European Wind Farm Project Costs
History and Projections
2008 Study

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List of Abbreviations

Abbreviation	Meaning
BoP	Balance of Plant. The BoP covers all civil and electrical work up to the point of grid connection, including: roads, foundations, crane pads, electrical collection system, communication system, SCADA, turbine transformers and substation.
EPC	Engineer Procure and Construct. This type of contract structure is often referred to as ‘turnkey’. The main feature is single point responsibility for all aspects of delivering the project work.
GH	Garrad Hassan and Partners Limited
O&M	Operations and Maintenance. This is the work required to perform scheduled and unscheduled maintenance work on the turbines for the life of the project.
TSA	Turbine Supply Agreement. The TSA agreement typically covers supply, installation and testing of the turbine equipment (rotor, nacelle and tower) as well as equipment warranties.
WTG	Wind Turbine Generator. The WTG includes the rotor blades, the nacelle, generator, gearbox, tower and other associated equipment.

EXECUTIVE SUMMARY

Introduction

At the request of Enova (the "Client"), Garrad Hassan and Partners Limited ("GH") has provided technical advice on capital cost expectations for wind farm developments. In summary, the work provides a survey of the present and future 5-year prognosis for costs and conditions facing developers and suppliers in the European wind power market.

The report will be used as a benchmark to support tendering for future Norwegian projects. As such, it will also provide discussion of how project characteristics can influence project cost.

Data Used in the Analysis

GH has obtained data on the investment costs for 35 projects developed or in development in Europe. The projects represent to the extent possible the characteristics representative of potential Norwegian projects.

The data used in this analysis are from actual projects in: France, Germany, Hungary, Ireland, Italy, Northern Ireland, Portugal, Scotland, Spain and Wales. The turbine capacities represented in the data are typically 2 MW or above, except in one case where a mix of turbines sizes was used at the project.

Total Project Costs

For 22 of the projects (located in 7 countries) in the study, the full development and construction cost "Project Cost" is known. The total costs include all hardware, grid connection (where applicable), project development, financial arrangement, legal and other transaction costs for the projects.

The Project Costs range from €1,200,000 to €2,000,000 per MW. The variance in project costs can be explained through: increased turbine and balance of plant costs over time, variances in balance of plant charges due to terrain, remoteness and forestry, different electrical charges due to different connection voltages, varying development and lending costs.

To assess the potential variation in costs in different wind regimes, GH has analysed the costs based upon the expected production of the project. The data suggests a trend of decreasing cost per kWh for higher capacity sites, as would be expected.

GH reviewed the data in order to see whether cost is influenced by the size of the wind farm. The data suggests that there is no trend in project cost as a function of project capacity alone.

Capital Cost Breakdown

The breakdown of the following subsections have been analysed; turbine supply contract costs, full Balance of Plant ("BoP") costs (including civil and electrical works), civil works, electrical works, substation, grid connection and project management costs.

The turbine supply contract is the largest cost item for wind farm projects, typically being 70% to 75% of the total hardware costs. There is a clear suggestion of a trend of rising costs over time, which is in line with GH market experience. The data suggest an increase from approximately €750 k/MW to €950 k/MW (26%) between 2005 and 2006 and an increase from approximately €950 k/MW to €1050 k/MW (11%) between 2006 and 2007.

The BoP works cover all the civil and electrical works required for the project that are not included in the turbine supply contract. The BoP costs range from 100 to 800 €k/WTG (typically 100 to 350 €k/MW) and vary significantly from one project to another.

Electrical costs are a sub-set of the total BoP cost. There are no specific trends in the data other than a cost increase over time, the allocation is typically between 40 and 100 €/kW.

Civil costs are a sub-set of the total BoP cost. There is no specific trend in the data other than a cost increase over time, the allocation is typically between 50 and 150 €/kW.

Substation costs are a sub-set of the total BoP cost. The separate substation contract costs are available for 5 projects and range from 40 to 70 €/kW.

For the projects studied in this analysis the connection charge ranges from €10,000 to €300,000 per MW. There is a large variance in costs even in specific countries; for example in Scotland the grid connection charges range from €10,000 to €200,000 per MW. In Norway, this cost element is expected to be highly project specific, within a range similar to that seen for the selected European projects, possibly even greater in range.

Other development and transaction costs make up a significant percentage of the total project costs GH is not in a position to comment on these costs as they are not reviewed in a typical due diligence review. In general the total for these other costs was in the region of 10% to 20% of the overall project cost.

Operating Costs

The largest single operating cost for a wind farm is the operations and maintenance ("O&M") cost for the turbines. Other significant operating costs include both technical and commercial costs. Cost items such as land lease, property tax and use of system or grid charges are dependant on local pricing influences.

The O&M proportion of the operating costs are in the region of 15,000 to 20,000 €/MW/annum. In general GH would expect an allocation of approximately 25% to 30% of revenue (income from energy sales) for all operational costs.

5yr Prognosis

Typical breakdowns of project costs were analysed, as a percentage of the overall project cost as well as a typical historical cost range. GH has used this information to provide a general estimate of the likely cost breakdown and cost range for projects over the next 5 year period; meaning projects that will enter into turbine supply agreements and construction contracts over the next 5 years (up to 2013).

GH has summarised its opinions in the table below.

Cost Item	Typical % Range	Typical Cost Range 2007 (€k/MW)	Typical Cost Range Next 5 years (€k/MW)
TSA	60 to 70%	1,000 to 1,100	1,100 to 1,500
Total BoP	10 to 15%	150 to 350	150 to 350
Grid	5 to 15%	50 to 100	75 to 125
Other Construction	0 to 5%	25 to 50	40 to 60
Development	5 to 15%	50 to 100	50 to 100
Contingency	2 to 5%	25 to 50	40 to 60
Transaction	2 to 5%	50 to 100	80 to 120
Total	**100%**	**1,400 to 1,800**	**1,600 to 2,300**

GH typically assumes a turbine O&M cost in the region of 20,000 €/MW/annum and it would be prudent to allow for increases to a level of 25,000 €/MW/annum for the next five years to cover potential cost pressures from lack of experienced staff.

Other costs are very variable and will likely not show specific trends for increases other than typical inflationary factors. It would be prudent to assume total operational costs in the range of 45,000 to 50,000 €/MW/annum for cost forecasting purposes for the 5-year prognosis.

Mapping of Significant Participants

The top 10 manufactures in 2007 in order of MW supplied in 2007 are: Vestas; GE Wind Energy; Gamesa; Enercon; Suzlon; Siemens; Acciona; Goldwind; Nordex and; Sinovel.

GH highlights that because of high demand for turbines, the main manufacturers have recently been offering to meet delivery schedules for new orders from late 2010. For new tenders it is likely that delivery timeframes offered will now be for 2011 deliveries. As a result of the current ‘Seller’s Market’, production capacity typically relates directly to the number of turbines sold in the year; therefore for 2007 the annual production capacity was approximately 22 GW. GH is aware that turbine suppliers across the market are working to increase their production capacity in order to ease the pressure on the market, however, there are bottlenecks through the supply chain at the sub-component level.

As a result, increases in production capacity will likely remain at a relatively steady state in the short term.

Energy Assessment

The energy assessment of a project is the area over which developers and financiers will be most focused over the development process. The concept of a power station for which the fuel is entirely free is attractive. However, this advantage is balanced by the variability of the wind which, to the uninitiated, may make an investment in such a scheme appear highly risky.

In order to assess the energy production of a wind farm over the project life, it is necessary to determine accurately the long-term mean wind speed at a potential site.

The prediction of energy production of a wind farm is dependent on many inputs for which the uncertainties can be objectively defined. This area therefore lends itself to a statistical assessment of the risks associated with a project. The wind analyst will review the uncertainties associated with the assessment and will obtain a ‘standard deviation’ for the analysis that can be applied to the central estimate. The result will be a series of exceedance cases for the analysis over a short and long-term basis that can be used to assess the risk of variability in output over short and long term periods. GH typically provides its exceedance cases on a 1-year and a 10-year basis.

It is important to appreciate how sensitive the output of a wind farm is to the long-term mean wind speed at a wind farm site, for example, it might be expected that energy production for an 8 m/s site could be as much as twice that of a 6 m/s site.

It is also important to understand that banks will typically assess the level of loan that a project can support by basing its financial model on the long term P90 exceedance case. Based upon GH experience, where appropriate wind measurements have been made and diligently analysed and wind turbines with a good track record are used, it is likely that the 10-year 90% exceedance level (P90) for the wind farm production will be of the order of 10% to 15% below the central estimate (P50) of energy production for the wind farm.

Contract Strategy

The contract structure of a project is the area within which the developer has the most power to control and assign risks and any lender will be keen to see mitigation of the construction risks. Historically developers have sought to minimise risk through the use of a turnkey Engineering Procurement and Construction (EPC) Contract.

Turnkey contracts were typically let to the turbine supplier, who then let sub-contracts for the balance of plant. This is often not the lowest cost option, but provides more certainty over costs for the owner and lender. Turnkey contracts are now available in only a limited number of regions.

The second option for contracting is a limited number of separate contracts; typically covering civil works, on-site electrical works, electrical connection works and turbine supply. Such an approach is typically a cheaper option than a full turnkey contract, however, it is a more risky route as each of the individual contracts need to be very carefully defined to ensure the developer is not left with a situation where all contractors have, or claim to have, fulfilled their commitments but the developer is left with a non-operational wind farm or a wind farm which does not perform to specification.

Within this contract structure the sponsor is accepting the turnkey risk and their technical competence and financial strength must be ensured.

A third approach is a multi-contract with several contracts in each of the main work areas. Such a contract structure will typically be managed under a project management agreement, with the Project Manager being responsible for the tendering process, oversight of the designs process and day to day management of the contractors on site.

Operation & Management

It is typical for an O&M contract to be let to the turbine supplier for the duration of the defects liability period. Where the initial warranty period is only 2 years in term, the service period may extend to 5 years and cover unscheduled maintenance (repair) as well as routine servicing. After this initial contract period, the owner of the project can choose to extend the original contract, enter into a new 3rd party contract or carry out the works themselves. There are risks and benefits associated with the options and the option selected will reflect the experience and situation of each project owner.

The balance of plant works are generally covered through maintenance arrangements made by the owner with local contractors.

Project Life

Modern wind turbines are typically designed to be suitable for use within a specific envelope of climatic conditions over a 20 year design life. This lifetime assumption is generally supported by independent certification by a classification society such as Germanischer Lloyd or Det Norske Veritas, which has the primary purpose of ensuring that a design is compliant with specific safety requirements.

Despite the basis of the design and independent checks, some level of breakdown is expected over a project life as a result of imperfect manufacturing processes, external events, force majeure events and other conditions not forming part of the design basis. In addition to addressing breakdowns, as with any machinery, it is necessary to follow a maintenance and servicing programme over the project life in order to maintain the equipment in satisfactory condition.

Financial Arrangements

As part of any investment in a project, a lender will consider all areas of risk with the objective of removing, minimising and mitigating these risks within the investment transaction.

A typical loan term would be 15 years with an expected project period of operation of 20 years. The Debt to Equity ratio is typically in the region of 80:20 with a Debt Service Cover Ratio of 1.4 over the long term net cash flow using the central energy case.

1 INTRODUCTION

At the request of Enova (the "Client"), Garrad Hassan and Partners Limited ("GH") has provided technical advice on capital cost expectations for wind farm developments.

In summary, the work provides a survey of the present and future 5-year prognosis for costs and conditions facing developers and suppliers in the European wind power market. In particular it focuses on:

- investment costs and related key characteristics for projects constructed in Europe from January 2006 and after;
- a 5-year prognosis for the investment costs for wind power development;
- available production capacity among equipment suppliers;
- experience from the operation and management of existing wind power plants;
- mapping of the most significant market players and their respective market share;
- terms and conditions of the contracts between investors and technology suppliers.

The report will be used as a benchmark to support tendering for future Norwegian projects. As such, it will also provide discussion of how project characteristics can influence project cost.

The scope of work for the review was defined in the Technical Advisor's Appointment [1.1].

This report presents the findings of the review of the above areas of investigation including investment costs, project characteristics, 5 year prognosis for investment costs, operation and management, mapping of significant market participants and contracting strategy.

2 DATA USED IN THE ANALYSIS

GH has obtained data on the investment costs for 35 projects developed or in development in Europe. The projects represent to the extent possible the characteristics representative of potential Norwegian projects. In particular GH has concentrated on projects considered to have one or more of the following characteristics: steep slopes, rocky ground and remoteness.

GH has used its experience in European wind energy market and the project information provided for this study represents work undertaken by GH in connection with its consulting work in various regional offices.

The data used in this analysis are from actual projects in: France, Germany, Hungary, Ireland, Italy, Northern Ireland, Portugal, Scotland, Spain and Wales.

The turbine capacities represented in the data are typically 2 MW or above, except in one case where a mix of turbines sizes was used at the project.

A total of 15 developers is represented in the study including large scale multinational energy providers with large wind farm portfolios, medium scale developers with portfolios of around 10 projects and small scale developers with 1 or 2 projects.

A wide range of turbine manufacturers providing 2 MW plus turbines is represented, including: Vestas, Enercon, Nordex, REpower, Gamesa, GE and Siemens turbines.

The project sizes range from 5 MW to 150 MW, with the majority being over 25 MW.

The dates and planned dates for the start of commercial operations for the projects range from early 2006 to 2010. Please note that GH has not levelised the costs within this note to adjust for inflation over the time period covered by the project data; there will therefore be underlying inflationary rises in the costs within the data.

3 TOTAL PROJECT COSTS

For 22 of the projects (located in 7 countries) in the study, the full development and construction cost "Project Cost" is known. The total costs include all hardware, grid connection (where applicable), project development, financial arrangement, legal and other transaction costs for the projects. It is highlighted that within the data there are no financial costs relating to interest over the construction or operational period, or other operational costs.

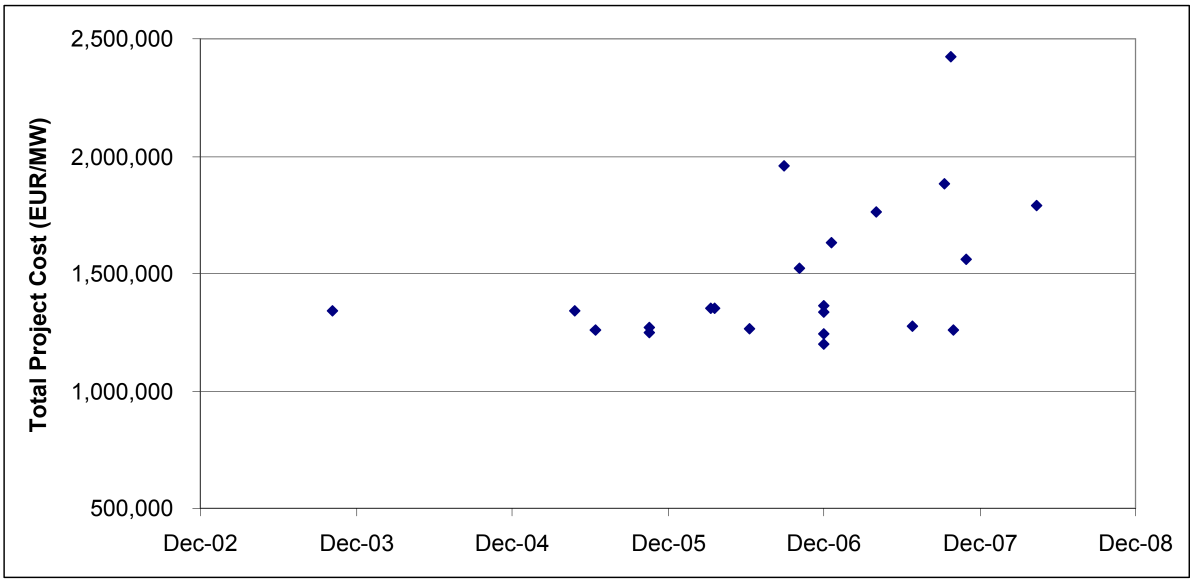


Figure 3.1: Total Project Cost per MW

Figure 3.1 shows the total Project Cost per MW for the projects with reference to the date that the turbine supply contract or turnkey construction contract was signed. GH has referenced the contract signing dates rather than completion dates, as they allow visibility of changes in contract prices over time. All of the referenced projects became operational after January 2006. Construction time for the projects within the study is between a few months and 3.5 years.

GH has not included a trend line in the graph, as the scatter of the data results in a trend that does not properly represent the data.

The Project Cost for one project is considerably higher than seen for the other projects. This project was sold to another developer before the start of construction, hence there is likely to be a developer profit within the cost. Excluding this project, the Project Costs range from €1,200,000 to €2,000,000 per MW. The variance in project cost can be explained through: increased turbine and balance of plant costs over time, variances in balance of plant charges due to terrain, remoteness and forestry, different electrical charges due to different connection voltages, varying development and lending costs.

The same data set is presented below, but with grid connection costs removed as such costs vary considerably from one site to another:

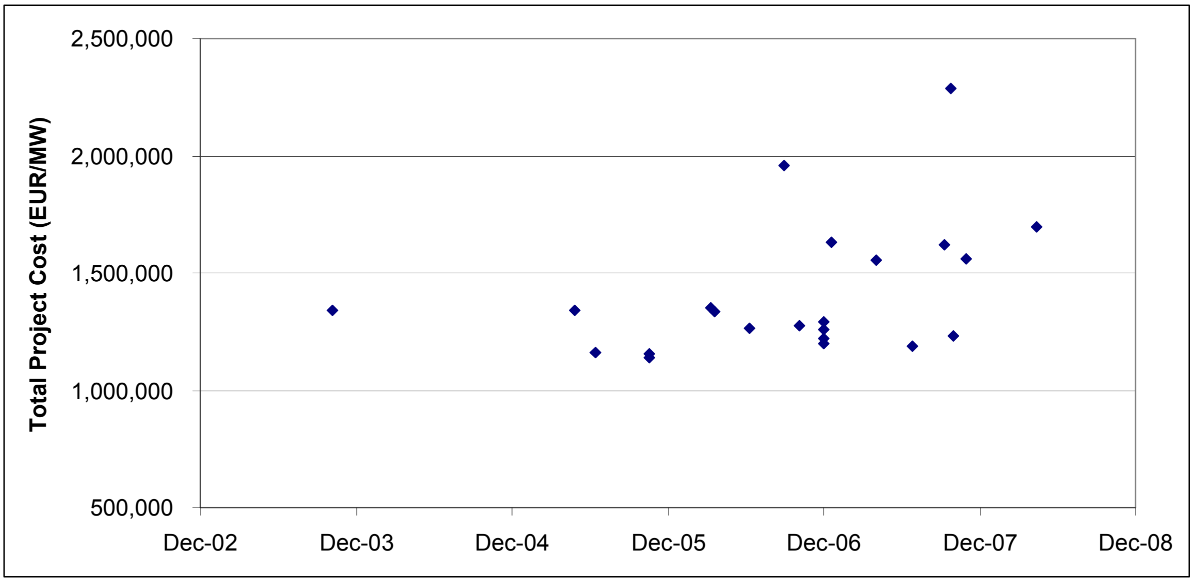


Figure 3.2: Total Project Cost per MW (grid costs removed)

Due to the variability in grid charges, the overall range of costs does not change significantly.

Figure 3.3 shows the total Project Cost (with grid costs removed) per anticipated kWh production over the life of the project, assuming a 20 year life for the project and forecast P50 annual production level. GH stresses that this is a crude calculation that does not take into consideration the operational costs associated with the projects, therefore it is not a measure of the equivalent energy price expected for these projects and is not equivalent to the 'cost of energy'.

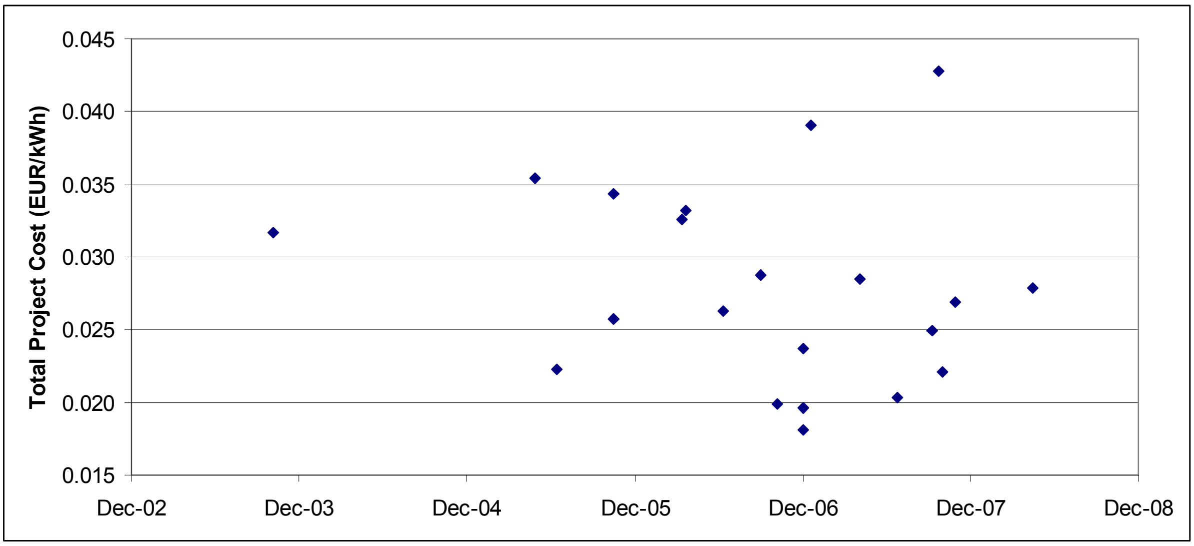


Figure 3.3: Total Project Cost per kWh (grid costs removed)

To assess the potential variation in costs in different wind regimes, GH has analysed the costs based upon the expected production of the project; Figure 3.4 shows the Project Costs per kWh against the forecast capacity factor[1] for the project. This plot suggests a trend of decreasing cost per kWh for higher capacity sites, as would be expected.

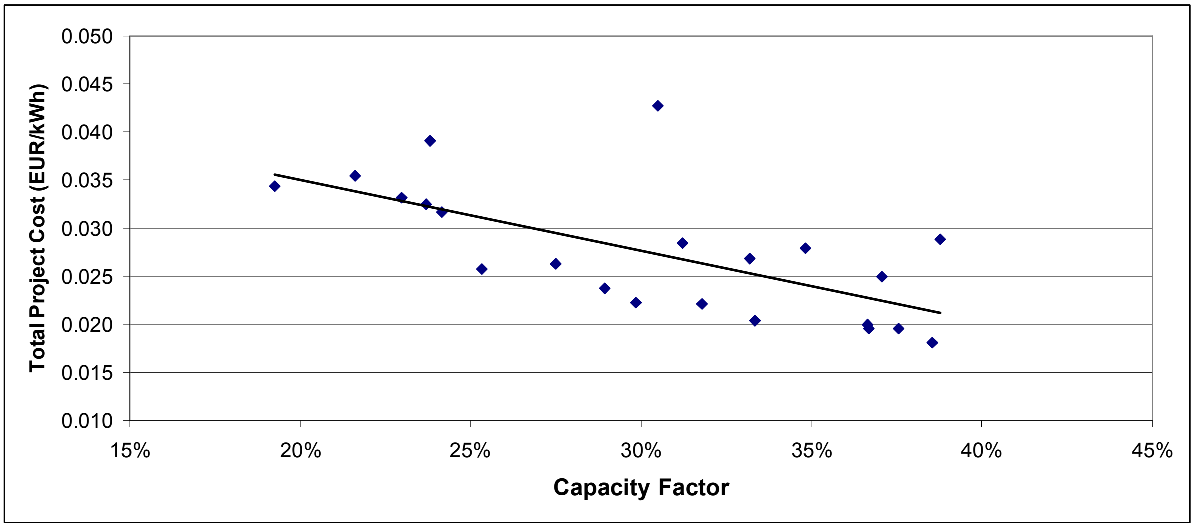


Figure 3.4: Total Project Cost per kWh vs Capacity Factor

For clarity, GH stresses that the projects in the assessment have not been selected based upon their expected production. The range of capacity factors for the 7 countries represented in the data set are shown in Figure 3.5 below.

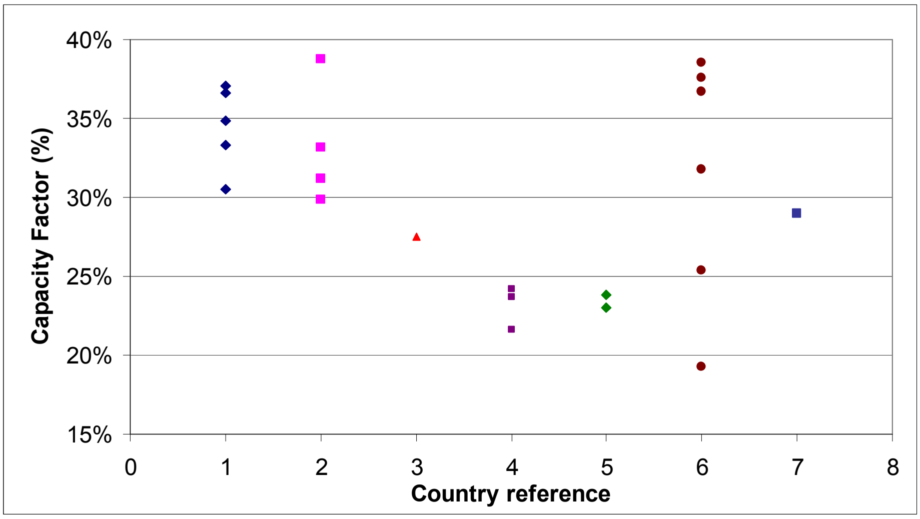


Figure 3.5: Capacity Factor for the Represented Countries

It is important to stress that capacity factor is heavily influenced by the relationship between the size of the turbine rotor and the capacity of the turbine; capacity factor cannot be used as a reliable measure of the productiveness of a particular site for this reason. It might be typical to see a range of

[1] The capacity factor is the ratio of the forecast annual energy production to the energy that would be produced if the turbine ran at full capacity all year. The number of full load hours during the year is the capacity factor multiplied by 8760 hours.

more than 5% in capacity factors for sites with very similar wind conditions. To illustrate this GH has presented a table below showing a distribution for a location with an average hub height wind speed of 8.5 m/s and the corresponding power output (power curve) of three example turbines across the wind speed range. The power curves shown are based upon but are not actual power curves from real turbines.

WTG Capacity (MW)		**2**	**2.5**	**3**
Rotor Diameter (m)		**80**	**90**	**100**
(m/s)	**Wind Speed Distribution**	**Power (kW)**		
0	-	0	0	0
1	2%	0	0	0
2	4%	0	0	0
3	6%	0	0	0
4	7%	50	75	100
5	8%	100	150	200
6	9%	250	300	350
7	9%	500	550	600
8	9%	800	850	900
9	8%	1100	1200	1250
10	7%	1450	1550	1600
11	6%	1750	1950	2000
12	5%	1950	2300	2500
13	5%	2000	2450	2850
14	4%	2000	2500	2950
15	3%	2000	2500	3000
16	2%	2000	2500	3000
17	2%	2000	2500	3000
18	1%	2000	2500	3000
19	1%	2000	2500	3000
20	1%	2000	2500	3000
21+	0%	2000	2500	3000
Gross Energy (MWh)		**8,142**	**9,510**	**10,617**
Net Energy (-20% loss)(MWh)		**6,514**	**7,608**	**8,494**
Capacity Factor		**37.2%**	**34.7%**	**32.3%**

Table 3.1: Capacity Factor Example

So although Figure 3.5 suggested a wide range of capacity factors for some of the countries shown, a significant part of the distribution is likely related to the project specifics in terms of turbine selection, layout and site specific losses. Some countries have a mix of both high and low capacity factor sites. The site with an apparently low capacity factor is a relatively low wind speed site using a turbine that is suitable for medium wind speed category sites; this will lead to a lower capacity factor than would have been seen had a low wind speed class machine (i.e. one with a larger rotor) been used.

In order to see whether cost is influenced by the size of the wind farm, Figure 3.6 shows the Project Costs per MW with the size of the project being identified. For the purpose of confidentiality, the projects have been grouped into bins with the project capacity rounded to the nearest 10 MW (e.g. a project of 16 MW would be shown as 20 MW).

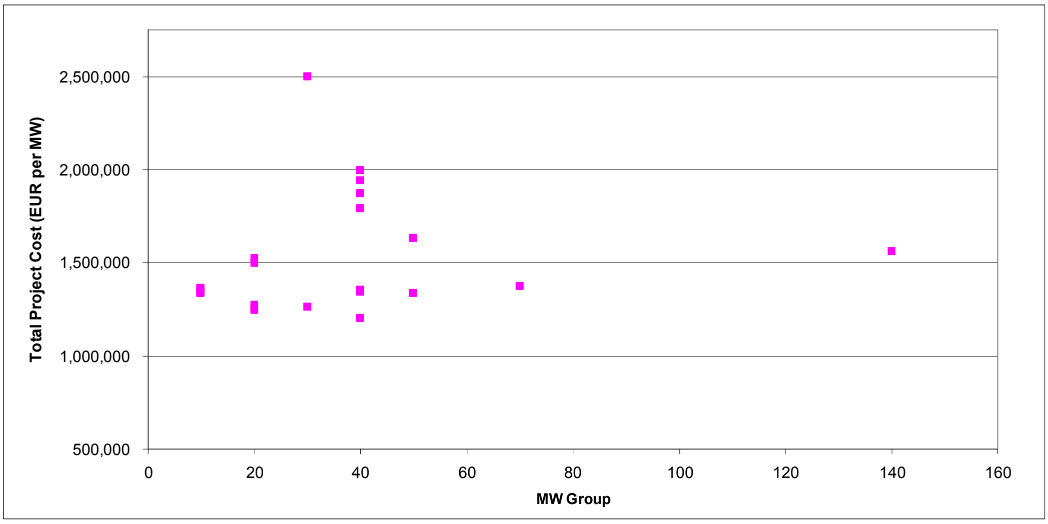


Figure 3.6: Total Project Cost per MW (Categorised by Project Size)

The data suggest that there is no trend in project cost as a function of project capacity alone.

4 CAPITAL COST BREAKDOWN

4.1 Project Costs

The following subsections analyse the breakdown of the turbine supply contract cost, full Balance of Plant ("BoP") costs (including civil and electrical works), civil works, electrical works, substation, grid connection and project management costs.

There are two main types of contract structures for the projects: full Engineer Procure and Construct ("EPC") contracts, and multi-contract structures. The full EPC contract structure covers the construction of the whole project up to the point of grid connection and is typically entered into between the wind farm developer and turbine supplier. This contract structure is now rarely used in the current European market. In a multi-contract structure the turbine works and BoP works will be split into separate contracts with interfaces, and the BoP works might be further split into multiple contracts. These contracts are further discussed in Section 7 of this report.

Of the data used in this analysis 9 projects are based on an EPC structure and 26 projects are based on a multi-contract structure. Accordingly, cost breakdowns were not available for 9 of the projects and available for 26 of the projects.

A typical breakdown of cost is given below in Tables 4.1a and 4.1b, based on data from 8 selected projects where costs in all areas are known. These tables show either the full BoP cost or the individual works contract costs (civil and electrical); this is because each project will have one main BoP contract or multiple contracts. In some cases substation costs are under a separate contract, hence shown outside of the total BoP.

Project Cost Item	1	2	3	4	5	6	7	8	Average
TSA	53%	63%	72%	70%	73%	58%	59%	62%	**64%**
Total BoP	14%	9%	-	-	12%	-	-	-	**12%**
Electrical Cost	-	-	4%	4%	-	6%	6%	2%	**4%**
Civil Cost	-	-	8%	5%	-	17%	9%	15%	**11%**
Substation	3%	-	3%	-	4%	-	3%	4%	**4%**
Grid	14%	16%	7%	5%	-	8%	1%	-	**9%**
Other Construction	2%	0%	1%	-	4%	2%	3%	3%	**2%**
Development	10%	4%	0%	9%	4%	3%	13%	9%	**7%**
Transaction	-	5%	2%	3%	2%	4%	2%	-	**2%**
Contingency	3%	3%	3%	5%	-	2%	4%	4%	**3%**
Total	**100%**	**100%**	**100%**	**100%**	**100%**	**100%**	**100%**	**100%**	

Table 4.1a: Overall Cost Breakdown (%)

Project Cost Item	1	2	3	4	5	6	7	8	Average
TSA	1,004	965	914	1,245	1,138	736	797	1,012	**977**
Total BoP	270	137	-	-	195	-	-	-	**75**
Electrical Cost	-	-	46	69	-	75	85	39	**39**
Civil Cost	-	-	100	90	-	217	125	237	**96**
Substation	49	-	41	-	64	-	47	69	**34**
Grid	265	246	90	92	-	96	15	-	**100**
Other Construction	29	4	16	-	60	26	36	52	**28**
Development	194	57	5	159	66	35	173	150	**105**
Transaction	7	71	30	56	39	48	23	4	**35**
Contingency	64	44	36	81	-	25	53	68	**46**
Total	**1,884**	**1,524**	**1,277**	**1,791**	**1,562**	**1,259**	**1,352**	**1,631**	**1,535**

Table 4.1b: Overall Cost Breakdown (€k/MW)

Specific costs for the individual items are discussed in the following sections of this report.

Within the above tables it is noted that grid costs are not shown for several of the projects. These costs may have been met by the grid operator or recouped through an annual fee.

4.1.1 Turbines

The turbine supply contract is the largest cost item for wind farm projects, typically being 70% to 75% of the total hardware costs (hardware is the sum of the TSA, BoP and grid connection cost). Within the European market, the Turbine Supply Agreement ("TSA") cost will typically include the supply, delivery and installation of the wind turbines, plus initial warranty.

Figure 4.1 shows the turbine supply cost per MW for the projects where the cost is known (28 projects). The cost includes the turbine (rotor, hub, nacelle and tower), transport, installation and commissioning.

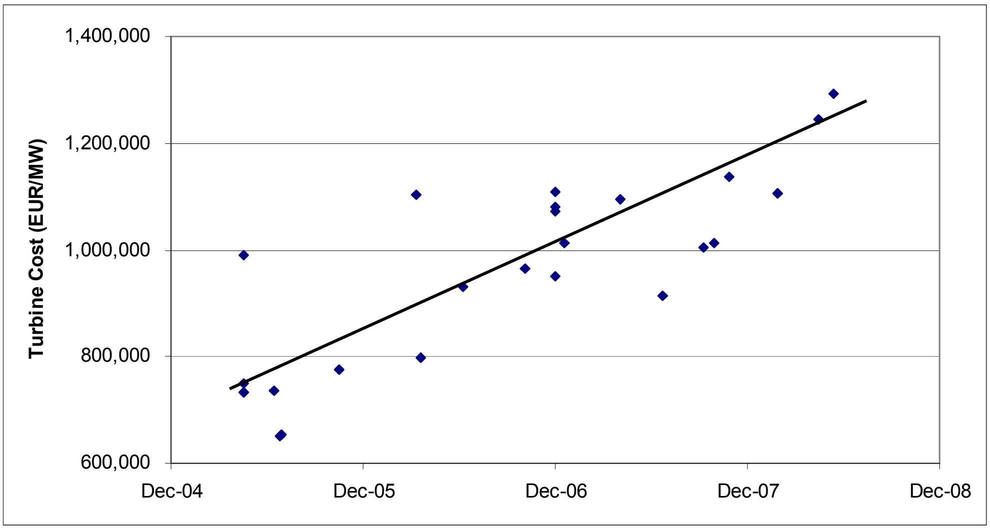


Figure 4.1: TSA costs per MW

There is a clear suggestion of a trend of rising costs over time, which is in line with GH market experience. The data are too limited to obtain reliable trends, but suggest an increase from approximately €750 k/MW to €950 k/MW (26%) between 2005 and 2006 and an increase from approximately €950 k/MW to €1050 k/MW (11%) between 2006 and 2007.

GH has reviewed the data to see if there are specific trends for pricing based upon the turbine model capacity; there were none.

4.1.2 Balance of Plant Cost

The BoP works cover all the civil and electrical works required for the project that are not included in the turbine supply contract. The works generally covered under a BoP contract include: access roads, crane pads and laydown areas, turbine foundations, turbine transformers (although these are sometimes included in the turbine supply contract), power collection network, substation and meteorological mast. The total BoP cost is known for 27 projects.

As the infrastructure is typically dependent on the number of turbines and not the capacity of the turbine, Figure 4.2 shows the BoP cost per turbine. There is a lot of scatter in the data, so the trendline shown is indicative only.

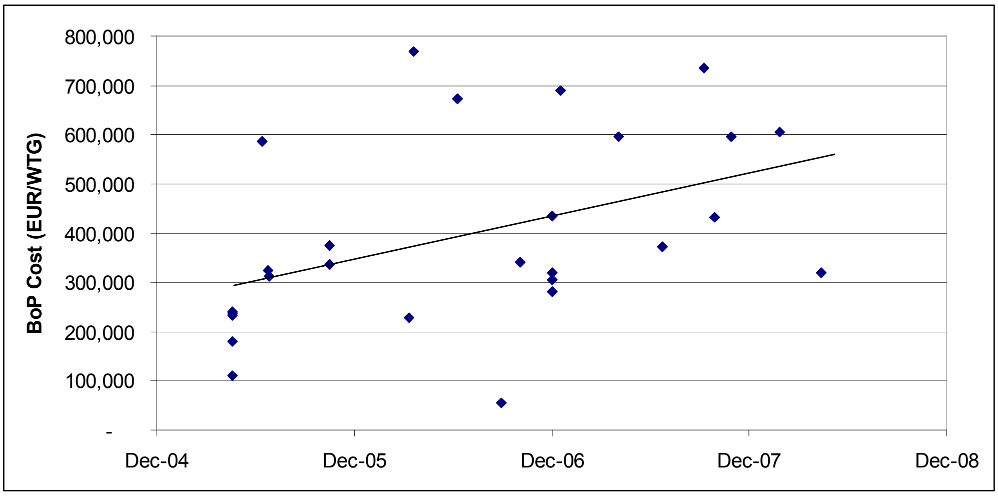


Figure 4.2: BoP costs per WTG

The BoP costs range from 100 to 800 €k/WTG (typically 100 to 350 €k/MW) and vary significantly from one project to another. To preserve confidentiality, GH has not shown the full data set of BoP costs per Wind Turbine Generator ("WTG"). To demonstrate the lack of specific trend by turbine size, GH notes that the BoP cost per turbine (for the 2 MW turbines) generally ranged between 100 and 250 €/kW.

GH has also reviewed the overall BoP cost as a function of project capacity, but no specific trend was noted. There is some evidence of higher costs for the Scottish and Italian projects than with projects in the other regions reviewed.

The BoP price will also be driven by commodity price increases, with sensitivity to the costs of steel, copper, aluminium, concrete and aggregates. Labour market costs will also impact the price of these works over time. Review of historic pricing per MW suggests increases in the region of 50 €k/MW/annum or 100 to 150 €k/WTG/annum depending on the turbine capacity. It would be prudent to assume similar price rises in future years.

Electrical Works

Electrical costs are a sub-set of the total BoP cost.

For 18 of the projects analysed, the contracting structure split the BoP into separate contracts for the civil and electrical works. The electrical works contracts normally cover:

- turbine transformers (dependant on requirements in the TSA);
- HV electrical cabling between turbine transformers and substation;
- substation electrical equipment including switchgear and main transformers.

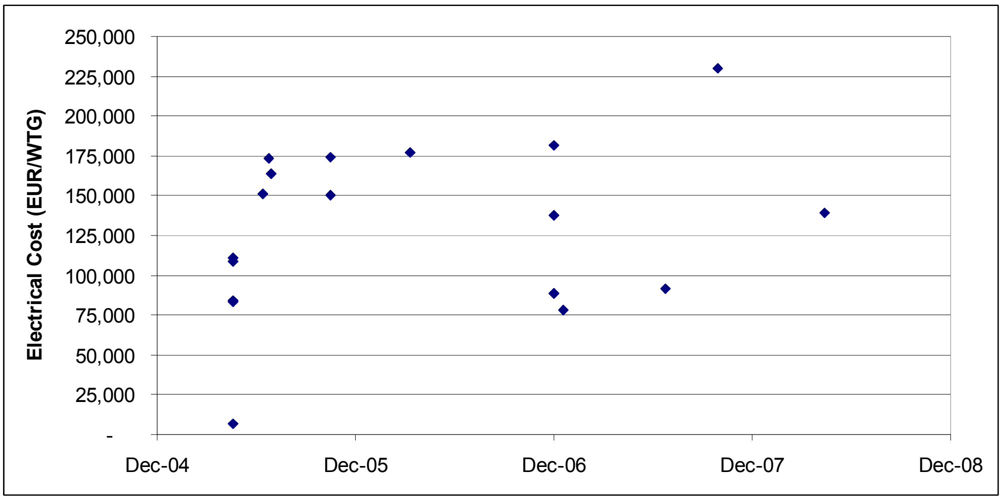


Figure 4.3: Electrical Works Costs

Figure 4.3 above shows a large variance in the electrical costs per turbine, with a trend suggesting costs increasing over time (based on the movement in the top of the range costs over time). The large variance in the electrical costs is considered to be related mainly to the connection requirements of the project and the requirements under the electrical contract.

In order to maintain confidentiality of the data used in the analysis, GH has not shown the above costs on a per MW basis. GH has also not shown this plot as there are no specific trends in the data other than a cost increase over time as can be seen from the figure above. The allocation is typically between 40 and 100 €/kW.

GH has reviewed the data to see whether there is any relationship between the costs for electrical works and the total size of the plant (in MW). This trend was not apparent in the data as the costs were simply variable; this is expected as other project conditions will influence costs, such as the balance of overground and underground cabling and the distance of the cable routes on the site.

Civil Works

Civil costs are a sub-set of the total BoP cost.

Civil works contracts typically cover the construction of the project access roads, turbine and transformer foundations, lay down areas and construction of the substation building. The civil costs from project to project will vary due to differences in the local conditions. The length of site roads, steepness of slopes, requirement for construction of any bridges, forestry, geology and foundation requirements will all have an effect on the cost of the civil works contract. Figure 4.4 below shows the data for the 18 projects for which data are available.

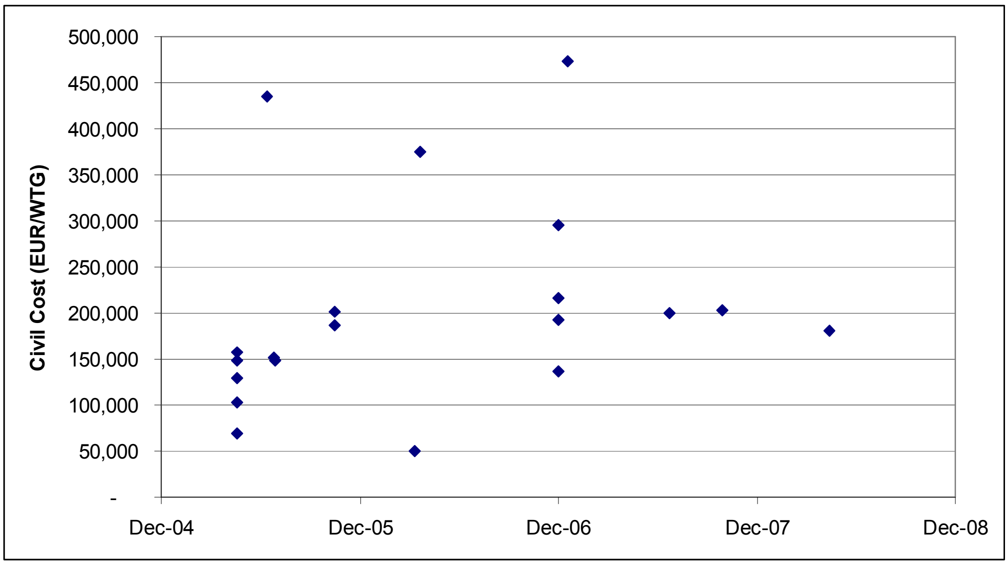


Figure 4.4: Civil Works Cost

As with the electrical costs, GH has not shown the above costs on a per MW basis. There is no specific trend in the data other than a cost increase over time as can be seen from the figure above. The allocation is typically between 50 and 150 €/kW.

Substation Works

Substation costs are a sub-set of the total BoP cost.

Substation contracts typically cover the construction of the substation building and installation of all electronic equipment (including main transformers) depending on project requirements. The separate substation contract costs are available for 5 projects and range from 40 to 70 €/kW.

The different connection requirements at different projects will be the main influencing factor in the variance of cost. Also some items that could be considered as the substation contractor's scope of work may be covered under the civil and electrical contracts.

4.1.3 Grid Connection

There are various mechanisms through which projects are able to attain grid connection. The process is typically dependent upon the country the project is located, whether connection is to a transmission or distribution network and the size of the project. The method of payment may be an up front fee or an annual connection charge throughout the life of the project. In some regions where local energy generation is specifically required, connection charges may be waived.

GH has access to 19 grid connection charges showing a large variation in connection costs. What is not always highlighted in the information used for the study is whether the connection charge is an up-front fee, or whether there will be further yearly charges included. For the projects studied in this analysis the connection charge ranges from €10,000 to €300,000 per MW. There is a large variance in costs even in specific countries; for example in Scotland the grid connection charges range from €10,000 to €200,000 per MW.

In Norway, this cost element is expected to be highly project specific, within a range similar to that seen for the selected European projects, possibly even greater in range.

4.1.4 Development and Transaction

Other development and transaction costs make up a significant percentage of the total project costs and consist of the following items:

- Development costs including: land options, wind assessment, site studies, equipment tendering, preliminary engineering, environmental assessment, permit applications and other site specific costs.

- Transaction costs including: legal fees, bank fees, advisors fees and insurance costs.

GH is not in a position to comment on these costs as they are not reviewed in a typical due diligence review. In general the total for these other costs was in the region of 10% to 20% of the overall project cost.

GH has data on the development costs (cost of initial studies and work to develop the project to the time of financing) for 10 of the projects in the study; these varied between €50,000 and €200,000 per MW or between 5 and 15% of the overall project cost. There appears to be no correlation between project size and development cost, which is to be expected as some developers are expected to take a profit margin from the project when it is financed.

There are various parameters that will affect the development costs. The experience and the size of the developer will have an effect in terms of available resources within the company to perform the majority of the development work rather than subcontracting out the work. The site conditions will also determine to a large extent the level of the investigations required.

GH understands that projects in Norway to date have been developed primarily by Norwegian developers. If the policy environment is found to be attractive to wind development, it can be expected that there will be increased levels of interest from European developers. This might in turn bring different types of development models to the market, with increased interest in early sale and acquisition of development sites, and equity investment structures. Many of the more established markets in Europe are now dominated by sophisticated financial investors, who will acquire projects during the development stage, putting them into portfolios of projects in order to benefit from economies of scale in construction and financing costs. This may lead to an increase in the level of early stage developer cost being assumed within the financial structuring.

It is possible that increased development costs from an early acquisition project (e.g. developer buys a site with a lease and wind assessment) will be offset by the cost efficiencies in other areas (e.g. turbine contract costs) as a result of the negotiating power of a large developer. The effect may therefore be neutral overall.

4.1.5 Contingency

The level of budget contingency will vary depending on the contract structure used and the sensitivity to cost overrun within the financial structuring. GH would typically expect a contingency of:

- 1 to 2% of the hardware cost for a turnkey contract structure,
- 3 to 5% of the hardware cost for a multi contract structure (< 5 main contracts),
- 5 to 10% of the hardware cost for a multi contract structure (> 5 main contracts).

The level of contingency rises with the number of contracts, to account for the increased interface risks associated with this type of structure and because it is likely that the owner will have additional responsibilities and risks. It is likely that the cost saving achieved by using this contract route is balanced by the increased contingency required, hence there may be no overall saving in terms of total project costs within the financial model. However, if the contingency is not used, then there will be an upside in terms of equity saving for the project developer. If the multi contract approach does not bring a reduction in the overall contract price compared to using a small number of contracts, then the overall project cost for this contract option may be higher once the higher contingency level is taken into account.

5 OPERATING COSTS

The largest single operating cost for a wind farm is the operations and maintenance ("O&M") cost for the turbines. Other significant operating costs include both technical and commercial costs. Cost items such as land lease, property tax and use of system or grid charges are dependant on local pricing influences.

Civil and electrical maintenance costs will vary due to site conditions and site design. If the site is remote and hilly, the maintenance cost of the site roads might be greater than they would be at a flat site, especially if the region experienced high levels of precipitation.

In general GH would expect an allocation of approximately 25% to 30% of revenue (income from energy sales) for all operational costs. This would include:

Cost Item	Typical levels	Unit
Turbine maintenance, breakdown and repair	30,000 to 60,000	€/WTG/annum
Civil maintenance	5,000 to 30,000	€/project/annum
Electrical maintenance	10,000 to 50,000	€/project/annum
Operational management and monitoring	1,000 to 7,000	€/MW/annum
Company administration	1,000 to 6,000	€/MW/annum
Land Lease	2.5 to 4.5	% of revenues
Insurance	3,000 to 7,000	€/MW/annum
Grid connection charges	Variable	-
Taxes	Variable	-
Community funding	Variable	-
Services (electricity and water)	Variable	-
Training	Variable	-
Environmental monitoring	Variable	-
Health and Safety monitoring	Variable	-

Table 5.1: Typical Operations Costs

Further discussion on specific costs is provided below.

5.1 O&M Costs (Turbines)

Figure 5.1 shows annual maintenance costs for the turbines, for the 15 projects where this information was available. The work covered by this cost will cover the schedule servicing and repair work on the turbines, including all labour, consumables and spare parts. Also included will be operational monitoring of the wind farm over a remote computer system.

This data provided is for the initial contract period for the turbines, which usually extends for between 2 and 5 years after the project is installed. Within this discussion GH refers to this period as the 'Warranty Period'. This cost is typically fixed by contract with the turbine supplier. Further discussion on O&M is contained in Section 8 of this report.

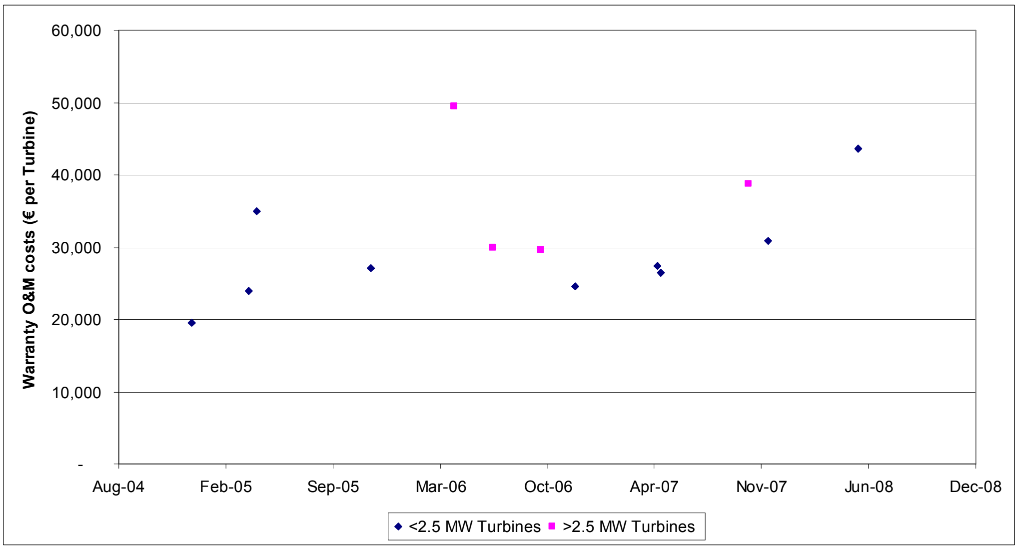


Figure 5.1: Annual warranty O&M costs

The data indicate a trend for the Warranty Period O&M costs increasing over time; this is in line with GH observations in the market. The O&M costs are related to the turbine size and this cost will be fixed at the time of purchase of the turbines.

GH would typically expect the O&M cost during the Warranty Period to be in the region of 15,000 to 20,000 €/MW/annum. The cost depends on the capacity of the turbine and site specific details.

The O&M costs after the Warranty Period will cover the breakdown and repair costs after the initial manufacturer's warranty has expired. As the data that GH has obtained is based upon initial forecast costs and not actual costs, GH has not presented a specific trend graph within this report.

It is useful to highlight that the O&M work requirements will vary depending on the type of turbine selected and the type of site that the turbine is located on. Turbines without gearboxes (direct drive) will benefit from a reduced risk of drive train issues, but will still require attention on other hydraulic and electrical components. Turbines in high wind sites or high wind turbulence sites might experience a more rapid rate of wear and tear of components than more benign sites. These characteristics should be considered as part of any project specific economic review.

GH would typically expect the O&M cost after the initial warranty to also be in the region of 15,000 to 20,000 €/MW/annum. Many developers will cater for variability in this figure by additional reserves and also a rising allowance in later years to cater for the increased uncertainty in fault rates and repair costs over time. It would be prudent to model 25,000 to 30,000 €/MW/annum to understand the sensitivity to this figure.

5.2 Civil and Electrical Maintenance Costs

As the data that GH has obtained on civil and electrical maintenance costs are based on initial forecast costs and not actual costs, GH has not presented specific trend graphs within this report.

The civil maintenance cost assumptions made by developers range from €500 to €2,000 per turbine per year. The civil maintenance includes: maintenance of site roads, checking turbine foundations, drainage and maintenance of the substation/control building.

Electrical maintenance cost assumptions made by developers range from €1,000 to €3,000 per turbine per year. Maintenance of the electrical equipment includes all equipment from the point of connection to the grid to the point of interface with the turbine (this can be before or after the turbine transformer). The equipment will typically include the main transformer, switch gear, cabling, fibre optic cable and turbine transformers.

5.3 Insurance Costs

Insurance costs for 11 projects have been extracted. The range of insurance costs vary from 3,000 to 7,000 €/MW/annum.

GH has sought advice regarding trends in insurance pricing and understands that costs will depend on the: type, age and location of plant as well as track record of the turbine and operator. The level of deductible and business interruption cover selected by the operator will also influence the cost.

In additional there are local and commercial influences on the cost including: stamp duty, insurance premium tax, emergency service charges and broker fees.

5.4 Land Lease

The wind farm owners will typically lease the land from the land owners on which the wind farm equipment is installed. The data from the study includes land lease rates for 7 projects, showing some regional variations in the revenues paid to the land owners. The data indicates that land owners receive around 2.5 to 3.0% revenues in the UK, 3 to 4% of revenues in Ireland and 4.5% of revenues in Italy. GH is also aware that German land owners have received approximately 4.5% of revenues. The average % of revenues for the projects in the study is 3.3%.

5.5 Operators Salary

Wind farm owners and developers will often subcontract the day to day management of the operations of the wind farms. The operator’s salary information was available for 7 projects in the study. The fees for this service ranges from 1,000 to 7,000 €/MW/annum, with an average of 3,000 €/MW/annum for the projects in the study.

5.6 Management Fees

Asset management fees are often included in the operations costs for the wind farms to cover all banking, legal and secretarial requirements amongst other things. This fee is normally paid to the project company. Within this study management fees are known for 8 projects, these fees range between 1,000 and 6,000 €/MW/annum averaging approximately 3,000 €/MW/annum.

5.7 Grid Charges

Projects will often have to pay an annual fee to the grid operator as a charge to use the network to transport project power. The charges might be referred to as ‘use of system’ or grid rental’ and are expected to vary from region to region and project to project. No specific trend was established from the data available to GH.

5.8 Other Costs

To be able to monitor and control the wind farm, there is a requirement to be able to remotely access the wind farm. The communications cost assumption ranges from 2,400 to 20,000 €/project/annum. The communications cost is available for 9 of the projects.

Turbines will import energy from the grid when they are not operating due to low wind or are being serviced by technicians. The electrical consumption cost values are provided for 11 of the projects ranging from 350 to 3,500 €/WTG/annum, averaging 2,200 €/WTG/annum.

Other costs to be incurred, and not specifically covered by the above discussion, will include:

- Health and Safety monitoring;
- Accounting and advisers;
- Bank fees;
- Training;
- Communications upgrades;
- One off purchases.

5.9 Example project

GH has provided an example of an O&M budget for a theoretical project, to demonstrate how the above cost items might appear within the budget. In this case, the project is assumed to be 50 MW.

Item	Cost	Per
Turbine maintenance and repair	20	MW
Electricity usage	1	MW
Insurance	5	MW
Local taxes	2	MW
Grid charges	2	MW
Bank fees	1	MW
Land payments	3	% of revenue
BoP maintenance	50	Project
Operations management	100	Project
Administration management fees	100	Project
Training, environment and safety	50	Project
Community funds	20	Project

Table 5.2: Operational cost assumptions per annum(€000's or %)

6 5-YEAR COST PROGNOSIS

Typical breakdowns of project costs were given in Section 4, as a percentage of the overall project cost as well as a typical historical cost range. GH has used this information to provide a general estimate of the likely cost breakdown and cost range for projects over the next 5 year period; meaning projects that will enter into turbine supply agreements and construction contracts over the next 5 years (up to 2013).

GH has summarised its opinions in the table below and discussed the different cost areas in more detail after the table.

Cost Item	Typical % Range	Typical Cost Range 2007 (€k/MW)	Typical Cost Range Next 5 years (€k/MW)
TSA	60 to 70%	1,000 to 1,100	1,100 to 1,500
Total BoP	10 to 15%	150 to 350	200 to 350
Grid	5 to 15%	50 to 100	75 to 125
Other Construction	0 to 5%	25 to 50	40 to 60
Development	5 to 15%	50 to 100	50 to 100
Contingency	2 to 5%	25 to 50	40 to 60
Transaction	2 to 5%	50 to 100	80 to 120
Total	**100%**	**1,400 to 1,800**	**1,600 to 2,300**

Table 6.1: Cost Prognosis

6.1 Turbine Cost

It is hard to predict how the turbine supply market will develop and change with time, as there are many influencing factors. GH suspects that the trend of large price increases seen in recent years will not continue in all markets, as it is unlikely that there will be further increases in policy based support mechanisms for renewable energy pricing; without changes in price it is unlikely that significantly higher turbine costs will be economic in project terms. The higher end of the range might be occupied by smaller projects. GH does not expect the mean price to be the mean of the range.

In the short term, production capacity is expected to remain pressured from high demand. In 2007 the installed capacity was in the region of 20 GW, representing a 30% increase of the previous year's installation figures. Some of this increase has been a result of increased production capacity and some will have been a result of the trend to increasing average turbine size; GH does not have a specific breakdown of the influence of these factors. In coming years it is expected that production capacity will continue to grow, but likely at a lower rate than in recent years. GH expects that by 2013 the rate of installations, and hence production capacity, will increase to between 30 and 32 GW per annum. This is a highly uncertain estimate as information of manufacturers' future plans are unknown, markets will likely be influenced by further acquisitions and the impact on Chinese manufacture on Western markets is at present unknown. While this estimate does indicate the expected continued growth in global markets, it is important to stress that established markets and emerging markets will continue to grow and will be impacted by a trend towards site repowering. The pressures on global supply are not expected to ease in the short term. GH understands that production capacity for the larger manufacturers is generally booked out to late 2010.

GH has carried out some modelling for an example project, in which each increase of 10% in the cost of a turbine requires an additional €3/MWh increase in energy price. If the energy price remains constant, an increase of 10% in the turbine price leads to a drop in the level of bank debt that the project can support and a corresponding 2.5% decrease in the equity rate of return. The conclusion drawn from this is that, in markets where energy prices are fixed through feed in tariffs or equivalent, the impact of price rises on the developer's bottom line could be significant. While this analysis is only indicative and does not take into consideration the structuring that might take place in actual transactions to absorb some of the impact of such changes, it is a useful indication of the impact of price increases.

It is possible that further increases in oil prices will lead to increased prices in the base cost of energy, enabling project prices to rise further. Such rises may take time to feed back through to power offtake contract pricing, unless project lenders are willing to take on market pricing (merchant) risk and there are indications in some markets that lenders are willing to take on some element of this risk. Taking these factors into consideration, GH therefore expects prices to continue to rise in the next few years to reflect continued pressure in supply markets and commodity inflation. GH expects that prices in different markets will exhibit different trends based upon energy pricing policy, but that increases will likely remain in the range €1,100 per kW to €1,500 per kW over the next five years.

GH anticipates that pricing for Norwegian projects will be within the range of costs seen in Europe, as it is unlikely that there will be country specific technical requirements other than cold weather packages. Until there is a significant market in Norway, it can be expected that manufacturer overheads (i.e. the costs of supporting sales and service teams in the country) will be greater than in established markets, especially those with stable renewable policy, and that this will be reflected in pricing at the higher end of the typical cost range.

6.2 BoP Cost

The historical BoP costs have varied considerably from project to project, with the majority of project costs within the range from 150 to 350 €k/MW in 2007.

The BoP price will be driven by commodity price increases, with sensitivity to the costs of steel, copper, aluminium, concrete and aggregates. Labour market costs will also impact the price of these works over time. Review of historic pricing per MW suggests increases of 50 €k/MW/annum. It would be prudent to allow for some similar price rises in future years.

In Table 6.1 above, GH has not shifted the overall price range significantly to take account of future price increases. GH does however expect a concentration of projects at the higher end of this range over time.

It is possible that the Norwegian projects costs will be influenced by:

- reduced road transport from proximity to coastal ports;
-
- ease of access to rock base for foundations;
- access roads from steep slopes;
- staff costs due to remoteness of sites;
- increase rock blasting for access roads;
- accelerated schedules to avoid winter construction.

It is not possible to estimate the overall balance or impact on price from the above factors, which will be very site specific for future projects. GH has not found specific reference to higher labour costs in the Norwegian market than elsewhere in Europe. If there were clear differences in labour market costs, it would be expected that these would have an influence on BoP costs.

6.3 Grid Connection

Historical grid connection costs have been variable. Costs will likely trend upwards due to the exposure to materials costs and this has been taken into consideration in the GH cost range above. This cost is also expected to rise since the cheaper connection options are used first.

6.4 Other Costs

Other costs: transaction, contingency costs and other general construction costs are expected to trend up in the future, in line with general increases in other line items as they are related to the main cost items above.

Development costs are not linked to commodity pricing and are less likely to see significant increases. Indeed, there is some evidence that the value placed on development – “development price” – may actually decrease.

6.5 Operating Costs

Future turbine maintenance prices may vary considerably through commercial influences as well as the price of underlying goods. GH typically assumes a turbine O&M cost in the region of 20,000 €/MW/annum and it would be prudent to allow for increases to a level of 25,000 €/MW/annum for the next five years to cover potential cost pressures from lack of experienced staff.

Other costs are very variable and will likely not show specific trends for increases other than typical inflationary factors. It would be prudent to assume total operational costs in the range 45,000 to 50,000 €/MW/annum for cost forecasting purposes for the 5-year prognosis.

7 MAPPING OF SIGNIFICANT MARKET PARTICIPANTS

7.1 Manufacturers

Table 7.1 shows the top ten manufacturers in 2007, based upon global market share:

Manufacturer	Accumulated supply (MW) at end 2003	2004	2005	2006	2007	Annual supply (MW) 2007
Vestas, DK[1]	14,797	17,580	20,766	25,006	29,508	4,503
GE Wind Energy, US	4,428	5,346	7,370	9,696	12,979	3,283
Gamesa, ES	4,965	6,438	7,912	10,259	13,306	3,047
Enercon, D	5,758	7,045	8,685	11,001	13,770	2,769
Suzlon, India	463	785	1,485	2,641	4,724	2,082
Siemens, DK[2]	3,367	3,874	4,502	5,605	7,002	1,397
Acciona, ES[3]	N/A	N/A	372	798	1,671	873
Goldwind, PRC[3]	N/A	N/A	211	627	1,457	830
Nordex, D	2,219	2,406	2,704	3,209	3,886	676
Sinovel, PRC[3]	N/A	N/A	N/A	75	746	671
Other manufacturers	6,256	7,291	6,578	9,193	11,269	2,076
Total	**42,253**	**50,765**	**62,108**	**78,110**	**100,318**	**22,207**

Note 1 Historical figures include both Vestas and NEG Micon, who merged in 2004.
Note 2 Siemens acquired Bonus in December 2004.
Note 3 Figures for Acciona, Goldwind and Sinovel are not available for some years
Source BTMConsult ApS – March 2008

Table 7.1: Largest manufacturers' market share (based on worldwide sales, end of 2007)

Table 7.2 shows the top 5 manufacturers of >1.5 MW turbines and >2.5 MW turbines in 2007, based upon global market share.

Position	1.5 + MW	Total MW Supplied / Market Share	> 2.5 MW	Total MW Supplied / Market Share
1	Vestas, DK	4,040 / 34.4%	Vestas, DK	995 / 84.7%
2	Enercon, GE	2,094 / 17.8%	Siemens, DK	104 / 8.9%
3	Gamesa, ES	2,028 / 17.3%	RePower, GE	30 / 2.6%
4	Siemens, DK	1,201 / 10.2%	WinWind, SF	27 / 2.3%
5	Suzlon, IND	796 / 6.8%	Enercon, GE	18 / 1.5%

Source: BTMConsult ApS – March 2008

Table 7.2: Top 5 manufacturers of 1.5 – 2.5 MW and >2.5 MW class turbines

GH has provided commentary on the main manufacturers that are active in the European market within the following sections of this report.

GH highlights that because of high demand for turbines, the main manufacturers have recently been offering to meet delivery schedules for new orders from late 2010. For new tenders it is likely that delivery timeframes offered will now be for 2011 deliveries.

As a result of the current ‘Seller’s Market’, production capacity typically relates directly to the number of turbines sold in the year; therefore for 2007 the annual production capacity was approximately 22 GW as shown in Table 7.1 above. GH is aware that turbine suppliers across the market are working to increase their production capacity in order to ease the pressure on the market, however, there are bottlenecks through the supply chain at the sub-component level. These typically relate to specialist items such as bearings. As a result, increases in production capacity will likely remain at a relatively steady state in the short term. Longer term increases are very difficult to predict and will be heavily influenced by the impact of Asian suppliers in the European market; at this time there is significant uncertainty as to how these markets will develop on a global basis.

7.2 Vestas

Vestas first began serial production of wind turbines in 1980 and erected the first eighty 55 kW models, soon after. Following-on from the end of the ‘Californian Wind Rush’ in 1986 the company retracted from the American market and established Vestas Wind Systems A/S.

In Spain, Vestas Wind Systems A/S joined forces with the Spanish group Gamesa and the development company SODENA to form a joint venture company - Gamesa Eólica S.A. of which Vestas Wind Systems A/S owned a 40 per cent share.

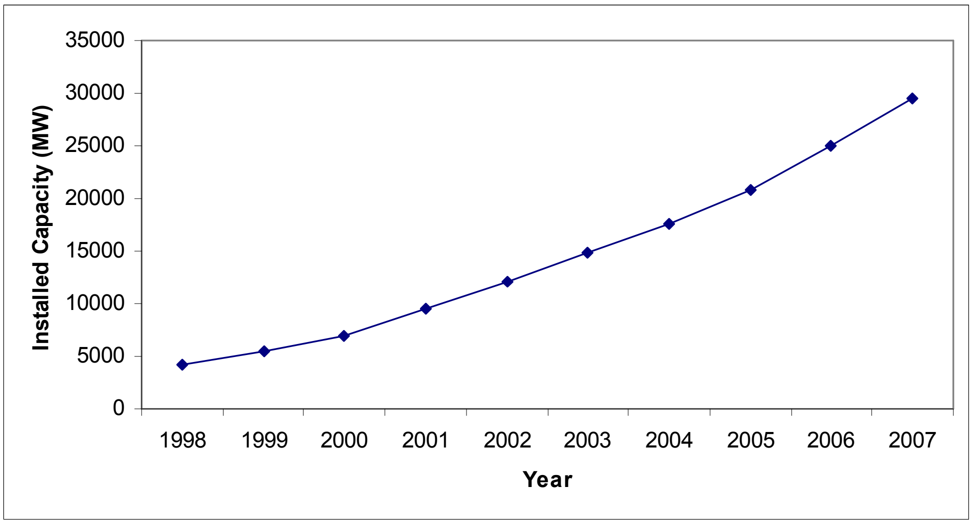
In 1998, Vestas was floated on the Copenhagen Stock Exchange to generate capital for growth for new facilities including a new fibreglass production plant and a new assembly plant.

In December 2001 Vestas Wind Systems A/S sold its 40% share of Gamesa Eólica S.A. to Sesa Sistemas Electricos S.A., a company in the Gamesa Group.

In 2004, Vestas acquired almost all of the shares of NEG Micon to effectively form a merger between the two companies. With the Vestas takeover this consolidated the company’s position as the world’s number one wind turbine manufacturer.

At the time of writing, the Vestas website states that the group has over 15,000 employees.

Figure 7.1 present the cumulative installed capacity of Vestas. The capacity installed in 2007 was 4,502 MW.



Source: BTM Consult ApS

Figure 7.1: Cumulative installed capacity of Vestas

The current Vestas range includes the following turbine models:

Vestas V52	850 kW
Vestas V82	1.65 MW
Vestas V80	2.0 MW (1.8 MW in N. America)
Vestas V90	2.0 and 1.8 MW
Vestas V90	3.0 MW

Current Vestas turbines, with the exception of the V82, are variable-speed and pitch-regulated turbines. Variable-speed is facilitated through the use of wound rotor, doubly-fed generators. The V82 is a NEG Micon design and is an active stall, fixed speed turbine with simple induction generator. It is understood that Vestas are developing the V100 which is a stretched version of the V90 3.0 MW.

As of 31 December 2007, the Vestas total installed capacity was 28,167 MW from 35,057 turbines.

7.3 GE Wind Energy

GE Wind Energy is a US company with affiliates and major production facilities in the USA (previously Zond and Enron) and Germany (previously Tacke and Enron), which have been their main markets to date.

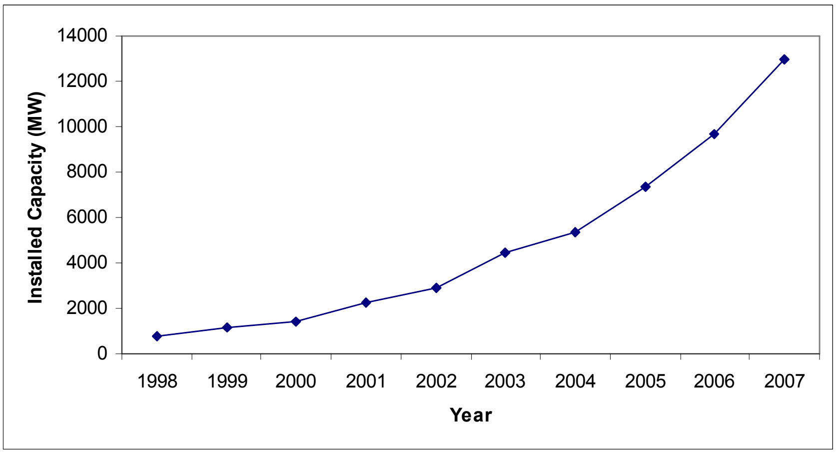
Zond and Tacke were originally independent companies that were purchased by Enron as part of their drive in the mid-1990's to develop a presence in the wind energy market. Until 1999, the two companies were operated separately with Zond concentrating on the USA and some European markets (UK, Greece) and Tacke concentrating on Germany.

In 2000, a more concerted approach became apparent under the Enron Wind brand.

In 2001, Enron Wind purchased the Dutch rotor blade manufacturer, Aerpac.

On 7 May 2002, GE Wind Energy acquired a substantial part of the assets of Enron Wind Corporation.

Figure 7.2 present the cumulative installed capacity of GE Wind Energy (and predecessor companies). The capacity installed in 2007 was 3,283 MW.



Source: BTM Consult ApS

Figure 7.2: Cumulative installed capacity of GE Wind

The current GE Wind models are:

GEWE 1.5s/1.5sl/1.5se/1.5sle/1.5xle	1.5 MW
GEWE 2.5xl/3.0s/3.0sl	2.5/3.0/3.0 MW
GEWE 3.6s	3.6 MW

The GE Wind 1.5s and 1.5sl were developed in Germany and are based on Tacke technology. The 1.5se and 1.5sle versions of the turbines were developed subsequently from these original designs and are modified so that they can be utilised in higher wind sites than the original s and sl units. For example the s turbine is certified for use in IEC 61400-1 Class IIB conditions. The se model is suitable for Class IB conditions. The 1.5xle is a low wind variant with a larger rotor, 82m.

The GE Wind 3.6s was developed for the offshore market. GH understands that this unit is being developed and that its capacity will be extended to approximately 5 MW.

GE has also developed the new 2.5/3.0 MW range. The 2.5 MW model is designed for lower wind sites than the 3.0 MW models; the former model is designed for IEC 61400-1 Class IIIa and the s and sl are designed for Classes Ib and IIa, respectively. These turbines were originally conceived prior to the GE purchase. However, GE has, effectively, redesigned the turbines in the period between their purchase and the production of the prototypes.

As of the 1st quarter of 2008 there were 32 GE 2.5MW turbines installed, 31 of which installed in Japan. There has also been one GE 3.2 MW turbine installed and eight GE 3.6 MW turbines installed.

7.4 Gamesa

Gamesa Eólica started to manufacture Vestas wind turbines under licence for the Spanish and South American markets in 1994, and has grown rapidly to become the market leader in Spain.

Gamesa Eólica is part of the Gamesa group, established in 1974, which comprises Gamesa Energía, Gamesa Aeronautica, Gamesa Industrial and Gamesa Servicios. Gamesa was floated on the Spanish Stock Market in 2001. In December 2001, Gamesa bought Vestas' 40% holding in Gamesa Eólica and also the 9% share-holding held by the Navarran government entity Sodena. The wind turbine manufacturer is now a wholly owned subsidiary of the listed parent company.

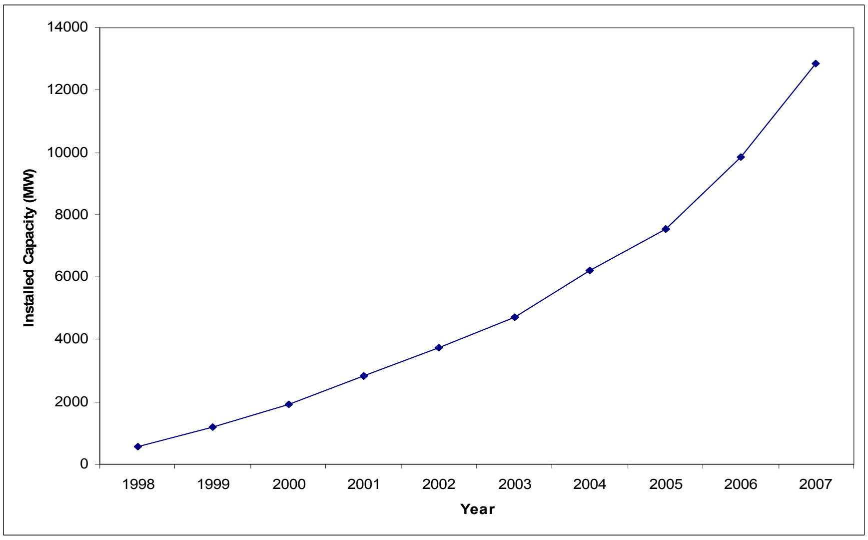
In 2001, Gamesa purchased the gearbox manufacturer Echesa and in 2003, the generator manufacturer, Cantarey Reinosa, which previously manufactured, amongst other products, permanent magnet direct drive generators for wind turbines.

In May 2003, Gamesa bought MADE, a Spanish wind turbine manufacturer owned by the utility ENDESA. The acquisition made Gamesa the fourth largest wind turbine manufacturer in the world in terms of total installed capacity, behind Vestas, Enercon and GE Wind.

In January 2004, Gamesa bought the company Enertron, based in Madrid. This company is specialized in the design and manufacture of integrated power electronic systems, thus bringing in-house the technology to manufacture the wind turbine and wind farm control system, which had previously been subcontracted to Ingecon.

In 2002, Gamesa set up a design office in Silkeborg, Denmark, close to where Vestas is located and where NEG Micon previously had its headquarter prior to the acquisition by Vestas. This is seen as a strategic move, enabling Gamesa to take advantage of the skills of experienced engineering staff who had previously worked for either NEG Micon or Vestas.

The cumulative installed capacity of Gamesa turbines is presented in Figure 7.3



Source: BTM Consult ApS

Figure 7.3: Cumulative installed capacity of Gamesa turbines

In 2007, there were 3,047 MW of shipments of Gamesa turbines, which accounts for 15% of the global market in 2007.

The current Gamesa range comprises:

G52	850 kW
G58	850 kW
G80	2,000 kW
G83	2,000 kW
G87	2,000 kW
G90	2,000 kW

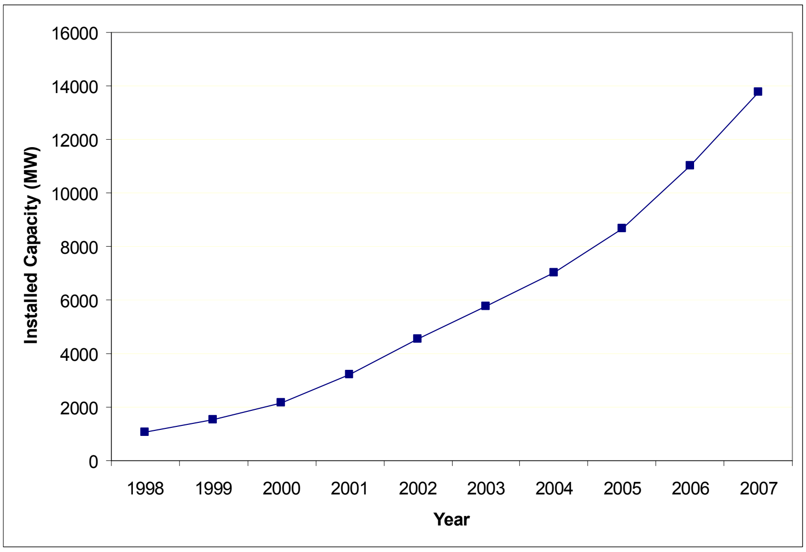
Gamesa has developed a number of variants on the G80 model, the G83, G87 and G90, designed for lower wind speed sites (IEC Class II and Class III).

7.5 Enercon

Enercon is a privately owned German company which was established in Aurich, in the northwest of Germany, in 1984 and is now the largest German wind turbine manufacturer.

Enercon is unique amongst the major (top-ten) manufacturers as it only produces direct drive (or gearless) turbines. Another distinction which is worthy of note is that Enercon insist on installing and maintaining all of their turbines themselves and offer extended maintenance agreements of up to 12 years with competitive warranted availability levels in developed markets, at least.

Figure 7.4 presents the cumulative installed capacity of Enercon turbines since 1991.



Source: BTM Consult ApS

Figure 7.4: Cumulative installed capacity (MW) of Enercon turbines

The current Enercon range comprises the following models:

E-33	330 kW
E-44	900 kW
E-48 and E-53	800 kW
E-70	2,300 kW
E-82	2,000 kW
E-112	4,500 kW

The current E-33, E-48 and E-70 E4 wind turbines are closely related to the original E-30, E-40 E-66 wind turbines, respectively, featuring newly developed blade profiles with improved aerodynamic efficiency.

The E-82 is similar to the E-70 but designed for lower wind speed sites and has a larger rotor diameter. A prototype of the E-82 was installed in the 4th quarter of 2005, and the turbine entered serial production in the 3rd quarter of 2006.

The E-44 and E-112 have been installed in prototype form only and are not yet available on a commercial basis. The capacity of some examples of the E-112 has been increased to 6,000 kW.

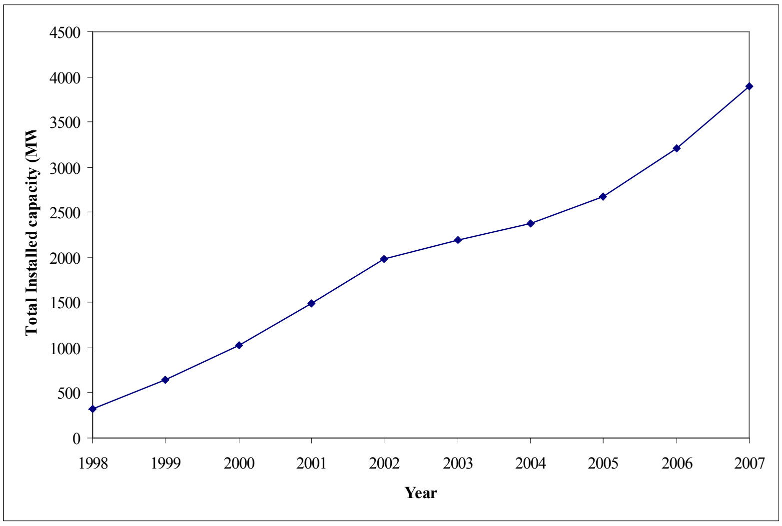
7.6 Nordex

Nordex AG is a German company based at Norderstedt, Hamburg, and was floated on the Frankfurt stock exchange in April 2001.

Nordex AG is the management holding company and controls and coordinates the activities of the two 100 per cent subsidiaries, Nordex Energy GmbH and NPV Planung & Vertrieb GmbH. Nordex Energy is responsible for turbine manufacture and contracting. NPV is a development company, primarily operating in Germany.

The company has manufactured wind turbines since 1987 in Denmark and since 1994 in Germany. In 2007, Nordex were the ninth largest world-wide manufacturer with a market share of around 3.4%. Previously, Nordex had a larger share of the market. However, concerns about the liquidity of the Company, rather than technical issues, had a major impact on sales in the period 2002-2004. The company was refinanced in 2005 and now claims significantly improved performance, boasting a full order book. The majority of Nordex wind turbines are installed in Germany with Denmark running second place in installed Nordex-manufactured capacity.

Figure 7.5 presents the cumulative installations of Nordex turbines.



Source: BTM Consult ApS

Figure 7.5: Installations of Nordex turbines – by year

As of end 2007, 3269 Nordex turbines have been installed with a total installed capacity of 3893 MW. It should be noted that the installations in 2004 and 2005 totalled approximately 186 MW and 298 MW, respectively, down from a peak of 500 MW in 2002. This drop in installations was the direct result of concerns regarding the financial performance of the Company rather than any issue directly concerned with the wind turbines produced by the Company.

The current turbine range offered by Nordex comprises the following models:

S70/77	1500 kW
N80	2500 kW
N90	2300 kW
N90	2500 kW
N100	2500 kW

The S70/77 designs were acquired from Südwind through purchase of the Company.

The N80 and N90 are closely related, and are pitch controlled, variable speed wind turbines. The N90/2300 is, effectively, a low wind speed version of the N80. The N90/2500 is a further development of the N80. It is available in two versions optimised for low and high wind speed sites. An offshore variant of the N90/2500 is also available, which is a marinised version of the N90/2500 is.

The N100 is a new development; two prototypes are currently under construction in Germany. Nordex is also currently developing a 5 MW offshore wind turbine.

7.7 REpower

REpower is a publicly listed company in Germany. Total REpower assets (in the 2005 annual report) were valued at €275m with gross revenues of €335m.

The company was formed in 2001 by the merger of two German turbine manufacturers, Jacobs Energie and BWU along with the engineering design company ‘pro + pro Energiesysteme’ and the wind farm developer Denker & Wulf. Collectively, these companies have manufactured and installed over 1000 wind turbines, mainly in Germany. In December 2004, Denker & Wulf was de-merged from REpower in a management buy-out and is now independent of REpower.

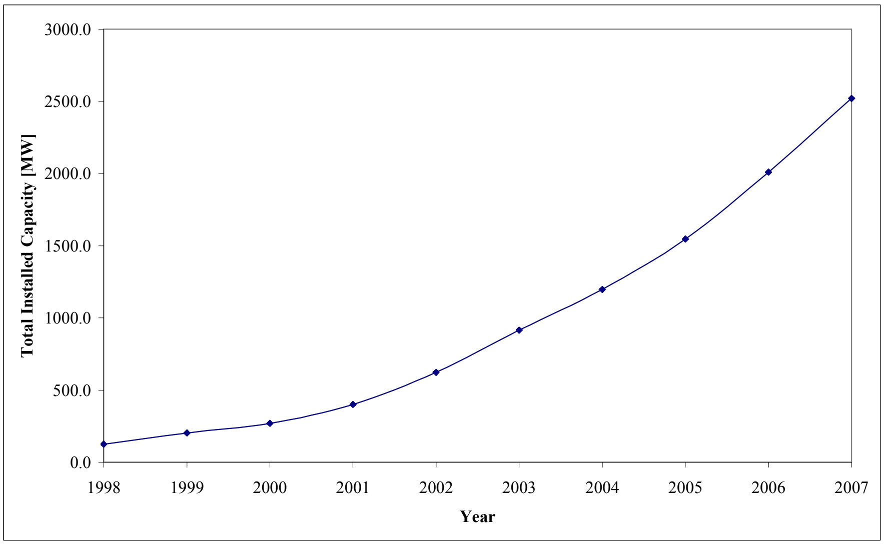
REpower has international operations in Australia, China, France, Greece, Italy, Japan, Portugal, Spain and the UK, mostly through alliances or agency arrangements with partner organisations. In 2005, the French branch of the company, REpower S.A.S. caused the company to become the French market leader with a market share of 40% of newly installed output.

The Indian turbine manufacture Suzlon successfully completed a takeover of REpower in May 2007. According to REpower it is the intention to continue running the two companies as separate entities. However, over time there will possibly be co-operation on some areas such as supply chain, etc.

GH considers it unlikely that the takeover by Suzlon will have a major effect on the development of the 5M turbine as well as the support from REpower for 5M turbines in operation.

The companies that formed REpower have manufactured wind turbines since 1987. The average size of the turbines has increased and the design has evolved since that date.

Figure 7.6 presents a summary of the installed capacity of the company and licensees since 1998.



Source: BTM Consult ApS

Figure 7.6: Installations of REpower Turbines – by Capacity by Year

The current turbine range offered by RePower comprises the following models:

MD77	1500 kW
MM70	2000 kW
MM82	2000 kW
MM92	2000 kW
5M	5000 kW

The MD 1.5MW series turbine was first manufactured in 1998. This design has also been licensed and manufactured by Nordex, Sudwind and Furlaender.

The first MM70 2.0MW turbine, for high wind speeds, was manufactured in 2002. The related lower wind speed design, the MM82 was first installed in 2003.

More recent model developments have included the MM92, an enlarged rotor diameter version of the 2MW MM82 for yet lower wind speeds, and the 5M, which is a 5MW design with 126m rotor diameter aimed at the future offshore market. The 5M prototype has been installed since late 2004 in Brunsbuttel, NW Germany and the MM92 has been on trial since mid 2005 in Meldorf, NW Germany.

7.8 Siemens

In December 2004 Siemens Power Generation, a division of Siemens Energy Division, purchased Bonus Energy A/S., a privately-owned company that has been continuously manufacturing wind turbines since 1980. Siemens currently ranks sixth among the world biggest turbine manufacturers

The wind power division of Siemens is headquartered in Brande, Denmark, which is also the location of the primary manufacturing facilities. The company employs around 2000 staff and has a production capacity of over 1000MW.

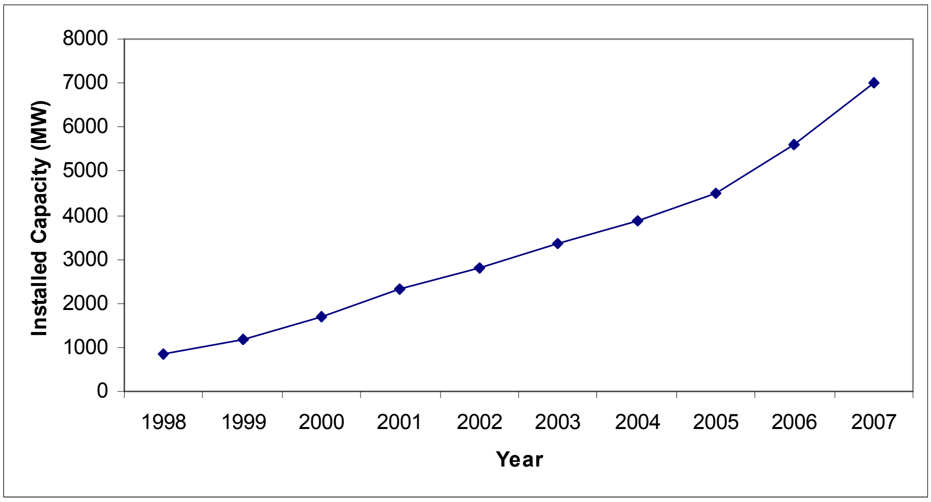
Historically, most of the Siemens installed capacity is in Denmark. More recently, Siemens has supplied significant numbers of turbines to the US, Germany and the UK. Siemens had a manufacturing partner in Spain, Izar, which has manufactured turbines for the Spanish and Portuguese markets.

Siemens has also supplied turbines to some of the larger offshore projects in Denmark including Middlegrunden, Samsø and Rødsand projects. Siemens has been selected as turbine supplier for a number of major offshore projects in UK waters.

With the exception of turbines for the Spanish market, Siemens performs all assembly in Brande, Denmark. Units for the Spanish market were assembled by Izar, in Spain. Siemens has historically relied on major component suppliers including LM for manufacture of the rotor blades on most models, ABB for generators and Winergy (Flender) for gearboxes. Siemens has developed an in-house blade design and manufacturing capability and most turbines are now supplied with Siemens blades. A blade manufacturing facility in Aalborg was opened in 2002.

In 2005, Siemens purchased Winergy, the largest supplier of gearboxes to the wind industry.

The total installed capacity of Siemens turbines is presented in Figure 7.7. The turnover includes turbines manufactured by a Spanish licensee, Izar.



Source: BTM Consult ApS

Figure 7.7: Installations of Siemens turbines

The current Siemens turbine range comprises:

SWT-1.3-62
SWT-2.3-82
SWT-2.3-82 VS
SWT-2.3-93
SWT-3.6-107

8 ENERGY ASSESSMENT

The energy assessment of a project is the area over which developers and financiers will be most focused over the development process. The concept of a power station for which the fuel is entirely free is attractive. However, this advantage is balanced by the variability of the wind which, to the uninitiated, may make an investment in such a scheme appear highly risky.

In order to assess the energy production of a wind farm over the project life, it is necessary to determine accurately the long-term mean wind speed at a potential site. Uncertainties associated with the project data and modelling can be minimised through:

- Siting the measurement mast at a representative location on the site
- Taking measurements as close to hub height as possible
- Taking measurements at other heights to establish changes over the mast height
- Buying good quality instruments (cup anemometers and wind vanes)
- Calibrating and maintaining the instruments
- Mounting the instrumentation to avoid influences from the mast
- Ensuring that no turbine locations are more than 1km from a measurement mast
- Measuring data at areas with complex site conditions (e.g. near trees or slopes)

It can be reasonably assumed that, over a project life, a wind speed very close to the long-term (i.e. 10 year) mean wind speed will be experienced. In order to determine the long-term conditions it is typical to correlate the data collected at the wind farm to a source of local reference data. Accurate estimation of the long-term mean wind speed is a difficult task and uncertainties are typically minimised by:

- Ensuring good data coverage from site masts. A minimum of one year of data would be required to capture seasonal effects.
- Obtaining a good source of local reference data with good correlation to the site
- Obtaining longer data on site where there is not a good correlation with the reference source

Having established the long-term mean wind regime at one location on a wind farm site it is necessary to predict the wind speed which will be experienced by each wind turbine considering the effects of surrounding terrain on the wind flow and also the wake effects from nearby wind turbines. The wind conditions at each turbine location can then be combined with the performance characteristic of the machine and site specific losses to give a prediction of the expected energy production of the wind farm.

The prediction of energy production of a wind farm is dependent on many inputs for which the uncertainties can be objectively defined. This area therefore lends itself to a statistical assessment of the risks associated with a project. The wind analyst will review the uncertainties associated with the assessment and will obtain a 'standard deviation' for the analysis that can be applied to the central estimate. The result will be a series of exceedance cases for the analysis over a short and long-term basis that can be used to assess the risk of variability in output over short and long term periods. GH typically provides its exceedance cases on a 1-year and a 10-year basis.

The fact that many of the uncertainties in predicted wind farm production can be quantified should give the potential lender or investor in a project considerable comfort. Based upon GH experience, where appropriate wind measurements have been made and diligently analysed and wind turbines with a good track record are used, it is likely that the 10-year 90% exceedance level (P90) for the wind farm production will be of the order of 10% to 15% below the central estimate (P50) of energy production for the wind farm. This general guideline can be a useful benchmark against which to carry out financial feasibility assessments, however, the actual level of uncertainty associated with any wind assessment must be calculated on a site by site basis for a reliable analysis.

This is demonstrated in the figure below, which shows how an estimated distribution of energy may appear for a wind farm. Such a graph could be presented once the central estimate and uncertainty analysis have been provided for a project. The distribution shows the probability associated with generating specific energy levels at the project; 50% of the shaded area lies below 50 GWh, which is the central estimate in this case. The standard deviation in energy terms is 3.5 GWh/annum, calculated from the uncertainty analysis for the project. From this the P90 can be calculated, which is the case where there is a 10% chance of net energy production lower than this amount (the sum of all of the shaded areas below 45.5 GWh/annum on the graph).

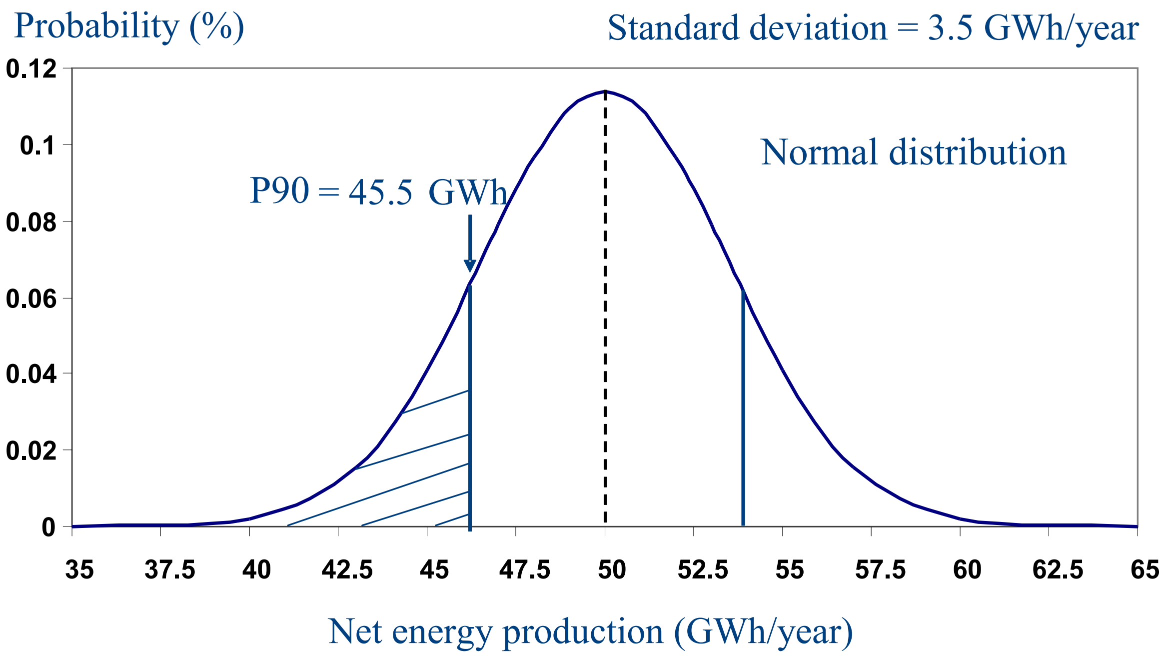


Figure 8.1: Example Uncertainty Distribution

It is important to appreciate how sensitive the output of a wind farm is to the long-term mean wind speed at a wind farm site, for example, it might be expected that energy production for an 8 m/s site could be as much as twice that of a 6 m/s site. This can be illustrated by taking an example wind distribution for a site across a range of average wind speeds and overlaying the power curve of a particular turbine, then adjusting for losses and uncertainty; an example is shown in Figure 8.2 (in this case a site with one turbine):

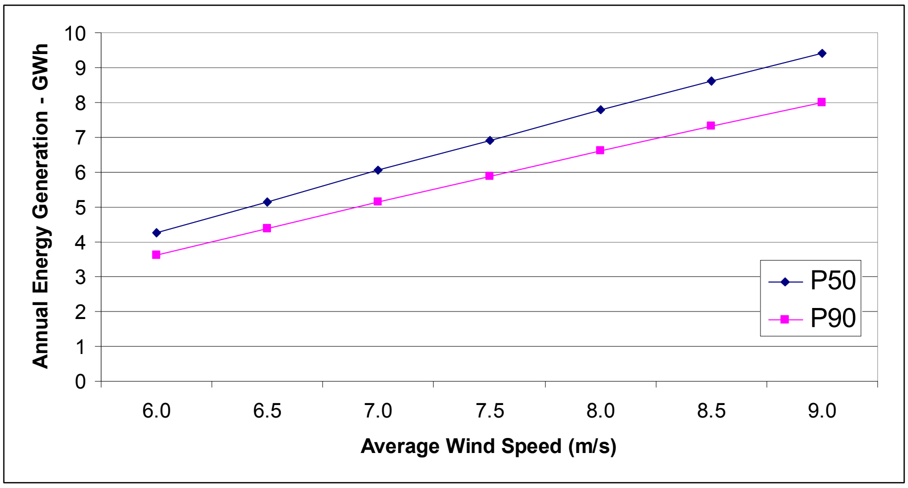


Figure 8.2: Example Variation in Annual Energy with Wind Speed

The actual variance will depend on the selection of turbine model and the variance can be reduced if selecting an appropriate turbine model for the specific site; typically a larger rotor diameter would be used for a lower wind speed site in order to optimise energy capture.

It is also important to understand that banks will typically assess the level of loan that a project can support by basing its financial model on the long term P90 exceedance case. Therefore a relatively small increase in costs to ensure a good quality measurement campaign can have a significant impact on the amount of money that a project can borrow and ultimately the equity return of the project owner.

In Section 3 of this report GH highlighted the need to use caution in using capacity factor as a reference for the 'windiness' of a particular region or site; this is because the size of the turbine rotor has a big influence on energy capture and is not necessarily directly related to the capacity of the turbine. This was illustrated in Table 3.1. Nevertheless, it can be useful to understand typical ranges for capacity factors for the range of site types, which are as follows:

- Low wind speed onshore site – 22 to 27%
- Medium wind speed onshore site – 28 to 32%
- High wind speed onshore site – 32 to 37%
- Offshore site – 35 to 42%

Up to date information on the validation of actual wind farm performance against original predictions can be found on the Garrad Hassan website. The exercise of validation is complex – adjustments are often needed to the data and influencing factors must be understood in order to fully appreciate the trends. Due to the complexity of this topic, GH has not discussed actual experience in detail within this report.

9 CONTRACTING STRATEGY

The contract structure of a project is the area within which the developer has the most power to control and assign risks and any lender will be keen to see mitigation of the construction risks. This section of the report discusses the contract structuring options available to developers.

9.1 Turnkey Contract

Historically developers have sought to minimise risk through the use of a turnkey Engineering Procurement and Construction (EPC) Contract. The important features of such a contract would be:

- Single point of responsibility for design, procurement and construction
- A completion deadline supported by a warranty payment in the event of delay
- Minimised requirement for owner's management of tasks
- Fixed cost

Turnkey contracts were typically let to the turbine supplier, who then let sub-contracts for the balance of plant. This is often not the lowest cost option, but provides more certainty over costs for the owner and lender. Careful structuring of the contract ensures that most liabilities remain with the turnkey construction contractor until the wind farm has been shown to perform to specification and is accepted by the owner. Appropriate liquidated damages could also be included to cover late commissioning of the wind farm or failure to meet specified performance levels.

Despite the protection afforded by such a contract it is necessary to assess whether the organisations involved are competent to undertake the development in commercial and logistic terms as well as through technical experience.

There is also the potential to rely too heavily on the turnkey nature and therefore to fail to provide an adequate functional specification for the project. This can be addressed through full review of the functional specification for the project.

Turnkey contracts are now available in only a limited number of regions. Lenders have become more comfortable with the use of multi-contract structures in which the delivery and completion risks are minimised through proper definition and management of the interfaces between contractors. Multi-contract structures are now commonly financed.

9.2 Multi-Contract (<4 contracts)

The second option for contracting is a limited number of separate contracts; typically covering civil works, on-site electrical works, electrical connection works and turbine supply. Each contract covers the design, supply, construction and completion of the relevant scope of work, with defined physical interfaces between each contractor.

Such an approach is typically a cheaper option than a full turnkey contract, however, it is a more risky route as each of the individual contracts need to be very carefully defined to ensure the developer is not left with a situation where all contractors have, or claim to have, fulfilled their commitments but the developer is left with a non-operational wind farm or a wind farm which does not perform to specification.

Within this contract structure the sponsor is accepting the turnkey risk and their technical competence and financial strength must be ensured. In some cases the developer will employ an experienced contractor to oversee the main contracts. Sometimes an interface contract will be put in place to define the working arrangements between the main contractors.

9.3 Multi-Contract (>4 contracts)

A third approach is a multi-contract with several contracts in each of the main work areas. For example:

- Turbine works: separate contracts for supply, transport and installation
- Civil works: separate contracts for design, supply and installation
- Electrical works: separate contracts for design, supply and installation

Such a contract structure will typically be managed under a project management agreement, with the Project Manager being responsible for the tendering process, oversight of the designs process and day to day management of the contractors on site.

9.4 GH experience

The majority of GH experience of wind farm construction (>20,000 MW globally) has been on projects constructed under turnkey contract structures or multi-contract structures with single point responsibility for design, supply and construction within a defined scope (e.g. civil works, substation works). Under the latter structure there are clear lines of physical interface between the contracts, and each contractor is fully responsible for all activities associated with its own scope.

As the market has progressed and more experience has been gained by developers, it has become more common to see a developer or owner free-issue certain aspects of the supply for equipment with long lead times. In such cases it is typical for the owner to cover potential issues with supply or delay of the free-issued equipment, and interface risks in general, with additional budget contingency.

In some markets there have been difficulties in tendering for contracts covering a wrapped design, supply and construction type scope and a managed multi-contract has been used. In some cases this type of structure has been used through preference of the developer. This type of structure has been successfully used on projects that GH has advised on, however, it is important to recognise the importance of the Owner's role in this arrangement and the increased risk of cost overrun and delay compared to the other options.

GH provides some additional discussion of key risk areas below.

9.4.1 Design

There are benefits to ensuring that the designer of the electrical system, roads or foundations is involved from the initial study stage and through to the construction stage. Ideally, this activity would be undertaken by the same party responsible for the construction, to ensure that the constructor does not claim additional costs or additional time for the work as a result of errors or omissions in the design scope.

While it may appear possible through contract to push the responsibility for a complete design, and any additional costs arising, back onto the designer, it is very difficult to make a determination on fault during construction. For example:

- If a foundation is shown to have settled outside of the turbine supplier's tolerances was there an issue with the initial ground studies, is the foundation design inadequate for the conditions on site, or is the settlement a result of poor construction methods?

- If the project does not meet the requirements of the grid code or connection agreement, was there an issue with the interpretation of the grid code in the design, does the free issued equipment perform as expected or were there an issue with the initial studies?

- If the main transformer does not fit the foundation, was there an issue with the foundation design or has the specification of the transformer changed in between order and supply?

Even if it is possible to show that the designer is at fault, their scope may have been for work of the order of tens or hundreds of thousands of dollars, while the cost to the project may run into the millions; in this case it would be unlikely that the full cost could be covered by the liabilities under the design scope, which may only cover the rectification of errors in the design document and may not cover consequential damage.

9.4.2 Delay

It is common to expect the completion of the works to be supported by a deadline and a warranty to compensate for additional costs and lost revenues in a contractor delay situation. Such warranty payments are typically referred to as 'liquidated damages'.

It has already been accepted by the industry that within a multi-contract structure the individual contract prices may not allow full coverage of daily lost revenues, however, it would be common to see a substantial portion of these covered.

Where equipment is being supplied through purchase order, there may be no damages paid for delay and the owner may be liable for significant extra costs to other contractors whose work may be impacted.

Typically turbine contractors will not cover the potential risks of construction delay through adverse weather and owners can expect to take on the risk of project delays as a result of delays to installation activities from wind speeds above 10 m/s. Allowance for this is typically built into a project schedule; the risk of delay must therefore be reviewed and built into the schedule on a site by site basis.

It is uncommon to see Balance of Plant contractors excluding weather events from its list of contract risks. However, in the event of extreme cold there will be impacts to work rates and if construction cannot be arranged for summer months, a longer than usual construction schedule is likely.

9.4.3 Damage

A key benefit from minimising the number of contractors on site is the ability to reduce the number of equipment hand-over events, with one party remaining responsible for the equipment from the factory, through installation and testing up until the project take over date. Every hand over event or interface allows an opportunity for one contractor to claim that its element of the scope is not in line with the requirements as a result of damage that has occurred prior to its work.

Where damage has arisen clearly through the fault of one contractor, it is likely that the contractor's scope of work or insurance will cover repair. However, there are occasionally times where an element of residual liability remains with the project, for example where:

- A repair will invalidate other warranties;
- The owner chooses to proceed with a repair at cost to reduce timescales;
- The limit of liability for the contractor is lower than the cost of the equipment,

10 OPERATION AND MANAGEMENT

It is typical for an O&M contract to be let to the turbine supplier for the duration of the defects liability period. Where the initial warranty period is only 2 years in term, the service period may extend to 5 years and cover unscheduled maintenance (repair) as well as routine servicing. After this initial contract period, the owner of the project can choose to extend the original contract, enter into a new 3rd party contract or carry out the works themselves. There are risks and benefits associated with the options and the option selected will reflect the experience and situation of each project owner.

The balance of plant works are generally covered through maintenance arrangements made by the owner with local contractors.

Key uncertainties associated with operating risks are the availability level, performance of the wind turbines and operational costs.

It is normal practice for there to be tests on completion of the wind farm to ensure that all parts of the wind farm are operating effectively before take over. It is typical for such tests to take the form of a series of individual component tests followed by a period of continuous operation without fault. The wind farm Supervisory Control and Data Acquisition System (SCADA) plays an important role in the assessment of the performance and warranty testing of all but the smallest wind farm. It is therefore important to ensure that an appropriate acceptance test is also included for the SCADA system.

The acceptance tests form only a part of the wind farm warranties. Warranties usually cover availability, performance and noise with the aim of mitigating financial risk to the sponsor and lender.

It has been common for the availability of wind turbines to be warranted by the manufacturer with levels of 95 to 97 % being the norm. Given the nature of the “Suppliers’ Market” these availability warranties are becoming less common, but are often available under an operations contract if not available under the original supply contract. Care should be exercised in the formal definition of availability. It is also necessary to ensure liquidated damages are adequately defined to ensure that lost revenue resulting from availability levels below the warranted level is appropriately reimbursed. A check of the practicalities of making such calculations is also essential.

There are two broad types of performance test used: the power curve tests of a small sample of machines or an attempt at a test for the wind farm as a whole. Both of these need to be defined with great care, particularly when they are exercised in complex terrain. The IEC standard (61400-12) is the industry standard for the power curve measurements for wind turbines and sets out the guidelines for the location of the test measurement mast, data collection requirements and interpretation of the results. Warranty Tests generally are referenced to this standard for the definition of many of the technical details of the test procedure. Warranty levels generally vary from 95% to 97% of expected performance.

For many developments, particularly in northern Europe, the consent for the construction of the wind farm will include a requirement with regard to the noise produced by the development, as measured at the nearest dwelling. This will be defined either as an absolute noise level for a given wind condition or as a level above background noise which must not be exceeded. The wind farm development may be forced to shut down if the condition is not met. To mitigate this risk a developer will need to assess whether any imposed planning conditions will be met, based on predictions using industry standard methods initiated with noise characteristics for the turbine to be used which are warranted by the manufacturer.

There is little operational data available for turbines in the current commercial range, as most will have been installed within the last 5 to 6 years. It is therefore difficult to accurately establish how maintenance costs may vary later in the life of a project, or in the case of the lender towards the end of the loan life. The risks of escalating maintenance costs are best managed by the use of a reserve fund which sets aside appropriate sums of money to cover a refurbishment part way through the project.

11 PROJECT LIFE

Modern wind turbines are typically designed to be suitable for use within a specific envelope of climatic conditions over a 20 year design life. This lifetime assumption is generally supported by independent certification by a classification society such as Germanischer Lloyd or Det Norske Veritas, which has the primary purpose of ensuring that a design is compliant with specific safety requirements.

Despite the basis of the design and independent checks, some level of breakdown is expected over a project life as a result of imperfect manufacturing processes, external events, force majeure events and other conditions not forming part of the design basis. In addition to addressing breakdowns, as with any machinery, it is necessary to follow a maintenance and servicing programme over the project life in order to maintain the equipment in satisfactory condition.

It is not possible to verify formally an extended operational time period without specific analysis of the loading characteristics of a specific site against the design conditions of a specific turbine. It is recognised that an extended life should be possible where the climatic conditions at a project site are less onerous than the design conditions and whether the maintenance carried out at the wind farm over the earlier years has been thorough and pro-active. A site specific certification could be carried out to verify an extended life assumption.

It would also be reasonable to assume that a proactive repair program might be used to extend the operating life beyond the design life. On this basis it may be reasonable to assume a longer (e.g. 25 years) operational life, provided that an appropriate cost allocation is made for component repair and replacement in these later years.

In selecting an extended lifetime assumption it will likely be necessary to weigh up the costs benefits of capital expenditure versus the potential ongoing operational time and revenues. It is likely that a reduced availability assumption would result at some projects, with some turbines being shut down and used for spare parts sourcing as an alternative to purchase of new components. This should be reflected in financial modelling.

The remaining term of any permits, power offtake arrangements, planning permission and land leases would need to be considered in conjunction with any technical analysis, as agreements are often entered into with a 20 year operational term in mind.

12 FINANCIAL ARRANGEMENTS

The key areas of lender risk in a project financed wind farm are:

- Completion of the project on time and on budget;
- Technology risk, meaning the ability to meet performance expectations;
- Energy production variability and accuracy of forecasts;
- Balance of plant design and the risk of extra cost or production impact;
- Connection risks, either delayed connection or operations impact;
- Planning compliance issues resulting in an order to change or stop the project;
- Offtake risk, including an inability to deliver power or meet contract requirements;
- Operating risk, including performance and cost variability;
- Regulatory issues, such as a change in access to the grid network or law;
- Insurance costs and policy coverage variability (e.g. inclusion or exclusion of specific risks);
- Financial risks such a interest rate and foreign exchange risk, or creditworthiness;
- Country risks, such as political instability.

As part of any investment in a project, a lender will consider the above areas of risk with the objective of removing, minimising and mitigating these risks within the investment transaction.

GH has provided an outline of the typical technical requirements that would be expected for an onshore wind farm. Other requirements of a commercial nature may also be required.

Expected period of operation:	20 years
Loan term:	15 years, although there have been loans of 20 years
Debt to Equity Ratio:	80:20
Typical DSCR[1]	1.4 over the long term net cashflow using the central energy case
Main contracts:	Turbine supply, Civil Works and Electrical Works
Equipment warranties:	2-5 years for turbines depending on technology
	1 year for balance of plant
	Liability capped at 100% of the contract price
Completion warranties	Liquidated damages to cover costs and lost revenue Capped at 10-15% of contract price
Operational warranties	Availability – at least 95%
	Power Curve – at least 95% of warranted curve
	Noise
	Electrical Loss – typically 2 to 3%
Other requirements:	Contractors to take responsibility for: - All aspects of design - Ground risk - Risk of loss until take over date - Compliance with 3rd party requirements: planning and grid - Health and Safety management
	Owner to be responsible for: - Grid connection - Commercial issues such as land lease and permits
PPA (power offtake)term:	Similar to loan term.

Note 1: Debt Service Coverage Ratio

Table 12.1: Typical Onshore Financing Terms