below are heavily influenced by the underlying assumptions in each case, and by the differences in these between countries. For example, for some sources of data, CapEx includes the financial cost of the construction phase whereas for others this is not the case. In another example, turbine prices quoted for China, the leading market, do not generally include the installation and may or may not include the transformer and the tower[23]. Thus, the elements that make up LCoE contain country-specific differences, and this hinders a widespread assessment based on LCoE.

The analysis of the data in Table 14 suggests that the average "Western" wind project (i.e. without Chinese or Indian data) CapEx was ***1513 €/***kW in 2012, a reduction of 4.3% over

[23] Compare two sales by the same company in China: "The order comprises turbine supply and delivery, towers… " (Vestas, 2013a) with "The order comprises turbine supply and delivery, installation supervision … does not include towers" (Vestas, 2013b)

the 1 580 €/kW of 2011, and the average turbine cost was ***937 €/kW*** in 2012, a 6.1% reduction over the 998 €/kW of 2011.

Country	**Turbine costs (EUR/kW*)**		**Total installed costs (EUR/kW*)**		**Installed capacity (2011) 2012**
	Min	Max or avrg	Min	Max or avrg	MW
Australia	(870)	(1570) 1220	(1300)	(2670) 2000	(234) 358
Austria	(1400)	(1800) 1430	(1600)	(1900) 1675	(73) 296
China**		(468) 464	(861)	(984) 1220	(17631) 12960
Ireland		(1000) 900	(1600)	(2100) 1500	(239) 153
Italy		***(1200) 1200***		***(1750) 1750***	(950) 1273
Japan		(1980) 1740		(2970) 2610	(168) 88
Mexico	(1100)	***(1200) 1200***		***(1500) 1500***	(569) 801
Spain		(820) 800	***(1000) 1000***	***(1400) 1400***	(1050) (1122)
Sweden		***(1400) 1400***		***(1600) 1600***	(763) 846
Switzerland		(1450) 1450		(2100) 2070	(3) 4
United States	(818) 720	(1004) 985		(1562) 1470	(6810) 13124

Table 14: Estimated average turbine cost and total project cost for selected countries in 2011 (figures between brackets) and 2012. Source: IEAWind (2012, 2013)[24] for costs and GWEC (2013) for installed capacity.

* Exchange rate 1 EUR = 1.294 USD (2011) and 1 EUR = 1.318 USD (2012)

** China turbine cost figures often exclude components than in most countries are generally included. For this reason these figures are included for reference only

Interestingly, the IEAWind data allows obtaining a ratio of turbine cost versus total CapEx which can be projected to other CapEx data to estimate turbine cost and vice versa. This ratio was 62.4 % in 2012 on a basis of 19.3 GW installed, and compares with 63.2 % in 2011 on a basis of 14.3 GW[25]. This slightly lower weight of the turbine cost in total CapEx can be taken as another, if indirect, indicator of the reduction of turbine costs.

4.2.4. Operational expenditure (OpEx) - onshore

The evolution of operational expenditure is a complex issue where seemingly contradictory statements may all be true, as detailed below.

OpEx include expenses linked to maintenance (predictive, preventive and corrective), and all the other expenses necessary to operate the wind turbine or farm: insurance, land rental, cost of exporting electricity, cost of trading electricity in wholesale markets, local taxes, national taxes, management and administration, etc. We call the first group operations and maintenance (O&M) and the latter group "*other operating costs*".

Table 15: shows reported full-service onshore O&M costs from different sources. BNEF costs refer to new wind farm contracts (***prices***) whereas Garrad Hassan refers to ***costs***, more exactly to US total turbine O&M and balance-of-plant (BOP) costs which "increased from 21 $/kW in 2008 to 31 $/kW in 2011" (Houston, 2013)

[24] Canada, China, Germany, Denmark, Finland, Greece, Korea, the Netherlands, and Norway, were excluded from this assessment because of methodological differences or lack of complete data. Chinese data, however, was included in the table for illustration purposes, given its significant differences with the rest.

[25] This selection covers the equivalent to 43 % of the 2012 installed capacity and 30 % of 2011 one.

Year	(BNEF, 2013c), global	(BNEF, 2014), global	GL-GH (Houston, 2013), US	(BNEF, 2014) O&M cost @ 25% CF
	€/kW/yr	€/kW/yr	€/kW/yr	***€/MWh***
2008		29.2	14.3	***13.33***
2009		28.6		***13.06***
2010	22.82	24.2		***11.05***
2011	20.12	26.8	22.3	***12.24***
2012	19.37	17.3		***7.90***
2013	18.56	20.8		***9.50***

Table 15: Cost of O&M onshore, in nominal €/kW, from several sources. Note: BNEF reports global figures minus China, and GL-GH (Houston, 2013) reports US costs. The figure in €/MWh assumes a 25% capacity factor.

The two claims are not comparable as they refer to different periods –even when overlapping (2010-2013 vs. 2008-2011)-, different costs might be included (BOP in the case of GL Garrad Hassan), different geographical scope (US vs. global minus China), and different concepts as well: contracted prices for BNEF and realised costs for GL Garrad Hassan. This shows the complexity of the issue and justifies apparently contradictory claims. The nature of O&M costs is that they are high during the first months after commissioning the turbine and then they go down and stabilise for some 8 – 12 years, before slowly rising as parts wear out. After 20 years O&M becomes the marginal cost that defines whether the wind farm is profitable.

Another key of the differences between claims is in the detail of the contracts. Nowadays O&M contracts include time- or energy-availability figures (e.g. 97% time availability) and the sharing of income beyond the agreed availability. These contracts provide O&M providers with additional income beyond the fixed price, and the improvement of technology and in particular of condition monitoring (and enhanced energy production controls) would enable the additional income for both parties.

The trend to lower costs for new contracts is caused by several drivers:

- Increased competition. OEMs are entering this market and making aggressive offers covering 5 to 15 years.

- Economies of scale. Increasingly utilities have become large developers and owners of wind farms and this gives them higher purchasing power when negotiating with O&M suppliers.

- Improvements in wind turbine reliability as a result of manufacturers' investment in product and process innovations including organisational changes to O&M planning and execution. This has resulted in more reliable machines which require less maintenance and provide higher availability.

See last year's issue of this report for a description of the specific items included as operational expenditure.

Under the assumption that OpEx is 150 to 200% of O&M cost, 2012 onshore OpEx was from 12 to 16 €/MWh, and 2013 figures would vary from 14 to 19 €/MWh. These higher figures would be a temporary separation from the long-term trend showed in Table 15.

4.2.5. Operational expenditure (OpEx) – offshore

Information on offshore O&M is more limited partly due to the lower number of wind farms and O&M players. During 2013 the offshore sector showed the first signs of expecting a radical future reduction of O&M costs. Table 16 shows the expected future offshore OpEx and O&M from different industry analysts.

Source	Scenario	OpEx (€/kW/yr)	OpEx (€/MWh)	O&M (€/kW/yr)	Assumptions
ARUP (2011)	Low	93	26.6	46	Expected cost for UK Round 3 projects, FID 2020. O&M assumed 49% of OpEx
	Median	152	43.3	74	
	High	213	60.7	104	
BVG (2012)		177	50.6	80	6-MW turbine costing: O&M 81 GBP/kW/yr; insurance 14 GBP/kW/yr; transmission charges 69 GBP/kW/yr. 2011 exchange rate 0.86788 EUR/GBP
GL-Garrad Hassan (2013)	Scotland	84	24.1	57	500-MW wind farm with 6-MW turbines, 55km from O&M port and O&M strategy of work boats with helicopter support. Exchange rate 0.849255 GBP/EUR
Fichtner-prognos (2013a)	Site B	97	27.7	74	Germany. 450-MW wind farm with 75 6-MW turbines at 40-m water depth on monopiles, 80 km to shore, FID by 2020

Table 16: Expected operational expenditure for future offshore wind projects. Figures in €/MWh calculated by assuming a 40% capacity factor, which is conservative for future projects. Note: Fichtner-prognos (2013a) do not include transmission costs in OpEx.

The table shows that from 2011 to 2013 the industry has reduced its OpEx cost expectations for wind farms given the go-ahead in 2020 from 43.3€/MWh (median, ARUP) to 24 – 28 €/MWh.

However, other sources suggest that ***currently*** offshore wind OPEX seems to be increasing over time as O&M includes more services and also other OPEX costs (insurances, others) seem to be increasing. Current O&M costs vary between 22 and 53 €/MWh (Badiola, 2014).

GL Garrad Hassan (2013) estimates the future operational costs of a 6-MW turbine (see Table 16) at £430,000 and offers a cost breakdown based on the type of O&M expenditure as shown in Table 17:

Crane barge (25%)	Parts & consumables (15%)
Vessels & logistics (11%)	Service provider profit and risk margin (10%)
Insurance (9%)	Technician workforce (8%)
Balance of plant maintenance (3%)	Onshore base and staff (2%)
Other OpEx (17%)	

Table 17: Breakdown of O&M costs per type of expenditure. Source: (GL Garrad Hassan, 2013)

In order to show the combined economic effect of both O&M costs plus downtime some assumptions are necessary. This assessment is based on the work of BVG (2012) and on the update by Fichtner-prognos (2013a), and on expert knowledge as follows:

- Fixed O&M cost for a 4 MW offshore turbine 97 EUR/kW/yr as in (Fichtner-prognos, 2013a) and representative of the German situation in 2013, and breakdown of cost as for figure 11.4 in (BVG, 2012);

- Average downtime 300 hours or 3.4%; this corresponds to 96.6% availability;

- Energy availability is lower than turbine availability, at 95%, downtime 5%;

- Theoretical capacity factor for 100% availability is 45% or 3 942 hours; energy produced for 95% energy availability is some 3 745 hours equivalent to 3.74 MWh/kW/yr; downtime results in a loss of 197 hours or 0.197 MWh/kW/yr;

- At a price of 170 EUR per MWh[26] the lack of income due to 197 hours downtime equals ***33.5 €/kW/yr;***

- Total economic effect of O&M and downtime is a total cost equivalent to ***130.5€/kW/yr***.

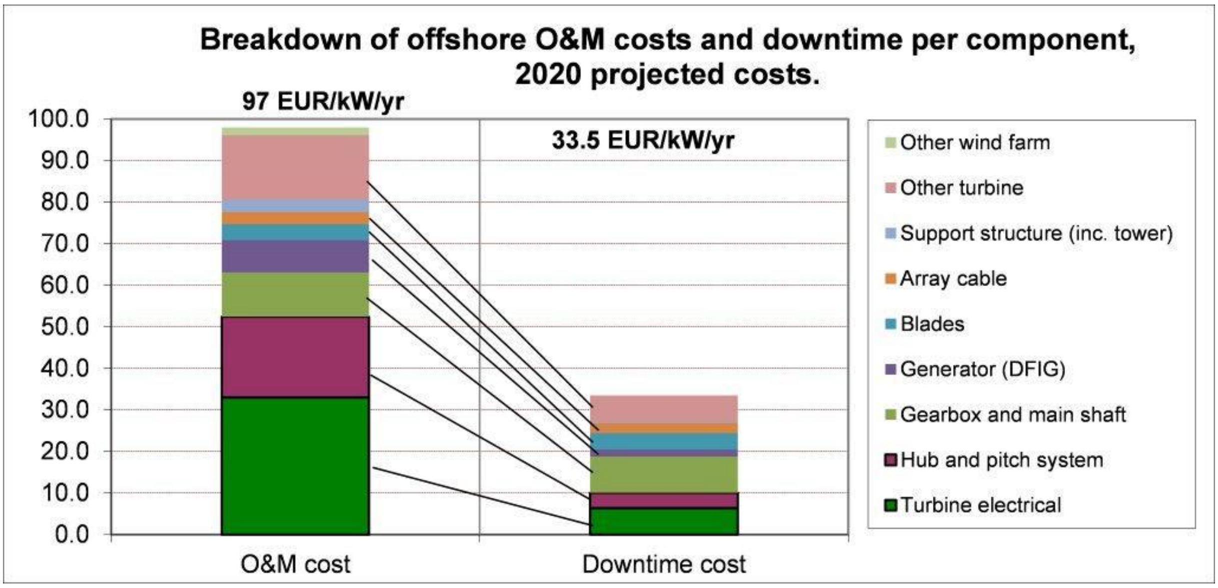


Figure 18: Projected costs from O&M and downtime for offshore wind farms with final investment decision by 2020. Source: JRC estimates based on BVG (2012) and Fichtner-prognos (2013a)

These two negative economic impacts are shown in Figure 18, and the combined effect and its breakdown per main components is represented in Figure 19.

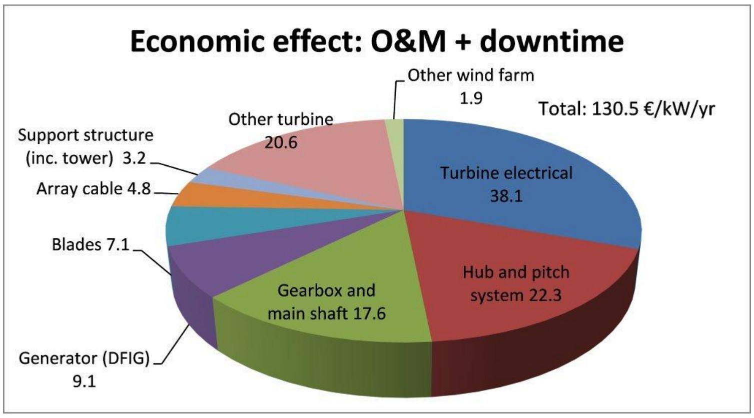


Figure 19: Net economic effect of O&M costs and downtime. JRC calculations based on BVG (2012) and on Fichtner-prognos (2013a)

The details of current O&M costs are included in last year's issue of this report following the same methodology. The authors estimate that O&M costs have not changed in a significant way from 2012 to 2013.

[26] French auction in 2012 resulted in 202€/MWh. Anholt offshore wind farm will earn 140 €/MWh, but the project did not bear transmission cost; German feed-in-tariffs and UK's income from renewable obligation certificates (ROCs) are consistent with a 170€/MWh level of payment.

4.2.6. Cost of energy

The fundamentals of the calculation of the levelised cost of energy were described in section 4.1. Table 18 exposes recent estimates of the CoE for offshore projects along with some of their underlying assumptions, and discusses the reasons for the uncertainties.

Component	GL Garrad Hassan (2013)	Fichtner-prognos (2013a)	BVG (2012)
Country focus	UK	Germany	UK
Cost of energy (€/MWh)	**-**	**128**	**158**
Turbine CapEx	30%	33%	36%
Foundation CapEx	15%	16%	20%
Electrical system CapEx	15%	8%	5%
Other CapEx	10%	17%	5%
O&M OpEx	25%	21.7%	33.8%
Other OpEx	5%	3.3%	

Table 18: Summary of figures for LCoE and breakdown. The latter is likely to be more consistent than the gross LCoE due to the different assumptions in LCoE, e.g. transmission to shore is not included in German projects.

4.2.7. Offshore: the path to cost reductions

Governments and other economic players acknowledge the need to reduce the cost of energy from offshore wind in order to fully exploit its potential. Some governments[27] are actively supporting this cost-reduction by, among others, providing high income levels to commercial plants, in order to obtain the economies of scale that will enable lower future costs.

Two recent reports analysed the state-of-the-art in the path to reducing offshore costs. BVG associates (BVG, 2013) analysed the supply chain and in particular how it evolved in the 18 months since the publication of its previous report (BVG, 2012), and found that significant improvements occurred in three areas whereas in one area the supply offer has weakened. Overall, the situation is worse in the supply of offshore wind turbines, subsea DC export cables and installation of foundations. We see this situation as follows:

- Turbine manufacture fails to establish a solid competition among several manufacturers and models. The market leader, Siemens, has overwhelming market domination and new models from other manufacturers (Alstom, Vestas, Gamesa…) are slow in its way to market because of the long development needed. Other existing manufacturers (Senvion, Areva) are only slowly taking market share.
- Subsea HVDC export cables are subject to a technology battle between lower-voltage extruded XLPE and higher-voltage (but of lengthy manufacture) mass-impregnated cables. Perhaps more importantly, there are limited suppliers and high entry barriers (it takes between 2 and 4 years to set up manufacturing facilities). Finally, HVDC demand for offshore connection is expected to overtake HVAC from 2019 (BVG, 2013).

[27] Germany, Belgium, Denmark, the UK, the Netherlands, France, Japan, China, Sweden and the US

- The activity of foundation installation has worsened "because a shortage of vessels is likely without new investment (…) and there has been little progress in developing specialist space frame installation vessels" (BVG, 2013)

As we can see in Table 13, the three problem areas highlighted by BVG associates (2013) cover roughly between 56 and 60% of the total CapEx.

4.2.8. Conclusion on costs

During 2012 and 2013 the expected capital investment trend towards lower onshore costs has been confirmed by different sources (BNEF, 2013b), (IEAWind, 2013), etc. The projections suggest that the trend will continue but at a lower reduction rate. However, this might change if the market changes, e.g. if Chinese manufacturers consolidate the recent export trend.

Technology factors such as the increasing size of turbine blades and a move towards PMG will also play a significant role but not so much for reducing CapEx but for reducing OpEx and increasing energy generation. Technology will continue to progress but, as wind turbines are viewed as a kind of commodity, it is likely that non-technological factors will have a stronger influence in the onshore turbine price.

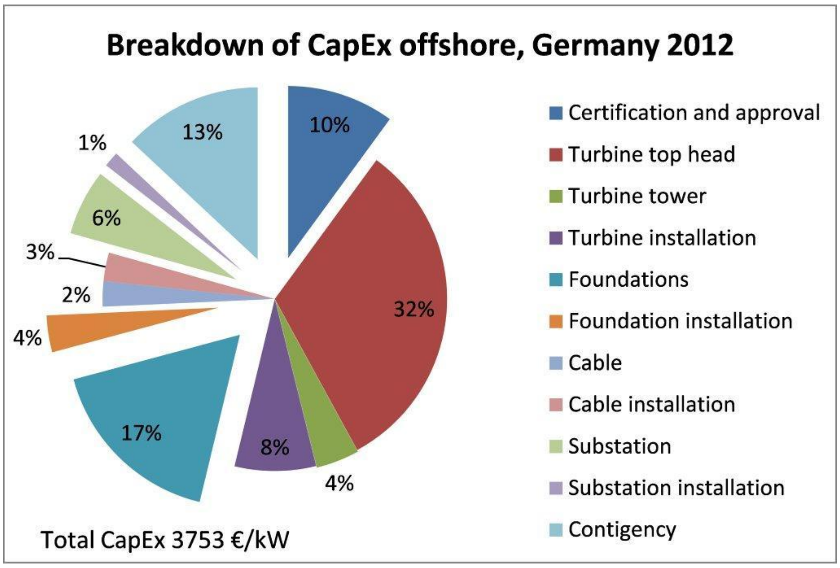


Figure 20: Breakdown of capital costs for an offshore wind farm under the following assumptions: 320-MW total with 80 turbines of 4 MW each, at a water depth of 30m and 40 km from shore, hub height 90 m (Fichtner-prognos, 2013a). The original data from Fichtner-prognos (2013a) has been modified in this graph to include the cost of the tower as part of the turbine instead of as part of the support structure (JRC).

As discussed in last year's issue, offshore wind is expected to maintain high costs (yet slightly decreasing) until 2015 and it is consolidating cost reduction from technology improvements e.g. to reduce foundation and installation costs.

Figure 20 shows the cost breakdown for a offshore wind farm in Germany in EUR_{2012}. These costs do not include grid connection from the wind farm substation to the shore.

If this breakdown is considered by functional element, the turbine *plus its installation* takes 43% of the total CapEx, the foundations take 22% and the cable installation 5% in a wind farm only 40 km from the shore. These data are consistent with other sources, as shown in Table 13

4.3. Energy produced

The typical European capacity factors onshore are 1 800 – 2 200 full-load hours equivalent (in which a wind turbine produces at full capacity), and 3 000 – 3 800 offshore. The clear technological trend is to increase these figures even when the best sites onshore have already been taken and new wind farms are built at lower wind speed sites.

It is sometimes assumed that energy production from offshore wind farms is more homogeneous than from onshore wind farms. Table 19 shows the energy produced in the Danish offshore wind farms and some located at sea but connected to the shore (defined as shoreline here). It has to be noted that year 2011 and 2012 were, in general, a good wind year in Northern Europe. The table therefore serves as well as an example of year-to-year variability.

Wind farm	Type	MW	Turbine model	No. of WT	MW per WT	Operational	Electricity production (MWh)		Capacity factor (%)	
							2011	2012	2011	2012
Vindeby	O	4,95	B35/450	11	0,45	1991	8 695	8 796	20,1	20.2
Tuno Knob	O	5	V39-500	10	0,5	1995	14 137	14 326	32,3	32.6
Middelgrunden	O	40	B76/2000	20	2	2001	88 431	90 742	25,2	25.8
Horns Rev I	O	160	V80-2.0	80	2	2002	669 833	675 995	***47,8***	***48.1***
Frederikshavn	O	2,3	N90-2.3	1	2,3	2003	6 837	4 675	33,9	23.1
Frederikshavn	O	2,3	B82/2.3 VS	1	2,3	2003	7 030	6 657	34,9	32.9
Frederikshavn	S	3	V90-3.0	1	3	2003	8 930	9 224	34,0	35.0
Nysted	O	165,6	SWT2.3-93	72	2,3	2003	600 649	575 157	41,4	39.5
Ronland	S	8	V80-2.0	4	2	2003	34 987	34 438	***49,9***	***49.0***
Ronland	S	9,2	SWT2.3-82	4	2,3	2003	37 468	38 772	***46,5***	***48.0***
Samso	O	23	SWT2.3-82	10	2,3	2003	87 745	95 800	43,6	47.4
Horns Rev II	O	209,3	SWT2.3-93	91	2,3	2009	911 031	956 028	***49,7***	***52.0***
Hvidovre	S	3,6	SWT3.6-120	1	3,6	2009	13 353	12 472	42,3	39.4
Hvidovre	S	3,6	SWT3.6-120	1	3,6	2009	11 805	12 533	37,4	39.6
Sprogo	O	21	V90-3.0	7	3	2009	66 432	67 060	36,1	36.4
Rodsand II	O	207	SWT2.3-93	90	2,3	2010	833 471	834 746	***46,0***	***45.9***
Hvidovre	S	3,6	SWT3.6-120	1	3,6	2011	3 774	13 046	12,0	41.3

Table 19: Electricity production from offshore (type = O) and shoreline (type = S) wind farms in Denmark, and capacity factors. Source: JRC analysis based on data from ENS.DK

It is interesting to note that the facility with the highest capacity factor in 2012, and nearly the highest in 2011, was also the largest Danish wind farm, Horns Rev II.

5. Learning effect in the installation of offshore wind farms

5.1. Introduction

The reduction of the cost of electricity produced from offshore wind farms (OWF) needs to tackle all the elements that make up this cost, which are, in essence, depicted in Figure 20.

The costs vary from project to project, but under certain general assumptions wind turbine and foundation installation contributes around 12% to a current OWF in Germany, in the latest published data (Fichtner-prognos, 2013a).

The objective of this section is to explore whether, and how, the installation rate of wind turbines offshore has evolved because an improvement in this rate will result in lower installation costs and a (possibly) significant contribution to the reduction in the OWF cost of energy. Whereas this research does not aim at quantifying the reduction in terms of costs, it aims at doing so in terms of installation days per "unit" installed where this "unit" can either be the wind turbine alone, the foundation alone (or its main parts thereof), the set[28] turbine plus foundation, or the respective equivalents in megawatt terms.

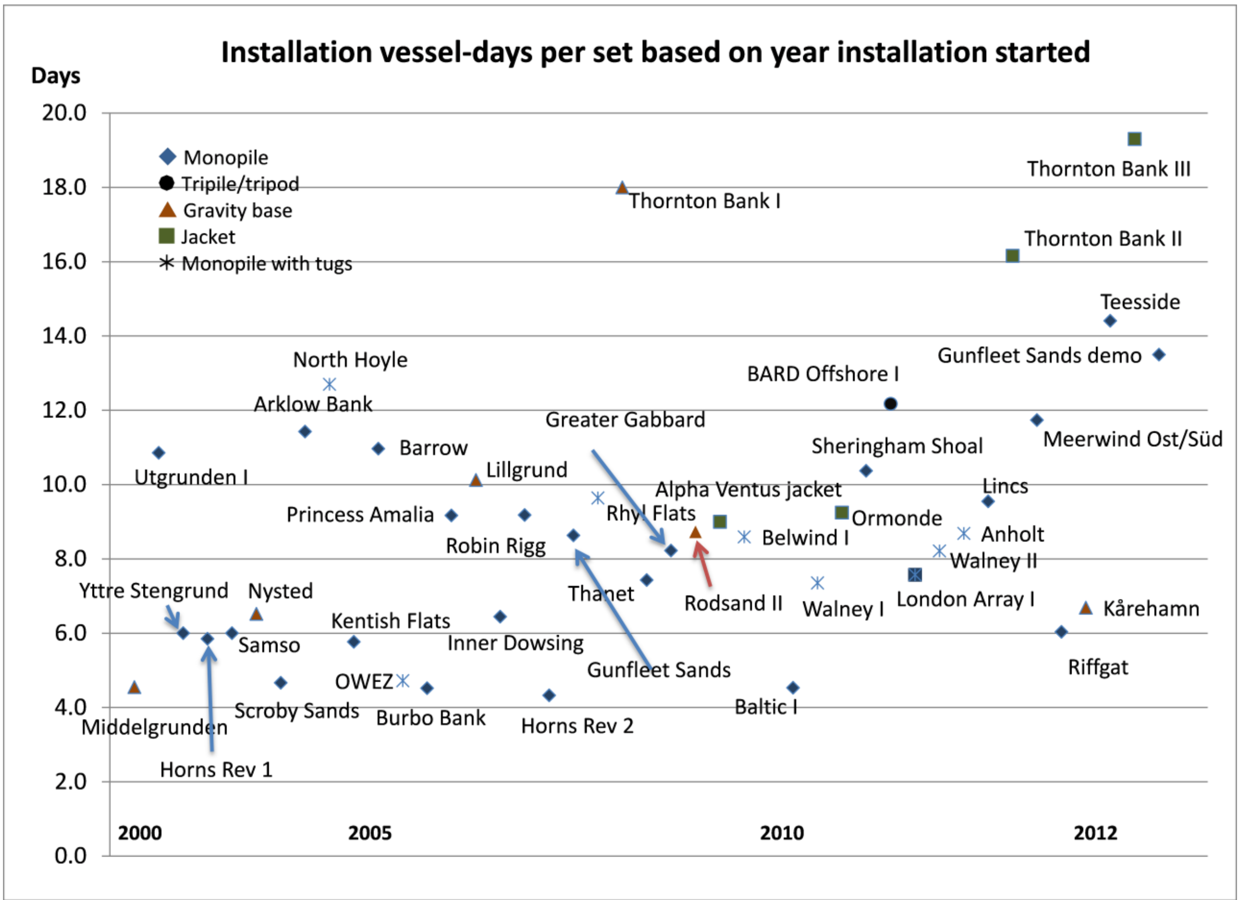


Figure 21: Overall picture of installation (vessel-) days per each set turbine-foundation.

[28] In this section the term "set" is used to reflect the set of turbine plus all the elements of the foundation, e.g. monopile/jacket, transition piece, piles, etc.

The data originate mostly from developer and subcontractors web sites, including press releases, and from the media and reports. When available, *Notice to Mariners*[29] or similar reports have been used. That information was complemented with data from the 4COffshore database, and in some cases from direct communication with the industry including developers and subcontractors.

Installation time lost due to mechanical breakdown -unless the vessel left the site for a period longer than two weeks- or to weather ("weather days") was not discounted. The author could not find out a way to obtain these data and, in any case, it was considered that those factors are influenced by technology improvements. For example, a new vessel able to install the nacelle with a wind of up to 13 m/s would have less weather days than an older vessel only able to install up to 10 m/s wind.

5.2. Overall picture

Figure 21 shows the overall picture of wind farms installed from 2000 to 2013, based on the year the first foundation was installed. The figure shows 31 monopile installations, six gravity base foundations, four jackets, and one tripile installation for a total of 42 offshore wind farms.

The vertical axis has been limited to 20 vessel-days in order to exclude some of the prototypes or demonstration projects (such as Belwind Haliade) which because of this prototype character had extraordinary long installation times and thus cannot be considered part of the trend. Lack of data prevented the inclusion of any OWF installed prior to the year 2000.

It is interesting to note that the spread of projects with installation days in Figure 21 is consistent with the evolution of installation costs, see e.g. figure 1-5 in page 17 of Navigant Consulting (2013).

5.2.1. Unit

The installation unit used for this analysis is the "vessel-day", i.e. two vessels installed the same type of element (turbine, monopile, etc.) during one week are counted as 14 vessel-days. This indicator can be used per turbine or per megawatt (MW) installed.

"Vessels" include only large installation vessels such as the self-propelled jack-ups (e.g. Sea Installer, Leviathan), jack-up barges which need tugs for propulsion (e.g. Brave Tern, JB114), or heavy-lift vessels (e.g. Oleg Strashnov, Javelin)

Items considered separately, when information is available, include: complete turbine, monopile, transition piece, jacket, tripile, support piles for jackets and tripiles, etc.

5.2.2. Milestones used

Ideally, the milestones used are

[29] See, for example, those in for Gwynt y Môr at http://www.rwe.com/web/cms/en/1203864/rwe-innogy/sites/wind-offshore/under-construction/gwynt-y-mr/latest-news-and-information/#anchor_1594372

- The first milestone is the day the vessel enters a harbour for loading the piece(s) that will constitute first installation, e.g. first monopile installed, first turbine installed.
- The last milestone is the day the last item (e.g. monopile) is reported as installed.

When the first milestone is not known the day of the first actual installation is used and an allowance is taken of 2 – 4 days for the loading of the item and transport to the OWF site.

5.2.3. Data issues and assumptions

Unfortunately the presence of an OWF in Figure 21 does not guarantee full reliability of the data, and some assumptions had to be made. For example, for the Lynn and Inner Dowsing OWF (here called Inner Dowsing because the installation was made in common), MPI Offshore stated that MPI Resolution returned to Esjberg "to start turbine erection for Centrica in February 2008" and finished the 54 turbine erection for Centrica in mid-July"[30], whereas a 18th-March Centrica press release said that " The construction of the Lynn and Inner Dowsing offshore wind farms is about to enter its final stage with the installation of the first of 54 wind turbine generators"[31]. Two issues arose in this example:

- "Mid-July" is not accurate enough for quantification and we had to assume the 15th July.
- The contradiction between the sources on the start date for turbine installation.

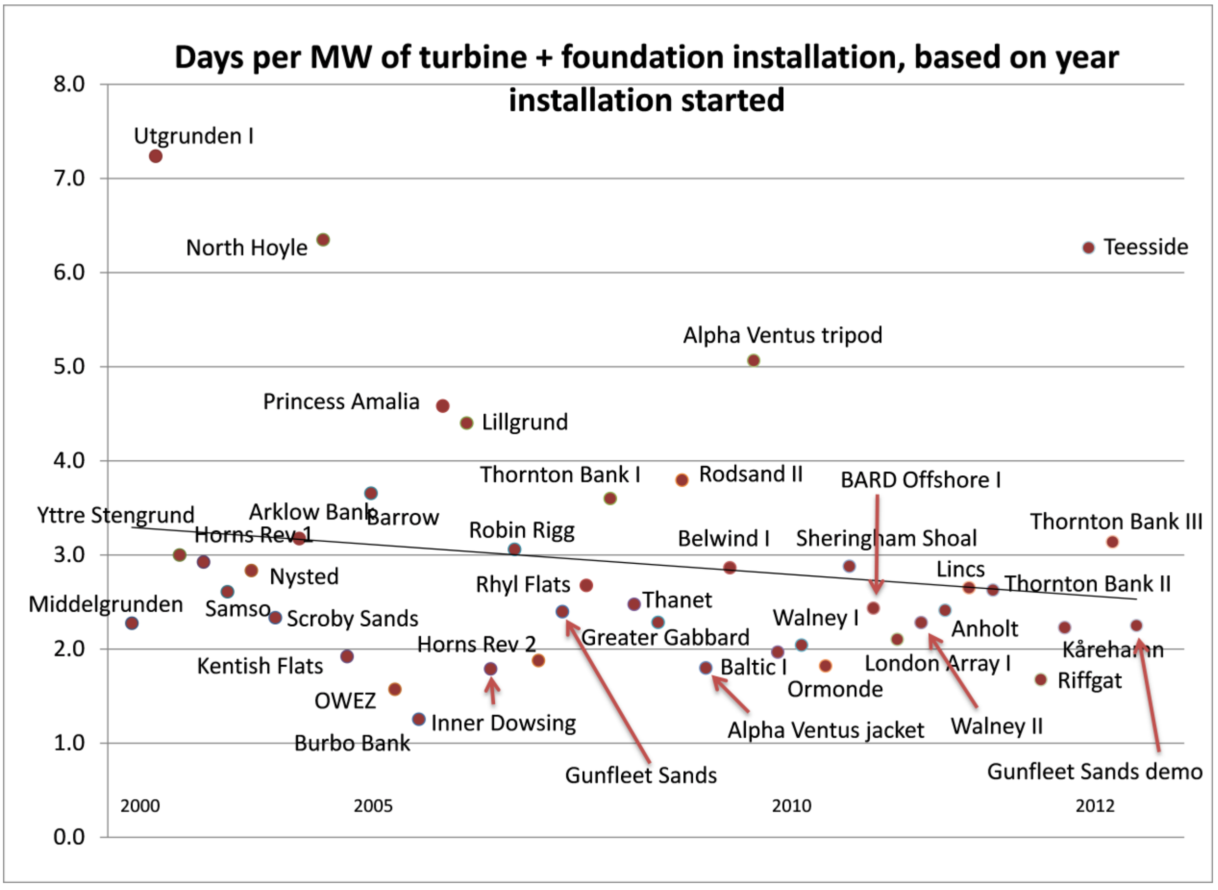


Figure 22: Number of installation days per megawatt of installed capacity, including both turbines and foundations.

[30] http://www.mpi-offshore.com/mpi-projects/robin-rigg-wind-farm/
[31] http://www.centrica.com/files/pdf/centrica_energy/18mar2008_lynn_and_inner.pdf

Transport of key items by a "minor" vessel, e.g. tugs transporting floating monopiles (the case of Rhyl Flats, OWEZ, or Anholt) or non-installation barges transporting jackets (as in alpha ventus) were not considered in this analysis even when it is acknowledged that these impact have a reduction in the use of larger installation vessels.

Figure 22 shows the same information as Figure 21 but the indicator used is vessel-days per MW of the set of a turbine plus its foundation. Both figures are comparable because the same OWF are included.

Comparing both figures the reader quickly realises that the bulk of the dots rotates in the direction of the clock. This shows the effect of larger turbines in reducing installation time per MW.

5.2.4. The effect of weather

Weather has a major effect on installation time, and three elements reflect this:

- wave limits: most installation vessels being jack-up vessels have a limit between 1 and 2.5 m for the jacking process;

- wind speed limits for crane operation;

- temperature limit for scour consolidation: if the ambient temperature is too low the transition pieces cannot be installed because the scour does not maintain its intended properties upon consolidation.

Technology has advanced and reduced the effect of weather. For example, within the same company a self-propelled jack-up vessel built in 1996 has limits of 1.25 m wave and 10 m/s wind speed during jacking operations, but a new (2014 delivery) vessel has limits of 2.6 m wave and 15 m/s of wind speed, a significant jump in specifications.

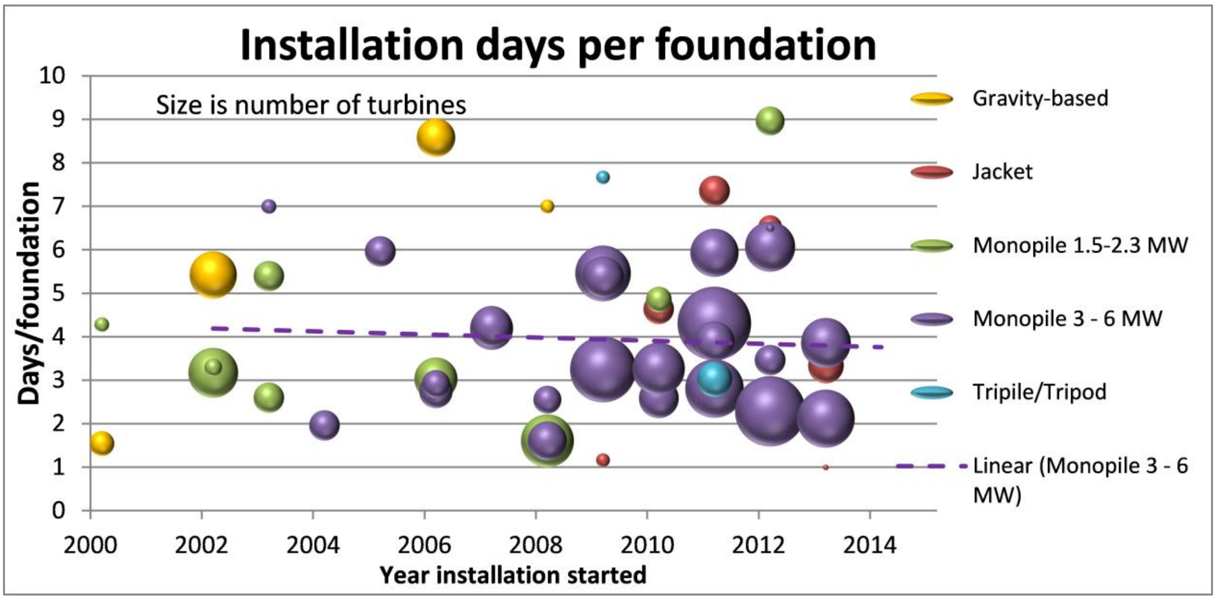


Figure 23: Overall picture of the time taken to install one foundation (without the turbine) for each OWF that has finished foundations installation. This includes both fully-operational OWF and those which still didn't finish turbine installation but did finish

5.3. Foundations installation

Figure 4 in section 2.1.3 shows the split of foundations per installed capacity, at the end of 2013, based on existing and under-construction offshore wind farms.

OWF which cannot be exactly defined as offshore were included in the overall figures in Figure 4 but not in the detailed analysis below. These include turbines in inner lakes (e.g. Vanern in Sweden), or physically connected to the coast at the shoreline (e.g. Ronland in Denmark, Bac Lieu in Vietnam, or Kamisu 2 in Japan).

Because some of the latest OWF already finished foundation installation there are more data points of those (47) than of turbine or whole-wind farm installation.

Figure 23 shows the overall picture of the number of vessel-days taken for the installation of the foundations only. The thickness of the bubbles reflects the size of the wind farm in number of turbines, this is intended to explore whether larger OWF involve time economies of scale. This figure shows that for gravity base, tripile/tripod and jacket foundations there are insufficient data points to demonstrate a trend. The graph also shows some data points which seem to break the trend, e.g. the green point taking 9 vessel-days per foundation starting in 2012 is the UK's Teesside, a project affected by very specific problems[32].

Given the pre-eminence of monopile foundations in the OWF installed or being installed, and therefore the larger population of data points prospectively available, it is appropriate to focus the analysis of foundations and whole-farms ("set") in monopile installations. However, the analysis of turbine installation can use all kinds of foundations for which data are available, and thus benefit from a larger dataset.

5.3.1. Installation time versus water depth/distance from the shore

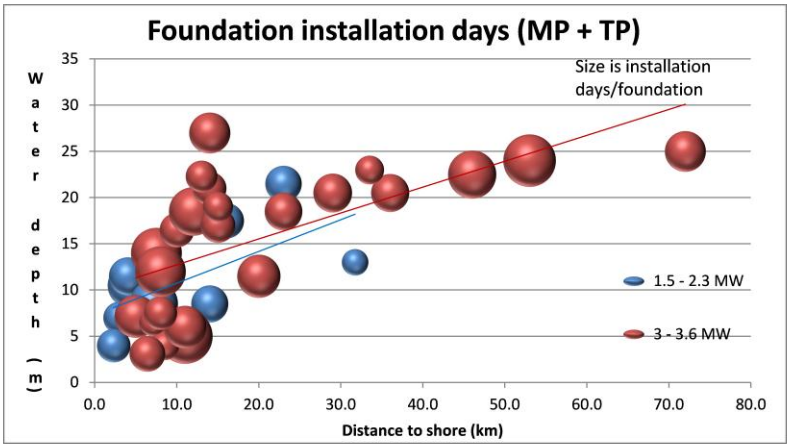


Figure 24: Relationship between water depth and distance to shore with foundation installation time

In theory at least, two elements of newer OWF push towards longer installation times: deeper water and farther from the coast, the former because of the additional complication of the installation and need for higher-specifications vessels and the latter because of the additional time OWF site - port.

Figure 24 shows that indeed the farther away the deeper the seabed, but the figure does not show that both elements contribute to longer installation time (as shown by the size of the bubble).

[32] E.g. one of the legs of the JB-114 became stuck in soft seabed mud when installing transition pieces, preventing retraction and movement of the vessel.

Figure 25, focused on monopile installation, suggests that:

(1) larger turbines have been installed recently;

(2) both for larger and smaller turbines show a trend to reduced installation time;

(3) the larger machine group overall require longer time to install. However, looking at this aspect in combination with Figure 24 suggests that this effect is also related to the deeper waters and farther distances of newer wind farms; and

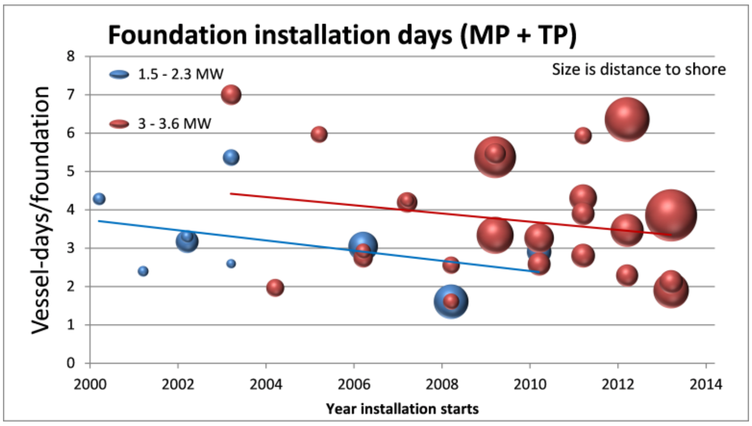


Figure 25: Evolution of monopile foundation installation rates for two families of turbines, 1.5 - 2.3 MW and 3 - 3.6 MW. Bubble size reflects the distance to shore.

(4) thicker bubbles are above the trend line, in particular in recent wind farms, in what can be perceived as a loose indicator of the effect of distance to shore.

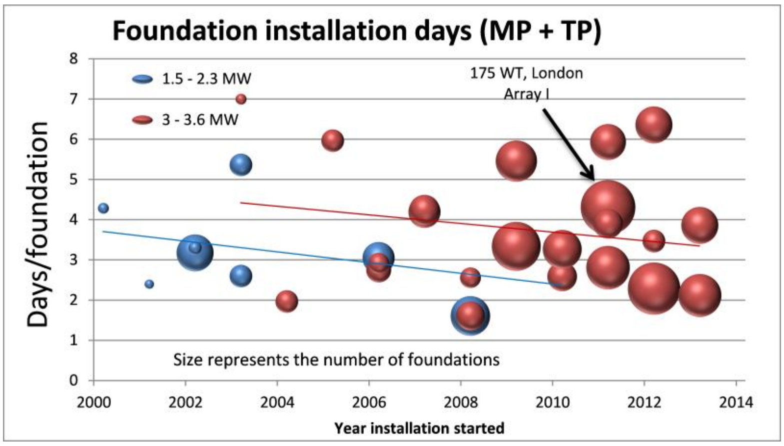


Figure 26: Evolution of foundation installation days and the impact of the number of foundations per project

Technology innovations addressing the distance issue include newer vessels with claimed capacity of up to 9 complete turbines. Process innovations with the same goal include new forms to store turbines in transport/installation vessels. Leg extensions have been undertaken in some installation vessels but the objective was to increase their working depth, not to reduce installation time in deeper waters.

Figure 26 explores the relationship between installation days and project size represented by the number of foundations per OWF, and it suggests that certain economies of scale exist as in general larger wind farms take less time per foundation to install. In effect, of the five largest OWF only the largest, 175 turbines, is above the 3-3.6 MW trend line; the next four (160, 140, 111, and 108 turbines) are below this trend line. This hinted at conclusion is confirmed by plotting data (this time for

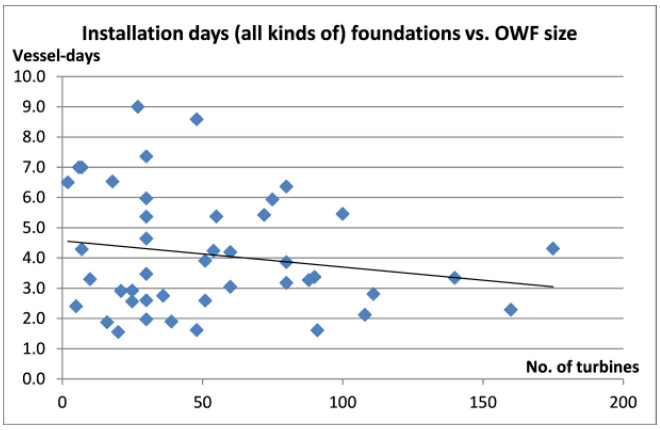


Figure 27: Comparison of installation time versus number of turbines in the OWF, for all types of foundations

all 47 OWF for which foundation installation data are available) against the number of turbines, as in Figure 27.

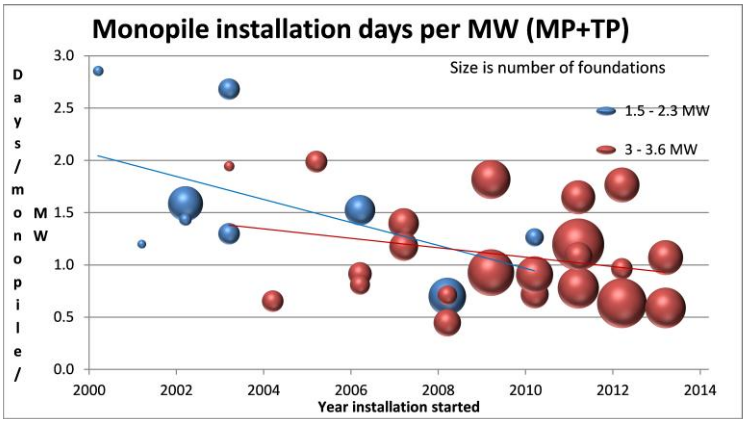


Figure 28: Monopile plus transition piece (when used) installation days per MW-equivalent

Figure 28 shows installation time per foundation MW-equivalent, for the two groups of turbine sizes (1.5–2.3 MW and 3-3.6 MW) on monopiles. The figure, which does not include Teesside (see reasons above), shows a very clear reduction in the installation rate since the early 2000 from some 1.5 days/MW to around 0.6 days/MW for OWF with foundations installed in 2013.

5.4. Installation of the turbine

Has the installation of turbines obtained the same efficiency gains as in the case of the monopile foundations?

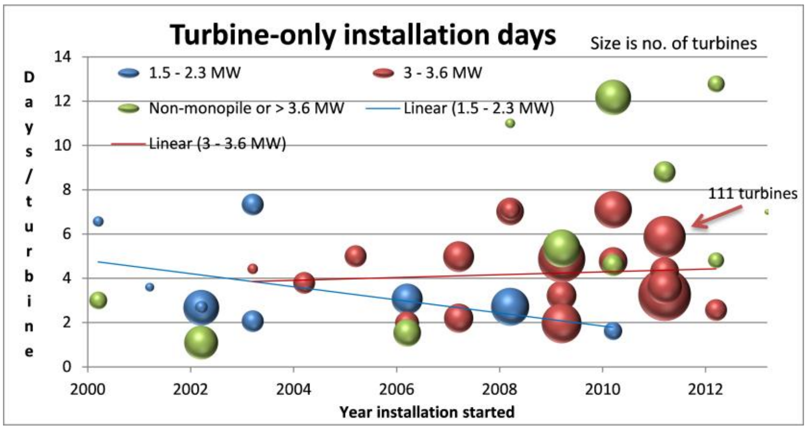
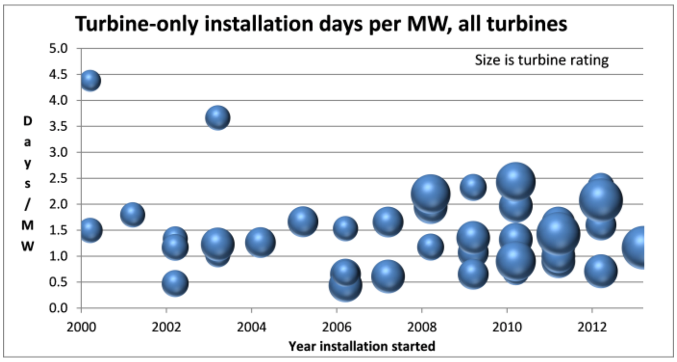


Figure 29: Evolution of the turbine-only installation days per turbine

Figure 29 suggests that this is not the case. This graph shows the installation rate for the turbine only of all European OWF from 2000. The three colours correspond to monopile-based installations with turbines between 1.5 and 2.3 MW (blue) and with turbines between 3 and 3.6 MW (red), as well as non-monopile-based installations of any turbine rating or 6-MW monopile installations (green). The data show no signs of reducing installation rate and rather they show an increase that is consistent with the increased turbine size. The thickness of the bubbles, which represents the size of the wind farm in number of turbines, could show economies of scale, but this does not seem to be the case either.

In the opinion of an industry insider whereas there has been changes to the techniques and technologies for installing monopiles during the last years, there have not been similar changes to the installation of turbines.

Figure 30 suggests that, with the anomaly of two older wind farms, turbine installation rates have remained stable throughout the period. The differences between both graphs are due to different foundations and in turbine nominal power (up to now only two turbines larger than 3.6 MW have been installed on monopiles, the Gunfleet Sands demonstration project), and they suggest that monopile-based turbines have more homogeneous installation rates of between 0.5 and 2 days per turbine.



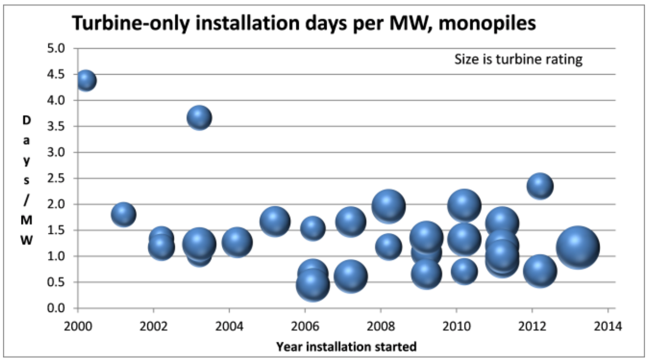


Figure 30: Evolution of turbine-only installation rates per MW for all turbines (left) and for monopile-only installations (right)

The figure also suggests that from the moment when a sufficient dataset per year became available, after 2006, turbine installation rates show a large variability of between 0.4 and 2.3 days/MW in the case of monopiles.

5.5. Installation of the whole set turbine-foundation

5.5.1. Installation rate (vessel-days/set), monopile-based

Figure 31 shows the evolution of the installation rate, including a clear trend towards a reduction in the installation rate of OWF using the smaller turbines (1.5 – 2.3 MW rated capacities), except Teesside. However, the installation of larger turbines has not seen this trend yet, and it even shows a slight increase that is probably due to the longer distances to shore.

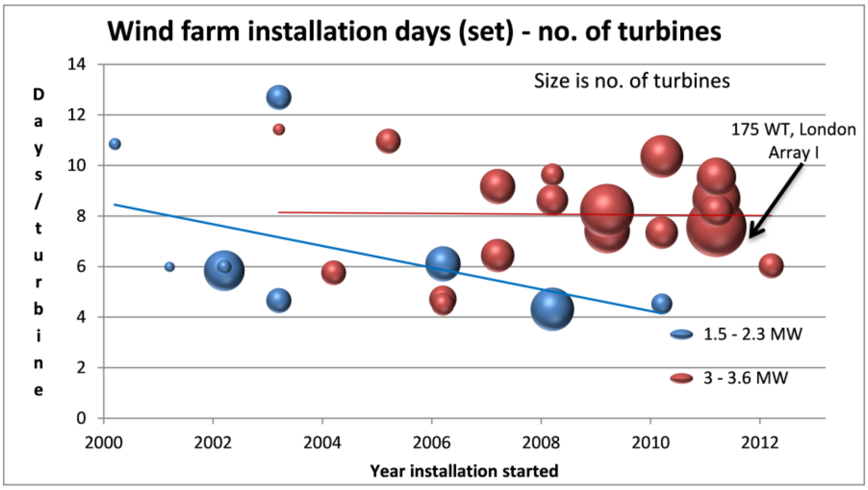


Figure 31: Installation rate for the whole set turbine-foundation, monopile-based only

When this information is contrasted with Figure 25 and Figure 30 (right), whereas the former shows that the installation of monopiles has indeed seen an improvement in its rate, the latter shows that installation rate of turbines on monopiles has remained flat or even increased slightly.

Therefore, the conclusion is that the overall reduction in monopile installation rate has been partly compensated by a slight increase in turbine installation rate that seems consistent given the larger turbine sizes being installed nowadays, to result in a flat evolution of wind farm installation rate.

5.5.2. Installation rate per megawatt of installed capacity

This conclusion is shown more clearly when looking at installation rates per MW of wind farm capacity, and concentrating the analysis on monopile installations. Figure 32 shows that the installation rate of OWF based on monopiles has improved on a per megawatt basis, both for the smaller and for the larger turbines. However, whereas the smaller turbines show a radical reduction, the group of larger turbines shows only a slight reduction.

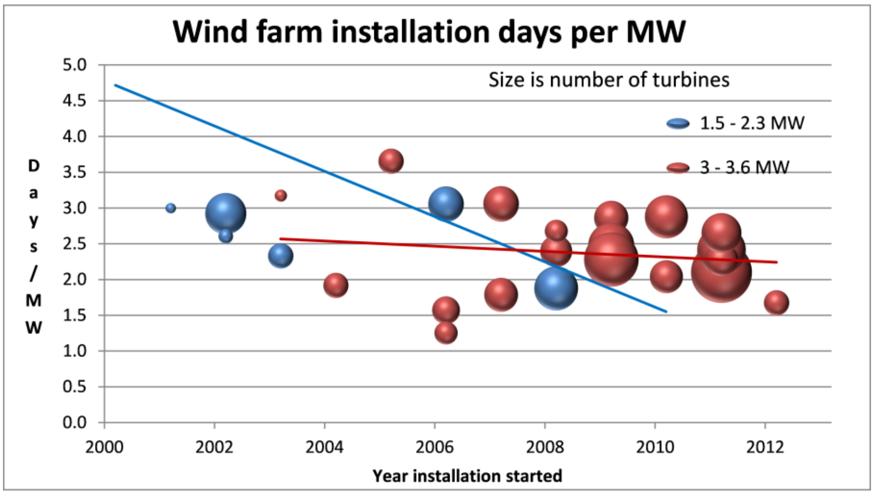


Figure 32: Evolution of wind farm installation rates per MW of installed capacity

Again, the comparison with Figure 28 and Figure 30 (right) shows that the improvements took place mostly (one can say "***only***") in the installation of the foundations. The results shown in Figure 32 are particularly relevant to support the view that turbine installation per megawatt is becoming more efficient.

Figure 33 shows the situation in relation with distance from shore, focusing only on the larger machines. The graph shows with a bit more detail the trend to lower installation rates. Interestingly, it also shows that some OWF farther offshore are, by 2012, reaching installation rates that were exclusive to near-shore OWF in the pre-2008 period.

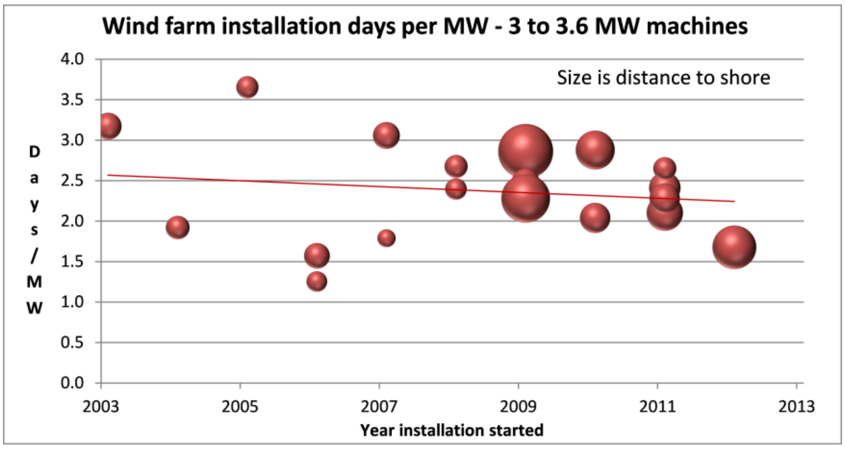


Figure 33: Evolution of the installation rate for turbines in the 3 - 3.6 MW range

5.5.3. Installation rate of monopiles vs. turbines

Another question is how the vessel installation time is shared between installing the foundations or the turbines.

Figure 34 plots the foundation share of the installation time against the total, the rest being the turbine installation time. The data points are weighted annual averages per MW installed for the three different groups of turbine/foundation sets (monopile 1.5-2.3 MW; monopile 3-3.6 MW; others) and for the weighted average of them all.

The data shows a trend to reducing variability: from the extreme year-on-year change of 40% in 2000/2001 to 55% - 80% in 2002 to the milder changes of 43% to 48% then 38% in 2010/2011/2012. One of the reasons of this lower variability is that the averages now correspond to much higher installations per year.

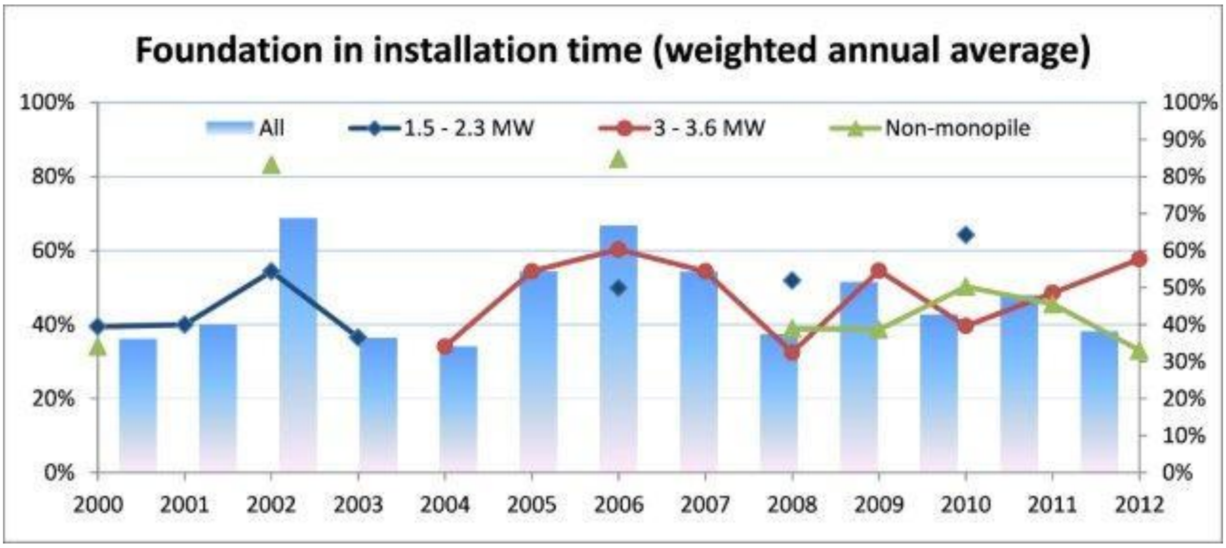


Figure 34: Weighted annual average share of foundation vs turbine installation time for the three groups of installations: monopile-based of 1.5-2.3 MW and 3-3.6MW and non-monopile foundations.

5.6. Conclusions and next steps in this research

5.6.1. Conclusions

The diversity of offshore wind farm installation, the uncertain effect of the weather, the presence of special data points (prototypes, and others), and the difficulty to find the necessary data are barriers for the quantification, in either time or cost terms, of learning-by-doing in the installation of turbine and foundations.

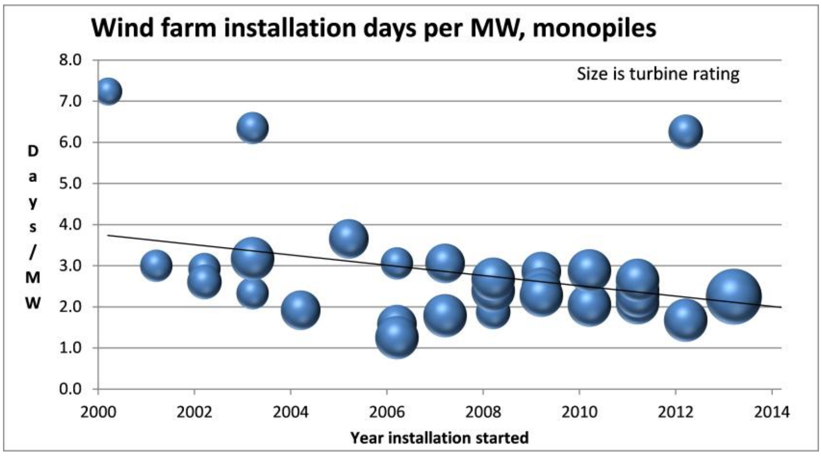


Figure 35: Evolution of the wind farm installation rate per MW, monopile installations

With these constraints in mind, the present study shows that turbine plus foundation installation time has decreased from a theoretical (measured on the trend line) 8.5 days in 2000 to 4 days in 2010 for relatively small turbines (1.5 to 2.3 MW rated power) on monopiles. For larger machines, 3 to 3.6 MW, also on monopiles there has been no reduction, and during the 2004 – 2012 period an average 8 days were necessary per turbine/foundation set.

However, the picture is very different when the effect of larger turbines is taken into account. As Figure 35 shows, the wind farm installation rate per megawatt was reduced from nearly 4 days per MW in 2000 (average on the trend line) to just above 2 days per MW in 2013.

This reduction is mostly caused by an improvement in the installation of monopile-based foundations from about 2 days per MW in 2000 to just above 0.6 days per MW for installations started in 2012. By contrast, turbine installation has not improved significantly. It has been suggested that the reason for this difference is that the method for turbine installation has not changed whereas the methods for monopile installation have changed in the last decade, aided by the first generation of purpose-built wind farm installation vessels.

Among the factors that led to a reduction in installation time are summer-only installation, e.g. Kentish Flats in summer 2004 installed the foundations and in summer 2005 installed the turbines, the use of auxiliary boats (tugs, barges) for transporting foundations to the wind farm site, or the arrival of new, purpose-built installation vessels. Among the factors that increased the installation time is the spells of unusually bad weather including high waves preventing vessels to jack, cold weather preventing grouting, etc., and the use of larger wind turbines.

5.6.2. Next steps in this research

A follow-up analysis could explore how two elements affect installation rates: severe weather and vessel mechanical breakdown. The sources for weather days include the vessel operators although perhaps an independent source should be found. The sources for mechanical breakdown could be vessel operators as well, although at times blogs and news can be good sources.

Developers find interesting to assess how is the impact of installation of foundations from floating vessels, as opposed to jack-up vessels.

An improvement possible to some of the analyses above is the re-definition of the distance to shore into distance to the construction ports, both for turbines and foundations separately as at times a different port is used.

The installation time considered could be improved by using the AIS (Automatic Identification System) tracking system. There are service providers that could perhaps provide accurate vessel routes and times.

The technical specifications of vessels are a fundamental factor determining installation time, and could be the subject of future research.

Appendix: installation data

The following table shows the key installation data used for the analysis in section 5.

Wind farm	Installation days			Installation vessels	
	Foundations	Turbines	Total	Foundations	Turbines
Utgrunden I	4.3	6.6	10.9	The Wind	The Wind
Middelgrunden	1.6	3.0	4.6	Eide Barge 5	MEB - JB1
Horns Rev 1	3.2	2.7	5.9	Buzzard, The Wind	Sea Energy, Sea Power
Nysted / Rødsand I	5.4	1.1	6.5	Eide Barge 5	Sea Energy
Samso	3.3	2.7	6.0	Vagant	Vagant
North Hoyle	5.4	7.3	12.7	Excalibur, The Wind	MEB-JB1, Excalibur, Resolution
Arklow Bank I	7.0	4.4	11.4	Sea Jack	Sea Jack
Scroby Sands	2.6	2.1	4.7	Sea Jack	Sea Energy, Excalibur
Kentish Flats	2.0	3.8	5.8	MPI Resolution	Sea Energy
Barrow	6.0	5.0	11.0	MPI Resolution	MPI Resolution
Lillgrund	8.6	1.5	10.1	Eide Barge 5	Sea Power
Egmond aan Zee (OWEZ)	2.8	2.0	4.7	Svanen	Sea Energy
Burbo Bank	2.9	1.6	4.5	Sea Jack	Sea Jack
Princess Amalia (Q7)	3.0	6.1	9.2	Sea Jack	Sea Jack, Sea Energy
Lynn & Inner Dowsing	4.2	2.2	6.4	MPI Resolution	MPI Resolution
Robin Rigg	4.2	5.0	9.2	MPI Resolution	Sea Worker, Sea Energy
Thornton Bank I	7.0	11.0	18.0	Rambiz	Buzzard
Rhyl Flats	2.6	7.1	9.6	Svanen	Lisa A
Horns Rev 2	1.6	2.7	4.3	Sea Jack	Sea Power
Gunfleet Sands I + II	1.6	7.0	8.6	Excalibur, Svanen	KS Titan, Sea Worker
Thanet	5.5	2.0	7.4	Sea Jack, MPI Resolution	MPI Resolution
Rodsand II	3.4	5.4	8.7	Eide Barge 5	Sea Power
alpha ventus (Areva)	7.7	17.7	25.3	Odin, JB-114, Taklift 4	
alpha ventus (REpower)	1.2	7.8	9.0	Buzzard, JB-115, Thialf	
Belwind I	5.4	3.2	8.6	Svanen, JB-114	JB-114
Greater Gabbard	3.3	4.9	8.2	Stanislav Yudin, Jumbo Javelin, Leviathan	Sea Jack, Leviathan
Walney I	2.6	4.8	7.4	Goliath, Vagant	Kraken, Sea Worker
BARD Offshore I	0.0	12.2	12.2	Wind Lift 1 (assumption)	Brave Tern, Thor, JB-115, JB-117
Baltic I	2.9	1.6	4.5	Sea Worker	Sea Power
Sheringham Shoal	3.3	7.1	10.4	Svanen, Oleg Strashnov	Leviathan, GMS Endeavour, Sea Jack
Ormonde	4.6	4.6	9.2	Buzzard, Rambiz	Sea Jack
London Array I	4.3	3.3	7.6	Sea Worker, MPI Adventure, Svanen, Sea jack	MPI Discovery, Sea Worker, Sea Jack
Lincs	5.9	3.6	9.5	MPI Resolution	MPI Resolution
Thornton Bank II	7.4	8.8	16.2	Buzzard, Rambiz	Neptune, Vagant
Walney II	3.9	4.3	8.2	Svanen, Goliath	Leviathan, Kraken
Trianel Windpark Borkum 1	3.0		3.0	Goliath	MPI Adventure
Anholt	2.8	5.9	8.7	Svanen, Javelin	Sea Power, Sea Worker, Sea Installer, Sea Jack
Teesside/Redcar	9.0	5.4	14.4	Sea Jack, JB-144	MPI Adventure

Wind farm	Installation days			Installation vessels	
	Foundations	Turbines	Total	Foundations	Turbines
Thornton Bank III	6.5	12.8	19.3	Buzzard	Goliath, Vagant
Borkum Riffgat	3.5	2.6	6.0	Olev Strashnov	Bold Tern
Gwynt y Mor	2.3		2.3	Stanislav Yudin	Sea Jack, Sea Worker
Meerwind Süd/Ost	6.4	5.4	11.7	Zaratan, Leviathan, Oleg Strashnov	Zaratan, Leviathan
Karehamn	1.9	4.8	6.7	Rambiz	MPI Discovery
Gunfleet Sands III	6.5	7.0	13.5		Sea Installer
Dan Tysk	3.9		3.9	Seafox 5	Pacific Osprey
West of Duddon Sands	2.1	2.8	4.9	Pacific Orca, Sea Installer	Sea Installer
EnBW Baltic II (jackets)	3.3		3.3	Goliath	
EnBW Baltic II (monopiles)	1.9		1.9	Svanen	
Yttre Stengrund	2.4	3.6	6.0	Excalibur	MEB-JB1
Belwind Haliade	1.0	43.0	44.0		Bold Tern

Notes:

- The level of uncertainty is built into this table by using colours. Thus, a yellow-coloured figure means assumptions had to be made that the analyst feels comfortable with, whereas a red colour reflects assumptions with a higher risk.

- The table does not reflect which wind farms used tugs for floating the monopiles to site (with the consequent time savings) or barges to move other elements (e.g. jackets) to site.

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Abstract
This report presents key technology, market and economic aspects of wind energy in Europe and beyond. During 2012 the wind energy sector saw a new record in actual installations and also a negative record year for the economics of its manufacturing sector. 2013, by contrast, saw a reduction in turbine installations but a better perspective for the economics of the sector. The global market reached 45 GW of installed capacity in 2012 of which 1.4 GW offshore, whereas in Europe 11.9 GW installed beat the 2009 record of 10.2 GW, with the offshore market also marking a new record with 1.275 GW. Global cumulative installed capacity reached 285 GW at the end of 2012 and, according to preliminary reports, it reached around 320 GW by the end of 2013. The installed capacity at the end of 2012 in the EU produces 203 TWh of electricity on an average year.
From a technology point of view in 2013 the outstanding results of the TWENTIES project for wind integration deserves credit. They showed e.g. that up to 15% more electricity can be transported in existing lines with minimum operational and technological improvements, and up to 25% more in newly-designed lines using new but within-reach technologies.
In 2012 both turbine and project prices onshore dropped, and 2013 showed the first indications that a 40% reduction in offshore cost is within reach by 2020. The analysis of data from IEAWind (2013) suggests that the average "Western" (i.e. without Chinese or Indian project data) wind project capital investment was 1510 €/kW in 2012, a reduction of 4% over the 1 580 €/kW of 2011, and the average turbine cost was 940 €/kW in 2012, a 6% reduction over the 998 €/kW of 2011. Calculations based on different sources suggest a significant reduction for 2013 to perhaps €1 410/kW.

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