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Offshore wind cost reduction pathways

Technology work stream

May 2012

BVG Associates

BVG Associates is a technical consultancy with expertise in wind and marine energy technologies. The team probably has the best independent knowledge of the supply chain and market for wind turbines in the UK. BVG Associates has over 120 man years experience in the wind industry, many of these being “hands on” with wind turbine manufacturers, leading RD&D, purchasing and production departments. BVG Associates has consistently delivered to customers in many areas of the wind energy sector, including:

- Market leaders and new entrants in wind turbine supply and UK and EU wind farm development;
- Market leaders and new entrants in wind farm component design and supply;
- New and established players within the wind industry of all sizes, in the UK and on most continents;
- Department of Energy and Climate Change (DECC), RenewableUK, The Crown Estate, the Energy Technologies Institute, the Carbon Trust, Scottish Enterprise and other similar enabling bodies.

The views expressed in this report are those of BVG Associates. The content of this report does not necessarily reflect the views of The Crown Estate.

Front cover: Ormonde Offshore Wind Farm with first turbine nacelle at sunset. Ben Barden Photography/Vattenfall

Executive summary

This report examines how technology innovation is anticipated to reduce the cost of energy from UK offshore wind farms. It was commissioned by The Crown Estate as a key part of the Offshore Wind Cost Reductions Pathways Project and should be read in association with sister reports covering the supply chain and finance and *The Crown Estate Offshore Wind Pathways report,* which draws together the findings of all three work streams. It provides a comprehensive, transparent evidence base built through significant industry engagement. Government and others can use it to formulate a long-term view of the contribution that technology innovation could make in reducing the cost of energy from offshore wind. It confirms that offshore wind has the opportunity to be a major and cost-effective part of a sustainable UK energy mix.

The work has been undertaken at a major milestone for the offshore wind industry, as it begins the transition from commercial deployment to industrialised electricity generation. It comes at a time when the industry is developing technology solutions fit for larger projects, in deeper water, further from shore, and in harsher conditions than ever before.

The key transition is from a typical wind farm with financial investment decision (FID) in 2011, which uses turbines with a rated power of about 4MW, to the use of next generation 6MW turbines for a project with FID in 2020. The figures used throughout this summary relate to this transition on a 500MW wind farm that is 40km from port and installed in 35m of water. More comprehensive analysis is presented in the rest of this report.

In the right circumstances, the impacts from technology innovations contribute an anticipated 25 per cent reduction in the levelised cost of energy (LCOE). Figure 0.1 shows that over 80 per cent of the total anticipated technology impact is achieved through seven areas of innovation, of which the largest is the increase in turbine size from 4MW to 6MW. By virtue of having fewer turbines for a given wind farm rated power, there are significant savings in the cost of foundations, installation, and operation, maintenance and service (OMS). Almost all of the 6MW turbines under development today have more optimum-sized rotors than used to date and therefore have higher energy production. The combined impact of larger turbines with optimum-sized rotors, improved aerodynamics and control and next generation drive train designs on the LCOE is about 14 per cent.

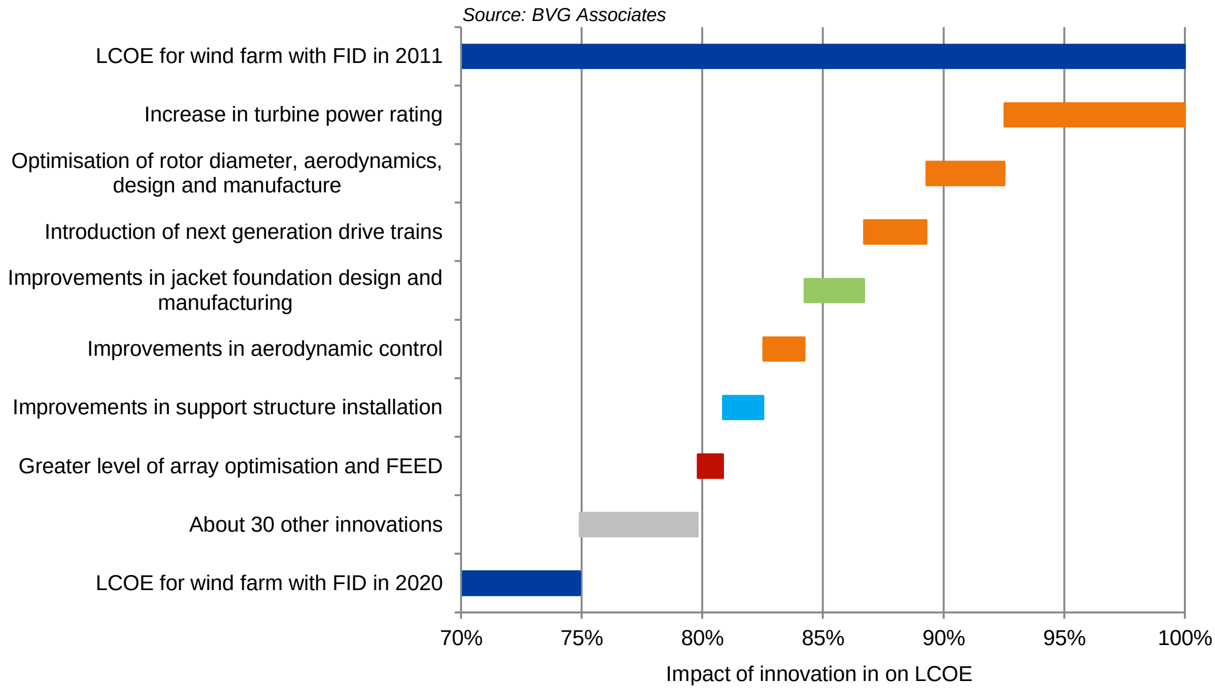

Figure 0.1 Anticipated impact of technology innovations for a wind farm using 6MW-Class turbines with FID in 2020, compared with a wind farm with 4MW-Class turbines with FID in 2011.[1]

[1] Comparison is on Site Type B as defined in Section 2.

Few of the 6MW-Class Turbines in development will go into industrial-scale production without a growing and sustainable market, which will enable wind turbine manufacturers to compete for a strong pipeline of orders. Public sector support can accelerate the route to market for these turbines by making available test sites that will contribute to the verification of new technology.

At the heart of this study is a cost model in which elements of baseline wind farms are impacted on by a range of technology innovations. These wind farms are defined in terms of the turbine rated power (4MW, 6MW and 8MW), site conditions (three at 40km from construction port at 25m, 35m and 45m water depth, and one at 125km from port at a 35m deep site, each with different wind conditions), and four points in time at which the projects reach FID (2011 (the baseline), 2014, 2017 and 2020).

Through detailed discussions with companies from across the supply chain using interviews and workshops, over 60 innovations were identified as having the potential to cause a substantive change in the design of hardware, software or process, with a resulting quantifiable impact on the cost of energy. Care was taken to distinguish these from supply chain innovations and the report clearly defines the distinctions.

In wind farm development, through investments in engineering and site characterisation, the LCOE is anticipated to reduce by about two per cent. The principal innovations relate to greater levels of analysis and optimisation during the front-end engineering design studies (FEED).

Aside from an increase in the turbine power rating, other innovations within the turbine nacelle are anticipated to reduce the LCOE by about three per cent. The major benefit here comes from the introduction of next-generation drive trains, including direct-drive and mid-speed generator solutions, which are anticipated to reduce OPEX costs through greater reliability. A challenge for turbine manufacturers will be in demonstrating this reliability to customers with experience of operational issues to date. A step change in verification testing and increased openness is seen as critical to achieving this.

While larger, more optimised rotors make the biggest single contribution, together, all innovations in rotor components offer about a six per cent reduction in the LCOE, delivered mainly via increases in energy production, rather than decreases in costs. Other key innovations relate to improved blade designs and manufacture and aerodynamic control.

The impact of innovations in support structure technology is dominated by improvements in jacket foundation manufacturing, through new processes that move from bespoke one-off structures for the oil and gas industry to series-produced, standardised foundations for offshore wind. Also significant are developments in jacket design, integrated tower and foundation design and the introduction of single section towers. Combined, innovations in support structure are anticipated to reduce the LCOE by approximately four per cent.

These savings do not include the introduction of concrete gravity base foundations. While these offer some benefit to support structure supply costs, especially in an environment of higher steel prices, their primary benefit is through reduced installation costs if installed as part of a float-out-and-sink strategy. The potential of such strategies is significant, minimising offshore construction, but it is anticipated that much of this benefit will be achieved only on projects reaching FID after 2020. Shorter term benefits will come from the introduction of installation vessels that can operate in a wider range of conditions and bespoke fleets for jacket foundation installation, where costs can be reduced through the introduction of large, floating heavy lift vessels designed for offshore wind. The industry will benefit from oil and gas industry experience and the entrance of major players from this sector is a positive sign that the potential savings can be realised. Overall, the anticipated reduction in the LCOE due to innovations in wind farm installation is about four per cent.

Innovations in array cables are anticipated to reduce the LCOE by approximately 0.5 per cent. Most significant is the introduction of high voltage cables, probably at 66kV, which reduce capital costs and losses.

The two biggest innovations in OMS are a move to holistic, condition-based maintenance (CBM), with reduced downtime and the frequency of large component retrofits, and improvements in the transfer of personnel from vessel to turbine. Both will have their biggest impact on far-from-shore projects where greater transit distances and more severe sea states are experienced. We anticipate the reduction in the LCOE due to such innovations to be approximately two per cent.

Overall, reductions in CAPEX per megawatt installed over the period are anticipated to be about 10 per cent. This is due to the adoption of turbines with higher rated power and more optimum rotor size, which balance other reductions. OMS costs are anticipated to reduce by approximately 17 per cent with the introduction of larger turbines. This is mainly due to the combination of the reduced number of units per megawatt installed and the introduction of more reliable turbines. Also driven by the same changes is a 16 per cent anticipated increase in energy produced per megawatt installed due to the above changes. It is this that provides the single biggest contribution to reducing the LCOE.

From a higher baseline, CAPEX reductions are greatest for sites furthest from shore. This is due to the relatively larger impact of the use of feeder solutions and innovations to increase the envelope of working conditions. OPEX reductions are also largest further from shore due to the greater opportunity for innovation presented when moving from today's state-of-the-art to much more severe conditions.

Reductions are also slightly more significant for turbines with higher rated power. It is anticipated that, as learning increases, the benefits of such turbines will also increase, just as we see the benefits of 6MW turbines over 4MW turbines today.

Central to this work stream is an environment supportive of "technology acceleration". This is one of four Industry Stories considered by the project. As discussed, the overall cost reductions due to technology in this Industry Story is 25 per cent. Reductions in the other Industry Stories range from 25 per cent down to about half of this in the Slow Progression Industry Story, where the appetite for investment in new technology is limited.

There are a range of innovations not discussed in detail in this report because their anticipated impact is still negligible on projects reaching FID in 2020. Among these are new turbine concepts, such as two-bladed rotors, generally regarded as well suited to offshore conditions, and floating foundation solutions, enabling access to higher wind speed sites close to shore, also offer interesting future possibilities. At a wind farm level, centralised grid control and moving complexity from each turbine to the substation offers the prospect of further savings, along with changes to the wind farm design life. At a system level, it is anticipated that there will be significant further progress in terms of high voltage direct current (HVDC) networks for transmission. The unused potential at FID in 2020 of innovations modelled in the project, coupled with this further range of innovations not modelled, suggests there are significant further cost reduction opportunities when looking to 2030 and beyond.

The impacts of innovations in this analysis have been modelled conservatively to provide confidence in the results, moderating down the impact of innovations suggested by industry players. Throughout, signs that indicate progress towards realising specific innovations are discussed. In addition, prerequisites have been identified for the potential impact of innovations to be realised.

Most critical is the industry's confidence in a growing and sustainable UK market in which to invest. Also of high impact is the availability of consented sites for coastal manufacturing and assembly and for testing and demonstrating turbines and support structures. Flexibility in the planning process to allow developers to delay technology choices until after consent and early collaboration between industry partners also have a significant impact.

Table of contents

Table of figures

List of tables

Glossary

AC	Alternating current
AEP	Annual energy production
Anticipated impact	Term used in this report to quantify the anticipated market impact of a given innovation on the LCOE innovation. This figure has been derived by moderating the "potential impact" through application of various features of the market and by its relevance to a Site Type and Turbine MW-Class combination, by default under Industry Story 2. For details of methodology, see Section 2.
Baseline	Term used in this report to refer to 'today's' technology, as would be incorporated into a wind farm reaching FID at the end of 2011.
CAPEX	Capital expenditure
CBM	Condition-based maintenance
CFD	Computational fluid dynamics
COE	Cost of energy
DC	Direct current
DECC	Department for Energy and Climate Change
DECEX	Decommissioning expenditure
DFIG	Doubly fed induction generator
DP	Dynamic positioning
EIA	Environmental impact assessment
EPC	Engineer, procure and construct
EU	European Union
FEA	Finite element analysis
FEED	Front end engineering and design
FID	Final investment decision, defined here as that point of a project life cycle at which all consents, agreements and contracts that are required in order to commence project construction have been signed (or are at or near execution form) and there is a firm commitment by equity holders and in the case of debt finance, debt funders, to provide or mobilise funding to cover the majority of construction costs
FMEA	Failure modes effects analysis
GW	Gigawatt
HALT	Highly accelerated life test
HTS	High temperature superconducting
Hs	Significant wave height
HSE	Health and Safety Executive
Industry Story	Term used in this report for a cohesive combination of market size and supply chain, finance and technology developments See Section 2 for details of methodology.

IPC	Infrastructure Planning Commission
LAT	Lowest astronomical tide
LCOE	Levelised cost of energy. Note that in this report, comparative LCOE results consider technology impacts only. The combined impact of technology, supply chain and finance is explored in *The Crown Estate Offshore Wind Pathways report*. For details of methodology, see Section 2.
m	Metre
MCA	Maritime and Coastguard Agency
MHWS	Mean high water springs
MW	Megawatt
MWh	Megawatt hour
OFTO	Offshore transmission operator
OMS	Operation, maintenance and service
OPEX	Operational expenditure
PM	Permanent magnet
Potential impact	Term used in this report to quantify the maximum potential technical impact of a given innovation on the LCOE for any Site Type-Turbine MW-Class combination. This impact is then moderated through application of various features of the market and by its relevance to a Site Type and Turbine MW-Class combination in order to derive an “anticipated impact”, by default under the Industry Story 2. For details of methodology, see Section 2.
RD&D	Research, development and demonstration
ROC	Renewables Obligation Certificate
ROV	Remotely operated vehicle
rpm	Revolutions per minute
SCADA	Supervisory Control and Data Acquisition
Site Type	Term used in this report to describe a representative set of physical parameters for a locationwhere a wind farm may be developed, installed and operated. For details of methodology, see Section 2.
SWATH	Small waterplane area twin hull
TIB	Transport and installation barge
TNUoS	Transmission network use of system
Turbine MW-Class	Term used in this report to describe a representative turbine size for which baseline costs are derived and to which innovations are applied. For details of methodology, see Section 2.
WACC	Weighted average cost of capital
WCD	Works completion date

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1. Introduction

1.1. Purpose

In July 2011, the UK Government published *Planning our electric future: a White Paper for secure, affordable and low-carbon electricity*.[2] It suggested its support for installing 11GW of offshore wind by the end of 2020, and offered the prospect of supporting a larger-scale market if it can see pathways to reducing costs in that timeframe.

The challenge that wind industry businesses have faced for some time is whether to invest wholeheartedly in the development of technology, manufacturing and construction processes, in order to drive down costs, if there is uncertainty in the market.

The purpose of The Crown Estate Offshore Cost Reduction Pathways project is to break this cycle by providing an authoritative and credible analysis of pathways to reducing costs based on evidence from across the industry, assuming confidence in a large-scale, long-term market.

1.2. Structure of the project

The project activity is split into three parallel and interlinked work streams covering Finance, Supply Chain and Technology. This report provides the evidence base underpinning *The Crown Estate Offshore Wind Pathways report* on cost reduction opportunities based on industry engagement with a technology focus. The level of informed industry engagement and the discipline of considering specific opportunities within each work stream sets this study apart from others that have sought to explore the future costs of offshore wind energy.

All work streams collaborated in project planning activities. This involved detailed agreement of the proposed methodology and interfaces across the project, including the structure and content of models, identification of the main cost reduction opportunities and agreement on the methodology for industry engagement. Following this, activity was delivered in three sequential phases:

- **Initial industry engagement.** In order to establish the technical innovations seen by industry as most important, 20 structured interviews were held with a cross-section of people with specialist technical understanding and a broad knowledge of wind farm technology and processes. These represented a wide range of companies covering all elements of wind farm activity with a focus on companies with a strong track record in the industry.
- **Wider industry engagement.** Following these interviews, seven workshops were facilitated in the UK, Germany and Denmark involving a total of 57 participants. The purpose of these workshops was to gather the quantitative and qualitative views of a wider group of industry players, using as a basis the innovations that had been identified in interviews. Workshops were followed up by addressing actions raised with some workshop participants and by further interviews, addressing specific areas where additional input was required.
- **Verification.** Following the aggregation of information received in workshops and subsequent dialogue, early draft sections of the report were issued for peer review. All sections were reviewed by at least two industry contacts that had both been involved in the project and who have specific expertise in the area under review.

Underpinning all activities, a detailed wind farm cost model was developed and populated, enabling the impact of individual and collected technology innovations to be investigated. This model was structured to interface with models developed by The Crown Estate and within the other work streams, in order to give robust and self-consistent overall levelised cost of energy (LCOE) results.

[2] *Planning our electric future: a White Paper for secure, affordable and low-carbon electricity, An Electricity Market Reform (EMR) White Paper 2011,* Department of Energy and Climate Change, 14 July 2011, available online at www.decc.gov.uk/en/content/cms/legislation/white_papers/emr_wp_2011/emr_wp_2011.aspx, accessed May 2012.

1.3. Structure of this report

Following this introduction, this report is structured as follows:

Section 2. Methodology. This section describes the scope of the Technology work stream, interrelations with other work streams, project terminology and assumptions, the process of technology innovation modelling, industry engagement and the treatment of risk and health and safety.

Section 3. Technology development lifecycle. This section describes the typical lifecycle for developing and introducing new technology in the offshore wind industry to date, including consideration of time and cost to commercial acceptance for new wind turbines and other key elements of supply.

Section 4. Technology baselines. This section summarises the parameters relating to the 12 baseline wind farms for which results are presented. Assumptions relating to these wind farms are presented in Section 2 and the derivation of parameters is provided in the relevant element section, below.

The following six sections consider each element of the wind farm in turn, discussing the existing situation and deriving baseline parameters before exploring the impact of innovations in that element, early signs of progress in implementing such innovations and the prerequisites indicated by industry for investing in such innovations. Unless otherwise stated, all quantitative results presented are derived by rationalising and combining the input received in interviews, workshops and verification activities.

We have considered opportunities for reducing costs up to the inputs to the offshore substation. Opportunities exist also for the offshore substation, subsea export cables and onshore infrastructure. Work jointly between government and industry assessing ways of developing and charging for the offshore transmission network is ongoing and the outcome of this work may have a considerable impact on the future costs of transmission. Based on this, The Crown Estate engaged a group of experts to provide a high-level assessment of the potential for reducing costs in transmission instead of a detailed analysis, as conducted for other elements of the wind farm. This assessment is described in the companion report, *Potential for offshore transmission cost reductions* and incorporated into the baseline wind farms in Section 4. The benefit of transmission cost reductions are not incorporated in this report, but are covered in the *Finance work stream report.*

Section 5. Innovations in wind farm development. This section incorporates the wind farm design, consenting, contracting and developer's project management activities through to the works completion date (WCD).

Section 6. Innovations in wind turbine nacelle. This section incorporates the drive train, power take-off and auxiliary systems, including those that may be located in the tower.

Section 7. Innovations in wind turbine rotor. This section incorporates the blades, hub and any pitch or other aerodynamic control system.

Section 8. Innovations in support structure. This section incorporates the tower and foundation, including the sea bed connection and secondary steel work to provide personnel and equipment access and array cable support.

Section 9. Innovations in array cables. This section considers subsea cables connecting turbines to any substation only. Export cables are not considered and cable protection is covered under innovations in wind farm installation.

Section 10. Innovations in wind farm installation. This section incorporates transportation of components from the port nearest to the component supplier, plus all installation and commissioning activities for the support structure, turbine and array cables. Decommissioning is also discussed in this section. It omits insurance costs during construction (which are derived within the Finance work stream). It also excludes installation of the offshore substation, the export cables and onshore transmission assets (which are modelled as transmission network use of system (TNUoS) charges and discussed in the companion report *Potential for offshore transmission cost reductions)*.

Section 11. Innovations in operation, maintenance and service (OMS). This section incorporates all activities after the WCD up until decommissioning. It excludes insurance costs during operation (derived within the Finance work stream), sea bed lease payments to The Crown Estate and TNUoS charges payable to the offshore transmission operator (OFTO).

Section 12. Summary of impact of innovations. This section presents the aggregate impact of all innovations, exploring the relative impact of innovations in different wind farm elements.

Section 13. Sensitivity analysis. This section provides technology-related input data for the sensitivity analysis presented in *The Crown Estate Offshore Wind Pathways report*.

Section 14. Conclusions. This section includes technology-related conclusions following engagement and analysis in this work stream.

Appendix A. Details of methodology. This appendix discusses project assumptions and provides examples of methodology use.

Appendix B. Index of innovations. This appendix consists of an index of the innovations modelled, and also includes the full technical potential impact and anticipated impact on a reference wind farm.

Appendix C. Data tables. This appendix provides tables of data behind figures presented in the report.

Appendix D. Industry consultees. This appendix lists the industry consultees who provided substantive input into this work stream.

This report provides input to *The Crown Estate Offshore Wind Pathways report*, authored by The Crown Estate. It is intended to be read in conjunction with the parallel work stream reports, to which it refers frequently.

1.4. Industry background

Over the last decade, the offshore wind industry has seen a significant change in scale in terms of the technology used, project size and annual installed capacity. At the same time, it has moved to operate in harsher sites that have deeper water and are further from shore, due to the lack of availability due to planning constraints of shallow, near-shore sites with a good wind resource. All these trends are anticipated to continue over the next decade, with a backdrop of a continuous drive to reduce the cost of energy from offshore wind, in line with the trend in onshore wind over the last 20 years.

Before 2000, a number of small-scale offshore wind projects were installed mainly in Denmark, Sweden and the Netherlands. The first commercial project installed in the UK was North Hoyle, off the north coast of Wales, in 2003 using 30 Vestas V80-2.0MW turbines on monopile support structures. Since then, the UK has installed at least one project per year, with a cumulative capacity exceeding that of the rest of the EU for the first time during 2011. The installation of the demonstration Alpha Ventus project in 2009 marked the completion of the first German project of any scale, using six REpower 5M and six AREVA M5000-116 turbines (both turbine models rated at 5MW) on jacket and tripod support structures. The growth in cumulative installed capacity in UK and the rest of the Europe is presented in Figure 1.1. Offshore wind farms have been installed outside Europe, but their cumulative installed capacity is far less.

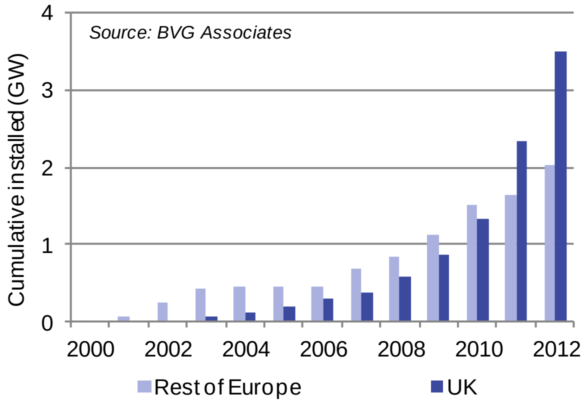

Figure 1.1 Cumulative installed commercial offshore wind capacity in UK and rest of Europe (2012 estimated).

Early installation was dominated by two Danish projects: Horns Rev I with a capacity of 160MW in 2002; followed by Rødsand 1 (formerly known as Nysted) in 2003. The first projects installed as part of the UK's Round 1 were generally limited to 30 turbines or 90MW, until the development of the combined 194MW Lynn and Inner Dowsing project in 2008. When Horns Rev II was installed in 2009, it became the largest offshore project in the world, at 209MW, but since then three larger projects have been installed in the UK. Greater Gabbard, once complete, will be the first offshore wind farm to exceed 500MW. The distribution of the size of commercial wind farm projects installed in Europe to date is presented in Figure 1.2. Prototype and small-scale demonstration sites are not included.

Although the UK's Round 3 has seen multi-gigawatt zones for wind farm development awarded to successful development partners, most companies consulted with during this project anticipate that, in the medium-term, zones will be built out in projects of rated power between approximately 500MW and 1GW. The choice of this scale is based on a range of factors including economies of scale, financing requirements, the amount of installation activity possible with given methods in each fair weather season, and substation and export cable and capacities.

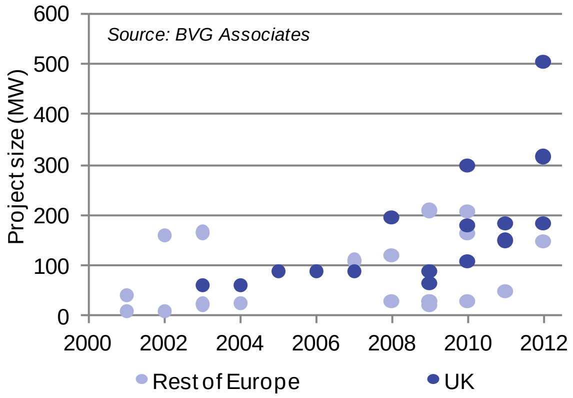

Figure 1.2 Distribution of commercial offshore wind project size (rated output) installed over time in UK and rest of Europe (2012 estimated).

In addition to more and larger projects, we have seen a steady rise in the maximum water depth in which projects have been installed, which is now also driving changes in support structure technology. The deepest water commercial site installed to date has been the 165MW Belwind project, which used monopiles installed in a wide range of water depths from 20m to 37m. The distribution of the maximum water depth for each project installed to date is presented below.

In the future, Germany in particular is likely to see the development of increasingly deep sites due to the bathymetry of available sites off its North Sea coast. For the UK, many of the projects included in the Scottish Territorial Waters (STW) round of development are also located in particularly deep water, with over half the anticipated installed capacity to be located in greater than 40m depth.

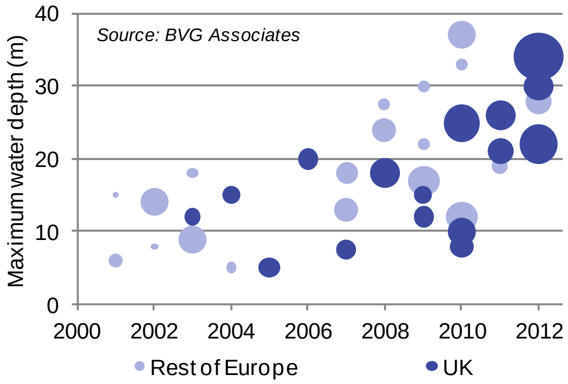

Figure 1.3 Distribution of maximum reported site water depth (LAT) over time for commercial UK and rest of Europe offshore wind projects (bubble size reflects wind farm rated output) (2012 estimated).

Projects further offshore generally benefit from higher wind speeds. In some cases, a challenge has been to find a suitable OMS port close to the site to minimise transit time. For example, the Danish Horns Rev I project, though only 20km from shore, is almost double this distance from its operations port, Esbjerg. The Horns Rev II project, which was further from shore, was the first to use an offshore accommodation platform to partly mitigate this problem. Developers of the UK Sheringham Shoal project off the north coast of Norfolk addressed the lack of suitable nearby port facilities by creating a new harbour facility to support operations in nearby Wells-next-the-Sea. The distribution of distance to nearest OMS port for projects installed to date is presented in Figure 1.4.

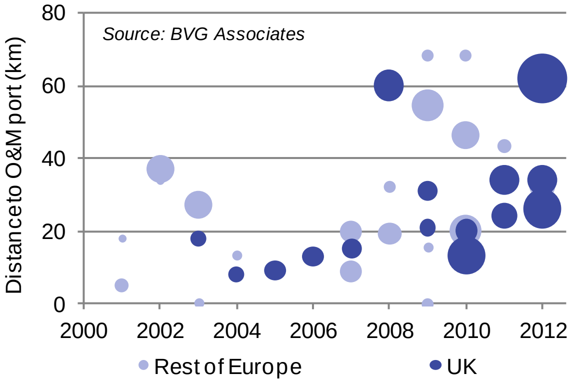

Figure 1.4 Distribution of distance to OMS port over time for commercial UK and rest of Europe offshore wind projects (bubble size reflects wind farm rated output) (2012 estimated).

There has also been a steady growth in the rated power of turbines installed each year throughout the history of the wind industry, with a significant increase in typical size for offshore projects compared with onshore. Since 2000, the maximum rated power of turbines installed in offshore wind farms has steadily grown from 2MW up to 6.15MW in 2012 with the Belgian project Thornton Bank 2. The distribution of rated power of turbines used in commercial projects to date is shown in Figure 1.5.

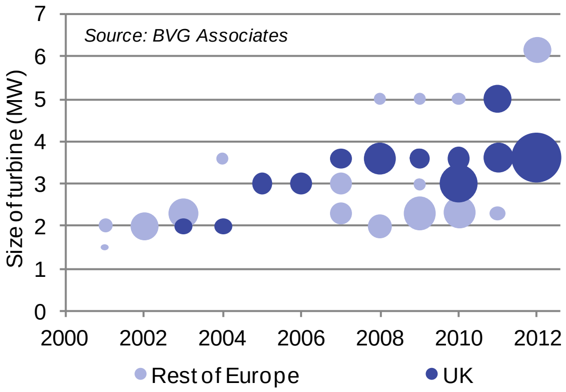

Figure 1.5 Distribution of size of turbine installed over time for commercial UK and rest of Europe offshore projects (bubble size reflects wind farm rated output) (2012 estimated).

Currently, the next generation of wind turbines is in development, including onshore prototyping and offshore demonstration. This next generation is characterised by:

- 6MW to 8MW-Class turbines designed exclusively for offshore use
- Rotor diameters of 150m to 170m, and
- A move towards lower-speed generator designs, either with or without gearboxes, with a much greater focus on reliability and maintainability offshore.

Such turbines offer the prospect of significantly reduced LCOE via reduced wind farm capital expenditure (CAPEX), operational expenditure (OPEX) and increased annual energy production (AEP), but this requires a major investment in technology development and manufacturing methods.

The increased size of turbines, coupled with increased water depth, also drives a change from monopile support structures towards the use of jacket and other steel and concrete designs. The change in foundation type, turbine size, distance to port and increased scale of the industry is leading to the adoption of new installation methods and operation strategies. The design voltage of subsea array cables likewise is anticipated to increase in response to the use of higher rated turbines.

Industry's view is that the adoption of this next generation of larger turbines, with associated innovations, is the most significant driver for reducing costs. Discussion of the historical trend in costs to date is presented in Chapter 1 of *The Crown Estate*

Offshore Wind Pathways report. Critical to having confidence in the modelling of future LCOE reductions is understanding the reasons for historical increases in CAPEX.

Industry recognises that the trends of working in deeper water and further from shore presented above will continue. These trends do drive up CAPEX and OPEX, which are only partially offset through increases in AEP due to higher average wind speeds, as discussed in *Offshore Wind: Forecasts of future costs and benefits* published in June 2011[3], and shown in the baseline costs presented in Section 4. Cost reductions due to developments in technology, supply chain and finance do still enable LCOE reductions over this period, but it is important to remember that these are within the context of the rising costs of delivering offshore wind farms due simply to the sites made available to the industry.

[3] *Offshore Wind: Forecasts of future costs and benefits*, BVG Associates on behalf of RenewableUK, June 2011, available online at www.bwea.com/pdf/publications/Offshore_report.pdf, accessed May 2012.

2. Methodology

2.1. Scope of work

The basis of the analysis presented here is a model in which baseline elements of CAPEX, OPEX and AEP for a range of different representative wind farms are impacted by a range of technology innovations. Analysis is carried out at a number of points in time and on a number of pathways along which the industry could develop, thus describing various potential pathways that the industry could follow, each with an associated progression of costs.

Output from the Technology work stream is then adjusted by the output of the Supply Chain work stream before being fed into the Finance work stream in order to derive a project LCOE for different wind farms at discrete time steps. All results presented in this report incorporate the impact of Technology innovations only. No benefit is taken here from Supply Chain or Finance work stream impacts. The combined impact from all three work streams is explored in *The Crown Estate Offshore Wind Pathways report*. The analysis does not consider maximising revenue (and hence decreasing the LCOE) through optimising power quality or energy forecasting, but does explore sensitivity to both internal and external factors, as discussed in Section 13 and *The Crown Estate Offshore Wind Pathways report*. In addition, as the analysis does not consider innovation in transmission assets, it does not consider innovations such as the underrating of transmission assets compared to the rating of the wind turbines on a given wind farm.

The analysis is structured around four different matrix variables: Turbine MW-Class; Site Type; date of financial investment decision (FID); and Industry Story as discussed also in *The Crown Estate Offshore Wind Pathways report*.

Turbine MW-Classes

Four different Turbine MW-Classes are considered, stretching from state-of-the-art today through to that which is anticipated to begin impacting the market at FID in 2020. These are summarised below, showing how existing products fit. Some turbines may have a rated power that fits in one Turbine MW-Class, but a rotor diameter that fits another. As an example, the REpower 6M, with 126m diameter rotor, is classified as 4MW-Class due to its rotor diameter.

Table 2.1 Summary of Turbine MW-Classes.

Turbine MW-Class	Nominal range of power rating (MW)	Typical range of rotor diameter (m)	Example current and future turbines
4MW	3 to 5	up to 145	AREVA M5000-116 and 135, BARD 5.0, GE 4.1-113, REpower 5M and 6M, Siemens SWT 3.6-107 and 120, Vestas V112-3.0
6MW	5 to 7	145 to 162	Alstom Haliade 150-6MW, BARD 6.5, Siemens SWT-6.0-154
8MW	7 to 9	162 to 180	MPSE Sea Angel 7MW, Samsung 7MW, Vestas V164-7.0MW
10MW	9 to 12	Above 180	AMSC Windtec Sea Titan 10MW

Site Type

Four generic Site Types are considered, which cover the range of sites likely to be developed to 2020. These are summarised in Table 2.2.

Table 2.2 Summary of Site Types.

Site Type	Average water depth (MSL) (m)	Distance to nearest construction and operation port (km)	Average wind speed at 100m above MSL (m/s)	Example UK wind farms
A	25	40	9	Walney 1 and 2, Westermost Rough
B	35	40	9.4	East Anglia ONE, Navitus Bay
C	45	40	9.7	Inch Cape, Neart na Gaoithe
D	35	125	10	Creyke Beck (Dogger Bank), Heron (Hornsea)

Site Type A is typical of a Round 2 site. Site Types B, C and D are typical of Round 3 and STW, as they are in deeper water and further from nearest port, but have higher wind speeds and therefore yield greater AEP.

Date of FID

Four dates of FID are considered:

- The baseline, wind farms with FID in 2011, which are likely to be completed four years later in 2015
- Wind farms with FID in 2014, which are anticipated to consist of the remaining Round 2 projects plus extension sites and the earliest Round 3 and STW sites
- Wind farms with FID in 2017, which are anticipated to consist of a wide range of projects from Round 3 and STW sites, and
- Wind farms with FID in 2020, which are anticipated to consist of the later phases of Round 3 and STW sites.

Industry Story

Four cohesive combinations of market size and supply chain, finance and technology developments are considered as representing reasonable boundaries within which the industry is likely to evolve. These are summarised in Figure 2.1.

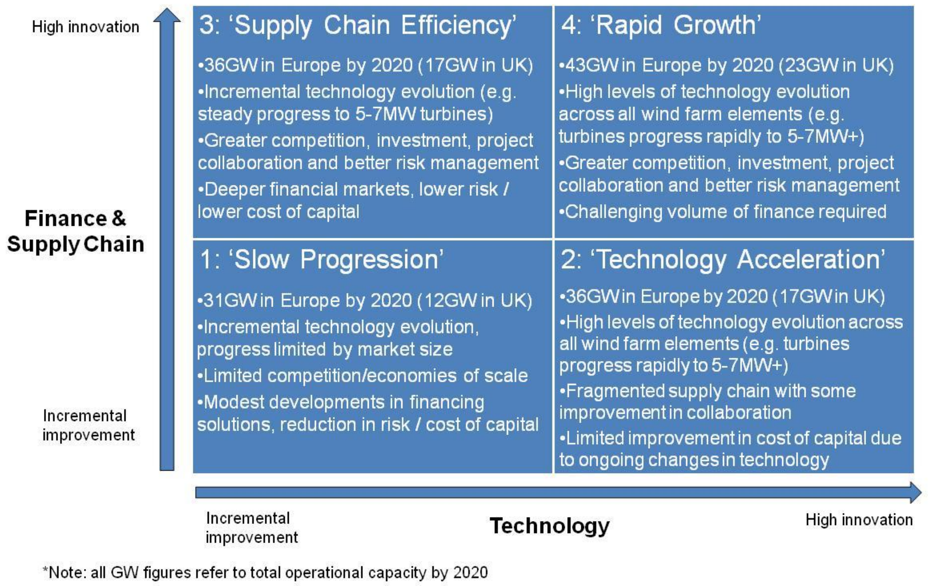

Figure 2.1 Summary of Industry Stories (taken from Chapter 1 of the *The Crown Estate Offshore Wind Pathways report*).

In total, with four Site Types, four Turbine MW-Classes, four FID dates and four Industry Stories, 160 combinations are considered, though discounting the commercial use of larger turbines in earlier years and smaller turbines on some Site Types in later years reduces the number of combinations.

Due to only a marginal anticipated benefit of 10MW-Class Turbines on the lifetime cost of energy at FID in 2020 compared with 8MW-Class Turbines, and an expectation by developers questioned of a low market share for projects reaching FID in 2020 using such large turbines, the impact of 10MW-Class Turbines is only discussed qualitatively in the report. See Section 12.5 for further discussion of 10MW-Class Turbines.

A Technology innovation in this context is defined as a substantive change in the design of hardware, software or process. The definition is wide and the change may be evolutionary or a breakthrough. It may be a collection of advances with the same objective or relate to the development of new technology standards. Examples include the adoption of larger rotors for a given turbine rating, the evolution of next generation geared drive trains, or the introduction of a new technology such as direct current (DC) generation and collection.

In contrast, the Supply Chain work stream considers the impact of:

- **Asset growth and economies of scale**. As capacity increases, cost savings can be achieved through, for example, productivity improvements (for example, having more vessels reduces the impact of installation delays as it affords increased flexibility) and logistics (for example, if new capacity and its associated supply chain are located closer to the market it is possible to minimise transport costs). With increased volumes, economies of scale can be achieved: in procurement, through “learning by doing”, by standardising processes and protocols reducing the need for more expensive bespoke solutions and by increasing the productivity of exiting assets (including manufacturing facilities) by increasing volume throughput and run lengths.

- **Changes in contract forms/terms**. Moving away from lump sum contracts, tightening terms and conditions and introducing more appropriate incentive mechanisms may lead to cost reductions.

- **Means of managing and pricing uncontrollable risk**. Uncontrollable risks include unpredictable weather (sea state and wind), ground conditions at the offshore construction site and consequential losses not covered by contract terms. A better understanding and apportioning of uncontrollable risk can accrue savings by reducing their impact.

- **Increased competition from UK, other European and low cost country players**. Greater competition in each of the main supply markets (for example, turbines, foundations and installation) will both squeeze margins and increase the drive for lower costs. In some supply markets the entry of players from countries such as China, South Korea and India may also have a significant impact as their cost bases are significantly lower than their European counterparts due to the lower costs of labour and, in some instances, access to lower cost raw materials or cheaper finance. The impact of competition from low-cost countries is considered on both the supply of complete wind farm products and key components.

- **Vertical collaboration across different tiers in the supply chain**. Currently contracts are mainly awarded on a project by project basis with most developers letting up to eight major contracts. This can lead to a silo approach without adequate recognition and management of the interdependencies between contracts. This often leaves the developer bearing much of the “interface risk”. Vertical collaboration includes: consolidating procurement contracts and so reducing interfaces, contingencies and cost overruns; improving interface management through developing and implementing programme management tools; and involving suppliers (such as designers, installers and OMS providers) early in the project life (for example, before procurement) in order to design out risk and avoid iterations that can result in cost overruns.

- **Increased horizontal cooperation**. This involves sharing best practices and facilities and developing joint intellectual property among the same tier of the supply chain. It may also involve working together to develop standards and sharing between peers (for example, sharing repair vessels among OMS operators).

It is recognised that there are links between Technology and Supply Chain impacts (for example the introduction of new technology has an impact on the competitive landscape) and that there is a continuum of innovations, at some point along which there is boundary between what is considered under the Technology work stream scope and what is considered under Supply Chain. The examples in Table 2.3 are intended to provide clarification of this boundary between Technology and Supply Chain.

Table 2.3 Examples of boundaries between the Technology and the Supply Chain work stream scopes.

Item	Technology work stream scope	Supply Chain work stream scope
Wind turbine gearbox	Modifications to designs to improve reliability	Improvements in manufacturing efficiency due to increased volumes
Jacket support structure	Substantively new manufacturing processes	New suppliers entering the market using improved efficiency and evolved manufacturing processes
Array cable installation	New processes or tooling to improve installation	Improving efficiency and avoiding errors
OMS	Moving to mother ships supporting fast work boats during operation	Sourcing work boats from low-cost suppliers

Although Supply Chain, Finance and Technology issues are closely linked, it is critical to the robustness of project conclusions that there are clearly defined boundaries between them. The tools developed for Supply Chain and Technology modelling have been designed together, with identical definitions of wind farm elements and results based on the same assumptions in order to ensure consistency.

Throughout the project, information gathered in one work stream and relevant to others has been transferred. In many cases, industry participants have provided specific evidence to two or three work streams in parallel.

2.2. Project terminology and assumptions

2.2.1. Definitions

A detailed set of project assumptions was distributed to project participants in advance of their involvement in interviews and workshops. These assumptions are provided in Appendix A, and cover technical and non-technical global considerations and wind farm-specific parameters.

The derivation of the LCOE as used in *The Crown Estate Offshore Wind Pathways report* and the *Finance work stream report* is explained in Section 2 of the *Finance work stream report*. To consider the impact of technology innovations alone in this report, a measure of the LCOE is used, based on a single set of financial assumptions. This is detailed in Appendix A. It is equivalent to discounting and annualising the CAPEX spend profile based on a discount rate of 10 per cent, combining this with a constant annual OPEX, and dividing by net AEP. This method gives the LCOE for a given project that is within a few per cent of that derived in Section 5 of the *Finance work stream report*. As all mention of the LCOE in this report is relative to a wind farm of 4MW-Class Turbines on Site Type B with FID in 2011, as presented in Section 4, this simplification introduces negligible inaccuracy.

The definition of scope of each wind farm element is provided alongside the derivation of baseline parameters in Sections 5 to 11.

The baseline costs presented are nominal contract values, incorporating supply chain effects typical of late 2011, rather than outturn values. Future costs follow the same pattern. The *Supply chain work stream report* discusses the impact of changes within the supply chain on these costs and the *Finance work stream report* discusses contingency and the impact of risk on the lifetime cost. All results presented in this report incorporate the impact of technology innovations only. No benefit is taken here of Supply Chain or Finance work stream impacts.

2.2.2. Terminology

For clarity, when referring to the impact of an innovation that lowers costs or the LCOE, terms such as reduction or saving are used and the changes are quantified as positive numbers. When these reductions are represented graphically or in tables, reductions are expressed as negative numbers as they are intuitively associated with downward trends.

Improvements in reliability are expressed in terms of an absolute percentage change in wind farm availability. For example, if availability is improved by one per cent, from a baseline of 95 per cent the resultant availability is 96 per cent.

2.3. Technology innovation modelling

The basis of the analysis presented here is an assessment of the differing impact of a series of Technology innovations relating to each of the wind farm elements on each of these baseline wind farms described, as outlined in Figure 2.2. This section describes the methodology for analysis of each innovation in detail. An example is given in Appendix A.

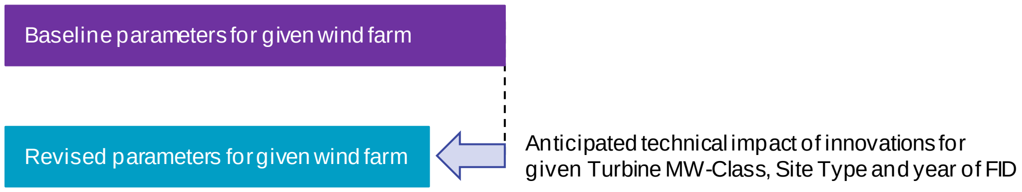

Figure 2.2 Process to derive impact of innovations on the LCOE.

Initially, more than 200 Technology innovations were identified. During the process of industry engagement, each was associated with a given wind farm element and assessed. In some cases, innovations were combined and, in other cases, innovations were deemed to relate to Supply Chain rather than Technology. Others were deemed either to have too marginal, narrow or uncertain a benefit, or were unlikely to have any impact even on projects reaching FID in 2020. This consolidation process resulted in approximately 70 innovations being modelled in detail here. For each of these, a four stage process is applied in order to evaluate the maximum potential technical impact of the innovation on the LCOE and then to moderate this impact to account for various features of the market in order to derive an anticipated impact under the default Industry Story for this work stream, Story 2. At a later stage, the impact of the other Industry Stories is applied, as discussed in Section 12.6. Figure 2.3 summarises this process of moderation.

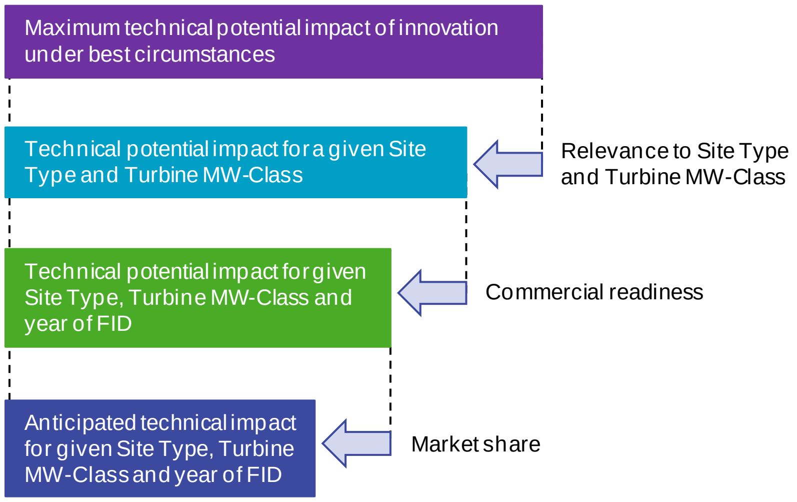

Figure 2.3 Four stage process of moderation applied to the maximum potential technical impact of an innovation to derive anticipated impact on the LCOE.

2.3.1. Maximum technical potential impact

Each innovation may impact a range of different costs or operational parameters as listed in Table 2.4. The maximum technical potential impact on each of these is recorded separately, relative to parameters relevant to the FID 2011 baseline wind farm most suited to the given innovation. Where relevant and where possible, this maximum technical impact considers timescales that may be well beyond 2020, depening on the development time associated wit the innovation. The treatment of the impact of technology innovations on risk is discussed in Section 12. The potential impact on the LCOE due to technology innovations that change timescales for development and construction activities is considered in the *Finance work stream report.*

Frequently, the potential impact of an innovation can be realised in a number of ways, for example through reduced CAPEX or OPEX or increased AEP. This analysis considers the implementation resulting in the largest reduction in the LCOE, which is a combination of CAPEX, OPEX and AEP.

Table 2.4 Information recorded for each innovation.

Information recorded for each innovation	Comment
Per cent impact on cost of: • Wind farm development • Wind turbine nacelle • Wind turbine rotor • Support structure • Array cables • Wind farm installation • Operation and planned maintenance • Unplanned service, and • Other OPEX.	A definition of the scope of each is in Sections 5 to 11.
Per cent impact on: • Turbine gross AEP • Other turbine losses • Wind farm aerodynamic array efficiency • Wind farm electrical array efficiency, and • Wind farm availability.	A definition of the scope of each is in Sections 5 to 11. In order correctly to model cumulative impacts of innovations, data is actually recorded, for example, as a per cent change in wind farm unavailability but, for simplicity, all discussion in this document refers to absolute per cent changes in availability.

2.3.2. Relevance to Site Types and Turbine MW-Class

This maximum technical potential impact of an innovation compared with a wind farm reaching FID in 2011 may not be realised on all Site Types with all Turbine MW-Classes. In some cases, an innovation may not be relevant to a given Site Type and Turbine MW-Class combination. For example, innovations relating to monopiles do not apply to large turbines in deep water, as monopiles are not commercially viable in those circumstances, thus resulting in a relevance indicator of zero per cent. In other cases, the maximum technical potential may only be realised on some Site Types, with a lower technical potential realised on others. For example, using feeder vessels in support structure installation is most applicable to sites far from nearest port, such as characterised by Site Type D. In this case, the impact on Site Type B may be 80 per cent of that of Site Type D. In this way, relevance indicators for a given Site Type and turbine combination may be between zero and 100 per cent, with (in almost all cases) at least one combination having relevance 100 per cent.

This relevance is modelled by applying a factor specific to each combination of Site Type and Turbine MW-Class independently (for example, 4-A, 4-B, through to 8-C and 8-D (12 combinations)). The factor for a given Site Type and Turbine MW-Class combination is applied uniformly to each of the technical potential impacts derived above.

2.3.3. Commercial readiness

In most cases, the technical potential of a given innovation will not be fully realised even on a project reaching FID in 2020. This may be for a number of reasons:

- Long research, development and demonstration period for an innovation, such as DC generation and collection
- The technical potential can only be realised through ongoing evolution of design based on feedback from commercial-scale manufacture and operation, such as the development of improved turbine blade pitch control where innovations are part of an ongoing process of technical improvement that is likely to continue for a further 20 years or more, or
- The technical potential impact of one innovation is decreased by the subsequent introduction of another, for example, increased array cable and switchgear reliability decreases the benefit of loop array cable arrangements.

This commercial readiness is modelled by defining a factor specific to each year (FID 2014, 2017 and 2020), defining how much of the technical potential is available to projects. If the figure is 100 per cent, this means that the full technical potential is realised by FID 2020. For many of the innovations modelled here, this is not the case as further progress is expected after this point.

The factor relates to how much of technical potential is commercially ready for deployment in a 500MW wind farm reaching FID in the year in question taking into account not only the offering for sale of the innovation by the supplier but also the appetite for purchase by the customer. Reaching this point is likely to have required full-scale demonstration. This moderation does not relate to the share of the market that the innovation has taken but rather how much of the full benefit of the innovation is available to the market. In Sections 5 to 11, the level of commercial readiness is described as a percentage of the technical potential that is available to the market at a given time.

The methods of recovering technology development costs are discussed in Section 3.

2.3.4. Market share

Many innovations are compatible with others, but some are not (for example, innovations relating to monopiles and jackets or geared and gearless drive train solutions). Each innovation relating to a given element is assigned to one or more groups of complementary innovations and each group is assigned a market share for each Site Type, Turbine MW-Class and year of FID. This is a market share of an innovation for a given combination of Turbine MW-Class and Site Type for projects reaching FID in a given year. It is not a market share of the innovation in the whole UK or European offshore wind market that consists of a range of projects with different Turbine MW-Classes and Site Types. Such a level of analysis is provided in *The Crown Estate Offshore Wind Pathways report*.

The resulting anticipated technical impact of a given innovation, as it takes into account the anticipated market share on a given Turbine MW-Class and Site Type in a given year of FID, can be combined with the anticipated technical impact of all other innovations to give an overall anticipated impact for a given Site Type, Turbine MW-Class and year of FID. At this stage, the impact of a given innovation is still captured in terms of its anticipated impact on each capital, operational and energy-related parameter, as listed in Table 2.3.

The anticipated impact of each innovation for each Site Type, Turbine MW-Class and year of FID is then applied to the relevant baseline costs and operational parameters, to give a set of costs and parameters for each Site Type, Turbine MW-Class and FID year combination. These costs are nominal contract values and the operational parameters are assuming the same supply chain impacts (for example, competition or contract structure) as for a project reaching FID at the end of 2011, all under Industry Story 2.

To account for the impact of Industry Stories 1, 3 and 4, a uniform delay to all innovations that is specific to each Industry Story and year of FID is applied, to reflect the slower introduction of technology, as discussed in Section 12.7.

These outputs are then factored to account for the impact of the various FID year, Site Type and Industry Story-specific supply chain levers explored in Section 3 of the *Supply chain work stream report,* before use in Section 5 of the *Finance work stream report,* and *The Crown Estate Offshore Wind Pathways report*.

2.4. Industry engagement

Industry engagement has been carried out in three phases, with some organisations being involved in all three phases. A full list of the 56 companies that were engaged formally and in substantive ad hoc conversations is provided in Appendix D. From within these organisations, approximately 120 individuals contributed directly, in many cases supported by input from colleagues. The engagement was focused on players with track record in the industry, rather than innovators from outside of the sector. The outcome of engagement therefore is an aggregate of experienced industry views, only partially taking benefit of experience from players in parallel sectors that may in the future have a key role to play as the offshore wind industry matures.

2.4.1. Interviews

The purpose of interviews was to explore in detail potential cost reduction opportunities, steps to realise these opportunities and prerequisites to taking these steps. Often this dialogue took many hours over a number of meetings. Interviewees were chosen based on their industry track record as well as their potential role in providing innovative solutions in the future. Care was taken to engage with technologists and technology cost modellers within organisations with hands-on involvement in the industry, recognising that, in some organisations, obtaining detailed information about a wide range of innovations required dialogue with more than one representative.

Three quarters of interviews were undertaken through structured face-to-face discussions; the rest were carried out by telephone following the same process. Interviews were mostly conducted under non-disclosure agreements with a documented system for determining what information could be shared with The Crown Estate or published. Due to this, in most cases, we have not been able to ascribe comments to specific organisations in this report.

In order to ensure clarity of responses and to capture quantitative and qualitative information, a detailed project briefing and interview structure were provided for participants to review in advance of the dialogue. Typically 10 to 20 pages of notes covering broad, big picture issues and detailed input on specific, defined innovations were prepared and mirrored back to the participant for clarification, to address outstanding issues (often involving others within their organisation), and for approval, both of its content and the sensitivity of information with regard to onward dissemination. Twenty formal interviews were carried out, with the distribution of participants and subject matter as set out below. A number of other interviews were held, addressing specific areas of innovation in order to provide supplementary input where this was deemed beneficial.

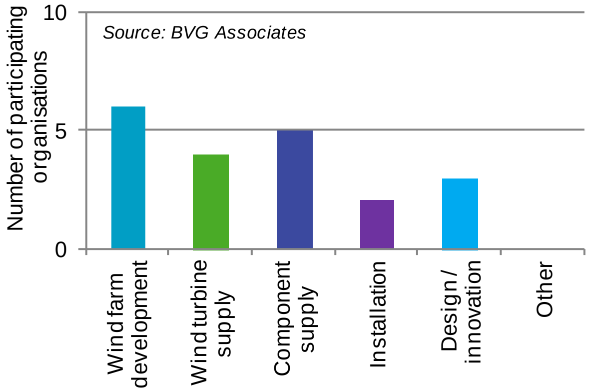

Figure 2.4 Interviewed organisation by core business sector (design / innovation incorporates technical design consultancies and organisations facilitating joint industry innovation projects).

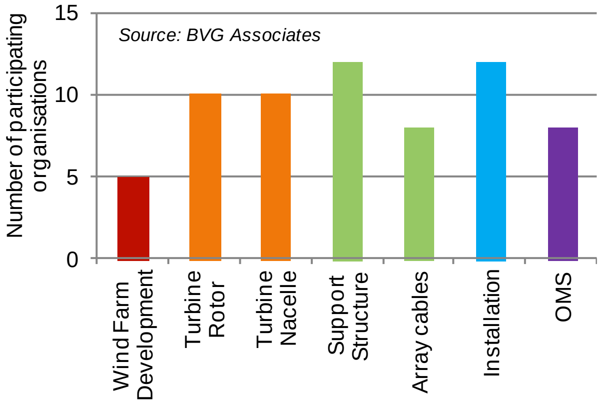

Figure 2.5 Interview scope by wind farm element (includes duplicates if the organisation was qualified to comment on multiple elements).

Overall, we experienced excellent cooperation and open dialogue, with organisations often prepared to do a significant amount of pre-and post-interview work. There was a reasonably strong correlation of views relating to many of the innovations likely to make the biggest difference over the next 10 to 15 years, though often with diverse views and less certainty expressed about the rate of implementation and the maximum technical potential savings achievable. This is not unexpected in a relatively immature sector.

Another feature of interviews was the openness to share ideas on a wide range of innovations. In some cases, estimates were based on detailed internal calculations not available to the project; in other cases, they were based on the significant industry-specific technical experience of the participant and the collective knowledge of their organisation.

In dialogue with some participants, we benefitted from their detailed modelling of the products currently in development, but fewer results were available for the next generation of products. In this case, we used participants to test our assessment of cost reduction opportunities. In a number of cases, we were able to use results from participants' in-house modelling to validate or evolve our models. Examples include the following:

- A number of developers provided cost breakdowns for specific wind farms in development or already operating. Others provided snapshots of actual operating costs and resulting forecasts for future projects.

- One turbine manufacturer provided a cost model for support structures based on different turbine parameters and under a range of conditions; another ran a series of cost models especially around costs and benefits of different Turbine MW-Classes, which showed a correlation of models to within one to two per cent for a number of wind farm elements.
- A number of component suppliers used site parameters and other assumptions from the project to present cost comparisons relating to specific innovations directly “in the language” of the project.
- Others provided time and cost breakdowns for installation activities to assist in building a model in order to evaluate the impact of different innovations on installation costs.
- One organisation undertook a specific wake analysis which verified project assumptions about aerodynamic array losses for different Turbine MW-Classes.

The result of engagement via interviews was a part-verified view of well over 100 specific innovations and a reasonable level of consensus on key issues and opportunities. Views on the overall technology-related cost reduction opportunities across the industry were mixed but rational, A bottom-up aggregation of opportunities led to savings that generally were higher than industry’s top-down estimates. The workshops provided a valuable forum for debating this difference and for bringing industry challenge to bear on each of the specific innovations discussed in the interviews and their potential impact on the market and cost reduction.

2.4.2. Workshops

The purposes of the workshops were to test the output from the interviews and related modelling and to facilitate dialogue between organisations playing different roles in offshore wind, in order to explore the impact of changes in one wind farm element on costs and risks relating to others. Particular attention was given to the interfaces between different activities and suppliers.

Table 2.5 Subject and location of technology workshops.

Theme	Location
Underpinning issues in installation and OMS	UK
Turbine and support structure	Germany
Turbine and support structure	Denmark
Turbine and support structure	UK
Installation and OMS	UK
Installation and OMS	UK
Wind farm development	UK

Workshops took place in UK, Germany and Denmark in December 2011 and January 2012 and involved about 50 companies, with a distribution of core business sectors as shown below. Twenty companies are based in UK, seven in Denmark, six in both Germany and the Netherlands, and the rest are based elsewhere in Europe and beyond.

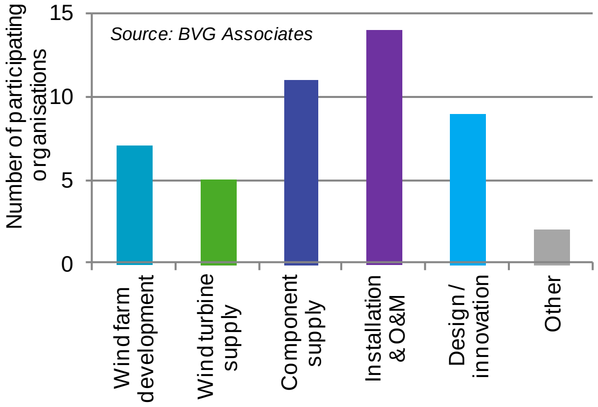

Figure 2.6 Workshop attending organisation by core business sector.

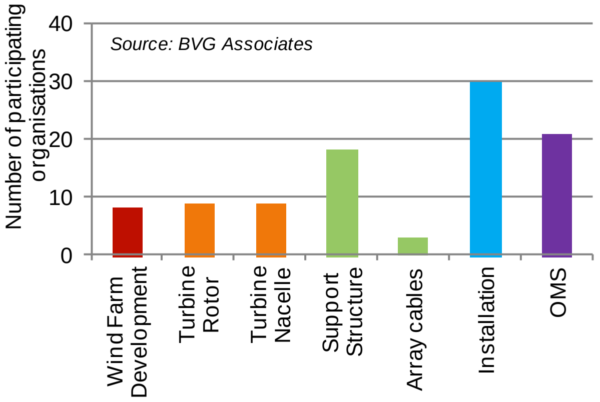

Figure 2.7 Workshop attending organisation by wind farm element (includes duplicates if the company attended multiple workshops).

Attendees were expected to review in advance a detailed project briefing and lists of innovations identified to date and their potential impact on the LCOE.

Typically, the agenda covered project purpose, modelling methodology and reviews of innovations, both including those already modelled and those advised in open dialogue by participants. Again, the information that was gathered in the workshop was verified and expanded upon by sending the notes of the meeting to participants with a request for further information where necessary.

To the level possible in each workshop, depending on attendees, for a range of innovations the following were discussed:

- Maximum technical potential impact, by element
- Relevance to Site Type and Turbine MW-Class
- Commercial readiness, by year of FID
- Market share, generally on wind farms using 6MW-Class Turbines on Site Type B, by year of FID
- Overall anticipated impact, generally on wind farms using 6MW-Class Turbines on Site Type B, with FID in 2020
- Early signs that indicate progress in implementing the innovation
- Prerequisites for investing in the innovation, and
- Other issues, dependencies and perspectives.

Generally, we found dialogue in workshops open and constructive, even though it was not carried out under a nondisclosure agreement. There was often significant interest in the overall modelling exercise and preliminary results. Dialogue was in some cases wide-ranging and provided a number of relevant additional perspectives, though most evidence supporting quantitative results was provided outside the workshop environment. In many cases, participants made new industry connections and gained substantive learning in areas outside of (but relevant to) their core business.

Structured feedback was requested following each workshop. On average, this was received from 30 per cent of attendees, and Table 2.6 summarises the overall response.

Table 2.6 Workshop feedback (Average score 0: Poor, 1: Average, 2: Good and 3: Excellent).

Question	Average score
What did you think of the workshop programme & how useful did you find the workshop overall?	2.1
What did you think of the whole group discussion?	2.5
What did you think of the discussions relating to innovations?	1.9

Output from workshops consisted of notes, actions that have since been closed, and a revised presentation capturing the changes in model inputs agreed.

2.4.3. Verification

Following the aggregation of information received in workshops and through dialogue after workshops, we prepared an early draft report. Specific sections of this report were issued for peer review. All sections were reviewed by at least two industry contacts that had both been involved in the project and have specific expertise in the area under review. In total, approximately 20 companies with core business sectors covering all the elements above provided feedback during this detail verification activity.

In general, feedback supported the findings and in many cases provided further supporting data or information. Inevitably, there were a range of views on some innovations and care was taken to balance these in redrafting the text while ensuring that the points raised were included even if the judgement of the impact of an innovation was unaltered.

2.5. Treatment of risk

Risk is treated in a holistic manner between work streams and Section 4 of the *Finance work stream report* contains a detailed exposition. New technology development generally has a long-term beneficial impact on risk but, in the short term, its introduction and any changes in related processes may add uncertainty.

The key areas where changes in risk due to technology developments are modelled relate to installation, operation and energy assessment relating to wind speed. Information regarding risk is passed to the Finance work stream through input to the definition of P10:P50:P90 ratios. A summary of changing risk due to technology-related activities under each Industry Story is provided in Section 12.7.

2.6. Treatment of health and safety

The health and safety of staff working on both onshore and offshore operations is of primary importance to The Crown Estate and the wider offshore wind industry. As part of the cost reduction pathways study, The Crown Estate initiated a process designed to identify the relative impacts on health and safety performance in the future from the cost reduction measures put forward. This was carried out in a consistent manner within each of the three work streams: information captured in the Technology interviews and workshops were subsequently passed to a specialist consultant, PMSS, for collation and analysis.

From a technology perspective, the engagement with industry was intended to incorporate into the cost of innovations any mitigation required in order to at least preserve existing levels of health and safety. Although difficult to quantify whether fully captured in the assessments, in some cases, for example, relating to offshore operations, preserving similar levels of health and safety limited the envelope of innovations modelled. Many of the innovations that are considered to reduce the LCOE over time have an intrinsic benefit to health and safety performance, for example:

- The increased rated capacity of turbines, hence fewer turbines to transfer per gigawatt installed
- The increased reliability of turbines and hence fewer transfers to turbines and less time working in the offshore environment, and
- Condition monitoring / remote diagnostics, which provide a more effective and proactive service and hence result in fewer complex retrofits.

Some of the technology-related drivers and issues raised during industry engagement are discussed in more detail in the following chapters: a summary of the main themes arising out of all the three work streams and their impact (positive, neutral or negative) is provided in the companion report, *Health and Safety Review*.

3. Technology development lifecycle

This section discusses typical technology development lifecycles in offshore wind, reflecting on the impact of these on reducing the LCOE. It focuses on wind turbines, as these have the longest development life cycle and the greatest impact on lifetime costs.

3.1. Wind turbines

The typical development lifecycle for a wind turbine consists of a number of stages, as shown in Table 3.1. In moving from each stage to the next, it is normal to have a gate review at which it may be decided to halt development or change the scope, pace or direction of development.

The decision to develop a new turbine is driven by the opportunity to gain a competitive advantage by reducing its lifetime cost for customers. Due to the long development cycle, the reduction needs to be quite significant (at least 10 per cent) to justify investment in a new design instead of stepwise improvement of an existing design through supply chain and individual component innovations.

There is a strong history of cost reduction in the wind industry onshore, linked to innovation and new product introduction, including larger turbines. For example, see the trends discussed in the United States Department of Energy *2010 Wind Technologies Market Report* published in June 2011.[4]

[4] *2010 Wind Technologies Market Report,* U.S. Department of Energy, June 2011, available online at www1.eere.energy.gov/wind/pdfs/51783.pdf, accessed May 2012.

Table 3.1 Typical development life cycle for a wind turbine.

<table>
<tr><th>Development stage</th><th>Typical scope</th></tr>
<tr><td>Concept design</td><td>This covers the development of a design basis and basic turbine parameters and a justification of the business case. It defines the test, certification and supply chain plans.</td></tr>
<tr><td>Detailed design</td><td>A detailed load and stress analysis and development of a full set of drawings, specifications and manuals enables purchasing, installation and operation of the prototype turbine. There may also be a third-party design approval element of type certification.</td></tr>
<tr><td>Prototype turbine testing and certification</td><td>The procurement, assembly, installation and operation of a prototype turbine is either funded by the wind turbine manufacturer, or by a developer specifically for test purposes. The prototype is most likely installed onshore as this lowers the cost and enables easier access, so it has less downtime compared with offshore. In UK, SSE Renewables' Hunterston site with three turbine locations is one of very few sites identified for onshore prototyping of very large offshore turbines. It is generally viewed that any differences in wind conditions offshore and onshore are of low importance in verifying the turbine design. Where offshore demonstration is most useful is in consideration of the dynamic interaction between the turbine and support structure and how this impacts turbine control.

It also covers:
Component-level testing (for example of blades and drive train).
On-site load and performance measurement.
Third-party type certification.
Generally, the characteristics of attractive prototype and demonstration sites, in addition to planning consent and grid connection are seen as:
High average wind speed. Hours in operation with above rated wind speeds, especially towards cut-out wind speed, are ideal for proving new turbines. Key activities on a prototype turbine, with associated ideal wind speeds include:
Commissioning and early turbine functional testing, which needs winds of 6 to 15 m/s
Safety testing, which needs winds of 6 to 20 m/s
Noise measurements, which need winds of 6 to 10m/s
Power curve measurements, which need winds of 3 to 20 m/s
Controller tuning and loads measurements, which need winds of 6 to 25 m/s, and
Rapid fatigue life accumulation, which needs winds of 10 to 25 m/s.
Reasonable logistics access. This is important not only to facilitate installation but also in case of a major component exchange during its early operation. There is also value in prototypes being located sufficiently close to the key engineering bases of manufacturers.
Clean topography. Measurement campaigns in particular are to be run for type certification, as local topographical conditions need to meet specific requirements.</td></tr>
<tr><td>Demonstration turbines</td><td>A number of demonstration turbines are supplied and operated, likely with some onshore and some offshore to demonstrate the turbine / support structure interaction.
There may be some element of public funding, which is below market pricing and technical rather than normal commercial scrutiny at FID.</td></tr>
<tr><td>Early commercial turbines</td><td>This refers to the supply and operation of a first commercial offshore wind farm that may have smaller number of turbines than full commercial scale farms.
A smaller proportion of risk resides with the asset owner than in a full commercial project, though the terms of such arrangements are often opaque and, externally, the project may seem fully commercial.

Typically, FID on such a project may be reached after about three years of operational experience on a prototype turbine (15 per cent of design life) on a high-wind speed site. A customer would also anticipate at least 15 turbine-years experience across a fleet of</td></tr>
</table>

Development stage	Typical scope
	demonstration turbines. Acceptable pedigree is also dependent on: • The experience of the wind turbine manufacturer and of its main component suppliers, including the operational track record of other turbines • The quality and extent of testing, including the harshness of test site conditions and the performance of the company in addressing issues relating to reliability • The risk involved in new designs, relating to the extent of changes in scale and technology compared with previous designs, and • The financial strength and commitment of the turbine manufacturer. The most significant series defect in offshore turbines to date was a drive train defect that led to the withdrawal of the Vestas V90-3.0MW turbine from the offshore wind market between early 2007 and May 2008. By the point of withdrawal, there had already been over four years operational experience on a prototype turbine and over 100 turbine-years experience across the fleet, including over 30 turbine-years offshore. This shows that, though the pedigree requirements reduce risk, they in no way guarantee reliability and it is anticipated that testing and verification requirements for new products will be increased over the next few years in response to experience from operating wind farms.
Full commercial implementation	This refers to the supply and operation of offshore turbines in quantity, to date with sales life significantly longer than for onshore turbines due to the length of the wind farm development cycle offshore.
Upgrade models during product life time	Most turbine manufacturers incorporate incremental design improvements in specific components in new upgrade model releases of a given turbine. In some cases, existing turbines will be retrofitted with these improvements. Most of the innovations discussed in Sections 6 and 7, such as those relating to turbine concept, nacelle layout or major component design will be introduced on a new wind turbine model, rather than on an upgrade model.
Introduction of variants	Frequently, once commercial operating experience has been obtained with a given turbine, one or more variants will be developed. An example of this is the development of Siemens SWT-3.6-120, with larger rotor than the original SWT-3.6-107. Such variants, though requiring full type certification, are considered of lower risk than a new turbine platform, and can extend the sales life of a turbine model considerably. Design changes may be limited to specific components or may affect most key components in some way.

Historically, the timescales for introducing new turbines has varied quite considerably. Typical timescales and an approximate indication of cumulative cost are presented in Figure 3.1. Based on industry feedback, development costs (including those incurred by the wind turbine manufacturer for new production facilities, but excluding supply chain investment) typically range from €200 to €500 million for a 6MW to 8MW-Class Turbine, depending on the scope of in-house supply and the scale of early production plans. This equates between about two to six per cent of lifetime revenue, depending on scope and product sales.

The key decision points in terms of spend committed are at the start of the prototype turbine testing and certification stage and, after some operating experience, at the point commitments are made to new manufacturing facilities and tooling for series production.

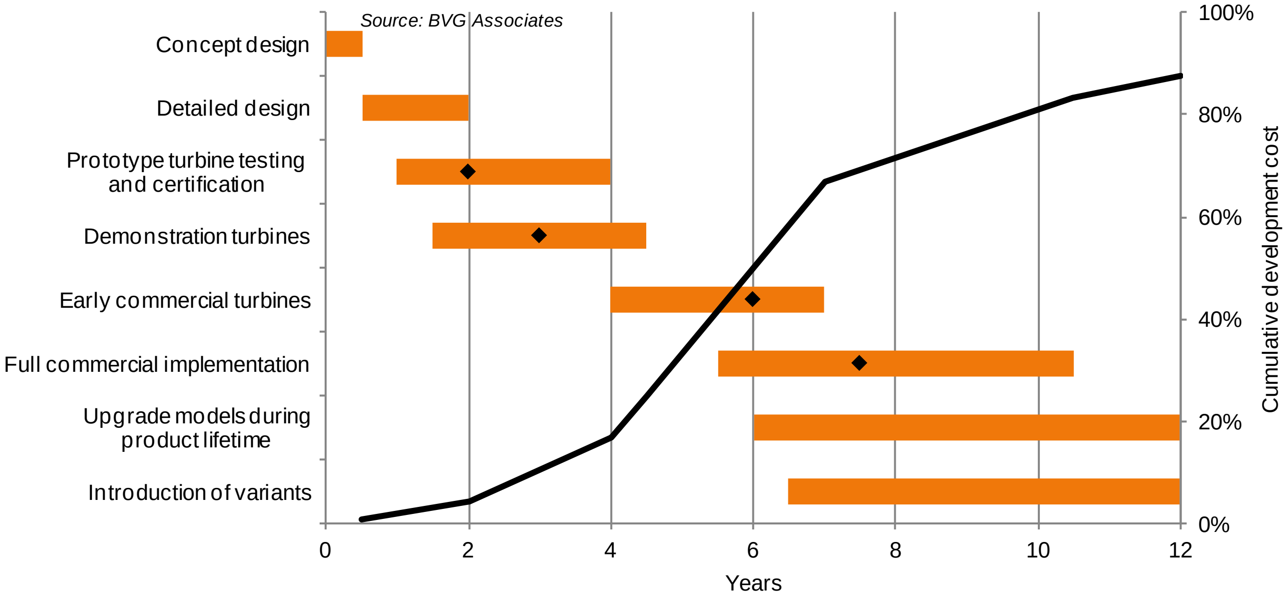

Figure 3.1 Summary of typical timescales and cumulative spend on new offshore wind turbine development. Diamonds indicate first turbine installation in stage.

A large wind turbine manufacturer employs a large engineering team, which it treats as an overhead cost. When deciding on a new product, it will look at the existing and upcoming product landscape and compare which new products are the most likely to provide best future earnings. It will assess the resources required both to develop the product and mature it, but the price it will actually realise is based on its ability of projects to pay and the level of competition for that product, rather than any function of development cost. A sales lifetime of seven or more years is expected, augmented by the release of variant turbines, such as one with a larger rotor diameter. Depending on the changes in scale of the turbine design, a manufacturing facility may be used for one or more turbine designs. Currently, we have a larger investment hurdle for a number of existing and potential future offshore wind turbine manufacturers, as they require for the first time a move to new coastal facilities in order to assemble and dispatch such large turbines with efficient logistics.

It is not only wind turbine manufacturers that have to invest to supply new turbines. It is common that key components suppliers also need to invest, both in the parallel development of components and in manufacturing capability. Typically, a wind turbine manufacturer will work with a single supplier with an existing supply relationship in developing a component for early turbines, with additional suppliers being integrated during or after the demonstration turbines stage.

It is relevant to note in considering investments by wind turbine manufacturers that some development and facility costs may only yield returns from the offshore market while others may also apply onshore. The development of other elements or of components within a wind turbine costs may be relevant to other sectors, but development costs for many large components such as blades, gearboxes and generators are quite offshore-wind specific.

3.2. Other elements

The technology development lifecycle for other elements varies quite considerably. Notable examples are discussed below.

Support structures

Two specific cases are relevant for support structures: the novel concept development and the evolution of existing designs. In both cases, this technology development may be driven by:

- The development of projects in deeper water with more challenging metocean conditions or different sea bed types
- The introduction of turbines with greater top tower mass and rotor diameter, or
- The incorporation of support structure innovations to reduce the LCOE. This may be focused on streamlining the manufacturing or installation processes or reducing the amount of steel that is required.

The first case is where there is a significant step change in the design concept. There are few (if any) truly novel concepts for offshore support structures available but there are many that have been used in the oil and gas sectors that have not yet been used in offshore wind. There are key differences between the two sectors that are of importance: offshore wind structures have to withstand more dynamic loading, and are required in higher volume and with more optimised designs.

Novel offshore wind foundation designs have tended to originate in specialist engineering consultancies or start-up companies. Following early stage assessments, promising designs have then tended to be picked up by large companies with greater financial backing and/or fabrication capability. For example, Keppel Offshore & Marine acquired a large stake in jacket designer OWEC Tower, DONG Energy (and now Fred. Olsen) have owned majority shares of Universal Foundation (formerly MBD Offshore), which is developing a suction bucket, and Seatower, who developed a concrete/steel gravity base foundation, has partnered with leading offshore wind civil engineers MT Højgaard.

A number of novel foundation designs have supported meteorological stations installed during the development stage of a wind farm. For example, Keystone Engineering has developed a twisted jacket foundation design that been scrutinised through the Carbon Trust Offshore Wind Accelerator programme and was selected by Mainstream Renewable Power for this purpose.

While this use provides information on the manufacturing and installation processes of the structure, feedback from industry suggests that this type of demonstration does not provide sufficient evidence to fully justify use in commercial quantities. This is because it is not built at full scale and is not subject to the dynamic loadings of a turbine. Such activity is therefore seen as a stepping stone to a full-scale demonstrator.

For full-scale demonstration, a test site is required and this has typically required involvement of a major utility/developer. For example, SSE Renewables was a key partner in the Beatrice Demonstrator project using jacket foundations for the first time in offshore wind and RWE and EDF Energy were partners in the Thornton Bank Phase I project using concrete gravity bases. Examples of future demonstration projects include DONG Energy installing two Siemens 6MW turbines at Gunfleet Sands , planned for late 2012, Vattenfall as the lead partner of the 11-turbine European Offshore Wind Deployment Centre off Aberdeen, Narec’s 100 MW site to test and demonstrate up to 20 next generation offshore wind turbines and associated infrastructure, and the agreement between DONG Energy and Vestas to demonstrate the new V164-7.0MW turbine at a site off Frederikshavn in Denmark.

It is expected that most of the key demonstrator sites available today will be allocated in 2012 or 2013 with installation in 2014 or 2015. Depending on the novelty of a design, some anticipate that a single demonstrator is sufficient to allow early commercial use while others expect to see a larger demonstration project, such as the Alpha Ventus project, consisting of two times six turbines.

For designs that involve a novel sea bed connection, such as suction buckets, it is expected that demonstrator projects will need to prove the behaviour of the foundation under dynamic turbine loading over a period of at least two years. A further challenge is that there may still be concerns about locating such a design in different seabed conditions to those in which they have been demonstrated.

Historically, there has been a gap of several years between the successful demonstration of a foundation design and its first commercial use. For example, OWEC Tower began the development of its Quadrapod jacket design in 2001. The first full-scale construction and installation of two foundations was in 2006 at the Beatrice Demonstrator Project. This was followed by a further six at the German Alpha Ventus project in 2009 and it was not until 2010 that the first fully commercial project, Ormonde, was installed.

Feedback from industry suggests there is strong pressure to reduce this lag through close cooperation between the design teams of suppliers and developers so that project planning can start before the completion of trial and full-scale production can start much more quickly, potentially within a year or two.

Where an existing design is in place, an evolution may be required to meet new requirements. In contrast to turbines, designs are typically project-specific so the development cycle is short. Costs are either paid separately or incorporated into the sales price for a batch of foundations.

It is believed that future development cycles for the evolution of the OWEC jacket design and the introduction of other jacket types will be considerably quicker than that describe above. This is because the quadrapod was a novel design for the offshore wind industry when it was first proposed and required significant demonstration before the industry was confident of its long-term performance. There was also little commercial demand for foundations for 5MW turbines during the development period for

OWEC designs. A range of variations on the jacket theme have been proposed in recent years and are likely to be accelerated through to commercial readiness in order to meet the growing market demand.

Early design stages are inexpensive with more advanced designs often receiving public support through grant programmes or enabling bodies like the Carbon Trust. Full-scale demonstration projects have typically required public funding to proceed, such as the Environmental Transformation Fund (ETF) in the UK. An example of this is the European Offshore Wind Deployment Centre in Aberdeen Bay, which received a grant award of up to €40 million Euros from the European Union.

In terms of investment in manufacturing facilities, early projects have been built in existing oil and gas fabrication yards which have required relatively little investment. Feedback from industry suggests that investment in advanced, large-scale manufacturing facilities is likely to range from £50 million to approximately £160 million for a throughput of about 100 units per year. Feedback is that such investment will not be speculative with some companies suggesting that a firm pipeline of two to three large commercial scale projects may be sufficient given confidence in wider industry progress while others would require commitment for up to five years of production.

Array cables

The underlying technology used in array cables is well established and has been developed over a long period of subsea cable supply. Innovations in array cables generally require evolution and optimised specification of products already developed for other applications.

For innovations such as introducing cables at a higher operating voltage or with alternative core material, most manufacturers may have provided similar products for other applications. The development cycle consists of modifying design features to meet specific offshore wind design requirements and then undertaking a limited production run to enable product certification and testing prior to full production.

Cable manufacturers will take the decision to develop new products based on market and customer demand. Initial design studies determine the potential for cost reductions and, with the necessary indicators of acceptance from the market, product development and production can take place. Taking a new product from concept to certification typically takes two years so decisions to use a new product on a wind farm should therefore be made around the date of FID. Scales of investment for new products are approximately £100,000 for initial feasibility studies and design and about £1 million for initial product runs and certification. Where similar products do not exist within the product catalogue of a cable manufacturer, levels of investment could be significantly higher.

Installation

Innovations in installation are primarily linked to the introduction of new vessels, driven by the trend away from the use of monopile foundations towards space frame structures such as jackets and by the benefits from working in a wider range of weather conditions.

For turbine installation vessel designs, there is a degree of certainty over the turbine size and technology, and ship designers such as GustoMSC and Wärtsilä have developed designs for turbine installation jack-ups, a number of which are entering service in 2012. This is less true for foundation installation and, while the vessels will probably be floating, heavy lift vessels, there are fewer concepts under development. It is likely that the foundation installation fleet in 2020 will include a mixture of new build vessels and modifications of existing vessels from other sectors. In both cases, investment is hampered by the lack of market clarity on required specifications, due to uncertainty about what vessels will be installing and what the optimum installation method(s) will be.

The lead time from vessel investment decision to operation is typically three to four years. For example, following the success of the Resolution, MPI Offshore decide to construct two new, larger jack-ups in 2008, and it took delivery of MPI Adventure and MPI Discovery in March and November 2011 respectively. In May 2007, Master Marine engaged Labroy Shipyard in Batam, Indonesia, to construct the jack-up Nora, which was subsequently contracted to install turbines at Sheringham Shoal starting in January 2011. The contract was cancelled when it became apparent that the vessel would not be ready in time.

There is a shorter lead time for conversions. A2SEA reported in November 2011 that its proposed venture with Teekay to convert a supertanker into a foundation installation vessel was at the engineering stage and that the vessel would be completed in 2013, ready for service in early 2014. Given the shorter lead time for vessel conversions, it is likely that the first bespoke offshore wind foundation installation vessels available to the market will be such modified vessels. There are a significant number of tankers no longer suitable for oil transport which could be available to the offshore wind sector.

For innovative installation equipment or processes such as blade lifting systems, sea fastenings or cable pull-in processes, lead times are lower than typical times from contracting to construction.

The development of facilities for the manufacture and installation of CGBs has an additional barrier in that developers view the practical application of CGBs for 500MW projects as unproven and are likely to look for a significant demonstration project of at least 10 turbines before committing to the technology. If a demonstration site was contracted in 2012, construction could be achieved in 2014. Unlike turbine demonstration projects, customers of CGBs are more concerned with the logistical issues surrounding fabrication and installation and suppliers are optimistic that investment in a full-scale facility could follow immediately after the demonstration installation and be ready to supply a full-scale project 12 months later. This could only be achieved, however, if a customer was prepared to commit ahead of the demonstration. Where the concrete gravity base is being used as part of a float-out-and-sink turbine and support structure installation, the investment for the demonstration site is higher as the process requires that a bespoke vessel be constructed.

3.3. Returns on technology development

Returns are made by the supplier at a rate dependent on the level of competition it faces. In this report CAPEX and OPEX are not adjusted to account for this. This is equivalent to arguing that the margins introduced to recoup these costs today will continue in the future. Any change to this position will be a function of the competitive landscape for a given area of supply, and hence falls within the scope of the Supply Chain work stream.

3.4. Prerequisites

The key prerequisite for new investment in innovations is the confidence in a growing and sustainable market. This may come from assurance through framework contracts or similar or through the strength of a number of geographic or sector-specific markets relevant to the investment. The availability of test and demonstration sites is especially key in accelerating the de-risking of the introduction of new turbine designs, but also in bringing to market novel support structures. For turbines and support structures, the availability of coastal manufacturing and assembly sites is critical. Innovation in a number of areas is hampered by lack of early collaboration and data sharing, though it is recognised that, for an immature sector, such sharing currently is often complex to implement even if agreed as desirable by all parties.

Important in facilitating the uptake of new designs is flexibility in the planning process to allow developers to delay technology choices until after consent.

Prerequisites are discussed in more detail in Section 14.

4. Technology baselines

The modelling process described in Section 2 is to:

- Define a set of baseline wind farms and derive costs, reliability and energy production parameters for each
- For each of a range of innovations, derive the anticipated impact on these same parameters, specifically for each baseline wind farm, for a given year of FID, and
- Combine the impact of a range of innovations to derive costs, reliability and energy production parameters for each of the baseline wind farms for a given future year.

This section summarises the costs and other parameters for the baseline wind farms. The derivation of these is provided in Sections 5.2 to 11.2. The baselines were developed using models covering each element, the structure, inputs and outputs of which were verified by a range of industry players.

Based on the data received, it is recognised that there is significant variability in costs between projects, due to both Supply Chain and Technology effects, even within the portfolio of a given wind farm developer. Drawing out trends from such data would be misleading unless supported by a good understanding of underlying costs based on element-by-element modelling. It is also recognised that one player's view of current state-of-the-art can be quite different from another's, both in terms of technology and, for example, material costs. Care has been taken not to derive baselines dominated by input from any particular player.

The baseline costs presented are nominal contract values, rather than outturn values, and are for projects reaching FID in late 2011. As such, they incorporate real-life supply chain effects such as the impact of competition and vertical collaboration. The *Supply chain work stream report* discusses the impact of changes within the supply chain on these costs and Section 4 of the *Finance work stream report* discusses contingency and the impact of risk on lifetime cost. All results presented in this report incorporate the impact of technology innovations only. No benefit is taken here of Supply Chain or Finance work stream impacts. Discussion of the historical trend in costs is presented in *The Crown Estate Offshore Wind Pathways report*.

It is assumed that the first 6MW-Class Turbines will be commercially available to the market for projects with FID in 2014 and that 8MW-Class Turbines will follow for FID in 2017. "Commercially available" means that it is technically possible to build such turbines in volume and that they have been sufficiently prototyped and demonstrated so they have a reasonable prospect of sale into a 500MW project. No assumptions are made in this report about the market share of these products.

As shown in Figure 4.1, baseline wind farms that represent the envelope of projects anticipated to be installed in the UK over the next 12 years or so are generally outside the envelope of projects installed to date. This both illustrates the challenge faced by the sector in constructing these projects and the importance of deep industry engagement in order to obtain input data to models within this project.

To date, most projects have been installed in water depths and distances to port similar to or less than those of Site Type A. Some projects such as Greater Gabbard have been built in conditions similar to those of Site Type B but only one demonstrator project, the Beatrice Demonstrator Project, has been installed in water depths similar to those of Site Type C. Projects in the Greater Wash off the east coast of England have seen turbines delivered to site from Esbjerg up to 600km away, although this is not considered to be a sustainable solution, especially as UK port capacity develops. Of operating wind farms, Greater Gabbard has the greatest distance to its operations port, which is more than 60km away in Lowestoft. This is still significantly closer than Site Type D.

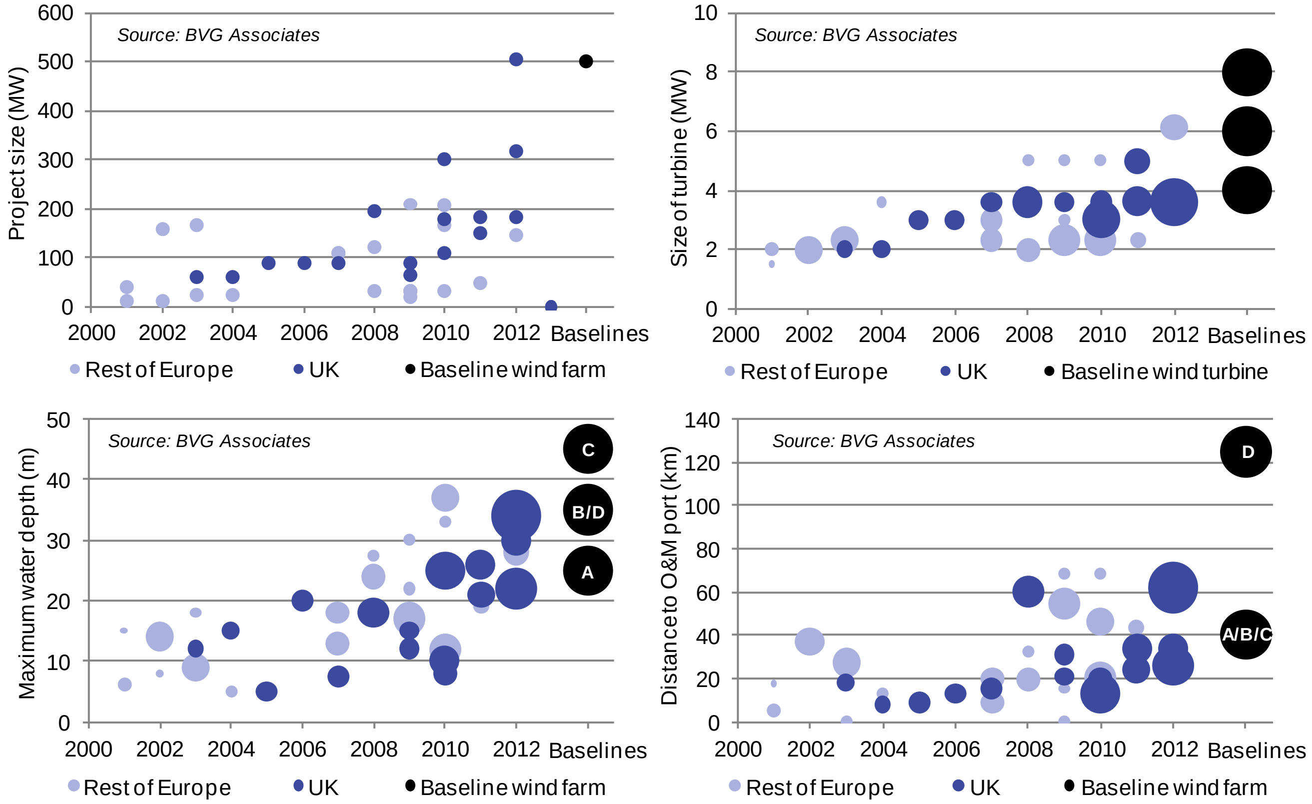

Figure 4.1 Comparison of key parameters of baseline wind farms with those of wind farms installed to date (bubble size reflects wind farm rated output; label reflects Site Type where relevant) (2012 estimated).

The baseline CAPEX, OPEX and AEP parameters for baseline wind farms are summarised in Table 4.1. It is important to note that, for example, 4-A refers to a wind farm using 4MW-Class Turbines on Site Type A. Net capacity factor is defined as the ratio of net AEP to the theoretical gross output of the wind farm, were it to operated at the maximum rated output from all turbines constantly for one whole year (for example, 8766MWh/yr/MW).

Table 4.1 Baseline parameters (construction phase insurance, contingency, operating phase insurance and transmission charges refer to Industry Story 2 and are the values for FID in 2020).

Type	Parameter	Source[5]	Units	4-A	4-B	4-C	4-D	6-A	6-B	6-C	6-D	8-A	8-B	8-C	8-D
CAPEX	Project up to FID	5	£k/MW	47	47	48	50	44	44	44	47	42	42	43	44
	Project from FID to WCD	5		37	37	38	39	34	35	35	37	33	33	34	35
	Construction phase insurance	Finance		40	40	44	44	40	40	45	45	38	38	43	43
	Turbine nacelle	6		632	632	632	632	671	671	671	671	733	733	733	733
	Turbine rotor	7		393	393	393	393	465	465	465	465	518	518	518	518
	Support structure (inc. tower)	8		551	690	795	693	551	622	692	624	558	612	665	615
	Array cables	9		80	81	83	81	78	80	82	80	75	76	78	76
	Foundation installation	10		232	371	389	497	251	260	277	350	212	213	228	271
	Turbine installation	10		102	102	103	136	89	89	90	103	75	76	77	88
	Array cable installation	10		138	138	138	159	97	97	97	112	77	77	77	88
	Contingency	Finance		219	247	259	266	225	233	243	246	229	235	242	244
	Total (inc. contingency)			**2,473**	**2,781**	**2,924**	**2,993**	**2,548**	**2,638**	**2,744**	**2,782**	**2,595**	**2,659**	**2,741**	**2,759**
OPEX (outside warranty)	Operation and planned maintenance	11	£k/MW/yr	26	27	28	31	21	22	23	26	20	20	21	24
	Unplanned service	11		53	55	57	64	44	45	46	53	41	42	43	49
	Other	11		2	2	2	2	2	2	2	2	2	2	2	2
	Operating phase insurance	Finance		14	14	18	18	16	16	20	20	17	17	18	18
	Transmission charges	Renewable UK		69	69	69	133	69	69	69	133	69	69	69	133
	Total			**164**	**167**	**173**	**249**	**151**	**153**	**159**	**233**	**147**	**149**	**152**	**226**
AEP	Gross AEP	7	MWh/yr/MW	4,288	4,520	4,683	4,834	4,384	4,613	4,772	4,920	4,453	4,679	4,836	4,981
	Wind farm availability	11	%	95.0	95.0	95.0	95.0	95.0	95.0	95.0	95.0	95.0	95.0	95.0	95.0
	Aerodynamic array losses	5		9.5	9.0	8.5	8.0	9.0	8.5	8.0	7.5	8.5	8.0	7.5	7.0
	Electrical array losses	9		1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0
	Other losses	7		4.6	4.6	4.6	4.6	4.6	4.6	4.6	4.6	4.6	4.6	4.6	4.6
	Net energy production		MWh/yr/MW	3,482	3,691	3,844	3,991	3,580	3,787	3,939	4,084	3,656	3,862	4,013	4,156
	Net capacity factor		%	40	42	44	46	41	43	45	47	42	44	46	47
DECEX	Decommissioning	10	£k/MW	355	458	473	595	328	334	348	424	273	275	287	335

[5] "Section" refers to the section number in this report, the *Finance work stream report* or RenewableUK's *Potential for offshore transmission cost reductions.*

For the purposes of LCOE modelling, *The Crown Estate Offshore Wind Pathways report* assumes a fixed value of £150,000 per megawatt for project costs to FID reflecting the market value of a consented project. Pre-FID CAPEX within the Technology work stream report is taken as a fixed proportion of the total modelled wind farm development CAPEX, excluding the implications of market value. This equates to about £45,000 per megawatt, depending on the impact of innovations, Site Type and Turbine MW-Class.

The cost of construction and operating phase insurance and the percentage CAPEX contingency both for the baseline wind farms and for wind farms reaching FID in different years and in different Industry Stories are derived in Section 5 of the *Finance work stream report*. They are incorporated here in order for the LCOE figures presented in this report to reflect the full cost base of an offshore wind farm. Similarly, transmission charges are discussed in the companion report, *Potential for offshore transmission cost reductions*, derived in *The Crown Estate Offshore Wind Pathways report* and incorporated here. The benefits of innovations over time that are presented in Sections 5 to 12 do not incorporate any change in these externally supplied values.

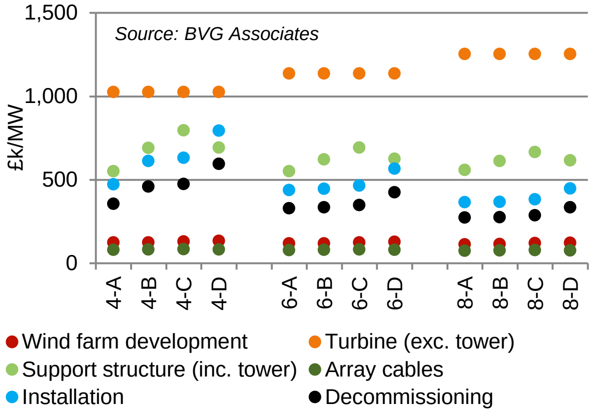

Figure 4.2 Baseline CAPEX by element (insurance and contingency not shown).

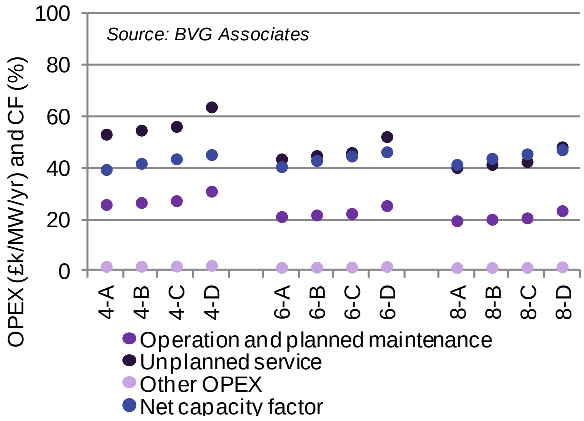

Figure 4.3 Baseline OPEX and net capacity factor (insurance and transmission charges not shown).

Discussion of the trends in baseline parameters is incorporated at their derivation in Sections 5 to 11. Section 5 also presents the timing profile of CAPEX and OPEX spend which is important in deriving the LCOE.

These baseline parameters are used to derive the LCOE for the 12 baseline Site Type and Turbine MW-Class combinations. In considering the impact of technology innovations, it is instructive to understand the baseline contribution of each element to the lifetime cost. A comparison of the relative LCOE for each of the baseline wind farms is presented in Figure 4.4.

A wind farm of 4MW-Class Turbines benefits from the use of monopile foundations on Site Type A, contributing to the lower LCOE compared with the other Site Types. This option is considered by industry as of only marginal benefit, if any, at Site Type B and is not feasible at Site Type C. The LCOE for wind farms on Site Types B and C are similar, with the additional CAPEX due mainly to increased support structure costs, offset by increased AEP due to higher average wind speeds.

The trend at 6MW and 8MW-Class Turbines is of lower LCOE with the change in Site Type from A through B to C. This is because of the decreased contribution of support structure costs for larger turbines, the term that increases most strongly with water depth, matched by the increased contribution of turbine costs, a term that does not change with water depth.

For reference, the LCOE derived in Section 5 of the *Finance work stream report* for a wind farm of 4MW-Class Turbines on Site Type B reaching FID in 2011 is £143/MWh. This wind farm is chosen as the reference as 4MW-Class represents the turbines on the market in 2011 and wind farms will be installed on sites characterised by the conditions associated with Site Type B following FID in 2011 and 2020.

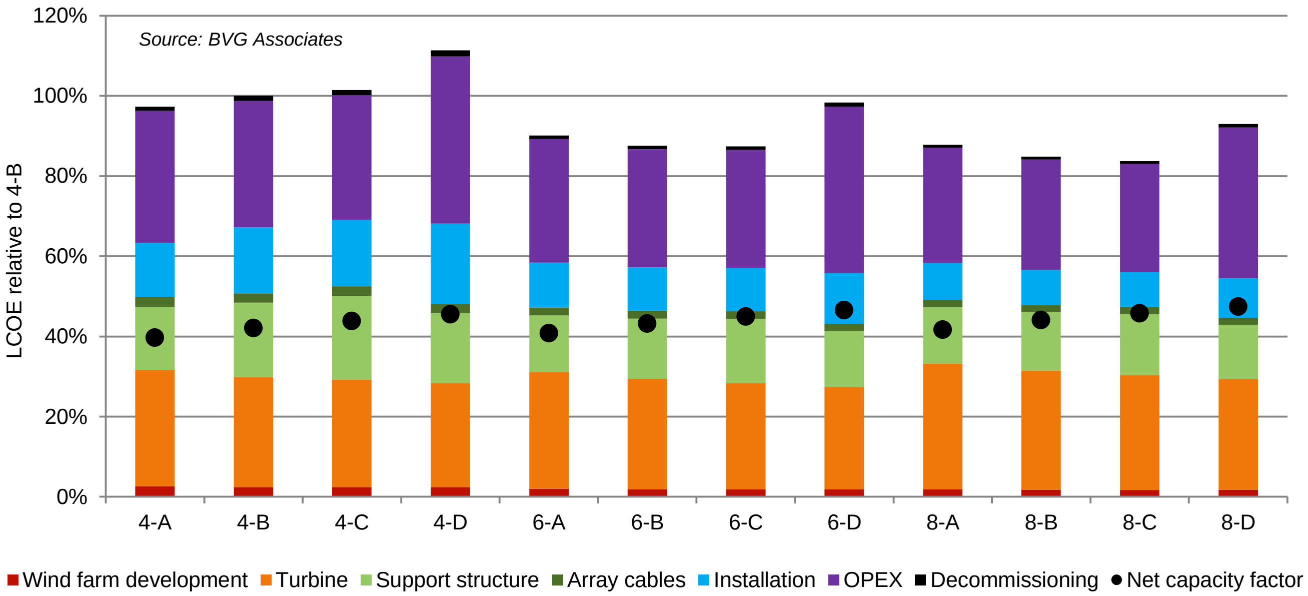

Figure 4.4 Relative LCOE for baseline wind farms.[6]

The relative contribution of the cost of each wind farm element to the LCOE for baseline wind farms is compared in Figure 4.5. This shows the trend of an increasing contribution of turbine CAPEX (excluding tower) and a decreasing contribution of installation to the LCOE, with increasing Turbine MW-Class. It also shows the increased importance of OPEX for Site Type D and the increasing importance of support structures with deeper water.

[6] CAPEX calculations include the construction phase insurance and contingency, which are fixed to FID in 2020 levels. Contingency is defined as a percentage of all other CAPEX (excluding insurance) and it is this percentage that is fixed to FID 2020 levels rather than the absolute value.

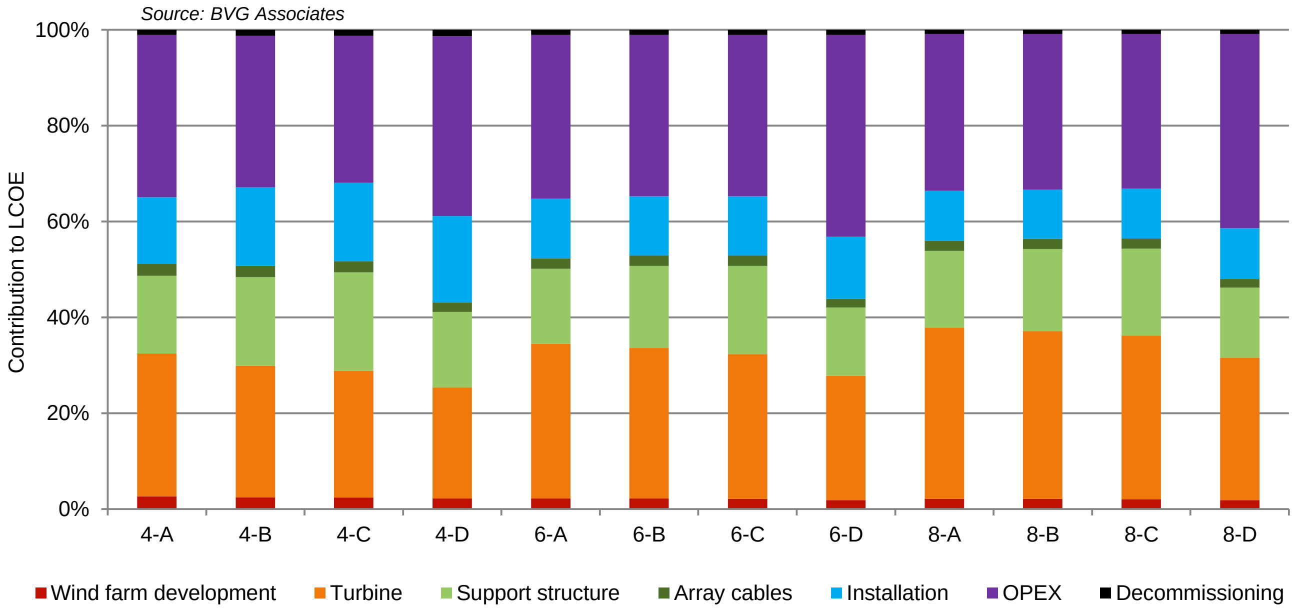

Figure 4.5 Relative contribution to the LCOE for each element baseline wind farms.[6]

5. Innovations in wind farm development

5.1. Overview

It is anticipated that innovations within the wind farm development element will reduce the LCOE by approximately 1.5 to two per cent between projects with FID in 2011 and 2020 for a given Turbine MW-Class and Site Type. Figure 5.1 shows that the savings are generated mainly through reduced CAPEX, but also through modest reductions in OPEX and increases in AEP. The aggregate impact of innovations in this element is actually to increase spend on wind farm development marginally but, through this, to enable reduced costs of other elements of the wind farm, primarily the support structure and installation. Though the cost of the technology development relating to this element is relatively low, progress will be limited unless there is sufficient confidence in a pipeline of projects enabled by an effective consenting process, robust OFTO arrangements and reasonable project economics. Developers also need to realise the opportunity of the additional value created by increased spend early in the project lifecycle.

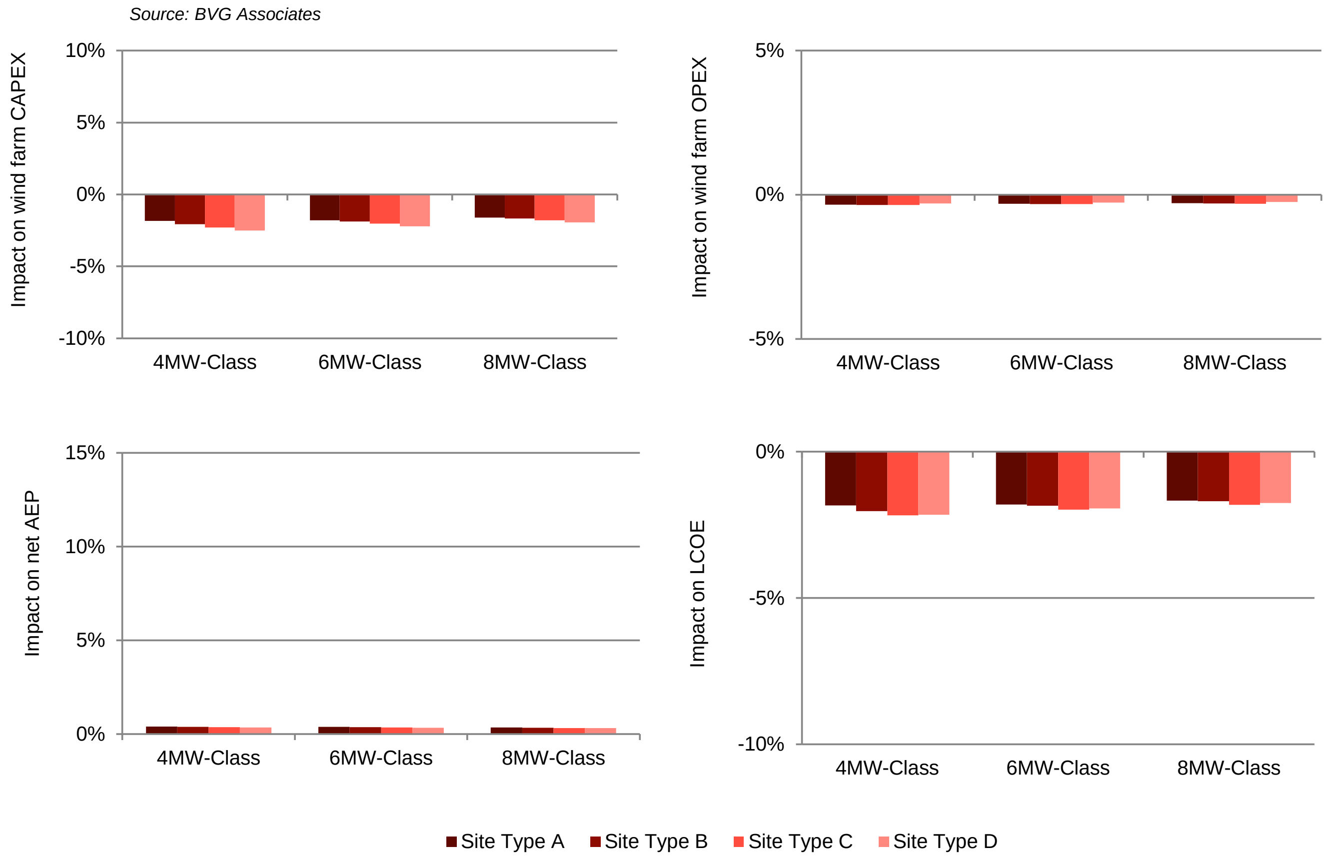

Figure 5.1 Anticipated impact of wind farm development innovations by Site Type and Turbine MW-Class in FID 2020, compared with wind farm on the same Site Type with the same Turbine MW-Class in FID 2011.[7]

Total CAPEX reductions increase from Site Type A through to Site Type D, due to the increased applicability of some of the innovations for sites further from nearest port or in deeper water. The benefit of introducing floating meteorological stations, for

[7] Negative values indicate a reduction in the item and positive values indicate an increase in the item. CAPEX calculations include the construction phase insurance and contingency, which are fixed to FID in 2020 levels. Contingency is defined as a percentage of all other CAPEX (excluding insurance) and it is this percentage that is fixed to FID 2020 levels rather than the absolute value. OPEX calculations include annual transmission charges and operating phase insurance, which are fixed to FID in 2020 levels. All OPEX figures are per year, from year six.The LCOE calculations are based on the CAPEX, OPEX and AEP values presented. This is in order to present accurate relative cost changes while only showing the impact of technology innovations. Appendix C provides data behind all figures in this report.

example, is greatest for Site Type C where the cost of a standard founded meteorological station is highest due to deepest water.

CAPEX cost reductions decrease as turbine size grows because of the relative increase in the proportion of CAPEX represented by the wind turbine. This cost is unaffected by innovations in wind farm development as, unlike support structures and array cable arrangements, turbines are not designed for project-specific conditions.

The increase in AEP reduces both as turbine size grows and from Site Type A through to Site Type D. This is because the impact of innovations giving a relative decrease in aerodynamic array losses is less for sites with fewer turbines and higher wind speeds, where the baseline aerodynamic array losses are typically lower for the same nominal array spacing.

The largest impact of innovations in wind farm development on the LCOE is seen for Site Type C. In this case, the innovations that reduce the cost of installation have a larger impact due to the higher installation baseline CAPEX for Site Type C, which has the deepest water.

The contribution of innovations in wind farm development to the reduction in the LCOE in going from a wind farm using 4MW-Class Turbines on Site Type B in 2011 to 6MW-Class Turbines on the same site in 2020 is anticipated to be about two per cent. Figure 5.2 shows that the largest savings from innovations in wind farm development are available from advances in wind farm design methodology and tools. These enable cost reductions in many other elements as well as reduce costs for the wind farm development activities themselves. A number of commentators from companies engaged in wind farm development activities indicate that the potential cost reductions arising from innovations in wind farm development could be even higher than those presented here.

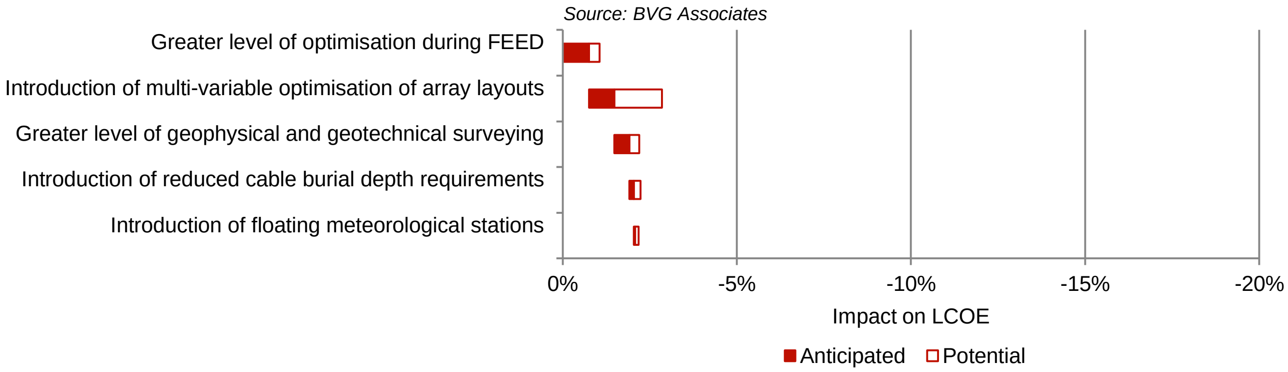

Figure 5.2 Anticipated and potential impact of wind farm development innovations for a wind farm with 6MW-Class Turbines on Site Type B with FID in 2020, compared with a wind farm with 4MW-Class Turbines on the same Site Type with FID in 2011.[7]

The two key innovations in wind farm development that give rise to the largest anticipated cost of energy reductions are greater levels of optimisation during Front End Engineering and Design studies (FEED) and introducing multi-variable optimisation of array layouts. Industry feedback reflects the general belief that a greater investment in wind farm design and optimisation activities at the development stage will yield cost savings later in the lifecycle providing lessons learnt are applied. Despite this, developers are ready to point out that expenditure at the development stage is at risk, and a long time before first revenue, although historical offshore wind farm consent success rate points towards early investment as a good potential strategy. These two innovations generate potentially small to moderate reductions in CAPEX for electrical array cables, support structures and installation, as well as small OPEX reductions and a fewer aerodynamic and electrical array losses. Wind farm development CAPEX is potentially increased for greater levels of optimisation during FEED and potentially decreased for introducing multi-variable optimisation of array layouts.

The combination of all of these widely distributed innovations in wind farm development gives the potential for a significant reduction in the cost of energy. It is important to note that, due both to the timing of development activities early in the life-cycle and that, in the zonal approach being applied in UK Round 3, some of the development work can be reused for project phases reaching FID later in the decade. This means that some of the opportunity for cost reductions relating to projects developed up to FID 2020 has already passed.

5.2. Baseline

Based on feedback from a number of industry players, the baseline cost percentage breakdown for wind farm development is presented in Figure 5.3. For the purposes of modelling, the baseline costs are for a wind farm as part of a UK Round 3 zone, but reaching FID at the end of 2011. It is recognised that, while no such project exists, the project size is representative of typical Round 2 projects in, or approaching, construction. In modelling as part of a zone, some baseline development costs such as the project management, various engineering studies, some environmental surveys and, in some circumstances, the meteorological station are effectively divided between a number of projects. This reduces the overall cost per 500MW project and it is this situation that is presented in Table 5.1.

Baseline wind farm development CAPEX increases by about six per cent from Site Type A through to Site Type D. The increase in cost is attributable to higher meteorological station costs, with deeper water as well as additional survey costs as the distance from shore increases. In some cases, significantly changed practices are required when planning work far from shore on Site Type D.

Baseline wind farm development CAPEX for wind farms using larger turbines reduces by a total of about 11 per cent between 4MW and 8MW-Class Turbines. The cost reduction is due to lower geotechnical and geophysical surveys and management and engineering study costs as a result of fewer turbine locations.

Table 5.1 Baseline wind farm development CAPEX for projects with FID 2011.

Turbine MW-Class	Wind farm development CAPEX (£k/MW)			
	Site Type A	Site Type B	Site Type C	Site Type D
4MW	84	85	85	90
6MW	78	79	79	83
8MW	75	76	76	79

The scope of wind farm development in the context of this project is:

- All work and project management costs for the wind farm developer up to the WCD. Project management includes wind farm developer staff overheads associated with managing engineering studies, planning applications and environmental impact assessments (EIA), and construction contract management activities, assuming a multiple engineer, procure and construct (EPC) contracting approach to wind farm procurement
- Environmental surveys including ornithological species surveys and collision risk assessments, commercial fishing studies, benthic species surveys, and pelagic species surveys
- Geophysical and geotechnical surveys including the geophysical surveying of a wind farm area (but excluding the substation and export cable route), and a geotechnical survey, assuming there is no unexploded ordinance risk
- The meteorological station, including design, procurement and installation of a fully equipped meteorological station including the mast to proposed hub height
- Engineering studies includes pre-FEED studies, which include concept design and constraints analysis undertaken prior to consent. It also includes FEED studies, covering array layout, foundation sizing and choice, electrical array architecture and installation methods undertaken after consent, and
- Onshore development costs are not considered in this analysis as these are covered by the transmission use of system charges to the OFTO.

The breakdown of costs shown in Figure 5.3 includes development activities until WCD but does not include construction phase insurance, which is covered by the finance work stream. The figure is presented following feedback and verification from a cross-section of experienced wind farm developers and development service suppliers. The breakdown is based on the baseline total spend of approximately £42 million for a 500MW project using 4MW-Class Turbines on Site Type B.

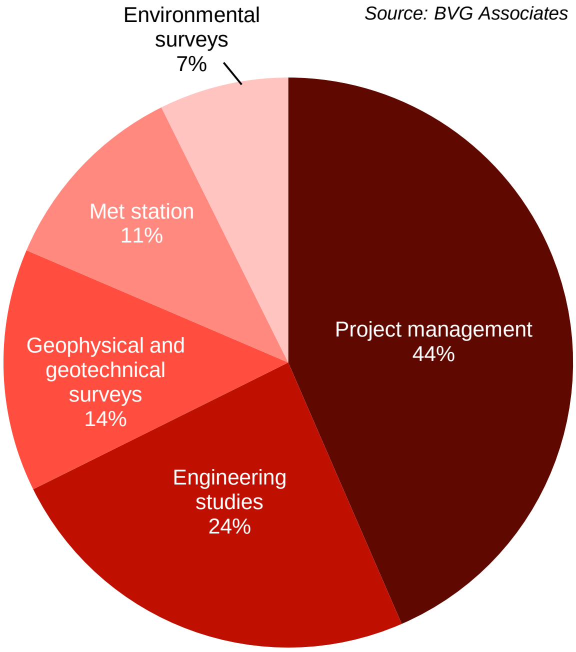

Figure 5.3 Baseline wind farm development cost percentage breakdown.

Wind farm development costs in 2011 represent approximately three to four per cent of total wind farm CAPEX, thus direct cost savings relating to the activities within this element have limited impact on the overall cost of energy, even taking into account the timing of spend. Where innovation within this element causes cost savings in other elements, the potential impact on the cost of energy is much greater. Established engineering service providers agree that, in principle, it is therefore more beneficial to invest at the wind farm development stage to realise greater cost savings later in the lifecycle, than to seek to reduce development costs, potentially increasing uncertainty in other areas.

A typical wind farm development cost profile is shown in Figure 5.4 for a wind farm of 4MW-Class Turbines on Site Type B, reaching FID in 2011. WCD is at the end of year 0, FID occurs at the end of year -4, with consent approximately one year prior to that. The economic activity in a given year is assumed to relate to when the developer is contracted to pay the primary contractor. Pre-FID spend represents approximately 60 per cent of the total cost and consists of initial environmental surveys with the introduction of seabed surveys and later the meteorological station installation. Other costs in this period include pre-FEED studies and project management. Following consent, the wind farm development costs are dominated by detailed geotechnical surveys, FEED studies and, eventually, project management costs for the developer relating to the construction activity. Since a large proportion of the wind farm development cost is related to activities that occur before FID, the development cost baselines are based on good practice prior to 2011.

For the purposes of LCOE modelling, *The Crown Estate Offshore Wind Pathways report* assumes a fixed value of £150,000 per megawatt for project costs to FID. This reflects the market value of consented projects and is demonstrated through evidence from recent sales of consented projects, or stakes in projects, where values have been about £150,000 per megawatt. Additionally, the cost of pre-FID expenditure to the developer is estimated to be approximately £50,000 per megawatt over a five to seven year period up to FID. It is appropriate to add a developer return, assumed to be 25 per cent per year, to this expenditure to reflect the risks associated with investment at this stage of the project lifecycle and a delay of about 10 years before returns on investment are made. The Crown Estate has profiled the expenditure over the period to FID, based on evidence from actual projects to date and, when including a 25 per cent return, results in a value of £150,000 per megawatt.

Pre-FID CAPEX within the Technology work stream report is modelled as the expenditure of about £50,000 per megawatt, depending on the impact of innovations, and not the £150,000 per megawatt value of a project.

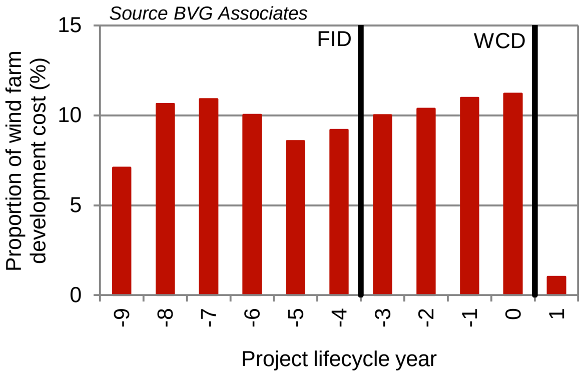

Figure 5.4 Baseline wind farm development CAPEX profile.

Baseline aerodynamic array losses are presented in Table 5.2. These are based on a turbine spacing of nine times the rotor diameter in the prevailing wind direction and six times the rotor diameter in the direction perpendicular to the prevailing wind direction. The aerodynamic array loss is applied to the gross energy yield to account for energy lost as a result of turbines operating in the wake of others.

Aerodynamic array losses vary as a function of mean wind speed, turbine size and turbine spacing. This is because, for higher mean wind speeds, a greater proportion of the time is spent at wind speeds where the reduction in local wind speed, for a given turbine operating within a wake field, does not affect the turbine power output as it can still operate at maximum power. As turbine size increases, fewer turbines are needed in a 500MW wind farm and a greater proportion of those turbines tend to be placed at the boundaries of the wind farm where the amount of time spent operating within a wake is reduced. As turbines are located closer together, aerodynamic array losses increase because there is less relative distance for the wake to dissipate before the effects of another wake are encountered. Each site type is associated with a defined average wind speed shown in Table 5.2. This wind speed is the P50 value at 100m above mean sea level, that is, the value which has a 50 per cent confidence of exceedance. The wind speeds have been defined by The Crown Estate as representative for the location parameters of each Site Type and are based on estimated typical wind speeds for projects in the UK development pipeline.

Table 5.2 Baseline aerodynamic array losses.

Turbine MW-Class	Aerodynamic array losses (%)			
	Site Type A (9.0m/s)	Site Type B (9.4m/s)	Site Type C (9.7m/s)	Site Type D (10.0m/s)
4MW	9.5	9.0	8.5	8.0
6MW	9.0	8.5	8.0	7.5
8MW	8.5	8.0	7.5	7.0

5.3. Innovations

All innovations in wind farm development discussed here can be applied together.

Existing situation

Today, surveys account for about one third of wind farm development costs and are contracted by the wind farm developer to specialist data acquisition companies. Currently, all surveys are carried out on a bespoke site-specific basis. Depending on the survey type, the contract may involve data collection and analysis, such as geotechnical surveys, or data collection only, where analysis is performed by the developer in house, for example, metocean data.

Historically, environmental and sea bed (geotechnical and geophysical) surveys and data collection start up to 10 years before the planned operation of the wind farm. EIA requirements determine critical path items such as ornithological surveys, where a minimum of two years of data are needed as part of best practice guidelines developed with input from the regulators and statutory consultees. Metocean data include the recording of wind conditions, air temperature and pressure, wave conditions and water current information and is captured by a single meteorological station on the site, usually installed one to two years before FID.

Currently, the wind farm layout, support structure choice and design, electrical architecture and installation methods for each wind farm are developed through an iterative engineering process typically taking about two years. The process involves various engineering teams and organisations. Most commonly for utility developers, the initial concept is developed in house during the pre-FEED stage through a constraints analysis and study of wind conditions. The constraints analysis defines the available areas for development within the lease area, based on the knowledge of the activities of other sea users, such as shipping, oil and gas pipelines, the fishing industry and communication networks, and geological features such as sand banks. Where these impact on the wind farm area, the developable area of the wind farm is restricted. Exceptionally deep areas of the site may also be removed from consideration at this stage. The wind study is used to generate an initial turbine layout considering basic array shape, spacing and orientation. Detailed design and optimisation occurs during FEED studies that are delivered via a mix of developer in-house expertise and contracted services.

A consent application will define an envelope of possible outcomes for the wind farm by incorporating a number of design case options. The environmental impact is presented for the extremities of this envelope. Developers aim to maintain a number of options so that there is both technical and commercial flexibility at the time of placing the contract, thus facilitating a competitive tendering process in order to drive down the cost of key infrastructure.

Developers, including those with significant project portfolios, are keen to stress the importance of flexibility in wind farm design, as it allows them to select the most cost-effective technical solution for the site at the time of FID, which can be some years after submitting a consent application. In this time new, more cost-effective options may have come to market that were not available when the consent application was submitted and this flexibility allows the option for introducing a wider range of cost-saving technologies. It also allows the developer to modify the site design if later survey data significantly affect potential costs and to maintain a position of competitive advantage if economic and market conditions change. Nevertheless, a balance is required, as too much flexibility and variation in design options lead to increased engineering study efforts and can make planning consent more difficult to obtain. Typically today, developers intend obtaining consent for UK Round 3 projects with turbines in the range of 3-7MW and with at least two support structure types.

Innovations

Developers indicate that a **greater level of optimisation during FEED** has potential for substantial reductions in the cost of energy. This includes the undertaking of additional detailed design studies at the FEED stage. It considers the use of additional survey data, such as those gathered through *a greater level of geotechnical and geophysical surveying,* and increased depth of design for the foundation, turbine choice and installation methods, which are usually completed later in the development process. Typically, FEED studies to date allow the basic concept and component size to be chosen. Usually this is completed for a variety of design options to compare economically viable solutions. At this stage, design options remain relatively flexible. With an increased level of study some of the detailed aspects of design can be brought forward, giving increased accuracy of cost estimates for solutions with varying parameters such as water depth, soil conditions and turbine choice. This allows for an increased certainty of design progression that are optimal at a wind farm level.

Feedback from one foundation designer says that there is a strong potential for cost reduction by involving contractors at an early stage to help define the scope of surveys and design studies to ensure that correct data are measured. Data and then passed to designers in the right format allowing an increased level of design to be undertaken with the available information. Additionally, the interviewee adds that optimisation studies at FEED would benefit from taking a more holistic view, for example, by examining costs for complete, installed solutions considering the impact of array cable arrangements and secondary steel costs, rather than simply comparing basic foundation structures and foundation installation costs on a per-tonne basis for a number of foundation concepts.

The benefits of this innovation cannot be extended such that a single full design is completed at the development stage, due to the need for the developer to retain design options so that a competitive advantage is realised when approaching the supply market. An overly defined project will not allow for the inclusion of technologies that have progressed since design freeze decisions were taken. Increased optimisation during development will lead to higher development costs and, potentially, increased development time.

One industry-enabling body notes that the impact of this innovation is less for simpler sites, where the options are more limited. Shallower sites with smaller turbines, for example, have fewer support structure solutions that are likely to be economically viable. Smaller sites, which are closer to shore, generally have more limited array options as they are typically more constrained than Round 3 zones.

An average of the potential technical impact of this innovation advised by a number of industry offshore engineering service providers and experienced wind farm developers is a two per cent increase in wind farm development CAPEX, a decrease of three per cent in support structure CAPEX, a decrease of 1.5 per cent in array cable CAPEX and a reduction of three per cent in installation CAPEX.

The timescales for realising both the technical impact and market uptake are such that, by FID 2020, 90 per cent of the potential of this innovation is anticipated to be captured for projects on Site Type B. Although initially low for projects with FID in 2014, the majority of the technical impact of this innovation is expected to be available for projects reaching FID in 2020 due to the application of learning and consent and cost drivers dictating more a detailed study. The market uptake for this innovation is expected to be initially relatively high, driven by planning requirements, and is expected to increase to affect all projects reaching FID in 2020 as the benefits of this work are understood and realised. The impact of the innovation increases for Site Types C and D compared with Site Types A and B due to the increased complexity and potential for using new designs on Site Types C and D as a result of the increased water depth and distance from port.

Significant reductions in the cost of energy are anticipated through the **introduction of multi-variable optimisation of array layouts,** which includes developing and using fast and reliable optimisation software tools that account for the effects and constraints of multiple technical disciplines. This innovation includes incorporating improved models for offshore wind farm wake modelling. The wind farm array layout could be optimised, for example, for the combination of wake effect, array cable cost, support structure cost and consenting constraints. Installation and operational costs would also be modelled, as each has an effect on lifetime cost.

The overall benefit of this innovation is to reduce the cost of energy through improving the location of turbines while accounting for the constraints of multiple design criteria. Depending on the site conditions, this is likely to involve: some reduced support structure and installation costs, by avoiding the more challenging areas of the site; reduced electrical array costs, due to considering the effect on the system cost when optimising; and an increase in energy yield through reduced wake losses and/or electrical array losses. Savings may also be available in OPEX due to, for example, better spaced turbines causing less fatigue loading and therefore less frequent replacement or repair of components. On some sites, optimisation may lead to increases in the cost of some elements, as not all of the potential savings can be achieved at the same time as the requirements for some are contradictory. Wider spaced turbines, for example, will reduce aerodynamic array losses but increase array cable and array cable installation CAPEX. The savings discussed here represent an industry view of the anticipated average saving that could be made over a number of typical real-world sites with different conditions.

Implementing this innovation will involve developing one or more tools that optimise the array layout for the lowest cost of energy, or other parameter set, depending on the specific targets of the developer. This will need to take into account wake effects, consenting constraints, seabed conditions, water depth, offshore electrical architecture, impacts of nearby wind farms and other factors. Investing in the development of these tools may be a commercial venture or an internal project for a developer but is expected to require a few person-years of effort. Investment would continue as tools are enhanced. Such tools will calculate sufficiently quickly that they can be used in pre-FEED concept design engineering studies as well as to finalise the layout. To date, multi-disciplinary optimisation tools have not been developed because of the relatively benign and uniform conditions in which the early Round 1 and Round 2 wind farms were deployed and the constraints imposed on the sites; instead, developers have used the existing iterative process involving multiple engineering teams and design loops occurring through the pre-FEED and FEED periods. The increase in wind farm scale and better understanding of the development challenges means that using optimisation tools and methods is even more important.

One large engineering services provider notes that the use of optimisation tools may lead to reduced wind farm development costs due to a reduction in the time taken to analyse and iterate through design options.

Following input and feedback from experienced offshore wind developers, offshore wind installation providers and engineering service providers, the potential technical impact of this innovation is anticipated to be a decrease of 2.5 per cent in wind farm development CAPEX, one per cent in support structure CAPEX, one per cent in array cable CAPEX and 2.5 per cent in installation CAPEX. A relative reduction in aerodynamic array losses and wind farm electrical array losses is expected to be 10 per cent and two per cent of current losses respectively, that is, a decrease in aerodynamic losses of 0.85 percentage points for a wind farm using 6MW-Class Turbines on Site Type B. In addition, savings of two per cent in both operation and unplanned maintenance and planned service are anticipated with an associated increase in wind farm availability of about 1.5 per cent.

The timescales for realising both the technical impact and market uptake are such that, by FID 2020, about 40 per cent of this technical potential is anticipated for projects on Site Type B. Progress towards the full benefit of this innovation is expected to be gradual as tools are trialled and then developed to include more variables. As capability of the tools becomes more trusted, the iterative loops of the current multi-departmental optimisation can be replaced. The market uptake of this innovation is anticipated to be low for projects with FID in 2014, as developers continue with the recognised methods, but the uptake rapidly increases for projects with FID in 2017 and beyond, reaching 90 per cent market share in 2020. While the majority of developers will adopt some form of multi-variable optimisation, the overall impact is limited by the slow integration of increasing numbers of variables and the considerable lead time between fixing the array layout and construction. The innovation has increased relevance for Site Types with higher average wind speeds and further from shore, and therefore decreased accessibility, because the impact of improved availability is increased where the cost of maintenance is higher. Following examples of significant unexpected costs during the installation phase of projects, there is a consistent trend within industry towards increasing investment in surveys to reduce uncertainty in technical data and realise later cost savings, albeit with the awareness that expenditure at the development stage occurs before FID and revenue and is therefore an at-risk cost. The main focus is on a **greater level of geophysical and geotechnical surveying**. Often, geotechnical and geophysical data are available only at turbine locations and with a focus on properties far below the sea bed, leading to significant uncertainties relating to cable design and installation. An improved knowledge of sea bed conditions, from surveys that focus on the other areas of the site or on soil conditions closer to the surface of the sea bed, can lead to cost reductions in array cable and installation CAPEX through earlier design work, and the prevention of conservative overdesign or late design changes. Support structure CAPEX savings are also possible with an increased number of core samples to be taken at turbine locations. Suppliers providing fixed price EPC services will be able to avoid a level of cost associated with uncertainty over sea bed conditions.

The innovation is considered alongside a *greater level of optimisation during FEED*, as the benefits of additional data will be best realised with increased optimisation studies and incorporation into design. The benefits of these innovations are therefore in similar areas but, while a *greater level of optimisation during FEED* can generate cost reductions independently of a *greater level of geotechnical and geophysical surveying*, the latter only generates cost reductions if the results are analysed and applied with a *greater level of optimisation during FEED*.

The amount of geotechnical and geophysical data gathered for a site has an impact on the level of risk associated with the support structure installation. Additional data have the added benefit of reducing the uncertainties for installation methods and costs, thus leading to an eventual reduction in both the allocated contingency and the cost of finance.

One cable supplier comments that past experience on one project shows that savings of 25 per cent in cable design and installation would have been possible, compared with a traditional conservative design based on the typically limited availability of soil data relevant to array cables. A foundation designer interviewee notes that certain developers are gaining benefit from engaging early with contractors to undertake more detailed designs at an earlier stage and allowing increased design optimisation. Developers and support structure designers with past project experience are showing evidence of applying lessons learnt with the developers starting to involve the support structure designers at an early stage to assist in improving the specification of geotechnical and geophysical surveying, thus ensuring that data are collected and presented in the most useful way for the data end-users to change and improve designs. The benefits of solely earlier or better collaboration are covered in the supply chain work stream (see Section 3 of the *Supply chain work stream report*).

Based on input from foundation designers, cable installers and foundation installers, all with strong track records, the typical technical impact of this innovation is anticipated by industry to be approximately a three per cent increase in wind farm development CAPEX, a two per cent decrease in support structure CAPEX, a three per cent reduction in array cable CAPEX and a two per cent reduction in installation CAPEX, with additional benefits of reduced installation risk.

The timescales for realising both the technical impact and market uptake are such that, by FID 2020, 70 per cent of this potential is anticipated to be captured for a typical project. The capability to undertake additional surveys already exists within the market today, however, for most of the projects with FID in 2014 the opportunity to do this has already been missed. It is expected that this innovation will affect the majority of projects with FID in 2020 but it is recognised that not all developers will choose to invest prior to FID. The innovation is equally applicable to all Site Types and Turbine MW-Classes.

The burial requirements for array cables are up to 3m below the sea floor. One cable installer, with a track record on wind farms across Europe, reports that there remains concern across the industry that cable burial requirements are frequently arbitrary and are neither based on the site conditions nor the risk of cable damage. This issue has a significant effect on cable installation costs, which can be addressed by the **introduction of reduced cable burial depth requirements**.

Cable burial depth typically exceeds 1m on the basis that the disturbance by standard fishing equipment and anchors would not normally exceed this. With due consideration of soil conditions and the penetration risk of fishing equipment and anchors, cable burial depth could be reduced. A cable buried shallower in clay, for example, can still be better protected than a cable buried deeper in sand, a reality often not taken into account in specifying cable burial depths to date.

The average technical impact of this innovation is anticipated to be a 10 per cent decrease in array cable installation cost, typically leading to a two per cent decrease in total installation CAPEX. A small increase in wind farm development CAPEX may be expected to account for an increased survey requirement.

The timescales for realising both the technical impact and market uptake are such that, by FID 2020, 40 per cent of the potential of this innovation is anticipated to be realised for a typical project. While the technical capability to bury cables to a shallower depth already exists, the ability to realise all of this potential is dependent on agreements between developers, insurers and cable installers and, in some cases, changes to planning requirements. Initially, the proportion of the potential cost reductions available for projects reaching FID in 2014 is low, as developers are reluctant to change from the established standards. Once a precedent is set, almost the full potential of this innovation is likely to be reached for projects reaching FID in 2017 and beyond. The innovation is equally applicable to all Site Types and Turbine MW-Classes. The remaining key innovation in wind farm development that industry points towards as having an important role in reducing the cost of energy is the **introduction of floating meteorological stations**. Specifically, within this innovation, it refers to the use of floating light detecting and ranging (LiDAR) units for wind data collection. The use of a meteorological station to collect other metocean data could all be integrated into a floating meteorological station.

The use of LiDAR units for onshore wind farm sites has become accepted practice, with the assessment of measurement uncertainty at similar levels to conventional meteorological masts. LiDAR units are not widely used onshore, however, because there is little to no cost saving when compared with the use of a meteorological mast, and their use is confined to locations that are either not suited to a meteorological mast or that require additional data, for example, in complex terrain.

Offshore, LiDAR units have been favourably compared, in terms of cost and accuracy, to meteorological masts when situated on fixed platforms, but floating systems are yet to be proven. In a floating system the wave, tide and current effects will cause the LiDAR unit to move with up to six degrees of freedom. Without mitigation or compensation, this would lead to inaccurate wind speed measurements. One approach is to avoid this through preventing the movement, and some floating structures are designed to actively stabilise the LiDAR motion; the alternative is to use software algorithms to correct the motion.

Floating meteorological stations are cheaper to install and quicker to deploy than a conventional meteorological station due to simpler consent requirements and a less complex or site-specific design. Floating meteorological stations also have the advantage of positional flexibility and can be reused in other areas within the site or on other sites. The benefits of such flexibility are hard to define so the focus here is on the potential cost reduction by replacing a meteorological mast with a floating meteorological station.

A one-for-one replacement of a meteorological mast with a floating LiDAR unit is considered here. This would reduce wind farm development CAPEX. The use of a floating meteorological station is expected to have an impact on wind speed uncertainty. While measurement uncertainty is expected to increase, the benefit of an earlier deployment and the ability to measure above hub height can reduce the measurement duration and spatial uncertainty. Another scenario anticipated by some developers is to use a floating meteorological station in conjunction with a fixed meteorological mast. This will incur an increase in wind farm development CAPEX but has the potential to reduce wind speed measurement uncertainty, which is a more powerful driver of lifetime cost than pure CAPEX savings.

The potential technical impact of this innovation is anticipated to be a six per cent reduction in wind farm development CAPEX, based on the estimated CAPEX for an installed meteorological mast compared with an installed floating LiDAR unit on Site Type C. The timescales for realising both the technical impact and market uptake are such that, by FID 2020, about 20 per cent of this potential benefit is anticipated to be realised for projects on Site Type B. Since floating LiDAR systems are yet to be proven, the proportion of the potential cost reduction that is available is zero until projects reaching FID in 2017. Likewise, the market uptake for this innovation is zero for projects reaching FID in 2014, and is anticipated to be approximately 30 per cent of the market for FID in 2020. It is not anticipated that the market share will exceed this by 2020 as only about half of the development zones are of sufficient size to merit installation of more than one meteorological station and the smaller zones are likely to have installed meteorological masts before the floating LiDAR technology is proven.

A floating meteorological station cost is relatively independent of water depth, but a founded meteorological station cost reduces slightly with water depth due to a lower support structure cost. The benefit of a one-for-one replacement of a mast with a floating LiDAR is therefore expected to be lower for Site Types A, B and D than for Site Type C.

Other innovations

Although technology development will assist in reducing the cost of environmental and geotechnical surveys through reduced survey length or increased speed, it is not a significant area of attention for developers and savings. Though impacting the competitive position of survey companies active in the market, cost reductions will have a relatively small impact on the LCOE. The integration of survey data with consideration of all end users, for example, may reduce costs in this area by reducing repeat processing and the scope of the initial data collection. In addition, due to the zonal approach applied in developing Round 3, much of the surveying for projects installed over the next 10 years has been or will be commissioned over the next three years, during which time little innovation will impact.

Further wind farm development cost savings are anticipated through the pooling and sharing of survey and operational data among developers allowing a reduction in the need to undertake new surveys. Since this constitutes no technical change in the wind farm development process, the benefits of this innovation are captured in the supply chain work stream, see Section 3 of the *Supply chain work stream report*.

Early signs of progress and prerequisites

A key milestone relating to the *introduction of multi-variable optimisation of array layouts* is the development of new software tools. They need to calculate quickly, remain simple to use, such that a single user can operate the tool, and retain flexibility to allow for complex optimisation rules to be included. A prerequisite to this is a better understanding of the wake interaction between turbines and wind farms, in order to make the output of the tools robust; advances in this area will need to be verified against real data. Robust and updateable cost models need to be included in such a tool. The Carbon Trust Offshore Wind Accelerator programme has undertaken some initial analysis of parameterised models for wind farm layout. Further early work is underway as part of a European-funded research project to develop optimisation tools and involves a consortium of companies led by DTU Wind Energy.

Initial indications of progress are being seen in the attitude of developers to considering wind farm layouts based on more than one criterion. Round 1 wind farms layouts, for example, were typically designed to maximise installed capacity, whereas later Round 2 and Round 2.5 layouts have considered the appropriate installed capacity along with water depth, sea bed conditions and aerodynamic array losses as typical design drivers. Further evidence for progress in this innovation includes introducing commercial optimisation software tools to the market. Including novel wind farm layout shapes within the design envelope of the planning application may also be seen, though are not a necessary indication of progress. One interviewee notes that the impact of this type of optimisation thinking is already being seen in the shapes of wind farms such as Horns Rev 2 and Anholt (see Figure 5.5). These designs have been arrived at by following the existing process by applying learning and focussing on optimising energy production or revenue rather than through a multi-variable optimisation tool, but they signal the way forward to more considered layouts than the rectilinear arrays that have often been used to date.

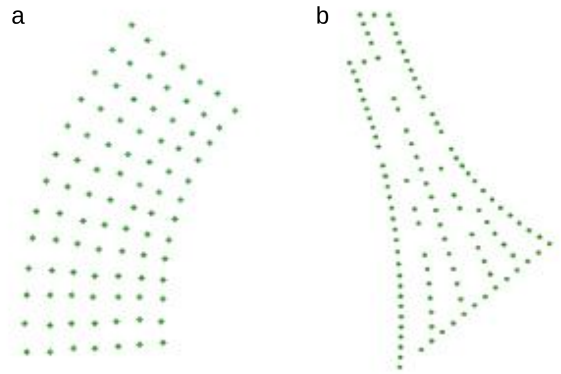

Figure 5.5 Wind turbine layout for a) Horns Rev 2 and b) Anholt.

Before both a *greater level of optimisation during FEED* and a *greater level of geotechnical and geophysical surveying* become widespread, developers need to understand and demonstrate internally the overall cost reduction benefit of investing in further detailed design studies at the development stage. Typically this will also require the early involvement of equipment providers to supply key design parameters for engineering calculations. Early signs of this can be seen in the approach of some developers who have partnered with specific suppliers during development. The further engagement of the supply chain at an early stage will be sign of progress in this innovation. Dong Energy, for example, has framework agreements with Siemens and Bladt Industries as well as stakes in A2SEA and CT Offshore, SSE Renewables has engaged closely with Siemens, Atkins, Subsea 7 and Burntisland Fabrication (BiFab), while Mainstream Renewable Power has development partnerships with Siemens and EMU.

Evidence for progress in a *greater level of optimisation during FEED* includes developing the larger Round 3 zones as part of an integrated solution of a number of smaller sub-projects, such that the whole zone is considered during optimisation. Evidence for a *greater level of geotechnical and geophysical surveying* occurring includes increased survey activity possibly taken over two distinct periods where initial surveys are undertaken in a similar manner to the baseline methodology and further data are gathered post consent. Coupled with this would be an increase in the survey vessel fleet to meet the increased demand, possibly with more specialist survey vessels introduced.

To date, a significant proportion of insurance claims that have been made by offshore wind farm operators are associated with damage to array cables. Appropriate risk awareness in this area is seen as an important factor in the cost of insurance premiums.[8] Before the *introduction of reduced cable burial depth requirements* can achieve its full impact, insurance providers will need to be certain that there is no increased risk associated with shallower burial depths. Signs of a relative reduction in insurance premiums for offshore wind farm asset owners will be a key milestone on the way to achieving cost reductions from this innovation. Early signs of progress in this innovation include increased consideration of the topic as shown by discussion and presentation topics, for example, at narrowly-focussed industry events that are starting to take place. Further progress may be indicated by an increased focus on cable design and installation that considers the lifetime cost of the cables (see Sections 9 and 10) and by reducing the number of cable damage incidents. One experienced cable installer proposes that an index of protection for offshore wind power cables is needed in order to progress this area, as used in other sectors, and this was supported during workshop discussions. The index would rate the protection level of different burial depths and in different sea bed conditions.

Further evidence of progress with this innovation would include the undertaking of a study to assess the impacts of different burial depths with the aim to use this information to build and publish an industry-approved set of cable burial guidelines. Investment levels to realise this innovation for an individual project are minimal and likely to be subsumed by general contract specification writing and supplier engagement. As industry-wide innovation investment would be higher with the need to propose, consult and agree upon a set of guidelines and verified possibly through test programmes, this process could take a number of years and require between hundreds of thousands and millions of pounds spent on research studies.

Contributors, including developers with offshore operating assets and engineering service providers, indicate a mix of optimism and scepticism about the potential of the *introduction of floating meteorological stations*, as the technology is yet to be proven in floating offshore applications. Industry needs to gain confidence in the reliability of the systems and financiers need to gain confidence in the accuracy of the gathered data before cost reductions can be realised. An early sign of progress is the Carbon Trust's trial of three devices in 2012 which will be compared with an offshore meteorological mast. The trial uses different LiDAR systems mounted on floating platforms with different design philosophies. Axys Technologies has published data comparing its floating LiDAR system with that of one operating onshore. Further tests and validation will be required to prove the accurate and reliable performance of these systems before their widespread use. Further evidence for progress in this innovation will include successfully validating test systems, the planning of further tests, increasing the use of LiDAR systems as both primary and secondary wind data gathering systems and incorporating (floating) LiDAR measurement systems into the design standards. The investment required for this innovation is expected to be tens of millions of pounds to design, manufacture, test and validate floating meteorological station systems.

A key prerequisite for investment in these innovations, as for all others, is confidence that there will be returns on that investment. In this case, returns will come from a pipeline of projects where consenting requirements are rational enough to enable technically optimised solutions to be used, whether relating, for example, to wind farm design or cable burial.

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[8] Overview of Offshore Cable Installation, Engineering & Maintenance Two-Day Windpower Monthly Forum Plus Workshop, *Wind Power Events,* available at www.windpowermonthlyevents.com/events/offshore-cable-installation-and-maintenance/, accessed May 2012.

Table 5.3 Potential and anticipated impact of innovations in wind farm development on Site Type B using 6MW-Class Turbines, compared with FID 2011.

Innovation	Maximum Technical Potential Impact				Anticipated Impact FID 2020			
	CAPEX	OPEX	AEP	LCOE	CAPEX	OPEX	AEP	LCOE
Greater level of optimisation during FEED	-1.5%	0%	0%	-1.1%	-1.1%	0%	0%	-0.8%
Introduction of multi-variable optimisation of array layouts	-1.0%	-1.2%	1.1%	-2.1%	-0.4%	-0.4%	0.4%	-0.7%
Greater level of geophysical and geotechnical surveying	-1.1%	0%	0%	-0.7%	-0.6%	0%	0%	-0.4%
Introduction of reduced cable burial depth requirements	-0.5%	0%	0%	-0.3%	-0.2%	0%	0%	-0.1%
Introduction of floating meteorological stations	-0.2%	0%	0%	-0.1%	-0.1%	0%	0%	-0.04%
Total					-2.3%	-0.4%	0.4%	-2.1%

6. Innovations in wind turbine nacelle

6.1. Overview

Two types of nacelle innovations are considered in this study: the first relates to increases in the rated power of the turbine; and the second relates to innovations in the technology used within the nacelle. The *increase in turbine rated power* is treated differently from other innovations considered in this study, as the change has been modelled and forms part of the baseline against which individual innovations are measured.

Innovations relating to the turbine nacelle are anticipated to reduce the LCOE by about three per cent on like-for-like Site Types and Turbine MW-Classes between 2011 and 2020, with marginally the largest LCOE savings anticipated for projects using 6MW-Class Turbines on Site Type A.

Considering first innovations in the technology used within the nacelle, and excluding the benefits associated with the *increase in turbine rated power*, Figure 6.1 shows that there is a small decrease in the wind farm CAPEX for each Turbine MW-Class and all Site Types, reflecting the trend away from high speed drive trains which enable reductions in the amount of material used. Wind farm OPEX is reduced for all Turbine MW-Class and Site Type combinations as a result of improvements in reliability achieved especially through the introduction of next generation drive trains, with the greatest OPEX reduction of about five per cent seen for 8MW-Class Turbines. AEP rises by approximately 1.5 per cent for projects with 6MW and 8MW-Class Turbines as an additional benefit of this increase in reliability. This results in an overall fall in the LCOE of between 2.5 per cent for 4MW-Class Turbines on Site Type A and 3 per cent for projects with 8MW-Class Turbines on Site Type A.

Source: BVG Associates

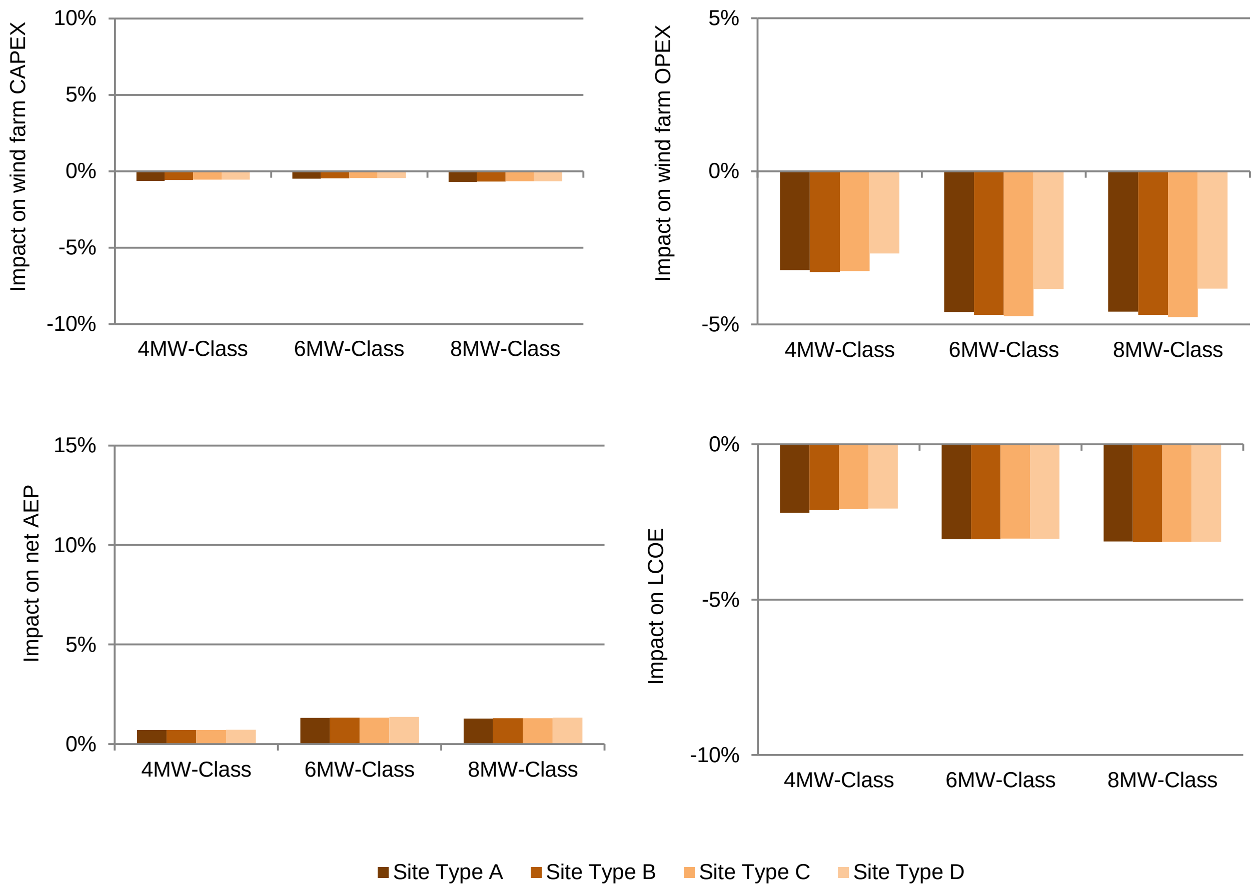

Figure 6.1 Anticipated impact of turbine nacelle innovations by Site Type and Turbine MW-Class in FID 2020, compared with a wind farm on the same Site Type with the same Turbine MW-Class in FID 2011.[7]

Figure 6.2 shows the anticipated and potential impact of innovations in stepping from a wind farm using 4MW-Class Turbines on Site Type B with FID in 2011 to 6MW-Class Turbines on the same Site Type with FID in 2020. It shows that the *increase in* *turbine rated power* is the dominant innovation, causing an eight per cent reduction in the LCOE. It achieves this despite increases in the turbine rotor and nacelle CAPEX per megawatt, through significant reductions in the support structure, array cable, installation, and OMS costs, which are due primarily to the effect of having fewer turbines for a given wind farm rated capacity.

The specific innovations anticipated to have a significant impact are those relating to drive train technology, especially the move to mid-speed and direct-drive concepts. Both offer significant further potential beyond FID 2020. Also anticipated to have an impact on projects reaching FID beyond 2020 are more radical changes in technology: the introduction of superconducting direct-drive generator and DC power take-off.

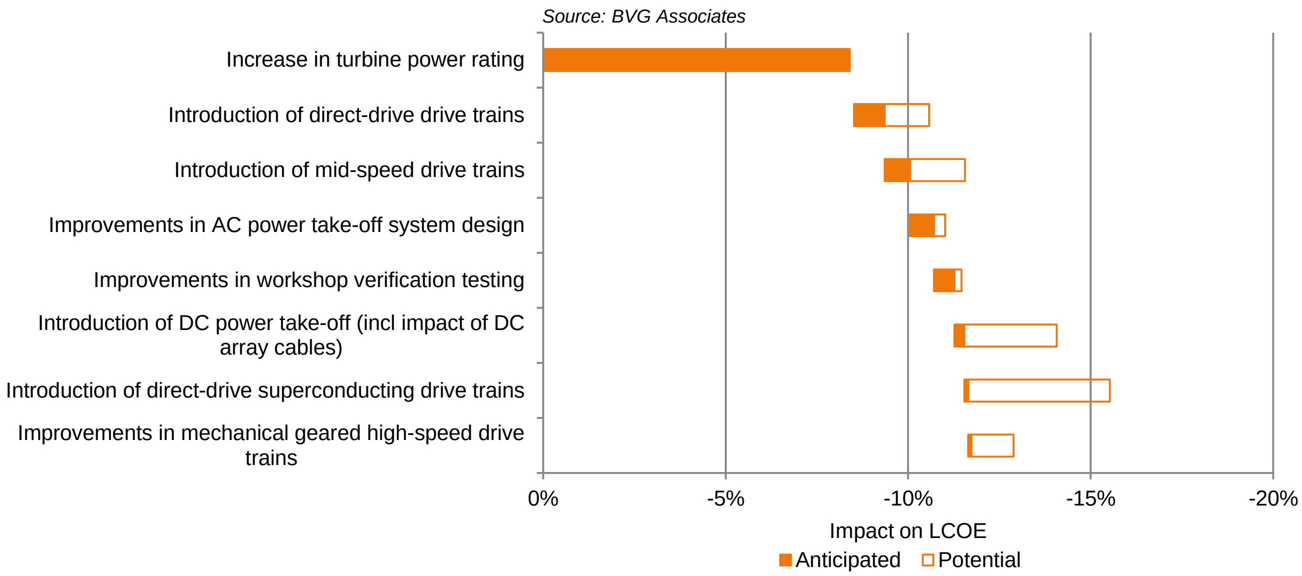

Figure 6.2 Anticipated and potential impact of turbine nacelle innovations for a wind farm with 6MW-Class Turbines on Site Type B with FID in 2020, compared with a wind farm with 4MW-Class Turbines on the same Site Type with FID in 2011.[7]

In Figure 6.3, the same information is provided for the step to using 8MW-Class Turbines. With a 14 per cent anticipated reduction in the LCOE, this shows that there are additional benefits to building turbines larger than 6MW. The order of innovations with the highest anticipated impact is different for 6MW and 8MW-Class Turbines. Mid-speed drive trains have a slightly more significant effect on 8MW-Class Turbines since mid-speed solutions are anticipated to have a greater market share for this Turbine MW-Class. The *introduction of continuously variable transmission drive trains* is also seen to impact on projects using 8MW-Class Turbines as turbine models such as the Mitsubishi Power Systems Europe (MPSE) SeaAngel 7MW turbines are being developed using this technology at this scale. This contrasts with 6MW-Class turbines where no such drive trains are known to be in development.

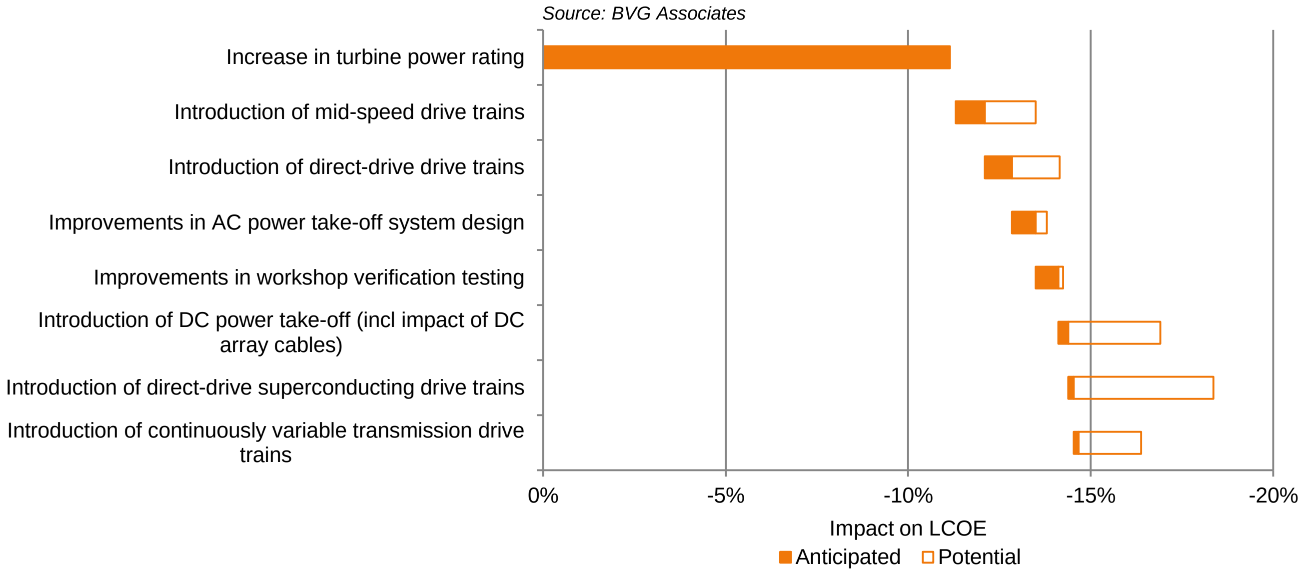

Figure 6.3 Anticipated and potential impact of turbine nacelle innovations for a wind farm with 8MW-Class Turbines on Site Type B with FID in 2020, compared with a wind farm with 4MW-Class Turbines on the same Site Type with FID in 2011.[7]

All turbine manufacturers recognise the pivotal role than turbine size plays in reducing the LCOE and this is manifested in the large number of turbine models rated at 6MW and above in development and the investment plans by market-leading offshore turbine manufacturers. These companies have shown a significant commitment to offshore wind but their investment plans will not be fully implemented without a significant order pipeline. In many areas of this report, market confidence is identified as the prerequisite for innovations to achieve their technical potential. Here it is especially critical as the scale of the investments required (as discussed in Section 3) and the impact anticipated are so significant. In effect, it is the investment in larger turbines that ultimately will make the industry viable.

6.2. Baseline

The turbine nacelle supports the rotor and incorporates the drive train which converts the rotational energy from the rotor into electrical energy. It also incorporates the yaw system that acts to turn the nacelle and rotor to face the wind, and various other electrical, control and auxiliary systems. The nacelle cover provides a weatherproof cover and space for maintenance and service. The baseline cost of the turbine nacelle is the contract payment to a wind turbine manufacturer for the supply of the nacelle and its subsystems and the turbine electrical system through to connection with the array cable. It also includes delivery of the components to the nearest port to the manufacturer, installation support, commissioning and warranty costs. It does not include the cost of the tower or the rotor.

As the design of wind turbines is not project-specific, it is assumed that the nacelle for all Site Types considered here is the same, designed for the harshest of wind speeds seen for offshore wind sites currently in development in Europe, corresponding to Class IA of the international offshore wind turbine design standard IEC 61400-3.

The baseline 4MW-Class Turbine is defined as a market-weighted average of four products at this scale available for FID in 2011. These are the AREVA M5000-116, Siemens SWT-3.6-120, REpower 5M (126m) and the Vestas V112-3.0MW. Based on the approximate market shares of sales of these turbines in 2011, the weighted average turbine rating is approximately 4MW and the weighted average rotor diameter is approximately 120m.

The drive train of all baseline turbines consist of a main shaft, main bearing, three-stage gearbox, a doubly-fed induction generator (DFIG) running at 1500 rpm and with output at 690V and a partial-span power converter. This typifies technology operating offshore today. It is recognised that, while this is a well understood technology arrangement and so makes a good baseline, some of the four turbines mentioned above incorporate a permanent magnet generator and full-span power converter. The baseline 6MW-Class and 8MW-Class Turbines have a rotor swept area scaled from the 4MW-Class Turbine linearly in proportion to rated power (that is, they have the same specific rating of about 350 W/m²). Further discussion of rotor diameter and tip speed is provided in Section 7.2.

The cost of the main components, including those listed above and the main frame, yaw system, electrical system, other auxiliary components, control system and nacelle cover, are calculated using empirically derived relationships based on turbine design experience and using as inputs, turbine rated capacity, rotor diameter, tip speed and generator input shaft speed. It is recognised that, due to different design philosophies, the masses and costs of the main components in different turbines do not all fit the same trend. In all cases, costs are based on market information historically gathered by BVG Associates and rationalised to 2011 contract values. The total cost of the turbine nacelle has been moderated in line with feedback from interviewees and workshop participants.

Although baseline costs are established for 4MW, 6MW and 8MW-Class Turbines for use on wind farms with FID in 2011, it is recognised that the first 6MW-Class Turbines are likely to be available to the market for 500MW-scale projects with FID from 2014 and that 8MW-Class Turbines are likely to be available for FID from 2017. No assumptions are made in this report about the market share of these products.

The breakdown of nacelle CAPEX for a 4MW-Class Turbine is shown in Figure 6.4. Costs are dominated by the mechanical drive train at approximately 40 per cent, followed by the electrical system at approximately 30 per cent. The category “Other” incorporates the nacelle bedplate as well as auxiliary systems and the nacelle cover.

Source: BVG Associates

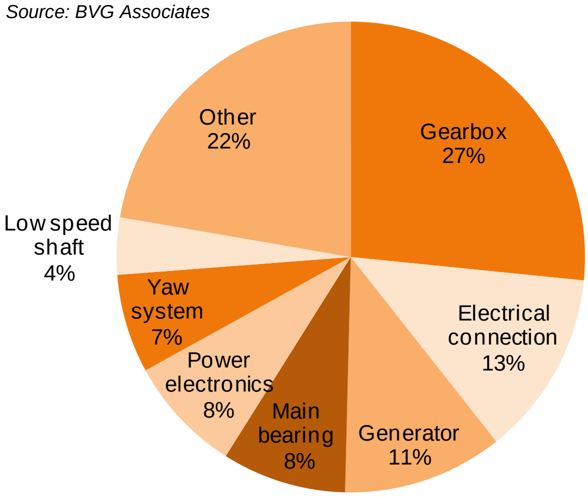

Figure 6.4 Breakdown CAPEX for a baseline 4MW-Class Turbine nacelle.

The nacelle CAPEX for each Turbine MW-Class is shown in Table 6.1.

Table 6.1 Baseline turbine nacelle CAPEX, constant for all Site Types.

Turbine MW-Class	Turbine nacelle CAPEX (£k/MW)
4MW	632
6MW	671
8MW	733

6.3. Innovations

One of the key innovations that will impact the LCOE in the coming years is the increase in the wind turbine power rating. The impact of this change alone, not combined with any other changes in technology, is represented in the baseline costs derived above and in Sections 5 and 7 to 11.

Innovations relating to the turbine nacelle are considered in three groups, as shown in Table 6.2.

Table 6.2 Turbine rotor groupings used in this analysis.Innovations listed * and + cannot be combined with others similarly marked.

Groupings	Innovations
Turbine power rating	Increase in turbine power rating
Drive train	Improvements in mechanical geared high-speed drive trains * Introduction of mid-speed drive trains * Introduction of direct-drive drive trains * Introduction of direct-drive superconducting drive trains * Introduction of continuously variable transmission drive trains * Improvements in workshop verification testing
Other nacelle components	Improvements in alternating current (AC) power take-off system design + Introduction of DC power take-off (including impact of DC array cables) +

It is recognised that there is technology development underway at a detailed level on almost all nacelle components. Conservatively, only key areas highlighted by wind turbine manufacturers consulted are considered in this analysis.

While improving reliability is not considered explicitly as a separate innovation in this analysis, it is a key factor behind many of the innovations and improvements in reliability are captured via reductions in unplanned service and increases in wind farm availability. Components in the nacelle are currently the source of about 70 per cent of OMS spend so increasing reliability and maintainability is a strong driver of the LCOE. Baseline OMS costs are derived in Section 11.

6.3.1. Increase in turbine power rating

Existing situation

New onshore wind turbine models have steadily grown in nameplate rated power over the last 40 years. This change, with the associated increase in the rotor swept area and in the turbine hub height, has been a significant contributor to the substantial decrease in the LCOE seen during this period. The rate of growth in the average turbine rated power for onshore projects has slowed recently in advanced markets because of the physical constraints relating to transport logistics and the visual and acoustic impact of large turbines. Without a breakthrough technology change, the largest turbines for onshore projects are likely to have rated power between 3 and 4MW.

For existing offshore wind farms, turbines have mostly been marinised versions of the largest onshore turbines available. This means that they have tended to have been designed to onshore market constraints. Offshore, turbine size is not as constrained by logistic, noise or visual constraints and a steadily and continuing growth in average rated power of turbines is anticipated by most interviewees, broadly continuing the trend presented in Section 1.4.

Innovations

Interviewees and workshop participants almost universally agree that the **increase in turbine power rating** has the single largest impact on the LCOE, especially for sites in deeper water and further from shore, where balance of plant costs are highest. This increase in scale from 4MW-Class Turbines requires a significant level of design and manufacturing innovation and investment, both by the wind turbine manufacturers and many other areas of supply. As part of the *increase in turbine power rating*, the turbine rotor area is scaled linearly in proportion to rated power, thus the 6MW-Class Turbine has a rotor diameter of 147m, for example. Discussion of the *optimisation of the rotor diameter* for a given Turbine MW-Class is a separate innovation that can act in addition to an *increase in turbine power rating* and is discussed in Section 7.

This *increase in turbine power rating* increases the CAPEX per megawatt of both the turbine nacelle and rotor, but reductions in balance of plant and installation costs and OPEX, coupled with increases in AEP, outweigh the additional cost. This gives significant LCOE advantages under most circumstances when moving from 4MW-Class turbines to 6MW or 8MW-Class turbines.

The benefit of the *increase in turbine power rating* is demonstrated in Table 6.3 which compares baseline costs, AEP and the LCOE for a wind farm using 4MW and 6MW-Class Turbines.

Array electrical CAPEX has the smallest percentage reduction. The change in cost with Turbine MW-Class is discussed in Section 9.2.

Table 6.3 Modelled anticipated impact of increase in turbine power rating for wind farm on Site Type B with FID in 2011.

Element	Wind Farm with 4MW-Class Turbines Site Type B FID 2011	Wind Farm with 6MW-Class Turbines Site Type B FID 2011	Change	Impact of change in element on LCOE
Wind farm development (£k/MW)	85	79	-6.8%	-0.1%
Wind turbine rotor (£k/MW)	393	465	18.4%	1.7%
Wind turbine nacelle (£k/MW)[9]	632	671	6.2%	0.9%
Support structure (inc. tower) (£k/MW)	690	622	-10.0%	-1.7%
Array electrical (£k/MW)	81	80	-1.8%	0.0%
Installation (£k/MW)	611	446	-27.1%	-4.0%
Construction phase insurance (£k/MW)	40	40	0.0%	0.0%
Contingency (£k/MW)	249	236	-5.2%	-0.3%
Total CAPEX (£k/MW)	**2,781**	**2,638**	**-5.1%**	**-3.5%**
Operation and planned maintenance (£k/MW/yr)	27	22	-18.0%	-0.9%
Unplanned service (£k/MW/yr)	55	45	-18.0%	-1.9%
Other (£k/MW/yr)	2	2	-18.0%	-0.1%
Annual transmission charges (£k/MW)	69	69	0.0%	0.0%
Operating phase insurance (£k/MWh)	14	14	0.0%	0.0%
Total OPEX (£k/MW/yr)	**169**	**151**	**-9.1%**	**-2.9%**
Gross AEP (MWh/MW/yr)	4,520	4,613	2.1%	-
Net AEP (MWh/MW/yr)	**3,691**	**3,787**	**2.6%**	**-2.6%**
DECEX (£k/MW)	397	290	-27.1%	-0.3%
Relative LCOE (%)	100	91	-9%	-9%

Figure 6.5 plots the change value in Table 6.3 due to the *increase in turbine power rating* for a wind farm using 4MW and 8MW-Class Turbines.

[9] This includes the impact of the increase in the turbine power rating.

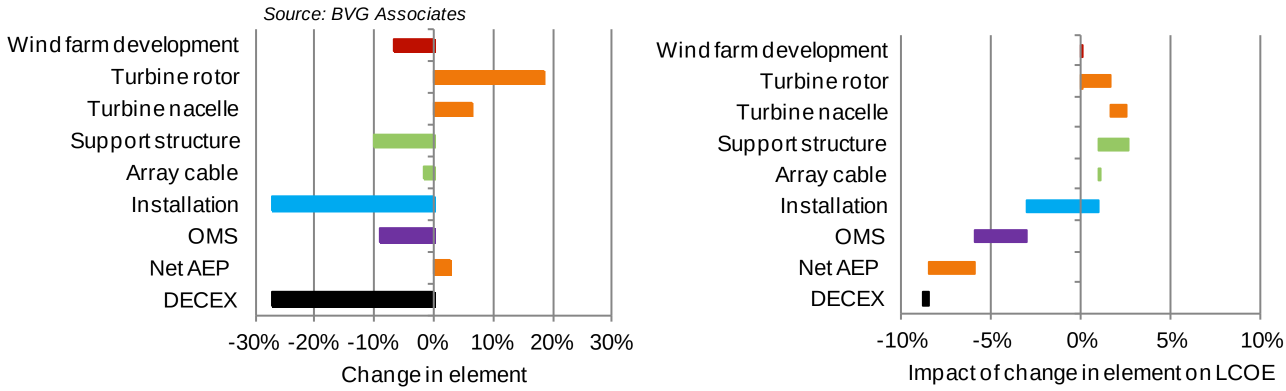

Figure 6.5 Anticipated impact of the increase in the turbine power rating fronm 4 to 6 MW for a wind farm on Site Type B with FID in 2011 with costs and energy output (left hand) and the impact on the LCOE cumulatively added (right hand).

It is important to note that, although the turbine cost per megawatt increases by 11 per cent, the cost of all other capital items decreases, giving an overall decrease in CAPEX per megawatt of about five per cent. This is due, for example, to an increase of only 35 per cent in the support structure cost per turbine in moving from 4MW to 6MW-Class Turbines that equates to a decrease of 10 per cent in the support structure cost per megawatt.

There is also an increase in annual OMS costs per turbine in moving from 4MW to 6MW-Class Turbines, which is shown by element in Table 6.4. The generator, array cable and other wind farm elements see the most increase in their OMS cost per turbine of just over 30 per cent. Some of the other wind farm elements costs, such as environmental monitoring and the OMS base, are fixed costs related to the wind farm, so they fall per wind turbine.

This increase in annual OMS per turbine of 23 per cent equates to a decrease of 18 per cent in OMS per megawatt and nine per cent in total OPEX per megawatt.

Table 6.4 Modelled anticipated impact of the increase in OMS per turbine for a wind farm on Site Type B with FID in 2011. This excludes the impact of innovations that improve reliability.

Element	% of OMS cost per turbine for wind farm using 4MW-Class Turbines on Site Type B with FID 2011	OMS cost per turbine for wind farm using 6MW-Class Turbines on Site Type B with FID 2011 as % of OMS cost for 4MW case
Blades	12%	14%
Hub and pitch system	11%	13%
Gearbox and main Shaft	14%	16%
Generator	17%	22%
Electrical	19%	22%
Other turbine	19%	22%
Support structure	1%	1%
Array cable	7%	9%
Other wind farm	3%	3%
Total OMS	100%	123%

These cost reductions are combined with an increase of 2.6 per cent in AEP due to the increased hub height wind speed, which is related to the forced increase in the turbine hub height in order to preserve a minimum blade tip clearance to the water, as discussed in Section 7. It also combines with an increase of 0.5 per cent due to decreased array aerodynamic losses, as discussed in Section 5.1.

While this increased hub height increases the tower CAPEX per megawatt, the larger reduction in the foundation CAPEX per megawatt gives a net reduction in support structure CAPEX per megawatt of 10 per cent. Overall, the above effects combine to give an anticipated 9 per cent reduction in the LCOE for a wind farm using 6MW-Class Turbines compared with 4MW-Class Turbines on Site Type B with FID in 2011, a result that is consistent across different Site Types.

For some in the industry, the anticipated increase in cost per megawatt for the turbine, bucking the trend of all other costs, is uncomfortable. A number of turbine manufacturers advise that they aim to hold the cost per megawatt of larger turbines roughly constant through introducing a range of other innovations in parallel to the *increase in turbine power rating*, thereby giving even larger LCOE savings. This aim is shown by the results of this analysis to be realistic.

Keeping all other things constant, the cost of some turbine components remains relatively unchanged with the increase in turbine rated power (such as the control system); the cost of other components increases roughly in proportion to rated power (such as the electrical system); and the cost of other items increases significantly more than this (structural components such as blades and any gearbox).

For structural components, this increase is driven by the laws of physics. The energy produced by a wind turbine is proportional to the swept area of the rotor, which is proportional to the square of the rotor diameter. Costs of structural components are, however, to a first approximation proportional to the mass of components, which in turn is proportional to volume, which is empirically known to be approximately proportional to the cube of the rotor diameter. This means that, for a doubling of the rated power of the turbine, and hence energy output, the rotor swept area typically will double (and the rotor diameter will increase by the square root of two). Without other innovations, the mass of the turbine will increase by the cube of the square root of two, or a factor of about 2.8. Thus, an energy increase of a factor of two has driven a cost increase for the structural components of a factor of 2.8, which, if replicated for all turbine components, would lead to a 40 per cent increase in the cost per megawatt. Considered another way, if the tip speed of the wind turbine is kept constant (a general requirement) then, for a doubling of rated power, the rotor speed is reduced by 30 per cent and the torque on the drive train is increased by a factor of 2.8. With about half the cost of a turbine driven by this type of scaling rule and half driven on average by a proportional rule (that is, a constant cost per megawatt), typically, one might expect to see a 20 per cent increase in the turbine cost per megawatt for a doubling of turbine rated power.

The modelled increase in the turbine cost per megawatt when doubling the rating of the turbine for the baseline is close to this, at 22 per cent.

It is recognised from industry trends that few wind turbine manufacturers offer a product with increased rated power without also incorporating other innovations, so real cost increases of this magnitude are not expected. Simply plotting a range of real costs of a given component against turbine rated power generally will show shallower trends than discussed above, as these real costs generally incorporate other technical innovations as well as supply chain effects.

Early signs of progress and prerequisites

All of the wind turbine manufacturers who have signalled their intent to participate in the future offshore wind market have developed, or are in the process of designing, turbines with increased rated power.

Among others, AREVA, Alstom Power, Daewoo Shipbuilding & Marine Engineering (DSME), Gamesa, Hyundai Heavy Industries, MPSE, REpower, Samsung, Sinovel, Siemens Wind Power, and Vestas have all made public statements regarding their intent to have a 6MW-Class Turbine or larger available on the European market for FID 2017, with a number on the market before then.

Turbines larger than 6MW are also under development. The following is intended only as a snapshot of a cross-section of activity:

- Acciona, Alstom Wind, Gamesa and other Spanish companies are collaborating with 22 research centres in the Azimut project to develop a 15MW offshore wind turbine. This €25 million project is partially financed by the Spanish Strategic National Technical Consortiums (CENIT).
- AMSC Windtec is working on the 10MW Sea Titan wind turbine with drive train variants including a direct-drive high temperature superconducting (HTS) generator.
- GE Energy is working on a two year project with the US Department of Energy as an early step to developing a wind turbine in the 10 to 15MW range, again using superconducting technology.

- The EU-funded UpWind project ran from 2006 to 2011 and involved 40 partners focussing on design tools relevant for the design of very large wind turbines (8MW and larger).

It is noted that, under some assumptions about market development, there is a case lowest for the LCOE from the continued use of 4MW-Class Turbines on Site Types that justify the use of monopiles, rather than moving to larger turbines that drive a change to using jacket foundations. The analysis presented here shows a four per cent higher LCOE for a wind farm of 4MW-Class Turbines on Site Type A for FID 2011 compared with 6MW-Class Turbines. Should investment in new jacket manufacturing facilities not progress due to market conditions, supply chain optimisation progress further for the smaller turbines and innovations in turbines be applied at the smaller scale in the same way as at the larger scale then, taking account of relative risks, this trend could reverse.

Due to the substantial technical and supply chain advances that are required to deliver this anticipated *increase in turbine power rating*, interviewees advise an anticipated step change in the levels of component system and turbine-level testing and verification to build confidence that designs are suitable for use on a commercial scale. The typical technology development cycle for a new offshore wind turbine design is explored further in Section 3.

A number of turbine manufacturers are already progressing with these verification plans, for example:

- Alstom Power installed an onshore prototype of its Haliade 150-6MW turbine at an onshore test site in March 2012 and plans to install an offshore demonstration unit in late 2012.
- Gamesa[10] expect to begin installation in Q2 2013 of a prototype G128-5MW turbine off Arinaga Quay in Gran Canaria. This location was chosen on the basis of technical considerations for certification, wind conditions in the region, market performance and customer investment plans. It will be the first offshore turbine installed in Spain.
- Siemens installed a prototype of its SWT-6.0-154 turbine (though with a reduced rotor size of 120m) at an onshore test site in May 2011 and expects to install another four before the end of 2012, including two offshore in the UK and ten more in 2013, including five in the UK.
- Vestas is scheduled to install a prototype of its V164-7.0MW turbine at DONG Energy's Frederikshavn offshore test site in Denmark in 2013.[11]

Interviewees say that a key prerequisite for accelerating the testing and demonstration of this *increase in turbine power rating* is the availability of both onshore and offshore sites, as discussed in Section 7.3.1. Also seen as of growing importance, though not yet a requirement, is the ability to test drive trains under dynamic, multi-directional loads more representative of turbine operation than those conventionally applied at gearbox manufacturers during the design verification phase. The UK will offer this capability when the the Narec Fujin drive train test facility is completed.

In the last two years, there has also been significant UK Government support in developing key components for these turbines, for example, to Siemens (for generator and power converters), Vestas (for blades), MPSE (including for hydraulic drive train), and David Brown working with Samsung Heavy Industries (for gearbox).

Alongside the research, development and demonstration (RD&D) investment in the technology development needed for larger turbines, investment is also needed in production sites and manufacturing technology before the technology can impact the market. Planning applications for a Siemens facility in Hull, UK for assembly of its 6MW turbine and a Vestas facility in Sheerness, UK for assembly of its 7MW turbine have been submitted. Gamesa[12] has also announced its intention to pursue a

[10] "Gamesa reaches a critical milestone in its offshore strategy: the first offshore prototype to be installed in Spain", *Gamesa*, 7 May 2012, available at www.gamesacorp.com/en/communication/news/gamesa-reaches-a-critical-milestone-in-its-offshore-strategy-the-first-offshore-prototype-to-be-installed-in-spain.html?idCategoria=0&fechaDesde=&especifica=0&texto=&fechaHasta=, accessed May 2012.

[11] "DONG tests Vestas' 7 MW offshore wind turbine", *RenewableEnergyFocus.com,* 31 October 2011, available at www.renewableenergyfocus.com/view/21701/dong-tests-vestas-7-mw-offshore-wind-turbine/, accessed May 2012.

[12] "Gamesa announces intention to pursue MOU with the Port of Leith as its UK manufacturing base" *Gamesa,* 23 March 2012, available at www.gamesacorp.com/en/communication/news/gamesa-announces-intention-to-pursue-mou-with-the-port-of-leith-as-its-uk-manufacturing-base.html?idCategoria=0&fechaDesde=&especifica=0&texto=&fechaHasta=, accessed May 2012.

memorandum of understanding with the Port of Leith as its UK assembly base for nacelles and manufacturing base for both blades. These companies need new coastal facilities to assemble and dispatch these larger turbines to offshore sites in a logistically efficient manner, but the UK is in competition with other countries for the opportunity to host these facilities. Having such facilities then improves the chance for the creation of significantly more jobs in the supply chain. Progress towards construction of these facilities is a visible sign of progress towards the introduction of larger turbines, although advice is that full investment will require a confirmed pipeline of orders, the extent of which is likely to become a matter of negotiation at some point.

Table 6.5 Potential and anticipated impact of innovations in increase in rated power, for wind farm on Site Type B, compared with FID 2011 using 4MW-Class Turbines.

Innovation	Maximum technical potential impact				Anticipated impact FID 2020			
	CAPEX	OPEX	AEP	LCOE	CAPEX	OPEX	AEP	LCOE
Increase in turbine power rating (6MW-Class Turbine)	-5.1%	-7.4%	2.6%	-8.5%	-5.1%	-7.4%	2.6%	-8.5%
Increase in turbine power rating (8MW-Class Turbine)	-4.4%	-11.8%	4.7%	-11.1%	-4.4%	-11.8%	4.7%	-11.1%

6.3.2. Drive train

Existing situation

Up until about 2002, the design of wind turbine drive trains seemed to be converging on a geared concept with a separate main shaft (with bearing) and a high-speed doubly-fed induction generator (DFIG) and partial span power converter, with only Enercon having a significant market share and offering a substantially different solution with a large diameter, wound gearless (direct-drive) generator. With the globalisation of the industry, the challenge of increased grid compliance requirements and technical advancements in gearless concepts using permanent magnet (PM) generators, the technology playing field has widened significantly.

As can be seen in Table 6.6, almost all turbines currently available in the EU offshore wind market are high speed geared systems. The AREVA M5000-116 is the exception, with a single-stage gearbox and mid-speed synchronous PM generator. The headline argument for such a concept is to avoid the final stage of the gearbox (the source of a significant fraction of downtime relating to gearboxes) without making the more significant change of introducing a low-speed (direct-drive) generator.

Table 6.6 Rated power, drive train concept and total installed capacity offshore for turbines currently in the EU market, with capacity installed offshore (as of Q1-12).

Turbine manufacturer	Model	Rated power (MW)	Drive train concept (full power conversion unless stated)	Total installed capacity offshore (MW)
AREVA	M5000-116	5	One-stage gearbox, mid-speed synchronous PM generator	30
BARD	5.0	5	Main shaft, three-stage gearbox, high-speed DFIG, partial power conversion	85[13]
REpower	5M and 6M	5 and 6.15	Main shaft, three-stage gearbox, high-speed DFIG, partial power conversion	120[14]
Siemens	SWT-2.3-93	2.3	Main shaft, three-stage gearbox, high-speed DFIG, partial power conversion	577
Siemens	SWT-3.6-107	3.6	Main shaft, three-stage gearbox, high-speed induction generator	731
Siemens	SWT-3.6-120	3.6	Main shaft, three-stage gearbox, high-speed induction generator	195
Vestas	V90-3.0 MW	3	Three-stage gearbox, high-speed DFIG, partial power conversion	960

There has been a range of drive train reliability issues with offshore turbines to date that have required the retrofitting of gearboxes and generators. The most high profile examples have been the withdrawal of the Vestas V90-3.0MW turbine from the offshore wind market between early 2007 and May 2008 due to gearbox issues and the replacement of all six AREVA M5000-116 gearboxes soon after installation at Alpha Ventus due to a supplier design quality issue. In March 2012 Vestas began replacing gearboxes and generators in about a quarter of the turbines at North Hoyle wind farm.[15] Installed in 2003, the thirty turbines at North Hoyle have had problems with high speed bearing failures in the gearboxes with seven gearbox replacements reported in the second and third years of operation.[16] One interviewee says that they would expect to see their first gearbox issue within three to five years of completion despite the fact that the units are typically certificated for a design life of for 20 years. Most developers are planning for major component exchange on existing wind farms after seven to 10 years.

In response to the high cost of maintenance and component replace in offshore wind, a number of turbine manufacturers have reassessed their nacelle concept with many choosing to move away from the three-stage gearbox and high-speed generator concept. Looking forward, four drive train concepts are under development in offshore wind:

- A geared concept with high-speed generator as described above, as used today by REpower, Siemens and Vestas, though in some cases with the incorporation of high-speed PM generator and full span power conversion
- A geared concept with a mid-speed generator, as used today by AREVA and proposed by Gamesa, Samsung Heavy Industries and Vestas for their next generation products
- A direct-drive concept, which is not yet operating offshore but has been proposed by Alstom, GE Energy and Siemens, and

[13] 80MW of the 400MW currently under construction at BARD Offshore 1 was online in February 2012. Turbine installation started in March 2010 with 190MW expected to be fully operational in 2012 and the full 400MW in 2013.

[14] A total of 147.6MW is planned to be installed at Thornton Bank Phase 2 in 2012.

[15] "North Hoyle engine swap", *Renewable Energy News*, Issue 236, 22 March 2012

[16] Department for Business Enterprise and Regulatory Reform, *North Hoyle Offshore Wind Farm: Third Annual Report,* Offshore Wind Capital Grants Scheme, July 2006-June 2007, available at www.decc.gov.uk/assets/decc/what%20we%20do/lc_uk/ic_business/env_trans_fund/wind_grants/file47340.pdf, accessed May 2012.

- A hydraulic drive concept, which is not yet operating offshore but with variants proposed by BARD as next generation product and MPSE as offshore market entry product.

Currently there about 25 players actively investing heavily in developing new turbines for the offshore wind market. Of these, where the concept is known, almost half are direct-drive, one third are geared mid-speed and the rest are shared equally between geared high-speed and continuously variable transmission.

It is noted that, in parallel to the innovations described below, progress is being made in developing and introducing new materials, material grades and material properties for the industry, including steel, ductile cast iron and rare earth materials optimisation and formulations. The intent is that the impact of these has been taken into account between the technical innovations and the supply chain levers described in Section 3 of the *Supply chain work stream report*.

Innovations

While there is an industry trend away from the existing drive train technology, interviewees say that **improvements in mechanical geared high-speed drive trains** can still offer important LCOE savings, principally focussed on greater system reliability due to developments such as:

- Improved bearing lifetime, especially with respect to steel quality and detail design
- Optimisation of gear mesh loading, especially considering robustness of design to manufacturing tolerances
- Development of oils and greases that better protect bearings over the whole range of conditions seen during the lifetime of a wind turbine
- Improvements in the gearbox design to allow a more robust manufacturing process and a relative reduction in gearbox mass as power rating increases, and
- New arrangements of planetary stages in response to the increase in torque in higher-power slower-rotating turbines.

A key advantage of retaining this drive train concept is the significant global experience with it, including substantial investment in understanding and addressing design and quality issues, only some of which can readily be transferred to other concepts.

Ongoing innovation in this area compared with the baseline turbines and including introduction of new materials is expected to result in a decrease in the turbine nacelle CAPEX per megawatt of three per cent to the mid 2020s. Interviewees also anticipate that the improved reliability will result in a five per cent reduction in unplanned service expenditure, as defined in Section 11, and an associated improvement in wind farm availability. Innovation in this field has been continuous since the start of the wind turbine industry and its impact is expected to continue at a gradually decreasing pace, partly dependent on the number of players that stay with the technology both offshore and onshore.

Interviewees report that the improved design of these drive train systems should also increase gross AEP in time by approximately 0.5 per cent, with most focus on mid-range efficiency.

Evidence of savings due to *improvements to mechanical geared high-speed solutions* has been obtained from a number of project participants, both at the turbine level and within the supply chain.

The **introduction of mid-speed drive trains,** also called hybrid drive trains, involves a move from the current standard configuration to a drive train without the high-speed gearbox stage(s) and incorporating a generator with a nominal speed in the range of 150 to 600rpm.

A reduced generator speed means that the gearbox and generator become more similar in size and may be firmly coupled, removing the need for a high-speed shaft coupling and potentially increasing reliability.

By removing the high speed stage in the gearbox, interviewees estimate that gearbox CAPEX can be reduced by 15 per cent due to the reduction in the number and cost of components and in assembly costs. Further savings are available, as this innovation enables a more compact nacelle arrangement. Additional costs are associated with the changes in the generator incorporating more poles and a higher torque, but these are smaller than the savings elsewhere, with the overall reduction in turbine nacelle CAPEX advised to be at least four per cent. The removal of a gearbox stage also reduces energy losses, which are partially offset by reductions in efficiency from moving to a multipole generator. Instead of using electrically excited wound generators, some designs are using PM generators that are about one per cent more efficient and also avoid the need for slips rings. Overall, it is estimated that the turbine gross AEP is increased by 0.5 per cent. Based on industry feedback, it is estimated that gearboxes are currently responsible for over a quarter of wind turbine costs offshore and large component replacements could be reduced by half so the improved reliability will result in at least a seven per cent reduction in unplanned service costs and an associated increase in wind farm availability.

Universally for mid-speed solutions, there is a technical tendency to move away from electrically excited wound generators to PM generators because of their ability to improve efficiency and avoid the need for slips rings. The use of more efficient PM generators is expected to increase gross AEP by about one per cent, notwithstanding pressures to reduce content due to supply chain concerns, see Section 4 of the *Supply chain work stream report*.

This innovation is relevant to all Turbine MW-Classes with 60 per cent of the technical potential expected to be available by FID 2017 and 90 per cent by FID 2020. The market share on 4MW-Class Turbines is expected to be low as there are already a number of established wind turbine designs and manufacturers advise that effort in changing concepts is focused on larger turbines. Market share for this innovation for the 6MW-Class Turbine is expected to be 20 per cent for projects with FID in 2014, while interviewees indicate that this share is likely to rise to about 40 per cent for FID 2017 and FID 2020 as AREVA will be joined by at least two major turbine manufacturers, Vestas and Gamesa, in offering mid-speed turbines.

The **introduction of direct-drive drive trains** involves moving from the current geared concept to using a multi-poled generator without a gearbox. Manufacturers confirm that doing so reduces the number of the parts in the drive train by about half which many interviewees anticipate makes the concept likely to be inherently more reliable than the current standard configuration in the long run. Others argue that the increased number of electrical connections and the introduction of new structural dynamics may mean that savings will be less than proponents anticipate. Currently just over a quarter of downtime is due to the gearbox and main shaft while five per cent is due to the generator, so using a drive train without a gearbox is likely to reduce overall downtime even if the downtime is due to the more complex generator trebles.

A direct-drive generator can either use permanent magnets or be direct wound. The existing large scale onshore direct-drive solution offered by ENERCON has an electrically excited wound generator but it is significantly heavier than conventional solutions. The next generation of offshore turbines are all expected to use PM generators. Next generation systems are being demonstrated to have comparable (or even lower mass) to geared solutions, but comparisons are not easy due to differences in design philosophies between players. For example, the onshore Siemens 3MW SWT-3.0-101 direct-drive turbine has a nacelle mass of 73t which is similar to that of the high-speed geared Vestas V90-3.0MW turbine.

Interviewees advise that, in order to mitigate possible further increases in PM costs, both PM and wound solutions are expected to be developed in the long term. The penalty of changing to wound solutions is an increase in mass and partial decrease in efficiency.

In both cases, the large quantity of copper or rare earth materials that are required combined with the complexity of manufacturing large multipole generators mean that some interviewees expect these direct-drive drive trains to have higher CAPEX than similarly rated high and mid-speed solutions for some time to come.

While some wind turbine manufacturers expect this innovation to result in an increase in the turbine nacelle CAPEX of more than 2.5 per cent due to the CAPEX of the multipole generator being higher than that of the baseline high speed gearbox and generator concept CAPEX, they anticipate the major impact to be a 50 per cent reduction in drive train-related OPEX, which conservatively has been modelled here as a 10 per cent reduction in unplanned service OPEX and an associated 0.4 per cent increase in wind farm availability. There is also anticipated to be a one per cent increase in gross AEP due to increased drive train efficiency.

This innovation is relevant to all turbine sizes, though GE Energy's turbine is currently the only direct-drive 4MW-Class Turbine on the market. The market share of this innovation on 6MW-Class Turbines is expected to be 60 per cent for FID in 2014, driven by Siemens Wind Power's market leading position, but interviewees indicate that this share is likely to decline for later projects as increasing numbers of mid-speed 6MW-Class Turbines are introduced.

The **introduction of continuously variable transmission drive trains** involves moving from the current standard concept to either a hydraulic or mechanical device with a variable ratio of output to input speed, coupled with a synchronous generator. This solution does not require a power converter, as compliance and the ability to keep the generator speed constant is provided by the device. The modular nature of some designs also enables major maintenance activities to be carried out without the need for large vessels.

Interviewees say that, as a convertor is not required and the gearbox consists of modular parts, they expect that this innovation could offer savings of up to eight per cent in turbine nacelle CAPEX. The variable ratio device is generally seen to be less efficient than a drive train plus converter, with gross AEP expected by turbine manufacturers to be approximately one per cent lower.

As with direct-drive solutions, the improved reliability of this innovation offers a 10 per cent reduction in unplanned service and an associated 0.4 per cent increase in availability. Despite this, this innovation is expected to have a relatively small market share because of the limited number of companies developing turbines with this technology. The main driver for any significant increase in market share is likely to be any change in grid requirements that increases the cost of compliance with a full-span converter.

This innovation is relevant to all Turbine MW-Classes but, based on turbine manufacturer technical choices, it is expected to only have a market share in 8MW-Class turbines first for projects reaching FID in 2017.

The **introduction of direct-drive superconducting drive trains** has the largest technical potential impact of any drive train innovation. Wind turbine and electrical generator manufacturers say is a likely eventual step for those developing direct-drive concepts for larger turbines. This innovation involves replacing conventional copper in the generator with superconducting wire which has zero electrical resistance when cooled below a given temperature, known as the critical temperature of the material. Technical advances in recent years have increased the critical temperature to above 77K, so that cooling can be provided via the use of liquid nitrogen. This HTS wire offers an eventual practical solution for use in wind turbines.

While superconducting generators require the use of more expensive materials, have higher manufacturing costs and require ancillary cooling equipment, these are offset by increases in efficiency and load density, and a generator mass advised to be 50 per cent lower than that of an equivalent permanent magnet generator. One electrical generator manufacturer advises that this innovation would enable a net two per cent reduction in turbine nacelle CAPEX, though noting a fair degree of uncertainty as superconducting wire is not yet in large-scale serial production. Interviewees also advise that greater conversion efficiency, especially at below rated power, will result in at least a two per cent increase in AEP.

Simplifications in the generator electrical system are somewhat offset by the need for the cryo-cooler, but industry advises that, in line with non-superconducting direct-drive solutions, this innovation offers an eventual 10 per cent reduction in unplanned service and an associated increase in wind farm availability.

The fixed costs associated with this innovation such as the cryo-cooler mean this innovation is most likely to apply to turbines with a larger capacity where this investment can be more easily absorbed. Only 8MW-Class Turbines or larger are expected to see the full impact of this innovation with some benefit for 6MW-Class Turbines and no benefit for 4MW-Class Turbines.

Feedback from a generator manufacturer suggests that the timescales for realising the technical impact are such that only half of the technical potential will be available for projects reaching FID in 2020. In general, developers express caution in the adoption of this radical technology, so it is anticipated that superconducting generators will have only a 10 per cent market share for wind farms using 8MW-Class Turbines with FID in 2020.

Improvements in workshop verification testing also offer reductions in the LCOE. These include the testing of drive train designs under more dynamic, multi-directional loads than have been used to date, and more testing of smaller electrical components whose failures cumulatively also result in significant downtime.

Dynamic testing of drive train designs involves applying simultaneously simulated varying torques and rotor forces and moments, rather than simply constant torques with little or no other loading. Both functional and highly accelerated life tests (HALT) can be performed to provide verification of new designs (or show up design issues) much faster than today’s approach, which is to build on experience, including monitoring “head of the fleet” turbines. With HALT testing, if damage or a lack of performance is found to occur, design changes can be made and subjected to further testing to confirm they have been effective. The provision of sufficient test rigs to do such testing on these increasingly large drive trains is an important consideration as testing can take months.

In contrast, providing greater testing of smaller electrical components whose failures cumulatively also result in significant downtime is far easier to achieve but is also important.

This innovation is expected to lead to improved reliability especially through the avoidance of serial defects in large components and fewer failures in smaller electrical components. There is a strong industry view that testing of this sort is beneficial. This is on two key levels. First, from a purely technical perspective, the testing offers the verification of design tools and, if the design is not right, has a reasonable chance of identifying this before a drive train is in series production. Second, such testing is anticipated to increase confidence in introducing new products, thus reducing the financing cost in time. This second benefit will only be realised once experience is gained that there is correlation between positive test results and long-term operational reliability. The benefits of testing are hard to quantify. If *improvements in workshop verification testing* were to reduce gearbox unreliability by a half, that would avoid sizeable OPEX as the gearbox currently accounts for over a quarter of OPEX relating to the nacelle. It would also avoid considerable downtime as the gearbox and main shaft is currently responsible for 11 per cent of wind farm downtime. Overall, it is assumed that this innovation results in a reduction of unplanned services of five per cent and an associated increase of 0.2 per cent in availability.

Other Innovations

Not included here are improvements in braking systems, shaft couplings and drive train component mounting arrangements. Condition monitoring is considered in Section 11.

Early signs and prerequisites

Evidence of further *improvements to mechanical geared high-speed solutions* include BARD's currently preferred drive train for the BARD 6.5-126 (the Winergy Multi Duored gearbox, which has two output shafts) and two synchronous PM generators which were installed in early 2011 at the Rysumer Nacken wind farm in Germany. This new compact drive train fits into its existing 5MW turbine nacelle and has lower mass than the original 5MW solution. REpower has also reconfirmed its commitment to the concept with an ongoing development programme.

Evidence for the *introduction of mid-speed drive trains* includes the existing AREVA M5000-116 turbine, of which six are being demonstrated at Alpha Ventus and a total of 240 are being installed in the German projects starting in 2012. The Vestas V164 and the Gamesa G128 are also confirmed as having mid-speed drive trains. South Korean engineering company DSME has publicly stated that its comparison between direct-drive and mid-speed geared drive systems for its proposed 7MW design shows a similar cost of energy over 20 to 25 years.[17] Aerodyn's SCD and GE Transportation's IntegraDrive are two examples of supply chain offerings in this space.

Further developments in direct-drive generators are also anticipated and, for example, DECC awarded a grant to Edinburgh-based NGenTec in April 2012 to develop its low-mass axial-flux permanent magnet generator technology with both direct-drive and mid-speed applications.[18]

Early signs for the *introduction of continuously variable transmission drive trains* include the development by MPSE of the digital displacement hydraulic drive, originally designed by Artemis, which MPSE acquired in 2010. It is expected that this drive train system will be used by MPSE in its SeaAngel 7MW. BARD is also developing a drive train with the hydrodynamic speed control[19] WinDrive system from Voith[20] and technology providers such as ChapDrive continue to develop solutions.

The supply of an HTS 1.7MW Hydrogenie generator by GE Energy Power Conversion (formerly Converteam) is an indication that the *introduction of direct-drive superconducting solutions* is likely. Although this example is to be used as a generator for E.ON's Wasserkraft's hydropower station in the German town of Hischaid in Bavaria, it demonstrates the same technology that would be used in wind turbines. According to GE Energy Power Conversion, the technology offers an increase in generator efficiency, and size and mass reductions of up to 70 per cent when compared with a conventional solution. AMSC Windtec is also developing the 10MW SeaTitan wind turbine which includes a HTS generator.

It is of fundamental importance to note that the key driver for the move to new drive train solutions is to improve OPEX and wind farm availability. Important signs of progress will be the presentation of reliability data showing that new solutions are indeed

[17] *Windstats Report*, Q4 (2011), Vol 24, No.4, p. 2.

[18] "NGenTec secures DECC grant as first tests prove technology at scale" *NGenTec press release,* 11 May 2012, available at www.ngentec.com/news_centre.asp, accessed May 2012.

[19] Dr. E.D. Engelbrecht-Schnür, BARD, Sales Director Offshore Wind Farms, February 2012.

[20] "Status Report. Bard 6.5 MW", Project Report 2010, *Voith Turbo Wind GmbH & Co. KG*, June 2010, available at www.windfair.net/pdf/Projectreports_2010_en.pdf, accessed May 2012.

delivering against expectation. Clearly, it will take time for this evidence base to be built, though improved HALT test results will also be a signpost.

The Energy Technologies Institute (ETI)[21] has announced that it is investing £25 million in the design, development and commissioning of a 15MW drive train test rig, and the former Regional Development Agency One North East invested £10 million into the building that will house the test rig. Called Fuijin, the test rig will be based at the National Renewable Energy Centre (Narec) in Blyth.[22] This will be open access and is expected to be commissioned in summer 2013.[23]

In the USA, the Department of Energy (DOE) announced in 2009 that Clemson University in South Carolina had been selected to receive up to $45 million for the Large Wind Turbine Drivetrain Testing Facility, which will perform accelerated endurance testing of drive systems for land-based and offshore wind turbines rated between 5MW and 15MW.[24] This is expected to begin commissioning in 2012.[25] A similar, but smaller, dynamometer test facility already exists at the US National Wind Technology Center (NWTC) which can test wind turbine systems up to 5MW.

In Spain, Centro Nacional de Energias Renovables (Cener) at its Wind Turbine Test laboratory (LEA) has a Powertrain Test Laboratory encompassing the Powertrain Test Bench, Generator Test Bench, Nacelle Test Bench and Nacelle Assembly Bench. The Powertrain Test Bench is designed and constructed to test the drive train and optionally the electrical equipment of wind turbines of up to 8MW, while the Generator Test Bench is designed and constructed to perform tests on generators and electronic power equipment integrated into wind turbines of up to 6MW. Both have been operating since 2010.

In Germany, the Fraunhofer IWES is working on a 10MW drive train test rig as part of its publicly promoted research project Dynamic Nacelle Laboratory (DyNaLab). This will be open access and is expected to be commissioned at the end of 2013.[26]

In addition, Lørc in Denmark is progressing a drive train test facility that will be open access, while at least one leading wind turbine manufacturer is developing such facilities in house.

Sufficient confidence is required in multiple long-term markets to secure the level of investment needed in new drive train solutions. The availability of test and demonstration sites and open access test facilities is dependent on continued public sector support, as they are unlikely to be viable as exclusively commercial ventures.

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[21] The ETI is a UK-based company formed from global companies and the UK public bodies. The ETI's six private sector members are BP, Caterpillar, EDF Energy, E.ON, Rolls-Royce and Shell. The ETI's public funds are received from the Department for Business Innovation and Skills through the Technology Strategy Board, and the Engineering and Physical Sciences Research Council (EPSRC).

[22] Sheena McGeorge, "ETI invests £25m in world leading offshore test facility at Narec supporting UK's future offshore wind industry", *Narec press release*, 7 July 2011, available at www.narec.co.uk/media/news/n/eti_invests_25m_in_world_leading_offshore_test_facility_at_narec_supporting_uks_future_offshore_wind_industry/, accessed May 2012.

[23] Sheena McGeorge, "Construction begins on the world's largest wind turbine drive train test facility" *Narec press release*, 16 February 2012, available at www.narec.co.uk/media/news/n/construction_begins_on_the_worlds_largest_wind_turbine_drive_train_test_facility_/, accessed May 2012.

[24] "DOE Awards $45 Million for a Wind Turbine Test Facility in South Carolina", *EERE Network News*, 25 November 2009, available at apps1.eere.energy.gov/news/news_detail.cfm/news_id=15642, accessed May 2012.

[25] "About Us: State-of-the-Art Wind Turbine Drivetrain Testing Facility", Clemson University Wind Turbine Drive Train Testing Facility, available at www.clemsonenergy.com/about/about-us/, accessed May 2012.

[26] "Drive Train", Fraunhofer Institute for Wind Energy and Wind Energy Technology, available at www.iwes.fraunhofer.de/en/abteilungen/drive_trains.html, accessed May 2012.

Table 6.7 Potential and anticipated impact of innovations in drive train components for a wind farm using 6MW-Class Turbines on Site Type B, compared with FID 2011.

Innovation	Maximum technical potential impact				Anticipated Impact FID 2020			
	CAPEX	OPEX	AEP	LCOE	CAPEX	OPEX	AEP	LCOE
Introduction of direct-drive drive trains	0.6%	-4.0%	1.5%	-2.1%	0.3%	-1.6%	0.6%	-0.9%
Introduction of mid-speed drive trains	-1.0%	-2.8%	0.8%	-2.2%	-0.3%	-0.9%	0.3%	-0.7%
Improvements in workshop verification testing	0%	-2.0%	0.2%	-0.8%	0%	-1.5%	0.2%	-0.6%
Introduction of direct-drive superconducting drive trains	-0.9%	-4.0%	2.5%	-4.0%	-0.02%	-0.1%	0.06%	-0.1%
Improvements in mechanical geared high-speed drive trains	-0.8%	-2.0%	0.2%	-1.3%	-0.05%	-0.1%	0.02%	-0.09%
Introduction of continuously variable transmission drive trains	-2.0%	-4.0%	-0.6%	-1.9%	0%	0%	0%	0%
Total					-0.1%	-4.2%	1.1%	-2.3%

6.3.3. Other nacelle components

Existing situation

The nacelle includes a range of other components including structural parts such as the nacelle bedplate, electrical systems such as the transformer, converter and the power take-off, the yaw system, cooling systems, the control system and sensors, maintenance and other auxiliary systems, and a weather-proof nacelle cover.

Developers say that, while large components such as the gearbox and generator can cause major problems, electrical problems in smaller components occur more regularly and collectively have a larger impact on OPEX offshore. This is especially important for offshore wind where downtime can be significant, even for small failures if it takes a long time until access to the turbine is possible.

Innovations

Improvements in AC power take-off system design includes using new materials in convertors including silicon carbide (and possibly diamond) instead of silicon to achieve more efficient, smaller and faster-switching power conditioning electronics, with greater reliability and self-health-monitoring, building on the strong trend over last two decades that has reduced the cost of converter technology. Also included are parallel electrical solutions using multiple generator windings and separate power converter blocks, which a number of players are starting to adopt for offshore applications. Electrical problems are a large cause of unplanned maintenance and some turbine manufacturers are convinced that using modular convertors alone will reduce unplanned maintenance and enable continued generation even with a fault at a reduced maximum output. Convertors are currently responsible for about eight per cent of downtime and reducing this by half by modularisation, redundancy and increased reliability is seen as practical by the industry.

This innovation is expected to result in a decrease in the nacelle CAPEX of one per cent, continuing the observed trend, a decrease in the unplanned service OPEX of six per cent and an associated increase in availability of 0.2 per cent.

The timescales for realising both the technical impact and market uptake are such that, by FID 2014, 30 per cent of this potential is anticipated to be captured for a typical project rising to 80 per cent in FID 2020. It is expected that this innovation will affect 60 per cent of projects with 4MW-Class Turbines and 85 per cent of projects with larger Turbine MW-Classes in FID 2020.

This innovation is relevant to all Turbine MW-Classes but the market share on 4MW-Class Turbines is smaller because there will be fewer new products available that can incorporate innovation.

Introduction of DC power take-off in effect involves removing the second half of the power convertor that converts back to AC and adopting DC architecture for power take-off and collection. This is an innovation that fits well with the use of DC systems for transmission, which is a proven concept for interconnectors and export systems with single source and single sink design.

Cable manufacturers say that savings are available from the introduction of DC array cables through reduced cable core requirements and electrical losses, as well as converter costs on each turbine. Moving to DC array cables reduces the number of cores required from three to two with an associated total reduction in core material of 20 to 30 per cent. This core saving translates into a capital cost reduction of 10 per cent of array cable CAPEX, a 0.5 per cent reduction in installation and reduced array electrical losses of 0.1 per cent. Treating conservatively the modelling from a power engineering company, savings are expected of at least four per cent on the nacelle CAPEX and the reduction in losses from the convertor increases AEP by 0.8 per cent. Unplanned service OPEX is expected to be reduced by five per cent due to fewer components and availability is expected to increase by about 0.05 per cent.

A cable manufacturer reports that there is no technical barrier to the introduction of medium-voltage DC cables, but time would be required to develop and certify these lower voltage cable designs as they would be developed especially for offshore wind use. DC array cables are expected to be applicable to all site and turbine types but with greater advantages anticipated from larger turbines where higher cable capacity and transmission lengths are required.

The technical impact will first appear in FID 2017 when 50 per cent of this potential is anticipated to be captured for a typical project rising to 70 per cent in FID 2020. It is expected that this innovation will first have a market share in projects with FID in 2020 of 10 per cent of projects with 4MW-Class Turbines and 15 per cent of other projects with larger Turbine MW-Classes in FID 2020.

This innovation is relevant to all turbine sizes but the market share impact on 4MW-Class Turbines will be low as new turbine designs are less likely to be procured from FID 2017. Conversely, the market share impact will be high on Site Type D where high voltage direct current (HVDC) links are more likely to be used for transmission.

Other innovations

There are a range of innovations not modelled quantitatively that may offer significant cost reduction opportunities.

There is a parallel innovation to that of the *Introduction of DC power take-off* whereby DC array cables are used with a conventional AC turbine with an additional convertor which itself adds complexity although calculations still show savings over today's AC solutions.

GE Energy Power Conversion and others are developing power electronics that, when incorporated into an electrical machine, enable electronic commutation and thus DC generation. The impact of this technology is anticipated to be minimal on projects reaching FID in 2020, but the potential after this is significant.

Improvements are also expected in turbine design standards and processes. Currently, the industry is gathering significant data relating to offshore wind and wave conditions, their interrelationship and their combined impact on wind turbine and support structure loading. In time, industry plans that existing standards such as IEC61400-3 will be revised to better reflect new understanding. In some cases, these will drive an increase in CAPEX; in other cases, undue conservatism will be removed. In all cases, the anticipation is that the LCOE will be reduced due to the development of designs that are more fit for purpose.

Improvements in control logic and the intelligent use of redundancy, particularly in electrical and control systems, are anticipated to offer benefits. There has long been a debate in the industry whether the route to improved overall wind turbine availability is best followed by improving component reliability, incorporating redundancy or developing of condition monitoring. Turbine manufacturers accept that customers are unwilling to pay higher up-front costs to achieve reduced lifetime costs without clear evidence that lifetime costs will be reduced. As the industry matures, it is becoming clear that, in different circumstances and for different components, different routes are most applicable. Data from a developer revealed that remote reset accounted for over five per cent of downtime in its fleet, much of which can be translated into increased AEP by minimising downtime due to resettable issues.

Increased attention is being paid to reduce capital costs, increase functionality and minimise OPEX through better design and quality of a wide range of components and the selective introduction of redundancy to enable turbines to run at full or reduced load until a routine service or suitable vessels and access are available to facilitate component replacement.

In parallel to these innovations, progress is being made in developing and introducing new materials, detailed design and manufacturing process for a range of nacelle components, some of which constitutes overlap with Section 4 of the *Supply chain work stream report* but the remainder conservatively is not considered here.

Early signs of progress and prerequisites

Many turbine manufacturers are considering maintenance at an early stage of offshore turbine development. Reports are that design failure modes effects analyses (FMEA) are being carried out much earlier in the process and in many cases now there is much closer engagement with customers regarding lifetime care.

Early signs of the Improvements in AC power take-off system design are that new turbine designs are incorporating modular convertors and Siemens[27] DECC ETF Call 1 grant awarded in 2009 for work to develop a new power convertor for their next generation offshore turbine.

Early signs of the *Introduction of DC power take-off* are that GE Energy Power Conversion (formerly Converteam) has carried out concept design work to determine the feasibility of creating the multisource system required for this application.

Table 6.8 Potential and anticipated impact of innovations in other nacelle components, for a wind farm using 6MW-Class Turbines on Site Type B, compared with FID 2011.

Innovation	Maximum technical potential impact				Anticipated impact FID 2020			
	CAPEX	OPEX	AEP	LCOE	CAPEX	OPEX	AEP	LCOE
Improvements in AC power take-off system design	-0.3%	-2.4%	0.2%	-1.0%	-0.2%	-1.7%	0.1%	-0.7%
Introduction of DC power take-off (including impact of DC array cables)	-1.5%	-2.0%	1.4%	-2.8%	-0.1%	-0.2%	0.1%	-0.3%
Total					-0.3%	-1.8%	0.2%	-0.9%

[27] "Environmental Transformation Fund: Offshore Wind Demonstration Call, Programme Objectives and Anticipated Effect", DECC, available at www.decc.gov.uk/en/content/cms/funding/funding_ops/innovation/historic/wind_demo/wind_demo.aspx, accessed May 2012.

7. Innovations in wind turbine rotor

7.1. Overview

Rotor innovations in this study are considered to be of three types: the first relates to the *optimisation of rotor diameter* above the baselines described in Section 7.2; the second relates to innovations in the blade design and manufacture; and the third relates to innovations in control and the hub assembly.

Considering first the *optimisation of rotor diameter*, the step up from the baseline and the anticipated impact is greatest for the 4MW-Class Turbine. For a wind farm using 4MW-Class Turbines, the increase in wind farm CAPEX due to the *optimisation of rotor diameter* is about seven per cent, comparable to the additional AEP. Additional OPEX however is minimal; hence there is a LCOE reduction of about three per cent. The anticipated impact for 6MW-Class Turbines is similar. For 8MW-Class Turbines, the pattern remains but the magnitude is less. This innovation has a dominant impact on CAPEX, AEP and the LCOE for all three Turbine MW-Classes.

Other innovations offer reductions in CAPEX and OPEX along with further increases in AEP. The largest increase in AEP, of approximately 10 per cent, is for 6MW-Class Turbines. This is because turbine manufacturers are not expected to optimise 4MW-Class Turbines, with their activity focussed on their next generation turbines, mostly in the 6MW Turbine Class.

Source: BVG Associates

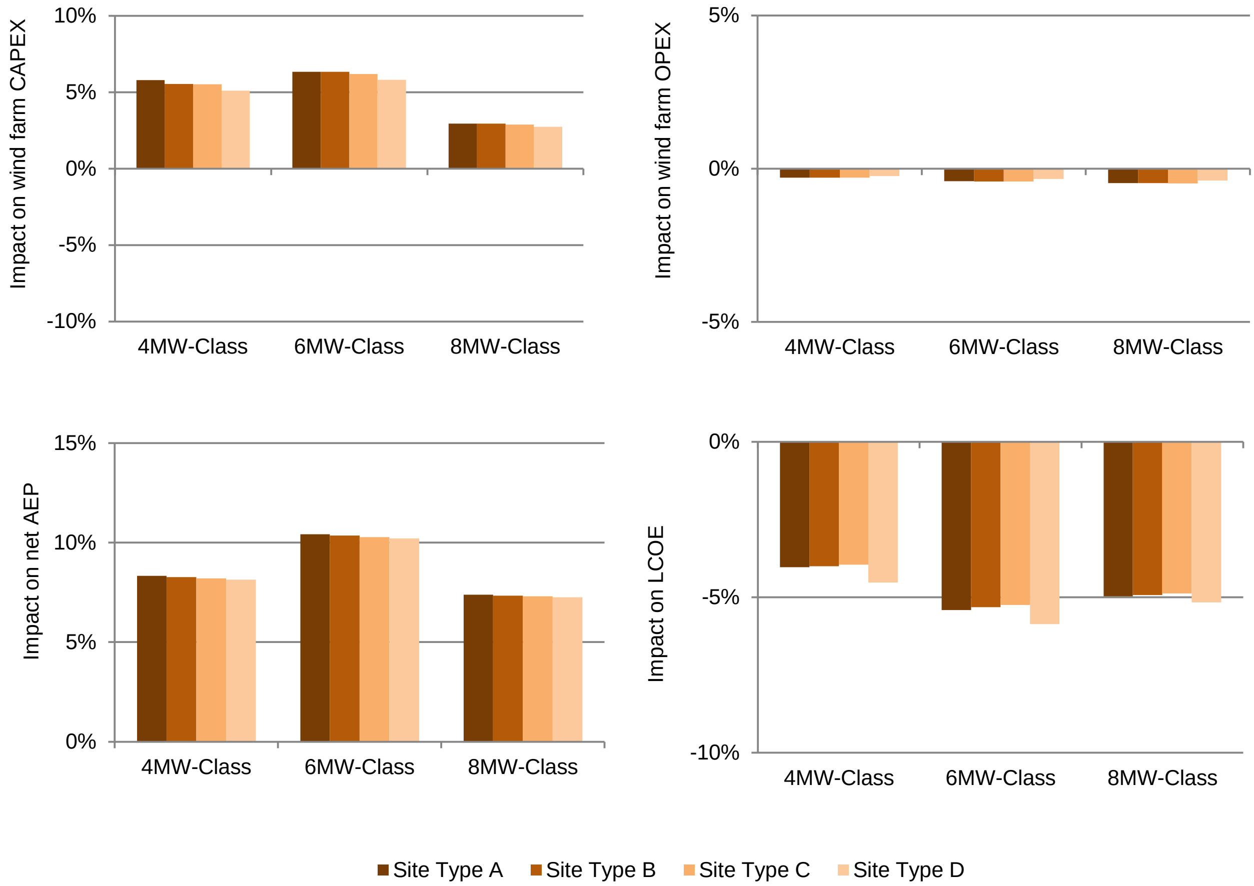

Figure 7.1 Anticipated impact of turbine rotor innovations by Site Type and Turbine MW-Class in FID 2020, compared with a wind farm on the same Site Type with the same Turbine MW-Class in FID 2011.[7]

The development of a new rotor is often part of the development process for a new turbine described in Section 3. The prerequisites therefore are similar to those discussed in relation to the rest of the wind turbine in Section 6. Confidence in the future market, and the availability of test sites and of workshop fatigue test facilities are all critical for the implementation of many blade innovations.

The key prerequisite is the engagement across the industry to design, test and demonstrate larger blades which are required as part of the *Increase in turbine power rating* (see Section 6.3.1), which is reflected in the baseline turbines and additional size increase, required as part of the *optimisation of rotor diameter* innovation discussed in this Section.

Figure 7.2 shows the anticipated and potential impact of turbine rotor innovations for a wind farm with 6MW-Class Turbines on Site Type B with FID in 2020, compared with FID 2011. About two thirds of the seven per cent anticipated impact is achieved through three key innovations: *optimisation of rotor diameter, improvements in blade aerodynamics*, and *improvements pitch control*. These all impact directly on AEP. In contrast, innovations in hub assembly, and blade design and manufacture primarily lead to rotor CAPEX reductions and, since the rotor accounts for only about 20 per cent of wind farm CAPEX for a 6MW-Class Turbine, their potential to reduce the LCOE is lower.

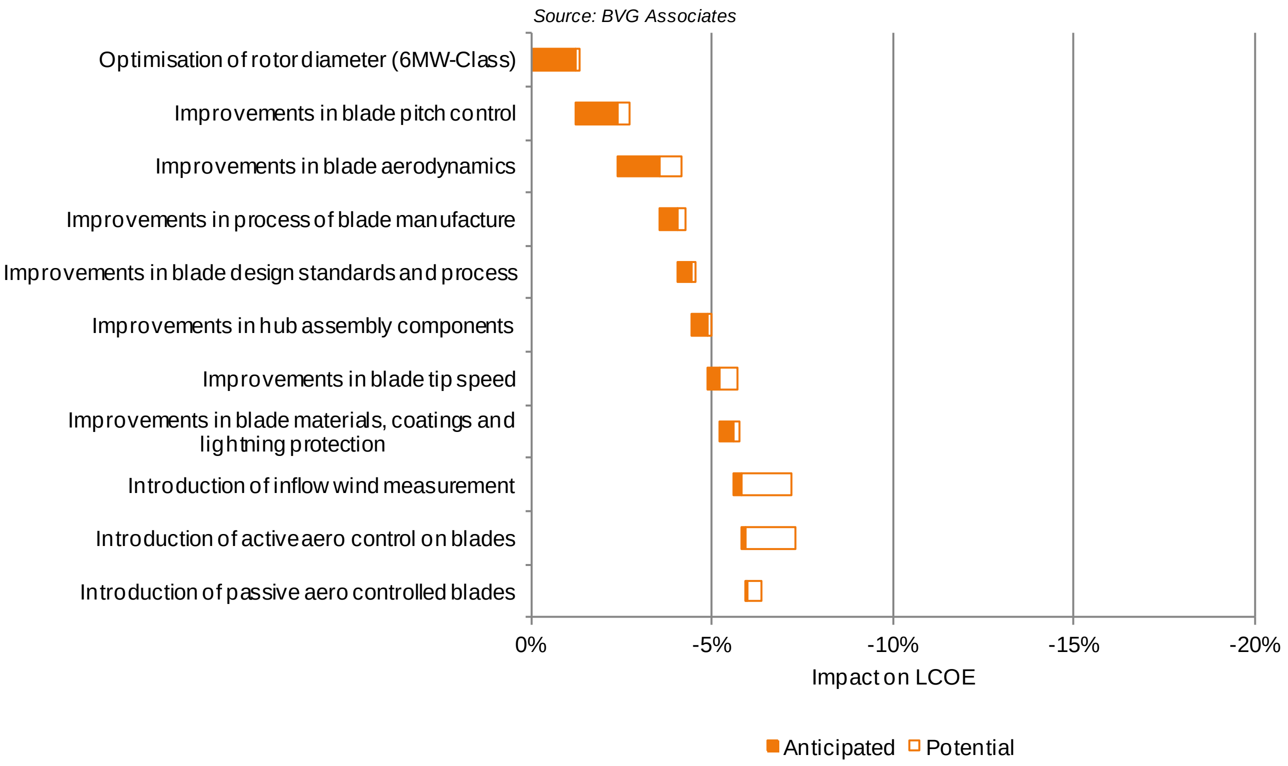

Figure 7.2 Anticipated and potential impact of turbine rotor innovations for a wind farm with 6MW-Class Turbines on Site Type B with FID in 2020, compared with a wind farm with 4MW-Class Turbines on the same Site Type with FID in 2011.[7]

7.2. Baseline

The turbine rotor extracts kinetic energy from the air and converts this into rotational energy. Full blade pitching is currently the primary method used to control the amount of energy extracted and to limit turbine loading. The rotors for all three baseline wind turbines operate upwind and consist of three blades, with the swept area scaled in proportion to rated power and tip speed constant. As discussed in Section 6.1, the starting point is a 4MW-Class Turbine with a rotor diameter of 120m.

The baseline cost of the turbine rotor is the contract payment to a wind turbine manufacturer for the supply of the three blades, the hub assembly incorporating blade bearings and pitch system, the hub cover, and fasteners used in the assembly to the nacelle. It also includes delivery of the components to the nearest port to the manufacturer, installation support, commissioning and warranty costs. As for all capital elements, the costs of OMS are excluded.

Onshore, often two or more rotor diameters are offered for a given turbine type, each optimised for a site with different average wind speeds. As average wind speeds for projects being constructed offshore in Europe fall within a much narrower band than for projects being constructed in a range of markets onshore, only a single rotor diameter is offered for each turbine type offshore. In line with this practice, only one rotor diameter is modelled for each Turbine MW-Class.

Wind shear at offshore sites is relatively low, modelled here with exponent 0.12. This means that there is no net benefit in increasing the tower height beyond that required to meet Maritime and Coastguard Agency (MCA) requirements[28] that the lowest point of the rotor sweep is at least 22 metres above Mean High Water Springs (MHWS).

As the rotor diameter is increased, the hub height is also raised to maintain this clearance, which increases the average wind speed at hub height and hence AEP. This change in hub height also adds to the support structure costs. It is noted that the higher baseline AEP for larger Turbines is driven purely by the increased hub height wind speed at the lowest allowable hub height. It is not the result of an optimisation process suggesting that taller towers are advantageous. The baseline parameters for each Turbine MW-Class are shown in Table 7.1.

Table 7.1 Baseline rotor diameter and hub height for each Turbine MW-Class, with resulting hub height wind speeds at example Site Type B (9.40 m/s at 100m).

Turbine MW-Class	Rotor diameter (m)	Hub height above MHWS (m)	Hub height wind speed (m/s)
4MW	120	82.0	9.18
6MW	147	95.5	9.35
8MW	169	106.5	9.47

As discussed in Section 6, the design of wind turbines is not project-specific. Instead, it is assumed that the rotor for all Site Types considered here is the same, designed for the harshest of wind speeds seen for offshore wind sites currently in development in Europe, corresponding to Class IA to international offshore wind turbine design standard IEC 61400-3.

The costs of the blades, cast hub, pitch system including blade bearings and the hub cover are calculated using empirically derived relationships based on turbine design experience and using as inputs turbine rated capacity, rotor diameter and tip speed. It is recognised that, due to different design philosophies, the masses and costs of components in different turbines in the market do not all fit the same trend. In all cases, costs are based on market information historically gathered by BVG Associates and rationalised to 2011 contract values. The total cost of the turbine rotor has been moderated in line with feedback from interviewees and workshop participants.

The breakdown rotor CAPEX for a 4MW-Class Turbine is shown in Figure 7.3. Costs are dominated by blades.

[28] Offshore Renewable Energy Installations (OREIs): *Guidance to Mariners Operating in the Vicinity of UK OREIs*, MGN 372 (M+F).

Source: BVG Associates

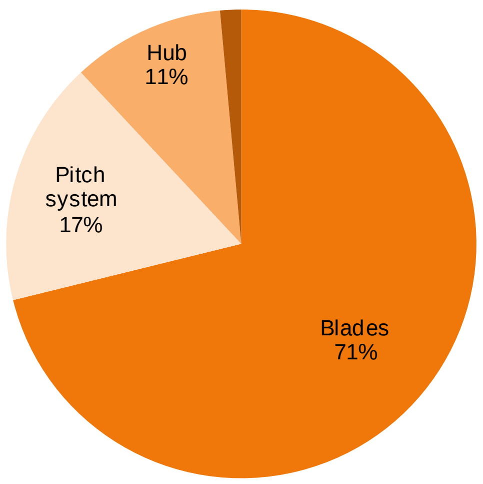

Figure 7.3 Breakdown CAPEX for baseline 4MW-Class Turbine rotor.

The rotor CAPEX for each Turbine MW-Class is shown in Table 7.2.

Table 7.2 Baseline turbine rotor CAPEX, constant for all Site Types.

Turbine MW-Class	Turbine rotor CAPEX (£k/MW)
4MW	393
6MW	465
8MW	518

The power curves assumed for the baseline Turbine MW-Classes are given in Figure 7.4. The power curve for the 4MW-Class Turbine was derived from the nominal published power curves of turbines in the offshore wind market today. The power curves for the higher-rated turbines are simply scaled in proportion to rated power, which is accurate as the rotor swept area is also scaled in proportion to rated power. Mechanical and electrical losses through to the output of the turbine transformer are incorporated in the published power curves used as input.

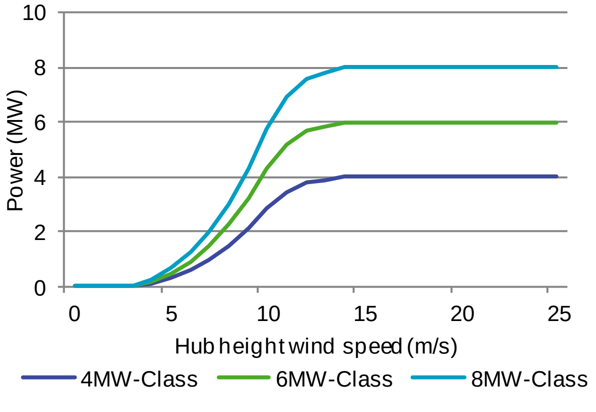

Figure 7.4 Baseline nominal power curve for each Turbine MW-Class.

The baseline nominal power curves were used to determine the gross annual AEP per megawatt at turbine outputs for the three Turbine MW-Classes on each of the four Site Types, as shown in Table 7.3.

The Site Type reference wind speeds were adjusted to the turbine hub height, as derived in Table 7.1, assuming a wind shear exponent of 0.12 and a Rayleigh wind speed distribution. Constant air density was used, corresponding to the typical UK average temperature of 10°C. AEP is assumed constant over the lifetime of the wind farm.

Table 7.3 Baseline gross annual AEP for each Turbine MW-Class for each Site Type.

Turbine MW-Class	Gross annual AEP (MWh/yr/MW)			
	Site Type A	Site Type B	Site Type C	Site Type D
4MW	4,288	4,520	4,683	4,834
6MW	4,384	4,613	4,772	4,920
8MW	4,453	4,679	4,836	4,981

To derive the net annual AEP at the input to the substation, the following losses are applied (again, assumed to be average values over life of a given wind farm):

- Other turbine losses, assumed to be 4.6 per cent for all baseline turbines, incorporating energy loss from cut-in/cut-out hysteresis (1.2 per cent), power curve degradation (one per cent), and power performance loss (2.5 per cent difference between nominal and actual power curve)
- Aerodynamic array losses, where baseline values are discussed in Section 5.2
- Electrical array losses, where baseline values are discussed in Section 9.2 and changes in electrical array losses are discussed in Section 9, and
- Wind farm availability, where baseline values are discussed in Section 11.2 and changes in availability are discussed for many innovations.

Table 7.4 Baseline net capacity factors for each Turbine MW-Class for each Site Type.

Turbine MW-Class	Net Capacity Factor (%)			
	Site Type A	Site Type B	Site Type C	Site Type D
4MW	39.7	42.1	43.9	45.6
6MW	40.9	43.2	45.0	46.6
8MW	41.7	44.1	45.8	47.4

The baseline net capacity factor for a wind farm using 4MW-Class Turbines on Site Type A is just under 40 per cent. It is recognised that this is higher than net annual capacity factors reported for many UK sites. Compared with typical projects reporting capacity factors today, the baseline wind farm has:

- Higher average wind speeds at 90m height above MSL, which increases AEP
- A lower specific rating, which increases AEP in below-rated wind speeds
- A larger rotor, which increases the hub height and hence the hub height wind speed, increasing AEP, and
- An average though-life availability of 95 per cent, which is higher than early years availability on some projects.

Capacity factors higher than 40 per cent are reported for offshore wind farms, for example at Horns Rev, installed in 2002 off the Danish coast. For Horns Rev, the higher capacity factor is dominated by higher wind speeds, as the Vestas V90-3.0MW turbines do not benefit from large rotors or low specific rating.

The increase in mean wind speed on Site Type A compared with that on Site Type D increases the capacity factor by about six per cent for a wind farm using 4MW-Class Turbines. Moving from 4MW-Class Turbines to 8MW-Class Turbines, the hub height increases to keep the minimum tip height at 22m above MHWS and the associated increased in hub height wind speed on Site Type D increases the capacity factor by just under two per cent. The net result of these two increases is that a wind farm using 8MW-Class Turbines on Site Type D has a capacity factor eight per centage points higher than a wind farm using 4MW-Class Turbines on Site Type A. This is equivalent to a 19 per cent increase in AEP.

7.3. Innovations

Innovations relating to the turbine rotor are considered in three groups, as shown in Table 7.5.

Table 7.5 Turbine rotor groupings used in this analysis. Innovations listed * and + cannot be combined with others similarly marked.

Groupings	Innovations
Rotor diameter	Optimised rotor diameter (that is, the change from the scaled rotor diameter discussed in Section 7.2).
Blade design and manufacture	Improvements in blade tip speed Improvements in blade aerodynamics Improvements in blade design standards and process Improvements in blade materials, coatings and lightning protection Improvements in process of blade manufacture
Control and hub assembly	Improvements in blade pitch control Introduction of inflow wind measurement * Introduction of passive aero controlled blades * + Introduction of active aero control on blades + Improvements in hub assembly components

While improved reliability is not considered as a separate innovation, it is a driver behind many of the innovations in rotors and is included in the impact of each innovation. There are some turbine rotor innovations that in isolation lead to lower availability and/or increased OPEX given the current technology, but give a reduced LCOE because they lead to increased AEP, which outweighs this penalty. Other innovations such as improvements in hub assembly components are anticipated to increase the reliability of pitch systems.

7.3.1. Rotor diameter

Existing situation

The specific rating is the ratio of the rated power of the turbine to the swept area of the turbine rotor. For the onshore market, turbine manufacturers often offer rotors with different diameters or specific ratings for a single design of nacelle. For low-wind applications, it is generally considered better to have a lower specific rating than for turbines for high-wind applications. An offshore wind farm is classed as a high wind application, but the optimum rotor diameter for an offshore wind turbine under the same conditions as an onshore turbine is different. This is because the turbine cost is a smaller fraction of an offshore wind farm total CAPEX than onshore, because of the additional costs associated with balance of plant supply and installation offshore. This means that the impact of spending more on the turbine rotor to obtain more energy output (accounting also for the knock-on costs on other elements such as nacelle and support structure) causes a smaller percentage change in CAPEX offshore than it does onshore. The optimum diameter for a given turbine is therefore larger offshore than it is onshore, for the same wind conditions.

Over the last two years, turbine manufacturers have announced increases in rotor diameters on existing models. Selected increases are listed in Table 7.6.

Table 7.6 Diameter and specific rating of selected existing and planned offshore turbine rotors on 4MW-Class Turbines.

Manufacturer	Model	Deployment	Rated power (MW)	Rotor diameter (m)	Specific rating (W/m²)
AREVA	M5000-116	Demonstration 30MW deployed at the Alpha Ventas 1 project, Germany (2010) with 200MW due to be install in Borkum West 2 Phase I in 2012	5	116	473
	M5000-135	New product announced November 2011	5	135	349
Siemens	SWT-3.6-107	First deployed at Burbo Bank, UK (2007) and in a further six wind farms with a combined world rated power of more than 1GW	3.6	107	400
	SWT-3.6-120	First deployed at Walney II, UK (2012) and more than 1.5GW due to be installed including in UK at Lincs, London Array 1 and West of Duddon Sands projects	3.6	120	318
Vestas	V90-3.0MW	First deployed at Kentish Flats, UK (2005) and in a further seven offshore wind farms with a combined rated capacity of just under 1GW	3	90	472
	V112-3.0MW	Launched in 2010 while yet to be installed in a commercial wind farm, although orders in the UK and across the rest of Europe have been placed	3	112	305

Innovation

There is a common industry view that there is room to increase the rotor diameter for 4MW-Class Turbines from that representative of products reaching FID in 2011 and to do the same for larger turbines. The optimum rotor diameter for a given wind turbine in the market is a function of the specific cost breakdown for that turbine, the blade technology used, the design conditions and other factors.

To assess the impact of the **optimisation of rotor diameter,** the indicative optimum rotor diameter, defined as that providing the lowest LCOE, is modelled for each Turbine MW-Class on Site Type B. Modelling shows that, as turbine rated power increases, the specific rating for the optimum LCOE also increases, as shown in Table 7.7. Both the logic of changing the optimum specific rating with the turbine rated power, and the calculated trend in optimum rotor diameter, have been confirmed through dialogue with a number of industry players. The impact of Site Type on the optimum rotor diameter can be shown to be minimal, as the impact of differences in average wind speed roughly balances the impact of differences in balance of plant costs.

It is recognised that this indicative optimum for a given Turbine MW-Class is only correct for the baseline turbine and conditions modelled here, rather than for any given turbine in the market. There are considerable challenges associated with developing larger blades, such as achieving the strength, stiffness, aerodynamic performance and stability and manufacturing quality required while retaining low material and manufacturing costs. When close to the optimum rotor diameter, the LCOE varies only slightly with changes in the rotor diameter. It may be expected, therefore, that commercially, the chosen rotor diameter for a given turbine will be somewhat less than the theoretical optimum for that turbine.

Table 7.7 Baseline and indicative optimum diameter for wind farm using each Turbine MW-Class, at Site Type B with FID 2011.

Turbine MW-Class	Baseline Rotor diameter[29] (m)	Indicative optimum rotor diameter (m)	Indicative optimum specific rating (W/m^2)
4MW	120	132	292
6MW	147	158	306
8MW	169	176	329

Figure 7.5 shows the diameter of selected existing and planned offshore turbines, plus the modelled indicative optimum rotor diameter. It shows that the increases in rotor size for turbine models on the market are moving turbines closer to the indicative optimum rotor diameter modelled. It is important to note that the baseline rotors modelled here all have the same specific rating as the average of 4MW-Class Turbines in the market in at FID in 2011.

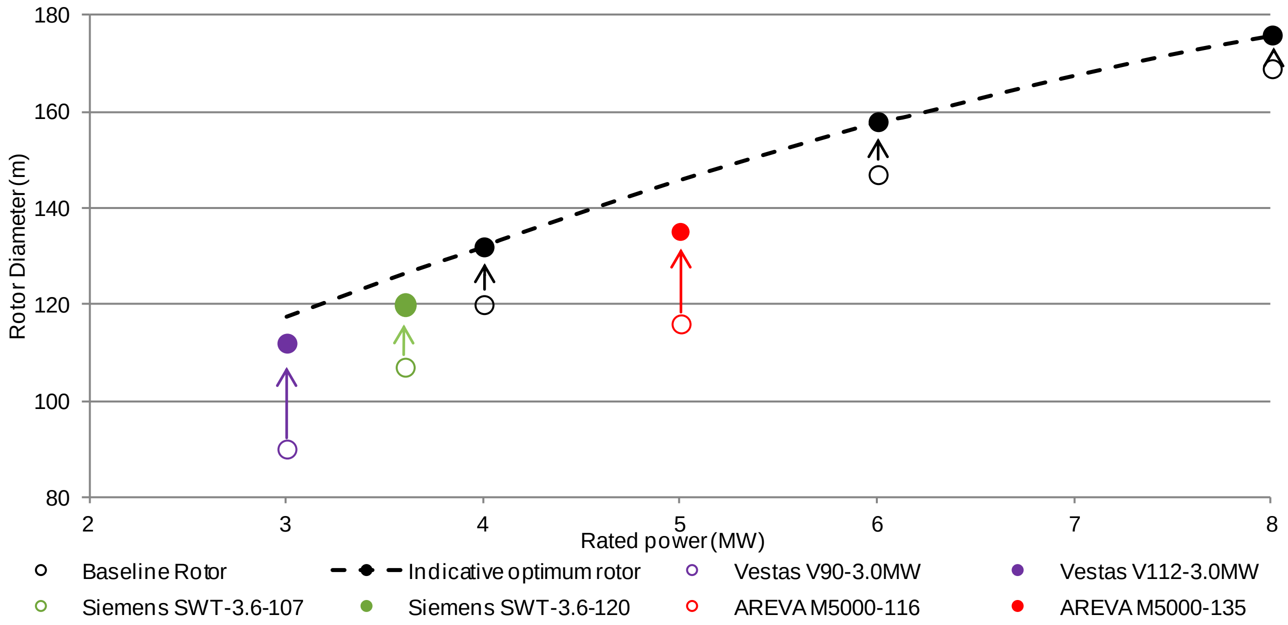

Figure 7.5 Trend of increasing rotor diameter versus turbine rated power (MW) for selected turbines where larger rotor versions have been announced in recent years.

In Table 7.8, the impact of increasing the rotor diameter from baseline to indicative optimum for a wind farm using 6MW-Class Turbines on Site Type B is presented. The trend is similar but more pronounced for the 4MW-Class Turbine and less pronounced for the 8MW-Class.

[29] All the baseline rotor diameters have the same specific rating of around 350 (W/m²).

Table 7.8 Impact from increasing the rotor diameter from baseline to technical optimum for a wind farm using 6MW-Class Turbines on Site Type B.

Element	Change	Justification
Rotor diameter	7.5%	Based on modelling
Rotor swept area	16%	Based on change in rotor diameter
AEP[30]	8%	A 7.3 per cent increase in AEP due to change in rotor swept area and 0.7 per cent due to increased hub height wind speed to keep the minimum tip height at 22m above MHWS. This results in increasing capacity factor from 43.2 per cent to 46.5 per cent
Rotor CAPEX	20%	Due to increased blade length, with knock-on impact on hub assembly cost
Nacelle CAPEX	9%	Due to increased rotor loading and torque due to lower rotor speed (keeping tip speed constant; changes in tip speed are explored in Section 7.3.2)
Support Structure CAPEX	12%	Due to increased rotor loading, and increased hub height required to preserve clearance to sea level
Array electrical CAPEX	6%	Due to the increasing the absolute turbine separation distances to maintain the six by nine diameter turbine separation
Installation CAPEX	2%	Due to increased blade size and rotor mass and subsequent increased nacelle mass, support structure mass and size and array cable length
Planned maintenance and unplanned service OPEX	0.6%	Due to increased component cost
LCOE	-2.3%	Due to combination of all the technical changes listed above, but not taking into account the impact of any changes relating to supply chain and financing

It is anticipated that, for a 4MW-Class Turbine, all the technical potential of this innovation will be realised by FID 2014. The market share of the innovation will be 25 per cent for wind farms with FID in 2014, rising to 60 per cent for FID in 2020. This is because manufacturers are expected to focus on the development of 6MW-Class Turbines, where we anticipate more rapid progress, with the innovation achieving 35 per cent of market share for FID in 2014, rising to 90 per cent for FID in 2020. For 8MW-Class Turbines, the first turbines entering the market are likely to be introduced with diameters close to optimum, thus the market share of the innovation is 80 per cent for FID in 2017, rising to 95 per cent for FID in 2020.

Early signs and prerequisites

As can be seen from Table 7.9 and Figure 7.6, the rotor diameter of example next generation turbines under development have rotor diameters that indeed lie closer to the indicative optimum than existing turbines shown in Figure 7.5. It is noted that only turbines outwardly targeted for the UK market are shown; others follow a similar trend.

[30] The losses and availability remain unchanged so both net annual AEP and gross annual AEP see the same percentage change.

Table 7.9 Diameter and the specific rating of wind turbines currently under development.

Manufacturer	Model	Rated power (MW)	Rotor diameter (m)	Specific rating (W/m²)
Alstom	Haliade 150-6MW	6	150	340
AREVA	M5000-135	5	135	349
Gamesa	G128-5MW	5	128	389
GE	GE 4.1-113	4.1	113	409
Mitsubishi	SeaAngel	>7	>165	<327
Siemens	SWT-6.0-154	6	154	322
Vestas	V164-7.0MW	7	164	331

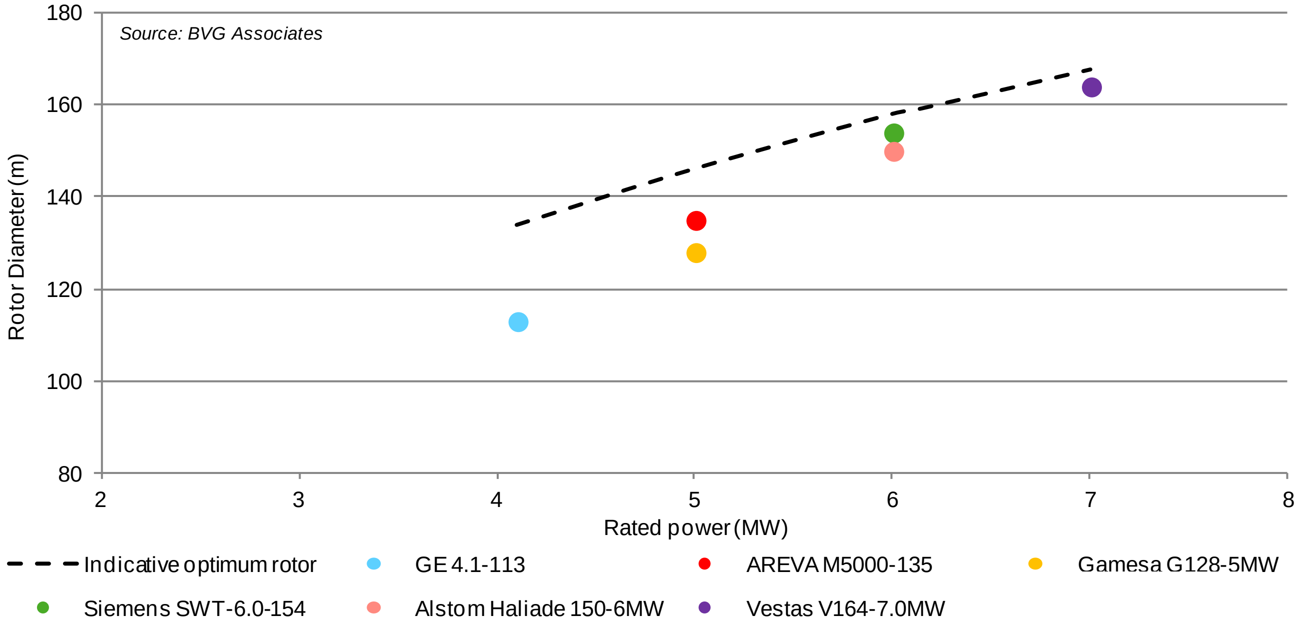

Figure 7.6 Graph of rotor versus turbine rated power for turbines with known rated power and rotor diameter being developed.

Larger rotors impact other aspects of the supply chain as, for example, they require larger vessels and advanced blade lifting technologies to avoid significant weather downtime as discussed in Section 10.

In 2011, the ETI, in recognising the value to the industry of increased rotor size, announced a competition for the development of "very long blades" in excess of 90m in length. This project is anticipated to accelerate both underpinning and blade-specific technology development covering both design and manufacture.

Due to the substantial technical advances that are required to deliver this anticipated *optimisation of rotor diameter* in addition to the *increase in turbine power rating* discussed in Section 6.3.1, interviewees advise an anticipated step change in levels of component system and turbine-level testing and verification to build confidence that designs are suitable for use on a commercial scale. The typical technology development cycle for a new offshore wind turbine design is explored further in Section 3. The cost of developing a new rotor with a diameter of about 150m including production is about £40 million, depending on complexity.

Interviewees say that a key prerequisite for accelerating the testing and demonstration of this innovation is the availability of both onshore and offshore sites, as discussed in Section 7.3.2.

Table 7.10 Potential and anticipated impact of the optimisation of rotor diameter, for a wind farm using each Turbine MW-Class on Site Type B, compared with FID 2011.

Innovation	Maximum technical potential impact				Anticipated impact FID 2020			
	CAPEX	OPEX	AEP	LCOE	CAPEX	OPEX	AEP	LCOE
Optimisation of rotor diameter for 4MW-Class Turbine	12.1%	0.4%	11.1%	-2.7%	7.2%	0.2%	6.6%	-1.6%
Optimisation of rotor diameter for 6MW-Class Turbine	9.3%	0.4%	7.8%	-1.4%	8.3%	0.3%	6.9%	-1.2%
Optimisation of rotor diameter for 8MW-Class Turbine	5.3%	0.2%	4.2%	-0.6%	5.0%	0.2%	3.9%	-0.5%

7.3.2. Blades

Existing situation

Today, all blades used on AREVA, Siemens and Vestas turbines offshore have been manufactured in house by the wind turbine manufacturer. Of the key players, only REpower has purchased blades from an external supplier, the global market leader, LM Wind Power. REpower has also now developed a blade in house through its PowerBlades subsidiary, with the same interfaces to that of the externally sourced blade. It is likely that this trend for in-house supply will change with the entrance of Alstom, Gamesa, GE Energy, Mitsubishi and others.

For a long time, some in the industry have argued that, in order to make such long blades meet the technical requirements imposed, carbon fibre is needed to augment glass fibre as the main structural element. Despite this, today, only Vestas uses carbon fibre in its offshore blades, in blades from about 40m in length for the onshore market. In line with its onshore designs, Gamesa is expected to follow suit.

All other suppliers use glass fibre as the main structural element, combined with epoxy-based resins and adhesives, while LM Wind Power has continued with its long-term choice of polyester-based resin.

For the last 20 years, the wind industry has been evolving design and manufacturing processes in order to manufacture larger and larger blades with reduced mould-times and increasing levels of quality and automation. Increases in the mass and CAPEX of larger rotors have been significantly less than would be achieved by extrapolating the original technology, which demonstrates significant advances in technology.

For onshore wind applications, aerodynamic noise constrains the rotor design, especially the rotor tip speed. In order to achieve consent for onshore wind projects within a reasonable distance of dwellings, the blade tip speed of onshore turbines is restricted to between 70 and 80m/s. Offshore, noise is of lower importance, leading to a marginal increase in tip speed for offshore-specific designs in the market today. While one manufacturer advised it does not intend to increase tip speed higher than that used onshore, a number of others have increased tip speed already to about 90m/s.

Innovations

As well as the expected increase in the size of blades, interviewees also say that they expect to see continued **improvements in blade aerodynamics**. This can be achieved through several independent routes:

- The development of new aerofoils designed for large blades offshore, enabling, for example, an improved balance between energy production, unwanted aerodynamic loading, structural efficiency, controllability and resistance to degradation due to dirt
- Better characterisation of 2D and 3D aerodynamic coefficients and behaviour by computational fluid dynamic (CFD) modelling and wind tunnel testing, and

- The improved use of passive aerodynamic devices such as stall strips, vortex generators and trailing edge flow modifiers. These are attached to the blade to improve aerofoil performance. Interviewees say that such devices are being used by most turbine manufacturers as well as independent blade designers.

Turbine manufacturers and independent suppliers view innovations in aerodynamics as key means of reducing the LCOE and are investing significant resources in this area, with a number now with in-house teams focused on aerodynamics.[31]

The potential impact of improvements in blade aerodynamics is anticipated to be an increase in AEP of two per cent. The overall reduction in the LCOE is offset by an increase in the turbine rotor CAPEX. This is advised to be approximately 0.4 per cent due to added the complexity of manufacturing and/or the decreased structural efficiency of the blade, and an increase in unplanned service of 0.5 per cent with an associated reduction in availability due to the lifetime care of passive aerodynamic devices.

This innovation is relevant to all Turbine MW-Classes but it is anticipated to have a limited impact on 4MW-Class Turbines as further design changes to this Turbine MW-Class are only likely to be undertaken before the full potential of this innovation is available to the market. Feedback from industry suggests that approximately 90 per cent of the technical potential will be available to the market for projects with FID in 2020, and it is anticipated that variants will be present on 80 per cent of 6MW-Class Turbines installed.

Improvements in the process of blade manufacture are being made by major blade manufacturers working in collaboration with academics, tool manufacturers and, in some cases, with companies from aerospace and other parallel sectors. These initiatives cover factory layout design and further the automation of the blade manufacturing process and other measures to increase quality and throughput of blades, especially with regard to the mould. The next stages vary for different manufacturers and for different blade designs. Overall, taking a conservative approach to industry feedback, it is anticipated that the potential technical impact of innovations in this area conservatively is anticipated to be a six per cent reduction in turbine rotor CAPEX. This is based on the argument from one experienced blade manufacturer that the manufacturing process contributes about 30 per cent of the cost of the blade and this can be improved by 25 per cent, in line with experience over the last 30 years. In addition, a one per cent reduction in unplanned service and an associated increase in availability are modelled as quality is improved.

This innovation is relevant to all Turbine MW-Classes but it expected to have a limited market impact on 4MW-Class Turbines as already established products may not be taken further. Approximately 80 per cent of the technical potential is anticipated to be available by 2020. This benefit is anticipated to be incorporated into 80 per cent of 6MW-Class Turbines by then, recognising that new blade manufacturing facilities will often be required specifically to build the next generation of blades.

It is important to note that some level of benefit relating to improvements in the manufacturing process inherently has been taken account of already in keeping manufacturing cost per tonne similar for the different length blades associated with the baseline turbines. Blade manufacturers also expect to see benefits from wider **improvements in blade design standards and process**, including:

- More use of holistic, design optimisation processes during the development of blades, optimising together the structural and aerodynamic performance of the blade
- Further development and use of software design tools, including CFD and finite element analysis (FEA)
- More holistic design optimisation of the rotor considering the whole turbine and support structure under offshore conditions
- Improved characterisation of materials (especially fatigue properties under the type of loading seen by offshore wind turbines) through extensive fatigue load and environmental testing, and
- Improved verification and testing of blade components and complete blades, increasing their fitness for purpose, reliability and confidence in the lifetime cost of blades.

[31] Frank Virenfeldt Nielsen, *The Power to Deliver: Future Demands to Subsupplier,* LM Wind Power, Hamburg, October 2011, available at www.eib.org/attachments/general/events/bei_hamburg_20111006_nielsen.pdf, accessed May 2012.

One market leader reports that, over the last decade, the sophistication of analysis, testing and verification has increased by an order of magnitude. This does not speed up the development of a new blade, but rather increases the level of confidence in new designs. These improvements are part of the confidence that technically underpins the innovation of *increase in turbine power rating* (see Section 6.3.1).

The technical potential impact of these changes conservatively is anticipated to be a two per cent reduction in the turbine rotor CAPEX and a 0.3 per cent reduction in unplanned service, with the associated increase in availability. A 0.3 per cent increase in AEP is also anticipated due to the more optimised design.

The impact is anticipated to have reached its maximum technical potential by FID 2020 and is relevant to all Turbine MW-Classes. It is anticipated that 80 per cent of 6MW-Class Turbines used on wind farms reaching FID in 2020 will be impacted.

Manufacturers say that the **improvements in blade tip speed** offer a range of benefits, but with risks. Higher tip speeds increase energy capture and it is forecast that the change from 88m/s to 100m/s has the potential to increase AEP by one per cent. The change also reduces input torque on the drive train and so reduces nacelle CAPEX by three per cent. Greater fatigue loading is experienced by the blade at higher tip speeds due to more fatigue cycles, and the innovation requires an increase of one per cent in the turbine rotor CAPEX and a three per cent increase in support structure CAPEX to keep the same fatigue life. Turbine manufacturers also report that higher tip speeds can lead to greater blade erosion and aerodynamic uncertainties of blade performance. These effects become disproportionately more important as the tip speed increases.

Wind turbine manufacturers suggest that the practical limit for tip speed on three-bladed turbines will depend upon other technology decisions made by the turbine manufacturer. For example, direct-drive systems benefit more from any increase in rotor speed than geared solutions. While tip speeds could reach 120m/s, turbine manufacturers do not expect to raise them much beyond 100m/s without significant operational experience.

This innovation is relevant to all Turbine MW-Classes but is expected to have a limited market impact on 4MW-Class Turbines as products of this size are already established and the focus now is on larger products. About 90 per cent of the technical potential impact of this innovation is anticipated to be available by FID 2020. For a 6MW-Class Turbine project with FID in 2020, it is anticipated that there will be a 50 per cent market uptake as some manufacturers do not intend to raise tip speed and others will raise tip speed but not necessarily to 100m/s as modelled here.

Manufacturers are working to increase the performance of the materials currently used in blades and they expect further **improvements in blade materials, coatings and lightning protection**. This is likely to be an evolutionary process with a number of small advances, rather than radical innovations in new materials. One such advance is in the Globlade family developed for onshore turbines by LM Wind Power, which uses a new formulation of glass fibre with improved properties.

Turbine manufacturers are also starting to develop additional functionality into their composite materials. Much of this work is still in its early stages but areas under investigation include:

- Self-healing composites. These are composites that self-slow crack development which could potentially extend the life of blades. This concept is at the laboratory stage.
- Low radar reflectivity materials. A UK Government-funded project was completed in 2010 to embed such materials into turbine blades and nacelles in order to reduce the radar reflectivity of the turbine. The development work was carried out by Vestas and QinetiQ and is in the prototype phase. They should be commercially available in Vestas turbines from the middle of 2013. This may enable a less expensive Radar mitigation where required.
- Nano-fillers, including nano-carbon tubes and nano-silicon additives, are being tested for use in wind turbine blade applications in order to increase stiffness and fatigue resistance of blades leading to blades that are 10 per cent lighter.
- Embedded lightning protection systems. Metallic or carbon fillers that can be added to resin during the blade manufacturing process are available. These fillers provide a path for lightning to travel safely down a blade during a strike and reduce the instance of blade damage.

New coatings are also being developed. For example, leading-edge erosion resistant coatings are being transferred from the aviation industry. These coatings are available as paint or, more commonly, as tape that is applied to the leading edge of blades to preserve its shape and structural integrity. Although a number of products are on the market and have been used for some time, accelerated progress is anticipated as tip speeds increase. Although blade manufacturers note that there is the possibility of cost-reductions of coatings themselves, process cost reduction through the more efficient use of facilities is likely to have a larger impact.

Self-cleaning and de-icing coatings can prevent dirt and ice build-up on blades which can seriously reduce their aerodynamic performance. These materials have hydrophobic properties that prevent water, ice and dirt accumulating on the blade. Although this is less of a problem offshore than in some onshore markets, ice and dirt build-up can cause a reduction of five per cent in AEP offshore for a period of time and it is estimated that new coatings have the potential to limit this by 75 per cent.

The lightning protection systems employed by most manufacturers consist of one or more metallic lightning receptors at the tip and along the surface of the blade, close to the pitch axis, connected by a copper wire running inside the length of the blade, connecting either to the blade bearing or arrangement to transfer current to the nacelle lightning protection system. Although systems perform much better than in the past, due to the increased frequency of lightning strikes experienced offshore, interviewees advise that there is room for improvements in this area. In particular, they highlight the benefit of collaboration or technology transfer from other industries such as aerospace.

These innovations are relevant to all Turbine MW-Classes and Site Types but the market impact on 4MW-Class Turbines is anticipated to be lower as the new development of products in this scale is less likely than for larger turbines. Despite this, coatings and materials could be incorporated into existing manufacturing processes. The technical impact of this innovation is anticipated to be a four per cent reduction in turbine rotor CAPEX, a one per cent reduction in unplanned service and an associated increase in availability. Innovations like these also enable the development of cost-effective larger rotors, but here the benefit is taken as CAPEX, recognising that any more effective methods will decrease the LCOE further. Feedback suggests that 80 per cent of this impact can be technically available by FID 2020, at which point 80 per cent of projects with 6MW-Class Turbines will take benefit at FID in 2020.

Other innovations

In addition to the innovations described above but not taken benefit of in this analysis, there are a range of further innovations that are likely to impact the LCOE, but are either likely after projects reaching FID in 2020 or with a less definable benefit.

Some consultees advise of the benefits of multi-part blades for assembly at the wind farm. Gamesa and Enercon have developed two-part blades for the onshore market where logistics costs preclude the transport of very large blades to some sites. Given that offshore turbine blade manufacture is likely to take place at coastal locations, there is little benefit in two-part blades for the offshore market and we have seen no appetite among players for this that will achieve any significant market presence by FID in 2020.

There remains some interest among potential offshore wind turbine manufacturers in developing downwind turbines. These have advantages in terms of a partial relaxation of maximum deflection requirements, which enables the development of a larger rotor or lower stiffness blades.

Another innovation is the introduction of two-bladed rotors, which are generally related to an increase in tip speed and are potentially linked to the introduction of a teeter hinge to allow the loads at the root of each blade to be balanced as in a child’s see-saw. Although there have been players offering this technology onshore for decades, the market share onshore has been low and, frequently, the technology has encountered negative perceptions relating to noise and visual impact. These considerations are of lower importance far offshore. The advantages are a reduction in rotor cost (each blade is more expensive, but fewer blades reduces the overall cost) and, in some cases, the nacelle and support structure costs, due to the reduced rotor loading and the ease of installation. For example, blades can be mounted on the nacelle before lifting the nacelle into place. For a given rotor diameter, there is a small AEP penalty.

Dutch start-up companies 2-B Energy and Condor Wind Energy (previously supported by ETI) aim to introduce a two-bladed downwind turbine. More established manufacturers also continue to explore such innovations, though there is little appetite to make such changes in the short-term, so market presence in projects reaching FID in 2020 is anticipated to be minimal.

More radical innovations include the introduction of multiple rotors on the same support structure, thus offering the potential of savings in support structure and installation costs.

Vertical axis turbines are also being developed for the offshore market, though any significant market presence by FID 2020 is unlikely. French team Nénuphar, Technip and EDF Energies Nouvelles are progressing a 2MW offshore prototype floating vertical axis turbine with three helical blades under the project name Vertiwind, with sea tests planned for 2013. Wind Power, Cranfield University, QinetiQ, Strathclyde University, and Sheffield University have been funded by ETI to develop the

Aerogenerator X concept, a two-bladed device in the form of a V, thus with no central tower. VertAx Wind is developing a more conventional H-rotor design with a number of UK-based partners.

Early signs of progress and prerequisites

New rotors are in development by all significant players in offshore wind and most are incorporating innovations in a number of the areas described above. Most of these players will establish new manufacturing facilities at coastal locations to produce these blades. A number of initiatives are supported by funding and enabling bodies, which recognise the strategic importance of innovations in turbine rotors for the offshore market and wish to accelerate their progress to market.

UK funding for improvements in the process of blade manufacture includes work to design and developing advanced manufacturing processes. This includes Vestas[32] DECC ETF grants, which were awarded in 2009 for work to design and develop a Next Generation Offshore Wind Turbine Blade with a focus on high speed fibre placement, and Blade Dynamics[33] DECC ETF call three grant, which was awarded in late 2010 to develop and demonstrate the use of modular blade assembly. In addition, Vestas is a Tier 1 member of the UK's National Composites Centre (NCC), shaping core research and technology programmes.

Further examples of collaborative work including technology transfer from other industries such as aerospace include the following:

- LM Wind Power's Blade King project, in collaboration with DTU Risø and other academic and commercial partners, is aimed at advancing automating manufacturing processes ready for the market in 2015. One partner is a developer and producer of commingled reinforcement yarns that combine glass and carbon with fibres spun from thermoplastic polymers, which are completely novel types of fibre.[34]

- Vestas is collaborating with Boeing in, for example, in a funded project on automated positioning of materials during blade manufacturing.[35]

Evidence for progress in increasing blade tip speeds includes announcements by some turbine manufacturers about the expected tip speeds of their next generation turbine rotors. For example, while the Siemens SWT-3.6-107 has a 72m/s tip speed, the larger rotor version SWT-3.6-120 has an 82 m/s tip speed and the Siemens SWT-6.0-154 turbine is expected to have a tip speed of well over 90m/s. Similarly, the Vestas V164-7MW is expected to have a tip speed 20 per cent higher than its current offshore product, the V112-3MW.

Evidence for improvements in blade design standards and processes include the publication of *IEC 61400-23 Ed. 1.0 Wind turbines - Part 23: Full-scale structural testing of rotor blades*, which has a forecast publish date of March 2013. The process of its preparation will already have moved the industry forward, with the preceding technical standard issued in April 2001.[36] Open access blade testing facilities for offshore-scale blades are now operational, including one at Germany's Fraunhofer Institute for Wind Energy and Energy System Technology, which opened in 2011 and is currently the world's largest test rig for rotor blades, capable of testing 90m blades. A larger rig is now in development at Narec and Vestas, while, for example, Siemens and LM Wind Power have their own in-house facilities.

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[32] Environmental Transformation Fund, *supra note 48,* available at www.decc.gov.uk/en/content/cms/funding/funding_ops/innovation/historic/wind_demo/wind_demo.aspx, accessed May 2012.

[33] *Ibid.*

[34] "The Danish National Advanced Technology Foundation supports LM Glasfiber's development of new gorund-breaking technology" *Press release,* LM Wind Power, 15 May 2008,available at www.lmwindpower.com/News/Archive/View%20News.aspx?id={7A8DCAF9-3B6D-4E14-9810-75A76A58569B}&y=2008, accessed May 2012.

[35] "Vestas and Boeing to collaborate on technology research projects" Press release number 3/2009, Vestas Wind Systems, 11 March 2009, available at www.vestas.com/files/Filer/EN/Press_releases/VWS/2009/090311-VWS_PR_UK-03.pdf, accessed May 2012.

[36] *IEC TC88 Work Programme*, International Electrotechnical Commission, (2012), available at www.iec.ch/dyn/www/f?p=103:38:0::::FSP_ORG_ID,FSP_APEX_PAGE,FSP_LANG_ID,FSP_PROJECT:1282,23,25,IEC 61400-23 Ed. 1.0#, accessed May 2012.

Significant work has been carried out by the SINTEF consortium in Norway to determine the suitability of new coatings for offshore wind applications. Blade Dynamics has also released a product named Bladeskyn for which it claims a range of excellent properties.

Prerequisites to commercial deployments include the availability of consented prototype and early series demonstration sites. This is a significant requirement since demonstration turbines are installed for durations similar to wind farms themselves. The Crown Estate Demonstration site gap analysis, published in August 2011, recommended urgent action on the part of industry and Government to bring forward such sites including streamlining consent, actively identifying sites , development by developers, and UK Government incentives.[37]

These programmes again require confidence in a strong ongoing market, though many innovations apply also to onshore turbines, which increases the value of development.

Table 7.11 Potential and anticipated impact of innovations in blades, for wind farm on Site Type B using 6MW-Class Turbines, compared with FID 2011.

Innovation	Maximum Technical Potential Impact				Anticipated Impact FID 2020			
	CAPEX	OPEX	AEP	LCOE	CAPEX	OPEX	AEP	LCOE
Improvements in blade aerodynamics	0.06%	0.2%	2.0%	-1.8%	0.04%	0.1%	1.3%	-1.2%
Improvements in process of blade manufacture	-1.0%	-0.4%	0.05%	-0.8%	-0.6%	-0.3%	0.03%	-0.5%
Improvements in blade design standards and process	-0.3%	-0.1%	0.3%	-0.6%	-0.25%	-0.1%	0.25%	-0.4%
Improvements in blade tip speed	0.2%	0%	1.0%	-0.8%	0.1%	0%	0.5%	-0.4%
Improvements in blade materials, coatings and lightning protection	-0.6%	-0.4%	0.05%	-0.6%	-0.4%	-0.3%	0.03%	-0.4%
Total					-1.1%	-0.7%	2.1%	-2.9%

7.3.3. Control and hub assembly

Existing situation

All offshore turbines on the market have active pitch control, which is enabled through the use of a large diameter slewing bearing mounted at the root of each blade. Adjusting the blade pitch angle uses either hydraulic or electrical systems. Hydraulic systems use one or more cylindrical actuators on each blade to rotate this blade bearing via action on a circulate plate attached to the bearing, while electric systems use one or more geared electric motors acting on a toothed ring on the blade bearing.

The pitch system is designed to operate each blade independently such that, if one blade fails to move to the desired angle, the other two blades can slow the turbine safely. In addition, a backup power supply is required in the event of the loss of electrical power to the pitch system. This backup is in the form of hydraulic accumulators (either piston or bladder) for hydraulic systems and batteries or capacitors for electric systems.

[37] *Demo Sites,* The Crown Estate, available at www.thecrownestate.co.uk/energy/case-studies/demo-sites, accessed May 2012.

The blade bearings and pitch system are mounted on a ductile cast iron hub, which is normally of a roughly spherical design and is machined, non-destructive testing (NDT) inspected and surface finished inside and out after casting. The complete hub assembly is weatherproofed using a glass fibre cover which also provides personnel access for OMS activities.

Some turbines measure the load on each blade and cyclically vary the pitch angle in order to reduce the loading on each blade; others apply the same control response to all three blades simultaneously, though there is more progress still to make in both these areas. It is already established practice by many to use pitch control to provide damping to tower movement, thus reducing loads.

The use of condition monitoring systems as input to manage loads is considered in Section 11.3.2 as such systems may be added or upgraded during the operating life of the wind farm.

Innovations

Improvements in blade pitch control typically are anticipated to both increase AEP and reduce CAPEX through reducing design-driving loads on key structural components, the drive train and yaw system. Innovations include further progress in both individual blade and collective pitch algorithms, improved load and other inputs to the control algorithm. Another key area for development is to manage loads through pitch control even when running in the wake or partial-wake of other turbines. One turbine control expert estimates that improvements to individual pitch control alone could further reduce lifetime loads by the about 20-30 percent compared with what is state-of-the-art today.

Overall, the collective impact of improvements in pitch control is seen by a number of industry experts as significant. Experience to date has been that actual savings have not always matched anticipated savings, reflecting the challenges of gaining benefits in real-world conditions. Conservatively, a reduction of only one per cent in the turbine rotor CAPEX, and a two per cent reduction in the support structure CAPEX are anticipated here, also taking into account changes to the pitch system and blade bearings to cope with the increase in duty. Rather than modelling a reduction in drive train CAPEX, benefit is taken though generating more AEP, which is anticipated to be 1.2 per cent. Based on the costs associated with the service of pitch systems and, notwithstanding upgrades in components to cope with additional duty, the increased pitching required for better blade pitch control is anticipated to increase unplanned maintenance by 0.5 per cent, with an associated small decrease in availability.

Innovations in pitch control are relevant to all Turbine MW-Classes and Site Types and it is anticipated that 80 per cent of the potential benefit will available to the market for projects with FID in 2020. It is anticipated that such a level of innovation will be incorporated in 30 per cent of 6MW-Class Turbines at this point.

The penalty of *improvements in blade pitch control* is an increase in unplanned service due to the extra pitch system cost and duty. This is one area addressed through **improvements in hub assembly components**, which cover advances in blade bearing and pitch system, hub structural design, hub materials and manufacture. Specific innovations include:

- Improved blade bearing designs with increased raceway life, improved lubrication and longer-lasting seal arrangements and improved gear tooth wear with electric pitch systems, verified through much improved test programmes
- Better solenoids and power electronic drives than those currently used in hydraulic, electric and pitch systems, increasing performance in terms of dynamic response and accuracy
- Improved backup power sources for both hydraulic and electric pitch systems, and
- Improved hub design methodologies, taking into account highly complex varying 3-D load and stress patterns, coupled with improved material properties, understanding of material properties and manufacturing methods.

Siemens has experienced problems with blade bearings and replaced about half of those on the SWT-3.6-107 turbines at Centrica's Lynn and Inner Dowsing wind farm in 2011 and 2012 as part of a preventive maintenance programme.[38] This indicates that even the current market-leading turbine design is not immune to reliability issues with hub components and this innovation assumes that the learning from such problems will be applied to future designs.

[38] *Renewable Energy News,* Issue 232, 26 January 2012, p.2

The technical potential of this innovation is a two per cent reduction in turbine rotor CAPEX through better design and manufacture and a two per cent reduction in unplanned service costs through improved reliability and an associated increase in availability. These innovations are relevant to all Turbine MW-Classes and Site Types. The timescales for realising the technical impact are such that, by FID 2014, 30 per cent of the technical potential is expected to be available commercially, rising to 80 per cent for projects with FID 2020. The market share for 6MW-Class Turbines and above is anticipated to be 70 per cent for projects with FID 2014 and 100 per cent for projects with FID 2020. For projects with 4MW-Class Turbines the market impact is anticipated to be limited to 70 per cent to FID in 2020 as few new designs are anticipated at this scale.

It is current practice for the turbine to react to the wind field, once it has impacted the rotor, and measure it using meteorological equipment mounted on the nacelle. The **introduction of inflow wind measurement** enables the power performance of the wind turbine to be much better assessed and incoming wind speed information to be used in turbine control, enabling the turbine yaw, pitch and torque demand to be adjusted in advance of the wind field impacting the rotor. This can be achieved using a LiDAR system to measure the direction and velocity of the wind at multiple points in front of the rotor. One turbine control academic advised that, with such a range of additional input data available, the challenge is to characterise the information coming in and decide how the limited control parameters of the turbine should be varied in response.

The potential technical impact of this innovation, which is additional to *improvements in blade pitch control*, is anticipated to be a two per cent increase in AEP. We recognise that one champion of such systems argues far more, assuming the results of onshore field trials are transferable to offshore wind turbines.[39] The cost of the LiDAR and its integration into the turbine leads to a two per cent increase in turbine rotor CAPEX and a conservative one per cent increase in unplanned service.

It is anticipated that the technology will not be available to the market for projects with FID in 2014 but 50 per cent of the technical potential will be available for projects with FID in 2020. While this innovation is relevant to all Turbine MW-Classes and Site Types, it is anticipated that it will be present in 30 per cent of 6MW-Class Turbines and above by this date. One view expressed is that initially LiDAR may be used relatively simply then, as confidence in results and reliability increases, inputs from LiDAR would become more integral to control and the overall impact will be therefore maximised.

The **introduction of active aerodynamic control on blades** involves the use of innovations such as flaps, active surfaces, air-jet boundary layer control, plasma effectors and extendable length or actively coning blades. Flaps are an established method of active load control in the aerospace industry. These can be activated either mechanically or electrically, and potential designs vary in scale from large, aircraft-type flaps of many meters in length, to flaps a few millimetres in size.

For larger blades, the rate of pitching due to the greater inertia of the deflected blade will be slower and a single control parameter for such a large surface area becomes coarser. Complementing this by faster-acting means of controlling the aerodynamics seems a logical step, although one expert interviewed anticipated that the benefit over pitching will be small.

Active surfaces can be used to change the aerodynamic properties of the blade surface, usually increasing and decreasing roughness using micro-actuation devices. This has not yet been tested on turbines in the field.

Air jet boundary layer control involves sucking or blowing air from holes positioned radially along the surface of a blade to alter the attachment of the air to the blade surface. This provides control over the loading of on a blade equivalent to a few degrees of pitching. It requires the addition of a pneumatic system arrangement.

Similar to the above, plasma control is used to prevent flow separation when desired and thus maximise the aerodynamic performance. It adds energy to the flow to achieve this, by creating a narrow plasma field on relevant areas of the blade using plasma aerodynamic control effectors (PACE).[40] This has advantages over mechanical actuation as it has no moving parts and is therefore less prone to fatigue. The energy added is small compared with the extra energy generated by the turbine.

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[39] Catch the Wind claimed in March 2011 that Vindicator® Laser Wind Sensor generated greater than 20 per cent increased energy output by better aligning a turbine with the wind, available at www.catchthewindinc.com/news/catch-wind-presents-field-trial-data-ewea-annual-event, accessed May 2012.

[40] Nelson, R., Patel, M., Corke, T., Othman, H., Vasudevan, S., Ng, T., *A Smart Wind Turbine Blade Using Distributed Plasma Actuators for Improved Performance*, 46th Aerospace Sciences Meeting, January 7-10, 2008, Reno, Nevada, American Institute of Aeronautics and Astronautics Paper 2008-1312, available at www.nd.edu/~rnelson/AIAA2008-1312Revison.pdf, accessed May 2012.

Extendable length blades or actively coning the blade could offer a significant benefit in terms of reduced loading and increase AEP by operating with a large diameter rotor in low winds and a smaller rotor in high winds. Though designs have been investigated, we found no evidence of progress from mainstream players. One approach is to have telescopic blade tip designs.

Technology developers say there is significant uncertainty about which innovations will proceed, but expect that, in time, some will. The potential impact of this group of innovation is modelled as a 2.5 per cent increase in AEP, but conservatively, this is combined with a five per cent increase in turbine rotor costs, a three per cent increase in unplanned service costs and an associated decrease in availability as device failure could limit its operation. This innovation is relevant to all Turbine MW-Classes but is expected to have a greater market share for turbines with larger power ratings. This is because it offers a more precise control of air flow for larger blades than is provided by merely adjusting the pitch angle. There is no impact on the market for 4MW-Class Turbines, as established designs already exist, but there is some potential for retrofitting.

The timescales for introduction are such that active devices are not anticipated to be commercially available for projects with FID in 2014, and only 50 per cent of the technical potential will be available by FID in 2020. A limited market share is expected for 4MW-Class Turbines due to existing designs and the focus on larger turbines as the basis for this innovation. For 6MW-Class Turbines and above, the market share of this technology is anticipated to be 10 per cent for projects with FID in 2020.

The **introduction of passive aerodynamic control on blades** can be achieved in a number of ways, two of which were raised by interviewees. The first is to incorporate in the blade a flexible trailing edge that deforms under high loads, thus spilling the load. The second is to introduce a load-twist coupling within the structural design of the blade so as passively to compensate for the increased load by the blade effectively pitching to reduce loads. A sweep-twist adaptive rotor concept is under development by Sandia National Laboratory and Knight & Carver in the US.

The control therefore is passive and inherent in how the blade responds to load. It decreases the need for fast measurement and control and simulations show that such innovations can work well with advances in pitch control. Blades with passive control capability such as load-twist coupling are not necessarily any more expensive, since they require only an alternative material layup in the existing blade mould and use standard manufacturing methods.

The potential technical impact of this innovation is anticipated by one established blade manufacturer to be a 2.5 per cent decrease in support structure CAPEX due to reduced loads. Reports of larger anticipated savings have also been received.

Half of this potential innovation is anticipated to be commercially ready for projects with FID in 2020. This innovation is relevant to all Turbine MW-Classes and Site Types but it is not expected to be implemented in 4MW-Class Turbines, as established designs already exist. Based on industry feedback, this approach is unlikely to be taken by many turbine manufacturers in the near future and so market share is anticipated not to exceed five per cent of 6MW-Class Turbines and above used in projects with FID in 2020.

Other innovations

In addition to the innovations described above, but not taken benefit of in this analysis, there are a range of further innovations that are likely to impact, either after projects reaching FID in 2020 or with less definable benefits.

These include fabricating hubs in steel, or moulding in composite and repositioning blade bearings away from the blade root, further from the rotor centre line. Both of these have been investigated by a number of players. In addition, on some turbines, the hub cover has been removed, though not on any offshore turbines.

Early signs of progress and prerequisites

Many of the innovations in control and the hub assembly are at an early stage of development and it will be the second half of the decade before they are proven for the market.

Inflow wind measurement is at an early stage but it is being developed separately by a number of companies including Catch the Wind, Avent Lidar Technology and Pentalum, and some benefits have been successfully demonstrated in trials onshore. Avent Lidar Technology's Wind Iris has been tested at the Høvsøre test site and offshore at the Alpha Ventus demonstration site. Catch the Wind has leased its Vindicator unit to a leading wind turbine manufacturer and signed a letter of intent with Technocentre Eolien to install the product on a REpower MM92 turbine for RD&D purposes. Pentalum launched its ground-mounted SpiDAR product at the end of November 2011, which is of interest because it does not utilise the Doppler effect to measure wind speed, in contrast to other such devices. It is therefore able to use off the shelf components, which Pentalum claims allows a significantly cheaper product.

Most of the early signs of innovations in aerodynamic control on blades are found in RD&D projects, for example, at DTU Risø, which undertook a successful trial of a flexible trailing edge system under wind tunnel test conditions. DTU Risø demonstrated the use of flaps for load control on turbines as a result of a Danish government-funded project, but no solutions are yet in series production. PACE has only been demonstrated on aerofoils under laboratory conditions, for example, by the University of Notre Dame. Indiana and air jets have not yet been demonstrated at a large scale on turbines but are used in some defence aircraft applications. An example of this is US patent 6940185.

At least one turbine manufacturer has taken extendable blades to the proof-of-concept stage, but the technology has not been taken forward due to concerns about long-term robustness.

Prerequisites to the commercial deployment of *improvements in blade pitch control* are limited, as costs are low and trials relatively easy to implement, though ideally these are performed on sites that enable power performance measurements to be certified.

Generally, improvements in hub assembly components will be made at the same time as introduction of a new wind turbine, and as such the prerequisites are similar to those listed in Section 6.

Prerequisites to the commercial deployment of aerodynamic devices include the availability of consented prototype sites, though likely initially at below offshore-scale for aerodynamic trials. Again, these programmes require confidence in a strong ongoing market to make long-term investment viable, especially as it is not clear which technology will prove to be the most attractive. These devices, however, are likely also to have a place on onshore turbine rotors, which offers a significantly increased available market.

Table 7.12 Potential and anticipated impact of innovations in control and hub assembly, for a wind farm on Site Type B using 6MW-Class Turbines, compared with FID 2011.

Innovation	Maximum Technical Potential Impact				Anticipated Impact FID 2020			
	CAPEX	OPEX	AEP	LCOE	CAPEX	OPEX	AEP	LCOE
Improvements in blade pitch control	-0.7%	0.2%	1.2%	-1.6%	-0.5%	0.2%	0.9%	-1.2%
Improvements in hub assembly components	-0.3%	-0.8%	0.1%	-0.5%	-0.3%	-0.7%	0.08%	-0.4%
Introduction of inflow wind measurement	0.3%	0.4%	2.0%	-1.7%	0.05%	0.06%	0.3%	-0.25%
Introduction of active aero control on blades	0.8%	1.2%	2.4%	-1.5%	0.04%	0.06%	0.1%	-0.08%
Introduction of passive aero controlled blades	-0.7%	0%	0%	-0.5%	-0.02%	0%	0%	-0.01%
Total					-0.7%	-0.4%	1.4%	-1.9%

8. Innovations in support structure

8.1. Overview

Innovations relating to the turbine support structure are anticipated to reduce the LCOE by approximately five per cent on like for like Site Types and Turbine MW-Classes between 2011 and 2020, with the largest savings anticipated for projects using 6MW-Class Turbines on Site Type D. The savings are dominated by improvements in CAPEX, rather than OPEX or AEP.

Figure 8.1 below shows that the impact on CAPEX is greatest for a wind farm using 4MW-Class Turbines on Site Type C, because this combination has the largest number of structures in the deepest waters. The least impact is on a wind farm using 4MW-Class Turbines on Site Type A, which is the only Site Type using monopiles, which is a more mature technology with less room for innovation.

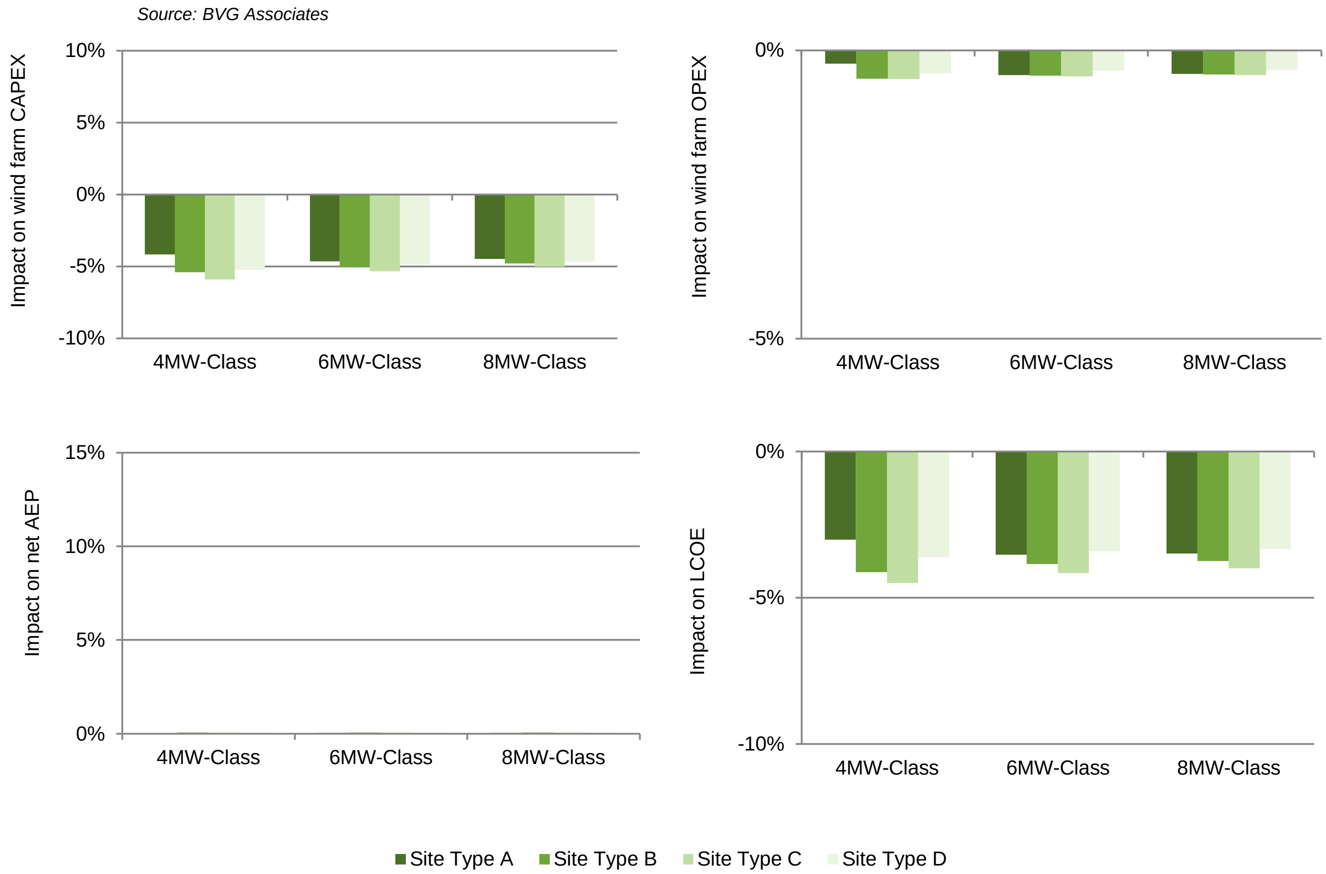

Figure 8.1 Anticipated impact of support structure innovations by Site Type and Turbine MW-Class in FID 2020, compared with a wind farm on the same Site Type with the same Turbine MW-Class in FID 2011.[7]

The contribution of innovations in installation to reducing the LCOE in going from a wind farm using 4MW-Class Turbines on Site Type B in 2011 to 6MW-Class Turbines on the same site in 2020 is anticipated to be 3.8 per cent. The most important individual innovations relate to improvements in the way steel jackets are manufactured. Investment in tooling and facilities, combined with innovations in the way these components are designed, means that costs can be significantly reduced as production levels are increased.

Figure 8.2 shows that, not only will improvements in manufacturing processes have the largest potential impact, but they are also anticipated to achieve much of this potential by 2020. This depends on a buoyant market where there is the confidence to invest in facilities that predominantly will service offshore wind. It will also rely on an increasing number of projects being built in Site Types B, C or D and using 6MW-Class Turbines or larger as this will require a move away from the existing monopile technology.

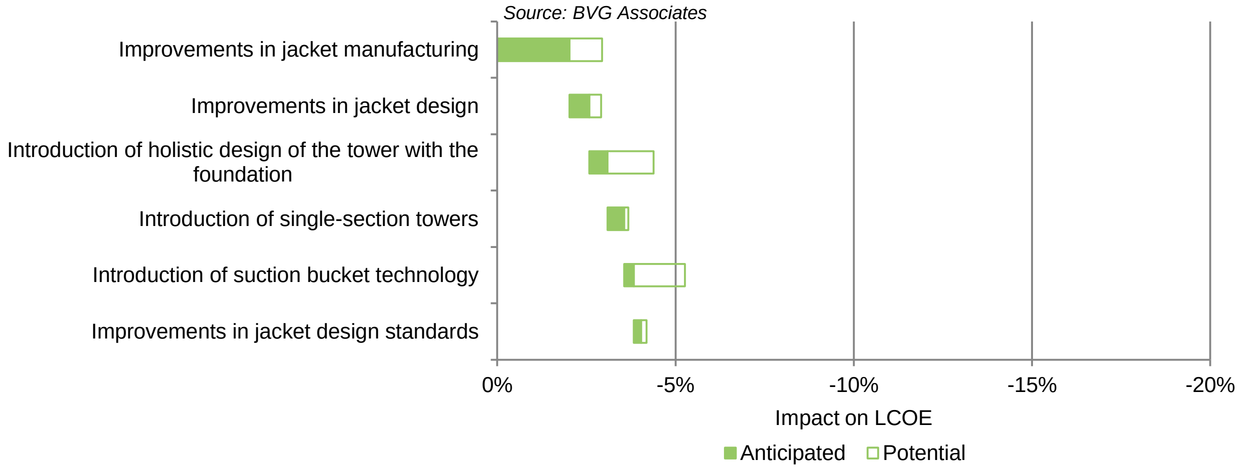

Figure 8.2 Anticipated and potential impact of support structure innovations for a wind farm with 6MW-Class Turbines on Site Type B with FID in 2020, compared with a wind farm with 4MW-Class Turbines on the same Site Type with FID in 2011.[7]

8.2. Baseline

For the purposes of this study, the cost of the support structure covers the supply of the turbine tower and the foundation.

Space frames, including jacket foundations, tripods and tripiles, are composed of the main structure and the sea bed connection which could be either pin piles or suction buckets. Monopile foundations are composed of the monopile and the transition piece. A concrete gravity base foundation is a single structure. In all cases, there are also secondary steel items such as personnel access structures and J-tubes. The cost also includes delivery to the nearest port to the supplier and warranty costs of the supplier. The tower and the foundation have been considered together in this study as they both require similar manufacturing processes. In all existing wind farms, the tower has been part of the turbine supply contract. It has also always been installed along with the turbine rather than the foundation as described in Section 10.

For our baseline calculations, in line with industry feedback, it is assumed that the most cost-effective foundation for a 4MW-Class Turbine on Site Type A is a monopile, while a space frame or gravity base is more economical for all other Site Types and Turbine MW-Class combinations.

Figure 8.3 represents an aggregated industry view on the most cost-effective foundation choice for a range of turbine ratings and water depths. Specific input from a foundation design consultant and a foundation fabricator indicates that the current crossover point between a monopile and a jacket is approximately 30m water depth for a 4MW turbine, reducing to 20m for a 5MW turbine. According to an experienced offshore developer, the variation in water depth across a site may mean it is cost effective to use a small number of oversized monopiles in individual deeper water locations where other foundation types would be more appropriate, if it enables a single foundation strategy to be used across the whole of the project.

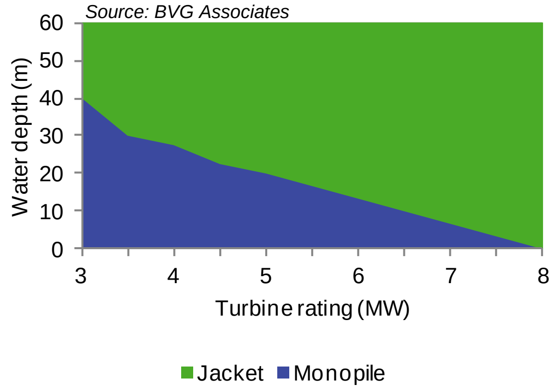

Figure 8.3 Indicative baseline transition between monopile and jackets.

The mass of a monopile foundation and transition piece is calculated using a model considering water depth, turbine rating, rotor tip speed and tower top mass, derived from known industry data, and validated through dialogue with both suppliers and purchasers. Ground conditions are assumed to be "average". Sensitivity to ground conditions is discussed in Section 13. For a 4MW-Class Turbine on Site Type A, the monopile has a mass of 660 tonnes and the transition piece has a mass of 220 tonnes, including secondary steelwork. Costs per kilogramme for a monopile (£1.4/kg) and a transition piece (£3.2/kg) are derived from dialogue with relevant suppliers and cover material and manufacturing costs.

For the baseline jacket, a standard four-legged design is assumed using welded nodes and pin piles. The masses of the jacket foundations (including pin piles) are calculated using a model considering water depth and turbine rating provided by a significant industry player and are validated both against known industry data and with a range of suppliers and purchasers. Ground conditions are assumed to be the same as for monopiles.

For a 4MW-Class Turbine on Site Type B, it is assumed the jacket foundation has a mass of approximately 530 tonnes and the pin piles have a total mass of about 350 tonnes. The jacket mass including secondary steelwork increases to approximately 650 tonnes for a 6MW-Class Turbine on Site Type B and 800 tonnes for an 8MW-Class Turbine on Site Type B. The pin pile mass increases to approximately 440 tonnes for a 6MW-Class Turbine on Site Type B and approximately 530 tonnes for an 8MW-Class Turbine on Site Type B. Costs per kilogramme for jackets (£3.2/kg) and pin piles (£1.4/kg) are derived from dialogue with relevant suppliers as above. It is recognised that pricing based on mass is somewhat simplistic but any inaccuracy is seen to be within the scatter of costs quoted by the industry.

In offshore conditions, the sea surface "roughness", and hence wind shear, is relatively low with the result that wind speeds do not increase significantly with height. This means that, with existing technology, the optimum hub height for offshore wind turbines is as low as is allowed.

Turbine hub height, which is defined as tower height, is fixed by keeping a distance of 22m between the tip of a rotor blade at its lowest point and the water level at MHWS. For all turbine sizes, the tower cost is assumed to be equal to approximately 15 per cent of turbine (nacelle and rotor) CAPEX, a relationship derived from feedback from a number of turbine manufacturers and tower suppliers for a range of turbine sizes.

Trends in support structure cost have been moderated in line with feedback from workshops and data gathered through industry interviews.

The baseline support structure CAPEX for each Site Type and Turbine MW-Class is shown in Table 8.1. These modelled baseline costs show that supply and installation CAPEX for 2011 FID projects using monopile foundations with 4MW-Class Turbines in Site Type A are similar for projects with 6MW and 8MW-Class Turbines on Site Type A using jackets. For all other Site Types, the 6 and 8MW-Class Turbines have lower CAPEX per megawatt than the 4MW-Class Turbines.

The use of monopiles on Site Type A with a 4MW-Class Turbine is therefore a competitive technology choice for projects with FID in 2011. Whether it continues to be so for projects with FID in 2014, 2017 and 2020 depends on the relative anticipated cost savings in monopile and jacket fabrication and installation.

Table 8.1 Baseline support structure CAPEX for a project with FID 2011.

Turbine Class	Site Type A		Site Type B		Site Type C		Site Type D	
	£k/MW	£k/turbine	£k/MW	£k/turbine	£k/MW	£k/turbine	£k/MW	£k/turbine
4MW	551	2,204	690	2,760	795	3,180	693	2,772
6MW	551	3,306	622	3,732	692	4,152	624	3,744
8MW	558	4,464	612	4,896	665	5,320	615	4,920

In Figure 8.4, the baseline support structure costs have been broken down into subcomponents. As the choice of technology will be based on a total installed cost, foundation installation costs have also been included. The installation baseline costs are discussed in detail in Section 10.2.

For each MW-Class Turbine, the total installed cost of the support structure increases as site water depth and distance to port increases. For a given Site Type, there is a significant drop in installed cost compared between 4MW and 6MW-Class Turbines with a more modest drop between 6MW and 8MW, except at Site Type A where the trend with Turbine MW-Class is flat.

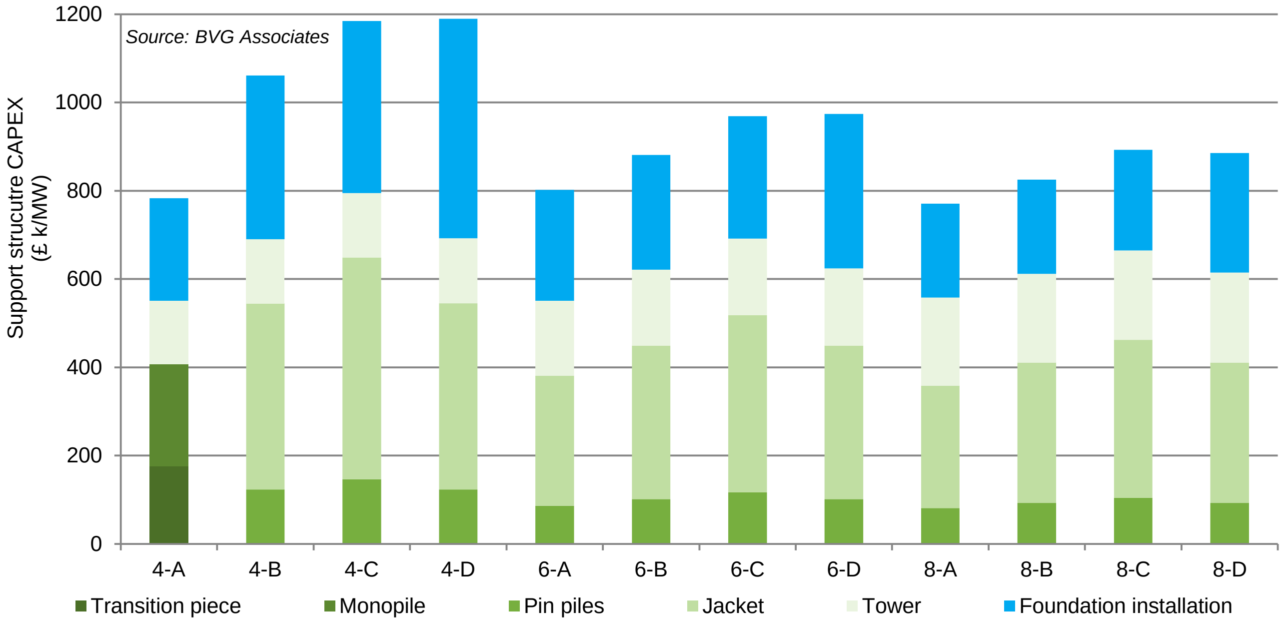

Figure 8.4 Baseline support structure supply and foundation installation CAPEX for a project with FID 2011, broken down by subcomponent.

8.3. Innovations

Innovations that affect the support structure have been categorised as either predominantly affecting the tower between the nacelle and the foundation, the foundation itself or the sea bed connection. These are listed below in Table 10.3.

Innovations related to the tower are not mutually exclusive and could be used in combination with each other. The innovations may also be combined with other foundation and sea bed connection innovations.

For foundations, there are a range of designs and each has specific innovations associated with them. For this reason, innovations have also been separated by whether they primarily affect monopiles or jackets. These are therefore mutually exclusive. Feedback from industry is that, apart from very shallow water conditions, the majority of the benefits associated with concrete gravity base foundations are captured during the installation phase. For this reason, the manufacturing processes involved are discussed in this section but innovations relating to concrete solutions are considered in Section 10.

The use of suction buckets as an alternative sea bed connection can be combined with both monopile and jacket foundation designs but not with concrete gravity base designs.

Current European offshore wind projects are largely focused on sites with water depths of less than 60m, but many of the areas in UK waters with the highest wind resource have much deeper waters. These cannot not be economically developed using sea bed-fixed foundations and there has been interest in developing floating structures. These have been used in a variety of other offshore applications which means there is already a reasonable underlying understanding of the technology. In most cases, the proposed designs fall into three categories: tension leg platforms, spar buoys and semi-submersibles. In each case, a key challenge is to provide a sufficiently stable platform so that acceleration and tilt thresholds are not exceeded in the nacelle during extreme operation. Some players, such as Principle Power, The Glosten Associates, Blue H and a number of established wind industry players have deployed or are seeking to deploy single demonstration units in the next three years.

The cost of this technology is still relatively uncertain at this stage of maturity and licences for deeper water sites in UK are unlikely to be available for some time. Some players argue that they have solutions competitive with jackets in 45m water depth. Even if this is the case, it is believed by many that the adoption of such technology is unlikely to materially affect the LCOE significantly on projects reaching FID in 2020. Before 2020, however, it is likely that projects will still be developed elsewhere, such as South Korea, Japan and the USA, where conditions favour the use of floating foundations.

It is noted that floating designs are less affected by changes in water depth than sea bed-founded designs, offering increased opportunities for savings through standardised production and installation activities.

Table 8.2 Support structure and turbine installation groupings used in this analysis. Innovations listed with # cannot be combined with others with @. Note different logic to similar tables in other Sections.

Groupings	Innovation types
Tower	Introduction of holistic design of the tower with the foundation Introduction of single-section towers
Foundation	Improvements in monopile design# Improvements in monopile design standards# Improvements in jacket manufacturing@ Improvements in jacket design@ Improvements in jacket design standards@
Sea bed connection	Introduction of suction bucket technology

8.3.1. Towers

Existing situation

All offshore turbines installed to date have used a tapered tubular steel tower. These are manufactured by rolling sheet steel into tapered cylindrical cans that typically have a diameter of 3 to 5m for a 4MW-Class Turbine. These cans are then welded together to form tube sections of length typically 30 to 40m. Flanges are welded to each end of these before they are surface-finished inside and out and internal components are installed. Towers, consisting of two or three sections are then generally pre-assembled at a local construction port before installation.

The maximum length and diameter limit of tower sections used for onshore wind projects is currently largely defined by road transportation limits. In the UK, cargo with a diameter of more than 5m or a length of more than 36m must have a special movements permit. Even if this limit is not exceeded, it is challenging to move any tower section with a diameter of more than 4.5m on the UK road system because of overhead restrictions from bridges. Safety regulations dictate that turbine towers are scaled to provide a minimum clearance but offshore wind characteristics mean there is no strong incentive to exceed this threshold. This means that towers for offshore use are relatively short compared with some onshore designs and the requirements of current offshore towers are not significantly different to onshore. This means that the same technology and design principles apply. There are reasonable levels of automation and efficiency already present in the industry because much of the welding is relatively simple, although the conical nature of the tower does present challenges.

Larger turbines require longer and larger diameter towers with thicker sections to carry the increased loads. Towers for larger turbines are anticipated to have a base diameter of between 5m and 7.5m. Such an increase in scale means inland production that requires the use of public roads for delivery will not be possible and the towers will be manufactured at a waterside facility and loaded directly onto a vessel.

As well as fulfilling its main structural role, the tower is also equipped with electrical switchgear, control panels, personnel access systems and lifting equipment to facilitate maintenance and allow components and tooling to be taken to the nacelle. In some designs, the transformer and power take-off system may also be in the tower.

As in onshore wind, the tower is currently part of the scope of supply of the turbine manufacturer although the manufacturing activity is usually subcontracted. Offshore towers are typically designed for a given turbine model and only in some cases are tailored to the requirements of a specific project. This is in contrast to the technology choice and design of the foundation which is made after the turbine supplier has been selected, and it is procured by the developer or the EPC contractor.

The installation of the tower is undertaken with the turbine and this is considered further in Section 10.

Innovations

Interviewees highlight the **introduction of holistic design of the tower with the foundation** as a means of reducing cost by reducing the amount of steel required. As an example, a foundation designer reports the case of a monopile with 80mm thick plate supporting a tower with only 40mm thick plate at the base. The greater monopile wall thickness is required to be stiff enough to compensate for the softer tower and provide the overall system natural frequency required. By considering the performance requirement of the combined support structure, it can be demonstrated that a slight increase in the mass of the tower would enable a more substantial decrease in the mass of the foundation.

Interviewees say that, in the case of monopiles, the total mass of the combined support structure could, in some cases, be reduced by up to 15 per cent due to this approach. In this study, a saving of 10 per cent of the support structure CAPEX is assumed for projects using monopiles. The impact of this innovation on the cost of jackets is anticipated to be about one third of this saving as the cost of jackets is less influenced by natural frequency requirements and steel content.

A number of interviewees highlight the fact that the tower is a standard design for a turbine and the supply responsibility has almost always been within the scope of the wind turbine manufacturer. Conversely, the foundation is project-, and generally location-specific. There are concerns that this existing situation could delay the introduction of this innovation as there may need to be a shift in contractual arrangements. It is expected that this issue could be mitigated by a close collaborative approach between design teams.

The integration of the design does not require the development of a single-piece structure, and feedback from interviewees suggests that it would be preferable to continue to transport and install the support structure in more manageable sections, rather than as a single sea-bed-to-yaw bearing component.

For jacket structures, an extension of this innovation is to move from the use of tubular towers to a lattice tower. Although this approach is being pioneered by 2B-Energy, leading foundation designers and turbine suppliers say this development is unlikely because of potential corrosion and maintenance risks and the need for a weatherproof enclosure for down-tower electrical components.[41] It is also essential to maintain clearance between blade and support structure, which restricts the diameter of the structure at tip-passing height. This concern would be lessened with a downwind design using soft blades.

It is assumed that the much of the benefit of this innovation will already be available in time for projects with FID in 2014 and will be fully available for projects with FID in 2020. Market share is anticipated to be 80 per cent of projects with FID in 2020. The total impact, however, is moderated by the fact that monopiles, which receive a higher cost benefit, account for a relatively limited proportion of the market.

The move to waterside locations for manufacturing facilities that will be required in order to cope with the larger towers is also likely to enable the **introduction of single-section towers**. Interviewees say that this could save up to 10 per cent of the tower cost by removing unnecessary manufacturing activity by requiring fewer flanges and allowing a more streamlined manufacturing approach.

[41] *Impression of the 2-B Energy 2B6 offshore wind turbine,* 2-B Energy, available at www.2-benergy.com/impression.html, accessed May 2012.

By reducing the amount of handling and lifting activity associated with moving multiple tower sections and avoiding the need for pre-assembly, it has been calculated that a one per cent reduction in installation CAPEX is also available. By avoiding the use of flanges, this also reduces the number of bolted joints that need to be inspected, thus reducing planned maintenance activity by approximately one per cent as well.

This innovation is relevant to all turbine and site combinations and it is anticipated that all of the benefit will be technically available for projects with FID in 2017. Given the likelihood that most manufacturing facilities will be required to be based in ports in order to cope with the increase tower dimensions, it is expected that this innovation will be implemented on up to 60 per cent of the market for projects with FID in 2017 and on 80 per cent by 2020.

Early signs of progress and prerequisites

Commercial interaction between developers and turbine and foundation manufacturers is typically confidential, so progress towards holistic designs may not be visible until the details are confirmed. Greater cooperation in the form of strategic alliances is likely to be the clearest signal of the type of cooperation that is required.

Examples of this trend can already been seen, for example, work undertaken by SSE Renewables for the Beatrice offshore wind farm, which includes support structure designer Atkins, foundation manufacturer BiFab and turbine manufacturer Siemens Wind Power.[42] The SMart Wind consortium, which is developing the Hornsea Round 3 Zone, is also seeking to build up such an alliance of manufacturers and designers. Increasing numbers of these arrangements will be an indication of the kind of cooperation required to allow the integrated design of the support structure.

The development of turbines that require towers with a diameter of more than 5m is considered the main driver for single section towers, as this will require the establishment of waterside manufacturing facilities in order to avoid public road restrictions. Announcements of investments in coastal tower manufacturing plants with facilities of the size required to manufacture single-section towers will be a strong sign of progress towards implementing this innovation. A prerequisite is therefore the availability of suitable coastal facilities, preferably close to turbine assembly facilities. As with any significant capital investment, confidence in medium-term demand is necessary.

Table 8.3 Potential and anticipated impact of innovations in towers for a wind farm on Site Type B using 6MW-Class Turbines, compared with FID 2011.

Innovation	Maximum technical potential impact				Anticipated impact FID 2020			
	CAPEX	OPEX	AEP	LCOE	CAPEX	OPEX	AEP	LCOE
Introduction of holistic design of the tower with the foundation	-2.8%	0%	0%	-1.8%	-0.8%	0%	0%	-0.5%
Introduction of single-section towers	-0.8%	-0.2%	0%	-0.6%	-0.6%	-0.2%	0%	-0.5%
Total					-1.4%	-0.2%	0%	-1.0%

8.3.2. Monopiles

Existing situation

Monopiles are the most commonly used foundation type to date and are considered as a proven technology by the offshore wind industry. The monopile is a cylindrical steel tube that is usually driven into the sea bed. In order to avoid damaging the turbine connection flange and secondary steelwork during piling, a separate transmission piece is also required. This is also

[42] Beatrice Offshore Windfarm, *BOWL signs offshore alliance agreement*, November 2011, available at www.sse.com/uploadedFiles/Z_Microsites/Beatrice/Controls/Lists/Resources/BOWLAlliancePressRelease.pdf, accessed May 2012.

used to correct any variation in the verticality of the installed pile to ensure a level platform on which to install the turbine. The transmission piece is a tube with a slightly wider diameter which is placed over the monopile. Secondary steel work such as a boat landing, cable J-tube and personnel access systems are also attached to the transition piece.

Other arrangements have been used, such as the drilling of a socket in the seabed and fixing a single monopile/transition piece assembly in place with grout.

The connection between the monopile and transition piece is normally made using a specialist grout. A variation was used at Scroby Sands in which the monopile and transition piece were fixed using a bolted flanged connection with a three-point hydraulic Ievelling system to ensure the tower verticality.[43] At London Array, an innovative conical joint is being used at the top of the monopiles to prevent the transition piece slippage that has been experienced with some of the grouting connections to date.[44]

The monopile is relatively simply to manufacture and there is already a reasonable degree of automation in the market. So far, production has largely been limited to two consortia: the joint venture of Sif Group and Smulders Projects and the partnership between EEW Group and Bladt Industries. The monopiles for the Greater Gabbard wind farm were produced by Chinese manufacturer Shanghai Zhenhua Heavy Industry (ZPMC). A number of other players are also seeking to enter the market, including TAG Energy Solutions in the UK and Dillinger Hütte in Germany.[45]

Because the manufacturing process is highly automated, the cost of monopiles is largely determined by the amount of steel that is required. In order to minimise the amount of steel used, monopiles today are generally individually designed to specific location conditions within each site. While this does offer a supply cost saving, it also leads to an increase in installation costs as it increases the complexity of handling different sized units.

The monopile length and diameter and the varying thickness of the steel along its length are determined by the maximum water depth at the site, sea bed soil conditions, metocean conditions, and the loading characteristics of the wind turbine. The latter is determined by the rotor size, turbine rated power and top tower mass. A key design driver is often the requirement for first-mode natural frequency of the wind turbine-support structure system to be about 0.3Hz to avoid critical rotor and wave loading frequencies. As Turbine MW-Class increases, the cost of staying within the allowable window increases.

Monopiles have been installed in water depths of up to 37m at Belwind 1 using Vestas 3MW V90s and at 32m at Greater Gabbard, which used Siemens SWT-3.6-107. The longest Belwind monopiles have a length of almost 68m, a diameter of 6.3m and a mass of almost 680 tonnes.[46]

Innovations

While the monopile design is already considered largely optimised, further **improvements in monopile design** (including the transmission piece and grouting) are still advised by industry as available.

Developers say that one key opportunity for improvement is in the grouted connection between the monopile and the transition piece. Concerns have been raised about the long-term physical properties of the grout which was developed approximately 20

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[43] Nils Fog Gjersoe, *Design of Monopile Foundations for large Offshore Windturbines: Experiences from the first Projects Offshore the British Coast,* LICengineering, (Esbjerg, Denmark), available at www.liceng.dk/files/papers/NFG_2005.pdf, accessed May 2012.

[44] Ben Backwell, "London Array turbine foundation design gets DNV approval", *Recharge,* 17 January 2012, available at www.rechargenews.com/energy/wind/article298266.ece, accessed May 2012.

[45] "Dillinger Hütte investing in offshore wind", *Press statement,* Dillingen Hütte, 29 September 2011, available at www.dillinger.de/dh/aktuelles/presse/00028561/index.shtml.en, accessed May 2012.

[46] Seaway Heavy Lifting, *Greater Gabbard foundations*, October 2010, available at www.seawayheavylifting.com.cy/pages/what_0we_do/offshore%20wind%20projects/Greater%20Gabbard%20Foundations.pdf, accessed May 2012.

years ago for use in other sectors and has a harsher duty cycle in offshore wind, especially if both mating parts are cylindrical and no other shear connection is provided. This led to a joint industry project (JIP) commissioned in 2009.[47]

Developers and installation contractors indicate that improved grouting material has already been developed to address the problems of cracking identified in early projects, while improvements have also been made to the design of the mating steel parts to improve the long-term stresses applied to the grout and reduce the risk of failure, such as those described above for London Array. This development activity addresses an issue found during operation without adding significant cost, but has been incorporated in projects reaching FID recently, so does not offer future savings.

Structural designers advise that some improvement in monopile costs is available through more thorough design processes, using a fuller set of metocean and wind loading data, in order to remove previous conservatism due to both a lack of wind and wave data and over-simplifications in the combination of this data. Related to this, limited measurement on operating sites indicate higher levels of structural damping, due to hydrodynamics and soil interaction, than assumed in calculations.

Other improvements in monopile design may have a further impact on installation costs. For example, an experienced cable installation contractor says that the J-tube design is not generally optimised for ease of cable installation. It is estimated that improving the design could reduce the amount of time spent on the primary and secondary cable pull-through by approximately one hour each, while improved placement away from the prevailing wind direction would lessen the risk that the vessel will collide with the foundation. Such measures are calculated to reduce array cable installation CAPEX by more than three per cent.

While monopiles are bespoke to site and turbine conditions, interviewees highlight that secondary steel components could be more standardised across projects. Interviewees agree that developer design teams spend a disproportionate amount of time on these items, which would be avoided through component standardisation. Standardisation could also allow greater production efficiencies in the supply chain, both in the direct manufacturing of the items and in the design of the vessels transporting technicians to the turbine. As it is unlikely that such a step will involve significant innovation, the impact of this change is considered in Section 4 of the *Supply chain work stream report*.

Overall, improvements in monopile design are conservatively estimated to offer a technical impact of up to three per cent of support structure CAPEX while improvements such as better J-tube design will reduce total installation CAPEX by approximately one per cent. It is assumed that the majority of this benefit is available for projects with FID in 2020. The impact of this group of innovations is only applicable to 4MW-Class Turbines on Site Type A.

The ability to extend the use of monopiles into deeper water would enable the industry to use the experience and infrastructure that it has developed on a greater number of projects. A market leading turbine manufacturer indicates that there is the potential for pushing monopile limits to 40m for 4MW-Class Turbines and that the key to achieving a meaningful increase is through **improvements in monopile design standards**.

There are two aspects relating to design standards that are considered here. First, there is an opportunity to improve the way that the pile-soil interaction is modelled. Existing standards reference the p-y approach which is highly empirical and relies on “old” test data from piles of less than 20 per cent of the diameter of piles being installed today. Work is underway to develop a more relevant data set, including via developers such as Mainstream Renewable Power, by conducting tests both onshore and offshore. The other key opportunity, relevant also to jackets, is to take advantage of the improved fatigue properties of current materials compared with those used when the routinely used standards were developed. This, coupled with a more rational use of partial safety factors, offers significant savings, especially when combined with more advanced condition monitoring methods, as discussed in Section 11.

A developer with one of the largest portfolios of offshore wind projects advises that the existing material design standards are based on offshore oil and gas industry requirements for manned structures and do not account for the improved understanding that has been gained from the offshore wind projects installed to date. The same developer argues that adjustments to the p-y curves should allow like-for-like monopile designs to use less steel and hence to be used in greater water depths.

[47] *Joint Industry Project: Summary report from the JIP on the capacity of grouted connections in offshore wind turbine structures*, Report No. 2010-1053, Revision No. 05, Det Norske Veritas, 12 May 2011, available at http://lorc.e-kvator.com/cgi-bin/lorc/uploads/media/Knowledge/Wind/2010-1053-r05-Summary%20report.pdf, accessed May 2012.

Figure 8.5 shows the trend of extended use of monopile rather than jackets that interviewees suggest is realistic compared with Figure 8.3 given improvements in standards. This shows that the innovation will not impact on turbines larger than 5MW but could extend the use of existing 4MW-Class Turbines into deeper water sites, such as Site Types B and D.

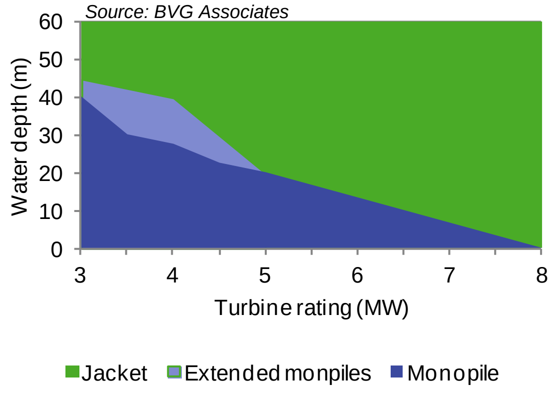

Figure 8.5 Extended transition between monopile and other foundation types.

Additionally, interviewees advise that it is also important to consider manufacturing and installation limits relating to the manufacture of larger monopiles. Some say that monopiles currently have a practical weight limit of approximately 800 tonnes, due to the challenge of economically moving units at the manufacturing and construction sites and the cost of heavy lift installation cranes, though this is likely to change and others have modelled monopiles at 1300 tonnes or more. One leading foundation designer is sceptical about the ability of companies to manufacture monopiles with a diameter of more than 7m as well as the availability of suitable installation tooling such as anvils. Others considered this to be a supply, rather than a technical, issue which could be easily overcome, especially in a confident market.

In terms of moving to larger turbines, a leading developer says that limiting the rotor diameter may enable 6MW-Class Turbines to be used on monopiles, but it is unlikely that such a compromise would be made given the reduction in AEP that would result.

As well as extending the use of monopiles to a proportion of Site Types B and D, improving standards will also positively impact the cost of monopiles installed on Site Type A. Feedback from interviews suggests that steel mass could be reduced by up to 20 per cent due to improved designs based on new standards.

In all cases, it was highlighted that the use of real data collected from operational wind farms is an essential means of verifying design methodologies.

Based on a range of interviewee feedback, a 7.5 per cent reduction in support structure CAPEX is expected from a reduced steel requirement and the ability to avoid the use of more costly jackets on a limited number of Site Types B and D, starting for projects with FID in 2014. The majority of this innovation is expected to be commercially available by 2020, although its assumed impact is moderated by the limited market share assumed for monopiles.

Other innovations

As well as the innovations discussed above, other innovations were indentified but not investigated in detail. These include alternative methods of extending the water depth in which monopiles can be installed such as using guyed monopiles, steel/concrete hybrids or sheer keys (fins) below the mud line.

There are also potentially disruptive manufacturing innovations such as the FabFound design that proposes an octagonal monopile design to avoid the need to roll oversized cans and circumferential welding.

Early signs of progress and prerequisites

There are signs that issues around monopile design are being addressed. In 2009, a JIP led by Det Norske Veritas (DNV) looked at some key aspects of offshore wind monopile design standards with a particular focus on the axial load capacity of large diameter grouted connections without shear keys. In 2011, it published a report updating the standards on this subject.[48] A subsequent JIP focused on connections with shear keys is expected to be published in 2012.

A leading developer indicates that there is work currently being undertaken to initiate a detailed study that will enable monopile standards to be substantially revised by the classification societies. It was expected that such a study would take several years to be completed and would therefore need to be started by 2014 in order to have any impact on Round 3 projects.

Table 8.4 Potential and anticipated impact of innovations in monopiles for a wind farm on Site Type A using 4MW-Class Turbines, compared with FID 2011. Note different subject Turbine MW-Class and Site Type to other similar tables.

Innovation	Maximum technical potential impact				Anticipated impact FID 2020			
	CAPEX	OPEX	AEP	LCOE	CAPEX	OPEX	AEP	LCOE
Improvements in monopile design standards	-1.9%	0%	0%	-1.2%	-1.0%	0%	0%	-0.7%
Improvements in monopile design	-1.0%	-0.2%	0.03%	-0.7%	-0.5%	-0.1%	0.02%	-0.4%
Total monopile innovations					-1.5%	-0.1%	0.02%	-1.1%

8.3.3. Jackets

Existing situation

Piled steel space frame structures have been commonly used in the oil and gas industry for more than 70 years with a wide variety of designs. As well as the conventional four-legged jacket (pylon) design, others include three-legged jacket designs, tripods and tripiles. Bottom-founded steel structures have been used in water depths of more than 150m.[49]

In offshore wind, jackets have been used in two full-scale demonstration projects and one commercial project. In 2007, the Beatrice demonstrator project was installed off the east coast of Scotland with two REpower 5M turbines, while a further six similar jackets were installed as part of the German Alpha Ventus project in 2010. The first commercial-scale application was the Ormonde wind farm, where 30 REpower 5M turbines were installed in 2011. Other projects, including Thornton Bank II and Nordsee Ost, are currently under construction using jacket foundations.

Turbine jacket manufacturing has so far been undertaken by a small number of offshore fabrication yards such as BiFab (UK), Aker Verdal (Norway) and Smulders Group (Belgium). Given the limited number of projects requiring jackets so far, production has typically been undertaken on a small batch basis. All of the jackets installed to date have been designed by Norwegian company OWEC Tower and have welded nodes. Water depths for the projects that have used jackets so far range from 12m at some Thornton Bank Phase II locations to 45m at the Beatrice Demonstration Wind Farm.

Interviewees expect the four-legged jacket to be the dominant design choice for projects in sites with average water depths of 35m or more. This is because the design only requires relatively small changes in geometry to accommodate deeper water and

[48] A project led by DNV has looked at offshore wind monopiles to improve the calculation of the axial load capacity and review current design practices. Companies involved included Ballast Nedam Engineering, BASF Construction Chemicals Denmark, Centrica Renewable Energy, Densit, DONG Energy, DNV, GustoMSC, MT Højgaard, Per Aarsleff, RWE Innogy, Statoil, Statkraft, Vattenfall Vindkraft. See Svein Inge Leirgulen, “New design practices for offshore wind turbine structures”, DNV, 28 January 2011, Available at www.dnv.com/press_area/press_releases/2011/new_design_practices_offshore_wind_turbine_structures.asp, accessed May 2012.

[49] *Design of Offshore Turbine Structures, Det Norske Veritas,* (October 2010), p,15, available at http://exchange.dnv.com/publishing/Codes/download.asp?url=2010-10/os-j101.pdf, accessed May 2012.

larger turbines, is not sensitive to scour and sand waves, and it can be used on sites with a wide variety of ground conditions, with piles or suction buckets providing the seabed connection. Even gravity base jacket arrangements have been proposed.

A number of alternative space frame designs have been developed. These designs are usually aimed at reducing the amount of steel or welding required or to reduce the length of the installation process.

Citing the extensive design activity undertaken by the oil and gas industry in the past, a number of interviewees feel it is unlikely that the offshore wind industry will generate an entirely new design concept, but recognise that one or more design concepts are likely to be established as the preferred. Work is still required to fully adapt these existing design concepts to address the particular challenges of offshore wind such as the need for mass production and the ability to resist dynamic loading.

To date, the two alternative deep water steel designs installed for turbines have been the BARD tripile and the WeserWind tripod. Tripods have been have been chosen for forthcoming German projects at Borkum West II and Global Tech I but feedback from suppliers indicates that tripods have a number of disadvantages compared with jackets. While there is less welding required overall, there are a lot of three-dimensional weld seams which can be made only by hand and the overall fabrication process is complex. Thick steel plates are also needed and the overall structure is relatively heavy compared with a similar jacket. The BARD tripile consists of a transition piece with three pins that slot in to the three pre-installed piles. It is reported that, while the design intent is to make handling and installation easier, the design is heavy and complicated to fabricate and install.

Innovations

In the oil and gas sector, jackets are normally one-off designs for specific site conditions using design standards applicable for manned structures. Interviewees say that significant savings could be achieved from **improvements in jacket manufacturing** by moving away from this project approach to a leaner, mass-production mindset in both the design and production of the foundations.

While approximately a third of monopile costs relates to tooling and labour, this increases to two thirds for jackets. Feedback from fabricators, supported by dialogue during workshops, indicates that significant costs can be extracted from this process.

Specifically, this change in approach includes the use of standard pipes to allow automated fabrication and automated welding. It also includes the use of railway systems to eliminate cranes, as well as possibly fabricating more fully completed standard leg sections before joining these together. By implementing these innovations, it is estimated that both production time and cost for this element of the process can be reduced by 50 per cent.

Foundation fabricators advise that a production throughput of at least 100 units per year will be expected from their customers. There are a range of views as to what commitment is required to justify the investment in research and development, tooling, and waterside infrastructure that would be required to achieve the full cost benefit. These range from production capacity for at least five years to the award of two to three projects. This investment is estimated to be in between £100 and £160 million for a facility which will provide the savings discussed.

This level of investment is likely to mean that only a small number of players will choose to invest. It is therefore anticipated that early movers will benefit from increased margins until the market sustains sufficient players to facilitate high levels of competition. For more information on this consideration see Section 4 of the *Supply chain work stream report*.

Such improvements in manufacturing are expected to be equally applicable for both standard jacket and novel designs. Based on interviewee feedback on the cost savings possible, a technical potential saving of 15 per cent on the whole support structure CAPEX has been modelled.

While the tooling and processes required for this innovation are likely to be available already, the high investment cost is expected to mean that not all companies will invest to be able to achieve the maximum savings over the period considered. This means that, while the innovation is considered to be largely commercially available for projects with FID in 2014 and fully commercially available for projects with FID in 2020, the market share is assumed to only have reached 70 per cent by this time for all Site Type and Turbine MW-Class combinations apart from Site Type A with 4MW-Class Turbines, where there is assumed to be zero per cent market share.

While interviewees say that the standard jacket design is already largely optimised, given current design standards, there are areas where **improvements in jacket design** could reduce costs. These innovations are particularly focused on optimising the design for mass productions and installation. In addition, the structures designed for the oil and gas sector have been one-off projects and the relatively high volumes required by offshore wind justify an increased investment in design.

Following monopile design practice, jackets are currently individually designed for specific site conditions. Interviewees indicate that producing a limited number of designs ("semi-standardisation") that are able to cope with small variations in water depth and sea bed conditions will enable far higher levels of automated fabrication, reducing labour requirements, decreasing production time and improving installation rates.

Design innovations that enable the use of the standard pipes, nodes and component lengths facilitate serial production. There is a balance to be struck in minimising steel content, maximising component standardisation and facilitating installation. The OWEC Tower tapered design minimises steel content but the footprint and dimensions vary with the height of the structure. The Smulders square design with parallel legs enables more standardised joints and fixed angles for greater automation and leads to less deviation in footprint. The WeserWind Variobase concept seeks to combine the standardised components with a tapered design. The innovations in monopile design and design standards discussed above can also be applied to pin piles but, conservatively, as they represent a smaller proportion of support structure costs, this has not been modelled in this study.

This type of design standardisation is separate from supply standardisation that includes using common pipe sizes to reduce material costs, adopting a standard tower interface across projects, and using stepped changes in footprint dimensions to allow reusable sea fastenings on installation vessels, all of which is covered in Section 4 of the *Supply chain work stream report*.

Further savings are advised by others relating to the use of cast or pre-fabricated nodes, although these do require an increase in manufacturing accuracy.

As with *improvements in monopile design*, discussions in workshops highlight that, by ensuring greater collaboration of input between designers and installation contractors, improvements in secondary steel components like J-tubes optimises offshore activity and removes risk. In addition, savings cited for monopiles relating to combining wind and wave loads are also relevant here, to varying degrees.

The overall technical benefit is conservatively anticipated to be about four per cent on support structure CAPEX with an additional one per cent saving in installation costs. Approximately 40 per cent of the technical potential will be available to the market in FID 2014, with a further 50 per cent by FID 2020. The innovation will be present in almost all jackets in FID 2020 and 70 per cent of all support structures in wind farms other than those on Site Type A using 4MW-Class Turbines, where there is assumed to be zero per cent market share.

Finally, the need to see **improvements in jacket design standards** is emphasised by a number of interviewees. Current standards for structure-soil interaction and fatigue analysis are considered excessively conservative because they are based on 20 to 30 year-old oil and gas industry requirements. While jackets are less sensitive to fatigue loading than monopiles, interviewees still assert that changes to standards will allow designers to optimise designs and allow a reduction in materials costs of up to 10 per cent. Such a shift would need to be undertaken in collaboration with classification societies such as DNV.

The technical potential of this is advised to be about two per cent of support structure CAPEX. Standards are likely to be revised through studies undertaken by the middle of the decade and will be available to the market in FID 2017, at which point 60 per cent of the potential will have been realised. It is anticipated that these will be rapidly adopted by most fabricators and be taken up by 70 per cent of the foundation market in FID 2020.

Other innovations

In the past, the introduction of novel space frame structures had been expected to offer significant savings compared with jacket solutions. Some interviewees highlight that this optimism has faded, suggesting that innovations with benefits in one area seem to have disbenefits in other areas, thereby providing insufficient net benefit to justify the risks inherent in a new technology. For example, the WeserWind tripod had offered fewer joints than a jacket, good stiffness and resistance against overturning but there are downsides as discussed under *Existing situation* above. It is anticipated that Global Tech I will be the last project to use this technology before the company shifts production to focus on jackets.

In order to be viable, novel designs will need to be competitive with jackets that have incorporated the innovations described above. Developers also attach value to proven designs, which may delay the full-scale introduction of new novel designs and slow the increase in market penetration. For these reasons, no specific innovation has been included for novel space-frame foundation designs and this is consistent with the views expressed by developers. It is anticipated that new designs will continue to be explored and some may well impact the market positively.

Novel designs have the potential to incorporate other innovations more easily, such as suction buckets and "float and sink" schemes, but these are accounted for separately.

Early signs of progress and prerequisites

Significant steps have already been taken by key players to advance jacket manufacturing. This includes: BiFab, which announced in 2010 an investment programme of £14 million to extend its manufacturing facility at Methil[50]; WeserWind, which has invested £90 million in their Bremerhaven facility; and Offshore Group Newcastle, which was awarded a DECC grant in April 2012 to develop a new jacket design for production at its facilities on the Tyne. Given a lead time of two years from FID to production, announcements on new facilities should be expected by existing and new players such as Heerema and Smulders by 2012 and 2015 in order to be operational in time for projects with FID in 2014 and 2017 respectively.

Investment decisions on this scale are dependent on a rapidly growing market for 6MW-Class Turbines or larger, and the development of projects in deeper water in order to create a sufficient demand for jackets instead of monopiles. Given the fact that units can be transported long distances relatively economically, facilities will address the entire European market and will not therefore be dependent on the development of one single market.

For investment to be made, fabricators and their investors will need confidence in the medium-term market. Feedback from fabricators during workshops is that a 100-jacket order would be a significant step and a framework deal would provide sufficient confidence to invest.

In addition to this growth in the market, it is stressed by interviewees, including foundation designers, that the positive investment decisions of fabricators will only be possible if developers change their procurement approach and move from a project-by-project basis to planning on the basis of a pipeline of projects. Such an approach will also need to be accompanied by greater cooperation and information sharing about long-term options with the supply chain.

The likelihood of investment will be increased through the development of partnerships between developers and manufacturers or through framework agreements. Examples of these have already been seen between SSE Renewables and BiFab, in which SSE Renewables acquired a 15 per cent equity stake in BiFab and announced a long-term framework agreement for the supply of at least 50 jackets a year from 2014 for up to 12 years.

WeserWind has already manufactured and installed an onshore demonstrator project using cast nodes in Bremerhaven. To date, no other manufacturer is as advanced and the industry may be waiting to see if the WeserWind cast node design proves successful before adopting them.

In terms of the introduction of novel designs, the BARD tripile and WeserWind tripod are already demonstrated at full scale offshore and are currently being installed on a commercial scale in German projects. While WeserWind may phase out production of the tripod, depending on customer demand, BARD is expecting to continue using its tripile technology using its proprietary design for the foreseeable future. There are no indications that other manufacturers are considering a similar solution.

Significant work has been undertaken to progress the development of novel foundation designs by the Carbon Trust and its partners through the Offshore Wind Accelerator programme. From an initial list of more than 100 submissions, it is now supporting more detailed studies for four designs, including two space frame structures: a twisted jacket system and a braced monopile design using suction buckets.

In order to overcome developer conservatism, feedback received is that full-scale testing in North Sea conditions over a number of years will be required before new designs are adopted on an industry wide scale. In 2011, a twisted jacket design was installed for a met station on the Hornsea Zone. Although is a valuable stepping stone towards commercialisation, feedback from industry suggests that this scale demonstration will not provide sufficient positive evidence to facilitate its use on a commercial scale, as it was not at full scale and a met station foundation is not subject to the dynamic loadings of a turbine.

Such full-scale testing will almost certainly need to be undertaken at the test sites proposed in the UK off the coast of Aberdeen and Blyth, as well as selected locations in full-scale wind farms in the UK, the Netherlands and Belgium. Units will need to be

[50] Stephen Vass, "BiFab's £14m expansion plan sets platform to create 200 jobs in Fife", Herald Scotland, 24 January 2010, available at www.heraldscotland.com/business/corporate-sme/bifab-s-14m-expansion-plan-sets-platform-to-create-200-jobs-in-fife-1.1000864, accessed May 2012.

installed by 2013 and 2016 at the latest in order to be considered commercially ready for projects with FID in 2014 and 2017 respectively.

The developments and timescales described above in Section 8.3.2 on monopiles are equally applicable to steel space frame standards improvements.

Table 8.5 Potential and anticipated impact of innovations in space frame structures for wind farm on Site Type B using 6MW-Class Turbines, compared with FID 2011.

Innovation	Maximum technical potential impact				Anticipated Impact FID 2020			
	CAPEX	OPEX	AEP	LCOE	CAPEX	OPEX	AEP	LCOE
Improvements in jacket manufacturing	-4.2%	-0.6%	0.08%	-3.0%	-2.9%	-0.4%	0.05%	-2.0%
Improvements in jacket design	-1.4%	0%	0%	-0.9%	-0.9%	0%	0%	-0.6%
Improvements in jacket design standards	-0.6%	0%	0%	-0.4%	-0.3%	0%	0%	-0.2%
Total					-4.0%	-0.4%	0.05%	-2.8%

8.3.4. Concrete gravity bases

The principle of a gravity base foundation is that the structure is placed on the seabed and that its mass is sufficient to provide stability against the impact of the wave, current and turbine loading. They have typically been built using reinforced concrete and can either have a flat base or conical design. There are designs that use a steel caisson that is filled with ballast such as iron ore but this is not considered in this report.

CGBs offer an alternative foundation system for sites where piling would either be impractical due to a rocky sea bed or where the piling noise would have an unacceptable impact on local wildlife. They are also far less affected by fluctuations in the cost of steel than other foundation types and require minimal lifetime maintenance.

Large CGBs have been widely used in the oil and gas industry and in bridge construction. For offshore wind, they have been used on a number of projects in the Baltic Sea since the beginning of the 1990s. These projects have typically been built in sites with water depths of 10m or less using smaller turbines than those used in UK projects today. The foundations have had an average mass of approximately 1,000 tonnes and are built in batches in either a dry dock or on a barge.[51]

The Belgian Thornton Bank I project is the only wind farm to have used CGBs in the North Sea so far. Six units weighing up to 3,000 tonnes each were built at Ostend in Belgium. Once complete, they were lifted into the water and transported to site using the heavy lift vessel Rambiz.

Innovations

While CGBs have been the most cost-effective solution for offshore projects in the Baltic Sea, the typical design that has been used is not appropriate for North Sea conditions. While the Thornton Bank I project proved that concrete structures could be used in the North Sea, the construction and installation processes were not considered optimal and are unlikely to be repeated.

[51] M.Ragheb, *Offshore wind farms siting* (2011), available at https://netfiles.uiuc.edu/mragheb/www/NPRE%20475%20Wind%20Power%20Systems/Offshore%20Wind%20Farms%20Siting.pdf, accessed May 2012.

A number of companies and consortia have developed new designs and processes that seek to achieve the benefits of concrete structures but address the issues identified in the Thornton Bank I project.

Feedback from prospective suppliers is that they do not expect to use innovative construction methods but will utilise existing expertise and skills from other sectors such as bridge building and oil and gas fabrication. Such sectors are experienced at manufacturing and handling large concrete structures and the techniques and tooling required is already available.

Suppliers emphasise that concrete solutions will only be competitive if they are built on a production line, rather than on a one-off project, basis. Feedback is that labour content for units built on a single project is estimated to account for up to 20 per cent of the total fabrication cost and that this could be reduced through investment in onshore equipment. This could include self-propelled modular transporters and purpose-built gantry cranes. Competitiveness may change significantly should steel prices rise. Indeed, some see concrete solutions as an excellent hedge against the high volatility of steel prices.

Data provided by suppliers show that masses will be approximately 3,500 tonnes for projects on Site Type B with 6MW-Class Turbines, rising to 7,000 tonnes for projects on Site Type C with 8MW-Class Turbines.

Suppliers report that, in order to justify the creation of a facility, a minimum production level of approximately 50 units a year with a five year pipeline is required, which would require a capital investment of about £50 million. The lead time would be approximately two years. Increasing the production level to 100 or more per year or increasing the pipeline to 10 years reduces costs per megawatt by up to 10 per cent. These issues are supply chain related and, as such, are covered the in Section 4 of the *Supply chain work stream report*.

While there is concern within the industry about the ability of suppliers to produce and install large numbers of units a year, suppliers highlight that the methods used in the construction process are well established and there is relevant experience from the construction of large marine concrete structures in quantity for bridges such as the Storebælt West Bridge in Denmark and the Confederation Bridge in Canada.

Interviews with suppliers revealed that the most recent designs are expected to scale well both in terms of Turbine MW-Class and water depth compared with jacket solutions. It is expected therefore that the benefits increase with Turbine MW-Class, with the greatest impact coming through the use of 8MW-Class Turbines at Site Type C.

Despite the positives, discussions with developers suggest that steel designs are likely to dominate the market at least until 2020. This reflects the challenges of mass producing CGBs and the desire expressed by a number of developers to standardise support structure concepts across the range of their projects. In this situation, it is seen that steel jackets offer a more flexible solution to address the range of ground conditions anticipated.

In total, it is estimated that such methods could reduced support structure CAPEX by approximately five per cent compared with the baseline (which was either a jacket or monopile foundation). In terms of total saving, however, feedback from industry suggests that the main savings from CGBs are achieved through innovative installation methods. For this reason, the cost savings associated with the manufacturing of concrete foundations are included in Section 10.3 as part of the innovations, *introduction of buoyant concrete gravity bases* and *introduction of float-out-and-sink installation of turbine and support structure*.

8.3.5. Sea bed connection

Existing situation

The driving of monopiles or jacket pin piles can produce levels of noise that have an unacceptable impact on local wildlife. This can prevent a project from proceeding or cause long delays in project schedules. Interviewees say projects have already been affected by limits on when piling can take place and there are stricter noise restrictions in German waters. Noise restrictions are discussed further in Section 10.3.1.

Suction buckets, also known as suction caissons, have been used as a foundation support in other offshore applications. During installation, the weight of the structure is combined with differential hydrostatic pressure on the structure, which is created by pumping water out of the bucket, to drawing the foundation down to penetrate the seabed to a depth of many metres. The operation can be completed without significant noise generation. Suction buckets can only be installed in certain soil conditions, preferably sand or clay that is neither too dense/hard nor loose/soft, and may require some sea bed preparation. Loose/soft soil conditions are associated with high levels of scour and, since suction buckets penetrate the sea bed less than piles, significant mitigating actions, either through design or scour protection soon after installation, may be needed. Sites with shallow bedrock or the presence of boulders in clay soils are not suited to suction buckets.

Innovations

The **introduction of suction bucket technology** has been proposed for both single-column monopods and space frame structures. Manufacturing savings can be achieved because the design uses less steel than a monopile, although this improvement is partially offset by the increased complexity to fabricate. No transition piece, and therefore no grout, is required because adjustments in verticality that can be made during installation. One manufacturer argues that the technology will have a lower environmental impact than piling, as the full structure can be fully removed though a reversal of the installation procedure and recycled at the end of its life.

Monopod structures are likely to face similar constraints as those for monopiles discussed in Section 8.3.2, although they will not be limited by the availability of suitable large hammers discussed in Section 10.3.1. To maintain verticality, the caisson can be compartmentalised so that differences in pressure can be applied across the base of the structure. High-pressure jets positioned around the skirt can also to help the levelling process. Discussions at workshops suggest that suction buckets are more likely to be used in conjunction with jacket foundations than monopods.

For a jacket structure using suction buckets to provide the sea bed connection, industry consensus is that the average installation process across the whole of a 500MW project can reduced from about 6.5 days per structure to approximately 3.5 days. In addition, CAPEX in vessel tooling can be reduced by 50 per cent as heavy cranes and piling hammers are not required. Furthermore, because little noise is generated during installation, the significant seasonal restrictions that can be imposed on piling operations because of impacts on marine life are avoided. These advantages are balanced by the cost of additional surveys to minimise risks during installation, such as the impact of rocks below the mud line. Additional costs during wind farm development are advised to be about 0.5 per cent of wind farm development CAPEX, depending on ground conditions.

The main challenge that interviewees identify is a lack of evidence about how a suction bucket structure will behave under long-term cyclic turbine aerodynamic and wave loading. The total market impact of suction buckets will also be limited by the range of ground conditions to which suction buckets are suited. Installation contractors report that, while there are theoretical benefits from the suction bucket in terms of speed of installation and piling noise, when the approach is applied to jackets it increases the height of the structure which makes handling more difficult and potentially lowers the number that an installation vessel can carry. Some installation contractors are also sceptical about how long it would take before installation savings would actually be obtained over a whole series of installations.

Overall, in considering data from manufacturers and discussion during workshops, it is concluded that, while manufacturing costs are not expected to change significantly from piled solutions, on suitable sites, suction buckets offer a potential reduction in support structure installation CAPEX of 20 per cent, 80 per cent of which will be available for projects reaching FID in 2020. While this innovation will be applicable to monopiles and jackets, due to the limited number of locations with suitable soil characteristics and conservatism among developers, it is not expected that the market share for suction buckets will exceed 10 per cent for projects with FID in 2017, rising to 20 per cent for projects with FID in 2020.

It is noted that the lack of piling means that suction buckets are well suited to float-out-and-sink installation solutions, such as that offered by SPT Offshore. The impact of this innovation is considered in Section 10.3.1.

Early signs of progress and prerequisites

The leading proponent in the market of suction buckets to date has been Universal Foundation, formerly MBD Offshore Power, which is now owned by DONG Energy and Fred Olsen. The concept was selected by the Carbon Trust Offshore Wind Accelerator programme and it has progressed to the second phase. A difficulty for a developer making an investment in suction bucket technology is that it may not be suitable for the sea bed conditions of the projects in its portfolio, which is the situation that DONG Energy has experienced.

This design was chosen by the Forewind consortium for two met stations on the Dogger Bank Zone, which will be manufactured by Fred Olsen subsidiary, Harland and Wolff, in Belfast. While these met stations will be an important development stage for the design, interviewees indicate that they believe the industry will need to see a full-scale, well monitored turbine demonstrator project to resolve concerns over long-term behaviour. There are a range of views about the number of demonstration projects that will be required and how long they will need to be before they are used on a project basis. As concerns are mainly focused on the long-term behaviour of the design, it is estimated that a period of up to two years will be required. Allowing for a demonstration period and establishing production capacity, a demonstrator project will need to be installed by 2013 or 2016 in time to be ready for commercial projects with a FID in 2014 or 2017 respectively.

There have been early uses of suction buckets. Activity to date includes a full-scale demonstration unit using an Enercon E-112 planned in the shallow waters off the coast of Germany in 2005. During installation, the bucket was damaged after the installation barge collided with it and the project was abandoned. A prototype suction bucket foundation was designed for a Vestas V90-3.0MW turbine in 4m of water at Frederikshavn. The bucket was installed in late 2002 and supports an operating turbine. A suction bucket met station was successfully installed at Horns Rev II wind farm in 2009 in water depths of approximately 15m. SPT Offshore proposes to use suction buckets as part of a turbine and support structure float-out-and-sink installation strategy. The installation aspects of this innovation are considered in Section 10. As with other novel steel and concrete foundation designs, developers are cautious about the deployment of new innovations and are may be slow to commit for a project based solely on the basis of even successful demonstration projects.

Table 8.6 Potential and anticipated impact of innovations in seabed connection for a wind farm on Site Type B using 6MW-Class Turbines, compared with FID 2011.

Innovation	Maximum technical potential impact				Anticipated Impact FID 2020			
	CAPEX	OPEX	AEP	LCOE	CAPEX	OPEX	AEP	LCOE
Introduction of suction bucket technology	-2.4%	0%	0%	-1.7%	-0.4%	0%	0%	-0.3%

9. Innovations in array cables

9.1. Overview

It is anticipated that innovations in array cables have the potential to reduce the LCOE by approximately 0.5 per cent between projects with FID in 2011 and 2020 for a given Turbine MW-Class and Site Type. Figure 9.1 shows that the savings are generated mainly through reduced CAPEX, but also through modest reductions in OPEX and increases in AEP. Installation of array cables is addressed in Section 10 and lifetime care addressed in Section 11. The potential introduction of DC array cables is discussed as part of the turbine nacelle innovations in Section 6 due to its impact also on turbine power conversion systems.

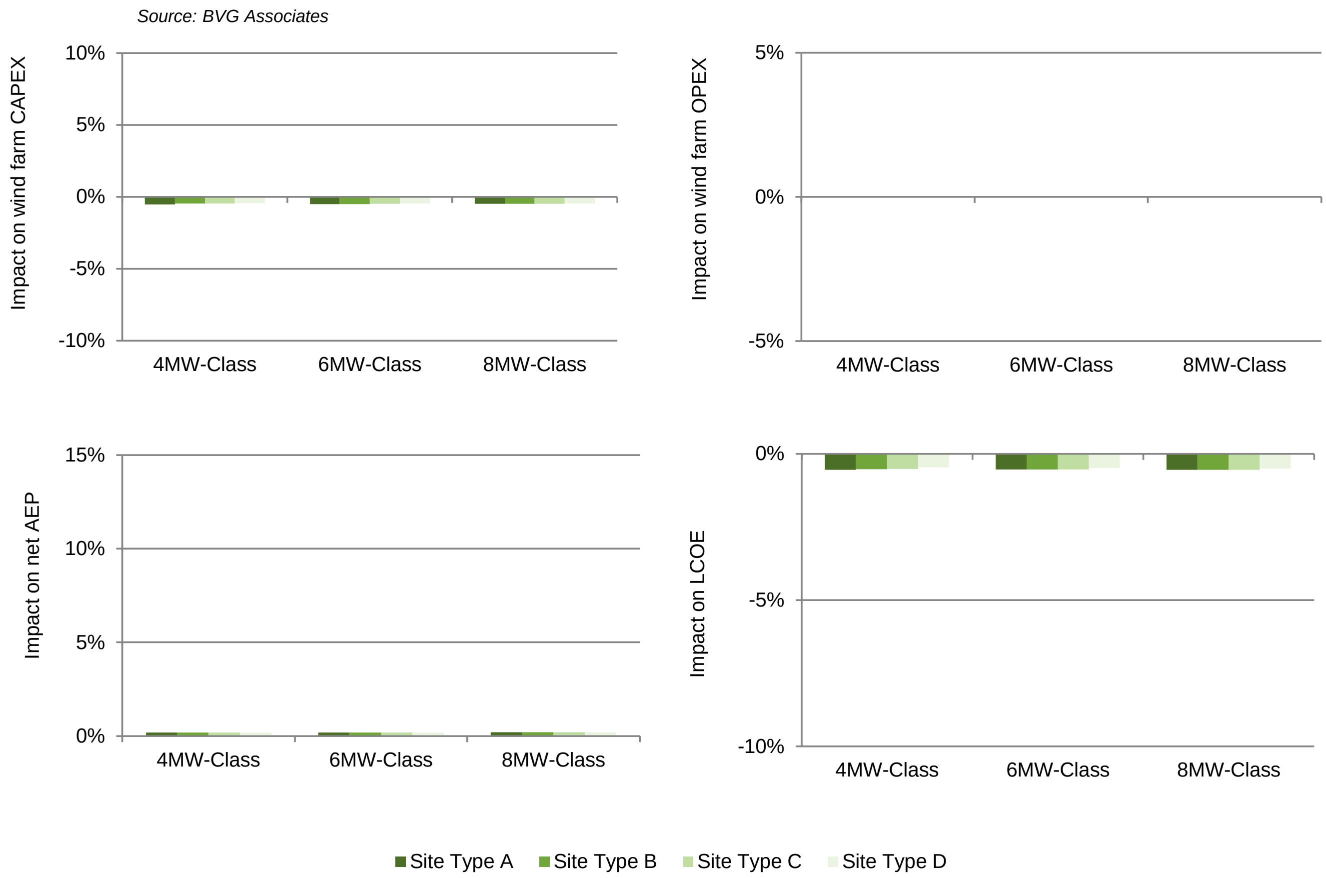

Figure 9.1 Anticipated impact of array electrical innovations by Site Type and Turbine MW-Class in FID 2020, compared with a wind farm on the same Site Type with the same Turbine MW-Class in FID 2011.[7]

The total CAPEX reductions decrease for wind farms using larger MW-Class Turbines and when moving from Site Type A through to Site Type D, due to the relative decrease in the contribution of array cables to total wind farm CAPEX.

Both AEP and OPEX remain almost constant for Site Types A and D because the only impact on the cable length requirement is the additional need for deeper sites, but this is a negligible increase. As turbine size increases, there is a negligible reduction in AEP and OPEX due to the reduced total cable used per megawatt.

The contribution of array cables to the reduction in the LCOE in moving from a wind farm using 4MW-Class Turbines on Site Type B in 2011 to 6MW-Class Turbines on Site Type B in 2020 is expected to be 0.5 per cent. Figure 9.2 shows that the largest savings from innovations in array cables are available from introducing cables with higher operating voltages. This innovation enables a reduction in both cable length and the total number of connections by reducing the number of cable strings required. It also offers a reduction in electrical losses.

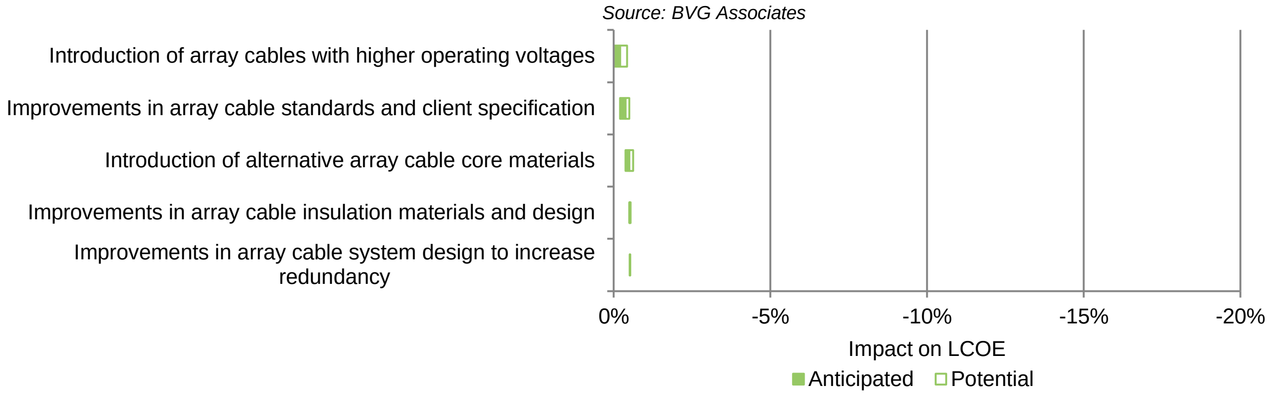

Figure 9.2 Anticipated and potential impact of array electrical innovations for a wind farm with 6MW-Class Turbines on Site Type B with FID in 2020, compared with a wind farm with 4MW-Class Turbines on the same Site Type with FID in 2011.[7]

Industry believes that there is relatively little potential to reduce the cost of energy through array cable innovations. The underlying technology is long established and proven in many industries. There is a strong recommendation from industry for developing and applying offshore wind-specific guidance to avoid unnecessary costs through over designing cables. It is also recognised that there will be a need to adapt the technology as wind turbines increase in size, moving to higher operating voltages and potentially to DC array cabling, driven by changes to turbine technology.

A prerequisite to cost reductions in array cables is confidence from manufacturers in the rate of project construction that is likely up to 2020, which will justify their involvement and investment in new facilities and product development.

9.2. Baseline

The baseline array cable cost covers the payment to a manufacturer for the supply of the array cables and ancillaries, such as cable connection terminations, delivered to the nearest port to the supplier. It also includes warranty costs but does not include subsea cable protection, which is included within wind farm installation.

The costs are based on a uniform turbine layout for a 500MW project with spacing between turbines of nine diameters (parallel to the prevailing wind direction) by six diameters (perpendicular to the prevailing wind direction). It assumes a centrally located substation with an equal distribution of turbines on either side, connected to the substation through a number of radial strings. The number of turbines per string (and hence also the number of strings required) is dictated by the maximum power capacity of the cable. It is assumed that the cable is connected to the turbine electrical system in an arrangement that allows the full isolation of each turbine from the array cable string.

A 33kV copper core cross-linked polyethylene (XLPE)-insulated AC “wet” cable design is assumed with a cross-sectional area either 240mm^2, with a rated capacity of 25MW, or 630mm^2, with a rated capacity of 40MW. The higher cross-sectional area cable is used to connect the substation with the inner turbines and the smaller cross-sectional area for the cables linking the outer turbines. A 10 per cent allowance has been made to account for the additional cable length required to accommodate sea bed and installation variances. The electrical efficiency of the array cables depends on the operating current level, which is lower at higher operating voltages, as well as the overall length of the cabling system. An electrical efficiency of the array cables of 99 per cent is typical and assumed for the baseline.

The baseline cost is £200 per metre for the 240mm^2 cable and £350 per metre for the 630mm cable, according to copper prices at the end of 2011. An allowance is also made for ancillaries such as cable terminations, which is dependent on the number of turbines, rather than the length of the cable. The length of cable between each turbine is proportional to the turbine rotor diameter, which increases with the turbine rated power. The total length of array cable required is not dependent on the distance of the site from the shore grid connection and the depth of water has only a minor impact on the length that is required: the cable must run from the sea bed to the surface for each connection.

Table 9.1 Baseline array electrical CAPEX for a project achieving FID in 2011.

Turbine Class	Array cable CAPEX (£k/MW)			
	Site Type A	Site Type B	Site Type C	Site Type D
4MW	80	81	83	81
6MW	78	80	82	80
8MW	75	76	78	76

As turbine rated capacity increases, the total length of the cable required decreases, as does the total number of cable ancillaries needed. The average cost per metre of cable increases, however, as a greater proportion of 630mm^2 cable is used. Table 9.1 shows that the overall cost of cable per megawatt decreases marginally with larger turbines and increases marginally with deeper water.

9.3. Innovations

All innovations in array cables that are discussed here can be applied together.

Existing situation

Today, 33kV three core subsea AC cable using a wet design without metal sheathing is the almost universal solution for array cabling. Cables of this design are rarely used in other applications. A single 33kV array cable has a connection capacity of up to 40MW and so may be used to connect 10 4MW-Class Turbines or six 6MW-Class Turbines in a radial string back to an offshore substation. The cables linking turbines in a radial string will usually have different conductor cross-sectional areas, depending on the maximum current requirement for a cable at that point in the string. Standard sizes are defined as 630mm^2, 500mm^2, 400mm^2 and 240mm^2 although in a string, only two or three different sizes are typically used.

Subsea cable design and manufacture is well established, with the first AC subsea cable installed in Germany in 1811 and the first DC system installed in 1954 between Gotland and mainland Sweden. XLPE was introduced as an insulation material in 1973. It is a thermosetting derivative of polyethylene that exhibits suitable strength, flexibility and durability characteristics. The majority of cable manufacturers that operate in the 10-36kV range have been operating in some form for over 20 years with many since the early 20th century. The manufacturing methods for cables have not altered dramatically over time but the last 20 years has seen a significant increase in the use of high volume automated production techniques.

The cable has several key layers and components as shown in Figure 9.3. It is manufactured in several stages that include: extrusion of the cores (conductors); jointing, where required to form longer continuous lengths; XLPE extrusion from resin pellets; the lay-up of the cores along with filler material and fibre optic cables to construct the three core design; and then armouring, by winding galvanised steel wire (or similar) around the cores to add additional mechanical protection. This assembly is then covered with an optional final polyethylene layer. At 33kV, a water-tree-retardant XLPE core is used to prevent water ingress to the conductors. This differs from cable design at higher voltages (over 66kV) where a lead sheath is introduced to provide an impermeable outer barrier against water.

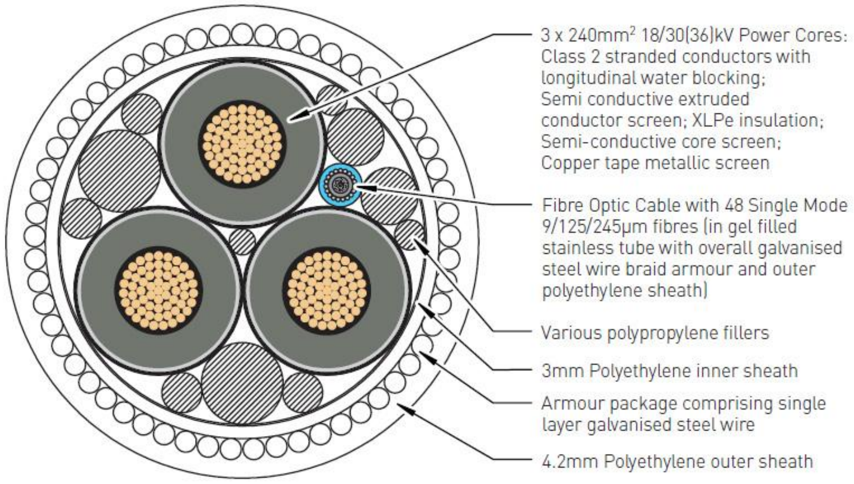

Figure 9.3 Typical construction of 36kV subsea array cable (courtesy JDR Cable Systems).

Figure 9.4 indicates that a large proportion of cable cost lies in its material, with the conductor having the highest cost impact and both armouring and insulation contributing significant components of the total cost. Assembly is a complex process for cable manufacturing and this makes up almost a quarter of the cost.

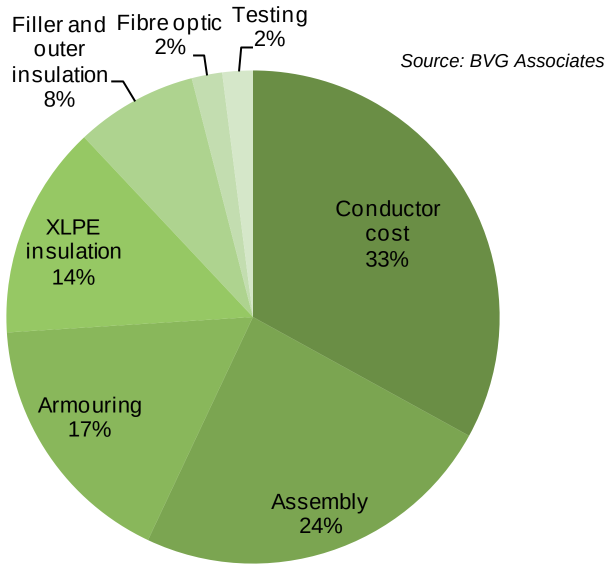

Figure 9.4 Baseline Array cable cost percentage breakdown.

A 400mm^2 cable typically has a mass of 30kg per metre and a typical minimum bend radius of 2m. The length and weight of a cable loaded on carousels means that manufacturing facilities must be located with direct water access. The key design considerations of the cable include both mechanical and electrical issues. Mechanically, the cable should be flexible enough to enable installation and durable enough to withstand the stresses of installation, sea bed movement during the operating life and some level of external disturbance including anchor hits and fishing activity. Electrically, the dielectric properties of the conductor and both the electrical and thermal insulation properties of the XLPE layer are key to the efficient transmission of power.

Despite the reliability of subsea cable technology in other applications, the offshore wind industry has experienced a relatively high failure rate. Subsea array cables are reported to suffer 0.001 to 0.01 failures per kilometre per year, which equates to 2.5 to 25 failures over the full life of a 500MW project.[52 53] Each failure, on average, should affect no more than three per cent of a 500MW wind farm capacity. Failures of cables are rarely attributed to deficiencies in design or manufacture, but rather to damage during installation and damage during operation, from activities such as fishing or anchoring.

Innovations

A number of companies advise that, as array cables contribute a relatively small portion of total project CAPEX, there is a current tendency for conservatism in client specification and designs chosen, which inhibits the implementation of lower lifetime cost solutions. **Improvements in array cable standards and client specification** include the selection of the most suitable cable core size, insulation thicknesses and the specification of cable delivery lengths to fit with the manufacturer's capability. Manufacturers are able to specify minimum requirements for all aspects of cable design, according to design standards, but project developers can choose to increase the specification and cost to provide electrical efficiency and mechanical durability benefits.

Cable manufacturers are regularly asked to produce cables to a higher specification than the minimum accepted by recognised standards. A leading cable manufacturer indicated an increased CAPEX for an array cable system of the equivalent of two per cent due to specifying a 1mm insulation screen thickness over the minimum requirement of just 0.5mm. Additional savings can be made by minimising the cable sizing so as only to meet the required loading duty and ensuring that specifications do not reduce manufacturing efficiency by overly defining how cable lengths should be delivered. Leading cable manufacturers indicate this reduction in specification would result in a decrease on average of 10 per cent in array cable CAPEX. Project developers specify several cable features in their functional specifications that are compliant with design recommendations but do not take account of application and project specific requirements. In carrying out additional investigation and design work during the development stages, the cable can be optimally specified for the specific site and project conditions.

It is only conservatism in project development approaches that restricts this saving, so a rapid introduction is expected beyond FID in 2014 through to the full realisation of potential savings in this area by FID in 2020. Joint industry collaboration to explore cable standards and specifications is seen as a key required activity to achieve this. As part of this collaboration, alternative specifications could be trialled and tested as part of full-scale or demonstration projects. The commercial readiness of this innovation is anticipated to be 100 per cent for projects with FID 2020. It is anticipated that market share will move from 10 per cent for projects with FID 2014 to 65 per cent for projects with FID 2020.

The number of turbines that can be connected to a single cable run is limited by the rated capacity of the cable. Through the **introduction of array cables with higher operating voltages,** this capacity can be increased and electrical losses can be reduced. Studies have proved the feasibility of extending the operating voltage of wet cable designs to close to 66kV.[52] This innovation is recognised by the majority of relevant industry players as the most important single innovation of the next 10 years relating to array cables.

A leading cable manufacture and public enabling body estimated that, in doubling operating voltage, a 50 per cent increase in cable capacity could be achieved, with only a 5 per cent increase in manufacturing costs through increased insulation specification and the modification of the cable design. Designs for cables up to 66kV have been developed by several leading manufacturers but they still require electrical and mechanical proof testing and certification.

Cable manufacturers state that it is unlikely that array cables will be operated at voltages of above 66kV by FID 2020, due to the standard requirement to introduce lead sheathing to protect against water ingress at this voltage. This dry cable design increases manufacturing costs by up to 100 per cent, making the introduction of array cables of voltages above 66kV not a cost-effective option for the industry at present. Using wet cables at up to 66kV is calculated to yield a 5 per cent reduction in total array cable CAPEX through a reduction in the number of connection strings and overall cable length as well as reducing electrical losses by 0.15 per cent from about one per cent.

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[52] Jan Matthiesen, *The Benefits of Operating Future Large Offshore Wind Farms at Higher (52-66kV) Voltages,* The Carbon Trust, Presentation made at the Renewable UK Annual Conference 2011, Manchester, 25-27 October 2011.

[53] The CIGRE Paper (1986). *Methods to Prevent Mechanical Damage to Submarine Cables*, presented by Cigré Working Group 21 as Session Paper 21-12 at the 1986 Cigré Session, Paris, France.

As the industry moves towards turbines with higher MW ratings, the need for higher capacity array cables becomes more critical, both to minimise both the total cable length and the number of substations required. At 33kV, only five 10MW-Class Turbines can be connected in each string. This restricts the site layout options or drives the need for additional cable lengths to connect the turbines. Having only the capacity to connect a small number of turbines on a single string means that either additional substations are required to connect all turbines to the export system or additional cable lengths will be required to reach turbines located further from the substation. The impact of higher capacity array cables is independent of the Site Type. Switchgear is available operating at higher voltages and the reduced step-up at the substation has positive cost benefits. The increased cost of higher voltage switchgear, terminations and the need for higher step up transformers in the turbine adds costs to reduce the overall benefit. These factors have been accounted for in the overall savings stated.

The commercial readiness of this innovation is anticipated to be 100 per cent for projects with FID 2020. It is expected that viable products will be available for inclusion in FIDs before 2014 and it is anticipated that market share will move from 10 per cent for projects with FID 2014 to 60 per cent for projects with FID 2020.

With the current approach of connecting radial strings of turbines to an offshore substation, an array cable (or related switchgear) failure will result in the loss of generation from all or part of the turbine string until a repair can be carried out. **Improvements to the array cable system design to increase system redundancy** will decrease the impact of failures significantly by connecting the end of strings together to form rings, thus introducing redundancy and facilitating the continued collection of most or all of the available energy output, even in the case of a single fault, and enabling repairs to be scheduled to minimise downtime and costs. This approach does, however, increase the required core cross-sectional area of cables further away from the substation, as all cables needs to be sized to take power from all turbines on the loop. It also adds an extra length of cable to make the loop.

The Carbon Trust[52] and a cable manufacturer agree that the introduction of this innovation will improve wind farm availability by 0.2 per cent and minor savings in the necessary repair of the fault can be realised by undertaking planned rather than reactive maintenance. An array cable CAPEX increase of 5 per cent is necessary, along with a one per cent increase in the total wind farm installation cost. The benefit of the innovation is highly dependent on the failure rates of array cables and switchgear, with higher failure rates resulting in greater savings. As a result, the technical potential of the innovation is expected to increase for projects reaching FID up to 2017 but then fall for projects with FID in 2020, by which point the failure rate per kilometre of array cable is expected to have decreased. At 33kV, the Carbon Trust advises an increased cost of energy for “high reliability” cables and a reduction in the cost of energy for “low reliability” cables. At approximately 66kV, the reduction moves from a small saving with “high reliability” cables and up to two per cent with “low reliability” cables; these figures do not include savings related to substation costs. The commercial readiness of this innovation is 90 per cent for projects with FID in 2020 and it is anticipated that market share will move from 10 per cent for projects with FID 2014 to 65 per cent for projects with FID in 2020.

One leading cable manufacturer advises that there is no significant technical barrier to this innovation, but additional efforts will be required during FEED studies to optimise the array electrical design. The perceived insurance liability of cables is seen as a driver to move to ring connections and a number of wind farm developers are currently investigating whether ring connections should be included as a design requirement.

To date, all array cables installed in offshore wind farms have had copper cores but in other sectors aluminium is used for both onshore and offshore interconnectors. At current commodity prices, the **introduction of alternative array cable core materials** could offer significant CAPEX savings.

Cable manufacturers confirmed that the cable conductor is the largest single contributor to total cable cost, typically accounting for approximately 30 per cent. Copper prices have increased rapidly over recent years and are currently significantly higher than aluminium. Although an increase core size is required, CAPEX savings from the use of aluminium cores are advised by cable manufacturers currently to be about 20 per cent but there are three significant considerations in making any change:

- Few manufacturers are able to offer a fully certified aluminium core design for offshore applications
- There are concerns about the increased risks of work hardening with aluminium due to flexing during installation, as the dynamic stresses imposed on offshore wind farm array cables are understood to be higher than those in interconnectors and onshore cabling applications, and
- The lower specific gravity of aluminium cables makes installation more difficult, particularly when using jetting methods, as the cable can become partly buoyant depending on the sea bed materials.

While project developers are aware of the CAPEX saving from the use of aluminium-cored cable for onshore applications, there have been only a small number of projects using aluminium-cored cable for subsea use in the offshore wind industry, and these have generally only been low capacity projects, usually at less than 30kV. Suppliers perceive this to be due to the conservative approach of customers. Field trials and life cycle testing are likely to be needed to support the introduction of the changed material. If the commodity price differential remains or increases, a rapid introduction to the market is expected once a first project adopts. There is no difference in the impact of this innovation for different Site Types and Turbine MW-Classes. The commercial readiness of this innovation is anticipated to be 70 per cent for projects with FID 2020 and it is anticipated that market share will move from 10 per cent for projects with FID 2014 to 70 per cent for projects with FID 2020.

Cable insulation material provides mechanical, thermal and electrical protection. **Improvements to array cable insulation materials and design** offer further reductions in cable CAPEX. Alternative insulation to XLPE exists, most notably ethylene propylene rubber (EPR), which could offer benefits despite having a higher unit cost. Manufacturers are also developing new insulation materials for the onshore cable market that could become available for offshore use.

A fuller understanding of the thermal impacts of cables on the environment could justify a reduction in electrical insulation performance and provide CAPEX savings. A leading cable manufacturer highlighted that opportunities exist to introduce alternative insulation materials that are either cheaper or enable reductions in insulation thickness and yield CAPEX reductions of approximately two per cent. This is relatively low due to the established nature of cable manufacture and insulation material technology. There is no difference in the impact of this innovation for different water depths and turbine sizes. The commercial readiness of this innovation is anticipated to be 50 per cent for projects with FID 2020. It is anticipated that market share will move from 10 per cent for projects with FID 2014 to 75 per cent for projects with FID 2020 as designs for insulation evolve.

Other innovations

Cable manufacturers indicate that changes to cable designs for the ease of installation is unlikely to yield significant savings, but there is potential to speed up the connection time by improving cable terminations. This issue is covered in Section 10.3.2 but no step change innovation is expected in this area.

Improvements in manufacturing and assembly as well as streamlined testing methodology are also likely to be implemented. These improvements have been captured in Section 3 of the *Supply chain work stream report*. Cable manufacturers indicate that high levels of demand would justify investment in process and efficiency improvements, including the set-up of dedicated additional facilities.

Early signs of progress and prerequisites

Testing and certification activities on cables are not often widely publicised by manufacturers, as there can be a commercial first-mover advantage in the proof of new cable designs. The best signals of progress in many areas will be feedback from developers about what array cable solutions they are being offered and feedback from suppliers about the increased project developer focus on cable specification and design discussion. The establishment of one or more JIPs relating to the specification of cables is expected within the next two years and, for the greatest impact, this is likely to have an element of new testing. This dialogue between developers and suppliers and any JIPs could be accelerated though private and public sector initiatives.

The Carbon Trust has published findings relating to the move to higher voltage cables and it is anticipated that future technology programmes will further these investigations. Similar pubic enabling bodes investing in cable specific actions are expected to continue. Development of “wet” cable designs from leading manufacturers and initial testing is expected before 2014, subject to developer interest.

Offshore wind cable workshops and conferences are regularly organised that indicate key issues are being identified and discussed. These events will indicate positive moves towards developing innovations.

Due to the perceived lack of understanding of some of the opportunities and risks, innovations relating to array cables will generally need to be trialled in smaller-scale projects before deployment at a large scale. Some of the innovations can be applied at full scale within a short period due to pre-existent design activities already completed by the industry, such as higher voltage cables and the use of alternative core material. Despite this, some concerns may still exist and extensive factory and independent lifecycle testing will be required.

A key prerequisite for investment in these innovations is confidence that there will be returns on that investment. In this case, returns will come from sufficient pipelines of consented projects to justify engagement from cable manufacturers on product development issues.

Table 9.2 Potential and anticipated impact of innovations in array cables, for a wind farm on Site Type B using 6MW-Class Turbines, compared with FID 2011.

Innovation	Maximum technical potential impact				Anticipated impact FID 2020			
	CAPEX	OPEX	AEP	LCOE	CAPEX	OPEX	AEP	LCOE
Introduction of array cables with higher operating voltages	-0.4%	0%	0.2%	-0.4%	-0.2%	0%	0.07%	-0.2%
Improvements in array cable standards and client specification	-0.4%	0%	0%	-0.3%	-0.3%	0%	0%	-0.2%
Introduction of alternative array cable core materials	-0.5%	0.2%	-0.05%	-0.20%	-0.3%	0.1%	-0.03%	-0.1%
Improvements in array cable insulation materials and design	-0.07%	0%	0%	-0.04%	-0.02%	0%	0%	-0.02%
Improvements in array cable system design to increase redundancy	0.4%	-0.1%	0.30%	-0.008%	0.2%	-0.06%	0.1%	-0.004%
Total					-0.5%	0.04%	0.2%	-0.5%

10. Wind farm installation

10.1. Overview

Innovations in the installation process for offshore wind farms are anticipated to reduce the LCOE by between three and five per cent between 2011 and 2020 for a given Turbine MW-Class, and these arise solely from reductions in CAPEX, rather than changes in OPEX or AEP. The impact of innovations is greatest for projects on Site Type D, due to the greater impact that improvements in the range of working conditions have on harsher sites.

The impact of innovations in installation is lower for larger turbines, which reflects the decreasing share of the wind farm CAPEX associated with the installation with larger turbines. Figure 10.1 shows the combined impact of innovations on CAPEX, OPEX, AEP and the LCOE for a 500 MW wind farm for each Turbine MW-Class and Site Type combination. In addition to these reductions, the *introduction of turbines with larger rated capacity*, discussed in Section 6.3.1, significantly reduces installation costs as the increase in the unit cost of installation is outweighed by the reduction in the number of units per 500MW wind farm.

The anticipated reduction in the LCOE from a wind farm using 4MW-Class Turbines on Site Type B in 2011 to a wind farm using 6MW-Class Turbines on Site Type B in 2020 is four per cent.

Source: BVG Associates

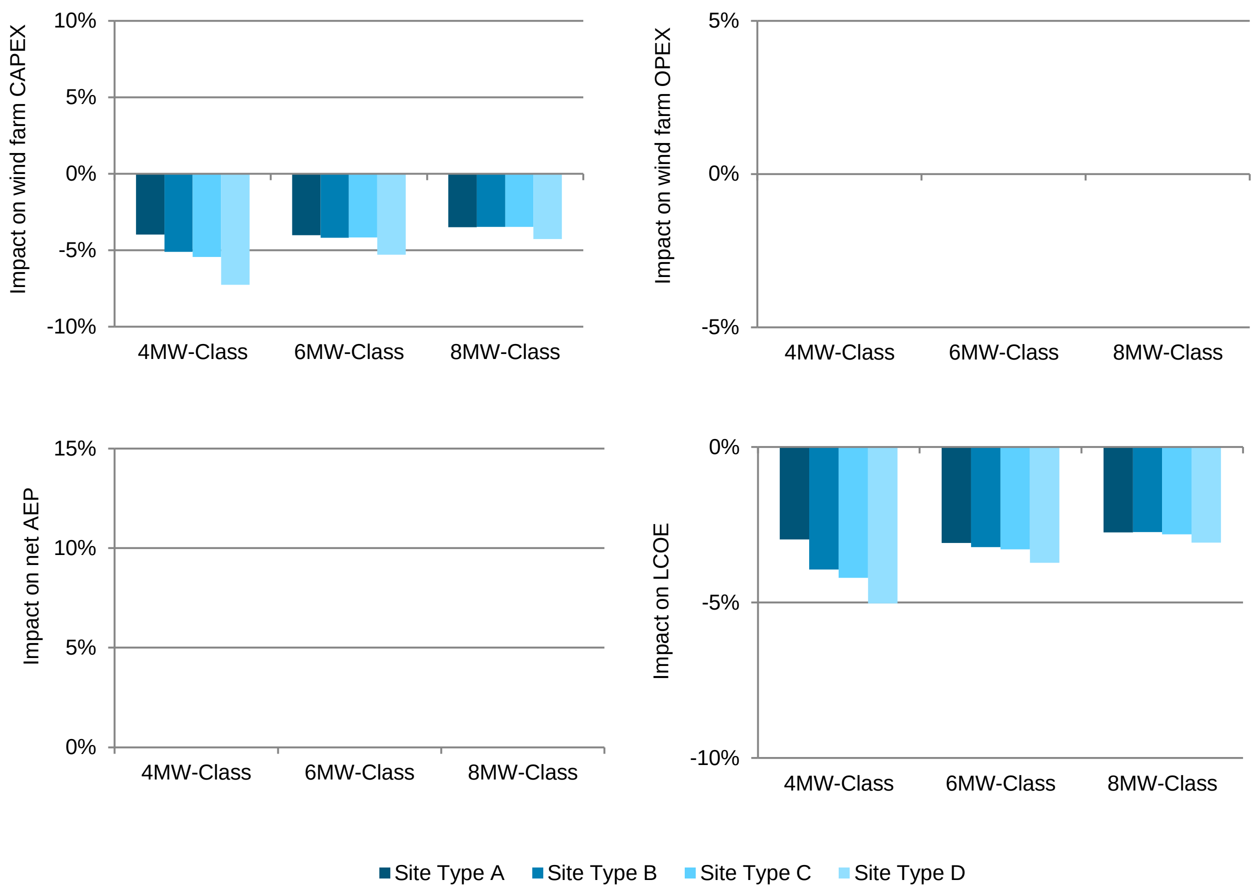

Figure 10.1 Anticipated impact of installation innovations in installation by Site Type and Turbine MW-Class in FID 2020, compared with a wind farm on the same Site Type with the same Turbine MW-Class in FID 2011.[7]

The largest anticipated savings from innovations in installation arise from improving space frame installation, developing installation vessels with the capability to operate in a greater range of conditions, and developing the pull-in and hang-off processes for cable installation. A summary of the relative anticipated impact of all innovations considered is presented in Figure 10.2.

The innovations with the largest potential impact on the LCOE are those that involve disruptive changes to processes, such as whole turbine installation, float-out-and-sink installation solutions and the introduction of buoyant gravity-based foundations. In all these cases, only a small fraction of the potential impact is forecast to be realised by FID in 2020. The impact of risk on the LCOE is considered in detail in Section 3 of the *Finance work stream report*.

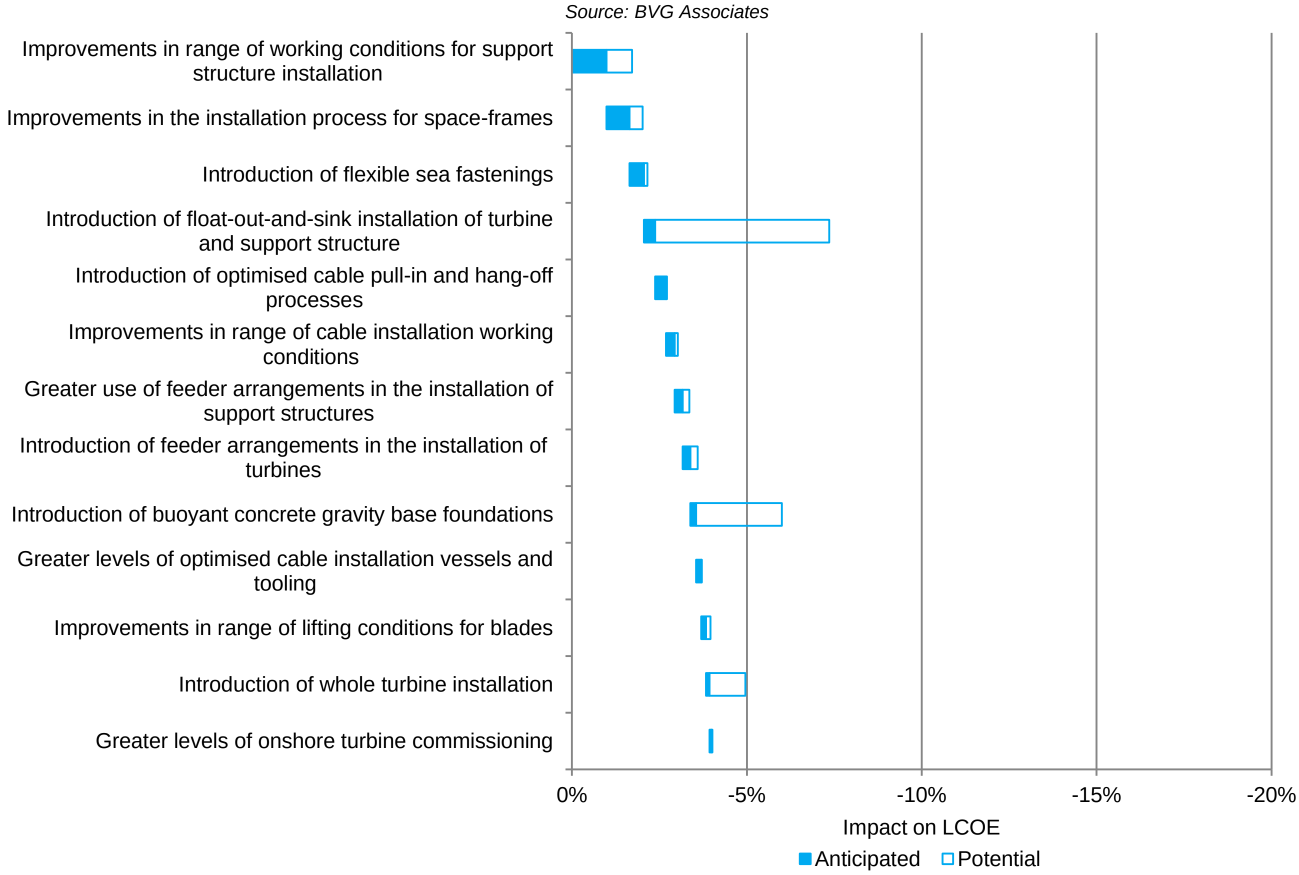

Figure 10.2 Anticipated and potential impact of wind farm development innovations for a wind farm with 6MW-Class Turbines on Site Type B with FID in 2020, compared with a wind farm with 4MW-Class Turbines on the same Site Type with FID in 2011.[7]

10.2. Baseline

The installation baselines for projects on all Site Types for all Turbine MW-Classes are based on current typical practice in the industry for a wind farm reaching FID in 2011. It is assumed that there is sequential installation of the support structure (excluding tower), array cable, then tower (pre-assembled from sections onshore) and turbine. Monopiles are assumed only on Site Type A with 4MW-Class Turbines. In line with practice up to now, the baseline analysis assumes that, in all cases, a jack-up vessel collects components from the construction port either 40km or 125km from the wind farm, depending on the Site Type. All installation activity is assumed to take place 24 hours a day, seven days a week, dependent on weather.

The scope of the installation process as defined for this project is the transportation of the support structure, nacelle and hub assembly, blades, towers and array cables from each supplier's nearest port, the pre-assembly work completed at a construction port before the components are taken offshore, and installation work for support structures, turbines and array cables, including scour and cable protection. Turbine commissioning work is discussed in this section although it typically forms part of the turbine manufacturer's scope of supply and any innovations impact on turbine nacelle CAPEX.

Array cable installation is assumed to be a two-stage process, with separate surface lay with a single cable vessel, and burial and survey operations with a remotely operated vehicle (ROV) with the support vessel. The pull-in is via a steel J-tube, which provides protection to the cable and runs from the sea bed to the base of the tower. Contractors to date have tended to be specialist cable installation companies, often working across the oil and gas, telecommunication and power interconnector markets.

As well as offshore activity, installation operations require significant activity in ports. For UK east coast wind farms either operating or currently under construction, UK ports have often been limited to playing a secondary role in buffering component supply and supporting installation contractors. This has been because there has been a lack of port facilities with the space available to support the installation of offshore wind farms, a situation which is anticipated to change over time.

So far, installation of a given wind farm element has mainly been arranged either through a single contract between the wind farm developer and an EPC specialist, for example, Fluor or Van Oord, or through multiple contracts awarded by the developer to a number of installation contractors, such as MPI Offshore, A2SEA and Global Marine Systems. In some cases, multiple EPC contracts are awarded for the design, supply and installation of different wind farm elements. For example, MT Højgaard has been awarded a number of EPC contracts for monopiles, including TPs. In the past, Vestas has offered a turbine EPC contract, for example, for Robin Rigg and with KBR for Barrow. Despite such instances, interviewees indicate that there is a lack of holistic thinking that limits the optimisation of installation activities, especially regarding support structure. For example, cost savings in support structure fabrication, particularly ones that seek to minimise the steel content, can impact the installation cost by adding significant variation in component dimensions, which increases the complexity of handling components.

Installation contractors report that projects are rarely delivered to the original timetable and interviewees indicate that the projects which have been delivered on time, such as Walney 2 and Ormonde, are more often than not led by the more experienced developers suggesting that there are good reasons that this picture of late delivery will change as other developers gain a track record in offshore wind project management. Developers express concern about the quality of the installation contractors but expect this to improve as they become more experienced in offshore wind installation.

According to installation contractors, better planning, eliminating mistakes and ensuring the most appropriate use of vessels and equipment and the right holding of spare parts will lead to significant savings, either in contracted costs or by reducing project overruns. Some advised that FEED studies could be better used to ensure that projects incorporate relevant experience to help reduce risk. Installation contractors also report concern over risk management during construction. They highlight the often poor levels of communication between developers and contractors and the uncertain lines of responsibility. A particular area of concern has been the role of marine warranty surveyors, who provide independent technical assurance of marine operations on behalf of the insurance underwriter and are seen by some to be inconsistent, generally over-conservative and with insufficient accountability. This has the result that available weather windows are not always fully exploited. The opportunity for improvement in efficiency through addressing these issues is seen to be more than 10 per cent by many. No benefit is taken here, but rather the impact of such savings is considered more fully in Section 3 of the *Supply chain work stream report*.

There is often a high level of learning “on the job”, which means that installation rates for projects start slowly and then accelerate before levelling off towards the end. Figure 10.3 shows the time taken for turbine installation during a recent UK project, reflecting that the speed of turbine installation increased significantly as the project progressed. Feedback from interviews suggests this trend is typical for all areas of installation, although the learning rate shown in this real case is significantly higher than usual. The baseline installation costs discussed later in Table 10.2 factor in a learning rate, equivalent to assuming that the onsite construction rate for the project as a whole is four per cent higher than the rate at the end of the project. The concern from developers and installation contractors is that this learning is often not applied to subsequent projects. While projects are managed as one-off ventures and there is considerably diversity in component design, this is likely to continue in the immediate future and potential further efficiency savings may not be realised.

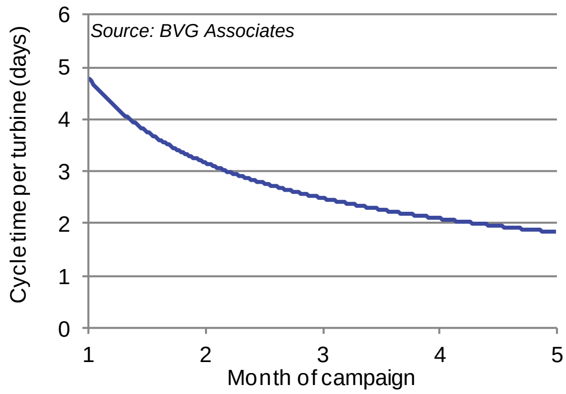

Figure 10.3 Indicative learning for turbine installation during a real UK project. This project introduced innovations that meant that the learning in this project was far greater than on projects using more established products. The turbine installation cycle time includes loadout, transit, turbine installaion and field move and any weather downtime in port or in field. It is anticipated that future projects will start with rate close to the end rate shown and improve more slowly than shown.

Weather downtime is a key cost consideration for any offshore activity and developers and installers agree that there are innovations for turbine, support structure and array cable installation activity that will extend the range of conditions in which activity can be undertaken. The current level of downtime is highly project-specific but the figures used in the baseline for a 4MW-Class Turbine on Site Type A are typical for the industry. The extension of operating ranges not only reduces project costs by reducing vessel requirements but also increases the potential for year-round working, which enables greater flexibility of scheduling and reduces risk from delays. Figure 10.4 shows how the maximum operating range of a vessel impacts on the number of workable days. Significant wave height (Hs) is the most widely-used measure of limitation offshore. In reality, this needs to be combined with wave periodicity, direction, persistence (the length and frequency of suitable weather windows), wind speed and direction and tidal flow to define the fraction of workable and non-workable days.

Figure 10.4 shows the number of workable days over a year in which a given significant wave height is exceeded for a recent UK project with conditions similar to Site Type A. Based on this data and information from other projects, it is assumed that support structure installation is a year-round process and, for a wind farm using 4MW-Class Turbines, has weather downtimes of 33, 34 and 35 per cent of activity for Sites Types A, B and C respectively, which are based on a maximum Hs limit of about 1.4m for jacking-up. The difference in weather downtimes for Site Types A, B and C are based on the higher wind speeds which place an additional limitation on heavy lifts. At Site Type D, the harsher conditions and the longer weather windows needed for transit will raise the weather downtime to 40 per cent of the support structure installation time. Feedback is that the increase in the size of structures has an additional impact on the weather downtime and it is assumed that the figures presented here increase by one and two percentage points for 6MW and 8MW-Class Turbines respectively. While adverse weather, in particular high winds, does have an impact on activity in port, it is assumed that mobilisation and demobilisation is unaffected and the percentages presented in Figure 10.5 to Figure 10.10 for total project time breakdowns throughout this section are slightly lower than those presented in this baseline section.

Turbine and cable installation are assumed to take place from March to October inclusive. This is because current cable installation practice requires personnel access to the support structure during the pull-in process, which is currently constrained by the safety of using access systems in higher sea states, and rotor lift sensitivity to high winds. In both cases, the maximum operational sea state is assumed to be an Hs of 1.4m, which leads to weather downtimes of 25, 26 and 27 per cent for Site Types A, B and C, rising to 32 per cent for Site Type D for a wind farm with 4MW-Class Turbines. These are lower than for support structure because it is assumed that turbine installation is only undertaken between March and October. As for support structure installation, the figures presented increase by one and two percentage points for 6MW and 8MW-Class Turbines respectively.

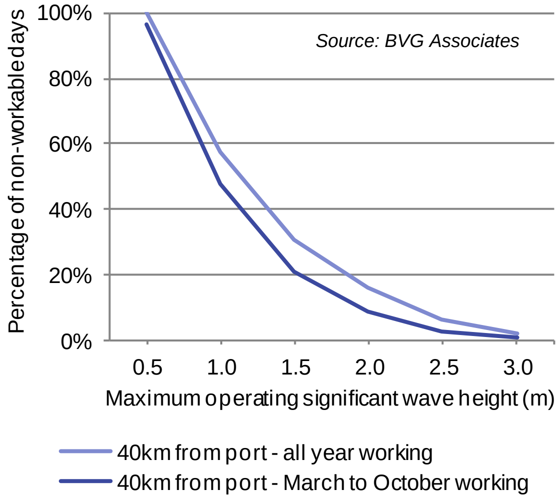

Figure 10.4 Percentage number of days in which a Significant wave height is exceeded, based on data from a recent project that is similar to Site Type A.

The vessels used in the baseline are medium and large self-propelled jack-up vessels, as defined in Table 10.1. In considering innovations in installation methods, a number of different vessel types have been considered in a range of combinations.

Table 10.1 Typical vessel charter day rates for existing turbine and support structure installation vessels.Note: Market conditions and the length of contract can have a significant impact on these prices. These are considered in Section 4 of the *Supply chain work stream report*.

Vessel type	Size	Day rate operating (£k)	Day rate waiting (£k)
Self-propelled jack-up vessel	Medium	120	110
	Large	150	140
Non-self-propelled jack-up vessel	Medium	50	45
	Large	90	85
Construction dynamic positioned vessel	Medium	180	170
	Large	220	210
Feeder dynamic positioned vessel	Medium	20	20
	Large	30	30

There is significant risk in introducing new processes and technologies and demonstration will be difficult in some cases. A concern is that some innovations in installation aimed at reducing costs tend to push the boundaries of what can be achieved in adverse conditions, and addressing health and safety considerations will play a big role. There are significant health and safety risks associated with the number of heavy and high lifts, working at heights, exposed offshore conditions, diving and the frequency of offshore transfers. These risks are compounded by the infancy of the sector. As well as the potential harm to individuals, any accidents can lead to project delays and increased costs.

Some innovations in installation will shorten the time taken to construct the wind farm. This not only has a benefit in terms of basic cost reduction, it can also lower the project risk during construction, enable earlier generation and reduce the size of the installation fleet required by the industry as a whole. These benefits are considered in Section 4 of the *Supply chain work stream report* and Section 5 of the *Finance work stream report*.

The breakdown of baseline installation costs for the different Site Types between support structure, turbine and array cables is show in Table 10.2. These have been derived by modelling vessel time and costs, weather downtime, port-related costs, and supply of grout, cable protection and a range of marine services based on typical vessel costs and times for activities provided and verified by a range of industry players. For support structure installation, the lowest installation cost per unit is for 4MW-

Class Turbines on Site Type A but, while the cost of installing a single jacket is higher, the one third reduction in the number of structures installed when 6MW-Class Turbines are deployed is such that there is little difference between installation cost per megawatt for monopiles for 4MW-Class Turbines on Site Type A and jackets for 6MW-Class turbines on Site Type B. Support structure installation cost is more sensitive to water depth than turbine or cable installation, partly because the time taken to install the structures is approximately 10 per cent longer and partly because the larger structures needed for deeper water require more deck space, which impacts on vessel cost.

The installation baselines include 10 per cent additional developer costs. These cover a range of activities but the most significant of these are the transport of components from the port closest to the manufacturing location to the designated construction port and the cost of securing space at the port for the storage and lay-down of components and pre-installation activity. It does not cover harbour dues incurred by the installation contractor as a result of quayside activity. Feedback from a port owner suggests that there are significant cost reductions from improvements in port logistics but these relate primarily to efficiency gains from standardised processes, which are considered in Section 4 of the *Supply chain work stream report*.

For monopiles installation, scour protection is a significant cost, especially for sites with high tidal flows and with a sandy sea bed, and a figure of £225,000 per monopile has been assumed. Mitigation is achieved largely through rock dumping around the base. Space frames are less at risk of scour than monopiles due to the lower sea bed footprint and the costs of mitigation are about a quarter per structure than those of monopiles. For space frames, mitigation can be achieved through support structure design, for example at Ormonde, where no rock dumping was considered necessary. The cost of scour mitigation for space frames is assumed to be one quarter of that for monopiles.

For turbine installation, 6MW-Class Turbines require a large jack-up vessel rather than the medium jack-up that can be used for 4MW-Class Turbines, due to the requirement for more deck space and a higher capacity crane. Despite this, the fewer units installed when using 6MW-Class Turbines is such that the cost of turbine installation per megawatt again is lower.

The process of laying the cable on the sea bed is relatively quick compared with the pull-in process at each end of the cable, and therefore the cost of cable installation is driven by the number of cable links, which is dictated by the number of turbines in the wind farm.

There are higher installation costs on Site Type D due to the increased transit time and harsher conditions which cause greater weather downtime.

Table 10.2 Baseline installation cost breakdown for a project with FID in 2011.

Turbine MW-Class	Component	Installation CAPEX (£k/MW)			
		Site Type A	Site Type B	Site Type C	Site Type D
4MW	Support structure	232	370	389	497
	Array cable	138	138	139	160
	Turbine	103	103	103	136
	Total	**473**	**611**	**631**	**793**
6MW	Support structure	251	260	277	349
	Array cable	97	97	97	112
	Turbine	89	89	90	104
	Total	**437**	**446**	**464**	**565**
8MW	Support structure	212	213	228	271
	Array cable	77	77	77	88
	Turbine	76	76	77	88
	Total	**365**	**367**	**382**	**447**

Decommissioning is assumed to be a reverse assembly process to installation taking one year for a 500MW wind farm in which piles and cables are cut off at a depth below the seabed and all other infrastructure is removed and sorted for recycling and scrap. It incorporates environmental monitoring. The residual value and the cost of scrapping are not considered. As such, the cost of decommissioning is assumed to be 65 per cent of the installation cost, because it is likely that similar vessels will be deployed, but the time taken to remove the relevant element will be less than for its installation. It is assumed that removal of the support structure will take 90 per cent of the time taken to install, turbine decommissioning will take 70 per cent for the time taken to install, and removal of the array cables will take 10 per cent of the time taken to lay. Due to discounting, the impact on the cost of energy is not significant and decommissioning technology innovations have not been considered in detail.

10.3. Innovations

Offshore wind farm installation generally consists of three discrete activities: support structure installation (excluding the tower); array cable installation; and turbine (including the tower) installation. This section is structured to reflect this breakdown, with innovations in which the support structure and turbine are installed as a single unit considered in the turbine installation section (see Table 10.3).

Table 10.3 Support structure and turbine installation groupings used in this analysis.

Groupings	Innovation types
Support structure installation	Monopile installation Steel space frame installation Buoyant concrete gravity bases
Turbine installation	Conventional turbine installation Whole turbine installation (final turbine assembly onshore) Turbine and support structure installation together (float-out-and-sink approach in which final turbine and support structure assembly is onshore)

10.3.1. Support structure installation

Existing situation

All commercial projects completed to date have undertaken the installation of the foundation separately from the tower, which forms part of the scope of turbine installation. While industry believes that a more holistic support structure design will save costs, it does not expect tower installation to form part of the scope of support structure installation unless float-out-and-sink solutions are employed. This section considers installation innovations that apply to the foundation only.

Monopiles have been the dominant support structure technology for offshore wind projects to date but there continues to be variation in installation methods. Most contractors have used jack-up vessels although there is an increasing use of floating crane vessels. Most monopiles have been driven into position due to favourable ground conditions, rather than the pile being inserted into a drilled socket. The pile-driving equipment includes a hammer and anvil and a pile guidance tool, of which IHC Hydrohammer and MENCK are leading suppliers. Typically, the transition piece is then installed on the monopile, often using the same vessel that installed the monopile while it remains in position. The transition piece is then grouted to the monopile. Discussion of issues and innovations relating to this connection is provided in Section 8.3. A breakdown of typical monopile and transition piece installation time is presented in Figure 10.5, based on feedback from a number of completed projects and experienced installation contractors. The scope of the activities is defined in Table 10.4. Most installation services are supplied on a day rate basis, principally for the vessel or vessels and the crew and equipment onboard. The time breakdown therefore provides a good indication of the areas where significant cost savings can be made.

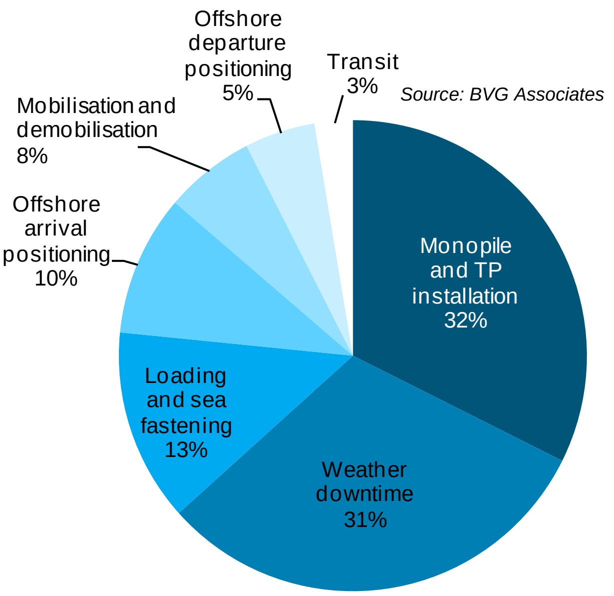

Figure 10.5 Modelled monopile and transition piece installation time breakdown for a 500MW project reaching FID in 2011 using 4MW-Class Turbines on monopiles on Site Type A in which monopile and transition piece are installed from the same large jack-up vessel (2.7 days per location average).

Table 10.4 Description of activities undertaken in monopile and transition piece installation using a jack-up vessel.

Activity	Description
Mobilisation and demobilisation	Periods at the beginning and end of a vessel contract during which the vessel transits to the site and appropriate equipment (deck spread) is installed on (mobilisation) or removed (demobilisation) removed from the vessel
Loading and sea fastening	Time spent in port, including jacking up and down at the quayside and loading and fastening components
Transit	Period from leaving the quayside to arrival at the construction location
Offshore arrival positioning	Process of positioning the vessel at the correct location and jacking up ready for the construction activity
Monopile and transition piece installation	Construction activity, including grouting
Offshore departure	Process of jacking down for departure
Weather downtime	Time when installation activity is delayed due to weather conditions

Each pile is designed with a maximum number of pile driving hits allowed and, when it is concluded that this number will not achieve the depth of penetration needed, or the ground conditions are found to be unsuitable for piling (for example, with rocky or heavy clay sea bed conditions), then drilling is used. This is a more expensive method as a single monopile can be driven in about 11 hours, including pile upending and positioning and, where additional drilling is required it can extend the process by up to a few days. When it is known that ground conditions may require the use of a drilling rig, it is seen as cost effective to carry this on the installation vessel, prepared for use at short notice.

Installation rates average two to three days per monopile and transition piece for projects using 4MW-Class Turbines in water depths of 20m to 25m, including weather downtime, transit and port activity. In most cases, the monopiles and TPs have been taken out on the installation vessel, although simple floating feeder barges were used for the Greater Gabbard project and, on some projects, the piles have been floated out with buoyancy aids due to the risks of losing buoyancy if simply plugging each end of the monopile. At Greater Gabbard, the decision is understood to have been driven by the high day-rate cost of the installation vessel and the distance to a port that could accommodate such a large vessel. Another advantage of the feeder system reported by an installation contractor is that fabrication or storage of the support structure can take place at a different location from the main construction port, which could make more cost-effective use of port space.

Most existing monopiles have a diameter of approximately 4m to 5m but units with a diameter of more than 6m may become more common as projects move into water deeper than 25m and use turbines of rating larger than 3.6MW. To date, no commercial wind farm using larger turbines has used monopiles. While the availability of large anvils and hammers that can handle this scale is limited, installers do not expect this to be a bottleneck as the lead time for the delivery of new equipment from suppliers such as IHC Hydrohammer and MENCK is believed be about a year, so is within project contracting timescales. The payback on investment in such tooling is understood to be reasonable but suppliers may be reluctant to invest when the pipeline of projects using large monopiles is uncertain. Further discussion regarding the structural design issues relating to larger monopiles is given in Section 8.3.

The challenges of installing steel space frame structures (jackets, tripods or other novel designs) are different from monopiles. Typically for conventional jackets, it is a three-stage process starting with pin pile installation using a template, followed by the positioning and securing of the jacket itself, and finally grouting. There are often three or four pin piles to be installed and the space frame foundation is more challenging to transport than a monopile due to its size and shape. A breakdown of steel space frame installation costs is presented in Figure 10.6 and Figure 10.7 and the total time is the sum of both activities. Definitions of activities are similar to those presented in Table 10.4.

An alternative sea bed connection to the pile is the suction bucket or caisson. Proponents of the technology suggest that there are benefits in terms or reducing installation time and avoiding piling noise. Suction bucket technology is discussed further in Section 8.3.5.

Steel space frames can be pinned to the sea bed with piles installed before or after support structure installation. Pre-piled solutions are generally completed by two standalone vessels with one vessel used to install the piles and the other employed to lift the structure into place afterwards. For post-piled operations, both activities can be undertaken from a single large vessel, as planned for Nordsee Ost. Alternatively, a dedicated piling vessel can be used to support the main jacket installation vessel. Post-piling is the main method used by the oil and gas industry and was used for the Beatrice Wind Farm Demonstrator Project in 2006; the oil and gas sector has relatively less experience of pre-piling. In offshore wind it was first used for the six Alpha Ventus jackets in 2009. Where pre-piling is undertaken, pin piles can be installed many months before the jacket is installed using a permanently located template.

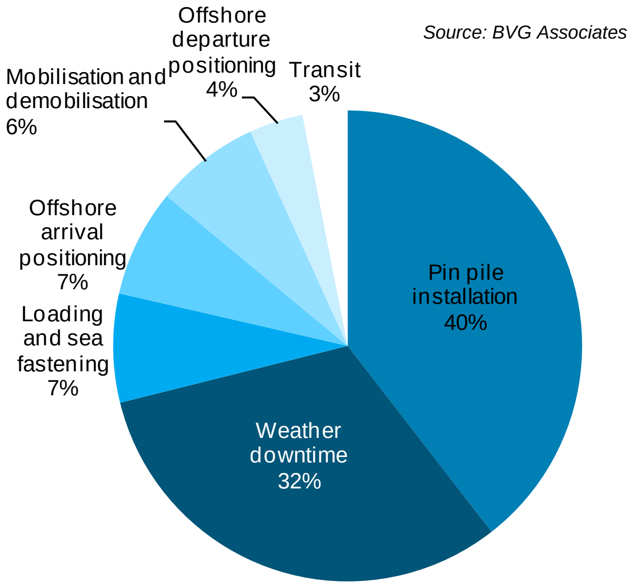

Figure 10.6 Modelled pin piling installation time (3.8 days per location average) breakdown for a 500MW project reaching FID in 2011 with 6MW-Class Turbines on Site Type A using a medium jack-up vessel. Weather downtime is based on all-year working with an operating Hs limit of 1.4m.

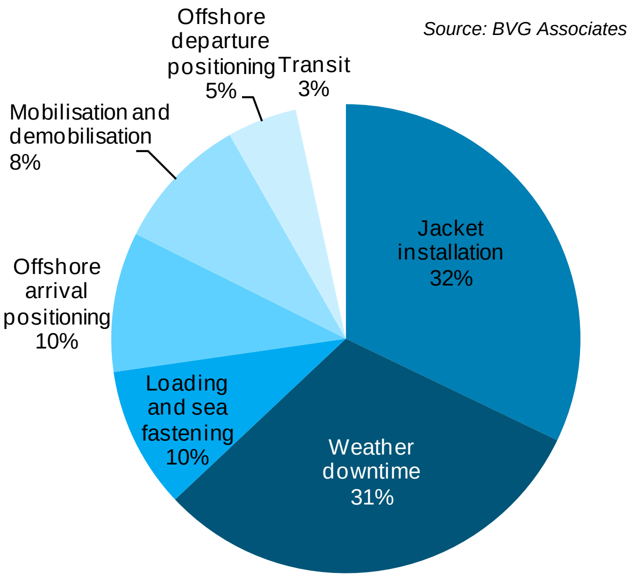

Figure 10.7 Modelled jacket installation time (2.9 days per location average) breakdown for a 500MW project reaching FID in 2011 with 6MW-Class Turbines on Site Type A using a large jack-up vessel. Weather downtime is based on all-year working with an operating Hs limit of 1.4m. Grouting is included within jacket installation.

It is anticipated that heavy lift, dynamic positioning (DP) installation vessels, variations of those currently in operation, such as the Jumbo Javelin and Jumbo Fairplayer (Jumbo Shipping) and the Stanislav Yudin and Oleg Strashnov (Seaway Heavy Lifting), will increasingly be used for foundation installation, with jack-up vessels reserved for turbine installation and OMS activities. The floating heavy lift vessels described above are typically over specified in terms of lifting capability for offshore wind requirements. For example, the Oleg Strashnov has a main crane with a 5,000t capacity. Although such vessels perform well, they are more expensive than jack-ups, currently costing approximately £220,000 a day. The semi-submersible vessel Thialf (Heerema Marine Contractors) was used to install the six jackets at Alpha Ventus, although this is likely to have been a still more expensive option. In the case of sheerleg cranes, they may have an operating Hs limit of about 0.5m which all but precludes their use in the winter months and for projects on Site Type D.[54] Pin piling and grouting can be undertaken using currently available small DP construction vessels, costing less than £50,000 a day.

For all piled solutions, the impact of high hammering noise levels on fish and sea mammals has been a consideration for consenting bodies, as it may interfere with basic survival functions such as finding food, migrating and mating. This is proving a constraint on the timing and cost of German projects in particular, but has also caused scheduling delays and complications for UK projects such as Gwynt y Môr. Piling blow rates are typically 15 to 60 per minute and, depending on the soil conditions, up to 5,000 blows are needed per pile. Noise levels increase with pile diameter and hence the shorter and smaller diameter pin piles used in securing jackets are generally less noisy to install than monopiles. Pin pile sizes are increasing and the 3.5m pin piles that will be used with the jackets at Nordsee Ost are approaching the diameter of the 4m monopiles used at Horns Rev in 2002.

For some projects, consenting authorities may impose limitations on piling noise and this may affect the time of year when piling can take place, for example, to reduce the impact on seasonal fish spawning, or be applied throughout the year. The current cost of noise mitigation is up to £150,000 per pile. The uncertainty surrounding the likely impact from limitations in piling on UK projects is such that it has not been included in baseline costs. Interviewees indicate that improvements in mitigating piling noise will be developed to reduce costs. Three methods of noise mitigation have been explored to date. An air bubble curtain (or multiple air curtains), produced in a ring around the base of the pile, reduces the propagation of the sound wave created when the hammer strikes the anvil. This was used at Alpha Ventus and has been tested at Nordsee Ost ahead of construction. The same principle is used with a pile sleeve or coffer dam, which creates an air gap between the pile and the water.[55] IHC

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[54] *Load Capacity Curve for 82m Mast,* Saldis Salvage and Marine Contractors, available at www.scaldis-smc.com/pdf/Rambiz-loadcapacity-curve.pdf, accessed May 2012.

[55] Rainer Matuschek and Klaus Betke, *Measurement of Construction Noise During Pile Driving of Offshore Research Platforms and Wind Farms,* Institut fur technische und angewandte Physik, (Rotterdam 2009), available at www.itap.de/daga09rmkb.pdf, accessed May 2012.

Hydrohammer has developed a noise mitigation screen, which is made out of two piles with an air gap between them. An alternative approach is using vibratory pile hammers which contain a system of rotating eccentric weights, powered by hydraulic motors. This method has not been applied to offshore wind so far. In addition, changes to pile design, such as having a bevelled pile toe (like the end of a syringe), can result in less energy being needed to drive the pile and therefore less noise.[56] The impact of innovations in noise mitigation is not modelled in this study because it is uncertain as to what constraints will be placed on projects in UK waters due to piling noise, but it is recognised by industry that over-conservative regulation could increase the cost of energy noticeably.

Suction bucket foundations have been used widely in the oil and gas industry. The benefits and challenges of their use are considered in Section 8. Again, their use offers a low-noise solution. Concrete gravity bases (CGBs) offer an alternative to monopiles and steel space frame structures that do not need piling or drilling and have different installation vessel requirements. The principle is that the mass of the structure is sufficient to provide stability against the impact of the wave, current and turbine aerodynamic and inertial loading. They are typically manufactured using post-stressed reinforced concrete, although steel designs that use iron ore as ballast have also been proposed. In some cases, preparation of the sea bed is required. This is normally with a levelled stone bed which can be as heavy as the support structure itself.[57] Once in situ, sand or water ballast is then pumped into the structure to provide additional mass if required.

Large concrete structures have been used widely in the oil and gas industry and for major offshore bridges. For offshore wind, they were also used in the first projects developed in Denmark in the Baltic Sea in the 1990s and at Middelgrunden (2000), Rødsand 1 (2003), Lillgrund (2007) and Rødsand 2 (2009). These projects were built on sites with water depths of 10m or less using turbines smaller than those currently being installed. The foundations had an average mass of approximately 1,000 tonnes[58] and were built on a batch basis in either a dry dock or on a barge. Units were then transported to site and lifted into position using a heavy lift crane best suited to the relatively calm conditions experienced in the Baltic. Though seen as a cost-effective solution, the specific designs used are not appropriate for scaling to North Sea water depths or larger turbines.

The Belgian Thornton Bank I wind farm is the only project to have used concrete CGBs in the North Sea so far, which were built at Ostend by MGB (part of the CFE Group). To support the six REpower 5MW turbines, each structure had a mass from 2,700 tonnes to 3,000 tonnes excluding ballast. Once complete, they were lifted into the water then transported to site and installed using the sheerleg crane Rambiz, a solution that was shown to be relatively expensive for that specific project.

Innovations

Although there is already significant experience in the installation of monopiles, interviewees expect that there is still scope for further **improvements in the installation process for monopiles** mainly through using well-specified floating DP vessels rather than jack-ups, as are used today. Today, typical day rates for existing medium floating DP construction vessels available to the offshore wind sector are higher than for large self-propelled jack-ups, at about £180,000 compared with about £150,000, mainly because these floating vessels are over-specified for monopile installation, but changing to a floating DP vessel would remove the significant amount of time currently taken up in jacking activity shown in Figure 10.5 and the process is potentially less sensitive to higher sea states. From dialogue with a range of existing installation contractors and their customers, on average it is anticipated that, for a 500MW project with 4MW-Class Turbines, a 20 per cent reduction in the average support structure installation time will be achieved by moving from jack-ups to floating vessels. This is based on a wide range of views and we recognise that those who are investing in new jack-up vessels intend to increase the efficiencies of their processes to match savings achieved by others through various innovations of their own. Innovations of this sort are anticipated by

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[56] Zohaib Saleem, *Alternatives and modifications of Monopile foundation or its installation technique for noise mitigation,* commissioned by the North Sea Foundation, May 2011, available at www.we-at-sea.org/docs/ecologicalReports/underWater/noise/Final%20Report%20alternatives%20and%20modifications%20of%20monopile%20foundation%20or%20its%20installation%20Zohaib%20Saleem.pdf, accessed May 2012.

[57] "The Gravity-Based Structure: Weight Matters", *Lorc Knowledge,* 14 March 2011, available at www.lorc.dk/lorc/kc_mapage164.aspx, accessed May 2012.

[58] M.Ragheb, *Offshore wind farms siting* (2011), available at https://netfiles.uiuc.edu/mragheb/www/NPRE%20475%20Wind%20Power%20Systems/Offshore%20Wind%20Farms%20Siting.pdf, accessed May 2012.

developers to reduce monopile support structure installation cost by up to two per cent, although some projects with FID in 2011 will already be benefiting from these changes.

It is anticipated that the well-specified floating DP vessels required will be a combination of vessels currently available to the market as well as some new build vessels and conversions primarily aimed at the jacket foundation installation market. Discussions during workshops indicates that such vessels are expected to be available to 60 per cent of projects reaching FID in 2014 and, for projects with FID in 2020, they are likely to account for 100 per cent of the monopile installation market, recognising that monopiles themselves will only be a small fraction of the market by then.

As discussed in Section 8, developers expect that steel space frames will become the dominant support structure technology in the market, peaking at approximately a 90 per cent share for projects reaching FID in 2017 before an anticipated gradual increase in the use of concrete solutions. Although a reasonable number of space frame structures have been installed offshore for the oil and gas sector, there is little industry experience in the series installation of a large number of similar structures and fabricators. Developers and installation contractors anticipate significant **improvements in the installation process for space-frames** over the next ten years compared with projects reaching FID in 2011. Industry indicates that there is scope for optimising the process through introducing a bespoke fleet of vessels, each optimised for a specific task, whether pin-piling, support structure installation or grouting. This could shorten the support structure installation process through the use of more efficient vessels, innovations in sea bed pile templates and parallel operations, as well as decrease the average day rate for vessels by not using over-specified vessels for less onerous tasks. Due to the specific geographical conditions and support structure designs of each project, workshop discussions considered how optimum solutions will vary and parallel use of vessels itself creates risk, through the knock-on effects of any delays on one part of the process causes more unutilised vessels elsewhere.

The key innovation will be new designs for the main foundation installation vessel. The next generation is anticipated to provide deck space for about six jackets for 6MW-Class Turbines as well as cranes with a lifting capacity matched to jacket mass and height and with sufficient outreach to enable safe installation. Such a vessel is likely to be a floating DP vessel about 250m long with a deck area of 6,500m².[59] By comparison, one of the largest offshore wind jack-ups expected to be available in 2014, Pacific Orca, will be 160m long and have a deck area of 4,300m². This may not be able to carry more than three jackets at a time. An important consideration in taking advantage of these next generation vessels is the sufficient availability of fabrication yards with deepwater quay facilities (up to 13m draft).

In modelling the impact of this innovation, based on detailed feedback from companies planning, managing and delivering installation services, we anticipate savings on all Turbine MW-Class and Site Type combinations, but the greater benefit will be seen in the installation of space frame foundations for larger turbines and harsher site types. Discussions with leading installation contractors at the workshops suggests that this innovation will be introduced to the market alongside optimised jacket foundations, which are expected to be available for projects with FID 2014. Based on the lead time for new vessel delivery and developers' acceptance to use vessels yet to be proven at the point of FID, it is realistic to expect such progress with the construction of new vessels commissioned by early 2013. Specialist new build vessels cost in the region of £100-200 million.

The amount of downtime caused and the risk introduced by weather makes a significant impact on the installation costs of support structures. Interviewees report that there is significant work underway to make **improvements to the range of working conditions for support structure installation** that will have a significant impact on cost by enabling greater working time, reducing vessel requirements, lowering risk to the developer and giving greater confidence in installation schedules.

Waiting on weather depends on the type of vessel selected and for jack-ups this can account for a third of the support structure installation cost, regardless of type. The working range of vessels is typically discussed in terms maximum operating significant wave height, although wave period, wind speed, tidal flow, and the predicted length of a working window also have a significant impact on operational decisions. Developers typically seek to install foundations all year round as the process is less sensitive to weather than turbine installation. Some developers advise that an approach of using vessels efficiently only in the summer months and allowing their use in other geographical markets and marine sectors at other times of year would be more cost effective, although this potentially increases the amount of mobilisation and demobilisation time and, with it, the vessel costs,

[59] *A2SEA News,* Autumn Edition, November 2011, available at www.a2sea.com/news.aspx, accessed May 2012.

The benefit of any such savings is not taken here. Forecasts of the total investment in vessels needed for offshore wind is dependent on such decisions.

The conclusion from workshop discussions is that increasing the average Hs working range from 1.4m to 2.5m represents a significant but achievable target, which would reduce weather downtime from approximately 34 per cent for Site Type B with 6MW-Class Turbines to about 20 per cent, and support structure installation costs by 20 per cent. Vessels designed for an Hs higher than 1.5m are likely to be large floating DP vessels of the type described above, as jack-ups are typically constrained by the conditions in which their legs can be lowered. Design features of a vessel that can operate in 2.5m Hs are station-keeping thrusters sufficiently powerful to maintain vessel position and a motion-compensated crane. An overriding issue for consideration in such designs will be personnel health and safety, and feedback from an experienced developer indicates that the cost to ensure a safe work environment for offshore workers is high. In defining the scope and impact of innovations, the intention has been at least to retain the existing level of safety risks. Although marine warranty surveyors, who act on behalf of the insurer, bring the experience, knowledge and expertise required to ensure safe installation, they are seen by some contractors as a potential limitation to improvement, being over-conservative in their assessments through the lack of application-specific knowledge and having little accountability or incentive to work together to reduce weather downtime while managing the risk of damage to components.

The innovation is relevant to all Site Types and Turbine MW-Classes, with the greatest benefit observed for Site Type D where higher sea states and wind speeds are expected and the long transit time narrows weather windows. The maximum operating range of vessels is only likely to increase incrementally and new designs will have a lead time of three to four years. This means there will be little improvement, beyond what is already commissioned, available to projects with FID in 2014, and it is thought unlikely that the full impact of this innovation will be achieved for projects reaching FID by 2020 because of these long lead times. Industry feedback suggests that there is likely to be strong demand from the market for such vessels, when available.

Dialogue with an EPC contractor and an experienced installation contractor indicates that the **greater use of feeder arrangements in the installation of support structures** can also reduce costs by maximising the efficiency of using expensive installation vessels by reducing the amount of time they spend in port and in transit, a view supported by dialogue in workshops. The amount of time that a mobilised installation vessel spends away from the construction site, excluding weather downtime, is approximately 16 per cent of installation time for a monopile on Site Type A, shown in Figure 10.5, and 12 per cent of installation time in the jacket scenario for Site Type A, shown in Figure 10.6 and Figure 10.7.

The offshore transfer of monopiles was first demonstrated on the Greater Gabbard project with monopiles shipped by cargo barge 120km from Vlissingen in the Netherlands to meet the installation vessel Stanislav Yudin at the site. Similarly, on the Ormonde project, barges carrying jacket support structures from the fabrication site at Methil met the sheerleg crane Rambiz stationed at the site. With this innovation, it is assumed that the foundations are lifted from the feeder vessel onto the deck of the crane vessel to create a buffer that will enable the installation vessel to continue operating while feeder vessels are in transit. A risk associated with this innovation is that a greater number of vessels will be inactive if there is a problem with one critical path activity and that the process introduces an additional weather-dependent offshore lift.

Feeder vessels typically have a similar operating range to the main installation vessel, but they do not require a crane. A typical day rate for such a vessels used to transport monopiles is estimated to be £30,000. This approach has not been used frequently for projects using monopiles so far, as most projects have been relatively close to shore and the transit time to port of the main installation vessel has been relatively short.

The innovation is relevant to all Turbine MW-Classes, and projects on Site Type D in particular will benefit as transit times form a larger proportion of the installation cost. Feeder vessels are unlikely to be used for Site Types A, B and C as the transit time from port is less than three hours. For a 500MW wind farm of 6MW-Class Turbines under the scenario in Figure 10.6 and Figure 10.7, the difference in transit times between 40km to 125km sites is such that, where no feeder vessel is used, the average unit installation time will differ by nine hours, which equates to a decrease in support structure installation cost of 5 per cent, taking into account the relative day rates of different vessels involved.

The full benefit of this innovation will be technically available by 2020 but the value of feeder arrangements to particular projects will also depend on factors other than Site Type, such as the location of manufacturing sites. The market uptake of this innovation is therefore unlikely to reach 100 per cent by 2020. The maximum potential impact is a 2.5 per cent reduction in whole project installation costs for projects on Site Type D with 6MW-Class Turbines.

Installation vessel mobilisation and demobilisation currently takes about 14 and seven days respectively and typically involve the fabrication of bespoke sea fastenings needed to secure components during transit. A leading installation contractor states that the vessel utilisation would be increased through the **introduction of flexible sea fastenings** that can be modified to handle both turbine and support structures and variations in size and design. For a 6MW-Class Turbine project on Site Type B, mobilisation and demobilisation makes up approximately eight per cent of turbine and support structure installation time. This innovation also applies to turbine installation and discussions with a specialist offshore consultant suggest that it could ultimately reduce the mobilisation and demobilisation period to five days and decrease installation costs by three per cent. The innovation only applies to conventional installation approaches using steel support structures.

There are no significant barriers to introducing this innovation and it is anticipated that the 60 per cent of the technical potential will be achieved by 2014. For the technical potential to reach 100 per cent, there needs to be certainty over the technologies being installed and their specifications and it is forecast that this will be the case by 2020. The design of new sea fastenings requires confidence that the vessels to which the sea fastenings are fixed will have a high level of use.

The market share of the innovation will therefore depend on the extent to which the vessels and the contractors are committed to the offshore wind market. It is anticipated that it will reach all the available market by 2017. A number of companies and consortia are proposing designs of concrete gravity bases targeted at sites of water depth 35m or greater, with sand, clay or rock sea bed conditions, and for projects using larger turbines. New concrete designs include buoyant and non-buoyant approaches. In both cases, suppliers have emphasised installation in an Hs of up to 3m, notwithstanding the health and safety risks of operating in such conditions, enabling them to transit and reduce weather downtime to less than 10 per cent even for projects in Site type D. Buoyant systems are installed separately from the turbine and are sunk with ballast, and are discussed here. Non-buoyant systems that require the use of a specialist transport and installation barge are being developed as part of float-out-and-sink concepts, and these are discussed below. The innovations associated with the design and fabrication of concrete gravity base foundations are presented in Section 8.3.

As well as avoiding the need for piling, the **introduction of buoyant concrete gravity base foundations** also removes the need for specialist vessels as these so-called “self-installing” designs can be towed to site using standard tugs. This approach is being taken by the Gravitas consortium, comprising Arup, HOCHTIEF and Costain, a consortium of Seatower and MT Højgaard, and the construction group Skanska. Some buoyant concrete technologies require specialist dredging and rock-lay vessels to prepare the sea bed. Dredging cannot be done too far in advance of installing the concrete gravity base because of the movement of the sea bed substrate. Concern is raised by some developers about the environmental impact of such activity, which is seen as more invasive than jacket installation.

Suppliers of CGBs advise that there are minimal maintenance requirements and the installation process can be reversed for decommissioning because the structure is not fixed to the sea bed. The whole structure can then be transported to a port facility for recycling. CGBs have the added benefit of not leaving piles embedded into the seabed. Decommissioning costs are expected to be in line with the costs associated with jacket structures, although an installation contractor reports that, in the oil and gas sector, recycling CGBs has been considered uneconomic and structures have been allowed to disintegrate on the sea bed, an option not available in the relatively shallow waters relevant to offshore wind.

Overall, according to a concrete gravity base supplier, the combination of avoiding the use of heavy lift crane barges and a wider installation weather window means it is expected there is a potential total installation CAPEX saving of 10 per cent. It is anticipated that 70 per cent of this potential will be available in 2017, at which point buoyant CGBs will hold 5 per cent of the market. In 2020, the technical potential will be 90 per cent and the technology will hold a 20 per cent market share on all Site Types other than A.

Other innovations

The innovations in this section have been limited by the support structure technologies considered in Section 8.3. While floating foundations could offer significant savings in installation costs, they are unlikely to be available to the market before FID 2020. Similarly, it is suggested that modular foundations supplied in sections, constructed offshore, could offer cost savings in installation but they are some way from commercial deployment.

Workshop discussions considered the benefits of changes in the sequencing of installation, perhaps with arrays of about a dozen turbines installed and grid connected in sub-phases. This would have the benefit of achieving earlier energy production and revenue. Most offshore wind farms have some degree of parallel installation with turbines energised in arrays and it was considered that the variability of projects and the uncertainty over the consequences on the flexibility and use of the installation fleet prevented robust modelling.

In Section 11.3, the impact of *improvements in weather forecasting* on wind farm OMS is considered. Any advances in this area will be useful during installation but, since the scheduling of the project is planned well in advance, the impact on costs is uncertain. The same is also true for turbine and array cable installation.

Early signs of progress and prerequisites

Jack-up vessels have typically been chartered from specialist offshore wind contractors such as MPI Offshore, Seajacks, and A2SEA, while floating DP vessels have usually been chartered from offshore contractors with heavy lift vessels that have been used in other sectors such as Visser and Smit, Scaldis Salvage and Marine Contractors, Ballast Nedam and Seaway Heavy Lifting.

Innovations in the installation of steel foundations require new investment in vessels, either new builds or modified existing floating DP vessels. At present, many of the new vessels being constructed for offshore wind installation are jack-ups and are primarily designed for turbine installation, although their operators will also target their use in installing support structures. Industry feedback is that relatively few conceptual vessel designs in development for the industry are primarily aimed at the steel support structure installation market. There are signs that the picture is changing with new concepts under development, of which those by NorWind and Teekay are notable examples. Greater interest from established wind industry players is likely to be important if the potential cost reductions in jacket installation in particular are to be achieved. A2SEA's collaboration with Teekay is a promising sign and they plan to design a floating DP support structure installation vessel to work in depths of up to 60m and an Hs of up to 3m. It is understood also that another established offshore wind installation contractor is developing a concept using twin floating installation vessels in tandem.

With significant potential for modifying existing vessels, the lead times for specialist floating DP vessels should be no more than three years, though one experienced offshore contactor suggested that, based on its experience, five years from concept design to offshore use is common. This is supported by recent experience at Sheringham Shoal in particular where Master Marine's new installation vessel was not completed in time for deployment. The recent investment in a number of bespoke vessels for the offshore wind industry, albeit mainly for turbine installation, is an extremely positive sign. Nevertheless, with so many new vessels in construction, there are significant project risks associated with contracting uncompleted vessels. A market leading installation contractor expressed concern at a workshop that the market was fragmented with new entrants to the market offering one, or perhaps two, vessels. Consolidation of the market would lower the risk for developers as contractors would have greater flexibility over the deployment of their fleets. The critical prerequisite to investment in new installation vessels is confidence in the European-wide market and, while vessel operators recognise that vessels cannot be well future-proofed, they will need some certainty over the future size and shape of the hardware that will be installed.

For concrete CGBs, suppliers indicate that there is a lead time of approximately three years to start commercial construction, including demonstrating the viability of the design and setting up a facility, although this in some cases will be dependent on obtaining consents for onshore works. This means it will be necessary for companies to have demonstrated successful deployment by 2015/6 in order to be ready for projects with FID 2017. There is a perception among developers that scaling up from a demonstration site to a 100 turbine project will be challenging due to the space needs and differences in logistics compared with better understood solutions and so a single demonstration will be insufficient for some concrete gravity base suppliers point out that projects of this scale have been delivered with similar technology in bridge construction, but it seems likely that developers will wish to see evidence that significant numbers can be installed efficiently.

The application of the Rochdale Envelope approach to consenting offshore wind farms allows developers a level of flexibility in the engineering envelope of designs which is submitted for development consent. While developers are keen to keep the envelope wide, and incorporate as many engineering solutions as possible, the flexibility allowable is limited. Currently there is a strong push from regulators to reduce the envelope as far as possible. Potential concrete gravity base manufacturers say that they believe this may be pushing developers to specify the type of foundation too early, and that this pressure from regulators may mean that developers are opting to limit their envelopes to steel designs, which are better understood and tested at this stage. Early indications are that developers are testing how much flexibility will be permitted. The role of marine warranty surveyors was raised by a number of industry players in constraining the timely delivery of projects. Evidence of emerging offshore wind industry specialists and increased accountability via insurers will indicate progress in this area.

Table 10.5 Potential and anticipated impact of innovations in support structure installation, for a wind farm on Site Type B using 6MW-Class Turbines, compared with projects with FID in 2011.

Innovation	Maximum technical potential impact				Anticipated Impact FID 2020			
	CAPEX	OPEX	AEP	LCOE	CAPEX	OPEX	AEP	LCOE
Improvements in range of working conditions for support structure installation	-2.5%	0%	0%	-1.7%	-1.4%	0%	0%	-1.0%
Improvements in the installation process for space frames	-1.5%	0%	0%	-1.0%	-0.9%	0%	0%	-0.7%
Introduction of flexible sea fastenings	-0.7%	0%	0%	-0.5%	-0.6%	0%	0%	-0.4%
Greater use of feeder arrangements in the installation of support structures	-0.6%	0%	0%	-0.4%	-0.3%	0%	0%	-0.2%
Introduction of buoyant concrete gravity base foundations	-3.8%	0%	0%	-2.7%	-0.2%	0%	0%	-0.2%
Improvements in the installation process for monopiles*	-0.25%	0%	0%	-0.2%	0%	0%	0%	0%
Total					-3.6%	0%	0%	-2.5%

* The anticipated change in the LCOE is zero because the Table shows the impact of the innovation of a 6MW-Class Turbine on Site Type B, for which a space frame foundation is assumed.

Turbine

Existing situation

Turbine installation on all existing commercial-scale projects to date has been undertaken with a jack-up. Although this report models the tower as part of the support structure, installing the turbine incorporates the tower installation, which reflects the current and likely future contractual basis of supply. In early projects, a number of general purpose jack-up barges and self-propelled jack-ups were employed. These vessels have typical day rates of £50,000 but are generally unable to operate in water depths greater than 25m and only have deck capacities for a small number of turbine component sets.

The MPI Resolution, which entered service in 2004, was the first jack-up vessel purpose-built for offshore wind and offers a large deck capacity that has been capable of carrying blades, nacelles and towers for up to nine Vestas V90-3.0MW turbines. It also has main and ancillary cranes. Interviewees anticipate that most projects that reached FID in 2011 will use turbine installation vessels purpose-built for offshore wind. This is based on investment in a number of new build vessels, all of which are jack-ups, and which are becoming available to projects. Some of these will be available to the market in 2012, such as Pacific Orca by Swire Blue Ocean, MPI Discovery and MPI Adventure, and Friedrich Ernestine by RWE Innogy. These typically have deck capacities for six or more 6MW-Class Turbines, can operate in water depths up to 45m, and have cranes with lifting capacities over 750 tonnes. Interviewees indicate that the value of increasing turbine carrying capacity is only relevant up to approximately 10 turbines, at which point the increased vessel cost outweighs the benefit of less transiting time to re-load.

Maximum transit speeds for purpose-built self-propelled jack-ups are typically 12 knots, although transit at this speed does have a significant impact on fuel costs. A medium-sized jack-up vessel steaming at 12 knots uses approximately 50 tonnes of fuel per day, with a current cost of approximately £25,000. This is halved when steaming at 10 knots.

For turbine installation, developers state that there is an operational balance to be achieved between assembling as much as possible onshore and having fewer but more complex offshore operations, and continuing with offshore operations but with simpler lifts. At one extreme is the whole turbine transfer concept, which has only been implemented on the two-turbine Beatrice demonstrator project. At the other end of the spectrum, the tower sections, nacelle and individual blades are carried out and assembled individually piece by piece onto the foundation. The current practice, which has been assumed in the baseline, is for the installation vessel to carry sets of turbine components with individual blades, the hub preassembled on the nacelle, and the tower, pre-assembled into one lift. To date, however, three variations in the rotor installation process have been used repeatedly:

- Placing the nacelle on the tower then lifting the pre-assembled rotor in one piece to mate with the nacelle (a single rotor lift)
- Mounting the hub and two blades on the nacelle "bunny ears" at port, before mounting the nacelle on the tower onsite and then fitting the final blade, and
- Placing the nacelle plus hub on the tower then lifting individual blades to mate with the hub, turning the rotor each time so as to repeat the same lift three times.

The third strategy been favoured by Siemens and Vestas for recent projects as the offshore lists are less complex. REpower to date has preferred the single rotor lift at Ormonde and at Thornton Bank 1 and 2.

Tower sections are typically preassembled onshore with any internal components and the completed structure is transported vertically to site. For the foreseeable future, offshore turbine installation will be undertaken by jack-up vessels because of the stability required for 100m height lifts.

Installation contractors say that they consider the turbine installation to already be largely optimised and this is evidenced by the similarity in the specification of new turbine installation vessels. Figure 10.8 shows the time breakdown for installing turbines on a 500MW project using 6MW-Class Turbines on Site Type A with an average installation time per turbine of 2.5 days including mobilisation and demobilisation, waiting on weather, loading and transiting (see Table 10.4 for definitions). For a project on Site Type D, transit times increase to six per cent of installation time and the percentage of weather downtime also increases, with the result that the average installation time is 2.9 days.

Turbine commissioning covers all activities after all the components of the wind turbine are installed, and mechanical and electrical completion work is complete. The work involves teams of about 10 technicians carrying out inspections, energising turbine subsystems then setting the turbine to work, often initially with a reduced operating envelope during a "running in" period.[60] For each offshore turbine, the commissioning work currently takes up to 50 full-time equivalent days including weather downtime. The final takeover after full commissioning of a project may not be completed for many months after the last turbine is installed. Access to the turbine for commissioning is currently by small workboat and this can be a significant cost with charter day rates of approximately £1,500 a day. Commissioning is usually covered within the turbine supply contact and, according to data from a forthcoming North Sea project and an offshore wind turbine manufacturer, represents about two to three per cent of total turbine CAPEX.

[60] "Walney 1 Offshore Wind Farm in Full Operation (UK)" *Offshorewind.biz,* 21 June 2011, available at www.offshorewind.biz/2011/06/21/walney-1-offshore-wind-farm-in-full-operation-uk/, accessed May 2012.

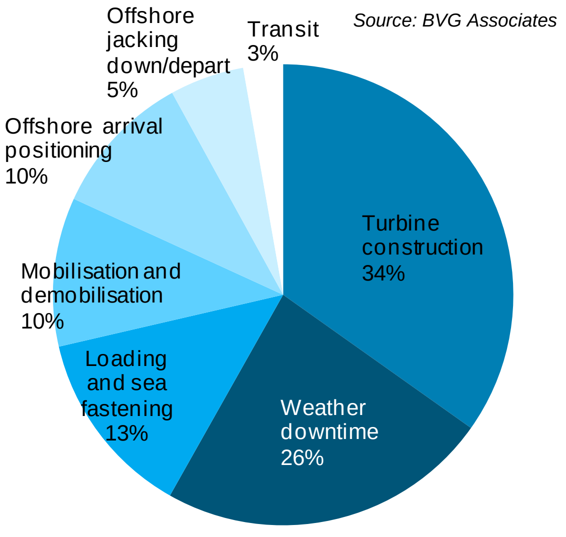

Figure 10.8 Modelled time turbine installation time (average time per turbine 2.5 days) breakdown for a 500MW reaching FID in 2011 project with 6MW-Class Turbines on Site Type A, using a large jack-up vessel.

Project developers have usually sought to secure port space as near as possible to the wind farm for turbine installation. Particularly for east coast projects, a lack of suitable facilities has forced developers to adopt alternative approaches. These have included using interim storage facilities for turbines outside the UK and transferring turbines to the installation vessel using barges within the sheltered water of a harbour, such as at Harwich for Greater Gabbard, or using a Continental construction port, thus increasing steaming times significantly but avoiding the double-handling of delicate components.

A constraint during installation is the acceleration limits defined by the turbine manufacturer to avoid invalidating warranties. Workshop discussions revealed that turbine manufacturers are perceived as being too cautious in defining acceleration limits, typically in the region of 0.5g, on the basis that these are defined by convention rather than evidence. An accelerometer on vessels could provide quantitative information on conditions for turbine installation and enable more objective decisions to be made on the decision to wait on weather.

Innovations

Turbine installation vessels are subject to similar weather restrictions as support structure installation vessels, such as wave height and periodicity, and tidal flow. In addition, there are also more restrictive wind speed constraints, especially relating to blade lifts. Discussions at workshops revealed that there are important cost reductions available through **improvements to the range of lifting conditions for blades**. Should the significant wave height be within the vessel jacking up limit, wind speed becomes the constraint on installation activities. For this reason, there is potential for innovations that can extend the range of lifting conditions in addition to extensions in the operability due to the sea state. Industry believes that targeting innovations to increase the maximum wind speed for blade lifts from 8m/s to 12m/s at hub height is realistic.

Interviewees report that the single rotor lift procedure is preferred by the Health and Safety Executive (HSE) because it minimises the number of offshore lifts. It is also favoured by some developers as it has the potential to reduce construction timescales. In contrast, interviewees stated that this technique is generally not favoured by installers, who prefer multiple lifts of single blades that are relatively straightforward rather than a single complex lift which is more sensitive to weather delays. As blade lengths increase, the offshore transportation of complete rotors becomes increasingly impractical due to the sheer size of a complete rotor when it is laid horizontally on the deck of a vessel. For example, the blades would overhang the vessel significantly in transit, which would prevent the use of some ports for construction. For this reason, interviewees say it is likely that this method will cease to be used with the next generation of larger offshore turbines. A number of methods of increasing the wind speed for blade lift are being investigated. One involves the blade still hanging from the crane hook, but supported in a frame with a hydraulic assembly to allow the blade to be rotated remotely to the preferred orientation, the position of the blade also being constrained by a series of remotely controlled ropes. An alternative solution involves the introduction of a lifting tool with a four-part attachment: two tag lines from the crane and a third running from a bracket fixed to the tower enables the blade position to be controlled in wind speeds up to 13m/s regardless of direction. Another approach could involve the rigid support of the blade so that at no point is its position influenced by wind loading.

The impact of such innovations will increase for larger rotors and in sites with greater wind speeds. For these reasons, projects located on Site Type D would benefit the most as it has the highest average wind speed and the narrowest weather windows due to its distance from shore. The innovation has the potential to reduce weather downtime by 35 per cent, leading to a seven per cent reduction in cost. Workshop discussions suggest that there will be significant market demand for such solutions when they become available, recognising also that they can be trialled on land and initially with smaller turbines. It is expected that the innovation will achieve 90 per cent of its potential technical impact by 2020 and will be rapidly adopted by the market.

As with support structure installation, interviewees report that savings can also be made through the **introduction of feeder arrangements in the installation of turbines**. As with support structure installation, such an innovation has the potential to maximise the value of expensive installation vessels by reducing the amount of time spent in transit, but here the challenges of the offshore transfer of more delicate components are greater. The benefit of a feeder arrangement is dependent on the transit time to the wind farm site from port; the heave compensation qualities of the heavy lift crane; the deck area of the installation vessel; and the relative cost of the feeder and installation vessels.

As Figure 10.8 shows, transit time comprises only three per cent of turbine installation time for projects in Site Type A. This is similar for projects on site types B and C and rises to six per cent for projects on Site Type D. A leading installation contractor suggests that vessels with higher transit speeds are unlikely to be cost-effective but that the use of feeder vessels could have a positive impact.

Whereas for support structure installation it is possible to use floating DP feeder vessels that have relatively low day rates of about £30,000, existing technology means a turbine feeder solution would probably require a second jack-up, albeit one without a crane. This is because the offshore transfer of turbine components from a floating vessel to a jack-up vessel is challenging because of the differential movements of the vessels. This challenge increases with poor weather and sea states and the sensitivity of turbine hardware to accelerations experienced during transfer operations. A feeder jack-up vessel would have a higher day rate of approximately £60,000 to £80,000 which would mean that this solution is only likely to be CAPEX-neutral in the short term as the cost saved in keeping the installation vessel on site is spent on the feeder vessel.

A variant of this approach being developed by an experienced offshore construction company is to use a jack-up barge stationed at the wind farm for the duration of the installation campaign for the final turbine assembly, with a floating DP vessel used for offshore transit of components and installation.

Floating feeder vessels cost significantly less and therefore should result in a benefit if technical innovations mean that the transfer from such a floating vessel to the jack-up installation vessel is practical. Inwind has designed a jack-up installation vessel with one static crane for construction and one heave compensated crane for transferring turbine components from a floating supply vessel. BargeMaster is also developing a motion compensated platform transferring turbine components. These concepts are still in development and a key challenge will be to obtain industry acceptance that they are safe for both components and personnel. Once developed, they will be most relevant to projects in Site Type D where longer transit times and shorter weather windows would make a feeder solution most cost-effective. Interviewees agree that the innovation could have a potential impact of five per cent on turbine installation cost and that 100 per cent of this technical benefit will be available for projects reaching FID in 2020. This innovation will be adopted selectively by the market as it may not prove cost-effective on all projects but is anticipated to have a significant market share for Site Type D projects.

Based on data from a forthcoming North Sea project and a offshore turbine manufacturer, turbine commissioning is two to three per cent of turbine cost and, while some electrical completion can only be done offshore, it is anticipated that the total commissioning time can be reduced by up to 30 per cent by installation teams completing as much work onshore as possible. **Greater levels of onshore turbine commissioning** is made possible through innovations in turbine design that allow “plug-and-play” installation through more advanced testing work carried out during turbine manufacture. An example of this approach is the Siemens SWT-6.0-154 in which the entire electrical system, including the medium voltage system and the full converter, is enclosed in the nacelle. Pre-commissioning testing can be achieved onshore faster and more safely than offshore. Other turbine manufacturers have also implemented additional dockside pre-commissioning, such as Vestas for the recent Belwind project and AREVA at its new test facilities in Bremerhaven. The innovation is relevant to all turbine and site combinations although its impact will be greatest for projects on Site Type D where weather downtime during commissioning is likely to be the highest. In such a case, total turbine CAPEX (including commissioning costs) could be reduced by up to 0.5 per cent. This innovation is already being incorporated into next generation 6MW offshore wind turbines, which it is anticipated will incorporate 80 per cent of the technical potential. It is likely to have a market share of approximately 40 per cent in 2014, rising to 70 per cent in 2020. It will not become higher than this as the innovation is anticipated to be superseded by the *introduction of whole turbine installation* and *introduction of float-out-and-sink installation of turbine and support structure* discussed below.

The underlying principle of minimising offshore turbine installation and commissioning was articulated by many in workshops as a key way to reduce the installation cost. It can be more fully applied by the **introduction of whole turbine installation.** This is where the complete turbine, including the tower, is assembled on land, then transported and lifted into place on the foundation. This reduces the number of offshore lifts as well as avoiding much of the offshore commissioning process. This approach has only been implemented for the Beatrice demonstrator project in 2005, where two 5MW turbines were installed using a sheerleg crane onto pre-installed jacket support structures. The project suffered from significant weather delays due to the narrow operating range of the vessel used and the approach has not been repeated in Europe. In 2009, Sinovel's 3MW turbines at the Shanghai East Sea Bridge 100MW wind farm were installed using a sheerleg crane with the whole turbine floated out vertically on a barge. New concepts are in development. A solution by Huisman involves a bespoke DP small water plane area twin hull (SWATH) vessel with motion-compensating systems. IHC Handling Systems and Daewoo Shipbuilding and Marine Engineering plan to use a self-propelled jack-up vessel, which would carry a number of fully installed turbines, while an Ulstein concept in development employs a floating DP vessel. These specialist vessels generally have carrying capacities lower than conventional turbine installation vessels so that, proportionally, more time would be spent in transit than would be anticipated for conventional offshore turbine construction.

Participants at workshops say that the impact of disruptive technologies such as these are more difficult to assess compared with incremental innovations, because of the number of uncertainties that are involved.

Whole turbine installation has a number of significant challenges. According to a leading offshore turbine manufacturer, onshore turbine construction would require a larger port area than the existing approach and this would increase turbine CAPEX. It is also likely that that the quayside area needed to store complete turbines could slow the rate of installation, A further issue raised by an EPC contractor is that assembling the turbines onshore would require a large and expensive crane and it would be necessary to obtain an additional planning permission as the installed height of the turbines is likely to be outside most port operational permitted limits.

The innovation is relevant to all turbine and site combinations but it is less attractive for Site Type D where the distance to site would make the process more weather sensitive. The potential impact of whole turbine installation is a six per cent reduction in total wind farm installation CAPEX. Although seen as a likely eventual installation method by many, it is unlikely that it will be available to the market in time for projects with FID before 2017 and it is anticipated that market uptake will be no higher than 20 per cent in 2020.

The concept of installing structures that have been assembled onshore could be developed the furthest by the **introduction of float-out-and-sink installation of turbine and support structure** in which the complete structure is assembled at the quayside and floated out using tugs, with or without a dedicated installation vessel. The approach can be applied to concrete gravity base foundations or steel structures with a suction bucket sea bed connection. Both are being supported by the Carbon Trust Offshore Wind Accelerator.

The concept is most commonly associated with non-buoyant CGBs such as those proposed by the Austrian construction group Strabag and the Anglo-French GBF construction group VINCI Construction (in conjunction with the consortium composed of Gifford, BMT Nigel Gee and Freyssinet). Both have designed a bespoke TIB which will be re-usable on projects for a given envelope of support structure designs. The concept has the advantage of fewer offshore lifts than the whole turbine installation alone and has similar challenges to the *introduction of whole turbine installation* described above. Key advantages and disadvantages of the concrete elements are discussed under the *introduction of buoyant concrete gravity bases*, above, and in Section 8.3.

SPT Offshore is developing a float-out-and-sink solution for a tri-bucket steel space frame, which can be installed off a standard flat top cargo barge.[61] For a discussion of suction buckets, see also Section 8.3.4.

The innovation is relevant to all Turbine MW-Class and Site Type combinations but it is a little less attractive for Site Type D because only a single turbine/support structure is installed at a time and a larger proportion of installation time is spent in transit as towing speed is likely to be about half that of a conventional installation jack-up vessel.

[61] *SIP 3 / SIWT®,* SPT Offshore, available at www.sptoffshore.com/bin/ibp.jsp?ibpDispWhat=zone&ibpPage=S8_FocusPage&ibpZone=S8_SIPIIIb&ibpDisplay=view&, accessed May 2012.

The potential impact of the float-out-and-sink concept is a 25 per cent reduction in total wind farm installation cost, primarily through eliminating offshore lifts. It will also benefit from the savings of at least the magnitude available from *greater levels of onshore commissioning* described above. Suppliers indicate that float-out-and-sink solutions will be available to the market for a project achieving FID in 2017, subject to securing a demonstration site, as discussed below, and it is anticipated that market uptake will be 10 per cent in 2020.

Other innovations

Some innovative offshore turbine designs have incorporated ideas on reduced installation costs. For example, the Vertiwind project incorporates a variant of the float-out-and-sink approach using floating foundations. As with other vertical axis designs, it is likely that it will be first deployed commercially in UK waters on projects with FID after 2020 (see Section 7.3).

Discussions at a workshop considered installation strategies in which the tower is installed with the foundation. This is considered to be feasible but unlikely to yield significant savings. Also discussed was decoupling nacelle installation from blade installation, recognising that blade installation is more weather sensitive. This approach enabled blade installation to be undertaken during periods with lower wind speeds. This has not been modelled as improvements to the range of lifting conditions for turbine blades are likely to make such an innovation obsolete.

Early signs of progress and prerequisites

Feedback from several players is that some options are being developed to increase the range of conditions under which blades can be lifted offshore. Indeed, it is reported that one solution is being deployed at a wind farm currently under construction. Other early signs would be onshore trials.

As with support structure installation, contractors say that marine warranty surveyors are a potential obstacle to developments. Signs of further progress in this area will be developers seeking alternative approaches to assurance and/or engagement by developers and installation contractors to develop a consistent and risk-based approach by marine warranty surveyors. This will be seen in the promotion of new concepts in industry forums and could be facilitated by specific industry stakeholders.

The developers of float-out-and-sink and whole turbine installation concepts face many of the obstacles discussed above in relation to introducing buoyant concrete CGBs. Developers wish to see evidence not only that the concept itself is proven but also that it can be reliably applied to a large wind farm.

Signs of progress will be if float-out-and-sink concept developers can secure access to demonstration sites. The VINCI-GBF consortium is currently exploring the opportunities for test locations at the Aberdeen Demonstrator site and Nordsee Ost. Strabag has constructed an onshore prototype at Cuxhaven and secured a stake in the consented 79 turbine Albatros I wind farm, which it plans to use as a test facility for 10 gravity-base foundations. This project is scheduled for construction in 2015. Another indication will be that developers are looking to retain flexibility within their planning applications, particularly those with rocky sea beds where CGBs have a more clearly defined advantage over established steel foundations.

A particular challenge for float-out-and-sink systems is that the purpose-built installation vessel is required for the full-scale demonstration stage, putting a particularly high cost on this early stage.

Concerning the acceleration limits imposed by turbine manufacturers, relaxed requirements will need to be established through testing and careful analysis, in collaboration with turbine manufacturers. Turbine manufacturers will also need to find a way of maintaining lubrication to key bearings, for example, to prevent damage during shipment. This may involve maintaining bearing movement, requiring some energisation of turbine systems and additional functional control options, which are all possible. Feedback from interviewees is that significant investment in cranes and additional working permits would also be required in order to undertake efficiently the high lifts that are needed at ports, while avoiding weather delays.

A prerequisite for innovations in turbine installation is market confidence. The innovations described in this section are highly specific to offshore wind and investors in new technologies will need to see a significant pipeline of projects for the remainder of the decade.

Table 10.6 Potential and anticipated impact of innovations in turbine installation, for a wind farm on Site Type B using 6MW-Class Turbines, compared with FID 2011.

Innovation	Maximum technical potential impact				Anticipated Impact FID 2020			
	CAPEX	OPEX	AEP	LCOE	CAPEX	OPEX	AEP	LCOE
Introduction of float-out-and-sink installation of turbine and support structure	-7.7%	0%	0%	-5.4%	-0.5%	0%	0%	-0.3%
Introduction of feeder arrangements in the installation of turbines	-0.6%	0%	0%	-0.4%	-0.3%	0%	0%	-0.2%
Improvements in range of lifting conditions for blades	-0.4%	0%	0%	-0.3%	-0.2%	0%	0%	-0.1%
Introduction of whole turbine installation	-1.6%	0%	0%	-1.1%	-0.2%	0%	0%	-0.1%
Greater levels of onshore turbine commissioning	-0.1%	0%	0%	-0.08%	-0.08%	0%	0%	-0.05%
Total					-1.1%	0%	0%	-0.8%

10.3.2. Array cables

Existing situation

Cable installation has long been an area of concern for the industry due to the number of problems that have been encountered, and developers cite the lack of credible suppliers as the greatest source of problems. Array cable laying is considered a more technically challenging process than export cable-laying due to the large number of operations that are involved and the cable pull-in interface at each foundation. There is scope for innovation as contractors do not consider pull-in to have evolved significantly from oil and gas umbilical laying or telecoms cable installation, even though it is of more importance due to the high number of cable pull-in operations per wind farm. Installation contractors indicate that it is common for cable installation to overrun, often taking a third longer than planned as a result of unforeseen problems being encountered. The Technology work stream considers contracted costs, and the additional costs incurred through delays and overruns are considered in the *Supply chain work stream report*.

It is often quoted that there have been a large number of insurance claims associated with array cable-laying.[62] Remedial work has often been necessary after wind farm operations have begun. The high project risks have also led to financial difficulties for cable installers, with CNS Subsea, Oceanteam, Submarine Cable and Pipe, and Subocean either withdrawing from the market at different times or having been acquired by larger players. Until recently, most contractors have been relatively small companies compared with the major offshore contractors and lack the resources to invest in new technology development. This is changing with the involvement of companies such as Technip, Van Oord, and Visser and Smit, and the acquisition of the majority shareholding of CT Offshore by DONG Energy. Most of the cable manufacturers have cable-laying capability but have tended not to offer this to the wind industry. Collaborations between installers and manufacturers have tended to be inhibited due to issues of risk allocation in case of cable damage. One developer reported that it had plans to charter the vessels and hire personnel to do the work in house in order to maximise applying learning from one project to the next, from now on.

[62] Per Wiggo Richardsen, *An insurance perspective on offshore wind projects* Interview with Murray Haynes, DNV, 22 November 2011, available at www.dnv.com/industry/energy/publications/updates/wind_energy/2011/windenergy_3_2011/aninsuranceperspectiveonoffshorewindprojects.asp, accessed May 2012.

For most UK sites, array cable installation can be undertaken using either a single lay and burial process with a plough or a separate surface lay with subsequent burial, using a jetting tool operated from an ROV. Cable installation contractors say that both approaches have their advantages, depending on the site conditions. The single ploughing process reduces the number of vessels required while the two stage process makes better use of weather windows. This is because the burial and survey process can take place when personnel access to the foundation is not possible because of weather conditions. The actual laying process for ploughing takes about three times longer than surface lay, when the manoeuvring of the plough is considered.

Both anchored barges and specialist DP vessels have been used for offshore wind projects to date. The latter are more costly, with day rates of about £95,000 compared with £65,000, but they have shorter mobilisation and demobilisation time. Furthermore, cable-laying companies report that anchored barges are considered unsuitable for working on Round 3 sites due to their slower transit times, lower freeboard (the height of the deck above the water level), lack of manoeuvrability, the time needed to shift anchors during the laying process and the increased distances to sheltered water.

The time breakdown for a typical surface and separate burial and survey approach is shown in Figure 10.9 and Figure 10.10 for an April to September installation for a wind farm using 4MW-Class Turbines on Site Type A. Here, the average installation time per turbine is three days, including mobilisation, weather downtime and transit. The distance from port only has a marginal effect on installation costs as the vessels will make fewer port visits (once every 30 days, weather permitting) than for support structure and turbine installation. Weather downtime is higher for a project on Site Type D than it would be for projects on other Site Types.

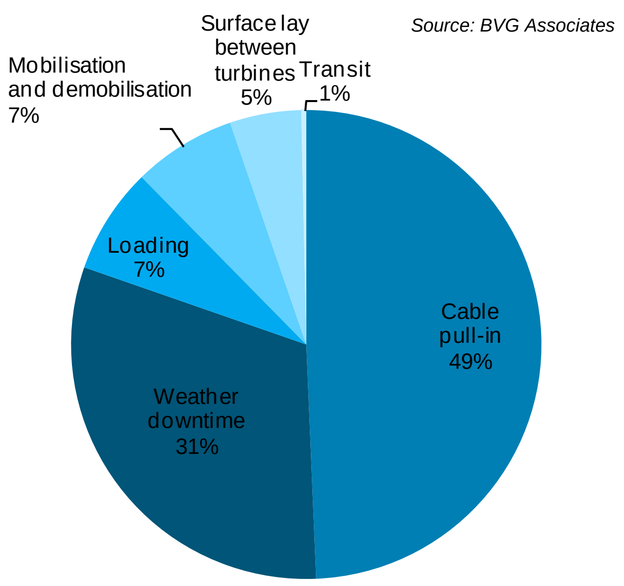

Figure 10.9 Modelled time breakdown for array cable installation surface lay (1.6 days per cable link average) for a 4MW-Class Turbine at Site Type A, assuming installation from April to September.

Source: BVG Associates

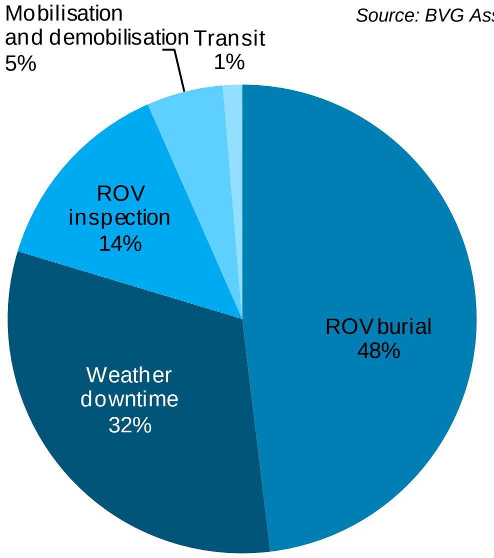

Figure 10.10 Modelled time breakdown for array cable installation burial and survey (1.4 days per cable link average) for a 4MW-Class Turbine at Site Type A, assuming installation from April to September.

As shown in Figure 10.9, the cable pull-in for both ends of the cable forms about one-quarter of the total cable installation time using the separate surface lay and burial and survey approach. As the current requirement is to transfer personnel to the foundation to support the cable pull-in, this process often must be undertaken in lower sea states than the operating limit of the installation vessel for other activities. As a result, the season for cable installation is reduced to April to September.

Cables can be supplied by the manufacturer as a single length or a number of lengths of up to approximately 4km and cut to size as required on the vessel in the specific lengths required for each link. Installers report a preference for a single length as this is quicker to load, offers greater flexibility in the sequencing of cable laying and, if testing forms part of the scope of the contractor, greatly reduces the number of tests needed at the quayside.

Innovations

Cable installation vessels used in offshore wind projects are currently shared with the oil and gas, telecoms and power interconnector markets. Interviewees report that **greater levels of optimised cable installation vessels and tooling** for the offshore wind market could contribute to significant reductions in cable installation CAPEX.

A leading cable installation contractor reports that few of the vessels available for cable installation are fit for purpose. The maximum stowage on a carousel at the cable manufacturers is approximately 7,000 tonnes, which would require a turntable requirement of about 28m to 30m in diameter and therefore a vessel beam of about 30m to 32m. This is not a standard vessel size and therefore requires bespoke design. Many of the vessels used for UK projects, especially those with shallow water, have been barges and many of the limited number of cable installation vessels that have been used for offshore wind array cables are less than 100m long. Features of an optimised array cable installation vessel include a minimum clear working deck length of approximately 20m to 25m aft of the turntable and tensioner to allow for the cable protection system deployment along with advances in onboard ergonomics and equipment capabilities.

A barrier to progress is that contractors are more likely to invest in multi-purpose vessels with layouts not ideal for offshore wind that could work in other sectors if required. For example, while subsea array cable diameters are about 100mm, depending on the current-carrying capacity and amount of armour protection, submarine oil and gas pipes can reach 1,500mm in diameter and submarine telecommunications cables have 17-50 mm diameter depending on armour. The layouts and tooling for laying each of these are different.

Discussions during workshops indicate that the potential technical impact of this innovation on the total installation costs is about one per cent and this is relevant to all Turbine MW-Class and Site Type combinations. It is anticipated that 50 per cent of this technical potential will be available to projects reaching FID in 2014, as new vessels are still designed to serve other markets, but this will rise to 90 per cent in 2020 as the growing market justifies investment in purpose built offshore wind array cable-laying vessels. By 2020 these vessels are expected to have a 100 per cent market share.

While cable installation has typically been scheduled between March and October, there is a benefit in laying cables all year round. For a 500MW wind farm, current installation rates for surface lay and survey and burial are approximately two and a half to three days per cable, so there is an expectation for a wind farm with 83 6MW-Class Turbines that cable installation will take about 270 days. There is therefore a high risk that any delays push the work into periods where there is a higher expectation of weather downtime. Turbine installation routinely is undertaken after array cable installation and the sensitivity of this work to adverse weather conditions, and in particular high wind speeds, makes summer working preferable. There is therefore an advantage in being able to schedule array cable installation over the winter to enable an early start for turbine installation in the spring. This has been achieved at London Array: cable installation was conducted throughout the winter of 2011/12, enabling the turbine installation to begin in February 2012, although there are reports that the work did suffer from weather delays.[63]

An Hs of 1.4m is currently generally considered to be the upper limit for safe multiple personnel transfer using current technology and it currently limits the conditions in which cable installation can be undertaken. **Improvements to the range of cable installation working conditions** are largely dependent on developments in access systems and this will enable fewer weather delays and shorter installation programmes. Increasing the upper Hs limit of 1.8m will generally decrease the days lost to weather by 15 per cent and the total cable installation time by eight per cent. The technical potential of this innovation thus is a two per cent reduction in installation costs.

While this reduction is significant, it is likely that developments are likely to be driven by the requirement for *improvements in personnel access from transfer vessel to turbine*, which is discussed further in Section 11.3.3. Here it is anticipated that 80 per cent of the technical potential will be available by FID 2020 and that 90 per cent of the market for all Turbine MW-Class and Site Type combinations will have adopted improvements by then.

The weather sensitivity of the pull-in process can be reduced through the **introduction of optimised cable pull-in and hang-off processes**. These include modifications of the processes by which the cable is pulled through the J-tube, which are solutions not requiring personnel access and more radical turbine-cable connections. A blind cable pull with appropriate cable protection is considered feasible by at least one cable installer. With appropriate bend restrictions and cable seals and a stab/locking system, the cable can be pulled through and left for a subsequent installation team to complete the cable termination off the critical path of the installation vessel, decreasing the sensitivity to weather and making better use of the expensive vessel. One challenge in implementing is in ensuring the early interface between the cable and support structure design teams and dialogue with installation contractors (including the support structure fabricators, cable manufacturers and installation contractor) to ensure that overall project costs are minimised. Based on the various methodologies discussed, this innovation could reduce the time spent at the support structure interface on average by 20 per cent, leading to a six per cent reduction in cable installation time and hence a 1.5 per cent reduction in total installation costs.

The introduction of a wet mate connection at the bottom of the structure or a dry mate connection away from the support structure at the end of a pre-installed tail would remove the need for any joining operation on the support structure. The required connector technology is being developed but present offerings to the market are typically up to 15kV for dry mate connectors and 10kV for wet mate connectors. This is less that the 33kV required but dialogue at workshops indicates that connectors could be developed relatively quickly and hence may offer further savings based on on-land installation of the cable on each foundation.

By removing the most weather-sensitive process from the cable installation, that is, personnel access to the support structure, feedback from a contractor is that there is an opportunity to introduce vessels and cable-handling equipment that will operate in an Hs of 2.5m. These exist in the oil and gas sector but they have not yet been applied to the offshore wind industry. Should these be used in array cable laying, there is an expectation among cable installers that this increase from an operational limit of 1.4 Hs would enable a decrease in March to October downtime of 20 per cent and a decrease for all-year working of 30 per cent. Installing cables in higher sea states would have an impact on cable design to withstand the higher mechanical loads and, while this may have an impact on manufacturing costs, it has not been modelled here.

New cable installation processes will be available to the market in 2014 and are relevant to all Turbine MW-Classes and Site Types. New connector technologies will not be available before 2017 FID but, if proven, there is likely to be significant market demand.

[63] "Cable Installation at London Array Faces Delay (UK)", *Offshorewind.biz,* 11 January 2012, available at www.offshorewind.biz/2012/01/11/cable-installation-at-london-array-faces-delay-uk/, accessed May 2012.

Improvements in array cable standards and client specification will have a small impact on cable-laying through a reduced weight and size of cable. These are discussed in Section 9.

The burial requirements for array cables are typically to 1.5m below the sea floor. Interviewees report that there is concern across the industry that the requirement is arbitrary and is based neither on the site conditions nor the risk of cable damage. The *introduction of reduced cable burial depth requirements* is considered as part of wind farm development in Section 5 and, for some sites, has a significant effect on cable installation costs. Cable layers report that developers are typically inflexible on burial depths until project delays force a rethink.

Other innovations

A developer suggests that a significant cost saving in cable installation could be achieved if no burial was required, particularly for rocky sea beds. For such an innovation an exclusion zone would need to be enforced and even if this were successful, this is likely to be considered too high a risk for insurers and investors. There would also be additional environmental considerations.

Early signs of progress and prerequisites

Cable installers say that cable installation has to date been given much less attention than turbine and support structure installation. Evidence of progress will be greater collaboration or integration between cable installers and developers, such as the acquisition of the majority shareholding of CT Offshore by DONG Energy, and framework agreements which would enable contractors to develop innovative and optimised solutions with a lower risk. ABB has signed a cooperation agreement with Canyon Offshore for trenching services to support export cable installation projects and similar agreements in the array cable market would be a positive sign of progress.

There is evidence that issues are being addressed collectively by industry. In 2011, DNV, along with industry stakeholders, initiated a JIP to gain a better understanding of the causes of subsea cable issues and develop guidance to effectively manage the risks. This was done with a view to developing an internationally acceptable design standard for offshore renewable cable connections. Publication is expected in late 2012. The Carbon Trust held an Offshore Wind Accelerator Cable Installation Study Workshop in August 2011, which explored many of the issues described above. In addition, commercial events focussed solely on offshore wind subsea cable and cable installation issues have now been established.

A number of cable installers have investment plans for bespoke cable-laying vessels. Evidence of future cost savings will come from commitments to those investments, which are likely to follow long-term relationships. As with other areas of installation, confidence in the market is important. Cable installation vessels have the potential to be used in other sectors and, while multi-sector vessels may be less optimised for offshore wind use, the risks of investment in them will be lower.

Cable installation contractors report that the tendering process leaves them little opportunity to develop a new methodology for a given project that will offer cost reductions. Framework agreements will also enable new solutions to be developed. An obstacle to new pull-in processes is the issue of contractual liability. Immediate connection and testing allows installers to prove it has installed correctly without damage and transfers liability to the customer earlier in the event of subsequent damage to the cable.

In addition, an early sign will be that innovative approaches by cable installers are being viewed favourably by the market with a declining number of contracts being awarded using outdated technology.

Table 10.7 Potential and anticipated impact of innovations in array cable installation, for a wind farm on Site Type B using 6MW-Class Turbines, compared with FID 2011.

Innovation	Maximum technical potential impact				Anticipated impact FID 2020			
	CAPEX	OPEX	AEP	LCOE	CAPEX	OPEX	AEP	LCOE
Introduction of optimised cable pull-in and hang-off processes	-0.5%	0%	0%	-0.4%	-0.4%	0%	0%	-0.3%
Improvements in range of cable installation working conditions	-0.5%	0%	0%	-0.4%	-0.4%	0%	0%	-0.25%
Greater levels of optimised cable installation vessels and tooling	-0.25%	0%	0%	-0.2%	-0.2%	0%	0%	-0.2%
Total					-1.0%	0%	0%	-0.7%

11. Innovations in wind farm operation, maintenance and service

11.1. Overview

Innovations in OMS have the potential to reduce the forecast LCOE at point of FID by 1.5 to two per cent between a wind farm reaching FID 2011 and another using the same Turbine MW-Class on the same Site Type reaching FID in 2020. This is achieved through a decrease in OPEX of between 2.5 and five per cent, depending on Site Type and an increase in AEP of approximately 0.8 per cent, with a minor penalty on CAPEX to implement more advanced condition monitoring systems.

This reduction comes mainly through the introduction of more holistic condition-based maintenance (CBM) and improvements to personnel access, especially from transfer vessel to turbine. This is in addition to the reduction in OPEX realised through innovations in capital elements of the wind farm, such as, for example, through more reliable drive trains. Figure 11.1 shows that the innovations in OMS have an approximately equal impact on all Turbine MW-Classes. The impact of all innovations on OPEX and the LCOE increases noticeably for Site Type D. Site Type D has the highest average wind speed, thus maximum operating time and fatigue duty on components, hence increasing the likelihood of failures and the benefit of improvements in addressing potential and actual failures. In addition, being furthest from port and in conditions not yet experienced in offshore wind, both the importance of improved processes and the opportunity to introduce innovations to reduce cost are greatest.

There are relatively few barriers to the development of OMS innovations, compared with other elements. The largest investments relate to the introduction of new mother ships for OMS far from shore. Although the development of concepts is at risk, there is time for new vessels to be constructed post FID and each project installed offers at least a 20 year market for such innovations. Elsewhere, innovations in inventory management and weather forecasting apply beyond offshore wind and there has been an appetite from both investors and innovators to progress condition monitoring and access solutions even at a point where relatively few wind turbines have been installed offshore and uncertainty about market development. A key prerequisite for the introduction of CBM based on new condition monitoring systems is the availability of data and turbines to enable the performance of condition monitoring systems to be demonstrated fully.

The impact of innovations documented here is the conservative forecast impact on the LCOE at the time of asset owner's FID. This reflects feedback from asset owners on their approach to budgeting OMS costs at FID. This approach is consistent with other elements, where the impact of innovations on contract values at FID are considered. It is recognised that actual contract prices for OMS in later years may be different; indeed it is anticipated that they will be lower due to the impact of innovations that the developer cannot take benefit of at FID because of their immaturity at that time.

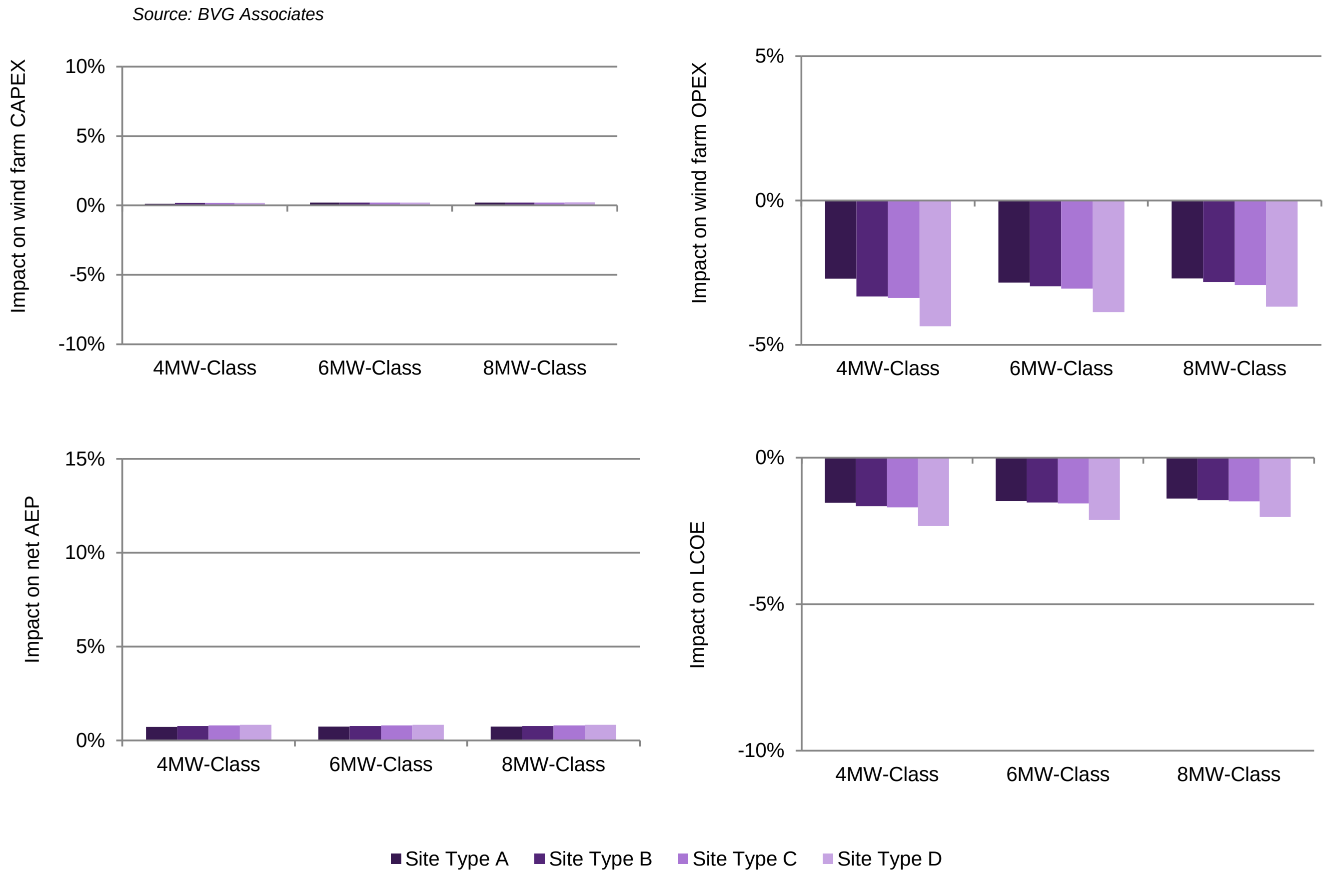

Figure 11.1 Anticipated impact of operations and maintenance innovations by Site Type and Turbine MW-Class, compared with FID 2011.[7]

The anticipated reduction in the LCOE from a wind farm using 4MW-Class Turbines on Site Type B in 2011 to a wind farm using 6MW-Class Turbines on Site Type B in 2020 is 1.7 per cent. Figure 11.2 shows that two key innovations in OMS dominate, the *introduction of turbine condition-based maintenance*, with an anticipated impact 0.6 per cent, and *improvements in personnel access from vessel to turbine*, with a similar impact. Most the innovations considered in this section are expected to achieve most of their technical potential by FID in 2020. It is noted that, for Site Type D, the impact of *improvements in OMS strategy for far-from-shore wind farms* approximately matches these top two innovations.

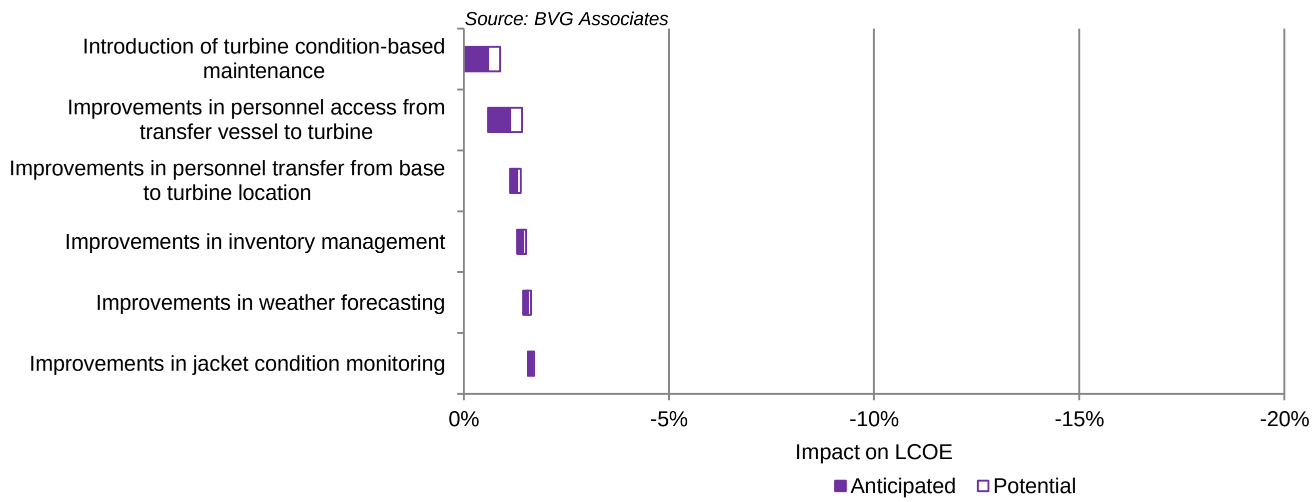

Figure 11.2 Anticipated and potential impact of operations and maintenance innovations for a wind farm using 6MW-Class Turbines on Site Type B in 2020, compared with a wind farm using 4MW-Class Turbines with FID in 2011.[7]

11.2. Baseline

For the purposes of cost modelling, the OMS expenditure for an offshore wind farm has been divided into the sub-elements described in Table 11.1. It excludes transmission costs derived in *The Crown Estate Offshore Wind Pathways report* and operations phase insurance derived in the *Finance work stream report*. Lease fees payable to The Crown Estate are discussed in *The Crown Estate Offshore Wind Pathways report*. The cost of a five-year warranty is included within the baseline costs presented in Sections 6 to 9.

The OMS expenditure is taken to be a conservative forecast by the wind farm asset owner at the point of FID, taking into account the following:

- Operational experience on own and others' wind farms, up to FID, normally with other turbine types
- Forecast impact of new turbine type, for example, increased Turbine MW-Class, and
- Forecast implementation of innovations not yet in commercial use but expected to be by the WCD.

Actual OMS spend is likely to vary over the operational life of a given wind farm due to the introduction of new innovations, including those at a pre-commercial stage at FID. As an example, for a project that starts operating in 2014 (after FID in 2011), it is likely that enhanced crew transfer vessels will be introduced at some point during its life. The wind farm may operate for half of its life before benefiting from an innovation that reduce OMS cost by four per cent. In this case, average OMS costs would be reduced by two per cent. Only the impact of innovations that are well understood and may be implemented before or relatively soon well after completion of construction work are incorporated in this forecast, in line with industry behaviour.

Table 11.1 Definition of OMS sub-elements.

Sub-element	Description
Operation and planned maintenance	Starts once first turbine is commissioned, including: • Operational costs relating to the day-to-day control of the wind farm • Planned preventative maintenance and health and safety inspections • Condition monitoring • Costs of rental of operations base, port facility, mother ship and crew transfer vessels.
Unplanned service	Starts once first turbine is commissioned, including: • Proactive service in response to predicted failures in the turbine or balance of plant by use of CBM systems and related tools. The turbine downtime is only related to the duration of the repair activity • Reactive service in response to unexpected systems failure in the turbine or balance of plant. Intervention is only undertaken to resolve a fault which results in shutdown of turbine. The turbine downtime includes time waiting for mobilization of equipment and personnel and for spare parts as well as the related repair time, and • Includes the costs of any additional vessels required to repair the fault.
Other	Fixed cost elements that are unaffected by technology innovations, including: • Contributions to community funds, and • Monitoring of the local environmental impact of the wind farm.

For the baseline wind farms, it is assumed that, for Site Types A, B and C, the operational base will be a local port and technicians are taken to site using crew transfer vessels. To access the turbine, the vessel is driven bow on against the turbine support structure and held in place by the thrust from the engines, allowing the technician to step over the bow and onto the personnel ladder on the support structure. It is assumed that such an operation can be safely carried out under conditions with an Hs 1.4m.

One experienced offshore wind turbine manufacturer indicates that, beyond 60km from port, the additional time and cost of transit is such that it becomes more cost-effective to have a ship permanently stationed at the wind farm with spares, tooling and crew on board, transferred from the ship either directly or using daughter crew transfer vessels. For projects with FID in 2011, it is assumed that this ship will be a hotel ship. See Table 11.3 for more information.

It is assumed that the number of wind turbine faults which lead to failures (and hence OMS budget) increases with average wind speeds (hence with Site Type from A to D) as the turbines build up more operational hours running at higher power. In addition, increased average wind speeds lead to greater weather downtime. Compared with Site Type A, OMS budgets at Site Types B, C and D are three, six and 20 per cent higher respectively, based on industry dialogue, then verified in workshops. It is recognised, however, that, as discussed in Section 4, there is no experience yet in operating wind farms in conditions represented by Site Type D.

Feedback from industry is that there is generally an expectation that, in time, as turbine size increases, the costs of the operation and planned maintenance and the unplanned service will reduce per megawatt installed, but not as much as in proportion to the number of turbines installed on a given wind farm.

The resultant baseline OMS budgets for each Turbine MW-Class and Site Type are shown in Table 11.2. These were formulated during interviews based on models of wind farm OMS costs, tested using real data from wind farms in operation in 2011, and verified during workshops. The shape of spend over the wind farm life is discussed below, including in Figure 11.5.

Table 11.2 Baseline average annual budgets for OMS expenditure for year six onwards for projects with FID 2011.

Turbine Class	Sub-element	Wind farm annual OMS budget (£k/MW)			
		Site Type A	Site Type B	Site Type C	Site Type D
4MW	Operation and planned maintenance	26	27	28	31
	Unplanned service	53	55	57	64
	Other	2	2	2	3
	Total	**82**	**84**	**86**	**98**
6MW	Operation and planned maintenance	21	22	23	26
	Unplanned service	44	45	46	53
	Other	2	2	2	2
	Total	**67**	**69**	**71**	**80**
8MW	Operation and planned maintenance	20	20	21	24
	Unplanned service	41	42	43	49
	Other	2	2	2	2
	Total	**62**	**64**	**65**	**74**

Figure 11.3 reflects data supplied by wind farm operators and shows the contribution to downtime by subsystem for operating wind farms in 2011. This has been used, along with related material costs and consideration of the contribution of downtime using data from the EU-funded Reliawind R&D project to estimate the OMS expenditure for operating wind farms by subsystem in 2011, as shown in Figure 11.4.[64]

[64] Michael Wilkinson, *Measuring Wind Turbine Reliability: Results of the Reliawind project,* GL Garrad Hassan, available at www.gl-garradhassan.com/assets/downloads/Measuring_Wind_Turbine_Reliability_-_Results_of_the_Reliawind_Project.pdf, accessed May 2012. It should be noted that this report refers to data from onshore turbines.

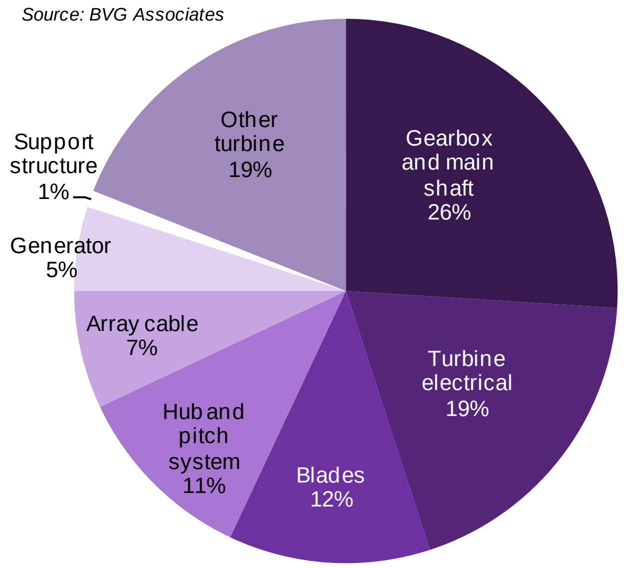

Figure 11.3 Typical downtime contribution by wind farm subsystem for wind farms operating in 2011, assuming 300 hours downtime per turbine a year.

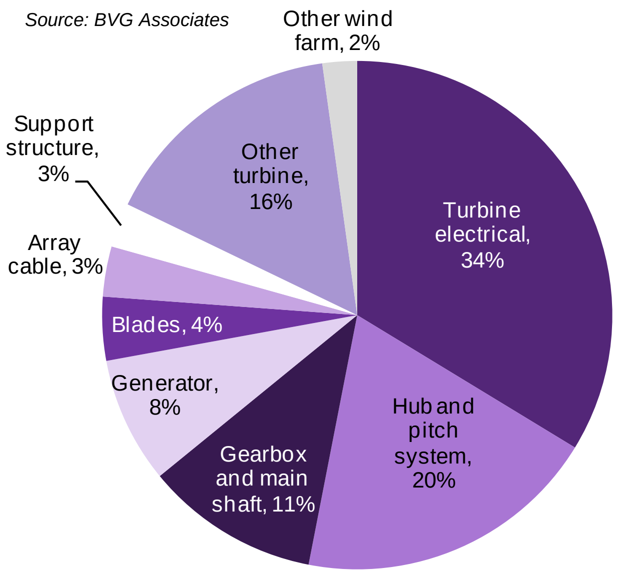

Figure 11.4 Typical OMS baseline breakdown of a £74k/MW/year budget by wind farm subsystem for wind farms operating in 2011.

By accounting for the share of costs of each subsystem, including lead time, costs of materials, equipment, travel time, weather downtime and repair time, we have derived the impact of innovations in Sections 5 to 9 on planned maintenance and unplanned service activities. These budgets, based on 3MW turbines, were scaled and used as input data to the overall model.

The breakdown of OMS expenditure varies though the operating life of the wind farm. The solid bars in Figure 11.5 show the trend used in the project model. The model assumes a 20 year operational life, with the first five years covered by a service and warranty contract provided by the turbine manufacturer. Feedback from two experienced asset owners, which was then verified by others, indicates a spend profile as shown by the dashed line. There are two key differences between the profile assumed in the model and the feedback from asset owners:

- Asset owners assume an annual increase in OMS expenditure is about 1.5 per cent a year through the lifetime of the wind farm. This reflects inflation, supply chain effects such as changing competition and changes in the failure rate of turbines and balance of plant. The project model assumes fixed OPEX throughout the life of a given wind farm and inflation and supply chain effects are not modelled in consideration of technology-only impacts, in line with the rest of this report.

- Estimates provided by asset owners, shown as a dashed line in Figure 11.5, incorporate supply chain spend during the nominal five year warranty period not paid by the asset owner. The actual spend by the asset owner during this period is less than in year six. Most of this difference equates to the wind turbine manufacturer's warranty provision fee. Some owners advise a bathtub-shaped curve, with high early spend, while others advise a flatter spend during the warranty period, with a peak about year three. The indicative range is shown in Figure 11.5. Typically, during warranty, an average fee of about £50,000 per megawatt per year is paid to the wind turbine manufacturer as a service charge for OMS support. During the warranty, this service charge does not accurately reflect the total cost to the turbine manufacturer. The cost paid by the asset owner is reduced by 25 to 30 per cent, thus reducing the total cost to the OMS owner by approximately 15 per cent. This is possible because the asset owner has already purchased the extended warranty as part of the capital phase of the project.

It is noted that, for a project with FID in 2011, feedback reported that the ratio of operation and planned maintenance and proactive service to reactive service is assumed to move from 40:60 in year six to 70:30 in year 20. It is likely that this trend will change for projects with later FIDs, but little clarity was available. Some operators advise planned significant maintenance (retrofit) activities in, for example, year 10. Others advise of earlier or later campaigns. Due to the variability of views, no such peaks are modelled.

Industry feedback is that an average through-life availability of 95 per cent is realistic for projects reaching FID in 2011, and that this is likely to have an inverse bathtub-shaped curve, while others anticipate a flatter early curve. The shape is likely also to be a function of the maturity of technology used. For the purposes of modelling, a uniform (average) availability is assumed throughout each project.

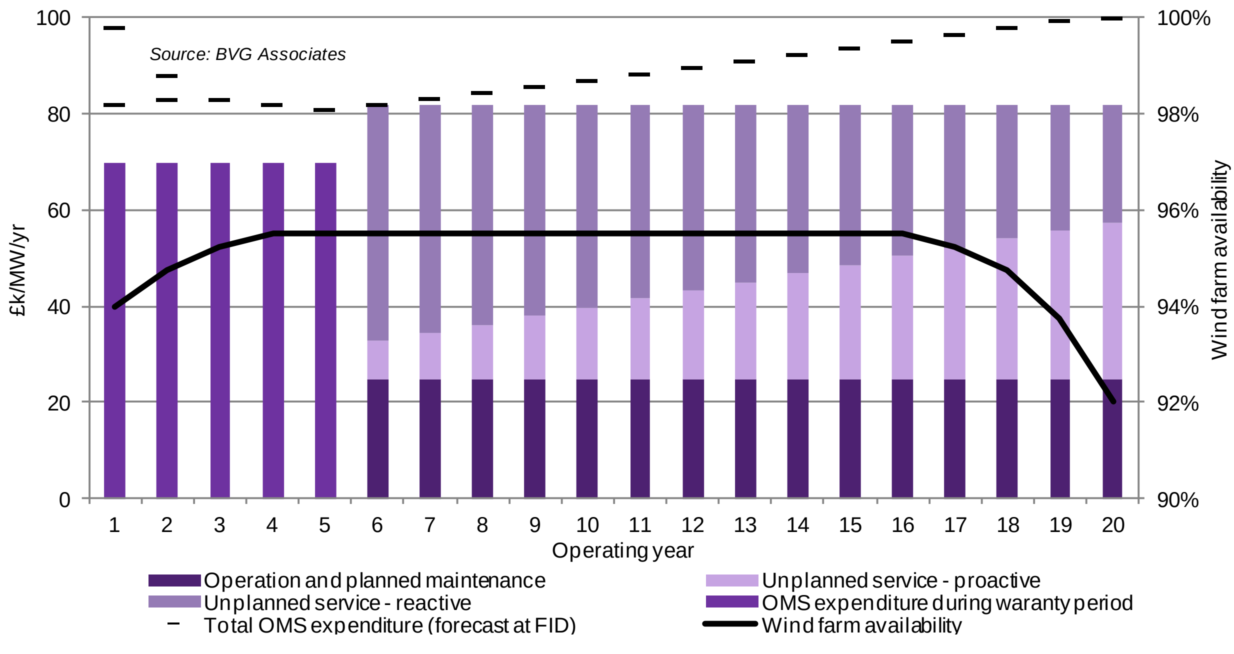

Figure 11.5 Baseline OMS spend and availability over wind farm lifetime for a 4MW-Class Turbine on Site Type B. In early years, an indicative range is shown by two markers.

Described in Table 11.3 is a range of dedicated OMS vessels types that have been considered as part of the baseline scenarios and in the innovations described later in this section. For other elements of unplanned service, such as blade replacement, jack-up vessels are used that are similar to those used for installation (see Table 10.1). As larger turbines are installed in deeper water, many of the medium jack-up vessels used for installation of turbines in Rounds 1 and 2 will increasingly be used for OMS activities for these larger turbines.

Table 11.3 Typical vessels considered for support of OMS. Vessel day rates include fuel and crew but not technicians.

Vessel type	Length (m)	Technicians on board (exc. crew)	Indicative spot day rate (£k)	Features
Crew transfer vessel	18-22	12	2	Carries technicians on daily trips, including basic spares and equipment up to two tonnes
Enhanced crew transfer vessel	28-32	24	3	Carries technicians on daily trips in greater comfort Carries more spares, including spares and equipment in small containers (20 foot and 10 tonnes), and may have small workshop
Turbine support vessel	40-50	50	10	Accommodate up to 50 technicians for up to two weeks Good standard of passenger and crew comfort Comprehensive stores and small workshops Fitted with DP and crew transfer systems
Hotel ship	100-200	100	25	Accommodation and stores May have a helideck
Mother ship	100-200	100	40	Accommodates up to 100 technicians and 35 crew for several weeks Good standard of passenger and crew comfort Comprehensive stores and workshops. Fitted with wet dock or cranes to support small transfer vessels and a helideck Fitted with DP and crew transfer system

A hotel ship will typically be a car ferry or similar vessel with existing accommodation for use by technicians, space for equipment and spares storage. Small transfer vessels used with the hotel ship may still transit to shore base, or be hoisted and secured on the deck of the hotel ship, for shelter in severe weather.

Typically a mother ship will be a new vessel custom designed for wind farm support, and may be supplied complete with associated small transfer vessels. These are not currently available and so the baseline wind farms on Site Type D use a hotel ship or an accommodation platform.

11.3. Innovations

For the purposes of this report, innovations that affect OMS have been categorised as predominantly affecting the planning and execution of offshore activity, whether planned, proactive or reactive; condition monitoring of wind farm components; and personnel access to the wind farm and turbines (see Table 6.2). There are no incompatible combinations of innovations.

Table 11.4 OMS innovation groupings used in this analysis.

Grouping	Innovations
Planning and execution of offshore activity	Improvements in inventory management Improvements in OMS strategy for far-from-shore wind farms Improvements in weather forecasting
Condition monitoring	Introduction of turbine condition-based maintenance Improvements in jacket condition monitoring
Personnel transfer	Improvements in personnel access from transfer vessel to turbine Improvements in personnel transfer from base to turbines

11.3.1. Planning and execution of offshore activity

Existing situation

The wind industry now has more than 20 years of experience operating wind farms offshore although, for much of this time, projects have been relatively small and located close to shore. For this reason, OMS strategies have not been very different to those for onshore wind farms.

Projects have generally been operated from a land base in a port less than 60km from the wind farm. From this operational centre, technicians monitor and control the operation of the turbines using a supervisory control and data acquisition (SCADA) computer system. Visits to the turbine to undertake planned maintenance or unplanned service activities are arranged by the operations team. Unplanned service may require the mobilisation of external resources such as a jack-up vessels or specialist engineers.

During the warranty period (generally five years), it is usual for the turbine manufacturer to lead the OMS activities for the turbines at least. Its local team will be supported by back office engineers located at a central support facility, who provide specialist diagnostic support. For example, condition monitoring engineers will use data to predict the remaining life of gearboxes and define when any repairs or replacements should be initiated. The scope of work covered by the turbine manufacturer staff during the warranty period varies between contracts, however, typically a periodic service charge will cover planned maintenance and unplanned service that does not require specialist vessels or heavy equipment. The cost of waiting time as a result of weather conditions or due to the unavailability of vessels or equipment is typically borne by the asset owner. Unplanned service that occurs during the warranty period that requires hiring specialist vessels and replacing major components, such as a generator, is paid for by the turbine manufacturer from provisions made in its warranty budget. To reduce costs, operators will endeavour to identify works in advance, such as generator or blade replacement, that require the use of a jack-up crane vessel, This vessel will then be hired for a period every six months in order to carry out a programme of work. To date, on smaller projects, this has been demonstrated to be cost-effective compared with a “fix-on-fail” strategy, which involves hiring a vessel short-term at spot rates when required. During the warranty period, the wind farm owner will normally provide staff to work alongside those of the turbine manufacturer, subject to the project-specific agreements. Under any changes of responsibility, maintenance staff can be transferred between companies under TUPE agreements. Owner’s staff costs have been included in the operation and planned maintenance element of the cost model.

Port facilities include a quay or pontoon for personnel transfer vessels, office and administration, workshop and stores for small components up to two tonnes. For large Round 3 zones, or where asset owners collaborate to minimise costs on wind farms using the same turbine models, some large spares such as gearboxes or blades may also be stored at the port or held by the turbine manufacturer as bonded stock.

Currently, access to the turbine from a crew transfer vessel typically can take place with an Hs of up to 1.4m depending on the direction of swell, wind speed, tidal current and precipitation. The decision regarding conditions for safe transfer is left with the master of the crew transfer vessel.

Weather-related inefficiencies are a significant burden to OMS budgets. One asset owner reports that the average technician time spent waiting on weather during each year can be 40 per cent. In addition, further technician working time can be lost as a result of transit conditions, making it difficult or unsafe to work for a period after arrival at a turbine.

Experienced asset owners say that, on a typical site operating now, the majority of the day-to-day operational costs are the result of unplanned reactive visits to turbines as shown in Figure 11.6. Of the unplanned visits, about half the costs relate to visits using large vessels such as jack-ups as shown in Figure 11.7.

Source: BVG Associates

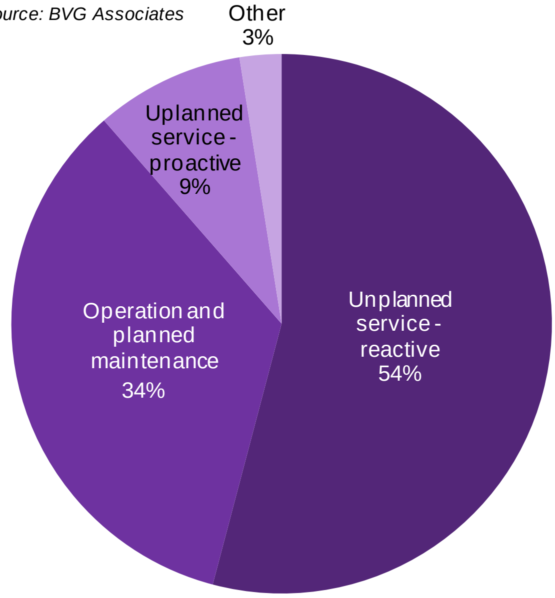

Figure 11.6 Baseline annual average OMS expenditure broken down by sub-element for a wind farm using 4MW-Class Turbine on Site Type B, with FID in 2011 (total spend £84k/MW, see Table 11.2).

Source: BVG Associates

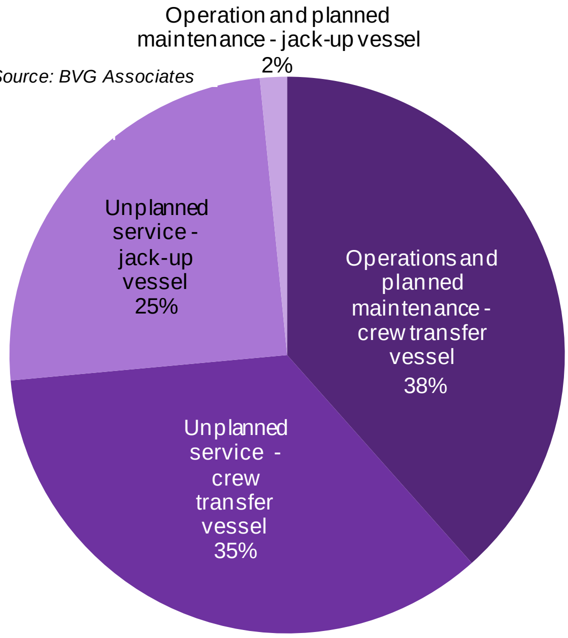

Figure 11.7 Baseline annual average OMS expenditure broken down by activity involving a given vessel for a wind farm using 4MW-Class Turbine on Site Type B with FID in 2011 (total spend £84k/MW as for Figure 11.6, see Table 11.2).

Most planned maintenance of turbines can be undertaken using a crew transfer vessel that takes personnel and equipment to the work site. Even some large components such as the generator and transformer can be replaced with the nacelle crane in some turbines, using a barge but without the need for jack-up crane vessel. Where a crane vessel is required, for example, to replace a gearbox or nacelle, some asset owners advise an existing strategy of hiring such a vessel for a period every six months in order to carry out a programme of work on a number of turbines rather than a “fix-on-fail strategy” involving hiring a vessel short-term at spot rates when required.

There are few far-from-shore wind farms operating and the current options are to use hotel vessels, which are typically converted ferries, and provide offshore accommodation and some storage and workshop facilities, or an accommodation platform, such as that used by Vattenfall for Horns Rev II and planned for the Dan Tysk wind farm, which begins construction in

2012. The Dan Tysk platform will have accommodation for 40 technicians and platform crew members and, as for Horns Rev II, it will be built close to the offshore substation with an interconnecting bridge.

In more established industries, such as the aerospace and automotive sectors, a ratio of 60 per cent unplanned maintenance in the first five years of operation would be considered unacceptable and interviewees say that the industry is already working to address this challenge.

Innovations

Much of the progress in planning and executing offshore activity relates to improvements in efficiency and better ways of doing the same task, and as such are discussed in the *Supply Chain work stream report*. Innovations that improve the reliability of wind farm components and the impact of such improvements are covered in Sections 6 to 10.

The operation of projects further from shore will demand the development of OMS strategies with a permanently stationed offshore base. Interviewees agree that there will be **improvements in the OMS strategy for far-from-shore wind farms.** This will be achieved through introducing bespoke offshore wind operations mother ships supported by two or more daughter vessels, combined with new processes to maximise the efficiency of the vessels and personnel.

A mother ship is likely to be a floating DP vessel 100m to 180m in length with features including a dry and sheltered wet dock, a helideck, cranes for loading to and from crew transfer vessels, a turbine access system, accommodation for up to 150 technicians as well as extensive catering and recreational facilities, and office space, storage and workshop areas. The vessel is likely to be supported by two or more enhanced crew transfer vessels. As personnel transfer systems are improved, and Health and Safety systems developed, they will operate a strategy which delivers OMS 24 hours a day, seven days a week, which would significantly reduce turbine downtime. New processes will maximise the efficiency of the OMS fleet gained through the transfer of skills and experience from other offshore sectors.

For the purposes of this study, the innovation applies only to Site Type D though, in time, it may become clear that similar strategies are applicable on sites with conditions represented by Site Types A to C, but where distance from suitable land base exceeds 60km.

The technical impact of this innovation is anticipated to be a five per cent reduction in both operational and planned maintenance OPEX and unplanned service OPEX. This innovation is only relevant to projects on Site Type D. About 80 per cent of the full benefit of this innovation is anticipated to be available for wind farms reaching FID in 2020, once mother ship functionality and cost has been optimised using experience gained on early projects. Almost universal market uptake on far-from-shore sites is assumed.

Based on the highly sophisticated systems used in some sectors, interviewees say there is scope for significant **improvements in inventory management**. This enables more accurate tracking of turbine parts, spares, consumables and tooling to ensure that the correct spares and equipment are on hand when required. By some, this is regarded as a key part of improving operational efficiency and maximising availability. A sophisticated system will keep records of part numbers and variants including serial numbers of key components, and build a history of spares usage, tracking the timescales required for replacements. Implementing the resulting spares strategy will also take into account the cost of the component, the maintenance requirements for components that are held in storage, the cost of transporting components and the locations and lead times for production, in order to plan whether components are held locally at a land base, on a mother ship, on a transfer vessel or in a central storage area. As technology being installed offshore is still young, different wind farms will have different releases of a given nacelle with different versions of subcomponents. In many cases, all interfaces, both physical and electrical, are identical, but in some cases there is not full compatibility. In this case, it is critical to know the version of the spare required and there are many examples of crews wasting visits and significantly increasing downtime by not having the right spares.

Many supply issues that relate to wind turbine operation have synergies with other more developed industries, where specialist systems track failure rates and optimise the supply chain and logistics of spare parts. For example, the civil aerospace industry has both high downtime costs and strict safety and quality requirements. Support services must be able to forecast customer demand on a wide geographical scale and be able to deliver specific components and tooling to meet short time windows. Standby power generation specialists Aggreko, and logistic specialists like UPS and Federal Express, also operate extensive logistics networks that offer cost reductions through optimised planning and storage.

This innovation is relevant for all Turbine MW-Class and Site Type combinations, but it will have the most impact on projects on Site Type D where the forward operations base will be a mother ship. Here, even if a component is held at the onshore port location then, if the spares and equipment held on the mother ship are not managed effectively, turbine downtime will be increased by at least a day in order for a spare part to be delivered to the wind farm site.

Feedback from industry suggests that the technical potential available through improvements in this area is a one per cent reduction in both operational and planned maintenance costs and unplanned service costs, with an associated small increase in wind farm availability due to the reduction in the lead time of replacement components. It is anticipated that 70 per cent of the benefit will be available to operators for projects with FID in 2014, with further benefits still available beyond projects reaching FID in 2020, as continued market growth will allow the further optimisation of logistics networks. The market share of this innovation is expected to be 90 per cent of all projects by FID 2020.

Interviewees agree that **improvements in weather forecasting** will increase the efficient use of staff and vessels by maximising the activity during weather windows. This requires improvements both to the accuracy and the granularity of forecasts. Currently, accuracy drops significantly for forecasts beyond five days ahead for an area of approximately 100km^2. Interviewees say that, in order to make the most efficient use of resources and especially heavy equipment such as jack-up vessels, this accuracy will need to be extended to a 21-day forecast, though more accurate shorter term forecasts will obviously help. Improvements in weather forecasting have applications in many fields including agriculture, leisure and transport and there will continue to be intensive effort put to improving modelling capability at a range of different scales for many years to come.

This innovation has relevance to all turbine and site combinations but is particularly significant to Site Type D where projects are located further from the operations base and therefore require more vessels that can operate in more adverse conditions for longer periods. Relevance is also higher for sites with harsher wind conditions, as there is more time and AEP lost to weather on these sites.

The technical impact of this innovation is anticipated to be a 0.5 per cent reduction in operational and planned maintenance cost and a one per cent reduction in unplanned service cost. When fully realised, it is anticipated that this innovation has the potential to increase wind farm availability by 0.05 per cent. It is expected that commercial readiness and market uptake are such that, for projects with FID in 2020, 60 per cent of this potential is assumed. Although forecasting models are becoming increasingly capable, interviewees doubt that forecasting will have advanced sufficiently in order to meet the requirements of projects operating beyond 2020. Long-range weather forecasting is in demand by a number of established and large industries and the offshore wind sector will benefit from advances in modelling driven by demand from others.

Other innovations

Logistics tools will be extended to include managing necessary paperwork such as technician job sheets, method statements and risk assessments. Paper will for the most part be replaced with electronic media, such as rugged tablet computers that are already in use as part of the logistics toolkit in other sectors. Software tools developed for Natural Power by Baze Technology and by SeaEnergy demonstrate that these tools are becoming available to the offshore wind market.

Early signs and prerequisites

There are a number of mother ship concepts being offered to the market, such as the Sea-Wind WMV by Offshore Ship Designers, the SeaEnergy Marine Vessel System and the Marine Asset Corporation semi-submersible. A visible milestone will be an investment to build one or more of each of these vessels. Wind farm operators of far-from-shore projects are unlikely to commit to such vessels until project FID, which means that they may be available a year or so following the WCD.

There is evidence that turbine manufacturers and wind farm operators are building up in-house teams to take best advantage of innovations. These teams will recruit from the oil and gas industry, which has a long history of managing personnel and resources based on offshore platforms, including shift working and ferrying staff from shore to the offshore base. Much of this learning can be applied to far offshore wind farms. Players such as Siemens and RWE are building in-house teams and Siemens already has over 40 people in its marine resourcing team, letting contracts for provision of custom-build transfer vessels and inviting proposals for the provision of mother ships. In 2010, RWE took the decision to set up RWE Offshore Logistics Company to provide its offshore wind projects with installation, commissioning and operations resources. This is expected to grow to 120 personnel by the end of 2012.

There are signs that offshore wind OMS is starting to benefit from expertise in other industries. In 2011, Vestas announced that Caterpillar Remanufacturing (Cat Reman) is to provide refurbishment services for turbine components, drawing on the company’s experience in providing maintenance, service, spares and remanufactured parts in locations which can be difficult to access. Further partnerships of this nature will provide evidence that the industry is developing OMS strategies that are fit for purpose.

Prerequisites for investment in the construction of advanced mother ships for OMS include confidence in an ongoing market. Although the development of concepts is at risk, there is sufficient time for new vessels to be constructed post FID, if they are already fully designed. Mechanisms to underwrite the initial investment in mother ships for the first far offshore sites would allow owners and shipyards to commit to build in advance of FID, so making the vessels available in time for the WCD. Innovations in inventory management weather forecasting are relevant to, and in demand by, other markets, thus reducing the investment risks.

Table 11.5 Potential and anticipated impact of innovations in planning and execution of offshore activity for a wind farm on Site Type B using 6MW-Class Turbines, compared with FID 2011.

Innovation	Maximum technical potential impact				Anticipated impact FID 2020			
	CAPEX	OPEX	AEP	LCOE	CAPEX	OPEX	AEP	LCOE
Improvements in inventory management	0%	-0.6%	0.05%	-0.2%	0%	-0.4%	0.04%	-0.2%
Improvements in weather forecasting	0%	-0.5%	0.05%	-0.2%	0%	-0.3%	0.03%	-0.1%
Improvements in OMS strategy for far-from-shore wind farms *	0.02%	-3.0%	0%	-0.8%	0%	0%	0%	0%
Total					0%	-0.7%	0.07%	-0.3%

This table provides figures for the impact at Site Type B to enable comparisons with the innovations described in other sections, however this innovation only applies to Site Type D.

11.3.2. Condition-based maintenance

Existing situation

Today, planned maintenance is carried out on turbines with a pattern of inspections of turbines and balance of plant. Typically, planned inspections of turbines are either at six-monthly or yearly intervals, depending on the wind turbine manufacturer. The scope of these inspections is relatively consistent but, with different players then specifying more thorough checks or planned exchanges of wear parts or lubricants every two to 10 years, a programme of planned work is established for several years ahead.

At present, all offshore turbines are fitted with drive train condition monitoring equipment in order to provide some prognosis capability and satisfy lender requirements. These systems typically comprise several accelerometers which monitor key components of the drive train, including the gearbox and main bearing. Such a system typically adds £2,500/MW to turbine CAPEX and £1,000/MW/year to OPEX. Additional sensors may be fitted to monitor the rest of the drive train, the nacelle structure, rotor, tower and support structure.

Turbines are monitored using SCADA systems, which process data from the turbine controller, switchgear in the tower base and, in some cases, condition monitoring systems. Using a combination of SCADA and condition monitoring data, some proactive service is carried out, for example, the replacement of a gearbox final stage prior to failure or the exchange of a complete generator.

Innovations

Introduction of turbine condition-based maintenance is anticipated to follow its successful introduction in other sectors. It combines the advanced use of condition monitoring with a risk-based approach to planned maintenance, thereby focussing on inspection and repair of components shown to have largest potential impact on the LCOE through faults, whether experienced or forecast. Utilities such as E.ON and RWE use CBM on most of their conventional power plant. Many water utilities, often considered as conservative in their approach, are moving to CBM in preference to a conventional time-based approach. CBM is now routinely applied to large vehicles such as those used in transport, agriculture, civil engineering and mining.

To fully implement, this innovation requires the use of integrated databases of SCADA, controller and condition monitoring data and a range of data mining and learning algorithms. These tools will provide technicians and condition monitoring engineers with prognosis capability as well as the related source data, turbine history and links to OMS manuals and spare parts databases. It also means reducing the focus on routine inspections that, over time, have been shown to be ineffective in reducing the LCOE. Condition monitoring on its own, however, without changing planned maintenance procedures, risks only taking a fraction of the benefit available in terms of improved process efficiency and time focussed on key issues.

Rotor condition monitoring is achieved by embedding load and damage detection sensors within the blades. The most promising load detection technology in this field is perceived to be fibre Bragg gratings. This technology, replacing the use of resistive strain gauges, is already being adopted by a number of blade manufactures to measure strain as an input in some cases to the turbine control system, in other cases, to condition monitoring systems. Knowing the strain can avoid operating in conditions where damage to the blade is likely, therefore avoiding catastrophic failure. Operating issues that affect the blades may come from problems within the pitch and yaw systems, as well as the blades themselves.

Nacelle and structure condition monitoring is typically carried out by using data from the condition monitoring accelerometers processed to derive health indicators, but more advanced systems also consider oil cleanliness and temperatures already provided to the turbine controller, as well as rotor condition inputs. Data processing is typically carried out by equipment in the nacelle that is independent of the control system. The health indicators are then made available through a data link to specialist support engineers onshore. In some wind farms a subset of this data and the health indicators may be passed to the wind farm SCADA and used to generate alarms that are visible to the wind farm operators. Interviewees say that such data integration is patchy and often only instigated by the owner or operator. A least two energy utilities with portfolios of wind farms use databases such as OsiSoft Pi to integrate and analyse data from SCADA, condition monitoring and other wind farm reporting streams.

It is also reported that only those basic systems that are required to meet third party requirements are generally fitted. A few turbine manufacturers, including GE Energy, are starting to offer systems which integrate control and condition monitoring data at the turbine and present an holistic data set to the operator via the SCADA system.

This low level of integration of the control system and condition monitoring data is historical and was driven by the lack of availability of cost-effective, industrial processing power and instrumentation. This is no longer the case and interviewees expect that, for turbines available for projects with FID in 2014, there will be improvements in the automatic integration and interpretation of all turbine operational data. This includes low frequency (1Hz) data from the control system and the SCADA system, high frequency (500Hz) condition monitoring data, turbine design data and turbine maintenance histories from technician records. It is also expected that there will also be an ongoing improvement in the accuracy of damage and life models to provide reliable, online, generic mean time to failure statistics and turbine-specific anticipated time to failure figures for key components. Innovations include the simplification of design models to allow remaining life estimates of components to be carried out on the turbine.

The implementation of holistic condition monitoring systems will provide clearer, near real time, information to the operations team. For example, remaining life estimates of components, such as high-speed bearings and pitch actuators, and consumables such as gearbox oil, allow better planning of resources for planned maintenance activities. Diagnosis of a problem in one subsystem that may impact upon another avoids the repeat exchange of components without addressing the root cause. An increase in the number of operations of one pitch cylinder compared with the other two could indicate a blade problem or a deteriorating seal, or a transducer with noisy output. Analysis of blade loads can demonstrate that the blade is not the source of the problem. The affected pitch system can then be highlighted for attention during a planned maintenance visit, and the possible spare parts included in the kit list for the technicians. Currently, technicians can identify the problem during a planned service, but may not have the necessary spares to undertake the repair at the time. Onshore, this is hardly an issue but offshore it is much more important due to the costs of access and the downtime risks of requiring further visits.

The technical impact of this innovation is anticipated to be a 1.5 per cent reduction in operational and planned maintenance OPEX and a five per cent reduction in unplanned service OPEX. This innovation adds between about 0.25 per cent (£1,250/MW) and 0.5 per cent (£2,500/MW) to the CAPEX of the rotor and wind turbine nacelle respectively. This innovation is expected to result in a 0.25 per cent increase in wind farm availability as the balance of unplanned service activity moves from reactive to proactive.

For all Turbine MW-Classes and Site Type combinations, there will be benefit from this innovation. The impact is greatest for 8MW-Class Turbines on Site Type D, because of the higher cost penalty associated with downtime, the more expensive components on a larger turbine, and the additional logistical time and cost associated with replacing components further from shore in more harsh weather conditions.

In 2011, no UK offshore turbines have fully integrated control, condition monitoring and SCADA systems or are maintained using CBM. It is expected that the industry will thoroughly embrace CMB over the next decade or so, as the industry builds confidence in such a strategy.

To date, the majority of support structures have consisted of monopiles or concrete gravity bases. These are comparatively simple structures and so impose a relatively low burden on the OMS budget. Despite this, as discussed in Section 8, there have been significant problems with the grouted connection between the transition piece and monopile. The anticipated large-scale adoption of jacket foundations, with many more fatigue-driven welded connections, will benefit from **improvements in jacket condition monitoring**. Jackets have a proportionately higher number of welded joints and a greater surface to volume ratio than monopiles. Increased use of jacket foundations will increase the need for routine monitoring for the integrity of welds and corrosion protection. Industry advises that, typically, a total of 60 person-hours of annual inspection visits will be required for a jacket compared with 20 person-hours for a monopile foundation. The installation of permanent sensors to continuously monitor load or stress cycles at critical points will allow more accurate estimates of the remaining life of the support structure and could reduce the costs of inspection by 50 per cent. Failing to identify early signs of corrosion or weld failure can result in costly repairs, or potentially the replacement of the foundation.

Implementing automatic, time-based scheduled inspections of the support structure, including subsea inspections, using autonomous systems will provide a consistency and repeatability that is unlikely to be matched by conventional methods, especially as the number of support structures increases.

The technical impact of this innovation is anticipated to be a 0.3 per cent decrease in operational and planned maintenance OPEX and a one per cent reduction in unplanned service OPEX for all projects using jacket foundations. Conservatively, no benefit of improved condition monitoring of other support structures is taken. This innovation will add 0.5 per cent to the CAPEX of the support structure. The technical impact and market uptake are conditional on investment in inspection equipment, taking advantage of work done in parallel sectors. Assuming the investment is forthcoming then, by FID 2020, it is anticipated that 90 per cent of this potential is assumed to be available for projects using jackets and 90 per cent of projects will be using it.

Other innovations

Interviewees report that improvements in array cable condition monitoring will have applications both in the installation and operational phases. Cable manufacturers and installers report that the premature failure of cable insulation is often as a result of inadequate handling and monitoring of cables during installation. Interviewees also state they believe that the amount of latent cable damage caused during installation is underestimated because of the number of premature failures of cables for other reasons. Although worthy of mention, interviewees could not provide substantive evidence to support the technical impact of such innovation on OPEX.

Some condition monitoring systems include fixed cameras to allow the visibility of key systems. Logically, this will be extended to include provision for wireless cameras carried by technicians to allow land-based specialist engineers to view problem components or systems.

Early signs of progress and prerequisites

Early signs that holistic condition monitoring systems are likely to become available to the market comes from investments being made by condition monitoring suppliers such as Moog and Bosch Rexroth and the developments in rotor monitoring technology being undertaken by turbine manufacturers such as Siemens and Vestas. Also, Gamesa, GE Energy, REpower, Siemens and Vestas all advise that they are developing control, monitoring and SCADA systems that provide for the integration of all data, though hard evidence of a move towards CBM is less available. Independent SCADA providers such as Iconics and GE Smart Signal, as well as utilities such as E.ON Climate and Renewables and RWE npower renewables, are further examples of companies applying their experience of data mining software and fault detection and diagnostic algorithms for other generating plant to condition monitoring systems.

Industry already recognises the need to improve prognostic tools to provide an early warning of turbine failure and minimise unavailability and unplanned reactive service. Programmes which encourage the transfer of prognostic techniques and systems from other industry sectors will accelerate the commercial readiness and adoption of these methods. ETI has invested in one such project, combining aerospace, automotive and rail experience from consortium members to develop a holistic, multi-component condition monitoring tool.

Players such as Wood Group, who have many years of experience monitoring structures in the oil and gas industry, are now offering similar services to offshore wind.

Key prerequisites for introducing new condition monitoring systems are the availability of data and demonstration turbines to enable the performance of condition monitoring systems to be proved to asset owners, and sufficient understanding about turbine behaviour to enable CBM to be implemented. Wind turbine manufacturers are generally reluctant to share any more data than that required by contractual obligations. Two asset owners have stated that, under current service agreements, turbine manufacturers service crews have little or no incentives to improve maintenance regimes, as the contracts are generally in favour of the manufacturer. Until there are more turbine manufacturers offering products offshore, the drive to implement condition monitoring systems will come from owners. They will develop such systems by growing the understanding of in-house teams by hands-on operation and a migration of personnel from turbine manufacturers. Tighter requirements in the EPC written by developers will require manufacturers to provide access to the turbine data necessary to support condition monitoring programmes.

Table 11.6 Potential and anticipated impact of innovations in condition monitoring, for a wind farm on Site Type B using 6MW turbines, compared with FID 2011.

Innovation	Maximum technical potential impact				Anticipated impact FID 2020			
	CAPEX	OPEX	AEP	LCOE	CAPEX	OPEX	AEP	LCOE
Introduction of turbine condition-based maintenance	0.2%	-2.3%	0.4%	-0.9%	0.1%	-1.5%	0.3%	-0.6%
Improvements in jacket condition monitoring	0.1%	-0.9%	0.02%	-0.2%	0.09%	-0.6%	0.01%	-0.1%
Total					0.2%	-2.1%	0.3%	-0.7%

11.3.3. Personnel transfer

Existing situation

While jack-up vessels will be brought in for activities that require heavy lifts, almost all the lighter activity on existing wind farms is undertaken by technicians that are delivered to site by crew transfer vessels from a dedicated onshore marine base that is normally less than 60km from the site.

Technicians travel to the site in crew transfer vessels at a typical cruising speed of up to about 22 knots. The more advanced vessels are typically twin hulled for stability, and have a modified bow with fender and gangway to facilitate transfer to the turbines. OMS budgets are normally set with an expectation of two planned visits to each turbine per year. Floating hotels have been used on some sites to support project installation and commissioning work and these are also now beginning to be used for OMS crews, as discussed above.

Innovations that reduce weather-related delays to access improve wind farm availability. Interviewees say that increases in availability afford a greater than one-to-one improvement in AEP because a turbine failure is statistically more likely when the wind speeds are above average, so lost energy is proportionally higher than average. A baseline 4MW-Class turbine on Site Type B it will spend about 75 per cent of the year operating below and about 20 per cent of the year operating above its rated specification, with an average net capacity factor of 42 per cent. A loss of one per cent of operating hours, if this falls in the above conditions when access is most limited, will reduce AEP by over two per cent.

Transfer of technicians from the vessel to the turbine remains a safety-critical activity requiring specialist training. Transfers are not normally made above an Hs of 1.4m, which limits the available access to approximately 84 per cent of the time in summer, and 58 per cent of the time in winter in the southern North Sea, an annual average of 71 per cent. Helicopter support is generally only provided as a back-up for occasional use and emergency evacuations, when the sea state is too extreme, or for medical emergencies. Provision for emergency transfers from the wind farm to shore by helicopter has been made in projects such as Greater Gabbard where a helicopter is on permanent lease. Interviewees advise that they do not see routine air transfers from base to turbine as an option that is viable economically or from a health and safety perspective, due to the total number of anticipated transfers required. Routine helicopter transfers of technicians and spares from the land base to the mother ship or accommodation platform are assumed for Site Type D, using experience gained from the oil and gas sector.

Innovations

Asset owners report that up to 40 per cent of the working time of a technician is currently spent waiting for weather windows. They emphasise that **improvements in personnel access from transfer vessel to turbine** will have a significant impact in reducing OMS expenditure as well as increasing AEP. This entails an increased use of larger, more capable support vessels fitted with systems that allow safe transfer of technicians to turbines in up to an Hs of 2.5m. This innovation will have more impact where sites are further from shore and have harsher conditions.

A range of access systems are available or in development and most involve the use of heave-compensating walkways or lifting pods that provide access to the support structure ladder or directly to the platform. Different solutions are best suited to existing crew transfer vessels, enhanced crew transfer vessels and turbine support vessels, as discussed in Table 11.3. An example of a commercially available system is supplied by Ampelmann. This uses a hydraulically stabilised access gangway that can be fitted to suitable vessels longer than 25m. With displacement greater than 120 tonnes, it can provide safe access to turbines in up to an Hs of 2.0m. This facilitates an annual accessibility of 85 per cent for the southern North Sea. The Ampelmann system has been used to support installation and commissioning, but has not yet been employed for OMS activities. Other examples of access systems are Neptune by Submarine Technology, MaXccess by Osbit Power, which received a DECC grant in April 2012, and the Turbine Access System designed by Houlder and BMT Nigel Gee.

The innovation assumes that, when full commercial readiness is reached, transfers will routinely take place in an Hs of up to 2.5m. This could increase the average number of working days in a southern North Sea site from 260 to 346, that is, from 71 to 95 per cent of working days. The technical impact of this innovation is anticipated to be a 0.8 per cent reduction in operational and planned maintenance, a 2.5 per cent reduction in unplanned service OPEX and an increase in wind farm availability of 0.5 per cent. Conservatively, this increase in availability is modelled as only increasing AEP also by 0.5 per cent, despite the likely additional benefit described above. It is anticipated that, by FID 2020, 80 per cent of this potential will have been achieved and this will have been adopted on 90 per cent of wind farms.

Improvements in personnel transfer from base to turbine location will come through the introduction of enhanced crew transfer vessels with the ability to carry more personnel, in greater comfort and with a more comprehensive stock of materials and tooling, which will significantly increase the efficiency of identification and repair of failed components. In this case, the base can refer to either a land-based port or a mother ship.

Enhanced crew transfer vessels will be fitted with mechanisms, such as stabilised technician and crew seats, which deliver technicians to the turbine better able to work efficiently. Large vessels also have a greater payload, have provisions for a small onboard workshop and a more comprehensive stock of spares, and can operate in up to an Hs of 2.5m. The average number of working days will increase as described for the previous innovation. Feedback from workshops indicates that there are higher levels of personnel retention of technicians where more capable vessels are deployed. For projects with FID in 2011, it is anticipated that more than half of projects will be serviced by enhanced crew transfer vessels.

All Turbine MW-Classes and Site Types will benefit from this innovation but the greatest benefit is at Site Type D, where there are harsher weather conditions. The technical impact of this innovation is anticipated to be a 0.3 per cent reduction in operational and planned maintenance OPEX, a one per cent reduction in unplanned service OPEX and a 0.1 per cent increase in wind farm availability. By FID 2020, 80 per cent of this potential will be available for the market, and it is assumed that it will have a 90 market share of Turbine MW-Class and Site Type combinations.

Other innovations

Many small innovations are being identified, developed and implemented to improve personnel access to turbines. These include redesigning guard rails to simplify access for personnel and small equipment, to designs for medium-sized support vessels allowing about 12 technicians to stay onsite for a week.

Early signs of progress and prerequisites

Public announcements by vessel manufacturers and designers provide evidence that there has been investment in custom transfer vessels and access methods.

Enhanced crew transfer vessels are now being specified and put into service in preference to generic work boats in some cases. An example is the WindCat Mark IV recently supplied by WindCat Workboats.[65]

The first commercial use of advanced access systems will signal progress with these. Further support such as that provided by the Carbon Trust to develop innovative methods of personnel transfer will accelerate the commercial readiness of such systems.

Investment in all of the above is relatively low compared with other elements and the growth of the installed base gives an ongoing market in OMS, so progress is anticipated without the need for specific prerequisites to be addressed. WindCat Workboats and SouthBoats are two examples of builders who are working with asset owners and vessel operators to design and develop custom designed transfer and support vessels.

Table 11.7 Potential and anticipated impact of innovations in personnel transfer, for a wind farm on Site Type B using 6MW turbines, compared with FID 2011.

Innovation	Maximum technical potential impact				Anticipated Impact FID 2020			
	CAPEX	OPEX	AEP	LCOE	CAPEX	OPEX	AEP	LCOE
Improvements in personnel access from transfer vessel to turbine	0%	-1.2%	0.5%	-0.8%	0%	-0.8%	0.3%	-0.5%
Improvements in personnel transfer from base to turbine location	0%	-0.5%	0.1%	-0.3%	0%	-0.3%	0.09%	-0.2%
Total					0%	-1.1%	0.4%	-0.7%

[65] “Windcat MK IV Series”, Windcat Workboats, available at www.windcatworkboats.com/#/fleet/wc_mk4/, accessed May 2012.

12. Summary of impact of innovations

12.1. Combined impact of innovations

Innovations across all elements of the wind farm are anticipated to reduce the LCOE by 15 to 20 per cent between projects with FID in 2011 and 2020 for a given Turbine MW-Class and Site Type. Figure 12.1 shows that the savings are generated through a balanced contribution of reduced CAPEX and OPEX and increased AEP. Appendix B provides a list of the potential and anticipated impact of all innovations.

It is important to note that the impact shown in Figure 12.1 is an aggregate of the impact shown in Figure 5.1 to Figure 11.1 and as such excludes any reductions forecast in the *Supply chain work stream report,* the *Finance work stream report* or anticipated reductions in transmission charges over time. The largest like-for-like reductions for the same Turbine MW-Class and Site Type that are available are for projects using 6MW-Class Turbines on Site Type D. This is due to the anticipated significant market uptake of optimum-sized rotors for these turbines and the opportunity provided by working for the first time so far from shore.

The impact on wind farm availability during the period is relatively constant across wind farms using different MW-Class Turbines and on different Site Types. The anticipated change for wind farms using 4MW-Class Turbines is from a baseline 95 per cent (averaged over the lifetime of the project) to between 96 and 97 per cent for wind farms reaching FID in 2020. For larger turbines, where it is anticipated by industry that there will be more innovations focused on improving reliability, the improvement will be about a further 0.5 per cent. Improvements are due mainly to innovations in OMS and in turbine nacelles.

The charts consider changes for a given Turbine MW-Class, thus there is no impact of a change in turbine rating incorporated in any of the figures.

Source: BVG Associates

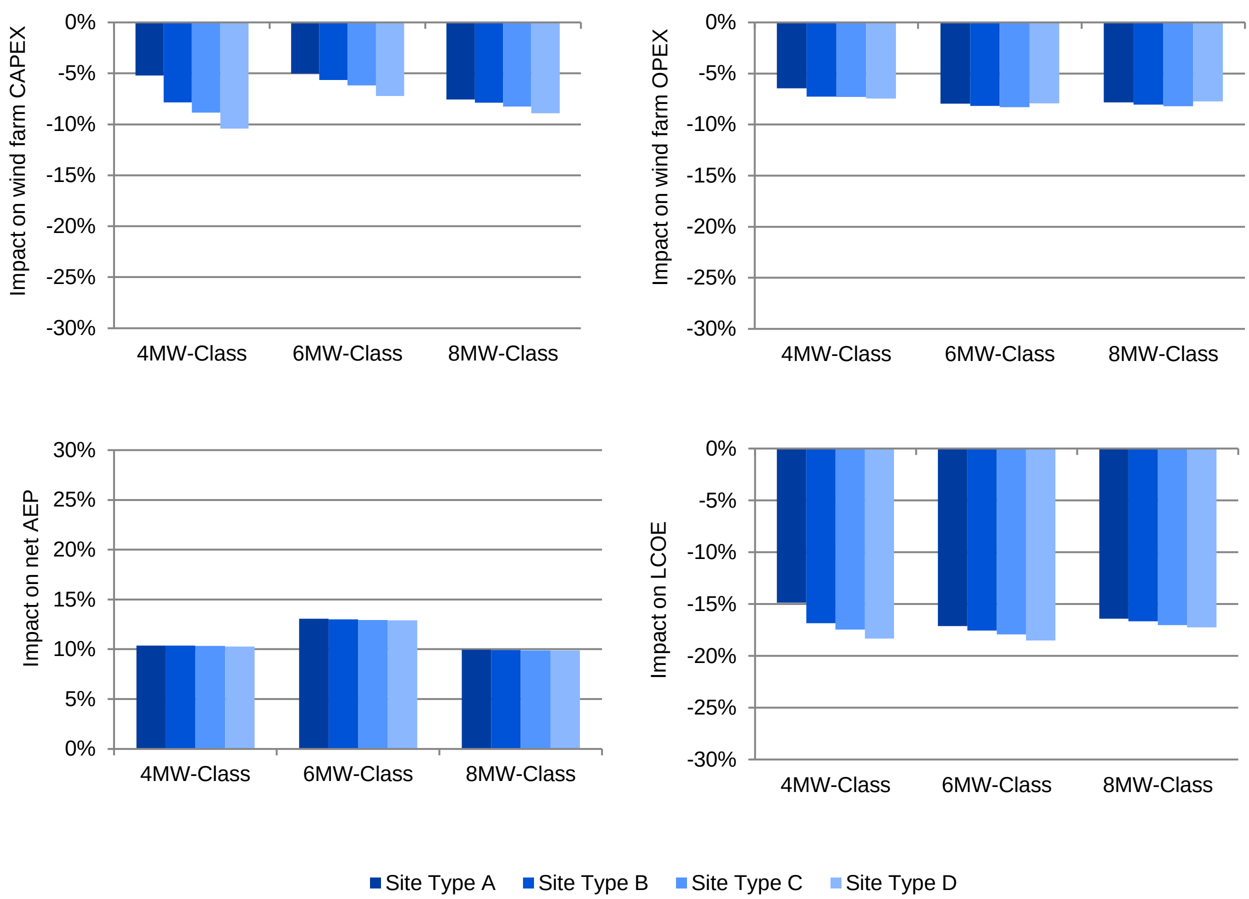

Figure 12.1 Anticipated impact of all innovations by Turbine MW-Class and Site Type, compared with FID 2011. Note no impact of change in turbine rated power is incorporated.[7]

A comparison of the progression of the anticipated LCOE for each Turbine MW-Class and Site Type is presented in Figure 12.2, with parameters benchmarked against the baseline wind farm of 4MW-Class Turbines on Site Type B reaching FID in 2011.

For FID in 2020, the wind farm with the lowest LCOE uses 8MW-Class Turbines, but the benefit over the use of 6MW-Class Turbines is only about one to two per cent, based on today's understanding of anticipated technology development. The feedback from industry is that most anticipate that 6MW-Class Turbines will dominate supply for projects with FID in 2020. For this reason, further discussion of the impact of innovations to FID 2020 is focused on a wind farm using 6MW-Class Turbines on Site Type B, compared with a wind farm of 4MW turbines under the same site conditions reaching FID in 2011.

In Figure 12.2, the trends of decreasing CAPEX and OPEX savings from Site Type A (gentlest) to Site Type D (harshest) are to be expected. This reflects the fact that, although savings on, for example, Site Type D are the greatest (as shown in Figure 12.1), these are not sufficient to offset the higher baseline costs. The CAPEX of wind farms using 4MW-Class Turbines on Site Type A is lower due to the use of monopiles though, again, due to the maturity of monopiles, less CAPEX saving over the period is shown for this Site Type in Figure 12.1.

Source: BVG Associates

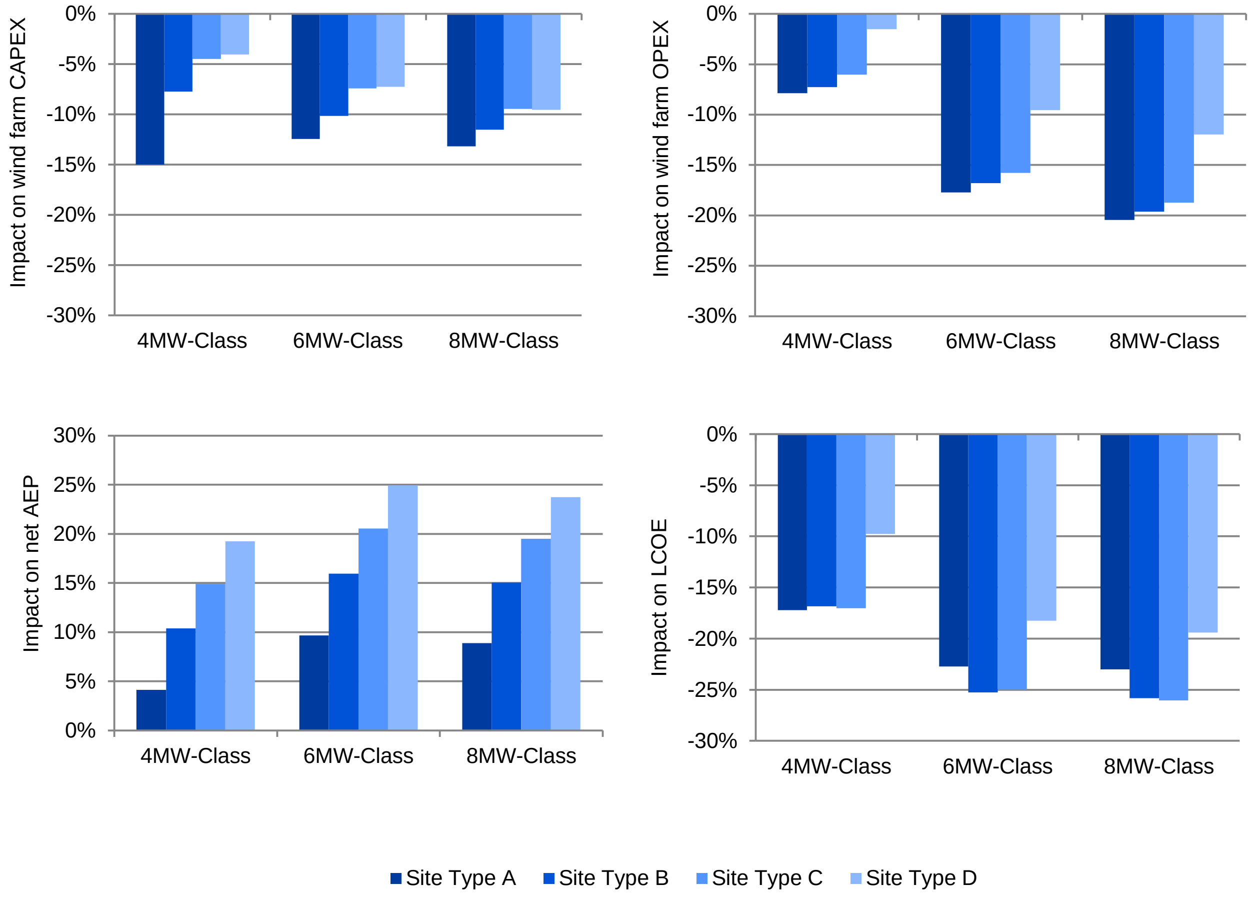

Figure 12.2 Anticipated impact of all innovations by Turbine MW-Class and Site Type, compared with a wind farm of 4MW-Class Turbines on Site Type B with FID 2011. Note the impact of change in turbine rated power and Site Type is incorporated.[7]

The progression of the LCOE with time for each Turbine MW-Class is shown in Figure 12.3, considering the impact both of changes to AEP (here shown as net capacity factor) and to annualised cost. Annualised cost combines CAPEX, OPEX and decommissioning expenditure (DECEX) rationally to reflect an equivalent annual cost, based on a discount rate of 10 per cent, as used in the other LCOE calculations presented in this report. The diagonal lines are contours of the constant LCOE. Figure 12.3 shows that an innovation causing an increase in CAPEX (contributing to an increase in annualised cost) can, if delivering significant increases in AEP, still contribute to a reduction in the LCOE.

The wind farms of 4MW-Class Turbines follow a trend of significant increase in rotor diameter during the period, due to the optimum still being significantly greater than the baseline typical of 4MW-Class Turbines in the market today. The increase in rotor diameter is the dominant driver in the increase in capacity factor between FID 2011 and 2020. The shape of the progression for the wind farms using 4MW-Class Turbines reflects the transition towards an optimum rotor diameter (which on its own tends to increase annualised cost) followed by a period of increasingly reduced costs.

Section 7 shows that wind farms using the 4MW-Class Turbines are anticipated to achieve the highest capacity factor with an optimum rotor. Here it is evident that wind farms using 6MW-Class Turbines actually have higher capacity factors. This is because industry generally does not expect rotor sizes to increase significantly on 4MW-Class Turbines due to the opportunity cost of developing new products at this size, compared with a move to focusing on optimising 6MW-Class Turbines, evidenced by a range of products coming to market at close to optimum rotor diameter, with some likely to be available for use in wind farms scheduled for FID 2014.

The 8MW-Class Turbine will enter the market with an optimised rotor diameter so there is little room for capacity factor increase and most of the LCOE saving achieved between its introduction in 2017 and 2020 relates to developments in support structure, installation and OMS. Both at introduction and in 2020, the 8MW-Class Turbine offers a slight improvement in the LCOE over the 6MW-Class Turbine, matching the trend shown in Figure 12.2.

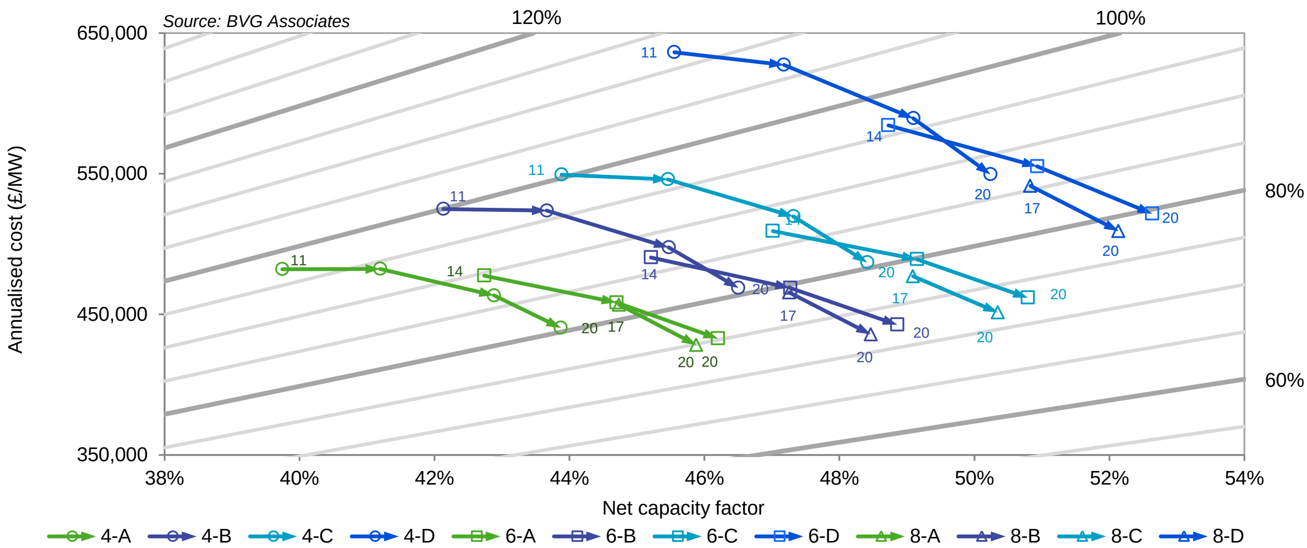

Figure 12.3 Anticipated impact of all innovations by Turbine MW-Class and Site Type, compared with a wind farm of 4MW-Class Turbines on Site Type B reaching FID in 2011.

The dominant prerequisites for achieving these saving are confidence in the market to invest, availability of test sites and access to other methods of verification such as large test rigs, in order to de-risk and accelerate the introduction of larger turbines and larger rotors, and collaboration to develop or revise relevant international standards and industry guidelines.

12.2. Relative impact of cost of each wind farm element

In order to explore the relative impact of the cost of each wind farm element, Figure 12.4 shows the LCOE of all baseline projects and the LCOE for similar projects with FID in 2020, all relative to a wind farm of 4MW-Class Turbines on Site Type B with FID in 2011. It also shows the relative contribution of each of the wind farm elements to this LCOE. This is followed by Figure 12.5 which presents the same data but with each wind farm LCOE normalised to 100 per cent.

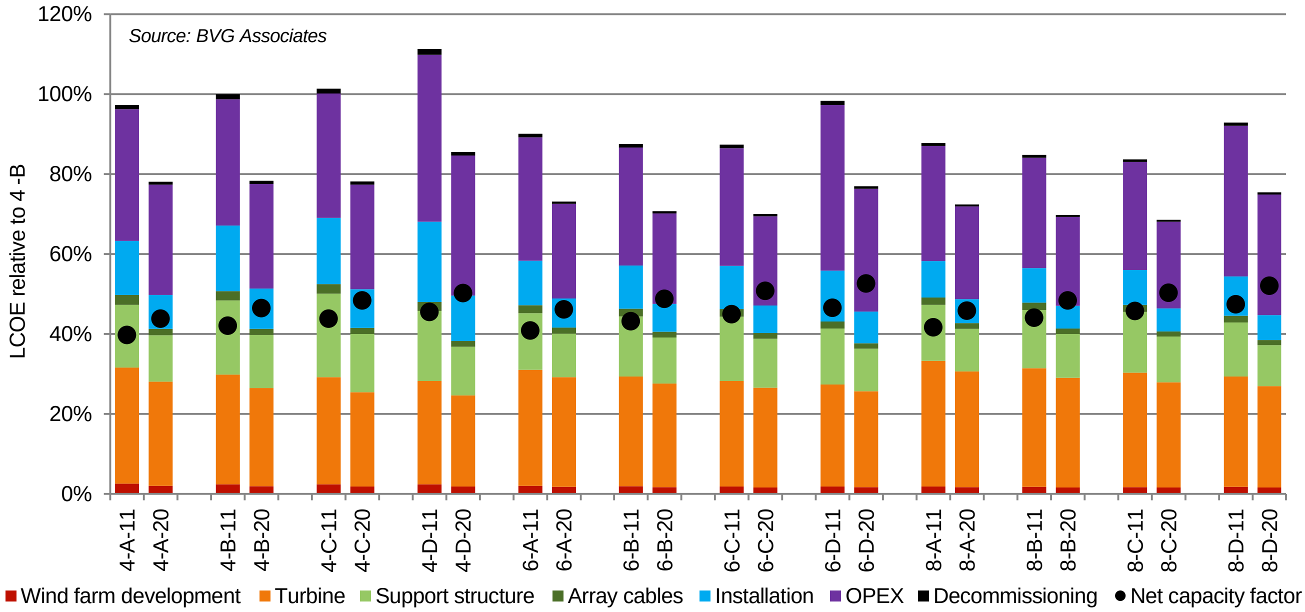

Figure 12.4 Relative LCOE for baseline wind farms with FID 2011 and FID 2020.

Figure 12.5 shows the increase in the proportion of the LCOE attributable to turbine CAPEX. For a wind farm using 8MW-Class Turbines on Site Type D, almost 80 per cent of lifetime cost is linked to the turbine CAPEX (36 per cent) and OPEX (40 per cent), a significant shift from wind farms of 3MW-Class Turbines operating close to shore today.

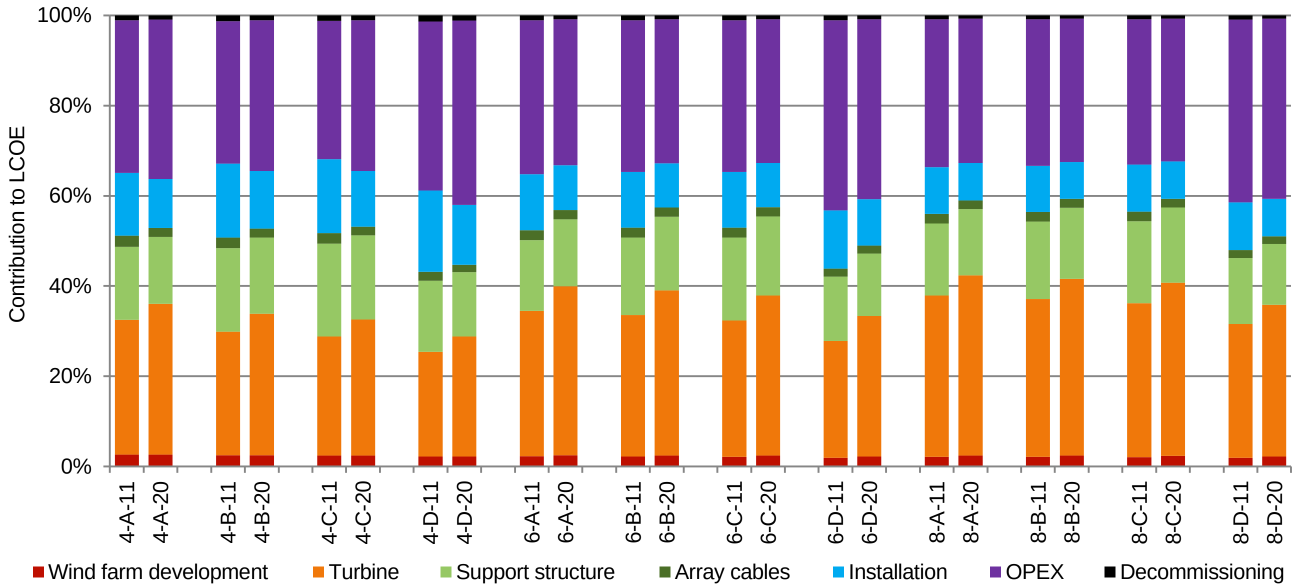

Figure 12.5 Relative contribution to the LCOE for each element baseline wind farms with FID 2011 and FID 2020.

12.3. Relative impact of innovations in each wind farm element

A comparison of the impacts each wind farm element is given in Table 12.1 for a single representative step from a wind farm of 4MW-Class Turbines on Site Type B reaching FID in 2011 to a wind farm of 6MW-Class Turbines on the same Site Type reaching FID in 2020. It is key to note is that innovations in one element often have just as big an impact on other elements as on that element itself. Column C contains the change in the given element between the wind farms in Column A and B, due to innovations in all elements. Column D contains the change in the LCOE due to the changes in that element in column C.

Column E contains the change in the LCOE due to the anticipated impact of innovations in the given element that may also affect the costs of all other elements. In the discussion below, precise numbers from the table are used to aid tracking. It is recognised that such accuracy is not warranted.

Of relevance to note is:

- The total LCOE reduction is 25 per cent. This is made up of 7.2 per cent (column D) due to a decrease in CAPEX, 5.3 per cent due to a decrease in OPEX, 13.8 per cent due to an increase in AEP, and a small decrease due to DECEX.

- The reduction is due mainly to innovations in the wind turbine nacelle (including changes in Turbine MW-Class and innovations that improve nacelle component reliability), leading to an 11.7 per cent reduction (column E), followed by 5.6 per cent for wind turbine rotor and 3.6 per cent for support structure. Overall, innovations in CAPEX-related elements lead to a 23.9 per cent reduction in the LCOE.

- Innovations in the wind turbine nacelle, even though driving a significant LCOE reduction, lead to an 11.3 per cent increase per megawatt in the nacelle cost. The trend is similar for the wind turbine rotor. Combining the rotor and nacelle gives an overall anticipated increase turbine cost (excluding tower) per megawatt of 18 per cent.

- Innovations in wind farm installation, driving a three per cent LCOE reduction, and in OMS at two per cent, are not significant, but the impact of innovations in other elements on the cost of these elements is significant, driving a 7.2 per cent and 5.3 per cent reduction in the LCOE respectively.

- Wind farm development, although of low overall cost, incorporates innovations that, at 1.8 per cent, contribute more significantly than might be expected to reducing the LCOE. In other words, early activity is influential in setting the future costs of energy.

Table 12.1 Anticipated impact of all innovations by element for a wind farm using 6MW-Class Turbines on Site Type B with FID in 2020, compared with a wind farm using 4MW-Class Turbines on the same site type with FID in 2011.

Element	'A' Wind Farm with 4MW-Class Turbines Site Type B FID 2011	'B' Wind Farm with 6MW-Class Turbines Site Type B FID 2020	'C' Change	'D' Impact of change in element on LCOE	'E' Impact of innovation in element on LCOE
Wind farm development (£k/MW)	85	80	-5.4%	-0.1%	-1.8%
Wind turbine rotor (£k/MW)	393	507	29.2%	2.8%	-5.6%
Wind turbine nacelle (£k/MW)[66]	632	703	11.3%	1.8%	-11.7%
Support structure (inc. tower) (£k/MW)	690	538	-22.0%	-3.8%	-3.6%
Array electrical (£k/MW)	81	67	-16.9%	-0.3%	-0.5%
Installation (£k/MW)	611	323	-47.1%	-7.2%	-3.0%
Construction phase insurance (£k/MW)	38	38	0.0%		
Contingency (£k/MW)	174	155	-10.9%	-0.5%	
Total CAPEX (£k/MW)7	**2,705**	**2,413**	**-10.8%**	**-7.2%**	**-23.9%**
Operation and planned maintenance (£k/MW/yr)	27	21	-21.1%	-1.1%	-2.0%
Unplanned service (£k/MW/yr)	55	34	-38.2%	-4.1%	
Other (£k/MW/yr)	2	2	-18.0%	-0.1%	
Annual transmission charges (£k/MW)	63	63	0.0%		
Operating phase insurance (£k/MWh)	14	14	0.0%		
Total OPEX (£k/MW/yr)[7]	**161**	**134**	**-16.8%**	**-5.3%**	**-2.0%**
Gross AEP (MWh/MW/yr)	4,520	5,118	13.2%		
Net AEP (MWh/MW/yr)	**3,691**	**4,280**	**16.0%**	**-13.8%**	
DECEX (£k/MW)	397	210	-47.1%	-0.6%	
Relative LCOE (%)7	100	75	-25%	-25%	-25%

The change in CAPEX, OPEX, net AEP and the LCOE between these two wind farms is summarised below. The total component (turbine and balance of plant) costs are level but, with installation and OPEX cost reductions and the increases in capacity factor, the LCOE saving of 25 per cent is significant. The per megawatt/hour turbine cost is almost unchanged.

The contribution of innovations in each element to this LCOE reduction is presented in Figure 12.6, below.

[66] This includes the impact of the increase in Turbine MW-Class.

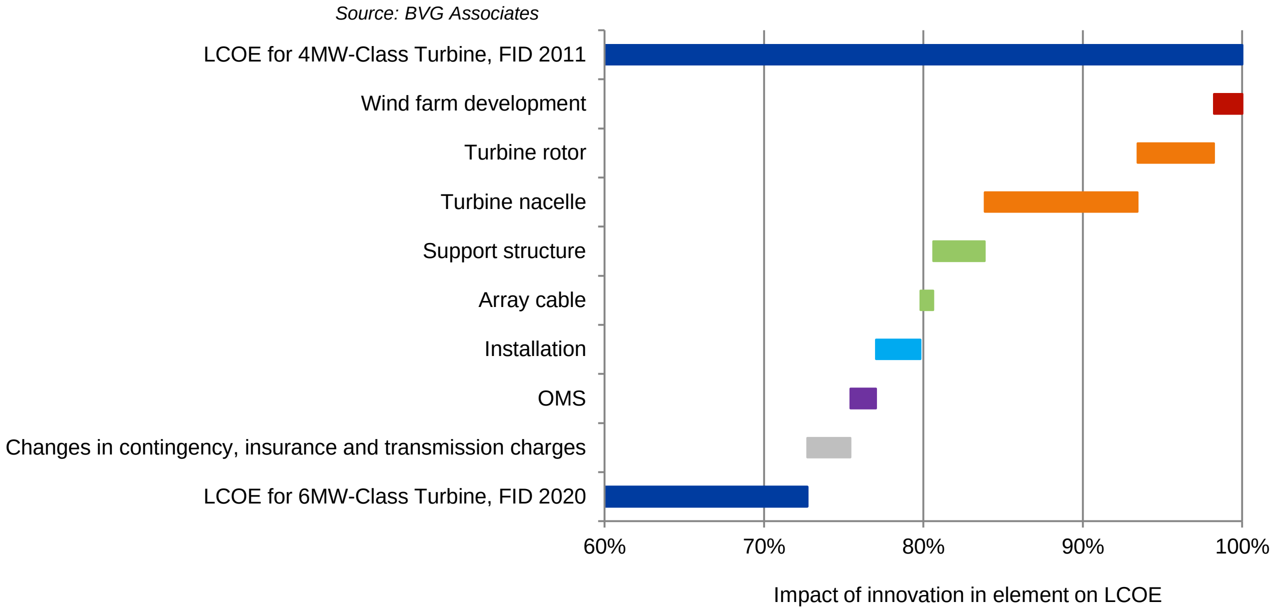

Figure 12.6 Anticipated impact of all innovations by element for a wind farm using 6MW-Class Turbines on Site Type B with FID in 2020, compared with a wind farm using 4MW-Class Turbines on the same site type with FID in 2011.

12.4. Innovations with the largest impact

The 12 innovations that have the largest anticipated impact on a wind farm of 6MW-Class Turbines on Site Type B with FID in 2020, compared with their impact on a wind farm using 4MW-Class Turbines on the same site type with FID in 2011 are shown below. These are extracted from Figure 5.2 to Figure 11.2. The anticipated impact is a combination of the maximum technical potential impact and the various other moderating factors, as discussed in Section 2. The dominant innovation is the change in Turbine MW-Class, which has knock-on benefits on the cost of many other elements. There are a number of other turbine-related innovations in this top 12. Three are related to the rotor, and have the benefit of increasing AEP, which has a one-to-one impact on reducing the LCOE. Two are related to drive trains and predominantly have the benefit of increasing reliability, and thus both decreasing OPEX and increasing AEP via increased availability. High on the list is *improvements in jacket manufacturing*, incorporating a number of aspects relating to reducing manufacturing cost. These are so important because jackets are considered by the industry to be the likely dominant foundation design over the next 12 years. Also shown is a group of innovations which aim to decrease weather downtime during foundation installation. Weather downtime has the potential to become an even bigger cost driver than now as the industry uses sites with more severe met ocean conditions. Lastly, there is a group of innovations with the intent of increasing the effectiveness of OPEX through the adoption of a more holistic, condition-based approach to OMS. Again, when using more severe sites, the fraction of spend on OPEX rises and it is recognised by the industry that, critical to its long-term sustainability, are operational strategies that are consistent with the challenges of working on an industrial scale so far from our shores.

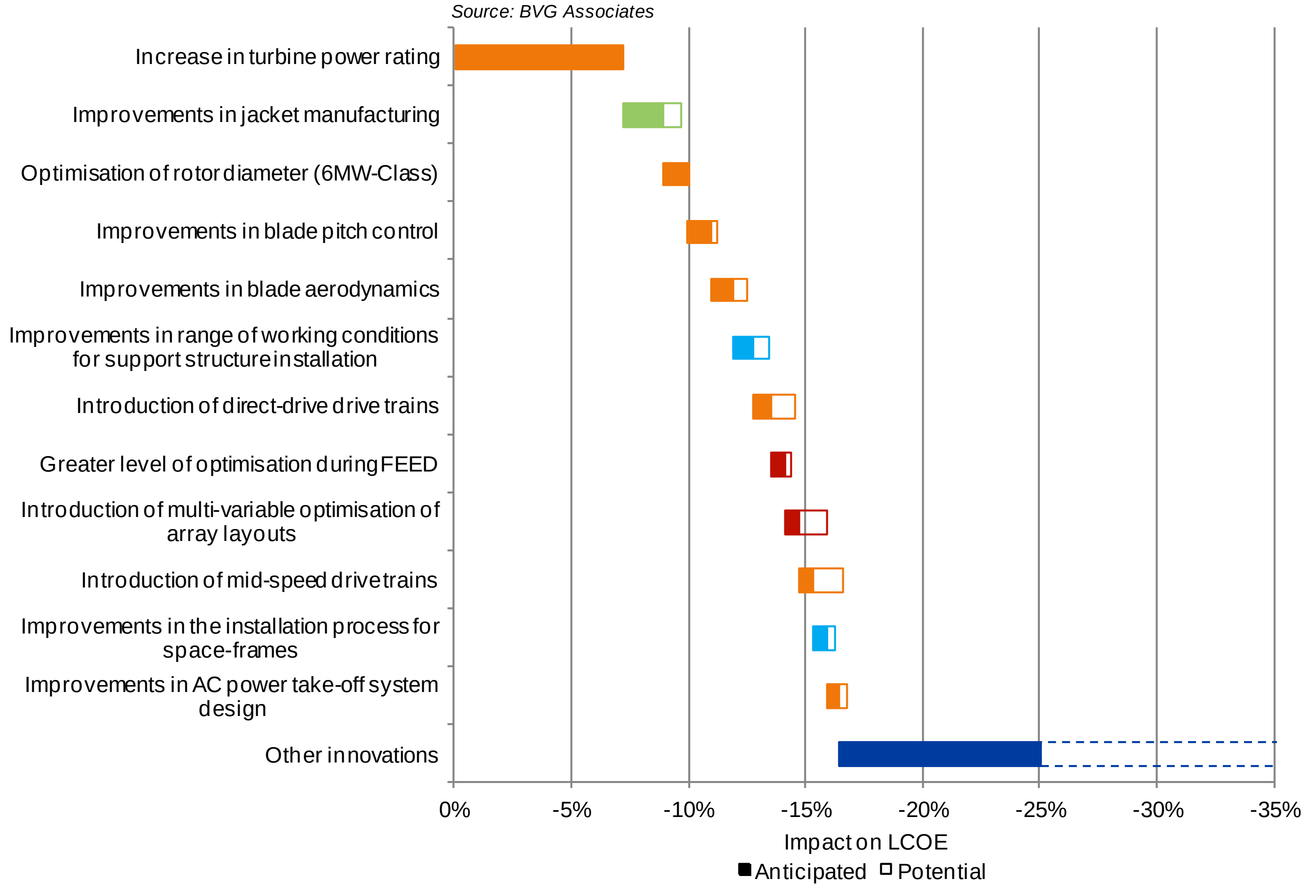

Figure 12.7 Anticipated impact of top 12 innovations (ranked by anticipated impact) for a wind farm using 6MW-Class Turbines on Site Type B with FID in 2020, compared with a wind farm using 4MW-Class Turbines on the same site type with FID in 2011. The potential shown is not limited by time, Site Type or Turbine MW-Class. The aggregate potential benefit for "Other innovations" is greater than the 35 per cent shown.

The top 12 innovations account for about 68 per cent of the anticipated LCOE reduction; the top 25 account for about 87 per cent. The distribution of cumulative reduction against number of innovations is provided below.

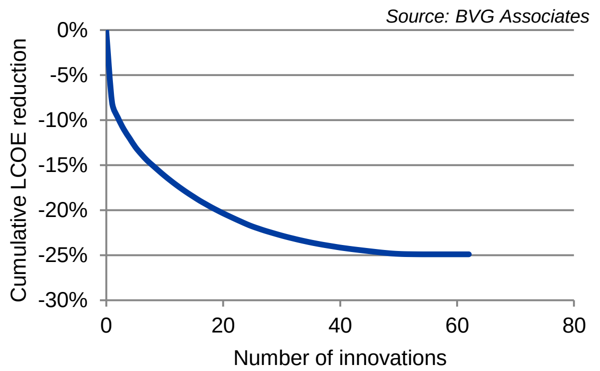

Figure 12.8 Cumulative anticipated LCOE reduction against number of innovations based on Site Type B using 6MW-Class Turbines, compared with FID 2011. Innovations are sorted in the order of maximum anticipated impact.

There are a number of innovations that either are not applicable to 6MW-Class Turbines or are not anticipated to impact the market significantly by FID 2020. The top 12 innovations ranked by maximum technical potential are presented below. Additional to the innovations discussed above, the *introduction of float-out-and-sink installation of turbine and support structure* is high on the list. This has the intent of increasing the fraction of onshore activities considerably, a principle almost universally recognised as critical in reducing both cost and risk. It also avoids the use of expensive specialist installation vessels and has the potential to decrease sensitivity to weather downtime, a critical feature of today's installation methodologies. It has little impact in the timeframe to FID in 2020 due to the anticipated timeframes for development and demonstration. Also listed is a halfway solution, the *introduction of buoyant concrete gravity base foundations*.

Disruptive innovations in electrical power take-off also feature, with the *introduction of DC power take-off*, with CAPEX, OPEX and electrical efficiency benefits and collection and the introduction of high-temperature superconducting generators with potential cost, efficiency, mass and reliability benefits. Both have significant development timescales, the latter likely only to be applicable to turbines of rating 8MW or larger and relying on the industrialisation of superconducting wire production.

Listed together are the two key innovations in the wind turbine drive train concept, as the industry moves from a conventional arrangement with a gearbox and high-speed generator. The potential technical benefits are evenly matched. Both feature in the top 12 list of innovations of anticipated impact, as shown in Figure 12.7. It is seen as a positive in the industry that competing concepts will exist at in the market at least for another 10 years as, for the more severe challenge of offshore operation, the industry needs a more reliable solution than it has had historically.

The other innovation listed relates to the *introduction of holistic design of the tower and the rest of the support structure*, most relevant to monopile solutions which are likely to be limited to use on wind farms using 4MW-Class Turbines. The innovation may be implemented relatively quickly but is not incorporated in Figure 12.7 as it is not as beneficial to jacket solutions, which are anticipated to be used by wind farms using 6MW-Class Turbines on Site Type B.

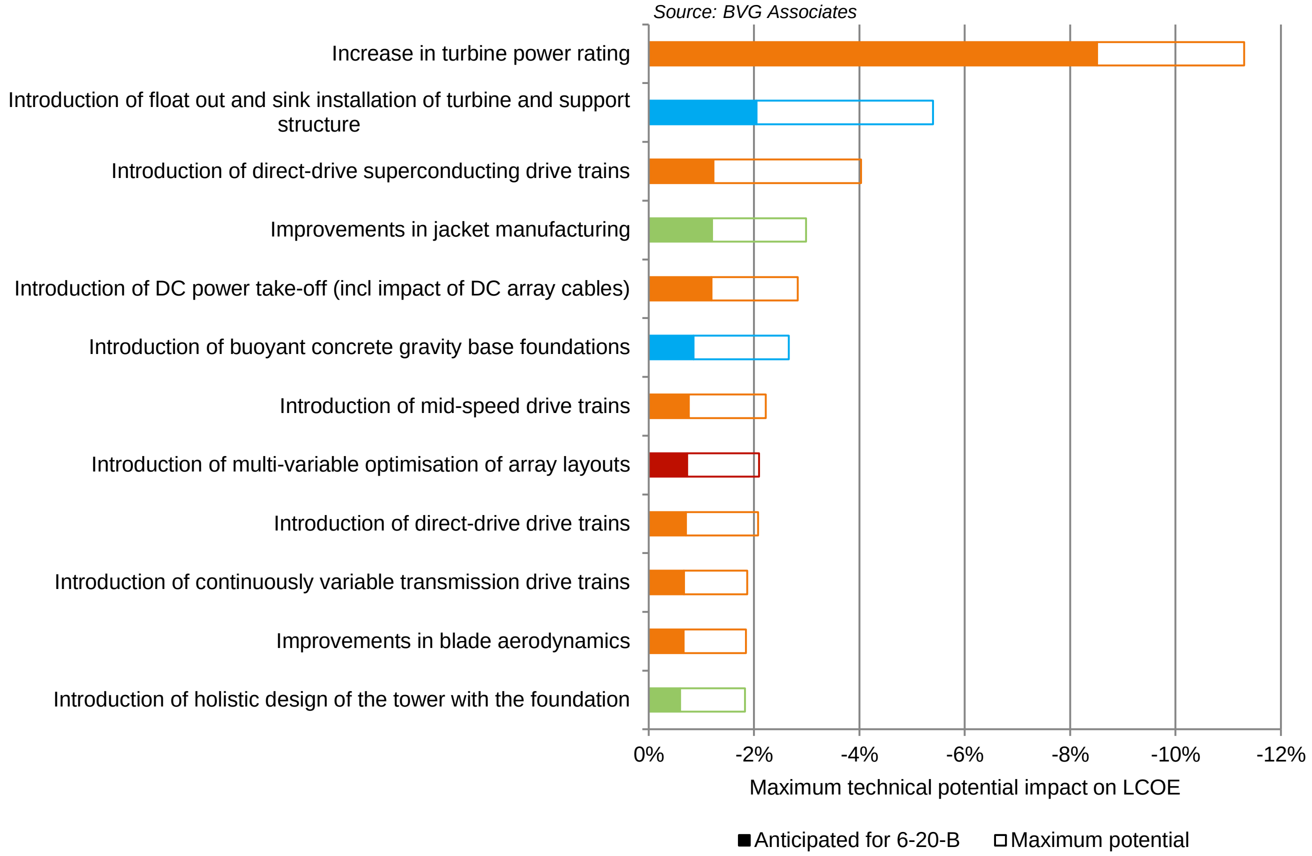

Figure 12.9 Impact of top 12 innovations (ranked by potential impact) for a wind farm using turbines and on the most relevant Site Type with FID in 2020, compared with a wind farm using 4MW-Class Turbines on Site Type B with FID in 2011.

12.5. Impact of technology innovation for different Turbine MW-Classes

Each innovation may impact projects using different Turbine MW-Classes to a different extent. Some innovations, such as those relating to monopiles, will have no impact on the LCOE of wind farms using the largest of turbines, whereas the introduction of higher-voltage array cabling is seen as more attractive for use with larger turbines.

Much of the analysis presented above is focused on the impact on a wind farm of 6MW-Class Turbines on Site Type B. In this section, we explore the time-varying different impact of technology innovation on 4MW and 8MW-Class Turbines. Section 12.6 considers the different impact on Site Types A, C and D.

In Figure 12.10, key points to note are:

- Reductions in CAPEX per megawatt between FID 2011 and FID 2017 are insignificant in the early years, due to the adoption of a more optimum rotor size, with the associated CAPEX increase, balancing other reductions. Generally, there is little difference in CAPEX per megawatt between wind farms using 4MW and 6MW-Class Turbines.
- There is a reduction in CAPEX per megawatt at the introduction of 8MW-Class Turbines at FID 2017. This is due to further reductions in the installation cost per megawatt for larger turbines and the relatively smaller optimum rotor size for 8MW-Class Turbines discussed in Section 7.
- There is a step change in OPEX per megawatt at the introduction of 6MW-Class Turbines at FID 2014. This is due mainly to the combination of the reduced number of units per 500MW wind farm and the introduction of the first large turbines designed solely for offshore use with a focus on higher reliability and maintainability.
- There is an ongoing increase in capacity factor throughout the period. The capacity factor for wind farms using 8MW-Class Turbines is lower than for wind farms using 6MW-Class Turbines due to the less optimum rotor size for 8MW-Class Turbines.
- There is a resulting step change in the LCOE for 6MW-Class Turbines when introduced in 2014. It s recognised that, due to real market effects, such step changes are rarely seen. Discussion of these effects in provided in the *Supply chain work stream report*.

Source: BVG Associates

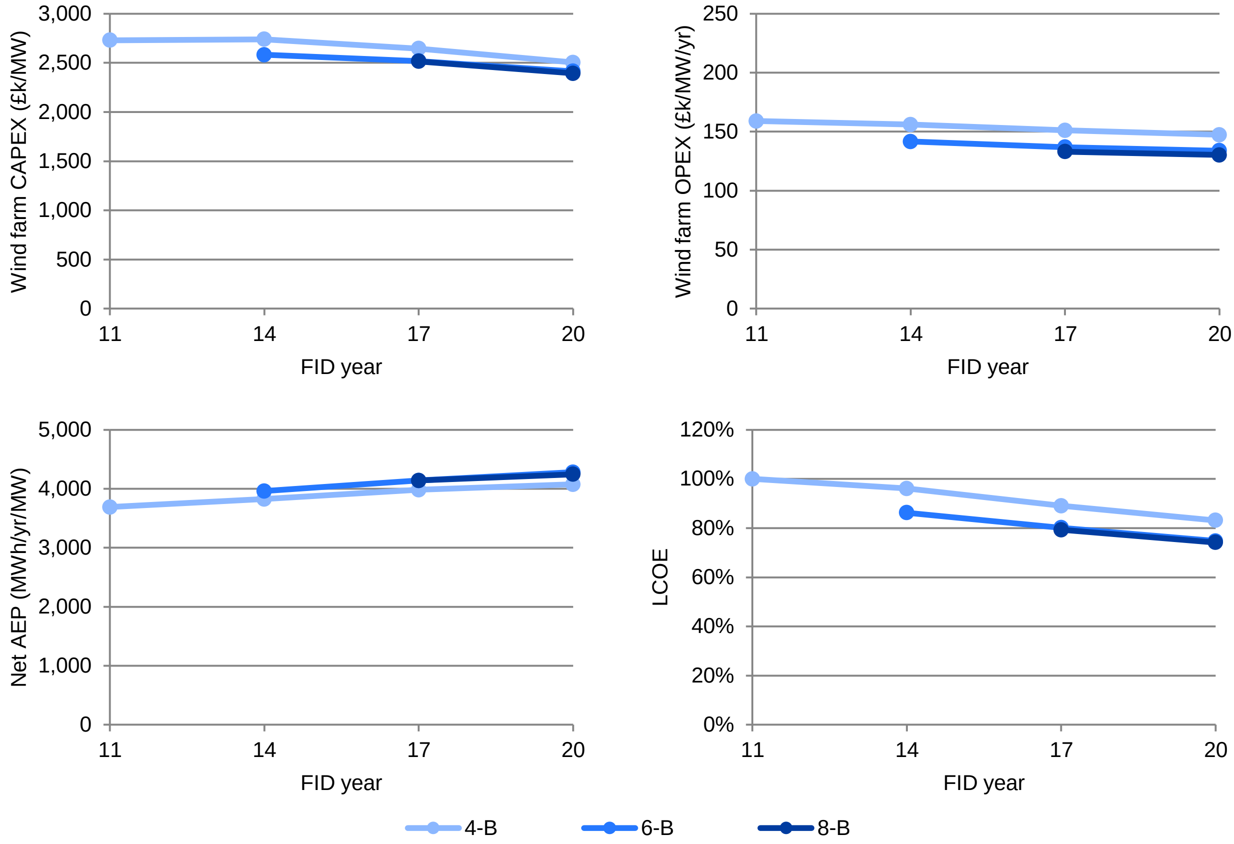

Figure 12.10 Anticipated impact of all innovations on CAPEX, OPEX, AEP and the LCOE by turbine size in Site Type B.

12.5.1. Wind farms using 4MW-Class Turbines

The 12 innovations that have the largest anticipated impact on a wind farm of 4MW-Class Turbines on Site Type B with FID in 2020 compared with a wind farm using the same rated turbines on the same Site Type with FID in 2011 are shown below. The pattern, as expected, is similar to that in Figure 12.7, but with overall anticipated savings in the LCOE less at 15 per cent and the following exceptions:

- There is clearly no benefit of a change in Turbine MW-Class.
- The benefit of moving to an optimum rotor size is larger because the difference between the baseline and optimum diameter is greater, even though the market penetration of larger rotors for 4MW-Class Turbines is anticipated to be lower than for larger turbines.
- Cost reductions due to the *introduction of holistic design of the tower and foundation* are more significant when considering a monopile, as used here, while other cost reductions in foundations are less significant for a monopile than for as a jacket foundation.
- There is a relative increase in the importance of innovations in OMS, due to the lower uptake of other turbine design changes at this scale, reflecting the industry view that focus should be placed on developing 6MW-Class Turbines and larger. This is shown also by the presence of improvements in the baseline drive train concept.

It is noted that, under some assumptions about market development, there is a case for the continued use of 4MW-Class Turbines on Site Types that justify the use of monopiles, rather than moving to larger turbines that drive the change to using jacket foundations. The analysis presented here shows a four per cent higher baseline LCOE for wind farm of 4MW-Class Turbines on Site Type A for FID 2011, compared with 6 MW-Class Turbines. Should investment in new jacket manufacturing facilities not progress due to market conditions, but supply chain optimisation progress further for the smaller turbines and innovations in turbines be applied at the smaller scale in the same way as at the larger scale then, taking account of relative risks, this trend could reverse during the decade.

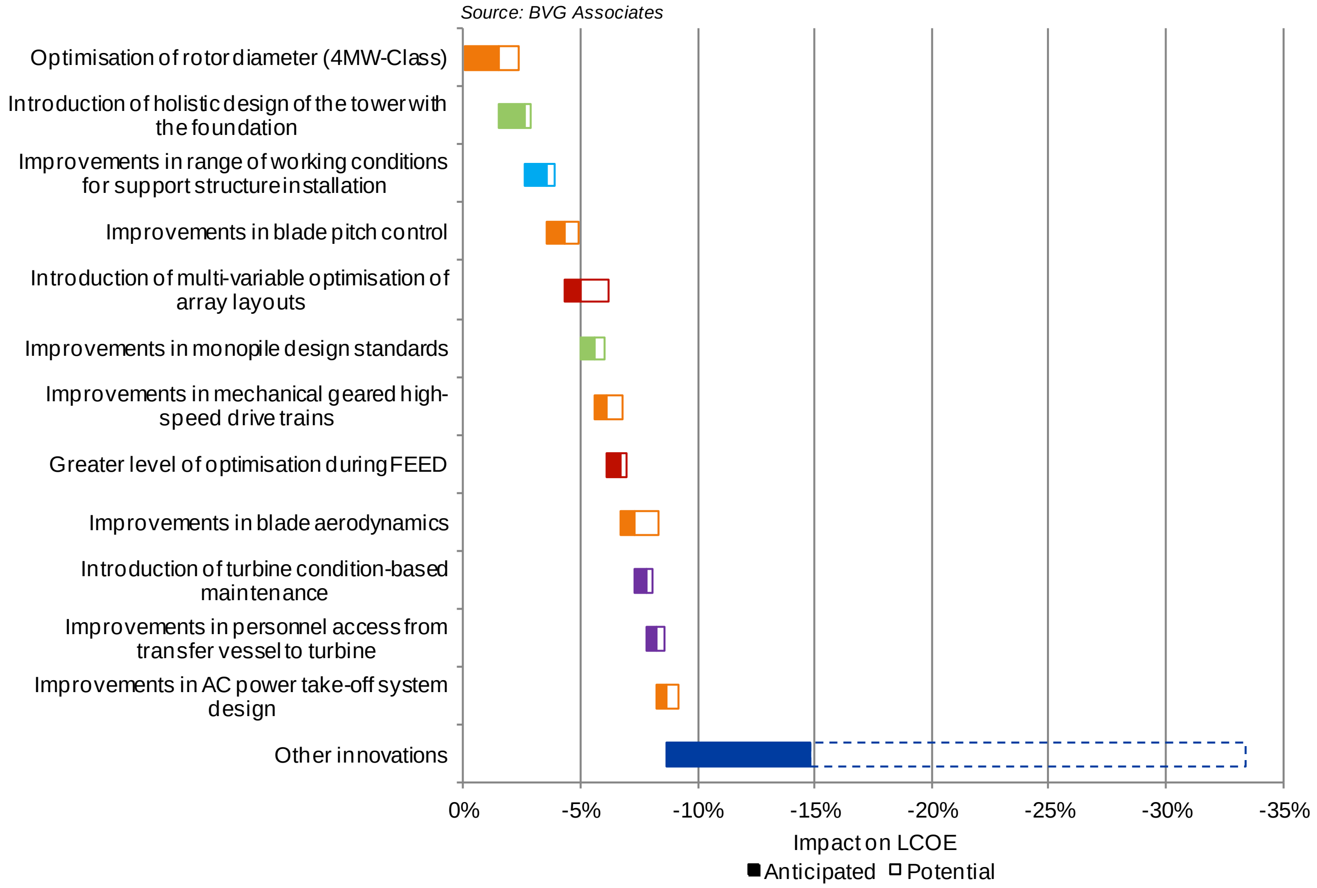

Figure 12.11 Impact of top 12 innovations (ranked by anticipated impact) for a wind farm using 4MW-Class Turbines on Site Type A with FID in 2020, compared with a wind farm on the same site type with FID in 2011. Potential shown is not limited by time, Site Type or Turbine MW-Class.

12.5.2. Wind farms using 8MW-Class Turbines

The innovations that have the greatest anticipated benefit for wind farms using 8MW-Class Turbines up to FID 2020 are generally the same as for wind farms using 6MW-Class Turbines, so the pattern in Figure 12.12, is similar to that in Figure 12.7, but with overall anticipated savings more, at 27 per cent. The only exception is the absence of the optimisation of rotor diameter. This is because the rotor diameter for the baseline 8MW-Class Turbine, scaled in line with the turbine rating as discussed in Section 7, is viewed as optimum already.

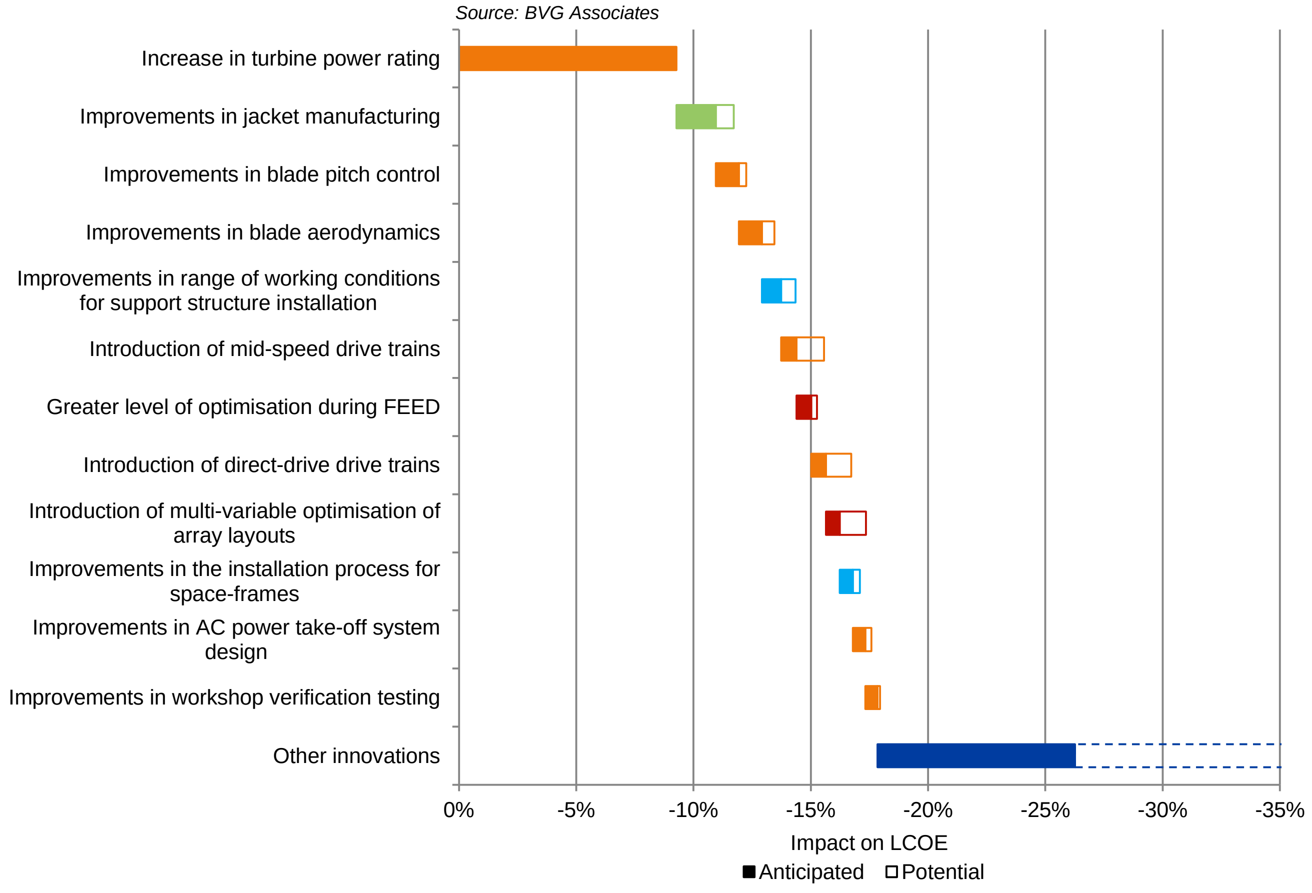

Figure 12.12 Impact of top 12 innovations (ranked by anticipated impact) for a wind farm using 8MW-Class Turbines on Site Type B with FID in 2020, compared with a wind farm using 4MW-Class Turbines on the same site type with FID in 2011. Potential shown is not limited by time, Site Type or Turbine MW-Class.

12.5.3. Wind farms using 10MW-Class Turbines

Though turbines of 10MW-Class have been fully modelled throughout the project, there is less certainty within the industry about costs, as suppliers have in general not invested time in considering the model beyond the one currently under development. Due to the pace of new development not only in new turbine concepts and products but also in technology development deep in the supply chain (for example, in rolling element bearings or new blade materials), it is recognised that, to some extent, the vision of what an optimum large turbine will be like is likely to change somewhat before such turbines are introduced, and these changes are anticipated to decrease the LCOE beyond the costs modelled in this project. In any case, the industry seems relatively consistently focused on implementing wind farms with 6MW-Class Turbines next, before applying the experience that will be gained to the next generation of products.

Historically, even some experienced industry players have a number of times stated that the optimum (or indeed, maximum) turbine rated power in the wind energy market has just about been reached. For example, it was once suggested that it would not be viable for the turbine rating to be increased to 1MW. On land, there is logic in suggesting a limit connected with transport limitations, for example, under bridges. Offshore, no such hard constraints exist, though, as explained in Section 6, the physics relating to large component design does act to increase costs faster than energy generated as turbine size increases.

It is assumed that optimum turbine MW-Class will, from a technology point of view at least, continue to increase for some time yet, taking advantage of general engineering progress as well as wind industry learning. It is less important what any eventual maximum is found to be, as long as there is an understanding that steps at least to 8MW-Class and 10MW-Class Turbines are realisable stepping stones along that path.

12.6. Impact of technology innovation for different Site Types

Each innovation may impact projects on different Site Types to a different extent. Some innovations, such as relating to monopiles, will not have an impact on projects in deeper water, whereas some new installation methods are most applicable to far-from-shore sites.

Again, as much of the analysis presented above is focused on the impact on a wind farm of 6MW-Class Turbines on Site Type B, here, we explore the different impact of technology innovation on wind farms on Site Types A, C and D, using 4MW-Class Turbines throughout. The 4MW-Class Turbine is chosen in order to explore more fully the impact of monopile foundations, modelled here only on Site Type A. For other Turbine MW-Classes, the trends are similar but without the impact of monopile use on Site Type A. It is recognised that, in a number of cases, wind farms on given Site Types will not reach FID in the given year. The anticipated distribution of wind farms using different Turbine MW-Classes on different Site Types is discussed in *The Crown Estate Offshore Wind Pathways report*.

In Figure 12.13, it is relevant to note the following:

- From a higher baseline, CAPEX reductions are greatest for Site Type D. This is due to the relatively larger impact of the use of feeder solutions and innovations to increase the envelope of working conditions. Reductions on Site Type A are less than for other Site Types, as innovations relating to monopiles are anticipated to have less impact than innovations relating to jackets.
- Again, from a higher baseline, OPEX reductions are greatest for Site Type D and this is due to innovations impacting mainly on projects with FID in 2020. This is mainly because of the greater development of suitable OMS strategies far from shore, and the greater opportunity for innovation from today's state-of-the-art in the more severe conditions.
- Overall, reductions in the LCOE for a given Site Type increase when stepping from Site Type A to B then C then D.

Source: BVG Associates

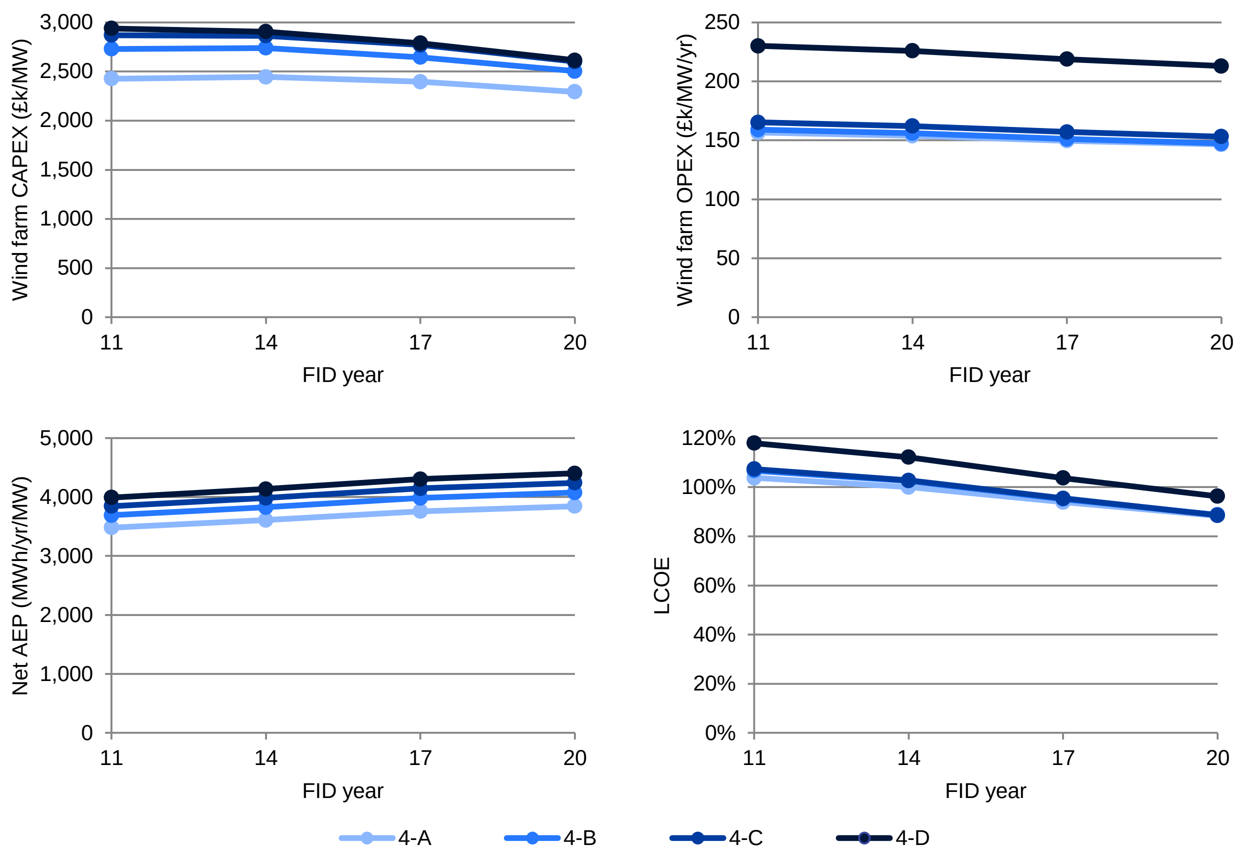

Figure 12.13 Anticipated impact of all innovations on CAPEX, OPEX, AEP and the LCOE by Site Type, for a wind farm using 4MW-Class Turbines.

12.7. Industry Stories

All of the analysis presented to this point in this report considers the commercial readiness and market uptake of innovations under Industry Story 2 “Technology Acceleration”, characterised by a high focus on technology development and a strong market.

The four Industry Stories are described in Section 2 and, in more detail, in *The Crown Estate Offshore Wind Pathways report*. Each has a different narrative linked to the development and acceptance of technology building on a common FID 2011 baseline, described element-by-element in Sections 5 to 11 and summarised here:

- Today's technology, with a nominal 20-year design life,
- Four MW-Class Turbine with a 120m diameter rotor and conventional geared drive train with high-speed, doubly-fed induction generator, alongside “stretched” variants of this turbine at 6MW and 8MW ratings, though with no market share on wind farms reaching FID in 2011
- Wind farm layout partially optimised for the lowest LCOE based on multiple single-variable modelling and “rules of thumb”
- Monopile foundations for Site Type A and conventional jacket for all other Site Types
- Tower designed with turbine
- 33kV AC array cables
- Conventional installation using jack-up for both foundations and turbines, with foundations and cables installed one year and turbines installed the next
- Shore-based OMS with nose-in access using sub-24m vessels and conventional installation vessels for large retrofits for Site Types A to C and basic accommodation ship or platform for Site Type D (Again, it is recognised that no wind farms on Site Type D reached FID in 2011), and
- Progress of introducing new technology discussed in Sections 5 to 11 is summarised in Table 12.2 below. It is noted that, with regard to technology, Industry Story 4 matches Industry Story 2.

Table 12.2 Summary of progression of technology under each Industry Story.

Industry Story	1. Slow Progression	2. Technology Acceleration and 4. Rapid Growth	3. Supply Chain Efficiency
Summary	• Incremental evolution from today's technology • Continuous improvement, focused on reliability improvement • Small technology steps – not big leaps • Gradual transition from 4MW-Class Turbines to 6MW-Class Turbines over the period	• Advances in wind farm design and layout optimisation • Progressive shift towards larger turbines and larger rotors to reduce overall costs and increase yield, driving innovation in many other elements of the wind farm • Significant design for increased reliability and maintainability • Little variation in the overall turbine concept but a range of drive train solutions developed • Innovation in support structures with focus on design evolution and production methods rather than novel designs • Some innovation in installation methods, but with only a partial impact of advanced solutions in the timescales considered in the project • Use of purpose-built maintenance mother ships that can remain permanently stationed at far-from-shore sites with the capacity to undertake larger component replacements	As for Story 1, but with: • Accelerated learning by doing • Increased investment in new production technology
Change by FID 2014	• Market dominated by existing turbines with some new versions with larger rotors • Next generation of purpose-built installation vessels starting to be used • Some improvements to access and evolution of vessels and maintenance strategies that only partially account for increased harshness of conditions. (Similar aggregate progress as for Story 2 but with a two year delay)	• Some optimisation of site layout based on multi-variable modelling, with limited verification of models • Some uptake of the first of next generation 6MW-Class Turbines with an increased focus on reliability • Refinements in support structure design and fabrication, with establishment of first purpose-built next-generation jacket manufacturing facilities • First commercial use of ~66kV AC array cables • Next generation of larger, purpose-built installation vessels available • New approaches to array cable pull-in • Improvements in access methods and evolution of vessels and maintenance strategies that account for increased harshness of conditions	As for Story 1 (Aggregate progress as for Story 2 but with a two year delay)

Industry Story	1. Slow Progression	2. Technology Acceleration and 4. Rapid Growth	3. Supply Chain Efficiency
Change by FID 2017	• Some optimisation of site layout based on multi-variable modelling, with limited verification of models • Still no 6MW-Class Turbines with optimised rotor diameters • Some improvements in jacket manufacturing • Next generation of purpose-built installation vessels available • Ongoing improvements to access and evolution of vessels and maintenance strategies that only partially account for increased harshness of conditions (Similar aggregate progress as for Story 2 but with a 4 year delay)	• Good progress in optimising site layout based on multi-variable modelling, with limited verification of models • Partial use of floating LIDAR to improve understanding of site conditions • 6MW-Class Turbines dominate with optimised specific rating and designed to maximise onshore pre-commissioning • A range of drive train solutions available to the market, evolved from existing solutions • Introduction of advances in design and manufacturing of blades • Some novel jacket solutions and concrete CGBs • More holistic design of tower with foundation, but tubular tower retained • Improved modelling of support structure/soil interface • Quarter of market using ~66kV AC array cables • Occasional use of optimised installation methods, using a bespoke fleets of vessels that can operate in a wider range of operating conditions • First use of float-out-and-sink installation of support structure and turbine • Partial use of purpose-built maintenance mother ships that can remain permanently stationed at far-from-shore sites with the capacity to undertake larger component replacements	• Some optimisation of site layout based on multi-variable modelling, with limited verification of models • Some uptake of first of new generation of 6MW turbines • Refinements in support structure design and fabrication, with establishment of first purpose-built next-generation jacket manufacturing facilities • Next generation of larger, purpose-built installation vessels available • New approaches to cable pull-in • Improvements in access methods and evolution of vessels and maintenance strategies that account for increased harshness of conditions (Similar aggregate progress as for Story 2 but with a three year delay)
Change by FID 2020	• Some uptake of first of new generation of 6MW turbines • Refinements in support structure design and fabrication, with establishment of first purpose-built next-generation jacket manufacturing facilities • Next generation of larger, purpose-built installation vessels available • New approaches to cable	• 6MW-Class Turbines dominate, but with early introduction of 8MW-Class Turbines from some existing suppliers and new entrants • First use of superconducting and continuously variable direct-drive drive trains, but with the market dominated by direct-drive and mid-speed generator solutions • Advanced array cable solutions dominate, including ~66kV AC and DC cables • Third of market using advanced	• Routine optimisation of site layout based on multi-variable modelling, with limited verification of models • Partial use of floating LIDAR to improve understanding of site conditions • 6MW-Class Turbines starting to dominate with optimised specific rating and designed to maximise onshore commissioning • A range of drive train solutions available to the market,

Industry Story	1. Slow Progression	2. Technology Acceleration and 4. Rapid Growth	3. Supply Chain Efficiency
	pull-in • Improvements in access methods and evolution of vessels and maintenance strategies that account for increased harshness of conditions (Similar aggregate progress as for Story 2 FID but with a six year delay)	installation methods, including float-out-and-sink solutions • Routine use of purpose-built maintenance vessels that can remain permanently stationed at far-from-shore sites with the capacity to undertake large component replacements	evolved from existing solutions • Introduction of advances in design and manufacture of blades • Some novel jacket solutions and concrete CGBs • More holistic design of tower with foundation, but tubular tower retained • Improved modelling of support structure/soil interface • Entry of ~66kV AC array cables • Occasional use of optimised installation methods, using bespoke fleets of vessels that can operate in a wider range of operating conditions • Partial use of purpose-built maintenance vessels that can remain permanently stationed at far-from-shore sites with the capacity to undertake large component replacements (Similar aggregate progress as for Story 2 FID but with a four year delay)

It is recognised that the pace of development and introduction of some innovations will be different for different Industry Stories. To fully model the complex picture across all four Industry Stories, different levels of commercial readiness and market uptake could be associated with each innovation under Industry Stories 1, 3 and 4, as has been described for Industry Story 2 “Technology Acceleration” in Sections 1 to 11 of this report.

As a proxy for this, a universal delay in the impact of technology innovations has been applied, as defined in Table 12.3.

In order to model the impact of technology innovation in Industry Stories 1, 3 and 4, the impact developed for Industry Story 2 is delayed by a varying amount for the output year, as shown in Table 12.3 below:

- Under Industry Story 1 Slow Progression, it is assumed that, for wind farms reaching FID in 2020, technology is at the same stage as for wind farms reaching FID in 2014 in Story 2, thus the first tranche of 6MW-Class Turbines are being adopted. A linear ramp-up of delay is applied leading up to this.
- Under Industry Story 3 Supply Chain Efficiency, the delay is such that, by FID in 2017, the first tranche of 6MW-Class Turbines are being adopted.
- Under Industry Story 4 Rapid Growth, the state of technology is assumed to match that in Industry Story 2.

The delays in Industry Stories 1 and 3 are consistent with the narrative in Table 12.3.

Table 12.3 Level of delay compared with Story 2 used by Industry Story.

Industry Story	Technology delay (years)		
	FID 2014	FID 2017	FID 2020
1. Slow Progression	2	4	6
3. Supply Chain Efficiency	2	3	4
4. Rapid Growth	0	0	0

The impact of these delays on a wind farm of 6MW-Class Turbines on Site Type B under the different Industry Stories is shown in Figure 12.14. Compared with the FID 2011 baseline, under Industry Stories 2 and 4, there is a 19 per cent reduction in the LCOE whereas, under Industry Story 3, this is reduced to 10 per cent and, under Industry Story 1, five per cent.

Source: BVG Associates

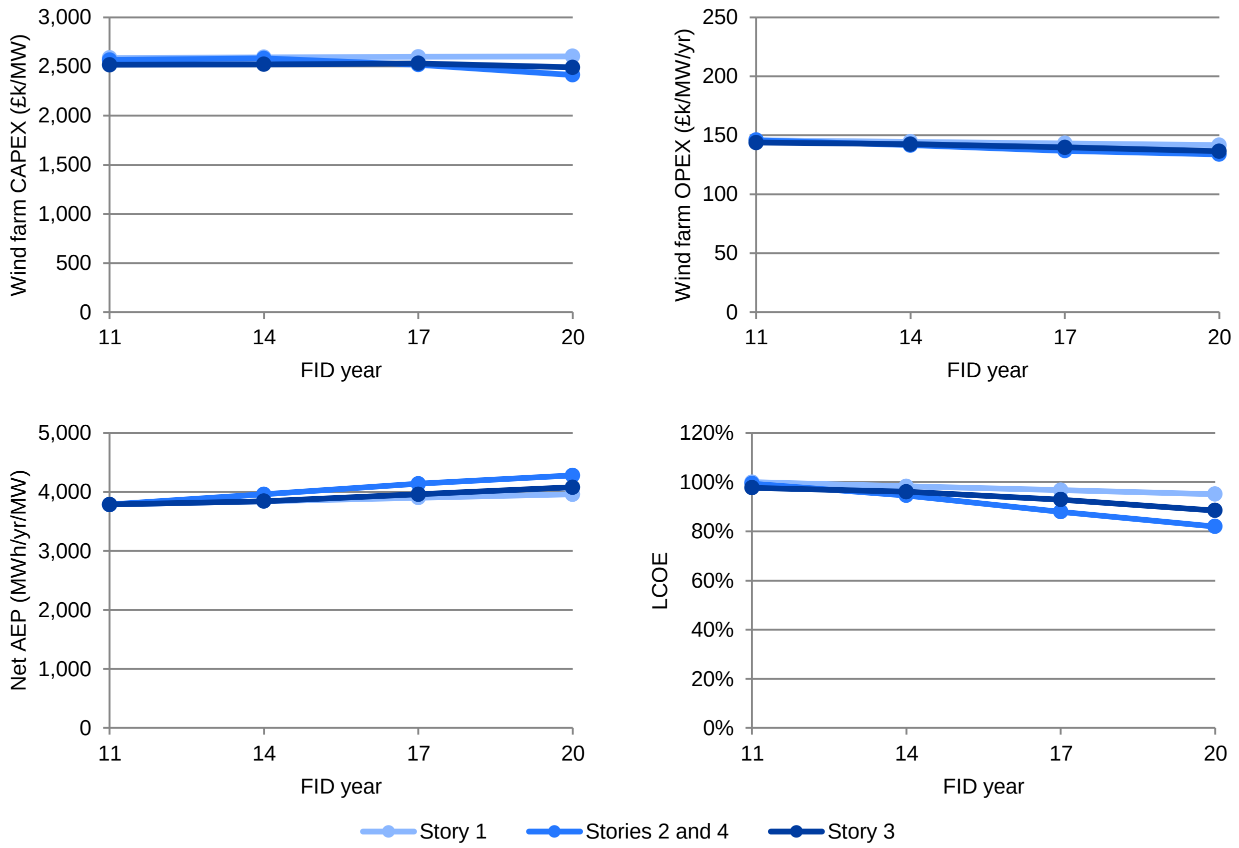

Figure 12.14 Impact of all innovations on CAPEX, OPEX, AEP and the LCOE under each Industry Story for a wind farm using 6MW-Class Turbine on Site Type B. (Note that the impact in Industry Stories 2 and 4 is identical.).

12.8. Impact of technology on risk

Risk is discussed in detail in the *Finance work stream report*. Inherent in any technical changes, whether in Turbine MW-Class or foundation type or maintenance access strategy are changes in cost, supply chain levers (such as competition) and risk. Technology development has a significant impact on construction and operational risk as well as on AEP uncertainty at time of FID. The impact of changing technology risk over time and under different Industry Stories is combined with a different pattern of changing risk developed in the Supply Chain and Finance work streams, to give an overall change in risk profile that is incorporated into the financial analysis in the *Finance work stream report*.

The key inputs to the Finance work stream grouped under construction, operational and AEP uncertainty at time of FID are discussed below.

Construction risk

It is recognised that there are different ways to take benefit of innovations in wind farm installation. As an example, *improvements in range of working conditions for support structure installation* can be used either to reduce installation cost through calculating a reduced number of weather days, but keeping the probability of exceeding this number the same, or the installation cost can be kept the same and the probability of exceeding the budgeted number of weather days will be reduced. Generally in this work stream, the benefit has been taken on cost, with the intent of not increasing risk compared with the position prior to introduction of the innovation.

The following are examples of innovations where the purpose is to improve the efficiency or reduce the risk of construction:

- *Greater level of geophysical and geotechnical surveying* as input to FEED activities, thereby increasing the certainty of ground conditions during installation
- *Improvements in range of working conditions for support structure installation*
- *Greater levels of onshore turbine commissioning*
- *Improvements in range of lifting conditions for blades,* and
- *Introduction of optimised cable pull-in and hang-off processes.*

There are some specific disruptive innovations that change the construction risk profile significantly, for example, the *introduction of float-out-and-sink installation of turbine and support structure*. This has the potential to reduce turbine and support structure installation to just one critical-path offshore operation with a wider weather envelope than for existing operations. It would also avoid onshore crane-hook operations, through the use of permanent fixed cranes. Until proven at the commercial wind farm scale, which may be in 2018, such innovations rightly do not impact on the finance community's view of risk.

Many of the innovations in turbine design have minimal impact on construction risk as installation activities are blind to the detail design of the components being placed. The change from 4MW-Class Turbines to larger turbines introduces short-term risks due to the changes in installation tooling and process, but the industry view is that, over time, a reduction in the total number of marine operations due to the reduced number of turbines in a given wind farm size reduces the construction risk.

In Industry Stories, where there is a higher focus on technology, there is:

- A more technical focus on risk reduction during installation
- An increased pace in the change of the physical size of turbines, though all Industry Stories lead to a predominance of 6MW-Class Turbines in 2020
- An increased range of foundation types, though each benefitting from a technical focus on design for installation, and
- A likelihood that there will be fewer wind turbine manufacturers in the market, reducing the number of different products to be installed.

Operational risk

Operational risk is dominated by issues relating to wind turbine reliability and maintainability. Feedback especially from technology departments within wind turbine manufacturers is that, for most, there continues to be a significantly increasing focus on reliability, maintainability and design verification, through simulation and scale testing, full-scale bench testing and prototyping and demonstration, both onshore and offshore. As above, the benefit of innovations in this space can be taken in terms of reduced anticipated OPEX cost or reduced risk of exceeding budgeted cost. Generally again, the benefit has been taken on cost, with the intent of not increasing risk compared with the position prior to introducing the innovation.

There are a range of innovations focused on operational risk reduction, including those on turbine reliability, including:

- *Improvements in mechanical geared high-speed drive trains*
- *Introduction of mid-speed and drive trains*
- *Introduction of direct-drive superconducting drive trains*
- *Improvements in workshop verification testing*
- *Improvements in blade materials, coatings and lightning protection*, and
- *Improvements in turbine design standards.*

There are also a number focused on balance of plant reliability, including:

- *Improvements in array cable system design to increase redundancy*, and
- *Improvements in jacket condition monitoring.*

There are others focused on improving the reliability of interventions:

- *Introduction of holistic, condition-based maintenance*
- *Improvements in weather forecasting*
- *Improvements in component and spares tracking / inventory management*
- *Improvements in OMS strategy for 125km from onshore base*
- *Improvements in personnel transfer from base to turbines*, and
- *Improvements in personnel access from transfer vessel to turbine.*

It is recognised that, until proven at a commercial wind farm scale, a number of turbine- and balance-of-plant design-related innovations cannot positively impact the finance community's view of risk, which is based on a demonstrable track record, rather than forecast. There is a long cycle time from the drawing board to a reduced risk premium, which is about eight years.

The change from 4MW-Class Turbines to larger turbines with new drive train solutions certainly introduces new long-term risks as well as reducing a number of known risks. The typical industry view again is that, over time, with a reduction in the total number of marine operations due to the reduced number of turbines in a given wind farm size and the reduced rate of major components requiring expensive intervention, the benefits outweigh the risks.

In Industry Stories where there is a higher focus on technology, there is:

- More technical focus on reliability, maintainability and verification
- Increased pace in the change of physical size of turbines, though again all Industry Stories lead to a predominance of 6MW-Class Turbines in 2020, and
- Increased range of drive train concepts, though each benefitting from a technical focus on design for lifetime cost reduction.

AEP uncertainty at time of FID

Estimates of AEP at the time of FID are based on predicted values, typically calculated from site-specific measured data using an installed met station. Uncertainty in this calculation has the potential to change the cost of finance for a project. A reduction in uncertainty, for example, will increase the expected yields associated with, for example, 90 per cent confidence of exceedance. Innovations in technology can impact the AEP uncertainty, for example, through the *introduction of floating met stations*. Currently, floating met stations are considered to have a higher measurement uncertainty than fixed met stations, as the measurement accuracy is not yet proven, however, they can therefore be used to gather wind data for a longer period than would otherwise have been available. The latter helps to reduce the uncertainty associated with extrapolating the data from the measurement term to the long-term average. Additionally, floating met stations can be deployed in conjunction with other met stations on a site to reduce the uncertainty associated with the spatial variation of wind conditions, by moving the floating met station to other areas of the site and comparing the station in a fixed location. The use of met stations in this way is considered to be a more powerful driver of cost reductions than the CAPEX reduction of replacement of a fixed met station modelled in the Technology work stream.

12.9. Beyond 2020

Throughout this document, the anticipated impact of innovations is considered with respect to wind farms reaching FID in 2014, 2017 and 2020. Figure 12.9 presents the innovations with the largest potential impact, showing how much of this impact is anticipated to have been realised in projects reaching FID in 2020. The potential of many innovations discussed will only be realised after wind farms reach FID in 2020 and there are a range of innovations not discussed because their anticipated impact only starts beyond 2020 FID.

Beyond the innovations considered in this project, experience suggests that there will remain significant opportunities for further LCOE reduction:

- At a turbine concept level, no benefit has been taken of different turbine concept solutions, such as two-bladed rotors, which are generally regarded as well suited to offshore conditions, and vertical axis turbines, where logic suggests a possible advantage over the conventional horizontal axis concept at a very large scale.
- At the unit level, floating foundation solutions enabling access to higher wind speed sites close to shore offer interesting future possibilities.
- At a wind farm level, centralised grid control and moving complexity from each turbine to the substation offers the prospect of further savings, along with changes to the wind farm design life, as explored also in Section 13.
- At a system level, it is anticipated that there will be significant further progress in terms of HVDC networks for transmission.

It is clear that, with a confidence in a long-term market, the opportunities for further LCOE reduction looking to 2030 and beyond are significant.

13. Sensitivity analysis

The analysis presented in this report is based on a single "best estimate" for all inputs. This section explores the sensitivity of results to a number of technology-related considerations. Section 6 of the *Supply chain work stream report* and Section 2 of the *Finance work stream report* cover other such sensitivities and *The Crown Estate Offshore Wind Pathways report* summarises sensitivity results for all work streams. The benchmark for the sensitivity analysis is a wind farm of 6MW-Class Turbines on Site Type B under Industry Story 3 (Supply chain efficiency), with FID in 2020. It is recognised that, for the purpose of this analysis, the benchmark wind farm consists of a basket of technologies, reflecting their anticipated market share at FID in 2020. This means that, when considering, for example, the steel content in the support structure, the anticipated market share of jacket and concrete foundations is taken into account, rather than just defining a single "most common" technology in the benchmark.

13.1. Sensitivity to material cost

Section 6 of the *Supply chain work stream report* considers the impact of variation of material cost, considering copper, steel and concrete. The basis for that analysis is the cost modeling carried out in the Technology work stream.

For the benchmark wind farm described above and, considering the contribution of material costs to the cost of each element, the contribution of each of the three materials to wind farm cost is established as follows:

- **Copper.** The contribution of copper is dominated by the turbine nacelle and array cables. For the nacelle, internal data matched well with a major generator supplier and externally available data. Copper content is much higher for direct-drive solutions than higher-speed generator solutions. Taking into account the anticipated market share of direct-drive turbines in the 6MW-Class, average copper content makes up approximately two per cent of the cost of the nacelle. From feedback from an experienced industry supplier of array cables, copper content currently is about one third of the cost of cables. Together with other minor contributions, it is calculated that copper makes up about one per cent of wind farm CAPEX. It is also calculated that copper makes up about one per cent of OPEX, primarily due to generator rewinds and replacements.

- **Steel.** The contribution of steel is dominated by that in the support structure, but also includes that in the nacelle. For the support structure, the market share of different foundation types is taken into account calculating that approximately one third of support structure cost is steel content, which matches well with externally available data. For the nacelle, steel content varies with both the drive train concept and the method of implementing that concept with, for example, a balance between the use of steel and cast iron. Overall, it is calculated that the average steel content is approximately four per cent of the nacelle cost. Together, with other elements, steel content therefore is anticipated to contribute 10 per cent of wind farm CAPEX for the benchmark wind farm.

- **Concrete.** The contribution of concrete is only from concrete support structures. Based on input from a number of fabricators, it is assumed that concrete contributes 17 per cent of the cost of a concrete structure. Taking into account the anticipated market share of concrete foundations for the benchmark above, the concrete share is calculated to be about one per cent of the wind farm CAPEX.

13.2. Sensitivity to exchange rate

Section 6 of the *Supply chain work stream report* also considers the impact of variation of the Sterling to Euro exchange rate, again based on an analysis of UK content carried out in the Technology work stream. For the benchmark wind farm described above, and considering the anticipated UK content of each element under Industry Story 3, the anticipated UK content of the capital element is 50 per cent and of the operational element is about 70 per cent. UK content is defined as the percentage by value of the share of all the contracts awarded to companies based in the UK relating to the wind farm. The following assumptions are made for the UK content in each wind farm element:

- **Wind farm development.** Almost all content is assumed to be from the UK, with UK-based development teams contracting UK-based suppliers who, in turn, are using UK-based assets, resulting in a total UK content of 95 per cent.

- **Wind turbine.** It is assumed that two to three UK-based blade manufacturing facilities and most nacelles for the UK market are being assembled in the UK, but with the majority of components (by value) imported. Resulting in a total UK content of 53 per cent).

- **Support structure (including tower).** It is assumed that there will be an increase in content from UK-based suppliers, although it is expected that existing overseas production centres are likely to continue to serve the market. This results in a total UK content of 51 per cent.

- **Array electrical.** The market barriers to entry are high and existing overseas production centres are likely to continue to serve the market, so the UK content will not differ greatly from the existing landscape. This results in a total UK content of 18 per cent.

- **Installation.** The international nature of installation vessel operations means the UK share of the installation and construction market will not differ greatly from the existing landscape. This results in a total UK content of 30 per cent.

- **OMS**. OMS infrastructure should be well established and will by its very nature be UK-based, with most content sourced in the UK, resulting in a total UK content of 70 per cent. Replacement component supply will follow the pattern described above for the wind turbine.

13.3. Wind farm lifetime

A frequent suggestion from project participants relating to reducing the LCOE is increasing the wind farm lifetime. Two options have been explored with industry participants.

- **Longer design life.** This refers to the purchase of wind farm components with a certificated life extended beyond the traditional 20 years. Few consider extensions beyond 25 years in the short term, though in some cases this is for reasons relating to lease and revenue arrangements with continental projects. The developer community raises a number of concerns about this option:

  - It adds initial cost to keep an option available in an environment where it is uncertain after 20 years of operation (24 years after FID), it will be economically attractive to operate the same assets further, or repower the wind farm site with different turbines (likely larger MW-Class), or decommission the site

  - A significant part of the additional cost relates to the turbine, where the lifetime of key components is already uncertain, and

  - Even if the wind farm technology lasts for the extended life time, support of the technology may no longer be available due to the anticipated changes in the commercial landscape of offshore wind over such a long period, such that a lack of spares and troubleshooting capability may significantly impact the revenue from the wind farm.

  The impact of a longer design life is anticipated to be dominated by the additional cost of materials to preserve design margins under increased fatigue duty (through the additional years of operation). Due to the different damage exponents for different materials, the percentage additional material required varies component by component. For a blade, the percentage additional material is low; for a tower, it is higher. Additional considerations relate to extending the lifetime of the surface finish and addressing the risk of obsolescence of technology and spare parts.

- **Life extension.** This refers to purchasing wind farm components with a certificated life of 20 years, followed by inspections and re-certification to extend life should the economic case justify this. This option is seen by most as the rational approach until there is confidence in the long-term operation of multi-MW turbines offshore, for the following key reasons:

  - The decision about whether it is economically beneficial to invest to extend operating life can be made over 20 years later than FID, in an environment therefore of decreased uncertainty about the economic case

  - Component or additional planned maintenance costs can take into account improvements in technology available at that point. This may include improved turbine control to reduce loads below design loads, thus actually enabling life extension with no change to selected components or improved condition monitoring methods which decrease operational cost and risk, and

  - The extension modelled is an additional five years, which is consistent with the previous option and seen by participants as likely to be achievable.

  The impact of life extension is anticipated to be dominated by additional certification, planned maintenance (inspection) and unplanned service costs, starting near the end of the standard design life and continuing to the end of the extended life.

The strategy for extending the safe operating life of each wind farm component may be different. Here, it is assumed that it is cost effective to increase OPEX to preserve AEP. In reality, it may be that the most cost-effective response to the forecast of a major component failure in the final years of a wind farm is to run the turbine at a lower power or cease production and make the turbine safe, rather than replace the component.

The change in spend and revenue profile for options 1 and 2 are compared with the benchmark in Table 13.1, below.

Table 13.1 Spend and revenue profile for options relating to wind farm life extension, relative to a benchmark wind farm of 6MW-Class Turbines on Site Type B under Industry Story 3 Supply chain efficiency, with FID in 2020.

Element	Option	
	Longer design life	Life extension
Wind farm development	Unchanged	Unchanged
Wind turbine	Four per cent increase in CAPEX mainly due to increased fatigue duty	Unchanged
Support structure	Six per cent increase in CAPEX mainly due to increased fatigue duty	Unchanged
Array Electrical	Unchanged	Unchanged
Installation	Unchanged	Unchanged
OMS	Unchanged	Six per cent increase in OPEX in years 18 to 25 due to increased certification, inspection and planned maintenance activity and increased frequency of unplanned service
AEP	Unchanged	Unchanged

Based on the above input data, the reduction in the LCOE due to increased wind farm life time as modelled in Section 5 of the *Finance work stream report* is five per cent for longer design life and six per cent for life extension.

As a separate issue, some industry participants advise that there is a perception of lower investment risk if using a wind turbine with a certificated design life greater than the standard 20 years, as defined in IEC 61400:3. The impact of defining a greater design life relates mainly to an increased material use in order to meet the increased fatigue duty. This does not necessarily have a direct relationship to improved reliability.

13.4. Sea bed conditions

In this analysis, a single set of ground conditions most relevant to Round 3 zones has been used, namely 10m dense sand on 15m stiff clay, only occasionally with locations with lower bearing pressure, presence of boulders or significant gradients.

For sites that do not fit this generic definition, there may be a change in the wind farm development, support structure, and installation costs. Based on input on each of these elements, and assuming a spread in ground conditions as weak, average and strong, the impact of the associated change in wind farm development is reported to have negligible impact on the LCOE. The variation in support structure costs is advised to be about of -10 to +15 per cent for monopile foundations but only -2 to two per cent for jacket foundations, which are anticipated to dominate the market for the benchmark site with FID in 2020. The variation in installation cost is modelled to be about -2 to five per cent. The impact on the LCOE for the benchmark site with FID in 2020 is therefore anticipated to be about -0.5 to one per cent.

14. Conclusions

This Technology work stream has considered a large number of innovations with the potential to reduce the LCOE by FID 2020. Within these, a number of distinct themes have emerged, which will be the focus of the industry's efforts to reduce costs:

- The introduction of turbines with a higher rated capacity and larger and more efficient rotors are more reliable and deliver higher energy production
- The introduction of mass-produced support structures for use in water depths of 35 metres and above
- Greater investment during wind farm development to reduce costs and risks though more extensive survey and engineering work early in the project life, and
- Enhanced installation and OMS methods using bespoke vessels and equipment which can operate in a wider range of conditions.

In this section, the prerequisites to achieving progress in these areas are explored.

Although we have treated larger turbines, increased reliability and optimised rotors under a range of distinct innovations, they are closely linked. Turbine manufacturers have recognised the value of these and most next generation turbines at 6MW and above will come to market with significant progress in all of these areas. One leading turbine manufacturer felt unable to disaggregate the costs and impacts of the drive train and turbine reliability, so closely were they linked in the development of its next generation offshore turbine.

Developers recognise the impact that these next generation turbines can have and, in particular, the wide-ranging impact of turbines with higher rated power on the balance of plant and installation costs. While several of these next generation turbines are at an advanced stage of development, developers will face a dilemma for projects with FID in 2014. It is possible that, at this point in time, only one or two of the new 6MW-Class Turbines will have had over a year of offshore operation. Some developers will face a choice between using 4MW-Class Turbines with an established, albeit not unblemished, track record and 6MW-Class Turbines with a significantly shorter track record. This is an uncomfortable position for developers of UK projects that wish to qualify for Renewables Obligation Certificates (ROCs) by having an operational wind farm in 2017. In the past, developers have considered in their decision making the benefit of maximising the competitiveness of the market looking towards Round 3 by choosing new turbine models, even if they have a shorter track record. Such a decision is easier when considering turbines for a project close to shore and with rated power in the range of 100MW to 300MW. With Round 3 phases likely to be 500MW to 1GW, the risks are recognised to be that much greater.

A prerequisite in meeting this challenge is a step change in the levels of component system and turbine-level testing and verification to build confidence that designs are suitable for use on a commercial scale. This will need to be accompanied by an increase in the quality assurance and quality control processes right through the supply chain, including for many low cost turbine components. This activity needs to be shared with developers to build confidence in manufacturers' commitment to reliability.

Essential is an increased acceptance among developers that the LCOE should be the key measure in evaluating turbine choices, hence including an assessment of OPEX. Larger turbines have an inherently higher CAPEX per megawatt but turbine manufacturers report anxiety that this is not fully appreciated by their customers. This may be a symptom of the uneasy relationship between developers and turbine manufacturers that has built up, with developers perceiving a lack of openness on the part of turbine manufacturers.

Offshore wind turbine manufacturers have demanding requirements for their factories. There are limited cost-effective options for sites with good access to North Sea projects. Siemens, Vestas and Gamesa have announced plans for new manufacturing locations in the UK, and AREVA and Alstom have announced their intention to build facilities in France. Further sites will be needed if the full potential impact of turbine innovations on the LCOE is to be realised. Despite this, the lack of coastal infrastructure will be immaterial if there is not the demand, and thus the issue of market confidence is critical. None of these factories will go ahead without a strong indication that orders for the turbines are forthcoming.

This focus on larger turbines and the increase in water depth of projects in development to 35m and more dictates a shift away from the monopile foundations that have dominated the market to date. Several decades of offshore oil and gas extraction and large bridge-building projects have delivered proven technologies in the form of space-frame structures such as jackets and concrete gravity bases. Offshore wind is another potential application and changes to the design are required to reflect the increased quantities of similar structures required, the higher focus on cost, the changed design margins and the greater importance of fatigue loading. The move to new foundation designs will require significant investment in manufacturing facilities. A catalyst for this investment will be the signing of framework contracts between developers and fabricators, similar to that which DONG Energy has with Bladt Industries for monopiles. This will be evidence that developers are passing on the benefits of the UK's zonal approach to developing the supply chain, which is an issue of concern to some companies.

For novel foundation designs, test sites are needed to prove the concept and, more importantly, the installation methods. For concrete gravity bases, for example, the underlying technology is less in doubt but developers will need confidence that they can be installed efficiently in volume. This drives additional requirements in terms of demonstrating new technology using multiple units. An example is Strabag's investment in the Albatros I project, where it plans to install 10 foundations with XEMC Darwind's 5MW turbine using a float-out-and-sink strategy.

A concern for concrete gravity base suppliers in particular is the flexibility of the consenting process to enable developers to defer a technology decision until after FID. There has not been clear guidance for developers from the Infrastructure Planning Commission (IPC) or its successor, the Planning Inspectorate, on how much flexibility will be possible and early submissions will be seen as test cases.

A recurring theme in this study has been the value in greater upfront investment in wind farm development, both in terms of site investigations and engineering studies. For example, a focus on optimising layout not only based on energy production but also taking into account the impact on CAPEX of different ground conditions and water depths, along with an improved understanding of wake effects will reduce the LCOE. In addition, more extensive cable route characterisation on average will reduce quoted costs and, in all cases, reduce the risks associated with cable-laying. A holistic approach to tower and foundation design is seen by many to also offer cost reductions. These measures require an increased investment in the development phase and the consolidation of experience from personnel from previous projects who can ensure that lessons are learnt.

Offshore wind operational practices, both during installation and OMS, are still relatively immature and future projects in deeper water and further form shore increase the scale and complexity of the work. A key element in maturing this area is investing in new fit-for-purpose vessels and equipment. For turbine installation, this process is underway, aided by a relatively clear view of the physical parameters of next generation hardware. This is less true for foundation installation. While there is a widespread recognition that jack-up vessels are not the best solution looking forward, there is less certainty about what should replace them. Feedback from industry is that jacket structures are likely to be the preferred solution and installation contractors should be in a position to refine vessel design concepts while retaining flexibility with new designs of sea fastenings. The entry to the market of companies such as Technip and Teekay will bring experience and vessels from the oil and gas sector. Having said that, there is a danger with new vessel operators entering the market that some of the offshore wind experience gained so far will not be fully used in the development of the next vessels. A catalyst to the rapid introduction of new bespoke foundation installation vessels will be partnerships between existing and new players such as that announced by Teekay and A2SEA. The process of acceleration will be aided by the long-term charters of vessels by developers, such as the contract between E.ON Climate and Renewables and MPI Offshore, which will enable early engagement of the contractor in the installation planning process.

Table 14.1 considers the key prerequisites for achieving the cost reductions discussed in this report for wind farms reaching FID in 2014. It is followed by consideration of the same for projects reaching FID in 2017 and 2020.

For a project reaching FID in 2014, typically, development work will have started in about 2009, consent will be applied for in 2012 and granted in 2013. The dominant decision is to use next generation turbines with higher rated power, optimised rotor diameter and increased reliability, which is ultimately reliant on the final three rows in the table.

The impact of decisions relating to the technology development of array cables has an insignificant impact on the LCOE of wind farm with FID in 2014 and so is not shown.

Table 14.1 Prerequisites for technology innovation to impact wind farms with FID in 2014.

No.	Element	Key decision to reduce LCOE	Owner	Timing of decision	Prerequisite
1	Wind farm development	Use multi-variable optimisation of wind farm layout and greater level of optimisation during FEED (anticipated 0.2 per cent LCOE reduction)	Wind farm developer	2012/13	Early engagement of suppliers Confidence to invest more up-front Access to tools or processes by which to better optimise layout and design Flexibility in the planning process to allow developers to delay technology choices until after consent (see row 14 below)
2	Wind turbine	Use turbine with higher rated power, optimised rotor diameter and increased reliability (anticipated 11.5 per cent LCOE reduction)	Wind farm developer	Start 2011; final decision 2014	Availability of sufficiently verified and demonstrated turbines with manufacturing plans (see row 3 below) Manufacturing plans for associated support structures Manufacturing plans for associated installation vessels Flexibility in the planning process to allow developers to delay technology choices until after consent (see row 14 below)
3	Wind turbine	Develop verified and demonstrated turbine with manufacturing plan (prerequisite to decision in row 2 above)	Wind turbine manufacturer	Start 2009/10; final decisions 2014	Confidence in a growing and sustainable UK market (or framework contract(s)) to enable decision to invest in development, verification and demonstration of turbine and construct manufacturing facilities (see row 13 below) Availability of consented test / demonstration site and verification facilities (see row 15 below) Availability of consented site for coastal manufacturing and assembly (could be outside UK)
4	Support structure	Use jacket foundations with improved design and manufacturing processes, designed holistically with tower; also use single-section tower (anticipated 1.5 per cent LCOE reduction)	Wind farm developer	Start 2011; final decision 2014	Availability of jacket foundations with improved design with manufacturing plan (see rows 5 and 6 below) Availability of single-section tower (see row 7 below) Flexibility in the planning process to allow developers to delay technology choices until after consent (see row 14 below)
5	Support structure	Develop jacket foundation improved design and manufacturing processes (prerequisite to decision in row 4 above)	Foundation manufacturer and designer	Start 2011; final decision 2014	Confidence in a growing and sustainable UK market (or framework contract(s)) to enable decision to construct improved manufacturing facility (see row 13 below) Availability of consented sites for coastal manufacturing (could be outside UK)
6	Support structure	Develop holistic jacket and tower designs (prerequisite to decision in row 4 above)	Foundation and designer and wind turbine manufacturer	2014	Collaboration between foundation designer and wind turbine manufacturer

No.	Element	Key decision to reduce LCOE	Owner	Timing of decision	Prerequisite
7	**Support structure**	Establish facilities to manufacture single section tower (prerequisite to decision in row 4 above)	Tower manufacturer	By 2015	Confidence in a growing and sustainable UK market (or framework contract(s)) to enable decision to construct manufacturing facility (see row 13 below) Availability of consented sites for coastal manufacturing (could be outside UK)
8	**Installation**	Use purpose-built fleet of installation vessels with greater operating envelope (anticipated 0.8 per cent LCOE reduction)	Wind farm developer	2014	Manufacturing plans for purpose built fleet of installation vessels (see row nine below)
9	**Installation**	Develop purpose built fleet of installation vessels (prerequisite to decision in row eight above)	Installation contractor	Start 2011; significant investment decisions from 2012	Confidence in a growing and sustainable UK market (or framework contract(s)) to enable decision to construct new vessels (see row 13 below) Collaboration including with developers and wind turbine manufacturers to provide sufficient clarity on what will be installed five to 10 years ahead
10	**OMS**	Use improved personnel transfer method, maintenance strategies and management tools (anticipated 0.3 per cent LCOE reduction)	Wind farm developer	2014 and later	Availability of sufficiently verified and demonstrated transfer methods, maintenance strategies and management tools (see rows 11 and 12 below)
11	**OMS**	Develop, demonstrate and manufacture improved personnel transfer method (prerequisite to decision in row 10 above)	Designer and supplier	Start 2012 or earlier; final decision 2014 and later	Confidence in a growing and sustainable UK market (or framework contract(s)) to enable decision to develop and demonstrate method and establish production (see row 13 below)
12	**OMS**	Develop and verify condition-based maintenance strategy (pre-requisite to decision in row 10 above)	Asset owner or third party supplier and wind turbine manufacturer	2012 and later	Confidence in a growing and sustainable UK market (or framework contract(s)) to enable decision to develop and demonstrate method and establish production (see row 13 below) Availability of data and turbines to enable the performance of condition monitoring systems to be demonstrated
13	**Various**	Provide clarity over market mechanism, and strike price for the contract for difference and long-term commitment (prerequisite to decisions in various rows above)	Government	2013	Confidence in Industry to deliver volume at the right LCOE
14	**Various**	Provide flexibility in the planning process to allow developers to delay technology choices until after consent (prerequisite to decisions in various rows above)	Government	2013	Confidence that industry will use flexibility to reduce the LCOE Sufficient underpinning research to enable flexibility

No.	Element	Key decision to reduce LCOE	Owner	Timing of decision	Prerequisite
15	**Various**	Provide further test and demonstration sites, both onshore and offshore, and verification facilities (prerequisite to decisions in various rows above)	Government, The Crown Estate and Industry	2013	Confidence in industry to use facilities to reduce the LCOE

Table 14.2 and Table 14.3 present a similar view for wind farms reaching FID in 2017 and 2020, but only including significant changes from Table 14.1 above.

Table 14.2 Prerequisites for technology innovation to impact wind farms with FID in 2017.

No.	Element	Key decision to reduce LCOE	Owner	Timing of decision	Prerequisite
1	**Wind farm development**	As Table 14.1 above, but also with increased early-stage surveying and improved treatment of cable burial depth requirements (anticipated 0.9 per cent LCOE reduction)			
2	**Wind turbine**	As rows 2 & 3 in Table 14.1 above, but incorporating innovations beyond those available in 2014, including impact of more verification testing (anticipated 14.4 per cent LCOE reduction)			
3	**Support structure**	As rows four to seven in Table 14.1 above (anticipated 1.9 per cent LCOE reduction)			
4	**Array cable**	Use higher voltage array cables and improved specification (anticipated 0.1 per cent LCOE reduction)	Wind farm developer	Start 2016; final decision 2017	Availability of sufficiently verified and demonstrated higher voltage array cable designs with manufacturing plan (see row 5 below)
5	**Array cable**	Develop and verify higher voltage array cable designs (prerequisite to decision in row 4 above)	Cable manufacturer	Start 2016; final decision 2017	Confidence in a growing and sustainable UK market (or framework contract(s)) to enable decision to develop and verify (see row 9 below)
6	**Installation**	As rows 8 & 9 in Table 14.1 above, but now also decision by wind farm developer to use float-out-and-sink solutions (see row 7 below) (anticipated 2.1 per cent LCOE reduction)			
7	**Installation**	Develop, demonstrate and establish manufacturing for use float-out-and-sink solutions (prerequisite to decision in row 4 above)	Installation contractor	Start 2010; significant investment decisions from 2012	Confidence in a growing and sustainable UK market (or framework contract(s)) to enable decision to invest in development, verification and demonstration of turbine and construct manufacturing facilities (see row 9 below) Flexibility in the planning process to allow developers to delay technology choices until after consent (see row 9 below) Availability of consented test / demonstration site and verification facilities (see row 9 below) Availability of consented site for coastal manufacturing (could be outside UK)
8	**OMS**	As rows 10 to 12 in Table 14.1 above (anticipated 0.9 per cent LCOE reduction)			
9	**Various**	As rows 13 to 15 in Table 14.1 above but, in addition, provision of access to licenses for development of further wind farm sites by The Crown Estate			

Table 14.3 Prerequisites for technology innovation to impact wind farms with FID in 2020.

No.	Element	Key decision to reduce LCOE	Owner	Timing of decision	Prerequisite
1	Wind farm development	As Table 14.1 above, but also with increased early-stage surveying and improved treatment of cable burial depth requirements (anticipated 1.8 per cent LCOE reduction)			
2	Wind turbine	As rows 2 and 3 in Table 14.1 above, but incorporating innovations beyond those available in 2014, including impact of more verification testing, turbines with further increased rated power, use of inflow wind measurements and further aerodynamic control and use of DC generation and collection (anticipated 16.6 per cent LCOE reduction)			
3	Support structure	As rows 4 to7 in Table 14.1 above (anticipated 3.6 per cent LCOE reduction)			
4	Array cable	As rows 4 to 5 in Table 14.2 above (anticipated 0.5 per cent LCOE reduction)			
5	Installation	As rows 8 and 9 in Table 14.1 above, but now also decision by wind farm developer to use float-out-and-sink solutions (see row 5 below) (anticipated three per cent LCOE reduction)			
6	OMS	As rows 10 to12 in Table 14.1 above (anticipated 1.5 per cent LCOE reduction)			
7	Various	As rows 13 to 15 in Table 14.1 above but, in addition, provision of access to licenses for development of further wind farm sites by The Crown Estate			

Table 14.4 summarises the key prerequisites, considering their impact on the introduction of new technology.

Table 14.4 Prioritisation of prerequisites according to impact and required intervention.

Prerequisite	Impact	Required intervention
Industry confidence in a growing and sustainable UK market	High	High
Availability of consented sites for coastal manufacturing and assembly (could be outside UK)	High	High
Availability of consented test and demonstration sites, both onshore and offshore, and verification facilities	High	Medium
Flexibility in the planning process to allow developers to delay technology choices until after consent	Medium	High
Early collaboration to optimise designs across elements, provide clarity on future requirements and use data to improve future designs	Medium	Medium

Appendix A. Further details of methodology

A detailed set of project assumptions was distributed to project participants in advance of their involvement in interviews and workshops. Assumptions that are relevant to the Technology work stream are provided below.

A.1 Definitions

Definitions of the scope of each element are provided in Sections 5.2 to 11.2 and summarised in Table A.1, below.

Table A.1 Definitions of the scope of each element.

Type	Parameter	Definition	Unit
CAPEX	Project up to FID	Development and consenting work paid for by the developer up to the point of FID. Includes: • Internal and external activities such as environmental and wildlife surveys, met mast (including installation) and engineering (pre FEED) and planning studies. Excludes: • Any reservation payments to suppliers.	£/MW
	Project from FID to WCD	Includes: • Further site investigations and surveys after FID • Engineering (FEED) studies • Environmental monitoring during construction • Project management (work undertaken or contracted by the developer up to WCD) • Other administrative and professional services such as accountancy and legal advice • Any reservation payments to suppliers Excludes: • Construction phase insurance • Suppliers own project management	£/MW
	Construction phase insurance	Cover from start of construction until operation start. All construction risks & third party	£/MW
	Turbine	Payment to wind turbine manufacturer for the supply of the nacelle and its sub-systems, the blades and hub, and the turbine electrical systems to the point of connection to the array cables. Includes: • Delivery to nearest port to supplier • Warranty • Commissioning costs Excludes: • Tower • OMS costs • RD&D costs	£/MW
	Support structure (including tower)	Includes: • Payment to suppliers for the supply of the support structure comprising the foundation (including any piles, transition piece and secondary steel work such as J-tubes and personnel access ladders and platforms) and the tower • Delivery to nearest port to supplier • Warranty Excludes: • OMS costs	£/MW

Type	Parameter	Definition	Unit
		• RD&D costs	
	Array cables	Includes: • Delivery to nearest port to supplier • Warranty Excludes: • OMS costs • RD&D costs	£/MW
	Installation	Includes: • Transportation of all from each supplier's nearest port • Pre-assembly work completed at a construction port before the components are taken offshore • All installation work for support structures, turbines and array cables • Commissioning work for all but turbine (including snagging post WCD) • Scour protection (for support structure and cable array) • Subsea cable protection mats etc., as required Excludes: • Installation of offshore substation / transmission assets	£/MW
DECEX	Decommissioning	Includes: • Planning work and design of any additional equipment required • Removal of the turbine and support structure to meet legal obligations • Includes further environmental work and monitoring	£/MW
OPEX	Operation and planned maintenance	Starts once first turbine is commissioned. Includes: • Operational costs relating to the day-to-day control of the wind farm • Condition monitoring • Planned preventative maintenance, health and safety inspections	£/MW/yr
	Unplanned service	Starts once first turbine is commissioned. Includes: • Reactive service in response to unplanned systems failure in the turbine or electrical systems.	£/MW/yr
	Operations phase insurance	Starts once first turbine is commissioned, taking the form of a new operational "all risks" policy and issues such as substation outages, design faults and collision risk become more significant as damages could result in wind farm outage. Insurance during operation is typically renegotiated on an annual basis.	£/MW/yr
	Transmission charges	Includes: • OFTO / Generation transmission use of system (G-TNUoS) charges.	£/MW/yr
	OPEX Other	Fixed cost elements that are unaffected by technology innovations, including: • Contributions to community funds. • Monitoring of the local environmental impact of the wind farm.	£/MW/yr
AEP	Gross AEP	The gross AEP averaged over the wind farm life at output of the turbines. Excludes aerodynamic array losses, electrical array losses and other losses. Includes any site air density adjustments from the standard turbine power curve.	MWh/yr/MW

Type	Parameter	Definition	Unit
	Wind farm availability	Energy production loss throughout the project life time due to unavailability of the wind farm system. Accounts for improvements in early years and degradation in later years. Includes: • Availability of wind turbines, structure and array cables, accounting for scheduled and unscheduled downtime. Excludes: • Transmission availability on substation and to shore and wider grid.	%
	Aerodynamic array losses	Typical wake losses within a 500MW wind farm, dependent on turbine rating.	%
	Electrical array losses	Electrical array losses between the turbines and the offshore metering point for a typical 500MW wind farm. Excludes transmission losses.	%
	Other losses	Life time energy loss from cut-in / cut-out hysteresis, power curve degradation, and power performance loss.	%
	Net energy production	AEP averaged over the wind farm life at the offshore metering point at entry to offshore substation.	MWh/yr/MW

A.2 Assumptions

Baseline costs and the impact of innovations are based on the following assumptions. While it is recognised that real projects are inherently diverse, for the purpose of developing the pathways, participants were asked to provide input to the project based on the same assumptions.

Global assumptions

The following are in addition to the discussion of Industry Stories presented in Section 2.1:

- Real (end-2011) prices
- Commodity prices fixed at the average for 2011
- Exchange rates fixed at the average for 2011 (that is, for example, £1 = €1.15)
- Energy prices fixed at the current rate
- Energy policy (The Electricity Market Reform progresses are on schedule in the White Paper, with Contract for Differences as the sole support from 2017, Renewables Obligation Certificate re-banding as stated in consultation document), and
- Deployment: three capacity trajectories with annual rates for obtaining consent, reaching FID and works completion for UK and the rest of EU are provided for each Industry Story, as presented in the Supply chain work stream report.

Wind farm assumptions

The following are in addition to the discussion of water depth, the distance to construction and the operation port and the average wind speed presented in Section 2.1.

General

The general assumptions are:

- A 500MW wind farm, as part of a multi-gigawatt Round 3 zone
- Turbines are spaced at nine rotor diameters (downwind) and six rotor diameters (across-wind) in a rectangle
- A wind farm design is used that is certificated for an operational life of 20 years
- The lowest point of the rotor sweep is at least 22 metres above MHWS
- The development and construction costs are funded entirely by the project developer, and
- A multi-contract approach is used to contracting for construction.

Meteorological regime

The meteorological regime assumptions are:

- A wind shear exponent of 0.12
- Rayleigh wind speed distribution
- A mean annual average temperature of 10°C
- The P90 energy yield is 11 per cent lower than P50 (in base case)
- The tidal range of 4m and the Hs of 1.8m is exceeded 20 per cent of the time, and
- No storm surge is considered.

Turbine

The turbine assumptions are:

- The turbine is certified to Class IA to international offshore wind turbine design standard IEC 61400-3
- The baseline turbines have a three-bladed upwind, three-stage gearbox, a partial-span power converter, a doubly-fed induction generator, 1500 rpm 690V output, and 88 m/s tip speed
    - The 4MW turbine has a 120m diameter, and a specific rating of 354W/m² (which is representative of the market-weighted average on wind farms reaching FID in 2011of four products at this scale available for FID in 2011, namely the AREVA M5000-116, Siemens SWT-3.6-120, REpower 5M (126m) and the Vestas V112-3.0MW)
    - The 6MW turbine has a 147m diameter, and a specific rating of 354 W/m², and
    - The 8MW turbine has a169m diameter, and a specific rating of 354 W/m².

Support structure

The support structure assumptions are:

- A monopile with separate transition piece and tower is used for wind farms using 4MW-Class Turbines on Site Type A; and a four-legged piled jacket with a separate tower is used for all other wind farm combinations, and
- Ground conditions are ”typical”, that is, most relevant to Round 3 zones, namely 10m dense sand on 15m stiff clay, only occasionally with locations with lower bearing pressure, the presence of boulders or significant gradients.

Array Cables

The array cable assumption is that a three core 33kV AC on fully flexible strings is used, that is, with provision to isolate an individual turbine.

Installation

The installation assumptions are:

- Installation is carried out sequentially by the foundation, array cable, then the pre-assembled tower and turbine together
- A jack-up vessel collects components from the installation port for turbine installation
- A single jack-up is used to install the monopile and TPs (Site Type 4-A only)
- Two jack-ups are used for jacket installation and pre-piling, collecting components from the installation port, and
- Array cables are installed via J-tubes, with separate cable lay and survey and burial. Decommissioning reverses the assembly process to result in installation taking one year. Piles and cables cut off at a depth below the sea bed, which is unlikely to lead to uncovering. Environmental monitoring is conducted at the end. The residual value and cost of scrapping is ignored.

OMS

OMS assumptions are:

- Transmission charges are incurred as OPEX not CAPEX, and
- Access is by work boats and mother ships or accommodation platforms for Site Type D, while jack-ups are used for major component replacement.

A.3 Calculation of the LCOE

The derivation of the LCOE as used in *The Crown Estate Offshore Wind Pathways report* is explained in Section 2 of the *Finance work stream report*. To consider the impact of technology innovations alone in this report, a measure of the LCOE is used, based on a single set of financial assumptions. It is equivalent to discounting and annualising the DECEX and the CAPEX and combining this with a constant annual OPEX, and dividing by net AEP. This method gives the LCOE for a given project that is within a few per cent of that derived in Section 5 of the *Finance work stream report*. As all mention of the LCOE in this report is relative to the 4-B baseline, this simplification introduces negligible inaccuracy.

The CAPEX spend profile is annualised by applying a factor of 0.1266, which is based on a discount rate of 10 per cent and is provided from modelling by The Crown Estate. Likewise, the factor for DECEX annualisation is 0.01587 and represents the fact that DECEX will not occur until 20 years post WCD.

The following example is intended to show the process of derivation and moderation of the impact of an innovation. There is some explanation of the figures used, but the focus is on methodology rather than content.

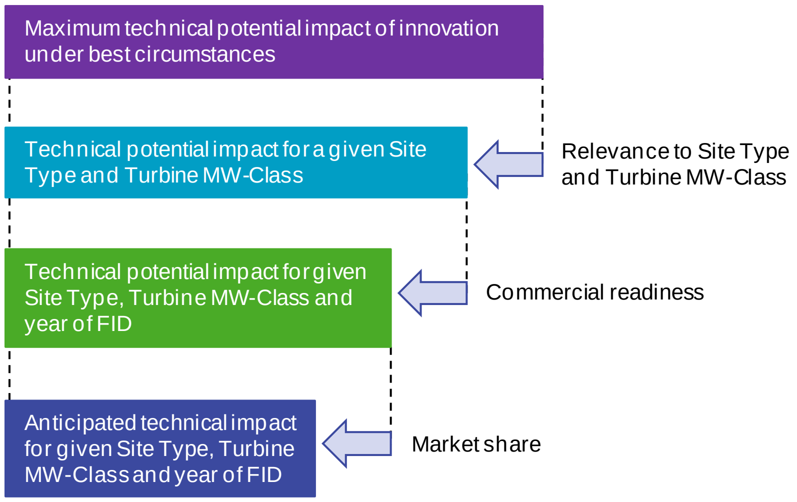

Figure A.1 Four stage process of moderation applied to the maximum potential technical impact of an innovation to derive the anticipated impact on the LCOE.

Maximum technical potential impact

Based on industry feedback, there is potential for reducing the foundation cost by 10 per cent due to the adoption of improved jacket foundation designs over those being implemented on projects reaching FID at end of 2011. This is in addition to *improvements in jacket manufacturing* and *improvements in jacket design standards*, two separate innovations. Two routes offering this reduction were identified: design improvements on standard designs; and designs new to offshore wind (such as the twisted jacket or three-leg design). On closer challenge, about one third of the savings were attributable to benefits in terms of standardisation, covered in the supply chain work stream. Taking into account the fact that the foundation is only approximately 70 per cent of the support structure cost, the maximum technical potential impact on support structure CAPEX modelled is 10 per cent x 0.67 x 0.7 = 4.7 per cent, conservatively rounded down to four per cent.

In addition, industry advised reductions in the installation cost due to improved foundation design. The potential for this varies with different designs, but an estimate of two per cent of the foundation installation cost was seen as conservative and reasonable. As the foundation installation is about half the total cost of installation, the maximum technical potential impact on installation CAPEX modelled is one per cent.

No potential impact on OPEX or AEP is modelled.

Relevance to Site Types and Turbine MW-Class

Should a jacket foundation be used on a wind farm with a given Site Type and Turbine MW-Class combination (Four Site Types x three Turbine MW-Classes = 12 cases), then the potential for reducing costs will be equally applicable to all, so the relevance is 100 per cent in each case. This parameter does not consider the market share of the innovation.

Commercial readiness

There is already a focus on reducing costs through this innovation and costs for a wind farm with FID in 2011 are already reduced somewhat. The development and introduction time for improving existing designs is relatively short. Feedback from industry is that approximately 40 per cent of the maximum technical potential of this innovation will be available for wind farms reaching FID in 2014, 70 per cent for FID in 2017 and 90 per cent for FID in 2020.

Market share

For a given Site Type and Turbine MW-Class combination, the potential market share of the innovation on wind farms with FID in 2014, 2017 and 2020 varies considerably. The market share for combination 4-A is zero as monopile foundations are anticipated to be used throughout the period. For all other combinations, and again based on industry feedback, the market share is anticipated to be 20 per cent for wind farms with FID in 2014, 40 per cent for 2017 and 70 per cent for 2020. The only adjustment to this trend is a 10 per cent share for combinations 4-B and 4-D for wind farms with FID in 2014, due to the anticipated use of some monopiles for such projects.

Taking a specific example of the anticipated impact on a wind farm using 6MW-Class Turbines on Site Type B with FID in 2020:

> The anticipated LCOE impact is evaluated by comparison of the LCOE calculated for the baseline case with the LCOE calculated for the target case. The target case includes the impact of the innovation on the costs for each element and AEP parameters, as well as the effects of relevance to Site Type and Turbine MW-Class, commercial readiness and market share. Target case impacts are calculated as follows:
>
> Impact for support structure CAPEX = Maximum potential impact (four per cent)
>
> x Relevance to Site Type B and 6MW-Class Turbine (100 per cent) = four per cent
>
> x Commercial readiness at FID in 2020 (90 per cent) = 3.6 per cent
>
> x Market share at FID in 2020 (70 per cent) = 2.52 per cent
>
> Impact for installation CAPEX = Maximum potential impact (one per cent)
>
> x Relevance to Site Type B and 6MW-Class Turbine (100 per cent) = one per cent
>
> x Commercial readiness at FID in 2020 (90 per cent) = 0.9 per cent
>
> x Market share at FID in 2020 (70 per cent) = 0.63 per cent

The LCOE for the baseline and target cases then is calculated as follows in Table A.2, below.

Table A.2 Calculation of the LCOE from cost and AEP data.

Parameter	Baseline case 4-11-B	Target case
Support structure CAPEX (£k/MW)	690	690 x (1 – 0.0252) = 673
Installation CAPEX (£k/MW)	611	611 x (1 – 0.0063) = 607
Other CAPEX (£k/MW)	1,411	1,411
Total CAPEX (£k/MW)	2,713	2,690
OPEX (£k/MW/yr)	161	161
DECEX (£/MW)	397	397
Net AEP (MWh/yr/MW)	3,691	3,691
LCOE (£/MWh)	(2,713 x 0.1266 + 397 x 0.01587 + 161) / 3,691 = 138.4	(2,690 x 0.1266 + 397 x 0.01587 + 161) / 3,691 = 137.6

The anticipated impact of the innovation on the LCOE is (137.6 – 138.4) / 138.4 = -0.57 per cent, or a 0.57 per cent reduction in the LCOE.

Appendix B. Index of innovations

Table B.1 List of innovations modelled, ranked in order of the anticipated impact for a wind farm using 6MW-Class Turbines on Site type B with FID in 2020, including a reference to the page number where the innovation is described.

Rank	Element	Innovation	Page number	Anticipated CAPEX	Anticipated OPEX	Anticipated AEP	Anticipated LCOE
1	Turbine nacelle	Increase in turbine power rating	48	-5.1%	-7.4%	2.6%	-8.5%
2	Support structure	Improvements in jacket manufacturing	94	-2.9%	-0.4%	0.05%	-2.0%
3	Turbine rotor	Improvements in blade pitch control	79	-0.5%	0.15%	0.9%	-1.2%
4	Turbine rotor	Improvements in blade aerodynamics	73	0.04%	0.1%	1.3%	-1.2%
5	Turbine rotor	Optimisation of rotor diameter (6MW)	69	8.3%	0.3%	6.9%	-1.2%
6	Installation	Improvements in range of working conditions for support structure installation	120	-1.4%	0%	0%	-1.0%
7	Turbine nacelle	Introduction of direct-drive drive trains	56	0.3%	-1.6%	0.6%	-0.9%
8	Wind farm development	Greater level of optimisation during FEED	37	-1.1%	0%	0%	-0.8%
9	Wind farm development	Introduction of multi-variable optimisation of array layouts	38	-0.4%	-0.4%	0.4%	-0.7%
10	Turbine nacelle	Introduction of mid-speed drive trains	55	-0.3%	-0.9%	0.3%	-0.7%
11	Installation	Improvements in the installation process for space-frames	120	-0.9%	0%	0%	-0.7%
12	Turbine nacelle	Improvements in AC power take-off system design	60	-0.2%	-1.7%	0.1%	-0.7%
13	Operation and maintenance	Introduction of turbine condition-based maintenance	147	0.1%	-1.5%	0.3%	-0.6%
14	Turbine nacelle	Improvements in workshop verification testing	57	0%	-1.5%	0.2%	-0.6%
15	Support structure	Improvements in jacket design	94	-0.9%	0%	0%	-0.6%
16	Operation and maintenance	Improvements in personnel access from transfer vessel to turbine	151	0%	-0.8%	0.3%	-0.5%
17	Support structure	Introduction of holistic design of the tower with the foundation	88	-0.8%	0%	0%	-0.5%
18	Turbine rotor	Improvements in process of blade manufacture	74	-0.6%	-0.3%	0.03%	-0.5%
19	Support structure	Introduction of single-section towers	88	-0.6%	-0.2%	0%	-0.5%
20	Turbine rotor	Improvements in blade design standards and process	74	-0.25%	-0.1%	0.25%	-0.4%
21	Wind farm development	Greater level of geophysical and geotechnical surveying	39	-0.6%	0%	0%	-0.4%
22	Turbine rotor	Improvements in hub assembly components	79	-0.3%	-0.7%	0.08%	-0.4%
23	Installation	Introduction of flexible sea fastenings	121	-0.6%	0%	0%	-0.4%
24	Turbine rotor	Improvements in blade tip speed	75	0.1%	0%	0.5%	-0.4%
25	Turbine rotor	Improvements in blade materials, coatings and lightning protection	75	-0.4%	-0.3%	0.03%	-0.4%

Rank	Element	Innovation	Page number	Anticipated			
				CAPEX	OPEX	AEP	LCOE
26	Installation	Introduction of float-out-and-sink installation of turbine and support structure	128	-0.5%	0%	0%	-0.3%
27	Installation	Introduction of optimised cable pull-in and hang-off processes	133	-0.4%	0%	0%	-0.3%
28	Support structure	Introduction of suction bucket technology	99	-0.4%	0%	0%	-0.3%
29	Turbine nacelle	Introduction of DC power take-off (including impact of DC array cables)	61	-0.1%	-0.2%	0.1%	-0.3%
30	Turbine rotor	Introduction of inflow wind measurement	80	0.05%	0.06%	0.3%	-0.25%
31	Installation	Improvements in range of cable installation working conditions	133	-0.4%	0%	0%	-0.25%
32	Installation	Greater use of feeder arrangements in the installation of support structures	121	-0.3%	0%	0%	-0.2%
33	Installation	Introduction of feeder arrangements in the installation of turbines	127	-0.3%	0%	0%	-0.2%
34	Array cable	Introduction of array cables with higher operating voltages	105	-0.2%	0%	0.07%	-0.2%
35	Support structure	Improvements in jacket design standards	95	-0.3%	0%	0%	-0.2%
36	Operation and maintenance	Improvements in personnel transfer from base to turbine location	151	0%	-0.3%	0.09%	-0.2%
37	Array cable	Improvements in array cable standards and client specification	105	-0.3%	0%	0%	-0.2%
38	Installation	Introduction of buoyant concrete gravity base foundations	122	-0.2%	0%	0%	-0.2%
39	Installation	Greater levels of optimised cable installation vessels and tooling	132	-0.2%	0%	0%	-0.2%
40	Operation and maintenance	Improvements in inventory management	145	0%	-0.4%	0.04%	-0.2%
41	Installation	Improvements in range of lifting conditions for blades	126	-0.2%	0%	0%	-0.1%
42	Wind farm development	Introduction of reduced cable burial depth requirements	39	-0.2%	0%	0%	-0.1%
43	Array cable	Introduction of alternative array cable core materials	106	-0.3%	0.1%	-0.03%	-0.1%
44	Installation	Introduction of whole turbine installation	128	-0.2%	0%	0%	-0.1%
45	Operation and maintenance	Improvements in weather forecasting	146	0%	-0.3%	0.03%	-0.1%
46	Turbine nacelle	Introduction of direct-drive superconducting drive trains	56	-0.02%	-0.1%	0.06%	-0.1%
47	Operation and maintenance	Improvements in jacket condition monitoring	149	0.09%	-0.6%	0.01%	-0.1%
48	Turbine nacelle	Improvements in mechanical geared high-speed drive trains	55	-0.05%	-0.1%	0.02%	-0.09%
49	Turbine rotor	Introduction of active aero control on blades	80	0.04%	0.06%	0.1%	-0.08%
50	Installation	Greater levels of onshore turbine	127	-0.08%	0%	0%	-0.05%

Rank	Element	Innovation	Page number	Anticipated			
				CAPEX	OPEX	AEP	LCOE
		commissioning					
51	Wind farm development	Introduction of floating meteorological stations	40	-0.06%	0%	0%	-0.04%
52	Array cable	Improvements in array cable insulation materials and design	107	-0.02%	0%	0%	-0.02%
53	Turbine rotor	Introduction of passive aero controlled blades	80	-0.02%	0%	0%	-0.01%
54	Array cable	Improvements in array cable system design to increase redundancy	106	0.2%	-0.06%	0.1%	-0.004%

Table B.2 List of innovations modelled, ranked in order of the maximum potential technical impact for a wind farm best suited to each innovation, including a reference to the page number where the innovation is described.

Rank	Element	Innovation	Page number	Potential			
				CAPEX	OPEX	AEP	LCOE
1	Turbine nacelle	Increase in turbine power rating (8MW)	48	-4.4%	-11.8%	4.7%	-11.1%
2	Turbine nacelle	Increase in turbine power rating (6MW)	48	-5.1%	-7.4%	2.6%	-8.5%
27	Installation	Introduction of float-out-and-sink installation of turbine and support structure	128	-7.7%	0%	0%	-5.4%
47	Turbine nacelle	Introduction of direct-drive superconducting drive trains	56	-0.9%	-4.0%	2.5%	-4.0%
3	Support structure	Improvements in jacket manufacturing	94	-4.2%	-0.6%	0.08%	-3.0%
30	Turbine nacelle	Introduction of DC power take-off (including impact of DC array cables)	61	-1.5%	-2.0%	1.4%	-2.8%
39	Installation	Introduction of buoyant concrete gravity base foundations	122	-3.8%	0%	0%	-2.7%
61	Turbine rotor	Optimisation of rotor diameter (4MW)	69	12.1%	0.4%	11.1%	-2.7%
11	Turbine nacelle	Introduction of mid-speed drive trains	55	-1.0%	-2.8%	0.8%	-2.2%
8	Turbine nacelle	Introduction of direct-drive drive trains	56	0.6%	-4.0%	1.5%	-2.1%
10	Wind farm development	Introduction of multi-variable optimisation of array layouts	38	-1.0%	-1.2%	1.1%	-2.1%
59	Turbine nacelle	Introduction of continuously variable transmission drive trains	56	-2.0%	-4.0%	-0.6%	-1.9%
5	Turbine rotor	Improvements in blade aerodynamics	73	0.06%	0.2%	2.0%	-1.8%
18	Support structure	Introduction of holistic design of the tower with the foundation	88	-2.8%	0%	0%	-1.8%
7	Installation	Improvements in range of working conditions for support structure installation	120	-2.5%	0%	0%	-1.7%
29	Support structure	Introduction of suction bucket technology	99	-2.4%	0%	0%	-1.7%
31	Turbine rotor	Introduction of inflow wind measurement	80	0.3%	0.4%	2.0%	-1.7%
4	Turbine rotor	Improvements in blade pitch control	79	-0.7%	0.2%	1.2%	-1.6%
50	Turbine rotor	Introduction of active aero control on blades	80	0.8%	1.2%	2.4%	-1.5%
57	Support structure	Improvements in monopile design standards	91	-2.1%	0%	0%	-1.4%
6	Turbine rotor	Optimisation of rotor diameter (6MW)	69	9.3%	0.4%	7.8%	-1.4%
49	Turbine nacelle	Improvements in mechanical geared high-speed drive trains	55	-0.8%	-2%	0.2%	-1.3%
9	Wind farm development	Greater level of optimisation during FEED	37	-1.5%	0%	0%	-1.1%

Rank	Element	Innovation	Page number	Potential CAPEX	Potential OPEX	Potential AEP	Potential LCOE
45	Installation	Introduction of whole turbine installation	128	-1.6%	0%	0%	-1.1%
12	Installation	Improvements in the installation process for space-frames	120	-1.5%	0%	0%	-1.0%
13	Turbine nacelle	Improvements in AC power take-off system design	60	-0.3%	-2.4%	0.2%	-1.0%
16	Support structure	Improvements in jacket design	94	-1.4%	0%	0%	-0.9%
14	Operation and maintenance	Introduction of turbine condition-based maintenance	147	0.2%	-2.3%	0.4%	-0.9%
25	Turbine rotor	Improvements in blade tip speed	75	0.2%	0%	1.0%	-0.8%
17	Operation and maintenance	Improvements in personnel access from transfer vessel to turbine	151	0%	-1.2%	0.5%	-0.8%
58	Support structure	Improvements in monopile design	90	-1.1%	-0.2%	0.03%	-0.8%
19	Turbine rotor	Improvements in process of blade manufacture	74	-1.0%	-0.4%	0.05%	-0.8%
55	Operation and maintenance	Improvements in OMS strategy for far-from-shore wind farms	145	0.02%	-3.0%	0%	-0.8%
15	Turbine nacelle	Improvements in workshop verification testing	57	0%	-2.0%	0.2%	-0.8%
22	Wind farm development	Greater level of geophysical and geotechnical surveying	39	-1.1%	0%	0%	-0.7%
20	Support structure	Introduction of single-section towers	88	-0.8%	-0.2%	0%	-0.6%
26	Turbine rotor	Improvements in blade materials, coatings and lightning protection	75	-0.6%	-0.4%	0.05%	-0.6%
21	Turbine rotor	Improvements in blade design standards and process	74	-0.3%	-0.1%	0.3%	-0.6%
60	Turbine rotor	Optimisation of rotor diameter (8MW)	69	5.3%	0.2%	4.2%	-0.6%
23	Turbine rotor	Improvements in hub assembly components	79	-0.3%	-0.8%	0.1%	-0.5%
24	Installation	Introduction of flexible sea fastenings	121	-0.7%	0%	0%	-0.5%
54	Turbine rotor	Introduction of passive aero controlled blades	80	-0.7%	0%	0%	-0.5%
33	Installation	Greater use of feeder arrangements in the installation of support structures	121	-0.6%	0%	0%	-0.4%
34	Installation	Introduction of feeder arrangements in the installation of turbines	127	-0.6%	0%	0%	-0.4%
35	Array cable	Introduction of array cables with higher operating voltages	105	-0.4%	0%	0.2%	-0.4%
36	Support structure	Improvements in jacket design standards	95	-0.6%	0%	0%	-0.4%
28	Installation	Introduction of optimised cable pull-in and hang-off processes	133	-0.5%	0%	0%	-0.4%

Rank	Element	Innovation	Page number	Potential			
				CAPEX	OPEX	AEP	LCOE
32	Installation	Improvements in range of cable installation working conditions	133	-0.5%	0%	0%	-0.4%
43	Wind farm development	Introduction of reduced cable burial depth requirements	39	-0.5%	0%	0%	-0.3%
38	Array cable	Improvements in array cable standards and client specification	105	-0.4%	0%	0%	-0.3%
42	Installation	Improvements in range of lifting conditions for blades	126	-0.4%	0%	0%	-0.3%
37	Operation and maintenance	Improvements in personnel transfer from base to turbine location	151	0%	-0.5%	0.1%	-0.3%
44	Array cable	Introduction of alternative array cable core materials	106	-0.5%	0.2%	-0.05%	-0.2%
41	Operation and maintenance	Improvements in inventory management	145	0%	-0.6%	0.05%	-0.2%
46	Operation and maintenance	Improvements in weather forecasting	146	0%	-0.5%	0.05%	-0.2%
40	Installation	Greater levels of optimised cable installation vessels and tooling	132	-0.25%	0%	0%	-0.2%
56	Installation	Improvements in the installation process for monopiles	119	-0.25%	0%	0%	-0.2%
48	Operation and maintenance	Improvements in jacket condition monitoring	149	0.1%	-0.9%	0.02%	-0.2%
52	Wind farm development	Introduction of floating meteorological stations	40	-0.2%	0%	0%	-0.1%
51	Installation	Greater levels of onshore turbine commissioning	127	-0.1%	0%	0%	-0.08%
53	Array cable	Improvements in array cable insulation materials and design	107	-0.07%	0%	0%	-0.04%
62	Array cable	Improvements in array cable system design to increase redundancy	106	0.4%	-0.1%	0.30%	-0.008%

Appendix C. Data supporting tables

Table C.1 Data relating to Figure 0.1.

Innovation	Relative impact of innovations on LCOE[67]
LCOE for wind farm with FID in 2011	100%
Increase in turbine power rating	8.5%
Optimisation of rotor diameter, aerodynamics, design and manufacture	3.7%
Introduction of next generation drive trains	3.0%
Improvements in jacket foundation design and manufacturing	2.8%
Improvements in aerodynamic control	1.9%
Improvements in support structure installation	1.9%
Greater level of array optimisation and FEED	1.2%
About 30 other innovations	5.6%
LCOE for wind farm with FID in 2020	74.9%

Table C.2 Data relating to Figure 4.2.

Element	Units	4-A	4-B	4-C	4-D	6-A	6-B	6-C	6-D	8-A	8-B	8-C	8-D
Wind farm development	£k/MW	124	125	129	134	118	119	124	128	113	114	119	122
Turbine (exc. tower)		1,024	1,024	1,024	1,024	1,136	1,136	1,136	1,136	1,252	1,252	1,252	1,252
Support structure (inc. tower)		551	690	795	693	551	622	692	624	558	612	665	615
Array cables		80	81	83	81	78	80	82	80	75	76	78	76
Installation		473	611	631	793	437	446	464	565	365	367	382	447
Decommissioning		355	458	473	595	328	334	348	424	273	275	287	335

Table C.3 Data relating to Figure 4.3.

Element	Units	4-A	4-B	4-C	4-D	6-A	6-B	6-C	6-D	8-A	8-B	8-C	8-D
Operation and planned maintenance	£k/MW/yr	26	27	28	31	21	22	23	26	20	20	21	24
Unplanned service		53	55	57	64	44	45	46	53	41	42	43	49
Other		2	2	2	2	2	2	2	2	2	2	2	2
Operating phase insurance		14	14	18	18	16	16	20	20	17	17	18	18
Transmission charges		69	69	69	133	69	69	69	134	66	66	66	124
Net capacity factor	%	40	42	44	46	41	43	45	47	42	44	46	47

[67] Note that the impact on the LCOE for a wind farm is calculated as a product of the individual impacts. The categories in the original figure are adjusted to reflect an accurate total impact.

Table C.4 Data relating to Figure 4.4.

Element	4-A	4-B	4-C	4-D	6-A	6-B	6-C	6-D	8-A	8-B	8-C	8-D
Wind farm development	3%	2%	2%	2%	2%	2%	2%	2%	2%	2%	2%	2%
Turbine	29%	27%	27%	26%	29%	28%	26%	26%	31%	30%	29%	28%
Support structure	16%	19%	21%	18%	14%	15%	16%	14%	14%	15%	15%	14%
Array cables	2%	2%	2%	2%	2%	2%	2%	2%	2%	2%	2%	2%
Installation	14%	16%	17%	20%	11%	11%	11%	13%	9%	9%	9%	10%
OPEX	33%	32%	31%	42%	31%	30%	29%	41%	29%	28%	27%	38%
Decommissioning	1%	1%	1%	1%	1%	1%	1%	1%	1%	1%	1%	1%
Total	97%	100%	101%	111%	90%	88%	87%	98%	88%	85%	84%	93%
Net capacity factor	40%	42%	44%	46%	41%	43%	45%	47%	42%	44%	46%	47%

Table C.5 Data relating to Figure 4.5.

Element	4-A	4-B	4-C	4-D	6-A	6-B	6-C	6-D	8-A	8-B	8-C	8-D
Wind farm development	3%	2%	2%	2%	2%	2%	2%	2%	2%	2%	2%	2%
Turbine	30%	27%	26%	23%	32%	31%	30%	26%	36%	35%	34%	30%
Support structure	16%	19%	21%	16%	16%	17%	18%	14%	16%	17%	18%	15%
Array cables	3%	2%	2%	2%	2%	2%	2%	2%	2%	2%	2%	2%
Installation	14%	16%	16%	18%	12%	12%	12%	13%	10%	10%	10%	11%
OPEX	34%	32%	31%	37%	34%	34%	34%	42%	33%	32%	32%	41%
Decommissioning	1%	1%	1%	1%	1%	1%	1%	1%	1%	1%	1%	1%

Table C.6 Data relating to Figure 5.1.

Impact of innovation on…	4-A	4-B	4-C	4-D	6-A	6-B	6-C	6-D	8-A	8-B	8-C	8-D
Wind farm CAPEX	-1.8%	-2.1%	-2.3%	-2.5%	-1.8%	-1.9%	-2.0%	-2.2%	-1.6%	-1.7%	-1.8%	-2.0%
Wind farm OPEX	-0.3%	-0.4%	-0.4%	-0.3%	-0.3%	-0.3%	-0.3%	-0.3%	-0.3%	-0.3%	-0.3%	-0.3%
Net AEP	0.4%	0.4%	0.4%	0.4%	0.4%	0.4%	0.3%	0.3%	0.4%	0.3%	0.3%	0.3%
LCOE	-2.2%	-2.0%	-2.2%	-2.2%	-1.9%	-1.8%	-2.0%	-1.9%	-1.8%	-1.7%	-1.8%	-1.8%

Table C.7 Data relating to Figure 5.2

Innovation	Impact of innovation on LCOE[67]	Potential impact of innovation on LCOE[67]
Greater level of optimisation during FEED	-0.8%	-1.1%
Introduction of reduced cable burial depth requirements	-0.7%	-2.1%
Greater level of geophysical and geotechnical surveying	-0.4%	-0.7%
Introduction of multi-variable optimisation of array layouts	-0.1%	-0.3%
Greater level of optimisation during FEED	-0.04%	-0.1%

Table C.8 Data relating to Figure 5.4.

Year	Proportion of wind farm development CAPEX
-9	7.1%
-8	10.6%
-7	10.9%
-6	10.0%
-5	8.6%
-4	9.2%
-3	10.0%
-2	10.4%
-1	11.0%
0	11.2%
1	1.0%

Table C.9 Data relating to Figure 6.1.

Impact of innovation on…	4-A	4-B	4-C	4-D	6-A	6-B	6-C	6-D	8-A	8-B	8-C	8-D
Wind farm CAPEX	-0.6%	-0.6%	-0.5%	-0.5%	-0.5%	-0.5%	-0.4%	-0.4%	-0.7%	-0.7%	-0.6%	-0.7%
Wind farm OPEX	-3.2%	-3.3%	-3.3%	-2.7%	-4.6%	-4.7%	-4.7%	-3.8%	-4.6%	-4.7%	-4.8%	-3.8%
Net AEP	0.7%	0.7%	0.7%	0.7%	1.3%	1.3%	1.3%	1.4%	1.3%	1.3%	1.3%	1.3%
LCOE	-2.1%	-2.1%	-2.1%	-2.1%	-3.0%	-3.1%	-3.0%	-3.0%	-3.1%	-3.1%	-3.1%	-3.1%

Table C.10 Data relating to Figure 6.2.

Innovation	Impact of innovation on LCOE[67]	Potential impact of innovation on LCOE[67]
Increase in turbine power rating	-8.5%	-8.5%
Introduction of direct-drive drive trains	-0.9%	-2.1%
Introduction of mid-speed drive trains	-0.7%	-2.2%
Improvements in AC power take-off system design	-0.7%	-1.0%
Improvements in workshop verification testing	-0.6%	-0.8%
Introduction of DC power take-off (including impact of DC array cables)	-0.3%	-2.8%
Introduction of direct-drive superconducting drive trains	-0.1%	-4.0%
Improvements in mechanical geared high-speed drive trains	-0.1%	-1.3%

Table C.11 Data relating to Figure 6.3.

Innovation	Impact of innovation on LCOE[67]	Potential impact of innovation on LCOE[67]
Increase in turbine power rating	-11.3%	-11.3%
Introduction of mid-speed drive trains	-0.8%	-2.2%
Introduction of direct-drive drive trains	-0.8%	-2.1%
Improvements in AC power take-off system design	-0.7%	-1.0%
Improvements in workshop verification testing	-0.6%	-0.8%
Introduction of DC power take-off (including impact of DC array cables)	-0.3%	-2.8%
Introduction of direct-drive superconducting drive trains	-0.2%	-4.0%
Introduction of continuously variable transmission drive trains	-0.1%	-1.9%

Table C.12 Data relating to Figure 6.5.

Element	Change in element	Impact of change in element on LCOE
Wind farm development	-6.8%	-0.1%
Turbine rotor	18.4%	1.7%
Turbine nacelle	6.2%	0.9%
Support structure	-10.0%	-1.7%
Array cable	-1.8%	0.0%
Installation	-27.1%	-4.0%
OMS	-9.1%	-2.9%
Net AEP	2.6%	-2.6%
DECEX	-27.1%	-0.3%

Table C.13 Data relating to Figure 7.1.

Impact of innovation on…	4-A	4-B	4-C	4-D	6-A	6-B	6-C	6-D	8-A	8-B	8-C	8-D
Wind farm CAPEX	5.8%	5.6%	5.5%	5.1%	6.3%	6.3%	6.2%	5.8%	2.9%	3.0%	2.9%	2.7%
Wind farm OPEX	-0.3%	-0.3%	-0.3%	-0.2%	-0.4%	-0.4%	-0.4%	-0.3%	-0.5%	-0.5%	-0.5%	-0.4%
Net AEP	8.3%	8.3%	8.2%	8.1%	10.4%	10.3%	10.3%	10.2%	7.4%	7.3%	7.3%	7.3%
LCOE	-4.5%	-4.0%	-4.0%	-4.5%	-5.9%	-5.3%	-5.2%	-5.9%	-5.2%	-4.9%	-4.9%	-5.2%

Table C.14 Data relating to Figure 7.2.

Innovation	Impact of innovation on LCOE[67]	Potential impact of innovation on LCOE[67]
Optimisation of rotor diameter (6MW)	-1.2%	-1.4%
Improvements in blade pitch control	-1.2%	-1.6%
Improvements in blade aerodynamics	-1.2%	-1.8%
Improvements in process of blade manufacture	-0.5%	-0.8%
Improvements in blade design standards and process	-0.4%	-0.6%
Improvements in hub assembly components	-0.4%	-0.5%
Improvements in blade tip speed	-0.4%	-0.8%
Improvements in blade materials, coatings and lightning protection	-0.4%	-0.6%
Introduction of inflow wind measurement	-0.3%	-1.7%
Introduction of active aero control on blades	-0.1%	-1.5%
Introduction of passive aero controlled blades	-0.01%	-0.5%

Table C.15 Data relating to Figure 8.1.

Impact of innovation on…	4-A	4-B	4-C	4-D	6-A	6-B	6-C	6-D	8-A	8-B	8-C	8-D
Wind farm CAPEX	-4.2%	-5.4%	-5.9%	-5.2%	-4.6%	-5.1%	-5.3%	-4.9%	-4.5%	-4.8%	-5.0%	-4.7%
Wind farm OPEX	-0.2%	-0.5%	-0.5%	-0.4%	-0.4%	-0.4%	-0.4%	-0.4%	-0.4%	-0.4%	-0.4%	-0.3%
Net AEP	0.0%	0.1%	0.1%	0.1%	0.1%	0.1%	0.1%	0.1%	0.1%	0.1%	0.1%	0.1%
LCOE	-3.6%	-4.1%	-4.5%	-3.6%	-3.4%	-3.8%	-4.2%	-3.4%	-3.3%	-3.7%	-4.0%	-3.3%

Table C.16 Data relating to Figure 8.2.

Innovation	Impact of innovation on LCOE[67]	Potential impact of innovation on LCOE[67]
Improvements in jacket manufacturing	-2.0%	-3.0%
Improvements in jacket design	-0.6%	-0.9%
Introduction of holistic design of the tower with the foundation	-0.5%	-1.8%
Introduction of single-section towers	-0.5%	-0.6%
Introduction of suction bucket technology	-0.3%	-1.7%

Table C.17 Data relating to Figure 8.4.

Turbine/Site Type			£k/MW			
	Transition piece	Monopile	Pin piles	Jacket	Tower	Foundation installation
4-A	176	231			144	232
4-B			123	422	145	371
4-C			146	502	146	389
4-D			123	422	147	497
6-A			86	295	170	251
6-B			102	348	172	260
6-C			117	401	173	277
6-D			102	348	175	350
8-A			81	278	200	212
8-B			93	318	202	213
8-C			104	358	203	228
8-D			93	318	205	271

Table C.18 Data relating to Figure 9.1.

Impact of innovation on…	4-A	4-B	4-C	4-D	6-A	6-B	6-C	6-D	8-A	8-B	8-C	8-D
Wind farm CAPEX	-0.5%	-0.5%	-0.5%	-0.4%	-0.5%	-0.5%	-0.5%	-0.5%	-0.5%	-0.5%	-0.5%	-0.5%
Wind farm OPEX	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
Net AEP	0.2%	0.2%	0.2%	0.2%	0.2%	0.2%	0.2%	0.2%	0.2%	0.2%	0.2%	0.2%
LCOE	-0.5%	-0.5%	-0.5%	-0.5%	-0.5%	-0.5%	-0.5%	-0.5%	-0.5%	-0.5%	-0.5%	-0.5%

Table C.19 Data relating to Figure 9.2.

Innovation	Impact of innovation on LCOE[67]	Potential impact of innovation on LCOE[67]
Introduction of array cables with higher operating voltages	-0.2%	-0.4%
Improvements in array cable standards and client specification	-0.2%	-0.3%
Introduction of alternative array cable core materials	-0.1%	-0.2%
Improvements in array cable insulation materials and design	-0.02%	-0.04%
Improvements in array cable system design to increase redundancy	-0.004%	-0.01%

Table C.20 Data relating to Figure 10.1.

Impact of innovation on…	4-A	4-B	4-C	4-D	6-A	6-B	6-C	6-D	8-A	8-B	8-C	8-D
Wind farm CAPEX	-4.0%	-5.1%	-5.4%	-7.3%	-4.0%	-4.2%	-4.2%	-5.3%	-3.5%	-3.5%	-3.5%	-4.3%
Wind farm OPEX	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
Net AEP	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
LCOE	-5.0%	-3.9%	-4.2%	-5.0%	-3.7%	-3.2%	-3.3%	-3.7%	-3.1%	-2.7%	-2.8%	-3.1%

Table C.21 Data relating to Figure 10.2.

Innovation	Impact of innovation on LCOE[67]	Potential impact of innovation on LCOE[67]
Improvements in range of working conditions for support structure installation	-1.0%	-1.7%
Improvements in the installation process for space-frames	-0.7%	-1.0%
Introduction of flexible sea fastenings	-0.4%	-0.5%
Introduction of float-out-and-sink installation of turbine and support structure	-0.3%	-5.4%
Introduction of optimised cable pull-in and hang-off processes	-0.3%	-0.3%
Improvements in range of cable installation working conditions	-0.25%	-0.3%
Greater use of feeder arrangements in the installation of support structures	-0.2%	-0.4%
Introduction of feeder arrangements in the installation of turbines	-0.2%	-0.4%
Introduction of buoyant concrete gravity base foundations	-0.2%	-2.7%
Greater levels of optimised cable installation vessels and tooling	-0.2%	-0.2%
Improvements in range of lifting conditions for blades	-0.1%	-0.3%
Introduction of whole turbine installation	-0.1%	-1.1%
Greater levels of onshore turbine commissioning	-0.1%	-0.1%

Table C.22 Data relating to Figure 11.1.

Impact of innovation on…	4-A	4-B	4-C	4-D	6-A	6-B	6-C	6-D	8-A	8-B	8-C	8-D
Wind farm CAPEX	-4.0%	-5.1%	-5.4%	-7.3%	-4.0%	-4.2%	-4.2%	-5.3%	-3.5%	-3.5%	-3.5%	-4.3%
Wind farm OPEX	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
Net AEP	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
LCOE	-5.0%	-3.9%	-4.2%	-5.0%	-3.7%	-3.2%	-3.3%	-3.7%	-3.1%	-2.7%	-2.8%	-3.1%

Table C.23 Data relating to Figure 11.2.

Innovation	Impact of innovation on LCOE[67]	Potential impact of innovation on LCOE[67]
Introduction of turbine condition-based maintenance	-0.6%	-0.9%
Improvements in personnel access from transfer vessel to turbine	-0.5%	-0.8%
Improvements in personnel transfer from base to turbine location	-0.2%	-0.3%
Improvements in inventory management	-0.1%	-0.2%
Improvements in weather forecasting	-0.1%	-0.2%

Table C.24 Data relating to Figure 11.5.

Year	1	2	3	4	5	6	7	8	9	10
OMS during warranty period (£k/MW/yr)	69.7	69.7	69.7	69.7	69.7					
OMS (Operations & planned maintenance) (£k/MW/yr)						24.6	24.6	24.6	24.6	24.6
OMS (Unplanned service - Proactive) (£k/MW/yr)						8.0	9.8	11.6	13.4	15.2
OMS (Unplanned service - Reactive) (£k/MW/yr)						49.4	47.6	45.8	44.0	42.2
Total OMS expenditure (forecast at FID) (£k/MW/yr)	82.0	83.0	83.0	82.0	81.0	82.0	83.2	84.5	85.7	87.0
Total OMS expenditure (forecast at FID range top) (£k/MW/yr)	98.0	88.0								
Wind farm availability (%)	94.0	94.8	95.3	95.5	95.5	95.5	95.5	95.5	95.5	95.5

Year	11	12	13	14	15	16	17	18	19	20
OMS during warranty period (£k/MW/yr)										
OMS (Operations & planned maintenance) (£k/MW/yr)	24.6	24.6	24.6	24.6	24.6	24.6	24.6	24.6	24.6	24.6
OMS (Unplanned service - Proactive) (£k/MW/yr)	16.9	18.7	20.5	22.3	24.1	25.8	27.6	29.4	31.1	32.9
OMS (Unplanned service - Reactive) (£k/MW/yr)	40.5	38.7	36.9	35.1	33.3	31.6	29.8	28.0	26.2	24.5
Total OMS expenditure (forecast at FID) (£k/MW/yr)	82.0	83.0	83.0	82.0	81.0	82.0	83.2	84.5	85.7	87.0
Total OMS expenditure (forecast at FID range top) (£k/MW/yr)	98.0	88.0								
Wind farm availability (%)	94.0	94.8	95.3	95.5	95.5	95.5	95.5	95.5	95.5	95.5

Table C.25 Data relating to Figure 12.1.

Impact of innovation on…	4-A	4-B	4-C	4-D	6-A	6-B	6-C	6-D	8-A	8-B	8-C	8-D
Wind farm CAPEX	-5.2%	-7.9%	-8.9%	-10.4%	-5.0%	-5.6%	-6.2%	-7.2%	-7.6%	-7.9%	-8.3%	-8.9%
Wind farm OPEX	-6.5%	-7.3%	-7.3%	-7.4%	-8.0%	-8.2%	-8.3%	-7.9%	-7.8%	-8.0%	-8.2%	-7.7%
Net AEP	10.4%	10.4%	10.3%	10.3%	13.1%	13.0%	12.9%	12.9%	9.9%	9.9%	9.9%	9.9%
LCOE	-18.3%	-16.9%	-17.5%	-18.3%	-18.5%	-17.5%	-17.9%	-18.5%	-17.2%	-16.7%	-17.0%	-17.2%

Table C.26 Data relating to Figure 12.2.

Impact of innovation on…	4-A	4-B	4-C	4-D	6-A	6-B	6-C	6-D	8-A	8-B	8-C	8-D
Wind farm CAPEX	-15.0%	-7.7%	-4.5%	-4.0%	-12.5%	-10.1%	-7.4%	-7.2%	-13.2%	-11.5%	-9.4%	-9.5%
Wind farm OPEX	-7.9%	-7.3%	-6.0%	-1.5%	-17.7%	-16.8%	-15.8%	-9.5%	-20.5%	-19.6%	-18.7%	-12.0%
Net AEP	4.1%	10.4%	14.9%	19.2%	9.7%	16.0%	20.6%	24.9%	8.9%	15.0%	19.5%	23.7%
LCOE	-17.2%	-16.9%	-17.0%	-9.8%	-22.7%	-25.3%	-25.0%	-18.3%	-23.0%	-25.8%	-26.0%	-19.4%

Table C.27 Data relating to Figure 12.3.

		4MW-Class				6MW-Class			8MW-Class	
	Site Type	FID 2011	FID 2014	FID 2017	FID 2020	FID 2014	FID 2017	FID 2020	FID 2017	FID 2020
Annualised cost (£k/MW)	A	482	482	463	440	478	458	433	457	428
	B	525	524	498	469	490	469	443	466	436
	C	550	546	520	487	509	489	462	477	451
	D	636	627	589	550	585	555	522	542	509
Net capacity factor	A	40%	41%	43%	44%	43%	45%	46%	45%	46%
	B	42%	44%	45%	47%	45%	47%	49%	47%	48%
	C	44%	45%	47%	48%	47%	49%	51%	49%	50%
	D	46%	47%	49%	50%	49%	51%	53%	51%	52%
LCOE relative to 4-11-B	A	97%	94%	88%	83%	89%	83%	77%	82%	77%
	B	100%	96%	89%	83%	86%	80%	75%	79%	74%
	C	101%	96%	89%	83%	87%	81%	75%	79%	74%
	D	110%	105%	97%	90%	95%	88%	82%	86%	81%

Table C.28 Data relating to Figure 12.4.

Element	4-11-A	4-11-B	4-11-C	4-11-D	6-11-A	6-11-B	6-11-C	6-11-D	8-11-A	8-11-B	8-11-C	8-11-D
Wind farm development	3%	2%	2%	2%	2%	2%	2%	2%	2%	2%	2%	2%
Turbine	29%	27%	27%	26%	29%	28%	26%	26%	31%	30%	29%	28%
Support structure	16%	19%	21%	18%	14%	15%	16%	14%	14%	15%	15%	14%
Array cables	2%	2%	2%	2%	2%	2%	2%	2%	2%	2%	2%	2%
Installation	14%	16%	17%	20%	11%	11%	11%	13%	9%	9%	9%	10%
OPEX	33%	32%	31%	42%	31%	30%	29%	41%	29%	28%	27%	38%
Decommissioning	1%	1%	1%	1%	1%	1%	1%	1%	1%	1%	1%	1%
Total	97%	100%	101%	111%	90%	88%	87%	98%	88%	85%	84%	93%
Net capacity factor	40%	42%	44%	46%	41%	43%	45%	47%	42%	44%	46%	47%

Element	4-20-A	4-20-B	4-20-C	4-20-D	6-20-A	6-20-B	6-20-C	6-20-D	8-20-A	8-20-B	8-20-C	8-20-D
Wind farm development	2%	2%	2%	2%	2%	2%	2%	2%	2%	2%	2%	2%
Turbine	26%	25%	24%	23%	27%	26%	25%	24%	29%	27%	26%	25%
Support structure	12%	13%	15%	12%	11%	12%	12%	11%	11%	11%	11%	10%
Array cables	2%	2%	2%	1%	1%	1%	1%	1%	1%	1%	1%	1%
Installation	8%	10%	10%	11%	7%	7%	7%	8%	6%	6%	6%	6%
OPEX	28%	26%	26%	35%	24%	23%	22%	31%	23%	22%	22%	30%
Decommissioning	1%	1%	1%	1%	1%	1%	1%	1%	0%	0%	0%	1%
Total	78%	78%	78%	86%	73%	71%	70%	77%	72%	70%	69%	75%
Net capacity factor	44%	46%	48%	50%	46%	49%	51%	53%	46%	48%	50%	52%

Table C.29 Data relating to Figure 12.5.

Element	4-11-A	4-11-B	4-11-C	4-11-D	6-11-A	6-11-B	6-11-C	6-11-D	8-11-A	8-11-B	8-11-C	8-11-D
Wind farm development	3%	2%	2%	2%	2%	2%	2%	2%	2%	2%	2%	2%
Turbine	30%	27%	26%	23%	32%	31%	30%	26%	36%	35%	34%	30%
Support structure	16%	19%	21%	16%	16%	17%	18%	14%	16%	17%	18%	15%
Array cables	3%	2%	2%	2%	2%	2%	2%	2%	2%	2%	2%	2%
Installation	14%	16%	16%	18%	12%	12%	12%	13%	10%	10%	10%	11%
OPEX	34%	32%	31%	37%	34%	34%	34%	42%	33%	32%	32%	41%
Decommissioning	1%	1%	1%	1%	1%	1%	1%	1%	1%	1%	1%	1%

Element	4-20-A	4-20-B	4-20-C	4-20-D	6-20-A	6-20-B	6-20-C	6-20-D	8-20-A	8-20-B	8-20-C	8-20-D
Wind farm development	3%	2%	2%	2%	2%	2%	2%	2%	2%	2%	2%	2%
Turbine	33%	31%	30%	27%	38%	37%	36%	31%	40%	39%	38%	34%
Support structure	15%	17%	19%	14%	15%	16%	18%	14%	15%	16%	17%	14%
Array cables	2%	2%	2%	2%	2%	2%	2%	2%	2%	2%	2%	2%
Installation	11%	13%	12%	13%	10%	10%	10%	10%	8%	8%	8%	8%
OPEX	35%	33%	33%	41%	32%	32%	32%	40%	32%	32%	32%	40%
Decommissioning	1%	1%	1%	1%	1%	1%	1%	1%	1%	1%	1%	1%

Table C.30 Data relating to Figure 12.6.

Element	Relative impact of innovations on LCOE[67]
LCOE for 4MW-Class Turbine, FID 2011	100%
Wind farm development	1.8%
Turbine rotor	5.6%
Turbine nacelle	11.7%
Support structure	3.6%
Array cable	0.5%
Installation	3.0%
OMS	1.5%
Changes in contingency, insurance and transmission charges	3.4%
LCOE for 6MW-Class Turbine, FID 2020	72.7%

Table C.31 Data relating to Figure 12.7.

Innovation	Impact of innovation on LCOE[67]	Potential impact of innovation on LCOE[67]
Increase in turbine power rating	-8.5%	-8.5%
Improvements in jacket manufacturing	-2.0%	-3.0%
Optimisation of rotor diameter (6MW)	-1.2%	-1.4%
Improvements in blade pitch control	-1.2%	-1.6%
Improvements in blade aerodynamics	-1.2%	-1.8%
Improvements in range of working conditions for support structure installation	-1.0%	-1.7%
Introduction of direct-drive drive trains	-0.9%	-2.1%
Greater level of optimisation during FEED	-0.8%	-1.1%
Introduction of multi-variable optimisation of array layouts	-0.7%	-2.1%
Introduction of mid-speed drive trains	-0.7%	-2.2%
Improvements in the installation process for space-frames	-0.7%	-1.0%
Improvements in AC power take-off system design	-0.7%	-1.0%
Other innovations	-10.2%	-29.2%

Table C.32 Data relating to Figure 12.9.

Innovation	Impact of innovation on LCOE[67]	Potential impact of innovation on LCOE[67]
Increase in turbine power rating	-8.5%	-11.3%
Introduction of float-out-and-sink installation of turbine and support structure	-2.0%	-5.4%
Introduction of direct-drive superconducting drive trains	-1.2%	-4.0%
Improvements in jacket manufacturing	-1.2%	-3.0%
Introduction of DC power take-off (including impact of DC array cables)	-1.2%	-2.8%
Introduction of buoyant concrete gravity base foundations	-0.9%	-2.7%
Introduction of mid-speed drive trains	-0.8%	-2.2%
Introduction of multi-variable optimisation of array layouts	-0.7%	-2.1%
Introduction of direct-drive drive trains	-0.7%	-2.1%
Introduction of continuously variable transmission drive trains	-0.7%	-1.9%
Improvements in blade aerodynamics	-0.7%	-1.8%
Introduction of holistic design of the tower with the foundation	-0.6%	-1.8%
Increase in turbine power rating	-8.5%	-11.3%

Table C.33 Data relating to Figure 12.10.

Turbine MW-Class-Year	Wind farm CAPEX (£k/MW)	OPEX (£k/MW/yr)	Net AEP (MWh/yr/MW)	LCOE
4-11	2,730	159	3,691	100%
4-14	2,739	156	3,825	96%
4-17	2,645	151	3,983	89%
4-20	2,503	147	4,074	83%
6-14	2,581	142	3,960	86%
6-17	2,518	137	4,141	80%
6-20	2,413	134	4,280	75%
8-17	2,514	133	4,139	79%
8-20	2,393	130	4,245	74%

Table C.34 Data relating to Figure 12.11.

Innovation	Impact of innovation on LCOE[67]	Potential impact of innovation on LCOE[67]
Optimisation of rotor diameter (4MW)	-1.6%	-2.6%
Introduction of holistic design of the tower with the foundation	-1.3%	-1.6%
Improvements in range of working conditions for support structure installation	-1.1%	-1.5%
Improvements in blade pitch control	-0.9%	-1.5%
Introduction of multi-variable optimisation of array layouts	-0.7%	-2.1%
Improvements in monopile design standards	-0.7%	-1.2%
Improvements in mechanical geared high-speed drive trains	-0.7%	-1.3%
Greater level of optimisation during FEED	-0.7%	-0.9%
Improvements in blade aerodynamics	-0.6%	-1.8%
Introduction of turbine condition-based maintenance	-0.6%	-0.9%
Improvements in personnel access from transfer vessel to turbine	-0.5%	-0.9%
Improvements in AC power take-off system design	-0.5%	-1.0%
Other innovations	-6.9%	-27.8%

Table C.35 Data relating to Figure 12.12.

Innovation	Impact of innovation on LCOE[67]	Potential impact of innovation on LCOE[67]
Increase in turbine power rating	-11.3%	-11.3%
Improvements in jacket manufacturing	-2.0%	-3.0%
Improvements in blade pitch control	-1.2%	-1.6%
Improvements in blade aerodynamics	-1.2%	-1.8%
Improvements in range of working conditions for support structure installation	-1.0%	-1.7%
Introduction of mid-speed drive trains	-0.8%	-2.2%
Greater level of optimisation during FEED	-0.8%	-1.1%
Introduction of direct-drive drive trains	-0.8%	-2.1%
Introduction of multi-variable optimisation of array layouts	-0.7%	-2.1%
Improvements in the installation process for space-frames	-0.7%	-1.0%
Improvements in AC power take-off system design	-0.7%	-1.0%
Improvements in workshop verification testing	-0.6%	-0.8%
Other innovations	-10.3%	-29.2%

Table C.36 Data relating to Figure 12.13.

Turbine MW-Class-Year	Wind farm CAPEX (£k/MW)	OPEX (£k/MW/yr)	Net AEP (MWh/yr/MW)	LCOE
4-11-A	2,427	157	3,482	104%
4-14-A	2,445	154	3,609	100%
4-17-A	2,397	150	3,756	94%
4-20-A	2,293	146	3,843	88%
4-11-B	2,730	159	3,691	107%
4-14-B	2,739	156	3,825	103%
4-17-B	2,645	151	3,983	95%
4-20-B	2,503	147	4,074	89%
4-11-C	2,870	165	3,844	107%
4-14-C	2,863	162	3,982	103%
4-17-C	2,770	157	4,145	95%
4-20-C	2,601	153	4,241	89%
4-11-D	2,938	230	3,991	118%
4-14-D	2,906	226	4,133	112%
4-17-D	2,789	219	4,301	104%
4-20-D	2,615	213	4,401	96%

Table C.37 Data relating to Figure 12.14.

Turbine MW-Class-Year	Wind farm CAPEX (£k/MW)	OPEX (£k/MW/yr)	Net AEP (MWh/yr/MW)	LCOE
Story 1	2,587	146	3,787	100%
Story 1	2,592	144	3,845	98%
Story 1	2,597	143	3,902	97%
Story 1	2,602	142	3,960	95%
Stories 2 and 4	2,565	146	3,787	99%
Stories 2 and 4	2,581	142	3,960	95%
Stories 2 and 4	2,518	137	4,141	88%
Stories 2 and 4	2,413	134	4,280	82%
Story 3	2,516	144	3,787	98%
Story 3	2,521	142	3,845	96%
Story 3	2,531	140	3,960	93%
Story 3	2,490	137	4,080	89%

Appendix D. Consultees

The following companies participated in this study by providing their perspectives and insights on potential future offshore wind cost reduction, together with supporting information:

A2SEA
Alstom
Ambau
AREVA
Atkins
Ballast Nedam
Burntisland Fabrication (BiFab)
Bladt Industries
BMT Nigel Gee
Carbon Trust
Centrica
CT Offshore
CTC Marine
DONG
DTU Wind Energy
E.ON
ETI
Fluor
Fraunhofer Institut für Windenergie und Energiesystemtechnik (IWES)
Fugro
GE Energy
GE Energy, Power Conversion
GeoSea
Global Marine Systems
Gravitas Offshore Limited
GustoMSC
JDR Cable Systems
KBR
KCI
Mainstream Renewable Power
Moog
MPI Offshore
Nexans
OGN Group
Peel Ports
Prysmian
Ramboll
REpower Systems SE
RES Offshore
Ricardo
RWE npower renewables
ScottishPower Renewables
SeaRoc
Seaway Heavy Lifting
Siemens
SLP Energy
Smulders Projects
Subsea 7
Technip
University of Strathclyde
Vattenfall
Vestas
VINCI Offshore Wind UK
Visser & Smit Marine Contracting
WeserWind
ZF Wind Power Antwerpen