

Current developments in wind - 2009

Going to great lengths to improve wind energy

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To the reader

Dear reader,

Thank you for downloading this report, we hope you will find it interesting and useful.

This report is not the conclusion of a project that is completely finished. Rather, it is meant as the first of a hopefully recurring publication that is updated every year. Therefore, ***we would really appreciate it if you share your comments, thoughts or links to data with us.*** You can e-mail your comments to:

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Thank you

Wouter Engels

Summary

The purpose of this report is to give the reader an understanding of current wind turbine designs, the differences between them and how changes in the main design parameters can affect the final cost of energy. For this purpose, we gathered data on more than 130 different wind turbines, 80 different offshore windfarms and from other cost studies. This data was analysed to see whether technological trends can be distinguished and what impact research and design changes may have on the cost, either on parts specifically or the total cost of energy.

The report consists of 3 parts. The first part examines the major parts of the wind turbines (drive train, rotor and support structure). The second examines the cost and the third examines current research.

An analysis of drive trains of turbines with a rated capacity of 3 MW or more did not show convergence to any particular drive train layout. Variable speed and pitch-to-feather control is universal in this class of turbines.

The mass of a tower can be approximated fairly easily, but the spread in the data is very large. For offshore foundations, trends in design are not very clear yet. Most farms have been installed with monopiles though.

Data on the blade designs of wind turbines blades shows a different trend than what would be expected on the basis of scaling functions published in literature, though both could be considered a valid approximation. This shows that one must be very careful when using such scaling functions. Onshore, the rotors of IEC class II and III turbines with higher power ratings are relatively larger in comparison to their rating than their smaller class II and III turbines. I.e. they have a much lower power density. Within each class, the difference in power density varied up to a factor 1.5.

Cost break-downs of existing turbines vary significantly in their cost-estimates of the main parts, even for similar wind turbines. On direct drive wind turbines too little data is available for comparison. Therefore, the costs of different drive-train layouts can not be compared across multiple studies. For onshore wind turbines an estimate of the *cost* price (excluding delivery, service, works, profit margin and warranties) was established on the basis of average cost distribution and turnover data from gearbox and blades manufacturers. This estimate amounts to 570-666 €/kW. Turnover data from the manufacturers indicate that onshore turbines are sold at a price of about 1000 €/kW (including, delivery and warranty). Contracts for offshore turbines show that these are significantly (200-750 €/kW) more expensive.

In terms of cost, prices for both onshore and offshore windfarms rose sharply in recent years. Onshore it can be shown that increases in raw materials can only have contributed a small part in this increase. High demand relative to supply chain capacity will certainly have played an important part. Offshore, the location of the wind farm in terms of depth and distance to shore plays a big role. The data had such high variability that it was unclear whether supply and demand mismatch played an important role here.

Given current designs and turnkey costs, it should be possible for onshore wind turbines to achieve a cost of energy as low as 0.04 to 0.05 €/kWh. Capital cost (7% interest) and maintenance have been taken into account in these figures. Offshore, current cost of energy ought to be between 0.08-0.10 €/kWh. These values with yields that were obtainable at 8.0 and 9.5 m/s respectively.

Current research focusses on reducing the uncertainties in calculating the loading of components,

reducing maintenance cost, improving the use and the properties of materials and on reducing the overall loads using control.

1 Introduction

1.1 Why do this study

During the work we do at ECN Wind Energy, be it theoretical or more practical for specific turbine manufacturers, it can be difficult to keep track of all the wind turbines and all the different turbine designs. At the moment, the offshore market in particular is growing rapidly and new manufacturers with new concepts are trying to cut themselves a slice of this fast growing market. Onshore both new and existing manufacturers are announcing new wind turbines at a high rate.

The purpose of this report is to give the reader an understanding of current wind turbine designs, the differences between them and how changes in the main design parameters and research can affect the final cost of energy.

This study laid the foundation of a database containing the main turbine characteristics. This database will be updated in the future, as new models emerge or more data on turbines becomes available.

1.2 Scope

This study examines:

- drive train designs
- different tower designs and offshore support structures and installation
- the trend in blade designs
- maintenance cost
- cost of energy
- current research

These items cover most major design choices in terms of layout for both onshore and offshore turbines.

1.3 Method

It should be noted that this research is conducted on the basis of a limited budget that did not allow the creation and evaluation of detailed cost models.

We have gathered *publicly available* data on more than 130 wind turbines of turbines of over 30 manufacturers. Turbines that are included are types that are currently commercially available, turbines that will become available in the near future and some turbines that are known, but of which the status is a bit unclear (for instance, the Enercon E-126 and the GE-3.6s offshore). The focus of the data is mainly on the turbines of rated more than 1 MW, the smallest turbine included in the data is 275 kW. The aim was not to include all turbines models ever produced, but to create a realistic image of the current state of turbine design.

The data is used to find trends. These trends will be mostly related to the size. This allows some comparison with published scaling functions. Ideally, one should also remove trends that are related to developments in time (technological learning) to get the actual scaling functions. Unfortunately, time-related trends were difficult to quantify.

For data on turnkey-cost for onshore wind turbines we have used the World Market Updates

2005-2008 [24, 25, 26, 27]. For offshore data we have also used their data and gathered our own data as well.

It should be noted that a lot of this data is gathered from manufacturers folders or from various press releases and news items and can thus be wrong in particular cases. However, as a whole, the data is expected to be accurate enough to reflect the ‘true’ trends.

1.4 Report layout

Sections 2 to 4 of this report examine the design of current wind turbines, focussing on the drive train, the blades and the support structures. These are also the parts that define a large part of the investment cost.

Sections 5 and 6 focus on the cost of maintenance, the cost distribution of a wind turbine over its parts and the total cost of energy. Section 7 discusses what topics are in current research in wind energy.

The last chapter concludes the study and examines whether the results that were found matched the goal of the study.

2 Drive train designs

To understand the differences between different wind turbines one must take a look at their drive trains. This chapter discusses different design layouts found in current wind turbines and some of the factors that drive them. It also examines how the weights of certain parts of the drive train change as turbine size increases. The weight of a part is at least a partial indication of its cost.

2.1 Introduction

Here we will examine mainly the layout of the drive-train. The cost breakdown of a turbine over its major components will be explained in section 6.

There are at least 30 different manufacturers that deliver wind turbines rated more than 1 MW. There are more than 130 different models of varying capacities. To limit our selection in this chapter, we have described turbines with a power of 3 MW or more, as well some alternative drive train designs of lower ratings.

To prevent any misconceptions due to terminology, the main parts of the wind turbine and the drive-train are first examined.

2.2 Basic turbine terminology

Figures 2.1(a) and 2.1(b) show the main parts of the turbine and its nacelle. The terminology used in these figures will be used throughout this report.

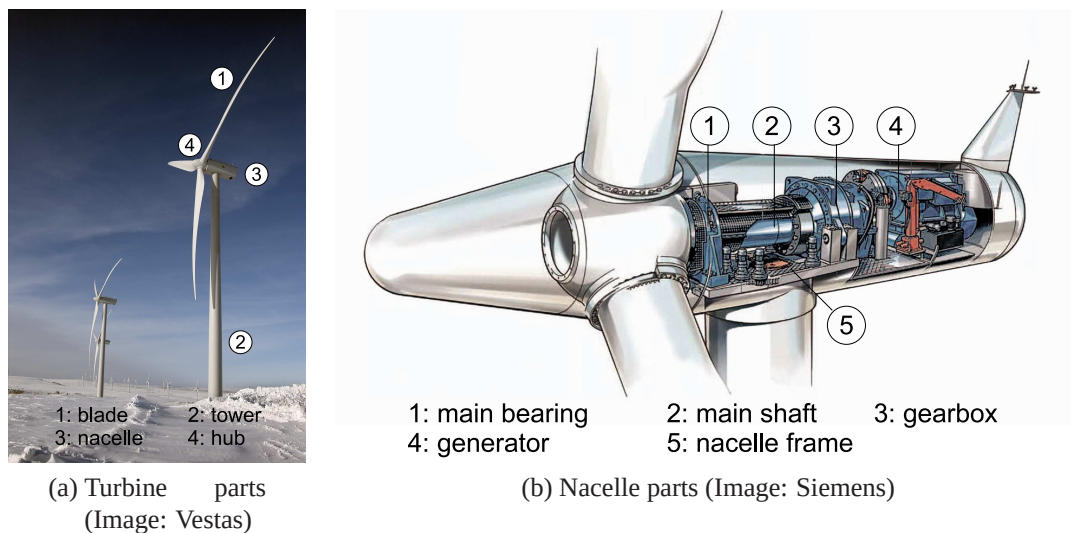


Figure 2.1: Basic parts of wind turbines

The main differences between turbines are found in the nacelle; more particularly, in the drive train. The drive train is basically all the parts that are used to convert the torque and speed of the rotor into electricity. By modifying the layout, manufacturers try to improve the reliability and reduce the cost.

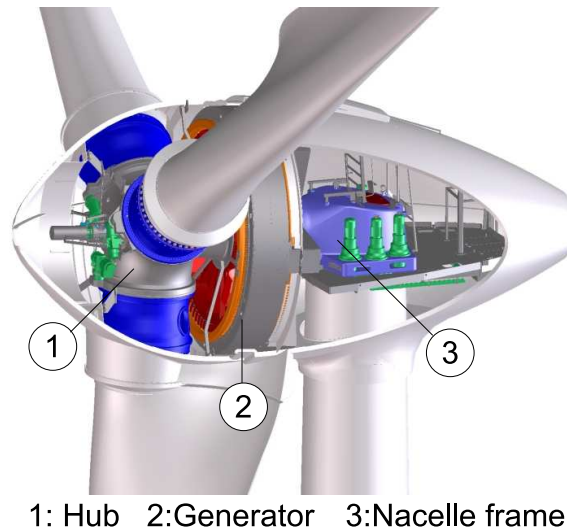


Figure 2.2: A direct drive layout, in this case, an Enercon E-70 or E-82 (Image: Enercon)

2.2.1 The classic layout

Figure 2.1(b) shows what we will call a ‘classic’ layout. This layout is or has been used by most manufacturers. The idea is that the rotor (the hub and the blades) is attached to a main shaft supported by two bearings. The front, main bearing is closest to the centre of gravity of the rotor and will carry most of the loads. The second bearing is located just before the gearbox. The gearbox transfers the power from the slow rotation of the main shaft to the fast rotating outgoing shaft. This so-called ‘high-speed’ shaft is connected to the generator.

The average rotational speed of the high-speed shaft at rated power is chosen in combination with the generator to match the frequency of the grid that the turbine will be connected to. That means that for this type of turbine, different gearboxes are necessary for different grids (e.g. North America has a grid frequency of 60 Hz, while Europe has 50). The classic layout originally allowed the generator to be similar to industry standard generators.

One thing that is different in comparison to industry standard electricity generation is the fact that wind tends to vary. To make maximum use of the wind, it has become common practice to allow the rotor speed to vary. The variation in the rotor speed also leads to a variation in the shaft of the generator. The resulting frequency variation is compensated using power-electronics.

2.2.2 Direct drive layout

A direct drive layout consists of a generator that is rigidly connected to the rotor, either with or without a shaft. Thus, a direct drive concept does not have a gearbox. Whereas in the classic layout normally only part a of the power passes through power electronics, with direct drive turbines usually all power generated is converted with power electronics. Direct drives have two varieties, one were both the rotor and the stator are wound electromagnets, the other uses permanent magnets for one of the two.

Figure 2.2 shows the layout of an existing commercial direct drive turbine.

2.3 Design limitations, driving factors

Wind turbines have several limitations that need to be taken into account. The main limitations are tip-speed and transportability. The main other design drivers are the fatigue and extreme loads.

Tip-speed

The tip-speed (i.e. the speed at which the tip of the blade moves through the air) is defining for how much noise a wind turbine generates. Because of the noise, onshore wind turbines are limited in their tip-speed to about 70-80 m/s.

From a mechanical point of view, a high tip speed seems desirable: the power a turbine can generate is the torque multiplied by the rotational speed. That means that, at equal power, a higher rotational speed means less torque. For the blades a higher rotational speed means that a lower chord is required to generate the same lift.

The design of the gearbox is determined by both torque and the rotational speed; the higher the torque, the larger the first stage of the gearbox will be; the higher the gearbox ratio, the more complex the gearbox. At equal tip-speed, increasing the turbine power, increases the torque by that as the power to the power of 1.5 while it decreases the rotational speed by one over the square root of the power (see appendix B):

$$T \propto P^{1.5} \quad \omega \propto \frac{1}{\sqrt{P}}$$

Thus, if we want to make onshore turbines bigger, their rotational speed must come down (because of the noise), increasing the torque and the required rotational speed. That means a higher gear ratio and a larger, more complicated gearbox. For offshore turbines that are located far offshore, noise is not as much of an issue so they could rotate faster (up to the point where aerodynamics limit the tip-speed). This allows extra leeway in design and operation.

Transportability

This is a fairly easy limitation to understand, though the consequences do have a large reach. Transportability is mainly concerned with size: the parts of the wind turbine must be small enough to be transported to the site where the turbine will be installed. This usually means a maximum height and width of about 4.5 m. This limitation is felt in the design of the nacelle and hub, the transportation of the lower segments of the tower and for the largest chord-length near the root of the blades.

Length can also be limited: if one must make a sharp turn to get to the site, that can be a problem with the blades.

For turbines that are installed offshore, these restrictions are obviously not as critical as on land.

Fatigue and extreme loads

With the number of cycles a wind turbine has to cope, fatigue due to varying loads is a very important design driver. Some varying loads are unavoidable (for instance, due to the changes in the wind speed) while others, such as rotor-imbalance and 1p, 2p and 3p tilt and yaw loads on the tower can be prevented or reduced.

Extreme loads occur when wind conditions vary quickly and unexpectedly or when the turbine

has to make an emergency stop.

Both fatigue and extreme loads affect the design of the wind turbine. Though these are important, we can not examine how the different designs were affected by these loads directly, but only indirectly through the average-wind speed and turbulence (i.e. the different wind-classes).

2.4 Turbines and their features

In this section we have mainly limited the descriptions to turbines of 3 MW or more, because those tend to be the newer models and because they are more relevant for the future if the current trend in sales of increasing turbine power holds. A number of exceptions were made to the 3+ MW ‘rule’: the Liberty 2.5 MW wind turbine made by Clipper, the 2 MW DeWind 8.2 turbine and the Vergnet GEV HP-1 MW turbine. These turbines were included because their layout or construction is different than the turbines already included.

Some turbines that have not been included due to a lack of data are the Gamesa G10X-4.5 MW turbine (Spain), the Sinovel 3 MW turbine (China), the ScanWind 3500DL 3.5 MW turbine (Norway, now owned by GE), the Clipper Brittanica 10 MW (US/UK), the announced Doosan Heavy 3 MW turbine (Korea) and the 2-B Energy 2B6 6 MW design (Netherlands). There are probably more wind turbines that are mentioned because the authors are not yet aware of them.

If the turbines have any other special features in the design of the wind turbine as a whole they have been pointed out as well.

The list of turbines examined here (sorted by manufacturer):

- Acciona: AW-x/3000
- Bard: Bard 5.0
- Clipper: Liberty 2.5MW
- Darwind: DD115
- DeWind: DeWind 8.2
- Ecotècnia (Alstom): Ecotècnia 100
- Enercon: E112 and E-126
- General Electric: GE 3.6/104
- Multibrid (Areva): M5000
- REpower: 3.xM and 5M
- Siemens: SWT-3.6-104
- Vergnet: GEV HP-1 MW
- Vestas: V90-3 and V112-3
- WinWind: WWD-3

Only the highlights of each of these turbines are examined below. A comparison by numbers and main components can be found in tables A.1 and A.1.

2.4.1 Acciona AW-x/3000

Acciona follows the ‘classic’ rotor-gearbox-generator design for its 3 MW turbine. They have also opted to keep two main rotor bearings (see figure 2.3), whereas other in the same class combined one bearing with the gearbox. This design is aimed at reducing loads on the gearbox.

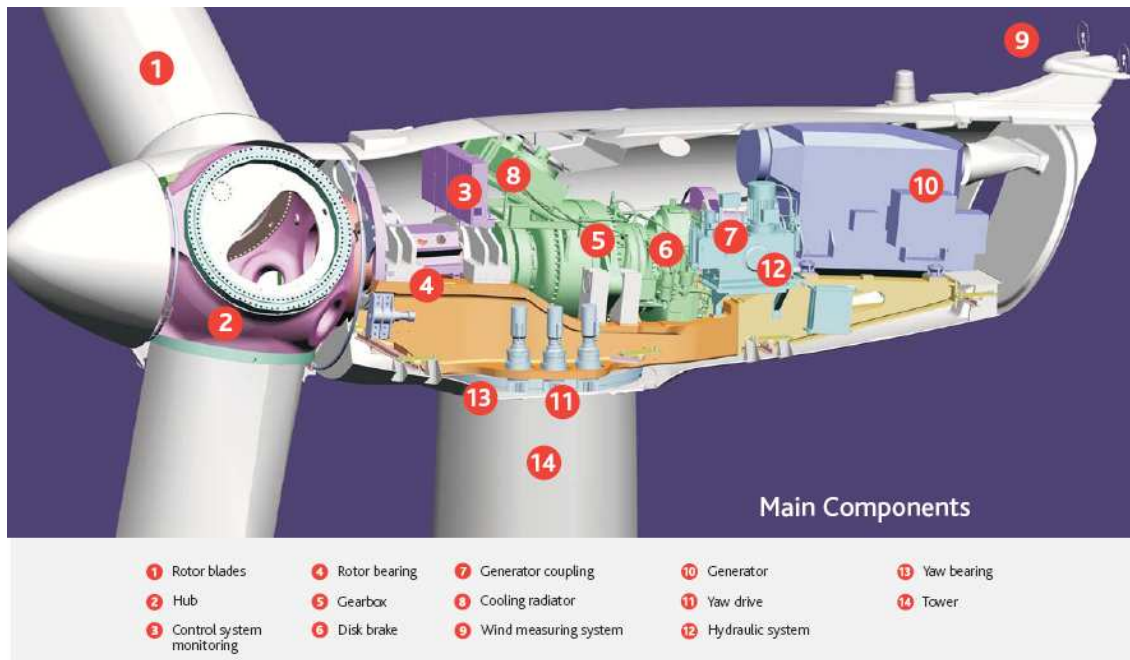


Figure 2.3: Acciona AW-x/3000 nacelle layout (Image: Acciona)

The AW-x/3000 can be equipped with 3 different sets of blades. The two smaller blade-options are LM blades, while the larger one is Acciona specific. The towers are made of reinforced concrete which suggests that these are meant only for installation onshore. So far, reinforced concrete turbine towers have not been applied offshore. The towers can be installed as separate sections, with the mass of each section in the order of magnitude of the mass of the nacelle.

The Acciona Energy Group (as opposed to Acciona Eolica (wind)) is one of the driving forces behind plans for a 1000 MW offshore park off the Atlantic coast of Spain.

Typical of this Acciona wind turbine:

- two main shaft bearing
- reinforced concrete tower

2.4.2 Bard: Bard 5.0

Bard 5.0 is the first wind turbine designed and built by Bard Engineering. The complete drive train was developed by Winergy. The turbine is designed specifically for offshore applications. Given its fairly low rated wind speed (12.5 m/s) and heavy construction it is expected that this turbine will be up-rated from its current rating of 5 MW to a higher power. This has also been confirmed by the company's director (at the time), Natalie Bekker and more recently in an article in Renewable Energy World (d.d. 15 May 2009). A rated speed of 15 m/s would bring this turbine to a power of about 7 MW.

The power electronics have all been placed at the bottom of the turbine tower. This reduces the top-head-mass and may prove more practical with maintenance (depending on whether maintenance staff flies in by helicopter or comes in by ship). The turbine's size and mass makes it difficult to install on a monopile. Bard Engineering has therefore developed its own tripile concept, which basically consists of three monopiles and a crosspiece. The crosspiece is still a very substantial piece of engineering, weighing in at 490 ton. Combined with a dedicated installation ship, Bard Engineering aims to be able to install an offshore turbine in two days.

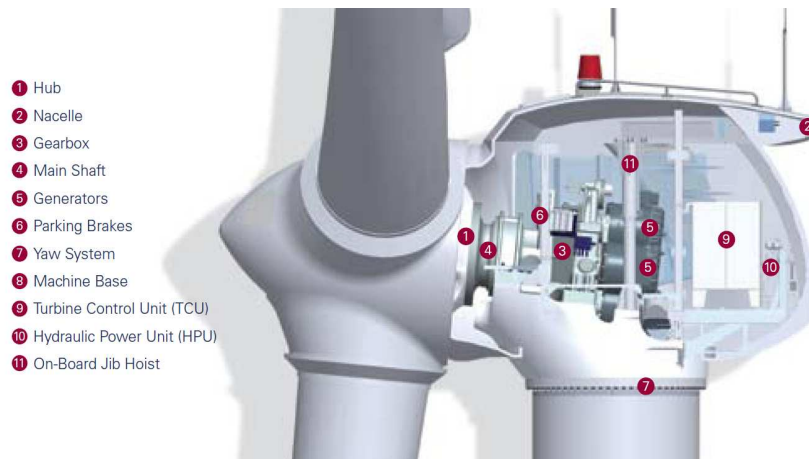


Figure 2.4: The Liberty 2.5 MW contains 4 generators (Image: Clipper)

Typical of the Bard 5.0:

- designed for offshore
- tripile offshore support concept
- heavy blades for its rating and length; will be uprated

2.4.3 Clipper: Liberty 2.5 MW

The Liberty 2.5 MW contains a two-stage gearbox that splits the torque generated by the rotor over four medium speed axes. Each axis is then attached to its own permanent magnet generator (see figure 2.4). This allows the wind turbine to function at reduced capacity if one of its generators is faulty. This reduces, to some extent, the cost due to generator failures. There is also the added advantage that smaller generators are easier to handle, in this case they can be replaced using the on-board hoist.

On the other hand, because there are four generators, the chance that one of them fails is higher than if there was only one generator. Also, if the gearbox fails, then the four generators do not produce any power either. For many turbines the gearbox has been the biggest source of downtime. Whether this results in actual cost savings, remains to be seen.

Other manufacturers are at least exploring the idea of driving multiple generators, for instance, one of the options for the uprated version of the Bard 5.0 is said to contain a gearbox that drives two separate generators.

The Liberty 2.5 MW is sold for onshore application. Clipper has also announced to build a 10 MW offshore turbine, named Britannia, based on the Liberty's architecture.

The most interesting points of the Liberty 2.5 MW:

- two stage gearbox driving 4, medium speed, permanent magnet generators
- can function at reduced level if there is a failure in one of the generators

2.4.4 Darwind: DD115

Like the Bard 5.0, Darwind's DD115 is a 5 MW turbine that has been specifically designed for offshore applications. Unlike Bard 5.0, it has a direct drive generator, which negates the need for a gearbox. There is only a single main bearing that is integrated into the generator. That

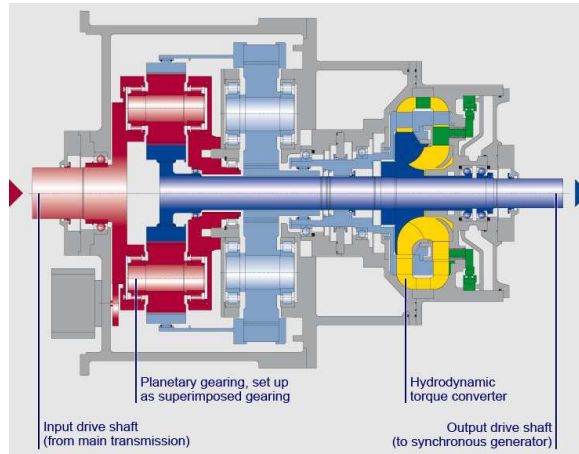


Figure 2.5: A schematic of the gearbox with a variable gear-ratio of the DeWind 8.2 (Image: Voith)

means there is no main shaft either. Though the final dimensions have not yet been published, the generator is relatively small in comparison to the generators used by Enercon. This could be because Darwind has opted for a higher tip-speed, which is unachievable onshore because of noise and because Darwind uses a permanent magnet generator instead of an electrically excited system.

As the turbine has not been built yet, quite a few of the specific design features are not yet known.

Typical of the Darwind turbine:

- designed for offshore
- permanent magnet, direct drive generator
- high tip speed

2.4.5 DeWind: DeWind 8.2

Where most variable speed wind turbines rely on power electronics to match the frequency to the grid, the DeWind 8.2 2 MW turbine uses two gearboxes, one of which has a variable transmission ratio. The variable transmission ratio is used to keep the generator axis at a constant speed, while allowing the rotor to rotate at a variable speed. According to the manufacturer, this can actually save mass because the amount of power electronics required is far less. The variable transmission gearbox can achieve a change in gear ratio from 1:3 to 1:5.5 with hydrodynamic coupling. Figure 2.5 shows a schematic of this variable gearbox. This type of drive is also under consideration for the uprated version of the Bard 5.0.

- variable gear-ratio gearbox
- synchronous, permanent magnet generator
- no frequency converter needed

2.4.6 Ecotècnia (Alstom): Ecotècnia 100

Ecotècnia follows a very similar design approach to Acciona's AW-x/3000 in that it also uses a gearbox and doubly fed, asynchronous generator. However, there are some differences. Most notably, the gearbox is claimed to be 'fully separated' from the support structure that supports the main bearings. The idea behind this is that the gearbox will then be subjected to lower, more predictable loads.



Figure 2.6: The Enercon E-126 prototype features a divided blade (Image: Enercon)

For sites that require a high hub-height, a hybrid tower is used. A hybrid tower consists of a reinforced concrete part and a steel top-part.

Recently a 110 m diameter variant of this turbine was announced.

Typical of the Ecotècnia 100:

- specifically designed to have lower gearbox loads.
- hybrid tower at 100 m.

2.4.7 Enercon: E-112 and E-126

Enercon was the first company to successfully adopt the direct drive system. The particular design of the Enercon direct drive does result in a very large and fairly heavy nacelle. The Enercon E-112 first prototype was built in 2002. It was a 4.5 MW turbine. At that time it was the largest wind turbine in the world and was also meant for offshore. Since then it has been upgraded to 6.0 MW and Enercon's management questioned the benefit of going offshore.

Enercon supports its rotor on a shaft. The rotating part of the generator is located in front of the main bearing (other direct drive concepts can have it at different locations).

Though there were some subsequent prototype installations, the E-112 has not become widely available. Meanwhile Enercon has moved on in their development to the E-126, which has also been rated at 6 MW and ought to contain all the lessons learned of the E-112. Interesting to see are the divided, partially steel blades on the E-126 (figure 2.6).

Typical of the Enercon E-112/E-126:

- direct drive, so there is no gearbox
- divided blade design (126 only)
- E-126 has a tower made of precast reinforced concrete sections
- relatively heavy construction
- E-112 and E-126 have only been installed in very limited numbers

2.4.8 General Electric: GE 3.6/104 offshore

General Electric's 3.6 MW turbine was first introduced in 2002 as a turbine meant for offshore. The drive train is standard. 7 of these turbines have been installed off the coast of Ireland to form the Arklow Bank wind farm, but a subsequent expansion of that project was cancelled. GE's attention seems to have focused more on the 1.5 and 2.5 MW class. Recently GE purchased ScanWind, who have built and are continuing to develop a 3.5 MW direct drive turbine meant for offshore.

- first commercial offshore turbine of more than 3.0 MW
- 'commercially inactive'

2.4.9 Multibrid(Areva): M5000

The Multibrid M5000 is a 5 MW offshore turbine that is halfway between the classic design and the direct drive design as employed by Enercon. On the one hand it avoids the large size (and thus mass) of the direct drive generator on the other it still uses a gearbox, so has more moving parts. The offshore tower uses a tripod construction.

6 Multibrid M5000s are going to be placed at the Alpha-Ventus offshore test site.

- medium-speed permanent magnet generator
- integrated design of main bearing, gearbox and generator
- tripod offshore construction

2.4.10 REpower: 3.xM and 5M

The basic layout of REpower 3.xM and 5M is standard. The 5M is designed for both offshore and onshore, while the 3.xM will only be sold for onshore applications. The 5M has been used in the far-offshore Thornton bank phase I and the Beatrice deep-offshore study.

REpower has built and is testing a 6 MW prototype turbine with the same dimensions as the 5M.

REpower turbines had so far used LM Glasfiber blades. However, REpower also has a joint venture with Rotec, PowerBlades. This joint venture builds blades for the MM92 and the 3.xM and is developing blades for the 6M (the uprated design of the 5M).

- first 5 MW turbine to be applied in an offshore windfarm
- 5 MW design being uprated to 6 MW

2.4.11 Siemens: SWT-3.6-107

Siemens also uses the classic layout for this turbine. However, Siemens has now erected two SWT-3.6-107 prototypes with direct drive generators. These prototypes do not require a gearbox. Unlike the Enercon and Darwind designs, the generator is located at the end of a shaft that is supported at two locations.

- in numbers second most installed offshore wind turbine of 3 MW or more in operational wind farms, but first in terms of rated power
- standard layout so far, but direct drive end-of-main shaft prototypes have been constructed.

2.4.12 Vergnet: GEV HP-1 MW

Unlike the other turbines examined here, this turbine by Vergnet is different in almost anything but the drive-train. The turbine is designed for installation without the use of separate large crane.



Figure 2.7: The Vergnet 1 MW turbine does not need a large separate crane for installation (Image: Vergnet)

Rather, it is its own crane: a small crane is attached to the tower under construction and can assemble the tower and lift the first part of the nacelle. In this part a second crane is present that hoists up the second part of the nacelle and the two-bladed rotor.

This turbine's specialities:

- installed without the use of a large crane
- two-bladed rotor
- tower is supported with guy-ropes.
- the rotor and part of the nacelle can be lowered to avoid hurricane damage
- full-power conversion with electronics.

2.4.13 Vestas: V90-3 and V112-3

The Vestas V90-3 is, at the moment, the most installed offshore turbine of 3 MW or higher in wind farms. 96 wind turbines are in operation so far (with the runner up being the Siemens 3.6 at 95 turbines in operation). The V90-3 uses a design that places the gearbox directly against the rotor hub, alleviating the need for and the mass of a low speed shaft. However, from its introduction it has been somewhat notorious for its low availability for offshore applications. Most problems occurred in the gearbox[75]. The V90-3 was withdrawn from offshore sales in early 2007, but re-issued a year later. Availability of the turbine at various offshore sites around the UK and at OWEZ in the Netherlands started off around 80% on average[89, 36, 75]. In a later report, availability is up to nearly 90%[91].

The new V112 reintroduced a low-speed shaft and has a 'redesigned' gearbox. The generator now sports permanent magnets. A prototype is to be constructed early 2010. The V112 seems to be cross of a redesign of the V90-3 and the V120, a 4.5 MW that Vestas had on the drawing boards as far back as 2004. The V120 has not been constructed so far.

- V90 is the most installed offshore wind turbine of 3 MW or more.
- V112 is designed with a permanent magnet generator.

2.4.14 WinWind: WWD-3

WinWind uses a smaller version of the Multibrid M5000 drives. The WWD-3 are designed for fairly benign wind sites (IEC class IIa and IIb).

- uses small version Multibrid, integrated generator/gearbox drive
- low class-rating in comparison to other turbines of the same size (diameter and power rating).

2.5 Trend in recent drive train design

Examining all the turbine designs reveals that pitch-to-feather with variable speed control is adopted almost universally for the turbines for which we have data. Nearly all turbines have three bladed, upwind rotors. There are some exceptions:

- Vergnet sells a 1 MW two-bladed upwind turbine.
- Fujitsu Heavy Industries has a 2 MW, 3 bladed, downwind design.
- 2-B Energy announced at EWE 2009 that they are designing a two-bladed 6 MW offshore turbine.
- Sway's concept is a floating offshore turbine with a down-wind rotor.

In terms of drive train layout (direct drive versus gearbox), there does not seem to be any clear trend. For the individual parts and the nacelle as a whole, we can discern some relations between size and weight and these are discussed below.

Gearbox

Most gearboxes for drive trains using a generator without permanent magnets, are three-stage gearboxes. Gearboxes in a drive train with generators with permanent magnets tend to have only two stages.

There was not a lot of data on the gearboxes available. The data contained 10 different gearbox and rated-power combinations used in 20 different turbine models. The data is depicted in figure 2.8(b). Two linear trend lines have also been added.

Figure 2.8(c) shows the data, but plotted against rated torque. This also seems to show a linear relationship. But the torque is supposed to vary as $P_{rated}^{1.5}$ (see appendix B), so they cannot both be true. Or can they?

A bad fit can be caused by outliers. In our case, one of the outliers is the Clipper Liberty 2.5 MW turbine and its variants. This gearbox is a different type of gearbox than the other ones in this figure and relatively heavy in comparison to the trend line, probably due to its more complex construction. If we also exclude variants of the same turbine with different blade lengths, then we would end up with only 7 data points, for which both linear relations still hold.

For these data points, fitting with a linear or power curve results in an equally good fit. So in that respect they are both true. One could also say that over this range, whatever the actual relationship between mass and rated power, it can be approximated as being linear over this data-range. The error of the approximation will be similar to or smaller than design variations.

NREL derived scaling functions for the gearbox and other parts of the wind turbine[43], The NREL model estimates the mass of a three stage gearbox to increase as:

$$\text{mass} = 70.94 \text{ low speed shaft torque}^{0.759} \quad (1)$$

Whereas for a single stage gearbox with a medium speed generator, the mass is predicted to increase as

$$\text{mass} = 88.29 \text{ low speed shaft torque}^{0.774} \quad (2)$$

And for a multi-path gearbox NREL estimates:

$$\text{mass} = 139.69 \text{ low speed shaft torque}^{0.774} \quad (3)$$

The first two are shown in figure 2.8(c) for all the gearboxes, except the Clipper gearbox, as NREL model 1 and NREL model 2 respectively. The third estimate is only shown for the Clipper gearbox and is indicated as NREL model 3. It is the result for the *single* stage gearbox that creates the best fit. Considering that the weight of the single stage gearbox is estimated higher than that of a three stage gearbox, it is likely this is an error in the report ([82] also indicates a lighter weight for a single stage gearbox). That means equation 2 actually describes the weight of the three stage gearbox.

The NREL estimate overestimates the weights at low torques and underestimates the weight at higher torque values, but the overall errors of the scaling functions are in the the same order of magnitude as the linear approximations based on power or torque. Thus these approximations predict the weight of the gearbox equally well (or equally badly).

Generator

The generator mass and cost is not expected to scale more than the power. Small electro motors also tend to scale in mass with their power rating.

Figure 2.8(d) shows the generator data for all high speed generators that are not permanent magnet generators. At both ends of the linear curve fit, data is underneath the fitted line. This indicates that a curve that scales less than linear may be fairer. NREL [43] also uses a scaling that is less than linear, but their estimates are almost consistently lower than the data.

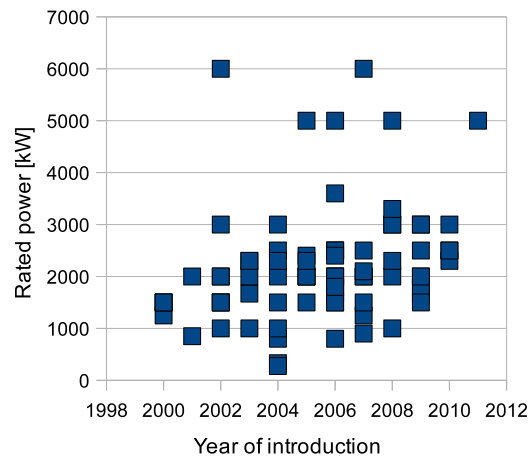
Nacelle

Apart from the individual parts of the drive train in the nacelle, one can also examine the nacelle as a whole.

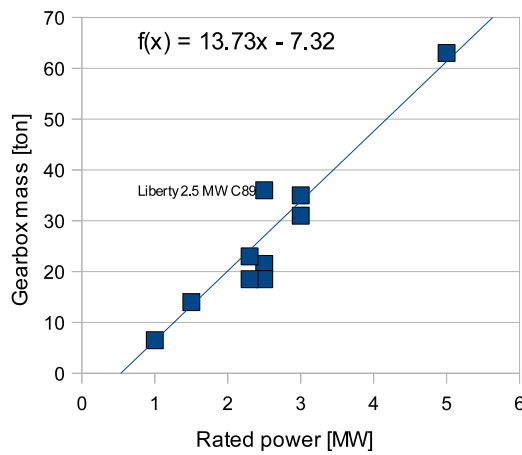
Figure 2.8(e) shows how the nacelle mass varies with the rating. This nacelle mass excludes the rotor (i.e. blades and hub). The blue line is the trend line for all the data, while the red line excludes the turbines of 5 MW and more. It is obvious that the turbines of 5 MW or more deviate significantly from the trend.

The Multibrid 5.0 manages to stay on target at a ‘mere’ 199.3 tons. The Darwind DD115 (not included in this data) would also be near or on target, with a total top head mass (i.e. including the blades and hub) of 265 tons.

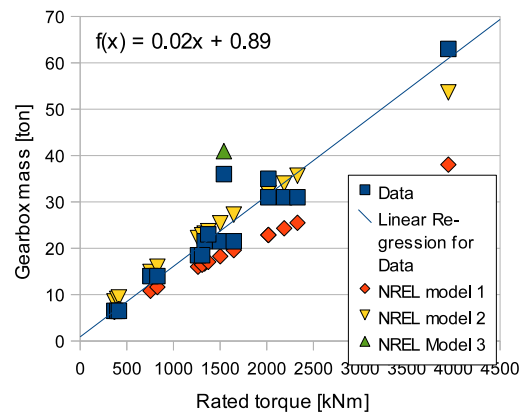
The Enercon E-126 (and the E-112) have particularly heavy nacelles (450 tons, including the generator). Because details are not known of the smaller Enercon designs, it is difficult to compare and see whether this is a relatively heavy design or whether it is in-line with smaller Enercon designs.



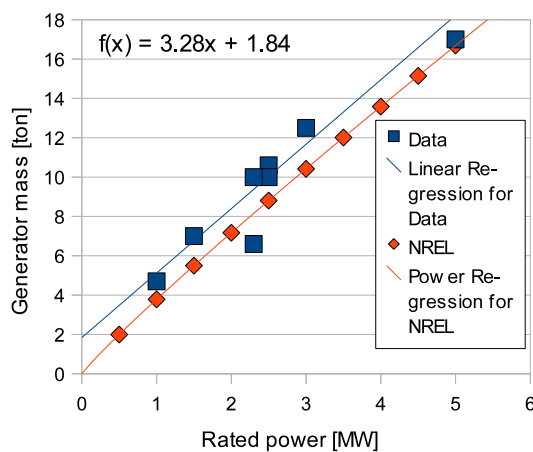
(a) Power rating trends



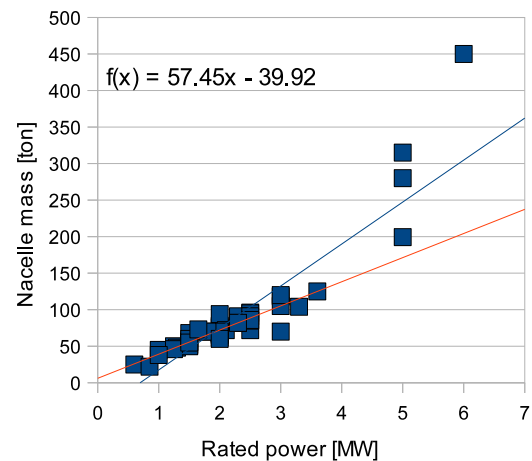
(b) Gearbox mass vs rated power;
is mass linear with power?



(c) Gearbox mass vs rated torque;
or is mass linear with torque?



(d) Generator mass vs rated power;
probably less than linear



(e) Nacelle mass vs rated power;
5 MW turbines buck the trend

Figure 2.8: Drive train trends

Some of the 5 MW designs may be relatively heavy due to the possibility of further uprating of at least some of these turbines. 6 MW versions of the REpower design have already been built in limited numbers with a nacelle that is only 5% heavier and the Bard 5.0 turbine is to use roughly the same structure for a 7 MW turbine.

The NREL design study on the drive train [82] found a gently declining cost of the drive train as a function of the power rating (up to 3 MW). The exception in that study was the direct drive, which would increase mainly in cost due to its size, which would make transport difficult. Direct drive designs with permanent magnets (PM) would end up a lot lighter according to this study. Examining the data for PM direct drives (Vensys, Zephyros, Darwind) in comparison to the Enercon designs does seem to validate this claim. We were not able to validate the costs that were mentioned in this paper.

Drive train layout

One aspect that does not have a trend, is the layout of the drive-train. One might even say there has been considerable divergence. The combination of medium speed, permanent magnet generators and low ratio gearboxes as well as the combination of variable gear ratio gearboxes and fixed speed generators are interesting alternatives to direct drive and the 'classic' drive trains.

2.6 Conclusion

The step into the 3+ MW range of wind turbines does seem to have brought some difficulties. Some suppliers made an original foray into this field, then proceeded to develop or redevelop their smaller turbines, before returning with a new 3+ MW turbine (e.g. REpower, GE, Vestas).

Pitch-to-feather and variable speed regulation is almost universal in wind turbine designs of over 1 MW.

The classic layout consisting of a main shaft, a gearbox and a generator is still favourite amongst suppliers with 11 out of the 16 turbines that we examined in the 3+ MW turbines. On the other hand, gearbox design seems critical in this class and often causes problems. It is not yet clear which layout is most economical.

Gearbox mass seems to scale nearly linear with power, while generator mass scales a bit less than linear. Nacelle mass on the other hand seems to scale a bit more than linear with power rating, but this may be biased due to the rather heavy 5 MW turbine designs.

3 Support structures

Towers and support structures would seem to be the most universal part of turbines. One would expect to find a good correlation with the loads. This section examines the towers, the support structures and the installation of the wind turbines.

3.1 Towers

Most turbine towers are tubular steel towers. Figure 3.1 shows the tower mass as versus height and different loads. There is a lot of variation in the data.

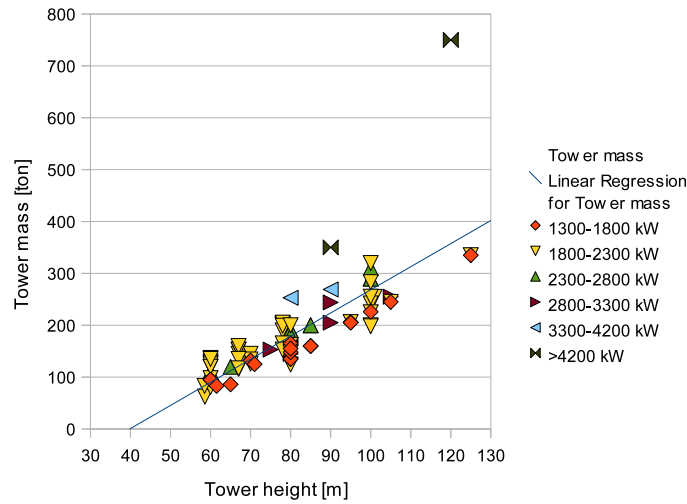


Figure 3.1: Tower mass vs tower height, by rating. (Tubular steel towers only)

It has been suggested that tower mass scales with height, power and the cross correlation of the two. Fitting the data for class Ia turbines on to these assumptions leads to the following equation:

$$m_{tower} = 1870h_{tower} + 5.38P_e + 0.41P_e h_{tower} - 59000 \quad (4)$$

where h_{tower} is the height of the tower in meters, P_e is the rated power in kilowatt and m_{tower} is the mass of the tower in kg. This approximation is off by over 14% on average and up to 40% and 54 tons at its maximum.

NREL [43] suggests a relationship between the mass and a product of swept area and tower height (if power is proportional to swept area, not unlike what is presented here). They came up with three relationships, a high estimate based on static load design, a medium baseline estimate and a low estimate based on data:

$$m_{high} = 0.4649(\text{Swept area} * \text{hub height}) + 324.33 \quad (5)$$

$$m_{medium} = 0.3973(\text{Swept area} * \text{hub height}) - 1414.4 \quad (6)$$

$$m_{low} = 0.2694(\text{Swept area} * \text{hub height}) + 1779.3 \quad (7)$$

Figure 3.2 shows the actual mass versus the product of swept area and low, medium and high NREL estimates. These estimates do enclose most data points, but the spread between these two is still almost 50% of the lower estimate.

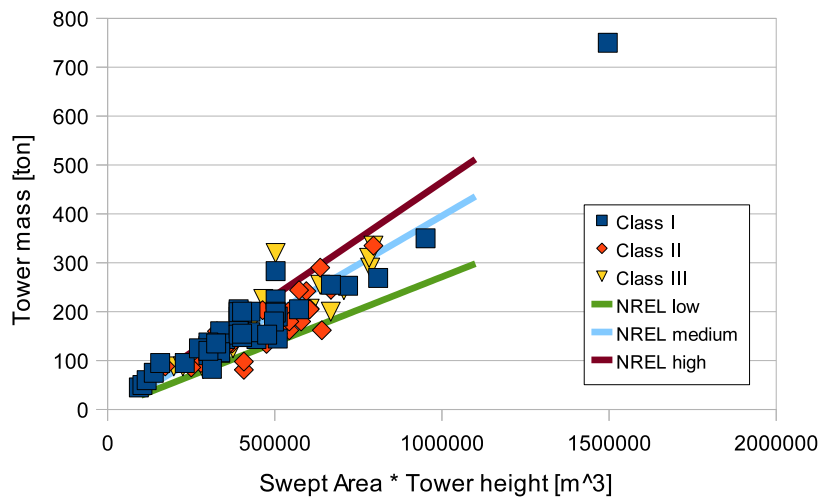


Figure 3.2: Tower mass vs swept area * hub height, by class. (Tubular steel towers only)

These approximations are obviously very severe simplifications of the design values and other factors may play an important role as well. One of them is the first eigenfrequencies of the tower. If that is near to or at the rotational frequencies (1p, 2p, 3p) in normal operation this may lead to excessive fatigue.

The array of towers designed for the Vestas V80-2.0 MW had significant differences in tower mass depending on the wind conditions (205 tons for IEC class IA and 165 tons for class DiBt II, both with a 78 m hub height). This suggests there must also be significant fatigue and/or extreme load effects.

For very tall turbines with high loads, manufacturers are opting for reinforced concrete or hybrid rather than steel towers. This is probably due to transportability. Steel towers are quick to erect, but consist of welded rings. To get the tower on site the entire section of the tower must fit at all places along the route to the site where it will be erected. For large towers, the required diameter at the bottom exceeds the limits of what can still be transported, especially for more remote locations or built-up areas. Reinforced concrete towers can be built up of smaller, more transportable segments or can be built on site. Hybrid towers have concrete sections in the lower half of the tower and steel top segments.

The price of steel can influence price of the tower significantly. During 2008 the prices of some steel products jumped from 400-500 €/ton to 700-800 €/ton and back again. With the tower of a multi-megawatt turbine at a 100 m hub height easily containing 200 tons of steel, that makes an appreciable difference in the cost. High steel prices are also likely to favour more light-weight designs or designs that favour reinforced concrete.

Offshore turbines can have lower towers, because the wind profile is more favourable (higher wind at lower height, less wind shear). Transportation is less of an issue. So far, only tubular steel towers have been used offshore.

Another alternative to the towers described above is the lattice tower. It is not used very often onshore because of visual aspects and bird-kill (birds are attracted to sit on the lattice structure and get killed more often as a result). Lattice towers are lighter than tubular steel towers but have a wider tower and base. Lattice towers with a cover to make them look like tubular steel towers have also been proposed. Although it would be better visually and for birds, as far as the authors

are aware no such towers have actually been built.

3.2 Offshore support structures

There are several offshore constructions that have been used so far to support wind turbines. They can roughly be divided into 6 categories: gravity based, monopile, multi-pile, suction bucket, jackets and floating. There is not enough publicly available data to get an idea of how these structures compare in terms of mass and cost.

3.2.1 Gravity based

Gravity based constructions are big concrete constructions that are built on land, towed to the target site where they are sunk onto the specially prepared seabed by filling them with sand. Then they are protected/half buried with rocks to prevent scouring. This system was used, amongst others for Thornton bank and Nysted wind farms. Figure 3.3(a) shows a picture of the foundations for the Thornton bank wind farm.

3.2.2 Monopile

Monopiles are large (e.g. up to 4 meters in diameter and 60 meters long for the Princess Amalia wind farm) steel tubes that are usually driven into the sea-bed up to 30 meters. Depending on the soil structure, driving can be done by simply vibrating the tower or by ramming. Each monopile carries a single turbine.

For very large turbines, monopiles are not suitable as they get too big and heavy to handle with normal offshore equipment. A new development on the part of monopiles is the drilled, concrete monopile. This can be installed without ramming, but requires a rather complex drill to install the monopile.

3.2.3 Tripile and tripod

One solution that is used for very large turbines is the concept of using several smaller piles and using a connection/transition piece to connect the wind turbine tower and distribute the loads over all the piles. The piles can be much smaller and are thus easier to install. Obviously, great care must be taken in positioning the piles. There are two variants, one has the connecting piece below the waterline near the sea-bed (tripod, Multibrid, see figure 3.3(b)), the other above the waterline (tripile, Bard, figure 3.3(c)).

3.2.4 Suction-buckets

A suction bucket is a round steel cylinder, covered on one side and open on the other. The bucket is dropped with the open end down into the seabed. By sucking out water through the closed end, the bucket is driven deeper into the soil. Due to the nature of the process, suction buckets can not go very deep into the soil and therefore have to cover more area than a monopile would use. The successful use of suction-buckets depends heavily on the soil. Installation is also tricky.

Scouring is obviously a problem for suction buckets, as they do not go deep into the soil. So far only one turbine in Fredrikshaven has used a suction bucket ([52]).

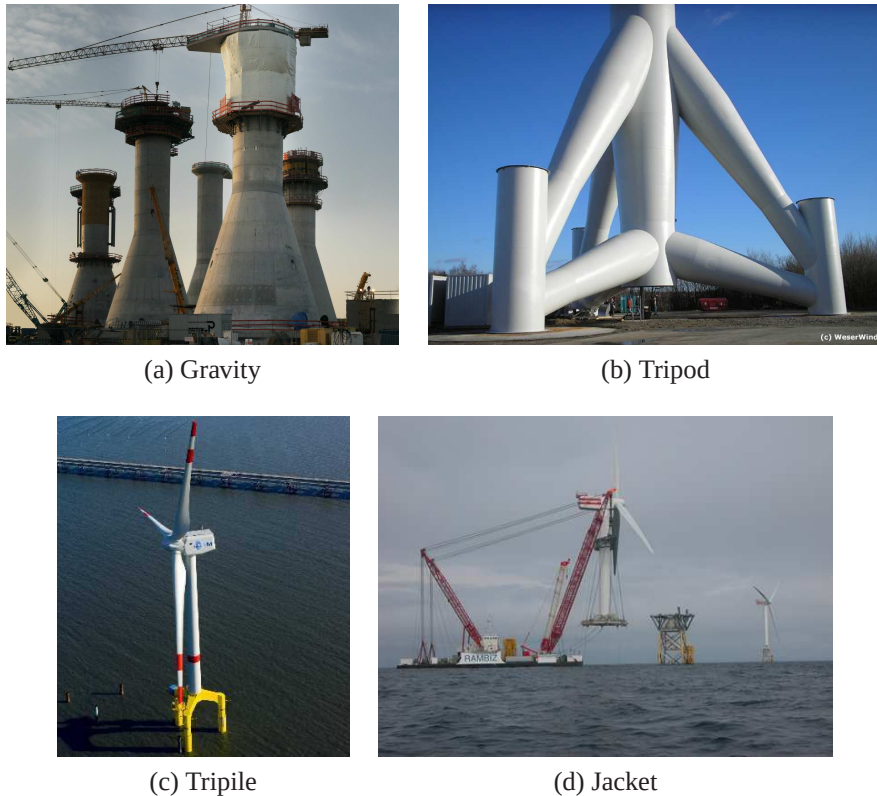


Figure 3.3: Different support structures for offshore wind turbines

3.2.5 Jackets

Jackets are basically underwater lattice towers that are mounted on piles or suction buckets. These are meant for deep offshore wind farms. This kind of structure was used for the Beatrice offshore farm where two 5 MW REpower turbines were installed in over 40 meter deep water. It will also be used for the Ormonde offshore project in 17-22 m water depth.

3.2.6 Floating

Floating structures were thought to be unlikely to be feasible in the Dutch area of the North Sea [7, 30], where water depth is limited. But recent developments imply that it may also be possible to apply floating offshore concepts in limited water depth. The trade-off is usually between a heavier support structure and easier installation of the support structure. Floating offshore structures would appear to have very low environmental impact.

There are 3 main concepts currently under development (as far as the authors are aware). A first concept is a 'free' floating structure, with the centre of gravity near or above the surface of the water. The company Blue H has built a floating offshore wind turbine prototype in 2007, off the coast of Italy. Their design is based on 6 connected floaters. The floaters are configured as a hexagon and the concept relies on spreading the load over a larger area, keeping the centre of gravity within that area.

The second concept is a 'free' floating spar structure. This is basically a long, vertical beam on top of which the turbine is placed. If the structure is balanced with ballast, it will have to be very heavy, as it must have a centre of gravity that is not only lower than the water surface while still providing enough lift to keep the turbine out of the water, but it also has to provide a sufficient counter moment to the rotor thrust. The spar concepts are only suitable for sites with a depth of

well over a 100 meters and up to 700 meters.

A project named Hywind has recently installed a spar structure in Åmøy Fjord near Stavanger (Norway). The support structure consists of a steel, vertical spar filled with ballast and extends some 100 meters below the surface of the water. The spar weighs some 1500 tons. A 2.3 MW Siemens turbine will be installed on it in the second half of 2009. For comparison: monopiles for the Greater Gabbard wind farm in the UK, designed for the 3.6 MW Siemens turbine, weigh 'only' 600 tons.

The Norwegian company Sway is also developing a 5 MW floating wind turbine based on the spar concept and claims the total capital costs will be similar to current offshore installations. Sway uses a downwind turbine, rather than an upwind one.

These structures are not completely free as they still need to be attached to the ocean floor to prevent them being blown away.

The third concept is a tension-cabled option: the support structure provides a more lift than necessary to lift the turbine, but is attached to the ocean floor with tension cables. The tension in the cables must be sufficiently large to overcome the toppling moment caused by the rotor thrust and increase stability for wave excitation. Arcadis is developing a floating 80-turbine offshore wind farm in the Ostsee (Germany) on the basis of a tension-cabled concept. The water depth there is between 30-45 m, which is quite shallow for a floating structure.

3.3 Offshore installation concepts

More and more offshore installation vessels are becoming available. In general they can be divided into two types: floating and jack-ups. Floating vessels, such as Ballast Nedam's Svanen or Scaldis' Rambiz, have the advantage that they can move from turbine to turbine quicker than a jack-up and are not dependent on the structure of the soil. Jack-ups have the advantage that they are less weather dependent once they are installed.

Either vessel can be equipped with machinery to install mono piles. Only floating vessels can be used to install gravity based turbines. Bard engineering has bought a jack-up vessel to install its tripile foundation. Both floating and jack-up vessels can assemble a wind turbine at sea in a similar way as is done onshore.

However, time at sea is very expensive indeed so new concepts are being developed. One of these involves assembling the wind turbine on/near shore and then lifting and installing it as a whole. This has been done for the REpower 5M turbines at the Beatrice platform. It has the major advantages that less time is needed at the site, the turbine could be tested while still onshore and the load, though more than the individual parts of the turbine, only needs to be lifted to the height of the support structure.

On the other hand, the (expensive) lifting vessel needs to go back and forth between the site of construction and the harbour to pick up turbines, whereas if one was to use jack ups, smaller vessels could carry parts to the offshore wind farm.

One concept that could also make sense is to install a wind turbine on a gravity based foundation near shore and lift both the foundation and the turbine to the site in a single trip. Shallow floating turbines could also achieve this.

3.4 Conclusion

Onshore tower construction seems to follow a very simple strategy: tubular steel until transport becomes impractical, then switch to concrete or hybrid towers. That does not necessarily mean that this is actually the cheapest option. If the impact on the landscape and birds are not an issue, a lattice tower is probably the cheapest option.

Offshore support structures are trickier to choose as the local environment has more impact. For example, if the water is very deep, monopiles are not an option. Jackets have competition from floating concepts in very deep water but if the water is not very deep it is probably not worth using a jacket. The choice also depends on the size of the turbine. If the turbine is in the 5 MW class, monopiles become so large, they are difficult to handle during installation.

Monopiles have been applied for most offshore wind farms so far, up to 30 meter depths for up to 3.6 MW turbines (Greater Gabbard). For 5+ MW turbines gravity-based supports, jackets, tripiles and tripods have all been used. Suction buckets have not been used on a commercial scale (yet). Floating supports have not been used on a large commercial scale, and tend to be heavier than monopiles or tripiles.

Cost-wise, there is no indication that there is much difference between monopiles and gravity based structures at the moment (see section 6). Tripiles and tripods have the advantage that driving smaller piles should be relatively small and easy to handle, but the substantial (490 ton for the Bard 5.0) connection between the piles and the tower is not.

3.5 Speculation

It seems clear that the offshore wind farms are only starting to get into mass production. Offshore companies had so far been geared towards one-off projects and the vessels used for installation of wind turbines reflect the versatility that was required for that.

The costs for offshore installation are defined as much (if not more so) by the installation as by the cost of the substructure itself. It is also important to include the installation of the turbine on top of the substructure itself. All these costs must be taken into account when one designs the support structure and the installation vessel. Possibly one should include the design of the wind turbine in this as well.

At the recent European Offshore Wind Conference 2009 in Stockholm, most new concepts of installation and supports seemed to focus on (reinforced) concrete supports.

It is likely that the combination of installation method and support structure that requires the least time at sea will be the cheapest option. In the short run, any such effects might be overshadowed as the sectors supply chain must gear up to a sufficient capacity.

4 Trends in blade design

The turbine blades represent between 11 and 33 percent of the total cost of the wind turbine (see 6). They are expensive because the process of producing a blade is capital and labour intensive as well as time consuming. If the mass of the blade is reduced, that can have a knock-on effect in other parts of the structure as well.

The area the rotor covers defines how much energy the turbine can capture. We have therefore examined the trend of the size of the rotor relative to the rated power of the turbine.

If we assume that at least time and labour are proportional to the total amount of material in a blade, then the mass becomes a good indicator for the cost of a blade. By studying the trends in the masses, one ought to be able to say whether the cost of blades increases or decreases as turbines get bigger.

4.1 Blade length and rated power

Theory tells us that the power a wind turbine can capture increases as the radius squared for equal wind speeds. Figure 4.1 shows the rated power versus the diameter for some 111 different turbines, divided by wind class. The figure implies that the power of (IEC) wind class I turbines does scale as the squared radius, but the rated power of wind class II and III turbines scales noticeably less than that.

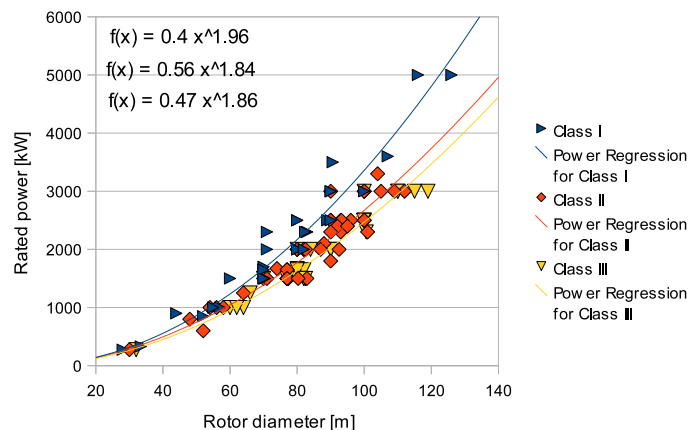


Figure 4.1: Rated power versus rotor diameter for 111 different turbines, by wind class

The consequence of the much longer blades for class II and III turbines is that the load factor at low-wind sites is considerably improved. The Vestas V100-1.8 (a class S turbine, for sites with a class IIIa average wind, but up to IIa extreme wind) is the most extreme example of turbines designed for low wind sites and covers 4363 m² per MW. That is 2.5 times as much as the Enercon E44 (class Ia, 900 kW) on the other end of the spectrum. Even *within* classes, the largest area per MW is 1.5 to 1.7 times bigger than the smallest area per MW (or energy density is 1.5 to 1.7 times as low).

Such large surface areas for capturing energy will have a marked improvement on the load factor at low wind sites (up to a factor 1.5-2.5). That means that for calculations of what areas are still economical for generating wind power (e.g. [39]), the choice of turbine becomes very significant and should be taken into account, as in certain areas this could reduce the cost of energy by said

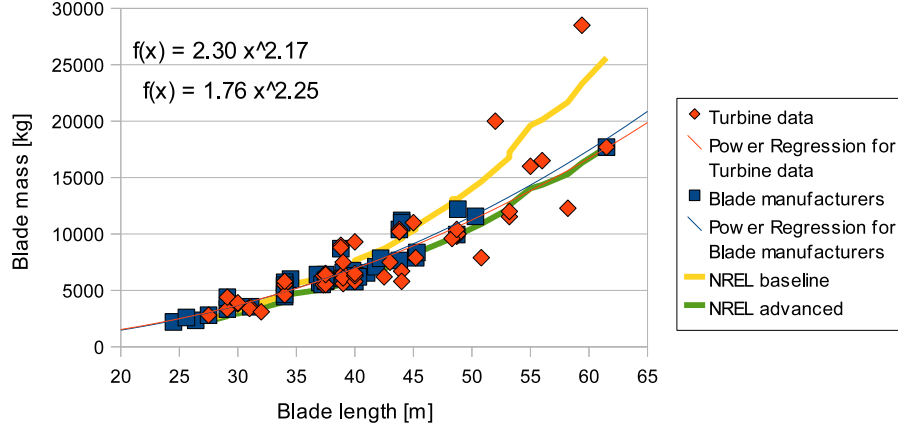


Figure 4.2: Blade mass versus blade length; 64 different turbines, 39 blade designs

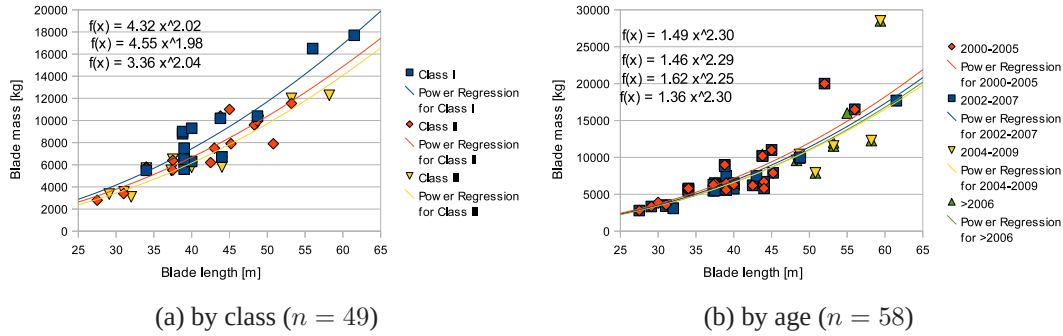


Figure 4.3: Blade mass versus blade length for n turbines organised by class

factor.

The larger class I turbines do not show a trend towards relatively higher blade lengths. But the load factor on these turbines could increase if the turbines are placed in areas with higher average wind speeds, for instance, farther offshore.

4.2 Blade mass and blade length

Figure 4.2 shows the mass versus the length of the blade for 64 different turbines as well as 39 different blade designs from blade manufacturers. For these data, the scaling factor x was found to be around 2.2. It should be noted the turbine data is particularly influenced by outliers. For instance, if we were to ignore the data-points for Bard 5.0 and Enercon E-112, because those blades are a lot heavier than the LM blades of similar length and class, then the factor x reduces to 2.0. If we assume that the power produced scales as l^2 , the difference in factors makes the difference between significantly increasing or hardly increasing costs, if the turbine grows in diameter. NREL [43] indicated two possible scaling functions, one baseline and one advanced function, both based on the rotor radius:

$$m_{\text{baseline}} = 0.1452 R_{\text{rotor}}^{2.9158} \quad (8)$$

$$m_{\text{advanced}} = 0.4948 R_{\text{rotor}}^{2.53} \quad (9)$$

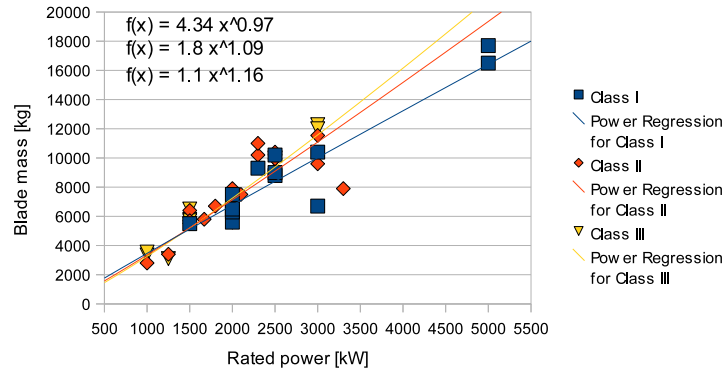


Figure 4.4: Blade mass versus rated power sorted by class ($n = 49$)

These have also been depicted in figure 4.2. Because these scaling functions are based on the rotor-radius, rather than the blade-length, this line is not quite smooth. The data-points for the Enercon blade was not plotted here. It was predicted to have a higher mass, due to the large diameter of the hub, but this rather ruined the trend. Plotting all the data as a function of rotor radius would have resulted in fewer data points for the blade manufacturers, therefore we chose to plot versus blade length.

One could argue that the factor would be higher if one compares only blades from the same load-class (e.g. IEC Ia, IIa etc.). Analysing the data per category did not result in an increase in the scaling factor, as can be seen in figure 4.3(a). In fact, the factor x is now 2.0 for all wind classes. Note that not all the data points of figure 4.2 were taken into account as the IEC class of some turbines (if it has been designed accordingly) is not known. Most noticeable are the lack of the Bard 5.0 and Enercon E-112.

Similarly, One could argue that older turbines are heavier than newer ones due to technological learning. Figure 4.3(b) shows curve fits for turbines organised in groups of 5 years. The curves does seem to show some learning, because later ‘generations’ are lighter than the earlier ‘generations’. The factor x increases from 2.2 (for all the data in that set) to 2.3. If we ignore the Bard 5.0 and Enercon E-112, than the factor drops to 2.0 for all data in the set and 2.1 including learning.

We saw in the previous section that the blade lengths for class II and III turbines have increased relative to their rated power. Figure 4.4 shows the blade mass versus the rated power, sorted by class. The data suggests that for sites with lower average wind, the rotors become relatively heavier in comparison to the power rating. Considering that they also become longer, this is to be expected.

The mass of the turbine blades is a function of length, class, technological learning and design choices. How much, for each class, length and technological learning each contribute is would require more data than is currently available. However, the difference between a factor of 2.0 that was observed in the data for each class and the factor 2.4 described in literature, leaves a rather large gap to be explained by technological learning.

4.3 Conclusion

As wind turbines grow in size, the differences between turbines for onshore, low-wind sites and offshore, high-wind sites seem to become more pronounced. Onshore turbines require much longer blades to capture the same amount of energy, than the offshore turbines that use relatively

short blades that can withstand the very high winds at far offshore sites.

This differentiation means that wind turbine selection must be taken into account when calculating the cost of energy for different wind sites, as for low wind sites, the energy produced might be 1.5-2.5 times more than would normally be assumed.

The NREL study suggested that the mass of the blade scales as l^x with x between 2.53 and 2.9. The data suggests a factor 2.0 or 2.2. Possibly a little higher if one takes technological learning into account.

The scaling factors 2.0 and 2.53 could both be considered ‘valid’ on the basis of the data. The consequences of this difference could be the difference between possibly decreasing and probably increasing cost of energy when studying the uprating of the wind turbine. One should therefore take great care when utilising scaling functions.

4.4 Speculation

It would be interesting to see why the ratio of blade-length and power rating decreases as the power rating of onshore turbines increases. Considering a possible increasing trend in power rating (figure 2.8(a)), this could indicate a trend to increasing load-factors onshore. Though the designs do not obviously show this, offshore turbines would have a trend to higher load factors if they are installed further offshore where there are higher average wind speeds.

There is more to the price of the turbine blades than just the mass. Transport, production machinery and moulds all influence the cost. What the net influence of that is per blade is very difficult to tell indeed. An interesting observation in this regard is the relatively stable ratio between revenue and MW of blades delivered of LM Glasfiber over the last five years [65, 66, 67, 68, 69]. LM Glasfiber appears to be competing with in-house manufacturing in a buyers market. The turnover of LM Glasfiber per MW of blades delivered varied relatively little over the last 5 years from 117 k€/MW in 2004 to 119 k€/MW in 2008. According to BTM Consult, the average turbine size increased from 1.248 MW to 1.566 MW in the same period. LM Glasfiber’s production increased even more from 1.1 MW to about 1.5 MW per 3 blades. This results in the conclusion that the cost of turbine blades has been roughly linear with power.

5 Operation and maintenance cost

Next to the cost of the wind turbine itself (next section), operations and maintenance is a very significant part of the cost.

There is a lot of discussion on what should and what should not be included in operation and maintenance cost. In particular, whether to include cost of capital and lost revenues depends. In the cost of energy calculation in section 6, we will not include the lost revenues as part of the cost, but rather as reduced overall availability.

For onshore wind turbines, a fair estimate can be made due to large volume of data from Germany, in the form of the ISET (now part of IWES) WMEP database. For offshore wind farms, the amount of data is improving as more numbers on maintenance are being published, but the total number of offshore wind farms and the time that they have been operational is still limited.

Also, as was particularly obvious for some wind farms, the design of offshore wind turbines was not really mature enough. In the following subsections the existing information on the cost of operation and maintenance (O&M) is presented. The O&M costs for onshore and offshore wind farms are discussed separately, because of the large differences between them.

5.1 Onshore

For onshore wind turbines, a lot of operating experience has been collected and analysed. Since onshore wind energy is a mature branch of industry, sufficient reliable data is available. In table 5.1 some key figures are presented, mainly derived from [38]-[37], [1] and [23].

Failure rate	1.5 to 4 failures per year
Availability	> 98 %
Service contract	0.5 to 0.8% of invest. costs per year
	5 to 8 €/kW
Service contract incl. warranty	1.0 to 1.6% of invest. costs per year
	10 to 16 €/kW
Corrective maint. year 5	0.5 to 0.8% of invest. costs per year
	5 to 8 €/kW
Corrective maint. year 15	4 to 6% of invest. costs per year
	40 to 60 €/kW
Average O&M costs over lifetime	2 to 4% of invest. costs per year
Insurance costs	5 to 8 €/kW
	(machine damage, third parties, revenue losses)
LPC (O&M costs)	5 to 10% of kWh price (of which half due to maint.)
	0.5 (year 1) to 1.5 (year 10) €cent/kWh

Table 5.1: Key figures for O&M onshore (Investment costs k€/kW)

From the WMEP database 2006, [1], it is revealed that the O&M costs become lower per installed kW. Figure 5.1 shows the total operational cost relative to the turbine size. In Figure 5.2, an analysis has been made in 2003 of the service contracts of available wind turbines related to their investment price [16]. The data has been compared with the figures presented in [38]-[37] and with the offers for four commercially available turbine types in the 1.5 to 2.5 MW range. It is clear that the figures presented in [38]-[37] and [4] do not include warranties, spare parts, consumables, 24 hours monitoring, etcetera.

Figure 5.3 shows the total maintenance costs split up into costs for preventive and corrective

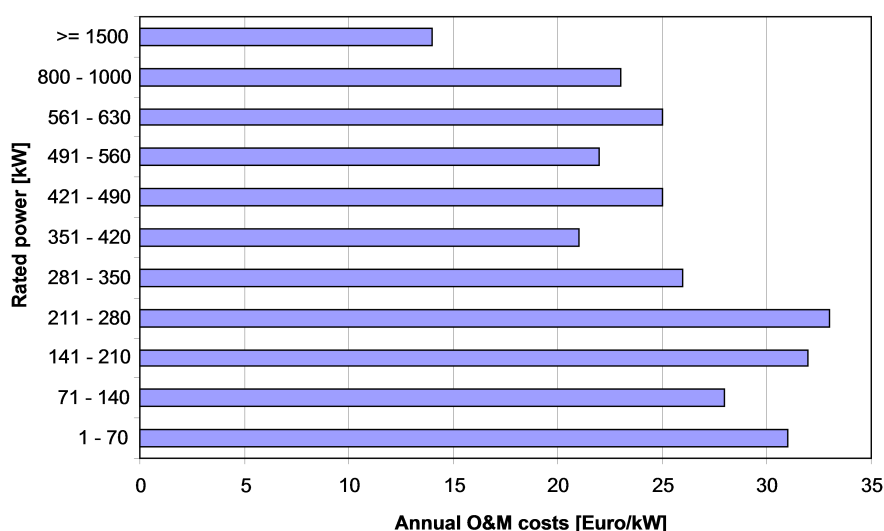


Figure 5.1: Operational costs as a function of turbine size

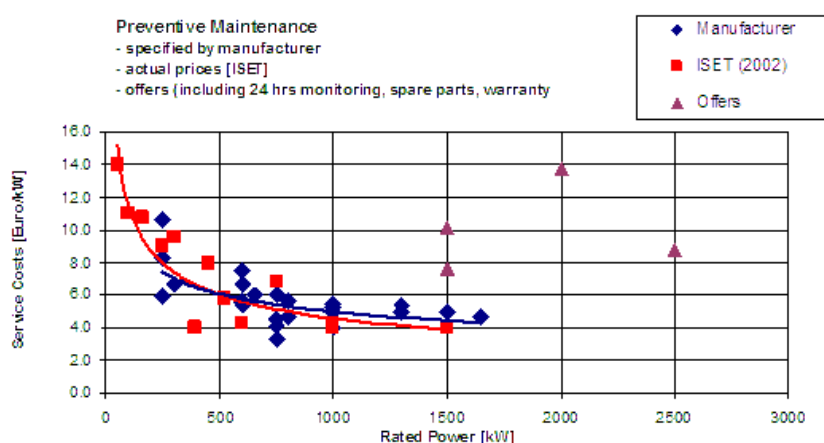


Figure 5.2: Prices of service contracts as a function of turbine size

maintenance. As can be seen, these costs are more or less equal. The analysis has been done in 2003, but the conclusions are still valid when compared with the data presented in 2006 [37].

A German study performed by DEWI [15] indicates that during twenty years of operation, approximately 64% of the investment costs is spent on spare parts. The study used data of smaller wind turbines. On average, this corresponds to more than 3% of the investment costs per year. With an investment price of 1380 €/kW, this equals 41 €/kW which is far higher than the figures given in figure 5.1.

5.2 Offshore

Because there are not many offshore wind farms yet and of those only a few have publicly available operation and maintenance (O&M) data, the cost is first examined by modelling and then compared with figures that are available.

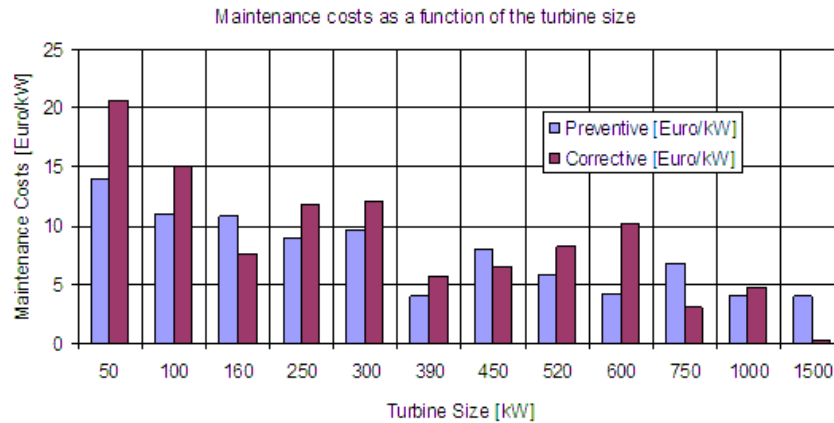


Figure 5.3: Costs for preventive and corrective maintenance as a function of turbine size

5.2.1 Model based analysis

An example of a model based analysis can be found in [84]. From further recent studies for developing O&M plans for offshore wind farms, ECN concluded that, unsurprisingly, the costs for maintaining offshore wind farms are higher than for maintaining onshore wind farms.

Typical figures (including costs for maintaining the park infrastructure, civil structures, etc.) are:

- preventive maintenance 0.003 to 0.009 (€/kWh)
- corrective maintenance 0.005 to 0.010 (€/kWh)

It is interesting that the costs for corrective maintenance are a factor 2 higher than for preventive maintenance, whereas for onshore turbines the costs for preventive and corrective maintenance are about equal. There are several causes for this; one is the expensive equipment that is needed such as crane ships. Another is that the costs for the revenue losses are substantially higher for offshore wind farms. Offshore, long downtimes occur due to lower accessibility of the turbines due to high waves and strong winds, whereas the accessibility of onshore wind turbines is hardly influenced by the weather conditions. Furthermore the capacity factors are generally larger for offshore wind farms. Analyses revealed that the revenue losses are about 50 to 80 % of the costs for corrective maintenance. The figures are subject to great uncertainty, originating from a.o.:

- the failure rate of the turbines, indicating the demand for corrective maintenance;
- the equipment to use for access and lifting and their fluctuating prices;
- the influence of the wave height and wind speed on the operational windows for accessing and repairing the turbine;
- the distance to the shore;
- logistical aspects (the crew size, stock control, contracts with equipment suppliers and offshore companies, etc).

It should also be noted that the number of wind turbines ought also be a factor in the calculation of the maintenance cost. With equal mean-time-between-failures (MTBF), the number of trips required for corrective maintenance would be lower in a wind farm consisting of 5 MW turbines than when it consists of 3 MW turbines. For preventative maintenance, the number of trips is also defined by the number of wind turbine installations.

For wind farms that are further off shore, trips will take longer and become more expensive. It could therefore be cheaper to build bigger wind turbines far offshore even if that increases the turnkey cost of relatively to smaller turbines.

Operational year:	1-2 year	3-10 year	11-20 year	Average O&M cost over lifetime (in 2001 value - not indexed)
Location:	DKK/kW h (\$US cent/kW h)			
The North Sea (20 MW)	0.047 (0.56 cent)	0.067 (0.79 cent)	0.10 (1.20 cent)	0.082 (0.98 cent)
The Baltic Sea (20 MW)	0.052 (0.62 cent)	0.075 (0.89 cent)	0.11 (1.31 cent)	0.090 (1.07 cent)
Assumptions: "State of the art" 2 MW wind turbines. Plant size 20 MW as integrated part in a +100 MW Offshore Wind Farm in Danish offshore location. Projected full-load hours are 3,700 hours and 3,300 hours for North Sea and Baltic Sea respectively. Exchange rate: 8.4 DKK = \$US 1				

Figure 5.4: O&M cost estimates for two Danish offshore wind farms[26]

Creating better failure prediction models that allow a shift from corrective to preventative maintenance would be welcome, as the high down-times could be avoided, resulting in higher availability and thus lower cost per kWh.

In [24], cost estimates are presented of Danish offshore wind farms in the North Sea and in the Baltic Sea, see figure 5.4. These figures match very well with the ECN figures.

5.2.2 Data from existing offshore wind farms

Only offshore wind farms with a total installed capacity of 40 MW or more have been considered. These are:

- Middelgrunden, Denmark, 2000, 40 MW
- Horns Rev, Denmark, 2002, 160 MW
- Nysted, Denmark, 2003, 165.6 MW
- North Hoyle, United Kingdom, 2003, 60 MW
- Scroby Sands, United Kingdom, 2004, 60 MW
- Kentish Flats, United Kingdom, 2005, 90 MW
- Barrow, United Kingdom, 2006, 90 MW
- OWEZ, Netherlands, 2006, 108 MW
- Burbo, United Kingdom 2007, 90 MW
- Lillgrunden, Sweden, 2007, 110 MW
- Q7/Amalia, Netherlands 2008, 120 MW

For only five of these listed offshore wind farms figures on the actual O&M costs have been found. The results are presented in table 5.2. This data is maintenance cost excluding revenue losses due. Below the results for the five wind farms are discussed in brief.

Barrow

The report mentions that since the wind farm is under a 5 year operation and maintenance contract, the cost risk is carried by the turbine manufacturer [36]. The O&M costs that are in the document only cover half a year and, taking availability into account add up to 3.2 €/ct/kWh. However, the average availability of the turbines during this particular period was very low, at 67%. At normal availability and normal production (305 GWh/year) this maintenance cost amounts to 1.9€/ct/kWh.

Name	Country	Turbines	Distance to shore [km]	Water depth [m]	O&M costs [€ct/kWh]
Barrow	UK	30x Vestas 3.0 MW	7-8	18-22	1.9
Middelgrunden	DK	20x Bonus 2MW	2-3	2-6	1.2-1.9
North Hoyle	UK	30x Vestas V80 2MW	7-8	12	2.06-2.31
Scroby Sands	UK	30x Vestas V80 2MW	2-3	4-8	1.45-1.65
Kentish Flats	UK	30x Vestas V90 3MW	8-10	5	1.55

Table 5.2: O&M costs for existing offshore wind farms

The next report [90] shows an improved availability of 78%, despite an extra low availability due to the exchange of all gearboxes. Production was 273 GWh, which results in a maintenance cost of 1.296 p/kWh or 1.77 €ct/kWh. This is much lower in Euros the amount of the previous report due to a drop in the exchange rate in 2007.

Middelgrunden

The specified costs include the cost of O&M as well as administration, insurances, coordination and electricity consumption and are published each year in annual reports [3]. Availability over the first 4 years was over 93%, lack of availability was mainly due lack of grid and a number of transformer malfunctions.

North Hoyle

The report mentions that since the wind farm is still under warranty the availability and non-routine maintenance cost risk is carried by the turbine manufacturer. It is unclear whether these maintenance costs are included in the listed figure [76, 77, 78]. Availability of the wind farm has been about 87% on average. O&M cost averaged 1.47 p/kWh or (using the average exchange rate during the last period of the reports).

Scroby Sands

According to the documents the turbine maintenance costs have been included in these figures [41, 42, 40]. Availability varied between 75 and 84%. In the last year, O&M was 1.13 p/kWh or 1.65€/kWh

Kentish Flats

The figure includes cost of turbine O&M (estimated value from O&M contract with turbine manufacturer), insurance, lease and rent, surveys, import power and administration [89, 92, 91]. Availability in the second year was down to 73.5% due to gearboxes, but was 89.2% during the last reported year.

5.3 Summary and conclusions of O&M cost analysis

Onshore maintenance is cheaper than offshore maintenance. It is also less weather dependent, resulting in much lower down-times. Current cost-estimates vary between 0.5 and 1.5 €ct/kWh.

From recent studies, [57, 58, 59, 34, 33, 5, 50, 60] combined with [16, 71, 24, 84], ECN derived the following generic key figures with respect to costs of offshore wind energy.

- The O&M costs form approximately to 30 to 50 €/kW per year, or 1.2 to 3 €ct/kWh (see also Figure 6.3).
- Approximately 2/3 of the O&M costs (say 20 to 45 €/kW installed capacity) are caused by

corrective maintenance.

- The revenue losses are in the same order of magnitude as the costs for corrective maintenance.

The O&M costs for the five investigated offshore wind farms vary roughly between 1.2 and 2.3 €/ct/kWh. It should be kept in mind that all five considered offshore wind farms are located close to shore. O&M costs for farms located further from shore are likely to be higher; mainly caused by harsher weather conditions and longer travel times. The harsher weather conditions are also likely to result in longer down-times due to lower accessibility.

During the past few years ECN has used its O&M Tool to estimate the O&M costs of offshore wind farms under development (which also include farms located further from shore and in deeper water). The estimated O&M costs for these farms vary roughly between 1.3 and 2.8 €/ct/kWh.

6 Cost distribution and cost of energy

6.1 Introduction

The cost of energy is probably the most relevant way of judging wind energy, because it is the main criterion for judging investments and policies. It is essential therefore to get a good idea of what it is. For researchers and designers it is important to see how the cost of energy is affected by different technologies and design choices.

To do that, we must first establish how the cost is distributed over the turbine and over the turnkey cost. The offshore and onshore turnkey cost are analysed separately. That leaves the maintenance cost, but that was already established in the previous section. The cost/value at the end-of-life of the turbine will not be considered here.

Then we will examine how this cost is affected by different factors, such as material cost, changes in the design, experience, or, for offshore, in the location of the wind turbine.

Once we have a good idea of the cost, the cost of energy is established by examining the yield of current wind turbines.

6.2 Cost breakdowns

6.2.1 Turbine cost distribution

Though a fair amount of cost studies on individual parts have been conducted in the past, there is actually fairly little original data available for the whole turbine. Quite a few studies are results based on a scaled version of another data set. So far we have found only a few independently published, original datasets regarding the cost breakdown of the turbine itself. Most of those seem to be estimates of cost rather than actual manufacturer supplied data.

The most recent publication features the cost breakdown of REpower's MM82 and MM92 2 MW turbines [8, 9] (2005,2007). Other studies are the OWECOP study [60] (2001), the DOWEC study (the results of which are not publicly available), the NREL WindPACT studies [43, 45, 88, 6, 85, 70] (mainly 2001) and studies by Risø, [44](1998). In the Wind Energy Handbook (2001) [29] one can also find a cost breakdown. A comparison of these studies in table 6.1 shows that the differences are large. Even for major components, estimates vary by a factor 1.5-3.0. An inspection of the data shows that the differences between these breakdowns is not related to the size of the turbine.

Because of the large inconsistencies, we will not hazard as detailed an analysis as was done in these studies. Instead we recognise that if we average the data of table 6.1, 74% of the cost of the parts of the turbine is defined by four component groups and the cost distribution is:

- Blades + hub: 23%
- Tower: 20%
- Gearbox: 14%
- Generator + power electronics: 17%

Note that any of the percentage of any of these parts can (apparently) vary substantially from turbine to turbine.

Hansen transmissions has published their sales data over the last 3 years [46, 47], but their wind

Rated power	MM92 2	DOWEC 6	NREL 1.5	Risø 1.5	OWECOP 2.5	MM82 2	WEH 1.5
Tower	26.3	25.0	11.0	21.0	11	33	18.7
Blades	22.2	14.4	16.0	22.0	13	18	19.5
Hub	1.4	7.6	7.0	3.0	7	2	2.7
Main bearing	1.2	2.4	1.3			1	
Shaft	1.9		2.2	5.0	5	2	4.5
Nacelle frame	2.8	1.4	7.0	13.0	10	3	11.5
Gearbox	12.9	13.1	16.4	15.0	11	14	13.3
Generator	3.4	6.1	10.6	9.0	7	4	8.0
Yaw system	1.3	2.0	1.3	5.0		2	4.5
Pitch system	2.7	10.3	3.9	5.0		5	
Power conversion	5.0	2.0	10.9		16	6	
Transformer	3.6		6.5			3	
Nacelle cover	1.4	0.7	4.0			2	
Brake system	1.3	0.7	0.3	2.0		1	1.8
Cables	1.0	1.9				1	
Misc	11.9	12.4	1.6		20	3	15.5
	100	100	100	100	100	100	100

Table 6.1: Percentage-wise cost distributions of different studies

Component Share	[%]	Component Share	[%]
Wind turbines	65	Wind turbines	75.6
Civil works (including foundations)	13	Foundation	6.5
Wind farm electrical infrastructure	8	Electric installation	1.5
Electrical network connection	6	Grid connection	8.9
Project development and management costs	8	Control systems	0.3
		Consultancy	1.2
		Land	3.9
		Financial costs	1.2
		Road	0.9

(a) According to [29].

(b) According to [13].

Table 6.2: Different cost breakdowns of a turnkey onshore wind turbine

turbine gearbox sales per MW increased from 70 €/kW to 86€/kW over the last 3 years. Combining this with the breakdown results in a cost price for the entire turbine between 512-630€/kW with an average of 570 €/kW.

On the other hand, combining the turbine breakdown of this section with the (more stable) turnover data of LM Glasfiber (see section 4) of 118 €/kW, that would result in the conclusion that the cost price of a wind turbine (excluding warranties, etc.) varies between 536 to 908, with an average of 666 €/kW.

6.2.2 Turnkey onshore capital cost and cost distribution

Obviously, installing a wind turbine is more than just combining its parts. Another process needs to be tackled that involves, amongst other things, site-planning, grid-access, financing and planning permissions. Onshore one also has to arrange land-rights, construction of access roads, building the foundation and transport and installation of the turbine itself.

The cost of all of these can vary significantly depending on the regulations in the country, the geological and ecological situation of the site, the size of the turbine, local attitudes towards wind

turbines, the size of park to be installed, etc. In general, the additional cost of these items add up to some 20 to 40% of the total project cost onshore. Some 10-15% of that amount is spent on the foundation.

The Wind Energy Handbook[29] contains a breakdown of a typical 10 MW onshore wind farm (table 6.2(a)). Wind Energy, the facts [13] gives a somewhat different breakdown in table 6.2(b).

Assuming that the wind turbines did indeed cost about 75.6% of the turnkey price in 2008 would result in wind turbine price of about 1043 €/kW. The average turnover of Vestas, Gamesa, Nordex, Suzlon and REpower in 2008 was 1000 €/kW¹.

6.2.3 Turnkey offshore capital cost and cost distribution

Onshore, the wind turbine makes up some 75% of the cost of a normal project, with the rest being spent on foundations, grid connection and project management. For offshore wind farms the turbines themselves only make up about 50% of the cost. The rest is needed for the far more expensive support structure, a substation at sea to convert the power for DC transport to shore, marine electrical cables, work to lead the cables safely onshore and larger project management costs.

EWEA[61] published the breakdown in table 6.3(a) for the cost of an offshore wind farm, based on an analysis by Risø of the Nysted and Horns Rev wind farms. The Nysted wind farm used a gravity based support structure, while Horns Rev used monopiles. The constructions do not seem to differ much in cost.

A different publication by EWEA[13] uses a somewhat different cost breakdown (table 6.3(b)), a report written by Garrad Hassan for British Department for Trade and Industry [72] contained a breakdown for the British 'Round 1' offshore projects (table 6.3(c)). Another cost breakdown is [81] (not reproduced here), which featured very similar numbers to these three studies.

A poster presented at EWEC 2009 put the price of a gravity based foundation at 400 €/kW for the Nysted/Rodsand II offshore wind farm. This would match with the data in table 6.3(b) if the turnkey price was about 2100 €/kW. However, the gravity based foundations for Thornton bank-phase I came to 27.5% of the cost of this 153 M€ pilot phase, according to the developers website. This would mean 1400 €/kW for the foundation alone.

Offshore wind turbines themselves are more expensive than onshore ones as well. Recently, large offshore contracts were announced by several manufacturers. These contracts amounted to between 1100-1750 €/kW.

It must be noted that as turbines are placed further offshore and in deeper water, the part of the turbine in the overall cost declines as the foundations and electrical supply become more expensive. This will be further examined in section 6.3.3.

6.3 Cost driving factors

There are many factors that influence the cost of wind turbines: materials, size and for offshore, distance to shore and water depth. These factors directly affect the cost price of a wind turbine. A less obvious effect is that of learning: as we produce more products, we learn how to control

¹Where available, only the (unconsolidated) sales from wind turbine installation were used. Probably, some of these figures include some service contracts. In the average the results were weighted equally for each company

Component Share	[%]
Turbines ex works, including transport and erection	49
Transformer station and main cable to coast	16
Internal grid between turbines	5
Foundations	21
Design and project management	6
Environmental analysis	3
Miscellaneous	<1

(a) Nysted and Horns Rev wind farms [61].

Component Share	[%]
Turbines and ancillaries	51
Support structures	19
Offshore electrical systems	9
Installation of turbines and support structures	9
Installation of offshore electrical systems	6
Surveying and construction management	4
Insurance	2

(b) Typical offshore wind farm [13].

Component Share	[%]
Wind turbine, transformer and tower supply	40
Foundation supply	18
Installation	22
Offshore electrical supply	6.5
Preliminary and management works	5.5
Onshore electrical works	4.5
Development expenses	2.5
Wind farm monitoring system supply	1.0

(c) 'Round 1' offshore wind farms [72].

Table 6.3: Turnkey offshore cost breakdown

production better which can be taken into account in the design and economies of scale allow cheaper production. The turnkey price is also dependent on the market.

6.3.1 Material cost

A wind turbine consists of quite large amounts of material. Some (very) rough estimates would amount to:

- About 150 tons of steel per MW for tower, hub, gearbox and nacelle frame (based on the data collected)
- Another 300 tons of steel per MW for offshore monopiles (30 m water depth)
- 400 tons of concrete and 40 tons per MW of steel for a offshore gravity based wind turbine
- Some 10 tons per MW of glassfibre reinforced material for the blades
- 4 tons or so of copper (depending on generator type, rough estimate based on generator weight)
- 100 tons of concrete for an onshore foundation

Sometimes a price-increase in the commodity, such as steel, may increase the cost price more as it passes up the supply chain, due to, for instance a relative profit margin on the material cost. This makes it difficult to judge the overall effect of commodity pricing on the final cost of the wind turbine as experienced by the manufacturer. In table 6.4 some estimates on material prices

Material	Amount [tons]	Price/ton [k€]	Total [k€]
Steel	150	0.4	60
GFRE	10	4	40
Copper	4	7	28
Concrete (onshore)	100	0.1	10
Concrete (gravity, offshore)	400	0.1	40
Steel (monopile, offshore)	300	0.4	120

Table 6.4: Material cost without work per MW for a wind turbine (very rough estimates)

have been made. The totals in this table are likely to be off the mark significantly, but ought to have the correct order of magnitude. It does give some idea of the sensitivity of the wind turbine to material pricing. With a turbine costing 1380 €/kW, materials add up to about 10%.

In a recent presentation by Dong Energy (EnergiRikekonferansen 2009, Haugesund), the material contents of the cost price of an offshore wind turbine is also estimated at 10%. The cost of the foundation and the cable however, was estimated consist of (respectively) 40% and 60% material cost.

For example: a doubling of the steel price (which happened early 2008, before halving again in the second half of 2008) would have (roughly) added an extra 180 €/kW to the overall cost price for an offshore turbine (including its foundation) and some 60 k€ for an onshore turbine. Based on our estimates in section 6.2.1, that is about 10% of the cost-price. Offshore it is about 6% of the turnkey price, the increase relative to the cost price will be higher than that.

6.3.2 Scaling

A recurring question that was seen in the last 20 years in the wind turbine industry, is whether bigger wind turbines produce cheaper energy. Scaling wind turbine designs is a fairly common way of studying this. Other question that might be studied in this way is how the cost of energy changes if one uses a higher tower, builds a wind farm further offshore or in deeper waters.

Scaling the costs as was done in the WindPACT and DOWEC studies, as well as certain books (e.g. [48]), consists of linking the cost to one of these factors. Usually the link consists of two steps, the first is linking the dimensions of individual parts to the factor, the second is to establish a cost function based on the dimensions (surfaces to be machined, volume to be cast etc.). E.g. linear upscaling of the rotor (multiplying every dimension by the same factor) would give a function:

$$m_{blade} = c_w D^3 \quad (10)$$

In a second step we could relate the weight to cost. Usually a linear relationship is assumed:

$$C_{blade} = c_{cost} m_{blade} \quad (11)$$

Alternatives for this function could relate the cost to the machined surface area, the maximum size of the piece that is being manufactured, etc. In this report, the functions that were fitted to the data could also be considered scaling functions.

One must take great care with assumptions in scaling functions, because they tend to oversimplify the problem. First of all, the assumed relationship between mass and a design factor could lead to the wrong conclusions, if the factors in the equation are wrong. We have already seen in the section on blades that the data indicates a scaling factor, that is possibly as low as D^2 whereas a factor $D^{2.53}$ or higher is used in literature.

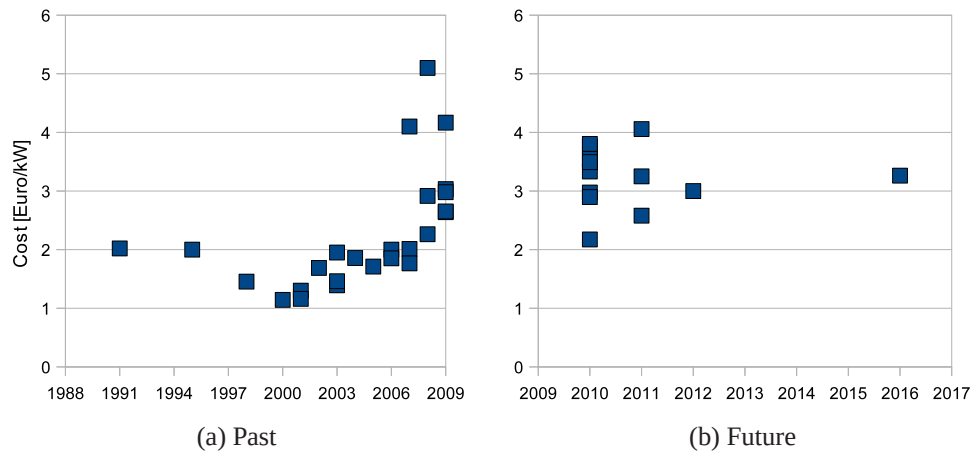


Figure 6.1: Rough turnkey costs per kW nameplate capacity of various offshore wind farms [€/kW].

Similarly, assuming that cost varies linearly with mass can be equally wrong. The costs can vary with any number of parameters that depend heavily on the production method that is involved. For limited production quantities, what is economically viable for one manufacturer is not necessarily viable for another, simply because they own different equipment.

The scaling functions could also be wrong because at a different design point, a different technology could become cheaper and this technology will probably have a different scaling function.

The scaling functions need to be correct for all parts that have a major contribution. That also includes the project cost of installing a wind turbine.

The only real way to establish whether a different design is more cost-effective than another is to really redesign in detail and establish the cost-price for that new design using known and valid manufacturing cost data. Such data is simply not available to us at this time.

This means that one must take great care when using scaling functions and be very critical of their results.

6.3.3 Offshore cost drivers

The cost of offshore wind farms has gone up significantly since 2006, see figure 6.1. In 2009, BTM Consult's WorldMarket Update [27] recommended using a turnkey price for offshore energy of 3000 €/kW, where in 2006 it was 1700 €/kW [24]. On-shore costs also rose from 1260 to 1380 €/kW in same period, but this increase is much smaller. EWEA [61] estimates that the investment cost will come down again to a level between 1550 and 2060 €/kW in 2015.

Some recent reports [12, 19], blame the rise for a large part on the rise in the price of raw materials. We have already seen in the material breakdown that in itself would increase the cost price of an offshore turbine by something in the order of 180 €/kW. This certainly influences the cost significantly, but it is still far short of the 1300 €/kW rise that is seen in turnkey cost.

What is relevant to know, apart from the absolute cost, is how the cost of wind turbines depend on various factors, such as the distance to shore and the water depth. Figure 6.2 shows that distance to shore and depth of offshore wind farms has increased significantly since 2000. A recent report on offshore wind energy costs by Garrad Hassan & Partners [54], as part of the Windspeed project,

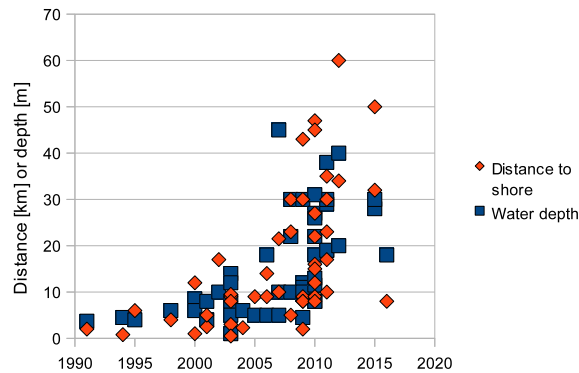


Figure 6.2: Does the change in offshore installation cost coincide with going further/deeper off-shore?

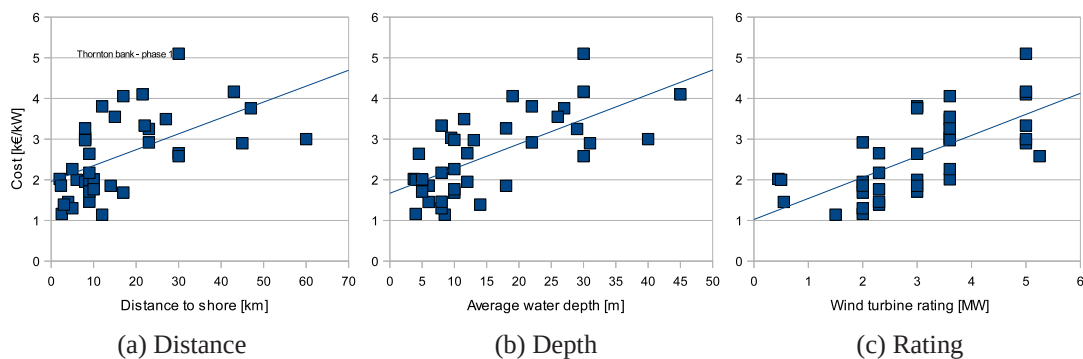


Figure 6.3: ‘Trends’ depending on distance to shore, water depth and turbine size.

gives detailed cost models for a ‘generic’ large far-offshore park consisting of 5 MW turbines. It also describes cost models in terms of distance and depth. Apart from depth, they also show that the cost depends on wave-height, tide-height and storm surges.

Figure 6.3 shows the price per MW relative to the distance to shore, the water depth and the turbine size for the projects where data is available. That the cost depends on the distance to the shore seems obvious; the boats take longer to get to the location and the cables going to shore have to be longer and are thus more expensive.

The export cable itself can contribute about 5-10% of the total cost of an offshore farm. A price of 3-5 €/kW/km for an AC cable, (based on data concerning Horns Rev II, Sheringham shoal and Greater Gabbard) for projects further offshore (>25 km) seems reasonable. For shorter distances, the price becomes nearly independent on the distance to shore. For larger distances and/or larger park sizes (>100 km and/or >500 MW) it is more efficient to use HVDC connections, which use cheaper cables, but have more expensive substations.

The trend lines suggest linear relationships with depth and distance to shore but the spread is still very large. Obviously there are some outliers, such as Thornton Bank, which includes costs for future expansions and Beatrice, which was the first application of offshore wind in very deep water, very far offshore. Apart from wave-height, tide-height and storm surges, another cause of the variation could be that the distance to shore is not equal to the length of the cables needed, because it is more convenient in terms of infrastructure to attach the cables elsewhere.

The same is true for the harbours. The nearest harbour able to accommodate the boats, equipment and people needed for the project may be at a different location. For instance: the distance to shore for the Alpha Ventus site in German waters is approximately 45 km. However, the distance to the nearest, significant harbour (Emden) is about 75 km, not taking shipping lanes into account. Similarly, for Thornton bank (Belgium) which is 29 km offshore, Ostend (at 36 km) was the main harbour of operations and was also the location for landing the transport cables. Shipping lanes and speed limits further complicate matters.

Ironically, if we do a simple analysis of the data, the price per kW seems most clearly related to the size of the wind turbine. This is a bit unexpected as larger turbines require fewer operations at sea per kW installed. First of all, there is a bias in this data, because there is a trend to use bigger turbines when building further out at sea and in deeper water. Other factors that make bigger turbines more expensive could be a smaller availability of suitable installation vessels and the fact that there is less experience with installing such turbines.

Another factor that could influence the price, is a competitive advantage of large wind turbines. A park consisting of 5 MW turbines ought to require 40% fewer maintenance trips (at equal mean time between failures) than a park consisting of 3 MW turbines. As maintenance results in a significant part of the total cost, this is a competitive advantage over the 3 MW turbines. If supply is still limited and the competition consists of smaller turbine types, rather than other manufacturers, this could result in a higher prices per kW as well.

Furthermore, large year-on-year increases in installed capacity during this period may have lead to a shortage of offshore installation capacity. The same as for onshore wind turbines, the offshore market must increase its supply chain to cope with the year-on-year increases. That also includes training of offshore crews and further development and building of offshore installation vessels. Unfortunately no clear explanation of the rise in turnkey offshore wind installation cost has been presented yet.

6.3.4 Cost reductions through technological learning

Technological learning is the reduction in cost achieved by applying knowledge, obtained through experience, research and use. Mechanisms identified by several authors studying learning ([55]) include:

- Learning-by-searching: structural research efforts into improvements in the product and manufacturing
- Learning-by-doing: improvements in manufacturing process by manufacturing the product repeatedly
- Learning-by-using: feedback from user experiences leading to improvements of the product design
- Learning-by-interacting: diffusing knowledge between actors (such as research institutes and manufacturers) supports diffusion of technology
- Upsizing: redesigning a technology can lead to lower specific costs.
- Economies of scale: standardized products allows upscaling of production plants.

Generally they are studied as a combined effect on the production cost, usually as an logarithmic function of the cumulative production:

$$\log C_{cum} = \log C_0 + b \log N_{cum} \quad (12)$$

$$PR = 2^b \quad (13)$$

where: C_{cum} is the cost per unit, C_0 the (virtual) cost of the first unit produced, N_{cum} the cumulative production, b the experience index and PR the progress ratio.

The progress ratio is a measure of the cost reduction achieved after each doubling of cumulative produced products. For wind this could be seen as the cumulative wind power installed. Up to 2001 at least, the progress ratio for onshore and offshore wind farms was about 82% (i.e. a 18% cost reduction per doubling of cumulatively installed wind power [55]). If this ratio had held since then, the turn-key solution of an onshore wind turbine nowadays would cost only 62% per MW of what it cost in 2001, offshore even only 42% (in 2001-€ and material prices).

Since 2001 market prices for complete turbines have not behaved according to any learning curve. A return to more stable prices is necessary before we can get a good idea of further developments on the production side of the cost. Economies of scale should now and during the next few years ought to play a more important role, but it is likely that the progress ratio has gone up as well, which means that the industry would have been learning at a lower rate.

6.3.5 Production cost vs turn-key installation cost and market forces

In the previous two sections, we examined how the costs are distributed over projects and wind turbines. In this section, we reflect on how the cost is related to the cost price.

In the last four years the price of a turn-key installation of a wind turbine onshore has steadily increased from about 1000 €/kW in 2004 to about 1380 €/kW in 2007[26]. In 2009 the forecast price was at the same level as the year before [27].

Several causes together create this increase in prices. On the one hand, rising material costs in the last few years will, to some extent, have increased the production cost of the wind turbine. On the other, there was a large increase in demand and a shortage of production capacity that can have resulted in price-inflation of wind turbines. We have already shown that the increases in material prices are unlikely to be the biggest part of the price increase as it amounts to about 10% in the estimated cost price onshore and only 6% of the turnkey price offshore.

It has also been noted that a high level of subsidies in certain countries can cause price increases elsewhere too as suppliers are more keen to deliver to countries where they can get the best value for their turbines. Furthermore, prices tend to vary per site due to (lack of) available infrastructure to physically get the turbine on site and install it. On the other hand, the price increase occurred during a period where the average power per turbine has steadily increased from 1.25 MW to 1.56 MW. The larger turbine size (and accompanying higher hub-heights and relatively larger diameters (section 4)) will also have resulted in higher yields.

With the price of wind turbines so heavily dependent on market forces and subsidies, one can not expect technological advances that allow cheaper production to result directly in cheaper turbines. It is also likely that technological advances that reduce maintenance cost or increase yields will also result in higher turbine pricing, regardless of whether the cost of producing the turbine has actually increased.

Though these effects may well be in line with market forces of supply and demand at the moment, in the (very) long run wind energy will have to compete against other forms of renewable energy. It is therefore important to keep trying to reduce overall cost of turbines.

In the short run, though, it ought to be profitable for suppliers of wind turbines to keep an eye on developments that increase their profit margin. Either way, technological advances that reduce

Cost component	Unit	Onshore	Offshore
Turnkey turbine	[€/kW]	1380.00	3300.00
Capital cost	[€/kW]	892.75	2134.83
Maintenance cost/15 years	[€/kW]	562.50	1311.50
Maintenance cost/20 years	[€/kW]	750.00	1748.00
Total cost/15 years	[€/kW]	2835.25	6745.83
Total cost/20 years	[€/kW]	3022.75	7182.83
Production/15 years	[kWh/kW]	56250	65550
Production/20 years	[kWh/kW]	75000	87400
CoE/15 years	[€/kWh]	0.050	0.103
CoE/20 years	[€/kWh]	0.040	0.082

Table 6.5: Calculation of CoE for an onshore class II windturbine and an offshore class I turbine.

the overall technical cost per kWh of produced power are the changes that are most likely to be adopted by industry. However, it may be that other issues have had priority the last few years, such as upscaling production or, more recently, examining the consequences of the financial crisis.

6.4 Cost of energy calculation

The target being used to judge wind energy is the cost of energy (CoE). The cost of energy would be the sum of the cost of installing a wind turbine, the costs of running the turbine and the cost of removing the wind turbine at the end of its life cycle, divided by the amount of power produced by the wind turbine during its life cycle.

However, what is included in these costs is very important. Examples for installation costs are the net-connection (especially for offshore wind-farms) and the capital costs (the money you would have made if you had invested in other things, or interest paid on borrowed money).

As running costs we will only use the maintenance cost. Other cost that could be included are insurance cost. For the costs at the end of the lifetime, one would have to put a value on all the parts of the wind turbine, either for resale as second hand parts, the value of the part as scrap material and the costs required to recycle, scrap or refurbish.

We will use the turnkey turbine cost, the capital cost and the cost of maintenance. End of life cost and insurance cost are not examined. Thus we get:

$$\text{CoE} = \frac{C_{\text{turnkey turbine}} + C_{\text{capital}} + C_{\text{maintenance}}}{\text{Energy produced}} \quad (14)$$

The turnkey cost were assumed to be 1380 €/kW for onshore and 3300 €/kW for offshore. Maintenance costs were assumed at 0.01 €/kWh for onshore and 0.02 €/kWh for offshore. Capital cost was assumed to be 7% interest on a loan covering the entire investment that lasts 15 years.

An analysis of the power curves for wind turbines we have data for, shows that a modern class II (onshore) turbine ought to be able to give 3750 full-load-hours on a good class II site (average windspeed of 8.5 m/s). Offshore turbines should be able to get 4600 full load hours (at an average windspeed of 10 m/s). These hours can be obtained by at least 25% of the turbines that were analysed in each class. If the average windspeed is 0.5 m/s less than these values, at least 10% of the turbines can still achieve these full load hours. Offshore an availability of 95% was assumed,

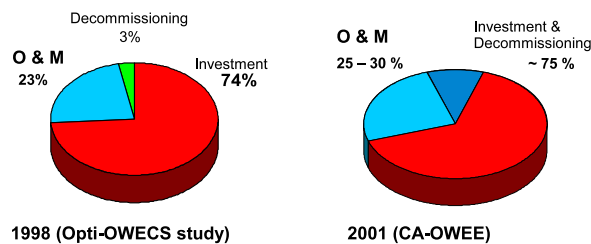


Figure 6.4: The cost breakdown determined in (left) the Opti-OWECS study of Delft University of Technology [50] and (right) in the concerted action [60] carried out by various European wind turbine manufacturers, offshore companies and R&D institutes

onshore (nearly) 100%.

From these assumption we see that onshore, the cost of energy can be as low as 0.04 €/kWh and offshore, 0.08 €/kWh.

The figures show that the contribution of maintenance to kWh our price is about 20-26% for onshore wind, where as offshore it is also between 20-25%. Earlier ECN studies revealed that for offshore the contribution to the kWh price is approximately 25 to 30% [50, 60] whereas onshore, the contribution was between 10 and 15%. The results of the ECN studies have been compared with public data, e.g. [57, 58, 59, 34, 33, 5, 16, 71, 24] and [84]. Other studies, see figure 6.4, also show the O&M costs contribute 25 to 30% of the total kWh costs.

Onshore, the maintenance part is higher than previously reported, because a significantly higher load factor is taken into account. This increased the maintenance part of the cost relative to the turnkey cost.

For offshore, the difference in percentages is likely due to fact that the investment cost taken into account here is the latest figure. This figure has increased dramatically over the last few years, increasing the total cost per kWh whereas maintenance remained (relatively) unchanged. The contribution to the total CoE has therefore decreased.

6.5 Market outlook - different scenarios

In 2008, 28 GW of wind energy was installed world wide, 9.2 of which was installed in Europe. World wide a global capacity was reached of 122 GW.

For the future, different organisations have some very different outlooks for the prospects of wind energy over the coming few years. The International Energy Agency (IEA, [10]) in 2007 foresaw by 2020 a global, accumulated wind power capacity of some 352 GW, half of which (176 GW) would be Europe. This would require some 24 GW of wind power to be installed annually worldwide and 10 GW in Europe. That is a reduction in annual installations compared with the current rate.

In 2008 ([11]), it was recognised that a so-called 450 scenario (based on 450 ppm CO₂ of greenhouse gas equivalence) would require an additional 270 GW of accumulated wind power installations, adding some 10 GW to be installed annually. The Global Wind Energy Council (GWEC, [83]) on the other hand foresees, in what they call a moderate scenario some 709 GW of accumulated wind power capacity. In their scenario Europe accounts for 180 GW. This scenario would require a yearly installation of 66 GW worldwide, a threefold increase over the current yearly installed capacity. Given that the wind energy market has increased more than threefold over the

last four years, the industry is certainly capable of delivering such an increase.

The European commission 2008 baseline model is more modest than either of these, planning 120 GW of wind energy by 2020. That would require only of 5 GW of wind energy to be installed in Europe each year up to 2020. That is only half of what was installed during 2008.

For all three of these scenarios, the growth in the market is certainly going to slow down over the next few years. For Europe the market is expected to remain at its current rate of installation or even drop somewhat. This is may also result in a return to the buyers market and will probably result in stable or gently dropping prices. For offshore projects the stabilisation of prices may take a while longer as the offshore market is still growing rapidly.

6.6 Conclusion

A breakdown of cost of a wind turbine over its installation and its parts is possible, but results differed significantly from one study to another. No verifiable cost breakdowns have yet been published for direct drive wind turbines. Based on the average of the cost breakdowns and turnover data from LM Glasfiber and Hansen, the cost price of a wind turbine (excluding warranties, transport and installation) is 570-666 €/kW. Based on the turnover data from manufacturers, the price of an onshore turbine was (ex works, warranties) was about 966-1043 €/kW. Offshore turbines are more expensive.

All in all, the picture of the cost price is not complete enough to easily judge different engineering solutions. The question is, if it ever will be. One needs accurate engineering data and accurate cost functions on the production processes for both the current designs and the alternative design.

The last few years, industry has struggled to keep up with demand. This has led to a 'sellers market' and higher prices. Increasing raw material cost also contributed to some extent to the increase in prices, but certainly not to the extent that market prices increased.

Offshore turn-key costs have risen much more than onshore. There are a number plausible reasons that each explain some part of the increase. The fact that most installations are now further offshore and in deeper water does explain part of the increase in cost, material cost will also have had some effect. However, the difference is larger than these combined effects. This could indicate a mismatch between supply (of offshore services) and demand.

Most scenarios predict a smaller growth in the wind turbine market during the next few years. This is likely to result in a more competitive market and reduced prices. For offshore, no slow down is projected yet, but more installation vessels are expected to become available. This could also have some consequences for offshore installation prices.

Calculating a cost-of-energy (CoE) on the basis of turnkey installation cost, a 7% interest rate, maintenance cost and average power curves for class II and class I turbines, results in an estimate of 0.04-0.05 €/kWh for onshore and 0.08-0.10 €/kWh for offshore wind energy.

6.7 Speculation

We saw quite a large spread in the amount of offshore contracts. The data published of the contracts for offshore wind turbines, were two 2 billion euro (G€) framework contracts for 500 Siemens SWT-3.6-107 turbines and up to 1900 MW REpower 5M and 6M turbines and a 700 M€MoU for 80 Multibrid 5000 (5 MW) at the Global Tech 1 site in Germany. Multibrid is

also said to have signed a contract valued at 500 M€ for Borkum West II. The first two contracts amount to about 1100 €/kW. Whereas the Multibrid contract amounts to 1750 €/kW and 1250 €/kW respectively.

This could be because the framework contracts are vastly undervalued in news items, or it could be because the Multibrid contract covered a lot more than just the turbines. If we speculate that the more expensive Multibrid contract includes a 5 year, 2€ct/kWh maintenance contract for some 4370 full-load-hours (based on the same assumptions as the cost price estimates), that amounts to 437 €/kW. If this is not included in the framework contracts and the other Multibrid contract, the main cost-difference is explained. The remaining difference could be down to the large difference in the number of turbines.

On a different topic, the turnover and production data from LM Glasfiber may suggest technological learning, because the turnover per MW of blades have remained more or less constant, especially if inflation is taken into account. That means blades are becoming relatively cheaper. Relating this to a particular learning factor is difficult though, because over the period we have data for, the length of blades have increased more than their power rating and the average power rating per blade increased. All together this implies a large drop in cost of energy, as far as the turbine blades are concerned. This perhaps warrants further study.

Considering the increase in the scale of production that is still proceeding at the moment, the theory of learning curves suggests that the cost price should be profiting from mass production effects. That implies that production technology advances are as likely to drive down the actual cost as much, if not more than the technological development of the turbine itself.

Finally, the cost of energy for onshore wind seems to be nearly on-par with whole-sale electricity prices (at least in parts of Europe). Assuming that the risk of yearly fluctuations in energy yield due to varying yearly wind are similar to the fluctuations in the prices of fossil fuels (for oil, this does not seem unreasonable), the main remaining risk would be the project risk of failed applications for the placement of new turbines. Could that mean that subsidies can be reduced or even abolished if the risks of failed applications is reduced?

7 Current research

We have seen in the previous sections how the main parts of the wind turbine have changed with size, how they contribute to the cost of energy, what the cost of energy roughly is for wind energy. This section examines what current research there is.²

At the moment there are many institutes around the world with significant research efforts in the area of wind energy. Though there are still fundamental problems to be solved, the research is mostly aimed at reducing the cost of energy.

The European Wind Energy Technology Platform recently published their Strategic Research Agenda (SRA, [2]). That document detailed to a large extent what the current state-of-the-art is and what main gaps in knowledge remain to be solved. It also examined what policy decisions and investments must be made to make sure the research needed to fill those gaps is done.

In this section we will focus on developments that are currently ongoing and that focus in particular on the aspects of wind turbine design, production and maintenance, i.e. on the aspects that define the cost of a wind turbine. That does not mean that other issues do not affect the total cost of energy.

The other topics, for instance the integration of large amounts of intermittent renewable energy sources in a grid, are not examined here because they do not directly influence the design of the wind turbine.

The main research topics are organised here in the following areas:

- External factors
- Modelling of the behaviour of a wind turbine
- Wind turbine and wind farm design
- Wind turbine and farm installation and operation
- New concepts

7.1 External factors

7.1.1 Wind

The wind resource is still not understood completely, in particular predictions in complex terrain can still be improved. Improved predictions would lead to improved siting of wind turbines. These predictions are mostly concerned with the average long term wind.

On a shorter time-scale it is also important to have good short term (12 to 36 hours ahead) forecasts the wind. On the one hand, these predictions are needed to predict the output of the wind farm. Depending on the local electricity market the differences between predicted and actual production can cost money. On the other hand, such predictions can aid offshore maintenance.

Extreme wind conditions are also important for the design, in particular the 50-year extreme [63, 64, 73]. Wind turbines have to be able to resist a 50-year extreme, but calculating accurately what the 50-year extreme wind is at a particular site requires a long data-history, which is simply not

²We would have also liked to examine its impact on the cost of energy, but we have not yet found a way to meaningful way of linking these two.

available at most sites. Also, in terms of loading and damage, representative gusts during high winds (e.g. a sudden drop in wind speed) may be much more relevant. These are only accounted for in a limited fashion in current norms.

Measurements at heights of more than a 100 meters, preferably at several heights are needed to verify the models of wind loading for larger wind turbines. Practical means to do such measurements robustly in various weather conditions are still under development.

7.1.2 Standards

We have already seen in section 3.1 (the different designs of the towers for Vestas V80-2.0MW) that standards can influence the design significantly. Though this may be because the different standards reflect different wind conditions and loading, it would be wasteful if different aspects of the turbine have to be over-engineered because different standards prescribe different ways of calculating essentially the same conditions.

It is therefore important that the design standards reflect reality as closely as possible, to prevent unnecessary over-dimensioning of parts.

Showing that a design matches the current IEC standard (IEC 61400-12-3) requires in the order of a 1000 simulations of the wind turbine in various circumstances. Wind turbine manufacturers are known to add additional simulation of their own to focus on particular issues. Research is ongoing to understand the practical implementation of the standards, especially when calculating the extreme loads (e.g. [80]).

The offshore norm is currently in its final draft. However, it is likely there will be more iterations as more experience is gained with offshore turbines in the near future. One of the issues that may lead to further changes is the interaction between waves, wind and the wind turbines itself.

7.1.3 Materials and production

A significant amount of the cost of a wind turbine is defined by the costs of materials and the effort required in processing those materials. The material properties, together with the loads, define how much material is needed and where it is best applied. If we utilise the material properties more effectively that could have a significant impact on the overall costs of the wind turbine.

It is also important to consider each part in the context of the whole turbine. For instance, reducing the mass of the rotor blades could also lead to reductions in the weight of the hub, the nacelle and the tower. Vice versa, the fibre-reinforced materials of the blades tend to be much more expensive than the steel used for the support structures. Thus using more expensive fibres with higher strength and stiffness will only lead to a cheaper turbine, if the amounts of other materials are reduced sufficiently.

The production methods that are used to create a wind turbine are also an important cost factor. The production of the blades in particular is labour, time and capital intensive. For other parts, such as the hub, the gearbox and the tower, the size of parts can lead to problems or additional cost in production.

Coatings that minimise the amount of dirt and also the drag of profiles, can improve energy capture.

Blade king is one of the projects that investigates materials and their use in production. Another

interesting development is the use of fibre reinforced concrete.

7.2 Modelling the behaviour of a wind turbine

Models are a very important tool during the design of a wind turbine. Research into models focusses on a number of topics, but in general one can see a clear differentiation between theory based, very detailed models that are used to improve design details or to clarify certain phenomena and practice based, engineering models that are less detailed. What model is used, is usually a balance between detail and speed. Modal reductions are sometimes used to change a highly detailed model to a model of limited detail for simulation.

7.2.1 Rotor aerodynamics and wake modelling

On the one hand, computational fluid dynamics (CFD) calculations use very detailed but computational very intensive models. CFD models are mainly used to model phenomena for which the engineering model needs to be improved or to study phenomena that are not yet understood. The engineering models give perhaps less accurate, but mostly acceptable results to study the turbine in operation with a lot less calculation effort. Both models can and ought to be improved further still, such that the difference between theory and practice is reduced or at least better understood.

For engineering models, it is becoming increasingly important to model the consequences of extreme wind conditions, including various wake conditions or extreme yaw angles. Current engineering models show varying degrees of agreement depending on the wind conditions [14].

Wind turbines are often installed as part of a wind farm. The interactions between wind turbines is an important factor in the design of a wind farm. The interaction is caused by the wake of the wind turbines. The models of the wakes are studied to improve load models when a turbine is in another turbine's wake and can also help to improve the siting of the wind turbines within the wind farm.

7.2.2 Aeroelasticity and aeroacoustics

Aeroelasticity and aeroacoustics describe the interaction of the structure with the wind. Aeroelasticity is used to study whether a certain combination of motions of the turbine structure in the surrounding airflow can produce large deflections or instability. This is usually done on the basis of the same aerodynamics of the rotor that are used to study the steady state of the wind turbine. Again, more extreme conditions and the (aero)dynamics in those situations are becoming more important.

Aeroacoustics is a relatively new part of wind turbines studies, but has gained significant importance over the last 10 years as the noise of a wind turbine has become one of the limiting design factors for the tip speed of the rotor. Research has shown that the noise of a turbine can be predicted fairly well, but that it is difficult to reduce the noise [86, 51, 18].

An interesting new line of research is the adaptation of the aerodynamic profile of the blade to different circumstances along the blade, so-called distributed control. It has been shown that applying distributed control on the blade could reduce the fatigue loads on a blade significantly[62] though further work on the controller will probably result in far larger reductions. However, these systems rely on relatively fast changes in the effective angle-of-attack and transient aerodynamics play a more important role there.

7.2.3 Structural modelling

The complexity of the models of the wind turbines used in simulation increases steadily due to increasing computational power and the models can be used to study more complex interactions between different parts of the wind turbine. In particular, the interaction of the gearbox with the rest of the structure has been a point of interest the last few years [74, 49]. This interaction can be modelled with various amounts of detail, including multi-body-dynamics and finite element models.

As with aerodynamics, a balance has to be found between the amount of detail one can study with the model and the computing time required to calculate such details. The main question is what level of detail is required at what point of the simulation. For instance, is it enough to have a fairly crude model of the gearbox in a turbine simulation to obtain the loads that act on the gearbox or do we need to take the flexibility of the casing into account or even complex modes of the gears in the gearbox?

7.3 Wind turbine and wind farm design

7.3.1 Wind turbine design: design tools

Wind turbine designs are becoming more and more integrated: the design of the blade influences the drive train and the tower all depend on the wind and wave conditions. This requires a good set of design tools that allow the detailed analysis of individual parts of the wind turbine, but also, at lower detail, the turbine as a whole.

Research is focussing on improving the integration of various models into one design tool and including the possibility to optimise the turbine design globally for the lowest cost per kWh. This requires a very careful balancing of all costs and the yield. That is why detailed cost models of production and maintenance, as well as accurate yield and load models are all necessary to design such an optimal system.

7.3.2 Wind turbine design: parts

Foundation, support and tower

Onshore, research focusses on making towers more transportable and installable, as those aspects contribute significantly to the total cost of the turbine. Lower weight and cost is limited due to the stiffness required to avoid resonance, the strength to cope with the thrust and fatigue due to variations in thrust and load distribution. Control systems that reduce tilt and yaw moment and generator torque variations or actively add damping to these motions, ought to allow a more flexible (i.e. lighter) tower.

Offshore, there is no convergence yet to a single support concept, though monopiles are favoured in reasonably shallow (up to 30 meters) water for turbines of less than 5 MW. Research into all types of offshore foundations is still ongoing.

Drive train

In the drive train, research focusses mainly on reliability and maintainability. The gearbox design tends to be critical in terms of reliability. Recent research has indicated that not all loads are understood well enough to correctly predict the behaviour and thus the lifetime of gearbox designs [49]. Research is focussing on a better understanding of the loads and on designing the wind turbine in such a way that the loads are reduced or at least less uncertain. For instance, the designs of Gamesa, Multibrid and GE in the 3+ MW class of wind turbines (claim to) feature

load separation to some extent.

For direct drive layouts, the focus is mainly on designing a generator that is as light and reliable as possible and whether or not the main bearing should be integrated.

Redundancy of or splitting certain parts of the drive train can also improve reliability or at least minimise the impact of failures. The Clipper Liberty design advertises with these arguments for their design featuring four independent generators. One of the new concepts for the Bard 7 MW turbine includes 2 variable gear ratio gearboxes and two generators. Other manufacturers are also opting for redundancy in at least some of the electrical system. Redundancy is only financially interesting if costs of repair and loss of production are sufficiently reduced. It is therefore more likely to be employed in offshore designs.

For both direct drive and geared drive trains, the trend is to use higher-voltage generators to minimise losses in the power electronics. Reducing either mechanical or electrical losses reflects immediately on the price per kWh. Recently, even electromagnetic bearings were suggested as a replacement for the main bearing to reduce mechanical losses [87].

Smart passive blade designs

For aeroelastic stability of the blades, coupling between edgewise and flatwise motions of the blade can increase aerodynamic damping. One way to achieve this is by using pre-bent blades. Another way is to use a clever lay-up of fibres that causes some structural coupling of the two. How to achieve good coupling that achieves sufficient damping while avoiding extra loads and costs is part of ongoing research.

7.3.3 Wind turbine control

The operation of a wind turbine should focus on minimising the loads on the most critical parts of the wind turbine, while maximising the energy production. That way, the mean-time-between-failures could be improved, loads reduced (and thus material saved) and yield could be improved.

Control algorithms such as 1p/2p/3p individual pitch control (IPC) show that a significant reductions in the yaw and tilt moments on the tower are possible, relative to current control design [21, 22, 28]. Control algorithms for specific events, such as gusts, can also reduce loads [56]. It is likely that further improvements are still possible by using more complex feedback control algorithms or by combining feedback with feedforward control methods.

The application of distributed control on the blade could further reduce the loads on the blade itself, the drive train and the tower. Practical actuators that allow distributed control have already been examined for a while now (e.g. tabs [53, 31, 32, 94, 35, 18], flaps [17, 28, 93, 15] and jets [20]) and have been shown to be fairly effective. This opens up an entirely new line of control research that requires very consideration of the design criteria. The controller design and its total impact on the structure and on operation is yet to be investigated.

As distributed control will require more actuators (moving parts) and sensors, the business case for wind turbine blades with distributed control is far from trivial.

If the influence of control increases and more sensors and actuators are used, the reliability of these parts becomes more important. Fault tolerant control would allow continuous operation, possibly at reduced power, if one or more of the sensors and actuators fails.

7.3.4 Wind farm design, control and integration

Improved wake models may allow improved wind farm designs. Also, controlling the wake direction and wake intensity could contribute to lower loads on the turbines and possibly improved energy capture.

For the electricity grid as a whole, wind turbines and farms operate to some extent as a normal power plant. To meet all the requirements of a power plant, various grid codes must be implemented, either in the design of individual wind turbines or in the design of wind farms as a whole. This is also a two-way process, because the grid-codes themselves are under development as well. This is discussed in more detail in [2].

7.4 Wind turbine and wind farm installation and operation

7.4.1 Offshore installation

A large part of the capital cost of offshore wind farms consists of the offshore activities needed to install the turbines. Offshore companies are examining different means of installing the wind turbine and its support to reduce cost. The main cost-drivers of offshore installation are weather dependence, the number of operations required and the total time at sea. If any of these can be reduced that would result in a lower CoE.

7.4.2 O&M planning

Maintenance is a very important topic for wind energy as it defines up to 25% of the final cost of energy. Research into the main factors that define this cost has led to tools that aid in the prediction of the maintenance need of a wind farm. The predictions are based on operational data and can serve as a base for optimising maintenance strategies.

For offshore wind farms improving the accessibility (time and cost need to get to the wind turbine) also decreases downtime and associated revenue losses.

7.4.3 Condition monitoring and prediction

By using condition monitoring, one can detect or predict fatigue and/or wear on certain parts. This gives the operator the chance to take action accordingly by maintenance or by reducing the loads (by operating at lower output) until maintenance is possible. This can prevent downtime and reduce maintenance cost.

To some extent this is done already, e.g. by measuring the quality of the oil of the gearbox, but research is still ongoing, for instance by including sensors in the blade itself (the Smart Embedded Sensor Systems project (SESS)).

There is also research into predicting the maintenance need of turbines in a farm, based on the relative loading on one or a few reference turbines [79]. Combining this information with data from inspections and other condition monitoring systems gives the possibility to adjust maintenance schemes for each turbine individually (based on its health) instead of a uniform strategy for the complete wind farm.

7.4.4 Accessibility

Offshore, safety is also a very important issue, because the sites are far more remote and difficult to access. The combination of safety requirements and accessibility has led to the development of specific maintenance vessels and mechanisms that allow safer access to the wind turbine in higher waves.

For future offshore wind farms placed further offshore, dedicated maintenance hubs, located close to or in the offshore wind farm, will most likely be used to service the turbines in order to avoid long travel times from the harbour.

7.5 Alternative concepts

Over time, different designs for utility-scale wind energy converters have been proposed. Here we will take a look at a few concepts that are being investigated at the moment. In particular: NOVA, Kite gen, Ladder Mill, Sky Wind power generator and the Magenn Air Rotor System.

7.5.1 NOVA

NOVA stands for Novel Offshore Vertical Axis (figure 7.1(a)). The idea begin the project is a new design for a vertical axis wind turbine (VAWT), specifically for offshore applications. VAWTs have been studied fairly extensively for a long time. Their main advantage was the fact that they did not require any yaw mechanism and that they could have the generator at ground level. The varying gravity loads that HAWTs suffer on their blades, is traded for varying aerodynamic loading on the VAWT blades.

Other disadvantages were the generally lower energy capture (lower c_p) and the total blade length required. VAWT using straight blades suffered pulsating loading due to variation of the angle of attack over the entire blade during each cycle. That loading also resulted in strong vibrations (resulting in failures). the largest VAWT ever built is a 4 MW Darrieus type wind turbine in Quebec.

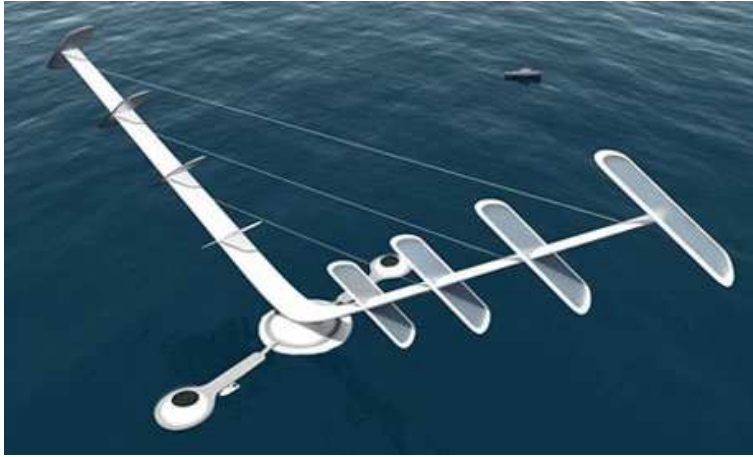
Some modern, small VAWT designs like Turby or Quietrevolution have been able to alleviate the pulsating load problem by using a helical profile. Each part of the aerofoil is still subjected to varying loads, but at different times. The net result is a (theoretically) constant load on the wind turbine. However, this type of design is more suitable for small scale applications than utility scale turbines.

The NOVA design features a V-shaped wing design with perpendicular winglets. The main advantage of the NOVA concept in comparison to HAWTs seem to be the lack of a tower. It is unclear how the V-shape design would alleviate the pulsating load on the structure.

7.5.2 Kite Gen and Ladder Mill

The motion of an aerofoil on a wind turbine is limited by the structure it is attached to. Ideally, one would wish to create a structure that is as simple as possible and generates power as efficiently as possible. Power is generated by the net velocity of the aerofoil in the direction of the lift. A kite on a rope could qualify as such a structure.

The main advantage of kites is that they can be used at much higher altitudes, with substantially higher wind speeds. Because there is much more energy available, one could choose to use a much lower induction and create the same amount of power with much lower loads on the



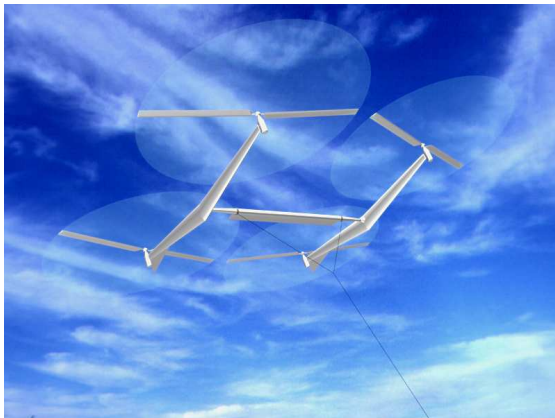
(a) NOVA VAWT concept (Image: NOVA project)



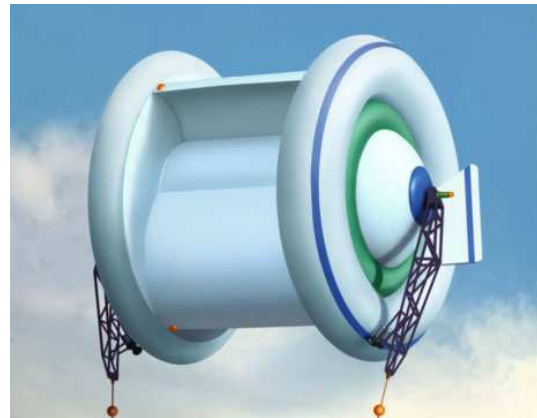
(b) Ladder Mill concept (Image: Ladder Mill)



(c) Kite Gen concept, artist impression (Image: Kite Gen)



(d) Sky Wind Power, artist impression (Image: Sky Wind Power)



(e) MARS prototype design (Image: Magenn Power)

Figure 7.1: Impressions of new concepts for harvesting wind energy

structure. Though proposed as early as the 1930s the concept has never really taken off. At least two concepts are still being investigated, they are named Kite Gen and Ladder Mill.

Kite Gen (figure 7.1(c)) is a concept of multiple computer controlled kites flying in formation between 800-1000 m above ground level. The idea focusses on creating torque and motion on a *vertical* axis generator.

Also using kites, but different in execution is the Ladder Mill (figure 7.1(b)). This idea focusses on using the lift of fixed or flexible aerofoils at heights of over 1000 m to drive a horizontal axis turbine. The kites follow a trajectory that pulls up a cable attached to the generator axis. The lift is reduced and the cable is reeled in again. The difference in lift between the ascent and descent results in power generation.

For both concepts, research is focussing on controlling the kites and finding effective trajectories. For neither concept a short term commercial application is expected.

7.5.3 Sky Wind Power and Magenn Air Rotor System

Two other concepts that are based on capturing energy at high(er) altitudes are the Magenn Air Rotor and Sky Wind Power systems.

Sky Wind Power (figure 7.1(d)) is based on the idea of an autogyro. Autogyros are similar to helicopters in that they generate lift through a set of rotating blades, but are different because the blades are not powered. A horizontal propeller provides thrust, which causes forward motion, which in turn causes the rotation of the blades, which creates lift. The Sky Wind Power system uses this same concept, except the wind provides the thrust and the system is held in place with a long cable. The rotating blades provide the power generation and one could imagine using them in a 'helicopter' setting to launch the vehicle.

The Magenn Air Rotor system (MARS, figure 7.1(e)) is nothing more or less than a helium filled balloon that rotates around a horizontal axis. The torque and rotation are caused by Savonius-like scoops. The generators are also airborne and attached to cables that hold the system in its place. Lift is provided mostly by the buoyancy of the balloon, assisted by some aerodynamic lift on the lower half of the balloon. A 10 kW prototype has been built a 100 kW prototype is planned to be ready for commercial operation in the next 3 years. This system has an estimated price tag of 500 k\$, i.e. 362 k€(at the current exchange rate (June 2009)) or 3620 €/kW. That is near the going rates for offshore wind power. If equal load factors can be obtained and maintenance is not more expensive, the price per kWh would be very similar to offshore wind energy.

7.6 Conclusion

Most of the research focusses on reducing the uncertainties in design by improving the load predictions. Control strategies can play an important role in reducing the actual loads, but to design them well accurate models are necessary. Advances in material properties or their application obviously allow design improvements, but can be very difficult to obtain.

On the maintenance side of things, there is a focus on damage prevention, i.e. trying to adjust maintenance and operation of the wind turbine such that the cost of repair remain limited. Both on- and offshore there is much to be gained as maintenance forms a significant part of the cost of energy (see section 6).

7.7 Speculation

It would be good if one could estimate the consequences of each research topic on the cost of energy. This could give a clearer indication of the potential of each research topic and result in a sort of 'business case' for that line of research. Some topics might have particular benefits in combination with others, e.g. improved aerodynamic models in combination with distributed control of the blade aerodynamics. We thought about getting expert opinions on each topic to quantify

their potential but quickly realised that this would probably result in very general statements. We would welcome suggestions whether and how to proceed on this point.

It is unlikely that all of the alternative concepts will succeed. Some of these concepts certainly have points that merit consideration. Tapping the high wind speeds that are available at high altitudes is a concept that is likely to remain an idea that people will come back to with new or improved concepts.

8 Conclusion

8.1 About the study

This study was meant to give insight in different current wind turbine designs, the cost of energy and how research and changes in turbine design can affect the cost of energy.

These goals were only partially met. We showed the main differences in drive train layouts and we established a global model in terms of cost. We also established how design changes affect certain parts of the turbine in terms of mass. However, the mass was not linked directly to the cost. We were also unable to quantify the possible impact of research on the cost of energy.

A lot of time was spent on gathering data and trying to make it more reliable. The idea is that the data gathered in this project will be maintained over the next few years. This should allow us to shed more light on cost developments, technological learning and to improve the quality of the data.

8.2 The data

This study has mainly consisted of gathering data and then trying to extract useful information from that data. Though data was gathered of over 130 different turbines, there are still gaps in this data that could do with filling. In particular, there was very little data on the weights of Enercon turbines, on Vestas' newest models or on any of the Chinese wind turbines.

The data itself was fairly raw and there were some factors that could introduce a small bias here and there. For instance, REpower has licensed its MD70 and MD77 designs to several manufacturers. Here they have been used as separate data-points on some of the graphs (not all manufacturers revealed the details of their version of this turbine). Considering the number of turbines, this was not a problem. There are more of such constructions though, and there are several companies that just design wind turbines but leave the mass-manufacturing to others, such as Wind To Energy and Lagerwey Wind. Not all 'doubles' have been identified yet and we still have to look at how to handle them.

Similarly, certain blades of LM Glasfiber, Euros or Sinoi are probably present on several turbine models.

Little data was found on generator cost or power electronics on the level of the wind turbine. This will be a focus for further research. We found a little more data on gearboxes and gearbox costs, but this could also do with further research.

For the cost of offshore farms, one of the problems is how to take inflation and currency effects into account. In particular for British offshore farms it was difficult to pin-point the 'correct' exchange rate. The rates that were opted for were linked to the date of earliest mention of the cost of each wind farm. We have had to assume this is correct and accurately reflects the terms of the contract.

8.3 Design trends

So far, there is no clear convergence in the drive-train layout. Quite a few manufacturers are starting to employ permanent magnet generators and direct drive technology, but it is not a universal trend. Almost universal are: pitch-to-feather, variable speed and a 3-bladed upwind design. There

are some exceptions though.

In terms of the rotor, onshore turbines show a trend to relatively larger diameters in comparison to the rated power. This ought to result in an increase of the number of full-load-hours.

Turbine towers for very tall, onshore turbines will probably be reinforced concrete, hybrid or lattice solutions, rather than the standard tubular steel due to transportability.

For offshore installation concepts, the monopile is used most. But it is not obvious whether this is the most economical solution. Gravity based solutions proved cheap in Denmark for Nysted I and II, but expensive for Thornton Bank.

8.4 Cost of energy

The original goal of this study was to see if we could judge whether certain design changes would lead to a better (i.e. with a lower cost of energy) wind turbine. In some ways this goal is met, in others it is not.

It is still not possible from the data found in this study to judge whether a drive train that is a direct drive, a medium speed permanent magnet or a classic design is cheaper than any of the others.

On the other hand, we found that the cost of the wind turbine is mostly defined by the blades, the tower and the gearbox and generator (i.e. the drive-train layout) and that each of these seems to behave approximately linear with the power, possibly slightly more than linear for the rotor and the nacelle. The cost-price of an onshore wind turbine was estimated to be around 570-666 €/kW. Turbines themselves sell at about 1000 €/kW with warranties included.

Offshore turbines were found to be more expensive. This makes sense, because the cost of the turbine is a smaller part of the project, but the turbine defines the whole yield. This means it is sensible to invest more in the wind turbine's reliability to get as high availability as possible.

The recent increases in onshore turnkey cost is only partly due to material cost increases, it is much more likely that the market forces (high demand vs limited supply) played a significant role.

Offshore, the picture is a bit unclear. The increases in offshore cost seems to coincide to some extent with increased distance to shore and increased water depths. Material cost also played a role here, more in absolute numbers than onshore, but similar in percentage of turnkey cost.

For class II and III (onshore) turbines, larger wind turbines have lower power densities than the smaller ones in their class. The differences between the different classes of turbines are large, with some turbines covering 2.5 times as much area per kW as others, but within classes the difference is still a factor 1.5. That means that high load factors are possible, even for sites with low mean wind speeds. For mean wind speeds as low as 6.0 m/s, turbines exist that can (theoretically) deliver more than 3000 full-load-hours. That means that when calculating the viable land-mass for wind turbines the wind turbine choice must be taken into account. If these turbines designed for low-wind sites are not much more expensive than average, the cost of energy should be similar.

For good onshore sites, wind turbines were found to deliver more than 4000 full-load-hours. Calculated with 3750 full-load-hours, 1380 €/kW turnkey cost, 0.01 €/kWh maintenance cost and a 7% rate of interest, the cost of energy (CoE) onshore amounts to 0.04 to 0.05 €/kWh.

Offshore, installation cost and maintenance cost are substantially higher. The yield is also higher, but not as much as the cost. Based on 3300 €/kW turnkey cost, 4600 full-load-hours, 95% availability and 0.02 €/kWh maintenance cost, offshore CoE is 0.08 to 0.10 €/kWh. To get this down to a number comparable with the onshore CoE, turnkey cost needs to drop substantially and maintenance cost must decrease.

8.5 Current research

A lot of research is aimed at improving the estimates of the loading of wind turbine components. To do that the models need to be closer to reality. This means that improved aerodynamic and structural models are necessary, but their complexity must be adjustable to the design context, to keep computation times realistic. International standards for wind turbine must also follow this trend, to keep designs safe, but not over-designed unnecessarily.

On the maintenance front, research is working on predicting the maintenance need of wind turbines correctly and on detecting wear and tear and reducing the loads on the wind turbine accordingly to prevent failures. One of the options under investigation is condition monitoring.

The designs can also become cheaper by reducing the loads and by using the correct materials. Loading can be reduced with improved control methods. Material utilisation could be improved by choosing materials that are cheaper and easier to produce, improving the materials themselves and by adding materials at certain locations, for instance by applying coatings, that locally improve certain properties.

Alternative concepts show some promise, but are not expected to be operating competitively within the next 5 years.

8.6 Future work

The goals of this project were only partially met, so more work is required if we want to create a more detailed picture of the cost. A question that is just as important, is whether more detail also results in more accuracy. The large differences found between the cost-breakdowns presented in section 6 indicate that a more accurate picture may not be possible.

One aspect for which it may be possible to include more detailed and more accurate data is the electrical system. This has not received much attention in this analysis so far, but some aspects can be particularly relevant; for instance when comparing the variable-gear-ratio gearbox with a constant speed generator and fixed-ratio gearboxes (or direct drives) with variable speed generators.

The electrical systems and the grid within an offshore wind farm contribute significantly to the cost and to electrical losses. The analysis of this aspect was not within the scope of the project, but could result in significant cost-savings.

The database should also be maintained, because of the large number of wind turbines that are announced each year. Apart from new turbines, existing turbines are improved. It is probably possible to find more data trends on the basis of current and new data.

8.7 Request

As we said in the introduction, we would really appreciate it if you share your thoughts, links to data or comments with us. Also, if you feel a particular analysis is lacking or that it could interesting results, please do not hesitate to e-mail the authors:

engels@ecn.nl

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A Wind turbine characteristics

Characteristic	Unit	Acciona AW-x/3000	Bard Bard 5.0	Clipper Liberty 2.5MW	Darwind DD115	DeWind DeWind 8.2	Ecotècnia Eco-100	Enercon E-112	GE GE3.6/104
Rated power	[MW]	3.0	5.0	2.5	5.0	2.0	3.0	4.5/6	3.6
Rotor diameter	[m]	100/109/116	122	93/96/100	115	80	100	114	104
Rated wind speed	[m/s]	11.7/11.1/10.6	12.5	13-14.5	12	13.5	13	13	14
IEC Wind class	[-]	Ia/IIa/IIIa	?	IIa/IIb/IIIb	1c	I	IIa	IIa	S/Ic
Blade length	[m]	48.7/53.2/56.7	57.5	45/47/49	39.1	48.3	55	50.5	
Blade weight	[ton]	10.4/11.5/12.3	28.5	?	16	6.2	9.6	20	?
Hub weight	[ton]	36	70	?	?	?	24	54	?
Nacelle weight	[ton]	118	156	72	180	66	105	440	?
Gearbox	[-]	2 helical, 1 planetary	2 planetary, 1 cyl- indrical	two stage, 4 outgoing axes	none	2 stage planetary & Voith Windrive	spur and planetary, 3 stages	none	3 stage planetary spur
Generator type	[-]	asynchron- ous 6 pole, double fed	double fed, asyn- chronous	4 permanent magnet	permanent magnet	4 pole brushless, synchronous	double fed, asynchron- ous	synchronous generator	double fed, asyn- chronous
Generator voltage	[kV]	3	?	1.3	?	4.16-13.8	1.0	?	?
Hub heights	[m]	100/120	90	80/site specific	100	80/100	80/90/100	124	site specific
Tower material	[-]	concrete	steel	steel	steel	steel	steel/hybrid/ hybrid	steel/concrete	steel
Year introduction	[-]	2008	2008	2006	2010(proto- type)/ 2011(com- mercial)	2007	2008	2002 (4.5 MW prototype), 2005 (6.0 MW prototype)	2002 (proto- type)

Table A.1: Wind turbine characteristics, part 1

Characteristic	Unit	Multibrid M5000	REpower 3.xM	REpower 5M	Siemens SWT-3.6-107	Vergnet GEV HP 1 MW	Vestas V90-3	Vestas V112-3	WinWind WWD3
Rated power	[MW]	5.0	3.3	5.0	3.6	1.0	3.0	3.0	3.0
Rotor diameter	[m]	116	104	126	107	55/58/62	90	112	90/100
Rated wind speed	[m/s]	12	12.5	13	ca.13	?/?/15	15	12	12.5/13
IEC Wind class	[-]	Ia	IIa	Ib	Ia	I/II/III	Ia	IIa	IIa/IIIb
Blade length	[m]	56	50.8	61.5	52	?	44	54.6	44/48
Blade weight	[ton]	16.5	11	17.7	17.5	4.5	8	?	17.5
Hub weight	[ton]	60.1	23	66.9a	42.5	?	17	?	42.5
Nacelle weight	[ton]	199	104	290	125	65	70	?	125
Gearbox	[-]	single stage, planetary	2 planetary, 1 double helical spur		3 stage planetary- helical	3 stage epicyclic	2 planetary, 1 helical	?	single stage, planetary
Generator type	[-]	medium speed, permanent magnet	double fed, asynchronous		asynchronous	asynchronous squirrel cage	double fed, asynchronous	permanent magnet	medium speed, permanent magnet
Generator voltage	[kV]	?	0.95	0.95	0.69	0.69	1	?	.66
Hub heights	[m]	?	80/100	117(on-), 85-95 (offshore)	80 or site-specific	70	80/105	84/94/119	80/88/100
Tower material	[-]	steel	steel	steel	steel	guyed steel	steel	steel	steel/steel/hybrid
Year introduction	[-]	2004(proto), 2009(commercial)	2008	2005	2006	2008(proto)	2002	2009	2004

Table A.2: Wind turbine characteristics, part 2

B Simple scaling functions

B.1 Generator torque at constant tip-speed

Suppose at equal tip-speed, we increase the size of the rotor a turbine. That means the rotational must be reduced:

$$v_{tip} = \omega_{old} r_{old} = \omega_{new} r_{new} \quad (15)$$

$$\Downarrow \quad (16)$$

$$\omega_{new} = \omega_{old} \frac{r_{old}}{r_{new}} \quad (17)$$

The power of a turbine increases with the swept area of the turbine:

$$P_{new} \propto cr_{new}^2 \quad (18)$$

$$P_{old} \propto cr_{old}^2 \quad (19)$$

$$\Downarrow \quad (20)$$

$$P_{new} = P_{old} \frac{r_{new}^2}{r_{old}^2} \quad (21)$$

The torque is equal to the power divided by the rotational speed:

$$T_{new} = \frac{P_{new}}{\omega_{new}} \quad (22)$$

$$= P_{old} \frac{r_{new}^2}{r_{old}^2} \frac{1}{\omega_{old} \frac{r_{old}}{r_{new}}} \quad (23)$$

$$= T_{old} \frac{r_{new}^3}{r_{old}^3} \quad (24)$$

Torque scales as the third power of the rotor radius. Power scales as the second power of the rotor radius. Or otherwise:

$$T \propto r^3 \propto P^{1.5} \quad (25)$$