FICHTNER prognos

Cost Reduction Potentials of Offshore Wind Power **in Germany**

Long Version

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For the
The German Offshore
Wind Energy Foundation
and partners

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Berlin, August 2013

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Year of foundation
1959

Scope of activities
Prognos provides Europe-wide consultancy services to policymakers and to decision makers in the industry. Based on unbiased analyses and solid prognoses, we develop practical foundations for decision-making and strategies for the future of companies, public entities and international organisations.

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Fichtner - The company at a glance

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Year of foundation

1912 (Fichtner Group)

Scope of activities

The Fichtner Group is a leading international, owner-operated engineering and consulting company specialising in the power industry. Fichtner plans and provides consultancy service for the construction and operation of power production and grid facilities. Fichtner Management Consulting AG is a centre of excellence for management consulting within the Fichtner Group and assists power companies regarding strategy, organisation and project management. Especially for The German Offshore Wind Energy Foundation, Fichtner established in Hamburg a centre of excellence in cooperation with its partner KED.

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Preface of The German Offshore Wind Energy Foundation

As of August 2013, an offshore wind power capacity of almost 400 MW produces electricity in Germany; another seven offshore wind farms with a total capacity of about 2,000 MW are under construction. Substantial investments into expert staff and the construction of production facilities have been made. In 2012, the sector already employed 18,000 people in Germany. This way, the necessary prerequisites have been created for another approved 6,000 to 8,000 MW of capacity and for other wind farms that are in the planning stage.

The framework conditions for investment decisions taken so far have been substantially improved by the introduction of the acceleration model. The Offshore-Windenergie program of the Kreditanstalt für Wiederaufbau (KfW) has provided further impetus. The Energiewirtschaftsgesetz was amended in order to meet challenges regarding warranty and network planning. All interested parties have an increased awareness of the specific planning schedules of capital-intensive offshore wind farm projects as well as of the interaction of grid connection issues and compensation.

At the same time, the discussion about the costs related to moving our energy supply towards renewable energies has been intensified since last autumn. The public opinion considers the competitiveness of offshore wind power increasingly important. In the context of this discussion, there is a risk that the development of offshore wind power is interrupted before this technology has reached its full potential through benefitting from learning effects.

Against this background, we have together with our partners in the offshore wind power industry commissioned Prognos AG and the Fichtner Group to analyse the potentials of decreasing the levelised cost of energy (LCOE) of offshore wind power in Germany over the next ten years. The present study shows the necessary prerequisites and the areas where the largest cost reductions of the offshore wind power industry can be achieved.

We hope that the results of this study are being taken into consideration as an active contribution to the current political decision-making processes.

My thanks go out to all those who have made this study possible through their commitment and support.

Jörg Kuhbier

Chairman of the Executive Board

The German Offshore Wind Energy Foundation

Result summary

(1) In Germany, the **offshore wind power** is **at the beginning of its growth path.** In the North and Baltic Sea, there are about 400 MW in operation. In the North Sea alone, there are currently seven wind farms under construction, with a total capacity of about 2,000 MW. Wind farms with an additional capacity of over 4,000 MW have been already approved. There are another 1,200 MW approved in the Baltic Sea. In Germany, the installed offshore wind power capacity is expected to reach between 6,000 and 10,000 MW by the year 2020.

(2) For the currently operational offshore wind farms, the **levelised cost of energy (LCOE)**, i.e. the average cost for generating electricity over an operational time of 20 years, amounts to between 12.8 to 14.2 $Cent_{2012}$/kWh in real terms. According to Scenario 1 and depending on the actual site, these costs can be gradually reduced by up to 32 %, and in the optimum market conditions of Scenario 2 by up to 39 % over the next 10 years. The main driver for the cost reduction is a continuous technological development across the entire value-added chain of the offshore wind power industry. It may bring about substantial savings regarding investment, operation and financing.

(3) 14 percentage points of the cost reduction in Scenario 1 and 21 percentage points in Scenario 2 are due to **investment costs**. Short-term, an improved logistics infrastructure for installing wind power plants will bring down the costs. In the long run, the trend towards larger turbines and more efficient production processes regarding the support structure will determine the development. In Scenario 2, an intensified competition and economies of scales due to larger turbines and production volumes will lead to large cost reductions.

In Scenario 1 and 2, respectively, 5 or 8 percentage points of the cost reduction result from bringing down **operational** and **maintenance costs**. This reduction is also triggered by an improved logistics infrastructure and faster ships. In the long run, particularly in Scenario 2 inter-operator maintenance concepts further decrease costs.

In Scenario 1, the **reduction of the cost of capital** and **reduced contingency provisions for project risks** account for another 12 percentage points of the cost reduction potential. As investment costs decrease at a lower rate, this issue is more important in Scenario 1 than in Scenario 2 where it amounts to 9 percentage points. As the growing experience with the technology results in reduced risk premia as part of the financing concepts this cost reduction potential is only indirectly a technological one. In both Scenarios, reduced **decommissioning costs** account for about 1 percentage point.

(4) The cost reduction potentials can be only realized if industry, politics and administration **jointly** create the necessary conditions. **Stable legal and political framework conditions** are essential in this context.

Already in the short term, an **efficiency increase** in the industry provides a substantial cost reduction potential. Technical standards for generator components and grid connections are an important prerequisite for serial production. Approval and certification criteria need to be simplified and standardised. Joint installation and maintenance concepts for adjacent wind farm locations increase installation and operational efficiency.

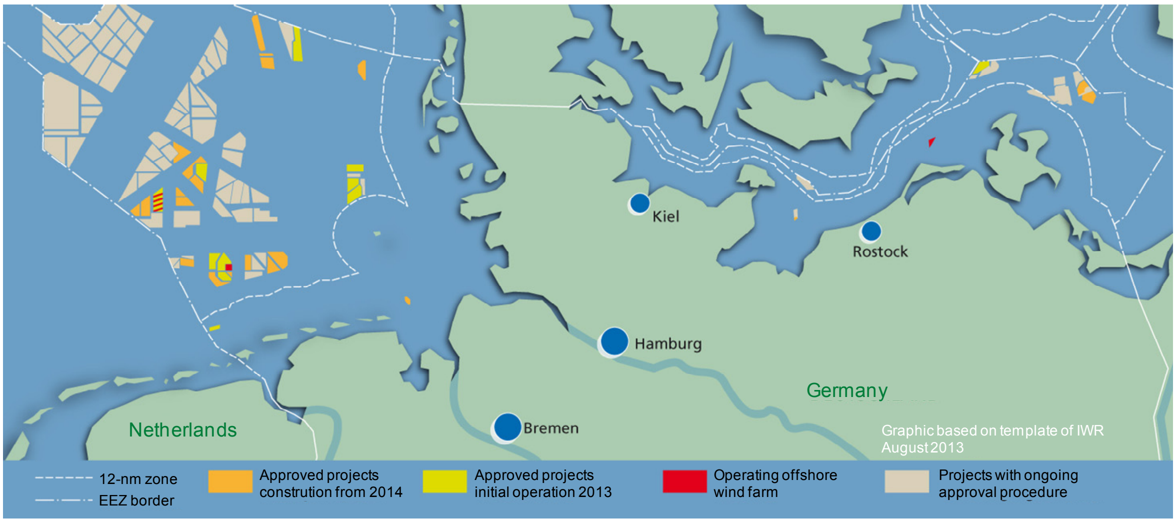
Technical innovation is a long-term field of action. More efficient turbines, optimised support structures and installation logistics offer a large potential for improvement. Here it is important to maintain a balance of innovation and risk minimisation.

1 Background and Task

(1) Reducing green-house gases by at least 80 % by the year 2050 in relation to 1990, increasing the share of renewables to at least 80 % of the German gross electricity consumption and exiting nuclear energy are essential goals of the **energy turnaround** (“Energiewende”). Society faces increasing challenges when this is put into practice. Against this background, in January 2013 Prognos AG and the Fichtner Group were commissioned by the German Offshore Wind Energy Foundation and 15 of its partners and companies to analyse the **cost reduction potentials of offshore wind power** in Germany. This is the first study to include industry contributions and analyse for Germany the current status as well as describe in detail a perspective of how the costs for offshore wind power will develop in the future.

(2) During the time of writing of this study, in Germany the first **offshore wind farms** with a total capacity of about 400 MW are **operational**. A total of 30 projects has been approved, with seven of them being under construction and another four preparing for construction after financing has been approved. Thus the **offshore wind power sector** is **at the beginning of its industrial growth path**. Capacities in planning, permit-granting and certification, production, port infrastructure and logistics have been built up and now should be put into productive use. Figure1 shows the wind farms that are approved and are currently under construction in Germany.

Figure1: Offshore wind farms in Germany



Source: The German Offshore Wind Energy Foundation / Blickfang Kommunikationsdesign 2013

(3) This study analyses the development of the **period between 2013 and 2023**. This period coincides with the specific planning horizons of the industry and authorities. **After the year 2023**, if the market develops dynamically, there might be **further cost-reducing developments** in technology and framework conditions. However, from a current perspective, it is not possible to reliably quantify them.

(4) As of June 2013, there is a total of over 6 Gigawatt of off-shore wind power capacity connected to the grid in ten European countries. Companies that are active on the German market are often also represented on other European markets which shows the **internationality of the offshore wind power industry**. In 2012, the first authoritative study on cost degression potentials was published by The Crown Estate (TCE) in the UK[1]. It arrives at the conclusion that for all investment decisions taken before 2020 the energy production costs of British offshore wind farms could be reduced by 30 % as compared to 2011 .

(5) The design of the **present study** follows the approach of the TCE study. This makes the results internationally comparable. However, **the framework conditions of German offshore wind power** are partially very different from those in the UK regarding water depth, distance to port, grid connection and financing. In addition, there have been further developments regarding technologies of and approaches to, among others, substructures, generator configuration, logistics and energy yield since the TCE study has been presented. Therefore, this study is based on **independent data and calculations** that have been **verified for the German market** along its entire value-added chain.

[1] The Crown Estate: Offshore Wind Cost Reduction Pathways Study (2012); http://www.thecrownestate.co.uk/tcform/TandCsDialog?f=%2fmedia%2f305094%2foffshore-wind-cost-reduction-pathways-study.pdf&fn=Offshore+wind+cost+reduction+pathways+study&m=1 (Downloaded in February 2013)

2 Methodology

The following chapter will discuss the methodology used in this study. Following the presentation of the project setup (Chapter 2.1), we will describe the basic construction of an offshore wind turbine generator (Chapter 2.2) and of a wind farm as well as the system boundaries of this analysis (Chapter2.3). After that, we will present the design of the analysis and the methodology of the cost analysis (Chapter 2.4) as well as the calculation of the levelised cost of energy (LCOE; Chapter 2.5).

2.1 Project setup

(1) The following figure presents a survey of the **project plan**.

Figure 2: Project plan

Phase 1: Model setup and cost base	Phase 2: Verification by industry and stakeholders	Phase 3: Optimisation approaches and recommendations
▪ Determination of cost base for all sites and years ▪ Model setup for Levelised Cost of Energy (LCOE) ▪ Evaluation of preliminary results	▪ Result validation by an expert panel (survey and financing workshop) ▪ Analysis of verified results	▪ Development of optimisation approaches ▪ Derivation of recommendations for politics, industry and other stakeholders
Project related supervision by representatives of the principals		

Source: [Prognos/Fichtner]

(2) The study is based on calculations that use a specifically developed **model**. The model includes the costs of offshore wind power and models the energy generation for all considered cases and scenarios. From there we arrived at the levelised cost of energy (LCOE). The model comprises **all costs** that - according to German regulatory provisions - are assigned to an **offshore wind farm** (see Chapter 2.3).

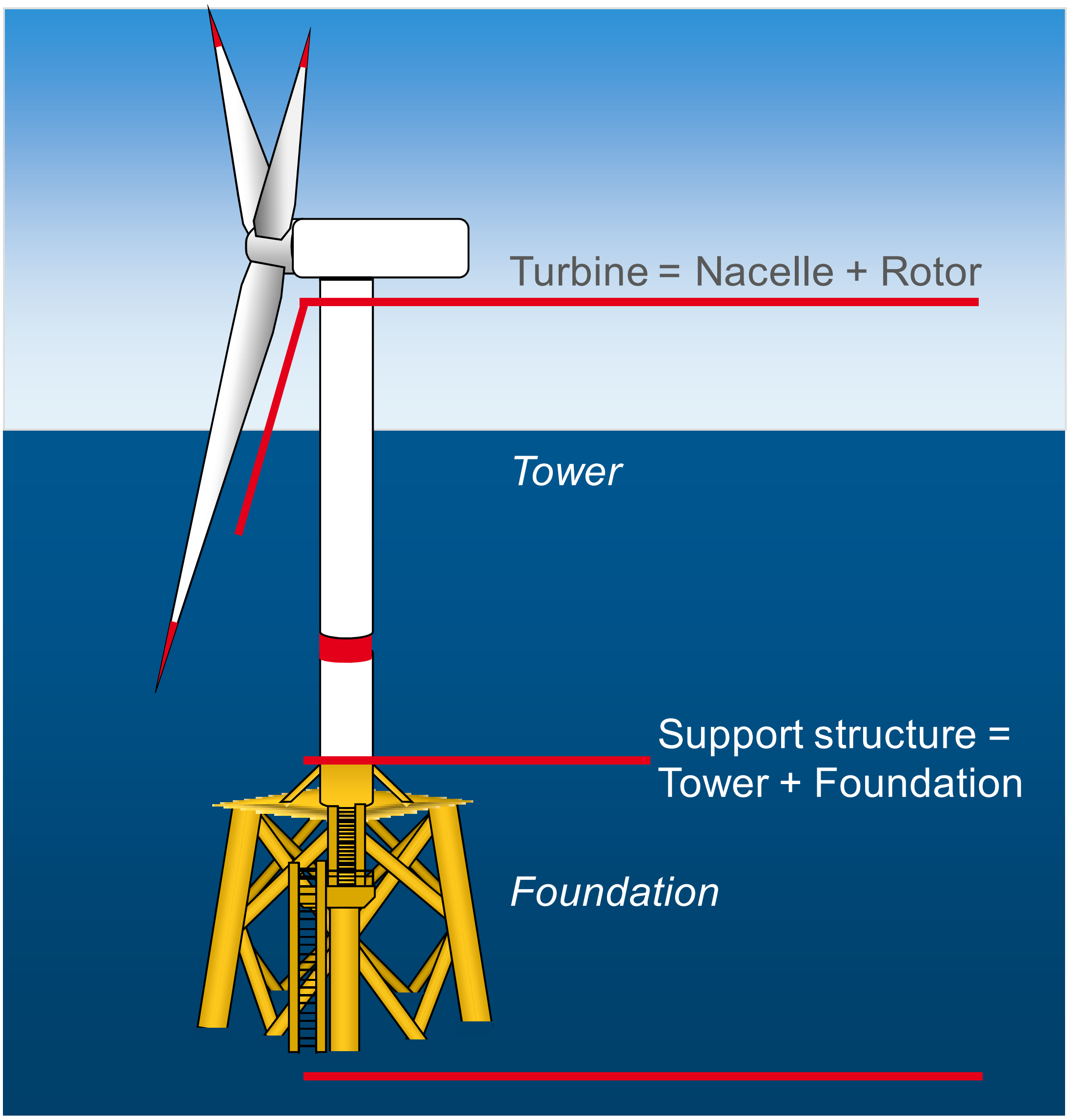
(3) In Phase 2, the results of the initial modelling were discussed and **validated** along the entire value-added chain during a financing workshop and in **expert interviews.** A total of 24 industrial companies and providers of project financing were interviewed in order to verify the results (Chapter 6.1 comprises a complete list).

This was followed by a sensitivity analysis and by establishing additional scenario options in order to arrive at how other turbine sizes and a longer operating life would affect the levelised cost of energy (LCOE; see Chapter 3.6). Based on Prognos' and Fichtner's calculations and expert evaluations, we arrived in Phase 3 at optimisation approaches and **recommendations for actions**.

2.2 Construction of an offshore wind turbine generator

(1) An offshore wind turbine generator basically consists of three **main components**: turbine, tower and foundation. Figure 3 shows the schematic construction. For the purpose of this study, tower and foundation will be called support structure and combined in a single cost component.

Figure 3: Construction of an offshore wind turbine generator



Source: [Prognos/Fichtner]; own illustration

(2) The **turbine** consists - similar to an onshore wind turbine generator - of the nacelle and the rotor. The key component of the nacelle is the **generator**. It transforms the kinetic energy of the rotors into electrical energy. In principal, we can distinguish three plant concepts: The classical concept with the gearbox being situated before the generator and as an alternative a generator without gearbox. Both concepts have different characteristics. The design with a gearbox can produce electricity, independent of the rotational speed of the turbine. As opposed to this, the design without generator has a higher efficiency and usually requires less maintenance. In addition to these two concepts, there are hybrid concepts that combine the characteristics of the two above-mentioned concepts.

The most eye-catching components of an offshore wind turbine generator are the **rotors**. They transmit kinetic energy via the hub to the gearbox or to the generator, respectively.

(3) The turbine is mounted turnably to the **tower**. The tower should have a minimum height of 75 m in order to allow for an optimum wind yield. The higher the tower, the larger the wind yield can become. Due to the turbine´s weight and the rotating masses of the rotor blades, the tower is especially exposed to powerful static and dynamic loads. As opposed to many onshore wind turbine generators, the towers of offshore plants are completely made of steel. Onshore, major parts of the tower are manufactured of concrete; and only the last section consists of steel.

(4) The tower is anchored to the **foundation**. The foundation or substructure, respectively, is responsible for a firm anchoring in the seabed and for bridging the water depth. It reaches above the water surface and there the tower is mounted to it. Currently there are different foundation concepts, in accordance with location, seabed and construction conditions as well as water depths. The most usual ones are monopiles, jackets, tripods, tripiles or gravity base foundations. We also can find floating foundations and suction buckets that use vacuum to push into the seabed. Suction buckets are already used for transformer platforms. As far as offshore wind turbine generators are concerned, this concept is currently in the testing phase. The most popular and technologically mature concepts are monopiles and jackets.[2]

A **monopile** is a steel tube that is - in accordance with the weight to be carried and the static load - rammed up to 50 m into the sea-

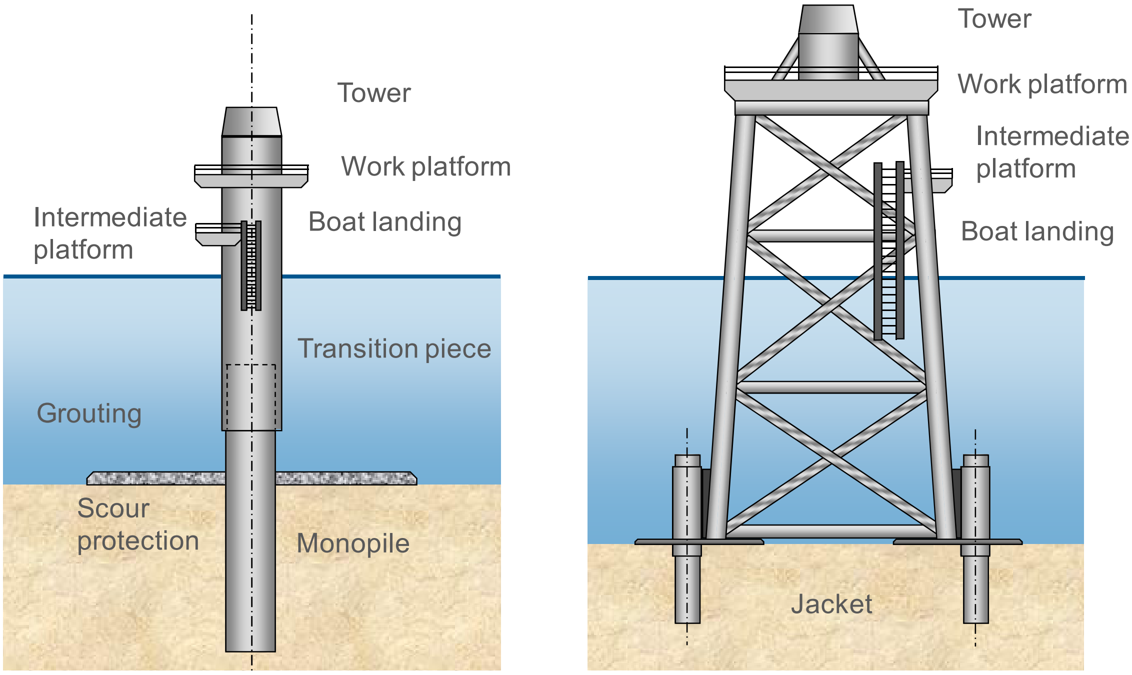
[2] Lüddecke, F., Kirsch, F.: Zur Optimierung von aufgelösten Gründungsstrukturen von Offshore-Windenergieanlagen; Veröffentlichung des Grundbauinstituts der Technischen Universität Berlin, Heft Nr. 60, Berlin 2012; http://www.gudconsult.de/uploads/media/120820.HLS.KirschLueddecke-09.pdf

bed and usually ends slightly above sea level. In a second step, a transition piece is mounted on the steel tube and attached with grout to the monopile. Finally the tower is mounted to the transition piece. Depending on turbine size, water depth and seabed conditions, monopiles can reach a length of 80 m and currently have diameters of up to 7 m. The tube walls can be up to 100 mm thick. Currently, monopiles are used for water depths of up to 30 m. There a plans to use monopiles for 40 m of water depth. Due to the heavy weight of up to 1,500 t, this kind of foundation places high demands on transport and installation.

The classical **jacket** is a so called disintegrated support structure consisting of four corner tubes. These steel tubes are welded together with diagonal braces. After preparing the subsoil, the jackets are lowered into the water and positioned at the respective site. Then the jacket is anchored to the seabed by steel piles with a length of 30 to 70 m and a diameter of 2.20 to 3.10 m. This method is also called post-piling. As opposed to this, pre-piling means that the steel piles are first rammed into the seabed and then the jacket is mounted to them. Similar to monopiles, jackets usually end - depending on the wave height at the location - between 10 to 20 m above sea level where the tower is mounted. Currently, jackets are also used in water depth exceeding 40 m. In addition to jackets, tripods are used in the North Sea. This is a disintegrated support structure basically consisting of three piles.

For both mentioned foundation types the offshore wind turbine generator can be accessed via jetties and working platforms. Figure 4 shows a schematic presentation of the structure of monopile and jacket foundations.

Figure 4: Schematic presentation of monopile and jacket.



Source: [Prognos/Fichtner] following Garrad Hassan, own illustration

As opposed to jackets and monopiles, **gravity base foundations** can be erected without anchoring them in the seabed. To ensure a firm connection to the seabed the foundations have to have a high weight and a large surface area. The most common material used for gravity base foundations is reinforced concrete. Together with lower maintenance requirements this may lead to substantial cost advantages over monopiles and jackets made of steel. In addition, concrete structures are better protected against corrosion than pure steel constructions. The use of gravity base foundations in deeper waters is currently still in the testing phase.

Floating foundations are another concept. In deep waters, the use of jackets is not economically viable any longer; this means that it is not possible any longer to manufacture the foundation on-shore and then transport it out to the sea. Floating foundations might be a solution for this issue. Here, offshore wind turbine generators are mounted to a floating platform that is subsequently fixed to the seabed with heavy chains. This prevents the plant from drifting off or capsizing. Similar to gravity base foundations, prototypes of floating foundations are currently being tested.

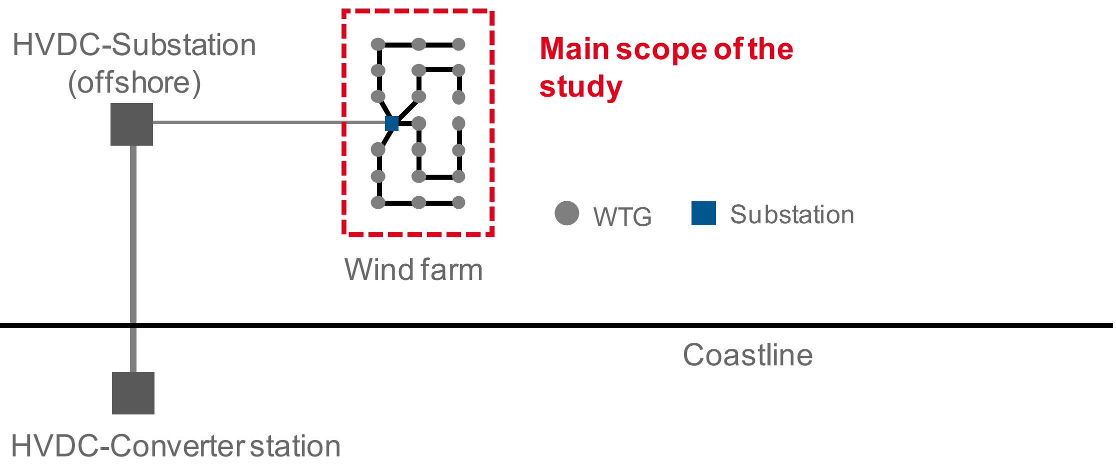
As of today, in Germany almost all wind farms that are approved or under construction use jackets (tripods) or monopiles. Within the framework of this study, we therefore will analyse the cost of foundation types with particular emphasis on monopiles and jackets.

2.3 Configuration of a wind farm and system boundaries of the analysis

(1) After erecting the individual wind turbine generators at sea, they are cabled in series and then connected to the **wind farm transformer station**. This substation transforms the incoming nominal voltage to high voltage in order to then transport the electricity to an offshore high-voltage direct-current platform (HVDC platform). There the alternating current is transformed into direct current in order to be transported to shore with very low transmission losses. For short distances to shore, the alternating current of the wind farm transformer platform can be directly transported to shore. This means larger transmission losses though.

(2) Please note that in the present study the calculated levelised cost of energy (LCOE) exclusively includes the costs of the offshore wind farm and the wind farm transformer station. In accordance with regulatory provisions, it does not take into account the costs of connection to the onshore power grid ("grid connection costs"), but only the pure levelised cost of energy (LCOE) at sea. Figure 5 shows the system boundaries of the applied cost model.

Figure 5: System boundaries of the cost model

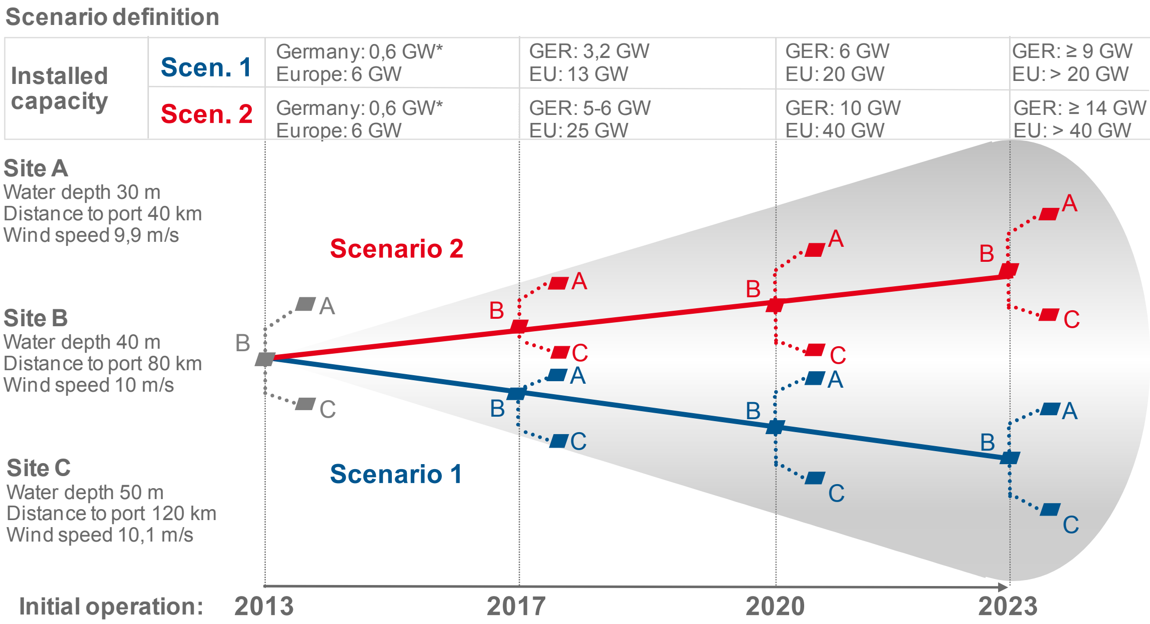


Source: [Prognos/Fichtner], own illustration

2.4 Scenarios and cases

(1) The present study analyses different development scenarios, times of initial operation, siting as well as generator and wind farm configurations (see Figure 6).

Figure 6: Analysis design/ Overview of the scenarios



*Source: [Prognos/Fichtner], own illustration; * expected value at the end of the year 2013*

(2) Development scenarios

The study uses **two development scenarios** to analyse the cost reduction potentials of offshore wind power in Germany until 2023.

Scenario 1 describes a moderate development path with a minimum of 9 GW of accumulated installed capacity in Germany, and with a total of over 20 GW in Europe by the year 2023. It is characterised by a long-term stable **market environment**.

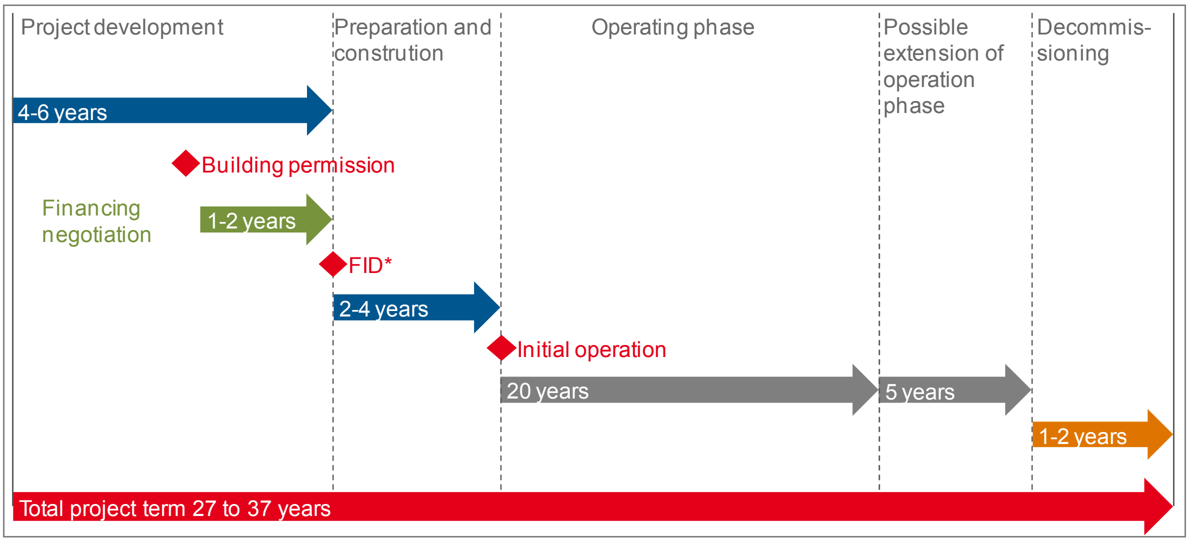
Scenario 2 calculates with a minimum 14 GW of installed capacity in Germany, and with a total of over 40 GW in the whole of Europe by the year 2023. This corresponds to the current political goals set for Germany and the EU. This ambitious development path assumes that all technical cost reduction potentials have been realized and an **optimum regulatory and competitive market environment** has been created. This includes an extended European common market that allows for a faster development of new and larger turbines and foundation structures.

Today, development Scenario 1 constitutes the more likely Scenario unless the political and economic framework conditions for offshore wind power change drastically. As opposed to this, Scenario 2 models a future development where all factors influencing the framework of a future growth of the offshore sector will progress in an optimum way.

(3) Initial operation

For both development scenarios, the study analyses investment and operating costs as well as the annual energy production for four different times of initial operation: 2013, 2017, 2020, and 2023. The year 2013 as initial operation is intended to provide a representative overview of the cost situation regarding wind farms that have been recently connected to the grid. Assuming usual planning periods and timetables, planning and investment decisions for these wind farms were taken between 2006 and 2010; construction started in 2011/2012. Currently, financing is ensured and investment decisions are taken for wind farms that will become operational in 2017. For these wind farms, construction is expected to start within the next two years. The same lead times apply to wind farms becoming operational in 2020 and 2023. The following Figure 7 shows an overview of the entire cycle of an offshore project. This overview illustrates the long lead times for offshore wind farms between final investment decision and initial operation.

Figure 7: Average time line of an offshore wind farm project



*Source: [Prognos/Fichtner], own illustration; *FID: Final investment decision*

(4) Siting of the wind farm

For the two development scenarios and four times of initial operation, we will additionally analyse the cost development at three different **sites** in the North Sea. The sites are different regarding average water depth, distance to port and average wind speed.

Site A describes a wind farm with an average water depth of 30 m, a distance to port of 40 km and an average wind speed of 9.9 m/s[3]. About 70 % of all existing and approved wind farms as well as those being under construction have similar characteristics to Site A.

Site B describes a wind farm with an average water depth of 40 m, a distance to port of 80 km and an average wind speed of 10.0 m/s. In Germany, the portion of wind farms that are planned or are under construction and have similar conditions amounts to about 30 %.

Site C describes a wind farm with an average water depth of 50 m, a distance to port of 120 km and an average wind speed of 10.1 m/s. These assumptions apply to sites of wind farms that are in the early planning stage, with an initial operation in 2013 and 2017 being purely theoretical.

As the majority of the planned wind farms is situated in the North Sea, the study does not include possible sites in the Baltic Sea. As mentioned above, the **site characteristics** of close-to-port wind farm A coincide with about 70 percent of today's approved projects. Between 2017 and 2020, the development will be dominated by the construction of further-from-port wind farms at site B. From 2020 onwards, there will be implemented an increasing number of projects at far-from-port deep-sea sites C. This means that for interpreting the results, the short-term focus must be on site A, medium-term on site B and long-term on site C.

(5) **Plant and wind farm configuration**

The present study does not only refer to different development paths, sites and times of initial operation, but also takes into account different **plant configurations of the wind farm**. This includes both wind farm size and dimensioning of the individual generators - particularly turbine capacity, rotor diameter and hub height.

Wind farm size: Starting with an installed total **capacity per wind farm** of 320 MW (80 turbines with a capacity of 4 MW each), for both scenarios the capacity of wind farms put into operation from 2017 onwards increases to 450 MW and then remains constant at this level until 2023. The turbine size of 4 MW is assumed to be the average value of **currently installed** generators. Today the maximum number of generators approved per wind farm is 80.[4]

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[3] The average wind speed applies to a hub height of 100 m. Correspondingly, average wind speed can be lower for hub heights under 100 m and higher for hub heights over 100 m.

[4] Until now, only 80 plants per wind farm have been approved for the first development stage ("pilot phase").

The assumption of **a future wind farm size** of 450 MW includes - in addition to an increased turbine capacity of 6 MW (Scenario 1) or 8 MW (Scenario 2), accordingly - the 900 MW of planned HVDC[5] platform capacity for transmitting the electricity to shore. Two wind farms with a capacity of 450 MW each can be connected to one HVDC platform. Each wind farm comprises 75 (Scenario 1) or 56 (Scenario 2) plants, respectively.

Turbine capacity: The different turbine capacities of today's and future commercial wind turbine generators constitute a challenge when modelling the costs of wind farms. Different manufactures currently produce turbines with a capacity of between 2.3 MW and 6 MW. In the future, there will be commercial turbines with a capacity of up to 10 MW. In order to be able to provide a representative picture of the offshore market, this study calculates with average turbine capacities of 4 MW, 6 MW and 8 MW. A 4 MW turbine represents an average of turbines ranging from 2.3 MW to 6 MW. A 6 MW turbine comprises a capacity range of 5 MW to 7.5 MW; and an 8 MW turbine of 7.5 MW to 10 MW.

Hub height and rotor diameter: In addition to different capacities, wind turbine generators of different manufacturers also vary in hub height and rotor diameter. It can be assumed that future generators will have a substantially larger rotor diameter and hub height. For the corresponding assumptions, see Table 1 and Table 2

(6) It is not possible to exactly estimate the time of market introduction of new turbine generations. For the different times of initial operation, we have therefore used **different assumptions** regarding average turbine capacity, rotor diameter, and hub height in order to calculate the two **development scenarios**.

In Scenario 1, a total of 80 generators with 4 MW each are erected in 2013. Due to the increased wind farm size of 450 MW in 2017, 75 generators with 6 MW turbines will be installed. The hub height of wind turbine generators increases from a current 90 m in Scenario 1 to 105 m in 2023. The rotor diameter will increase from a current 120 m to 164 m. This will result in a higher energy generation per plant. Table 1 provides a detailed overview of the assumptions regarding the wind farm configuration in Scenario 1.

[5] HVDC = high-voltage direct-current transmission

Table 1: Plant and wind farm configuration

	Scenario 1				
Initial operation	Number of WTG	Capacity WTG	Size wind farm	Hub height	Rotor diameter
2013	80	4 MW	320 MW	90 m	120 m
2017	75	6 MW	450 MW	100 m	145 m
2020	75	6 MW	450 MW	100 m	154 m
2023	75	6 MW	450 MW	105 m	164 m

Source: [Prognos/Fichtner], own illustration

In Development Scenario 2, there are also 80 generators with 4 MW each. In the following year of initial operation 2017, 75 generators with 6 MW turbines are installed. From 2020 onwards, we assume the market introduction of 8 MW generators. Assuming a fixed wind farm size of about 450 MW, this means that per wind farm 56 plants with an average capacity of 8 MW will be installed. In Scenario 2 the hub height of wind turbine generators increases from a current 90 m to 115 m in 2023. The rotor diameter will increase from a current 120 m to 178 m in 2023.Table 2 shows the assumption of the specific generator and wind farm configuration of Development Scenario 2.

Table 2: Generator and wind farm configuration Scenario 2

	Scenario 2				
Initial operation	Number of WTG	Capacity WTG	Size wind farm	Hub height	Rotor diameter
2013	80	4 MW	320 MW	90 m	120 m
2017	75	6 MW	450 MW	100 m	145 m
2020	56	8 MW	450 MW	110 m	164 m
2023	56	8 MW	450 MW	115 m	178 m

Source: [Prognos/Fichtner], own illustration

(7) In addition to the presented generator and wind farm configuration, we carried out two **sensitivity analyses** in order to examine the effect that different turbine sizes (Scenario 1a and 2a) and an extended operational life of the wind farms from 20 to 25 years has on the levelised cost of energy (LCOE). For the results of the sensitivity considerations, see Chapter 3.6.

2.5 Method for calculating the levelised cost of energy (LCOE)

(1) Investment, operating and decommissioning costs[6] (CAPEX und OPEX) of the individual sites and times of initial operation as well as the corresponding annual energy production will be used to calculate the levelised cost of energy (LCOE) for the respective cases. The corresponding cost reduction potentials until the year 2023 are expressed as decreasing levelised cost of energy (LCOE). In the following, the basic assumptions are described.

(2) **Assumptions regarding the costs**

This study presents results that have been verified for Germany and the entire value-added chain. For this purpose, we applied a **two-step procedure**.

In a first step, experts of the Fichtner Group prepared assumptions regarding the cost development of the CAPEX and OPEX components and the annual energy production at the individual sites and for the individual scenarios in order to carry out detailed calculations.[7] Based on these assumptions, we computed the levelised cost of energy. Unless otherwise stated, all costs and the levelised cost of energy are expressed in **real values with the base year 2012** (in Euro_{2012}).

In this study, costs are expressed as specific costs. They differ from absolute costs in that the specific costs refer to costs per MW of generator capacity. As opposed to this, absolute costs usually relate to the entire costs of a generator or a component. The specific costs of all other named components of a wind turbine generator are usually substantially reduced if generator capacity increases. This is mainly due to the fact that in the calculations the specific costs always relate to generator capacity (MW). Doubling average turbine capacity from 4 MW to 8 MW often results in increased absolute costs for the other components, but not in doubled costs. When moving towards larger turbines, this effect brings about lower specific costs of other cost items along the entire value-added chain.

The results of this first modelling were verified in **interviews** with experts from the entire value-added chain as well as in a separate financing workshop. A total of 24 industrial companies and providers of project financing were interviewed. Based on the information from the companies, the assumed cost development was partially adapted and the levelised cost of energy was re-calculated. For

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6 The decommissioning costs contain all costs that are necessary for dismantling the plant.

7 For more detailed information on the assumptions that were included in the calculation, see Appendix 6.4.

the participants in the expert interviews and financing workshop, see Appendix 6.1.

(3) The **investment and operational costs** of offshore wind turbine generators comprise the following cost components:

- **Certification and approval costs:** They comprise all costs that are incurred for procuring all necessary approvals for installing a wind farm. Among these are costs for soil examination, explosive ordnance searching, environmental impact and wind studies. In addition, prior to building a wind farm all components and their manufacturers have to be certified. Operators and/or investors commission special certification companies that monitor the entire production process. This block of costs also comprises project development and project management costs as well as costs for insurance cover during the building phase.

- **Technology costs:** Technology costs comprise investment costs of the turbine (nacelle and rotor), the support structure (tower and foundation), cabling costs for connecting the offshore wind turbine generators as well as the wind farm transformer platform. These costs were determined by the Fichtner offshore experts. The calculations included in addition to an in-depth knowledge of German and European wind farm projects also detailed assumptions regarding specific sites, such as the amount of steel required for components.

- **Installation costs:** The installation costs comprise all costs for building the offshore wind farm. They comprise the costs for preparing the building site as well as the costs for installing the foundation, tower, turbine, cables and wind farm transformer platform as well as the required logistics. Here also the costs for explosive ordnance clearance, sound insulation and environmental monitoring are included.

  The largest single cost item is rental costs for special ships that are required during the different phases of the installation process. They are necessary for the transport and installation of foundations, towers, and turbines. Depending on the specific foundation, the ships have to be able to ram monopiles or jacket piles into the seabed using special equipment. Also the wind farm transformer platform has to be transported and mounted to the foundation. The cost assumptions for this area comprise, for example, daily rental costs for different special ships. In addition, we made assumption regarding the duration of the installation processes and calculated weather slots during the installation phase.

- **Project contingencies:** The technology costs of a wind farm are usually fixed by contracts and can be therefore planned in a straightforward way. The installation of the components depends on sufficiently good weather conditions and other external factors, though. Therefore, bad weather can cause high unplanned costs. Usually the commissioning party takes on the weather risk when booking special ships. If during a planned installation phase bad weather prevents the generator from being erected, rental costs for ships will still be incurred.

  In addition, for new turbine types there are often unplanned issues that may delay the installation. Provisions have to be made to cover such unplanned additional cost. They are correlated to the total sum of the investment costs. In 2013, they are 15 % of total investment costs. Due to the learning curve effect regarding the installation, over time this portion decreases to 10 %. For the first-time use of larger turbines, this portion remains at the level of the previous installation.

  For instance, if in 2017 the first 6 MW turbines will be installed, the portion will remain at 15 %. In 2020 when reusing 6 MW turbines in Scenario 1, the portion decreases to 13 % and in 2023 to 10 %. In Scenario 2, the portion remains constant at 15 % until 2020 because following the 6 MW turbines in 2017, there will be 8 MW turbines installed in 2020. Only in 2023 when 8 MW turbines are re-used the portion will decrease to 13 %.

- **Operating and maintenance costs:** A wind farm has to be regularly maintained in order to be able to generate power. For this purpose, technicians inspect each generator at regular intervals and monitor them from onshore with the appropriate technical equipment. Special sensors are used to continuously monitor different parameters of individual critical components and transmit measuring date to a control centre. In spite of regular maintenance and monitoring, components may fail; and this causes additional unplanned costs.

  Also for these costs, we made comprehensive assumptions regarding daily rental costs for maintenance ships both for a land- and a sea-based maintenance concept. Additionally, we estimated costs for the use of a residential platform.

  Also insurance costs for the generators have to be included into operating costs.

- **Provisions for decommissioning and dismantling:** The owners of a wind farm have the obligation to provide for dismantling the wind farm. Without such provisions, an operating permission will not be granted.

Currently there is hardly any experience regarding the dismantling of offshore wind turbine generators. Therefore the costs had to be estimated. The following concept was applied: At first, the costs for dismantling a generator were examined. They amount to about 30 % of the original installation costs. Dismantling also requires special ships with high daily rental costs. Initially, rotor blades, nacelle and tower have to be disassembled. Then, monopile or jacket piles, respectively, are cut off with special equipment several meters beneath the seabed, they are loaded and then transported back to the port. Depending on the site, there will remain a varying amount of steel in the seabed. The recycled steal can be sold as steel scrap and generate additional revenue. Assuming a usable portion of the originally used amount of steel and a constant scrap price of 250 Euro/ton, we can arrive at the revenues from the sales that would reduce dismantling costs.

(4) Assumptions regarding energy generation

Based on empirical wind data[8] and experience from existing offshore projects, for each site and generator configuration the expected average **gross and net electricity yield** was calculated. For these calculations, average annual wind speed at the respective hub height and rotor diameters were essential. The larger the rotor diameter and the higher the hub, the larger the resulting gross electricity yield. Detailed characteristic curves for specific rotor diameters, hub heights (Hellman´s exponent of 0.14) and turbine capacities were used to model gross electricity yield. In addition, a Weibull distribution with a *k* parameter of 2.175 for site A and 2.250 for sites B and C were applied. Similar to internal and external wake losses as well as electrical and other losses, maintenance work and unplanned downtime reduce electricity production.

The first offshore wind farms in the German North Sea, in particular the generators of the wind farm alpha ventus, reach about 4,500 full-load hours and thus exceed the expected 4,100 full-load hours. However, there are no other wind farms adjacent to this farm. With only 12 generators, alpha ventus is a comparatively small wind farm with low internal wake losses. Future wind farms will be larger and be surrounded from several sides and will therefore not have such relative advantages.

External wake losses from adjacent wind farms increase with the number of wind farms that surround the respective wind farm.

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8 Among others of the FINO1 and FINO3 wind measuring platforms in the North Sea.

Wind farm configurations in specific clusters that are advantageous for grid connection will increase external wake losses in the future. The results of simulations show that in 2023 the external wake losses will amount to between 7 % (Scenario 1) and 9.5 % (Scenario 2). In Germany, cluster configurations will substantially reduce the options for minimising external wake losses as project developers will not be able to move to remoter areas.

In the long run, **internal wake losses** of wind farms will increase despite a decreasing number of generators. Due to higher rotor diameters, the relative distance between the generators in relation to rotor diameter will decrease. Internal wake losses will amount to between 9.75 % and 11 % of the gross wind yield.

The result of the calculation represents the average annual net electricity production of the generators for the corresponding site and wind farm configuration that is included into the computation of the levelised cost of energy (LCOE).

(5) Calculation of the levelised cost of energy (LCOE)

Using the specific levelised cost of energy (LCOE; (€/MWh) makes it possible to compare the costs of energy generation for different generation technologies, but also for different projects with the same generation technology. This study calculates and compares LCOE for three different wind farm sites for the two development scenarios.

The levelised cost of energy (LCOE) is the **finance mathematical average cost** over the lifetime of the generation plant. It is calculated as follows:

$$LCOE = \frac{I_0 + \sum_{t=1}^{n} \frac{A_t}{(1+i)^t}}{\sum_{t=1}^{n} \frac{M_{el}}{(1+i)^t}}$$

LCOE	Levelised cost of energy in Euro_{2012}/MWh
I_0	Capital expenditure in Euro
A_t	Annual operating costs in Euro in year t
M_{el}	Produced electricity in the corresponding year in MWh
i	Weighted average cost of capital in %
n	Operating lifetime (20 years)
t	Individual year of lifetime (1, 2, …n)

The levelised cost of energy (LCOE) is here calculated as the sum of the present values of annual operating costs and capital expenditure, divided by the present value of total electricity generation over a 20-year lifetime.

LCOE is not equivalent to the compensation level (feed-in tariffs), e.g. according to the Renewable Energies Act (EEG), that is necessary for projects to become profitable. The compensation from the EEG refers to parts of the total project duration (initial compensation and basic compensation). In addition, compensation rates in the EEG are nominal whereas the levelised cost of energy is calculated in real terms, i.e. without inflation.

(6) **Weighted average cost of capital (WACC)**

Particularly for **capital-intensive** technologies such as **offshore wind power**, the cost of capital strongly affects energy production costs. This study uses the weighted average cost of capital (WACC) that discounts annual operating costs and electricity generation in order to represent the real calculatory financing rate. The cost of capital over project duration is calculated taking into account the relative weight of return on equity (RoE) and cost of debt (CoD) with different risk profiles:

$$WACC \; = \mathrm{CoD_{portion}} {*} \mathrm{CoD_{return}} + \mathrm{RoE_{portion}} {*} \mathrm{RoE_{return}}$$

(7) The construction of offshore wind farms requires large amounts of equity. At the same time, risks relating to the projects are higher than for other investment projects, such as mature onshore technologies. These risks result in higher requested rates of return. In general, there are **two different financing concepts** for large investment projects. The undertakings can be either financed by the business group or be project-financed.

When using **group financing** the business group procures the required debt at conditions that are valid for the entire group. As a group's portfolio consists of both high-risk and low-risk investments, it can all in all achieve more favourable debt financing conditions than high-risk projects. Usually, such projects count with more favourable conditions than projects with a project company directly procuring debt for a specific offshore project.

For **project financing** cost of debt directly depends on the project risk. The project company has to procure capital from banks or via bonds or other instruments.

This study uses the **project-financing** concept. The assumptions made in the financing workshop were applied to project financing. Due to the current situation on the capital market, the experts do not expect costs of capital for project and group financing to differ significantly.

(8) Over the time period considered in this study, the **cost of capital** will **decrease** by more than 2 percentage points for generators becoming operational in 2023. The **reduction of risk profiles** is a key driver for a reduced cost of capital and compensates for the increasing interest rate levels due to the recovery of the capital market following the European debt crisis.

Firstly, the **portion of equity** that debt suppliers demand **decreases** from 35 % to 25 %. Simultaneously, this will increase the portion of debt from 65 % to 75 % and result in a corresponding leverage effect. As debt usually carries lower return requirements than equity, a lower equity portion results in a reduced weighted average cost of capital. However, debt providers are only willing to accept a lower equity portion if project risks decrease.
Secondly, **market margins for debt financing** substantially **decrease** due to the more favourable risk evaluation of offshore projects.
Thirdly, lower **project-specific risks** result in reduced risk premia regarding **equity financing**. We will not distinguish between the cost of capital for the different **scenarios**.

For Scenario 2, we assume - in spite of higher capital demand due to a faster market growth - that a flourishing market results in a competition of debt providers that brings down bank margins and thus keeps the cost of debt constant. Regarding equity, no investor liquidity bottlenecks are assumed. Consequently, the cost of capital for both scenarios remains at the same level (see Table 3).

Table 3: Development of real calculatory interest rates (WACC) in both scenarios

Initial operation	**2013**	**2017**	**2020**	**2023**
WACC, nominal (Pre-tax)	9.85%	9.19%	8.67%	7.68%
WACC, real (Pre-tax)	7.85%	7.19%	6.67%	5.68%
Debt (share)	65%	65%	70%	75%
Equity (share)	35%	35%	30%	25%

Source: [Prognos/Fichtner], own illustration

3 Cost development and electricity generation

The levelised cost of energy of offshore wind power is determined by the assumed development scenarios, times of initial operation, sites as well as generator and wind farm configurations. The following chapter describes the assumptions regarding the future development of costs, the wind yield at Sites A (Chapter 3.1), B (Chapter 3.2) and C (Chapter 3.3) and the resulting levelised cost of energy (Chapter 3.4). Chapter 3.5 deals with the influence of risk and financing costs on the levelised cost of energy. Chapter 3.6 discusses the effect that different generator sizes and extending the operating life of a wind farm from 20 to 25 years will have on LCOE as sensitivities. A detailed presentation of the factors causing the cost reduction that was calculated in Chapter 3 will follow in the later part of Chapter 3.

3.1 Site A

(1) With a distance to port of 40 km and a water depth of 30 m, Site A in principal represents the **site parameters of wind farms that are currently under construction.** Alpha ventus as wells as the wind farms Borkum West II, Meerwind Süd-Ost and Nordsee Ost that are currently under construction are closest to these site characteristics.[9] Table 4 shows the exact configuration of the site. It provides an overview of current and future generator concepts regarding number of generators, generator capacity, hub height and rotor diameter, substructure as well as operation and maintenance (O&M).

[9] Generator configuration and cost characteristics of these projects can differ from the presented costs.

Table 4: Site configuration wind farm A

	Scenario 1						
Site A Initial operation	Number of WTG	Capacity WTG	Size wind farm	Hub height	Rotor diameter	Foundation	O&M Concept
2013	80	4 MW	320 MW	90 m	120 m	MP	Land
2017	75	6 MW	450 MW	100 m	145 m	MP	Land
2020	75	6 MW	450 MW	100 m	154 m	MP	Land
2023	75	6 MW	450 MW	105 m	164 m	MP	Land
	Scenario 2						
Site A Initial operation	Number of WTG	Capacity WTG	Size wind farm	Hub height	Rotor diameter	Foundation	O&M Concept
2013	80	4 MW	320 MW	90 m	120 m	MP	Land
2017	75	6 MW	450 MW	100 m	145 m	MP	Land
2020	56	8 MW	450 MW	110 m	164 m	JK	Land
2023	56	8 MW	450 MW	115 m	178 m	JK	Land

Source: [Prognos/Fichtner]; MP – Monopile, JK – Jacket

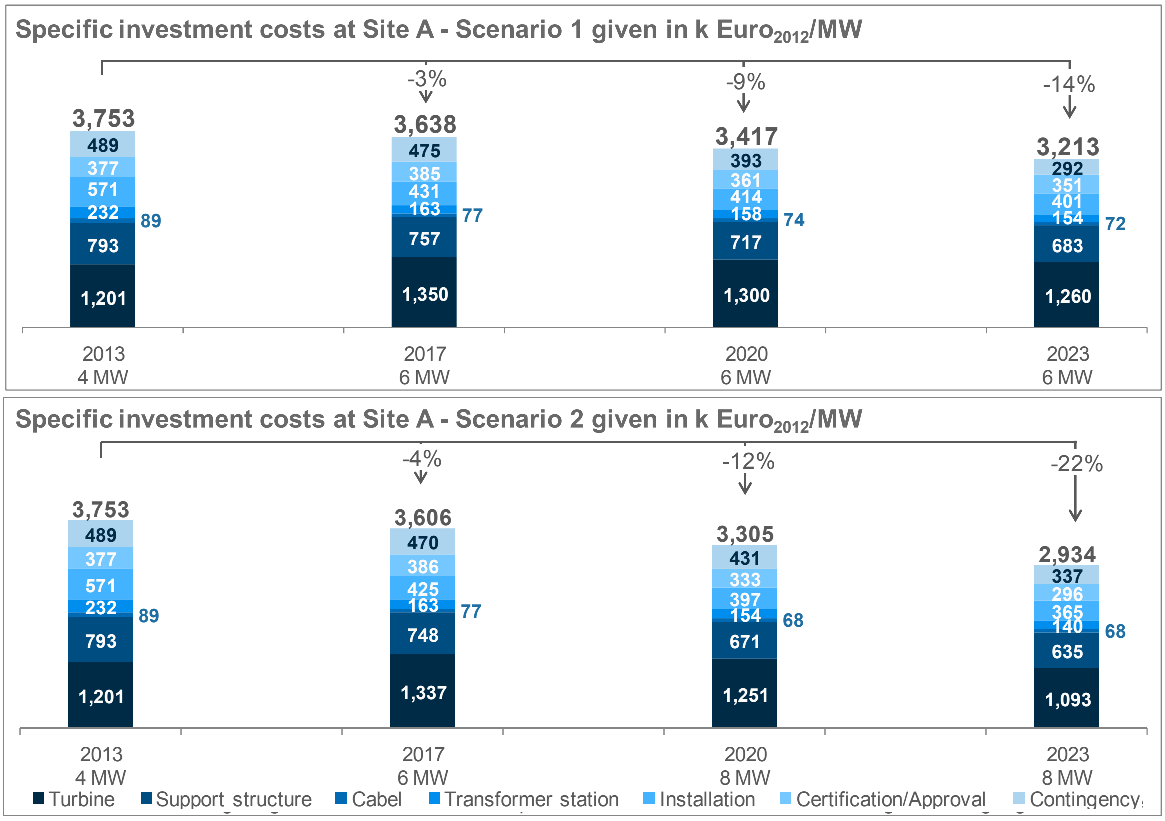
3.1.1 Investment costs

(1) **Total investment costs** consist of **technology costs** of turbine, support structure, cable and transformer platform, **installation costs** of the mentioned components, costs of **approval and certification** as well as **provisions** for covering investment risks. In the following, they will be presented as **specific costs** related to 1 MW of installed capacity.

For **Site A**, the specific investment costs in **Scenario 1** will altogether decrease from a total of about 3,750k Euro/MW in 2013 to about 3,210k Euro/MW in 2023. This corresponds to a **decrease by 14 %**.

By 2023, increased competition and a steeper learning curve will have reduced specific investment costs in **Scenario 2 by 22 %** to about 2,930k Euro/MW. Figure 8 summarises the development of the specific investment costs for both scenarios.

Figure 8: Development of specific investment costs at Site A



Source: [Prognos/Fichtner]

Technology costs

(2) Technology costs include investment costs for turbine (generator, rotor, etc.), support structure of the wind turbine generator (foundation and tower), cabling between wind turbine generator and wind farm transformer platform as well as the costs of the transformer platform.

(3) **Turbine**

Also in the offshore industry, there is a trend towards larger rotor diameters that result in more full-load hours and higher gross electricity yield.

As a result, the specific investment costs in **Scenario 1** will increase from about 1,200k Euro/MW in 2013 to about 1,260 k Euro/MW in 2023. With larger rotor diameters and the technology transition from 4 MW to 6 MW turbines, costs will temporarily increase to even 1,350k Euro/MW. Short-term until 2017, especially the increased generator capacity will affect prices. Long-term until 2023, the increased rotor diameters from 120 m to 164 m will be the key driver for the increased cost level in 2023. Due to substantially increasing requirements on technology and performance, in the long run the turbine only offers a limited saving potential. However, higher costs will be more than compensated by increasing gross electricity yields. The development of new turbines is also driven by the goal to reduce costs of transportation, installation, operation and maintenance. This way, in spite of its own limited cost reduction potential, the turbine affects to a large degree the cost reduction in other areas of the added-value chain.

In **Scenario 2**, after an intermediate peak specific investment costs will decrease to about 1,090k Euro/MW until 2023. Specific investment costs will initially become higher due to the fact that turbine size will increase twice - in 2017 from 4 MW to 6 MW and in 2020 from 6 MW to 8 MW - with a simultaneous increase of the rotor diameter from 120 m in 2013 to 164 m in 2020. Long-term (2023), in spite of a further increase in rotor diameter to 178 m, we will see higher competition levels due to the market entrance of several Asian turbine manufacturers. In addition, learning curve effects will become noticeable earlier due to the faster development of offshore wind power in Germany and Europe in comparison to Scenario 1. This will result in that in 2023 investment costs for the turbine with 1,090k Euro/MW will be almost 10 % lower than the initial level in 2013. In addition, the **specific costs** of all **other** named generator **components** are usually **substantially reduced** by the turbine's capacity increase. This is mainly due to the fact that in the calculations the specific costs always relate to the turbine capacity (MW). Doubling average turbine capacity from 4 MW to 8 MW often results in increased absolute costs for the other components, but not in doubled costs. When moving towards larger turbines, this effect brings about lower specific costs of other cost items along the entire value-added chain.

(4) **Support structure**

The investment costs of foundation and tower depend mainly on the water depth at the site and the generator size. Currently, monopiles can be used for water depths of up to 30 m and a generator size of a maximum of 6 MW. In the future it may become feasible to use monopiles for water depths of up to 40 m. If larger turbines result in higher weights, jackets have to be used as foundation structures. Currently, specific investment costs amount to about 790k Euro/MW.

In **Scenario 1**, specific investment costs will have decreased to about 680k Euro/MW by 2023. In Scenario 1, the maximum turbine capacity is 6 MW; therefore the more cost-efficient monopiles can be used at all times of initial operation. Absolute costs per generator will increase due to more material and manufacturing requirements for monopiles that are used for 6 MW generators; however, due to the simultaneous capacity increase from 4 MW to 6 MW in 2017, specific investment costs will decrease. Further cost reductions are mainly caused by increased demand and the corresponding continuous production of monopiles. Manufacturers will have less downtime than they have with a less continuous production. With the use of 6 MW generators hub height will increase and thus even the tower from a current 90 m to 105 m in 2023. The larger amount of material required will be compensated by the learning curve effect and serial production.

In **Scenario 2**, specific investment costs will have decreased to about 635k Euro/MW by 2023. Particularly, the additional capacity increase from 6 MW to 8 MW per generator will result in substantially lower specific costs in 2020. From this year onwards, at Site A jackets will be used as foundations due to the larger generator weight. Dimensions and material requirements of monopiles for 8 MW turbines are not economically feasible. Theoretically it would be possible to produce monopiles with especially thick walls for 8 MW generators. However, that would be technically extremely demanding. In addition, the transport and installation of monopiles with such dimensions and total weight would make them economically less feasible than jackets. For monopiles with such dimensions, it would be necessary for the design and approval phase to evaluate fatigue loads, eigenfrequencies etc. and their effect on the lifetime. However, absolute costs for the complete support structure will increase as, on the one hand, jacket production often is more expensive and, on the other hand, in 2020 in Scenario 2 hub heights and thus also the tower will have reached 110 m. In Scenario 2 new manufacturers will enter the market and increase competition; therefore costs for support structures and tower will still be lower than in Scenario 1.

(5) **Cable**

In **Scenario 1**, the specific investment costs for cabling will decrease from about 89k Euro/MW in 2013 to about 72k Euro/MW in 2023. Due to larger generators, in the future larger cable cross-sections will be required to transport the generated electricity to the wind farm transformer platform. The increased demand of conductor material will result in an absolute cost increase; regarding specific costs, the switch from 4 MW to 6 MW will compensate that. In addition, the continuous demand in Scenario 1 will reduce cable procurement costs.

In **Scenario 2**, specific investment costs will have decreased to about 68k Euro/MW by 2023 and will therefore be slightly lower than in Scenario 1. The higher cable demand caused by a stronger development of offshore wind turbine generators allows for a more efficient cable production and lower costs. Even though from 2020 onwards absolute costs increase due to the once more increased cable cross-sections for 8 MW generators, specific costs will decrease by about 25 % until 2023. For 8 MW generators, the number of generators required for a wind farm (450 MW) decreases from 75 to 56 when comparing to a design with 6 MW generators. Even though the larger distance between generators requires larger cables there will still be savings due to the lower number of generators. Bottlenecks regarding the availability of cable production capacities - that can be currently observed on the market - are not included; we assume that with a continuous market growth new competitors will contribute to providing capacities in accordance with demand.

(6) **Wind farm transformer platform**

In **Scenario 1**, the specific investment costs of the wind farm transformer platform will decrease from about 230k Euro/MW in 2013 to about 154k Euro/MW in 2023. The decrease is mainly due to increasing wind farm size from 320 MW in 2013 to 450 MW in 2023. Currently 70 % of total costs are related to ships and support structure; therefore increased capacity will not result in higher absolute costs. Long-term until 2023, absolute costs for the platform will decrease due to learning curve effects, optimisations of the foundation structure and an assumed serial production.

In **Scenario 2**, specific investment costs will have decreased to about 140k Euro/MW by 2023. Especially, the introduction of general standards for the platform design as well as regarding electrotechnical issues results in a larger cost reduction for the period 2020 to 2023 in comparison to Scenario 1. In addition, Scenario 2 is expected to have more new market entrants resulting in higher competition; as opposed to a more limited market in Scenario 1.

Installation costs

(7) In addition to technology costs for the individual components, costs are incurred for the **installation** of turbine, support structure, cables and wind farm transformer platform.

In **Scenario 1**, the aggregated specific installation costs will decrease from about 570k Euro/MW in 2013 to slightly below 400k Euro/MW in 2023.

In **Scenario 2**, specific costs will have decreased to about 365k Euro/MW by 2023 and thus will be substantially lower. In the following, we will present for the individual components the reasons for the decrease.

(8) **Turbine**

Decreasing installation costs for turbines are especially due to improved logistics. Larger and faster installation ships - with orders already being places with the corresponding shipyards - will be available within the near future and make installation possible independent of the weather. They will contribute the largest part to cost reduction. In addition, the specific costs per MW of installed capacity will decrease due to increased turbine capacity. In 2023, it will take the same time to install a 6 MW turbine as an average 4 MW turbine today. Even though in **Scenario 1**, absolute costs of the installation process will increase from 520k Euro to 570k Euro per turbine until 2023, the specific costs will decrease from 130k Euro/MW in 2013 to 95k Euro/MW in 2023. This corresponds to a decrease of 30 %.

In **Scenario 2**, the stronger development will lead to even more obvious learning curve effects. At the same time, 8 MW turbines will be used in 2023. Absolute costs per generator thus increase from 520k Euro in 2013 to 720k Euro per generator in 2023. In the same period, specific costs go down from 130k Euro/MW to 90k Euro/MW, though.

(9) **Support structure**

Installation costs for the support structure will be positively affected by the development of maritime logistics. In addition, in the near future new monopile and jacket installation procedures will be introduced. In particular, the expensive monopile ramming will be replaced by drilling or vibration and allow for connecting monopile and transition piece with flanges instead of grout. A positive side effect would be the reduced sound emission during the installation process. This would result in reduced costs for noise protection.

In **Scenario 1**, the specific installation costs for the support structure will decrease from 286k Euro/MW in 2013 to about 200k Euro/MW in 2023. In addition to the already mentioned effects that are due to a capacity increase from 4 MW to 6 MW, new installation processes and more powerful ships will contribute to reduced specific costs. The towers are usually installed together with the generators. Larger ships will result in that more components can be transported with each trip. This means that favourable weather conditions can be used more efficiently for the installation. Correspondingly, costs for downtime will decrease.

In **Scenario 2**, specific costs will have decreased to about 175k Euro/MW by 2023 and thus will be lower than the costs in Scenario 1. This additional cost reduction is due to that there will be a larger offer of special ships by 2023.

(10) **Cable**

In **Scenario 1**, the specific costs for cabling will decrease from about 100k Euro/MW in 2013 to 73k Euro/MW in 2023. The reason for this decrease is that the number of generators per wind farm is reduced from 80 to 75 and turbine capacity is larger. At the same time, over the years new experience regarding risks will have been accumulated, e.g. about cable ruptures during cable laying and other damages from external factors.

In **Scenario 2**, specific investment costs will have decreased to 69k Euro/MW by 2023. The even larger decrease is mainly due to the increased number of new market entrants, more competition and a steeper learning curve.

(11) **Wind farm transformer platform**

The development regarding the installation of the transformer platform is similar to that of the generator. In **Scenario 1**, due to larger wind farms the specific installation costs will decrease from 54k Euro/MW to 35k Euro/MW. In addition, improved logistics and larger ship capacities contribute to the reduction of absolute costs.

In **Scenario 2**, specific costs will decrease slightly more to 31k Euro/MW until 2023. The larger decrease is due to the simplified installation of standardised transformer platforms. This does not only accelerate production, but also installation. New platform concepts, such as floating platforms and transformer platforms with jack-up systems, will make installation faster and independent of large installation ships. This way, it is easier to use smaller and more cost-efficient ships as well as utilise optimum weather slots; and thus installation costs can be reduced.

Certification and approval costs

(12) Due to the increase in generator capacity from 4 MW to 6 MW, in **Scenario 1** the specific certification and approval costs will decrease from 377k Euro/MW in 2013 to 351k Euro/MW in 2023. In addition, the necessary certification and approval processes can be optimised because of learning curve effects.

In **Scenario 2**, specific costs will have decreased to 296k Euro/MW. Not only the larger generator capacity of 8 MW will reduce the effort and thus costs, but also the fact that all parties (industry, operators and certifying bodies) will have agreed on uniform certifying standards.

Project contingencies

(13) In **Scenario 1**, specific provisions will decrease from about 490k Euro/MW in 2013 to slightly less than 290k Euro/MW in 2023. As contingency provisions are calculated as a portion of the remaining investment costs it is reduced by decreasing total investment costs (absolute contingency provisions). Due to the one-off switch from 4 MW to 6 MW in 2017, in addition the portion of the provisions goes down from 15 % in 2013 to 10 % in 2023 (relative contingency provisions).

In **Scenario 2**, contingency provisions will have decreased to about 340k Euro/MW by 2023. In spite of lower investment costs, the costs are higher in comparison to Scenario 1. Due to the switch from 6 MW to 8 MW in 2020, the portion of the provisions only decreases from 15 % in 2013 to 13 % in 2023. The new generator technology requires higher contingency provisions for unplanned risks during project implementation.

3.1.2 Operating costs

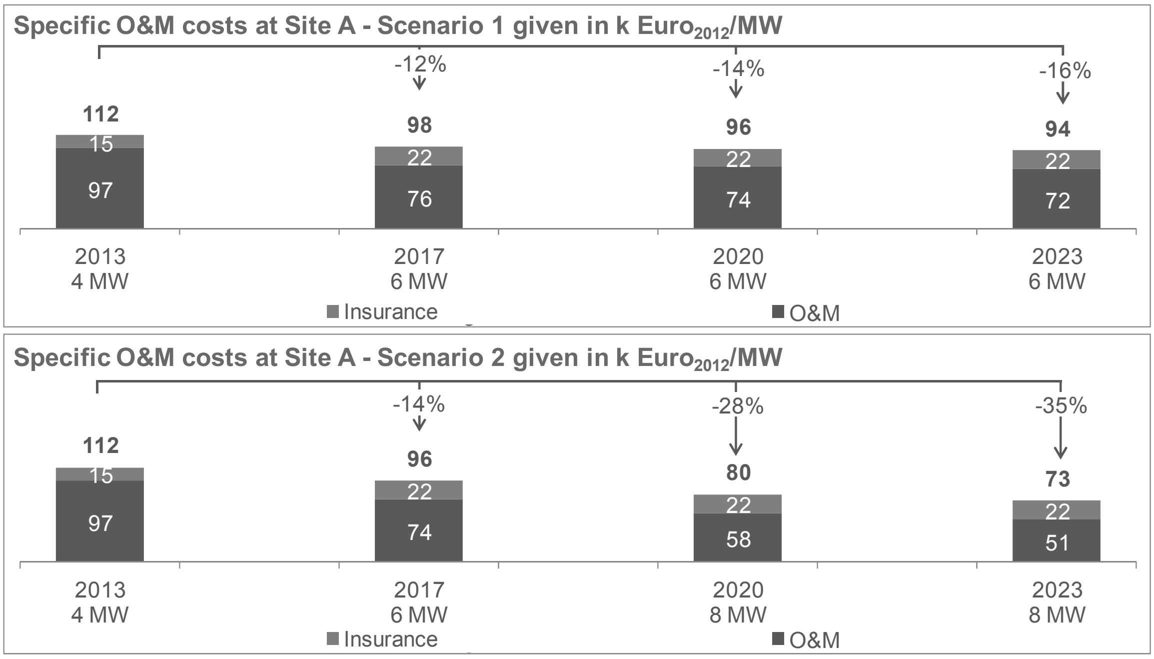
(1) In addition to investment costs, **the profitability** of offshore wind power is **largely affected** by the operating costs. Specific operating and maintenance costs (O&M) mainly depend on the wind farm's distance to port. The further away the wind farm, the larger the distance that maintenance ships have to cover. From a certain distance onwards, land-based maintenance of wind farms is not economically efficient any longer and sea-based maintenance concepts become more feasible. Maintenance work is carried out from supply and accommodation vessels or residential platforms.

For Site A with a distance to port of only 40 km, **land-based concepts** are used. In addition to higher generator capacity and the subsequently reduced number of generators per site, specific operating costs are also affected by logistics concepts and a higher availability of faster, modern ships. Specific insurance costs are kept constant from 2017 onwards.

In **Scenario 1**, the specific operating costs will decrease from 112k Euro/MW in 2013 to 94 k Euro/MW in 2023.

In **Scenario 2**, specific annual operating costs will decrease even more to 73k Euro/MW in 2023. Figure 9 shows the development of annual operating costs.

Figure 9: Development of specific annual operating costs at Site A



Source: [Prognos/Fichtner]

(2) Short-term, in both scenarios specific operating costs decrease due to the increase in generator capacity from 4 MW to 6 MW. In Scenario 2, this effect is repeated when in 2020 turbine capacity increases from 6 MW to 8 MW. Long-term in Scenario 2, absolute operating costs show a larger reduction due to inter-owner maintenance concepts. Using joint fleet and logistics infrastructure (landing and fuelling facilities for helicopters, ships, material storage, joint rescue and safety concepts) can contribute to reducing costs. Scenario 2 assumes a faster market entrance of specialised maintenance companies that have important generator wear parts stored on site in order to reduce expensive unplanned generator downtime.

3.1.3 Electricity generation

(1) The electricity production of an offshore wind turbine generator is affected by several factors. In addition to average wind speed at the site, other important factors are generator capacity, rotor diameter, hub height and internal and external wake losses. A larger rotor diameter generally results in a higher electricity generation. A higher turbine capacity can also increase the absolute energy yield of a generator. However, internal wind farm wake losses increase with larger rotor diameters if the distance between generators is kept constant. Due to larger rotor diameters, the relative distance between the generators in relation to rotor diameter will decrease.

External wake losses by adjacent wind farms increase with a growing number of surrounding wind farms. This applies particularly to adjacent wind farms that are located in the main wind direction. In the future, wind farm configurations in specific clusters that are advantageous for grid connection will increase external wake losses (see Table 5).

Table 5: Wake losses wind farm A

	Scenario 1						
Windpark A Initial operation	Number of WTG	Rotor diameter	WAKE losses			
			Total	Internal	External	Surrounded area
2013	80	120 m	13.50%	9.75%	3.75%	1.25
2017	75	145 m	14.50%	9.75%	4.75%	1.50
2020	75	154 m	16.50%	10.25%	6.25%	2.00
2023	75	164 m	17.75%	10.75%	7.00%	2.25
	Scenario 2					
Windpark A Initial operation	Number of WTG	Rotor diameter	WAKE losses			
			Total	Internal	External	Surrounded area
2013	80	120 m	13.50%	9.75%	3.75%	1.25
2017	75	145 m	14.50%	9.75%	4.75%	1.50
2020	56	164 m	17.25%	9.25%	8.00%	2.50
2023	56	178 m	19.50%	10.00%	9.50%	3.00

Source: [Prognos/Fichtner]

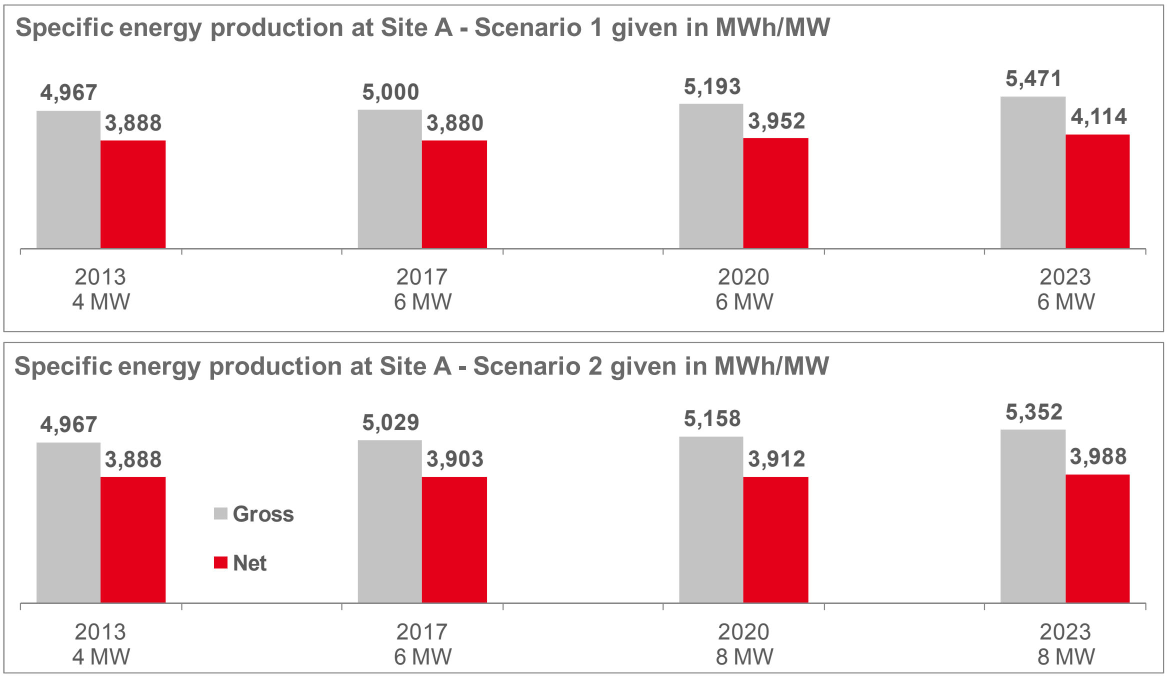
(2) In **Scenario 1** the specific gross electricity generation increases from 4,967 MWh/MW in 2013 by approximately 10 % to 5,471 MWh/MW in 2023. In the same period, net electricity generation increases by slightly less than 6 % from 3,888 MWh/MW to 4,114 MWh/MW (see Figure 10).

Short-term, both specific gross and net electricity generation remain almost constant. However, absolute net electricity generation goes up due to the increase in generator capacity from 4 MW to 6 MW. Until 2023, the continuous increase of rotor diameter to 164 m and of hub heights from 90 m to 105 m will result in a higher specific gross electricity generation of 5,471 MWh/MW. However, at the same time larger rotor diameters will increase internal wake losses; this means that higher gross wind yields from larger rotors and higher generators will be partially compensated by increasing wake losses. Therefore net electricity generation goes up to only 4,114 MWh/MW.

In **Scenario 2**, the specific gross electricity generation increases slightly less than 8 % to 5,352 MWh/MW. Net electricity generation goes up by about 3 % to 3,988 MWh/MW. The following Figure 10 presents the development of the specific electricity generation for both scenarios.

Due to the continuous improvement of all components, both gross and net electricity generation already short-term slightly exceed the values in Scenario 1. With the introduction of 8 MW generators in 2020, the specific electricity generation is somewhat lower than the corresponding value in Scenario 1. The reason is a better rotor-to-generator ratio for 6 MW generators in comparison to 8 MW generators. This ratio is decisive for the optimum utilisation of the wind. However, in 2023 the gross electricity generation of 5,352 MWh/MW clearly exceeds gross electricity generation in 2013. This is due to increasing internal and mainly external wake losses because of the larger number of adjacent wind farms resulting from the faster development of the technology. Until 2023, the specific net electricity generation will increase by only 3 % to 3,988 MWh/MW.

Figure 10: Development of specific electricity generation at Site A



Source: [Prognos/Fichtner]

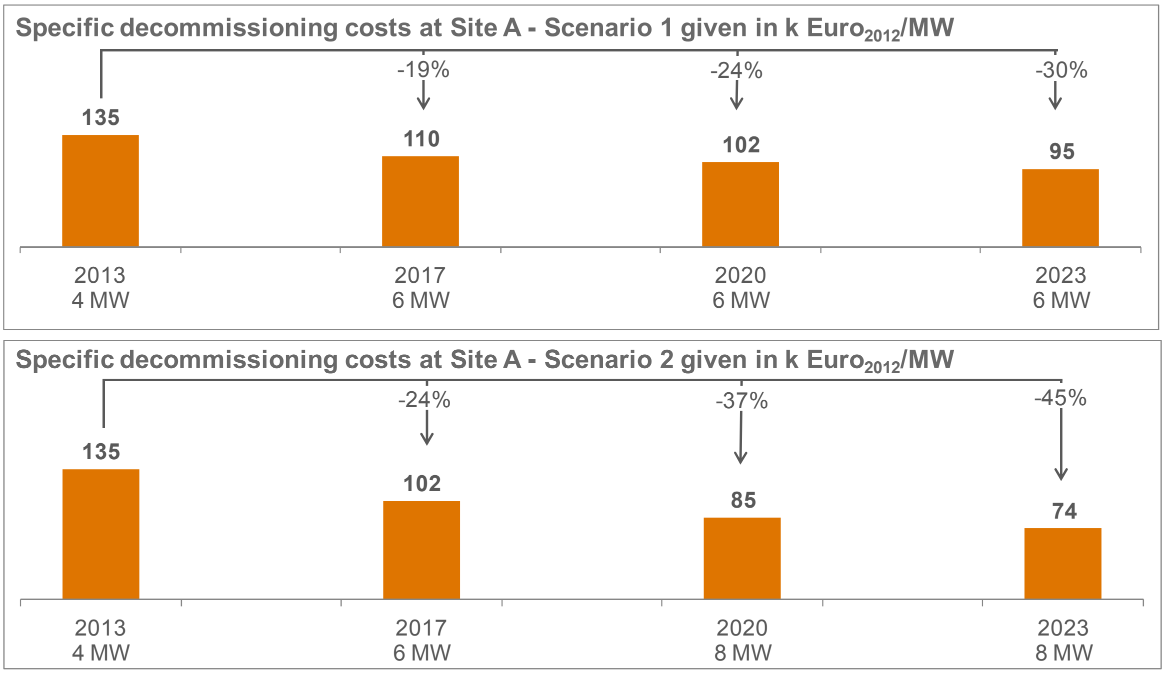
(3) In Scenario 2, the number of 56 generators per wind farm and the correspondingly improved distance ratio result in slightly lower internal wake losses of 10.0 % in comparison to 10.75 % in Scenario 1. Due to the faster development of offshore wind power in Scenario 2, there will be more wind farm clusters. Therefore the

external wake losses in Scenario 2 exceed with 9.5 % those of 7.0 % in Scenario 1. However, the 6 MW generators with 164 m in Scenario 1, have a substantially better rotor-to-generator ratio than the 8 MW generators with 178 m in Scenario 2. This means that in Scenario 1, the specific net electricity production with 4,114 MWh/MW is about 3 % higher than in Scenario 2. The absolute electricity generation is larger in Scenario 2, though.

3.1.4 Provisions for dismantling

(1) In the future, provisions for dismantling or decommissioning will decrease. In Scenario 1, the specific dismantling costs will decrease from 135k Euro/MW in 2013 to 95k Euro/MW in 2023. In Scenario 2, specific costs will have decreased to 74k Euro/MW by 2023. Figure 11 summarises the development of both scenarios.

Figure 11: Development of specific decommissioning provisions for Site A



Source: [Prognos/Fichtner]

(2) The **specific decommissioning costs** mainly decrease because of switching to larger turbines. However, currently there is hardly any experience regarding the dismantling of offshore wind turbine generators. Similar to other building measures, though, we can assume that by 2030 - when the first offshore wind farms will be decommissioned - there will be companies on the market that specialise in dismantling and have an appropriate logistics. Also de-installation can be expected to benefit from learning curve ef-

fects, which means that the specific dismantling costs for the wind farms that become operational in 2023 will be lower than those of previous projects. In Scenario 2, specific dismantling costs will further decrease due to the larger development and the correspondingly higher number of wind farms. A substantially higher number of competitors will result in larger cost reductions.

3.2 Site B

(1) The characteristics of Site B with a distance to port of 80 km and a water depth of 40 m – to a certain extent - currently only apply to the wind farm BARD Offshore 1 that is being completed. The wind farm Global Tech I is currently under construction. There are further approved projects that correspond to the criteria of Site B. Apart from BARD Offshore 1, none of these wind farms is likely to become operational before the year 2017. Table 6 shows the configuration of the site. It differs from the configuration of Site A (see Chapter 3.1) in the type of substructure and its operating and maintenance concept (O&M). Due to water depth and distance to port, adjustments had to be made.

Table 6: Site configuration wind farm B

	Scenario 1						
Site B Initial operation	Number of WTG	Capacity WTG	Size wind farm	Hub height	Rotor diameter	Foundation	O&M Concept
2013	80	4 MW	320 MW	90 m	120 m	JK	SB
2017	75	6 MW	450 MW	100 m	145 m	JK	SB
2020	75	6 MW	450 MW	100 m	154 m	MP	SB
2023	75	6 MW	450 MW	105 m	164 m	MP	SB
	Scenario 2						
Site B Initial operation	Number of WTG	Capacity WTG	Size wind farm	Hub height	Rotor diameter	Foundation	O&M Concept
2013	80	4 MW	320 MW	90 m	120 m	JK	SB
2017	75	6 MW	450 MW	100 m	145 m	JK	SB
2020	56	8 MW	450 MW	110 m	164 m	JK	SB
2023	56	8 MW	450 MW	115 m	178 m	JK	SB

Source: [Prognos/Fichtner]; MP – Monopile, JK – Jacket; SB - sea-based

(2) The presentation of costs and electricity generation at Site B follows the systematics of Site A. The different results are due to diverging site conditions and the interaction of different factors that affect costs.

3.2.1 Investment costs

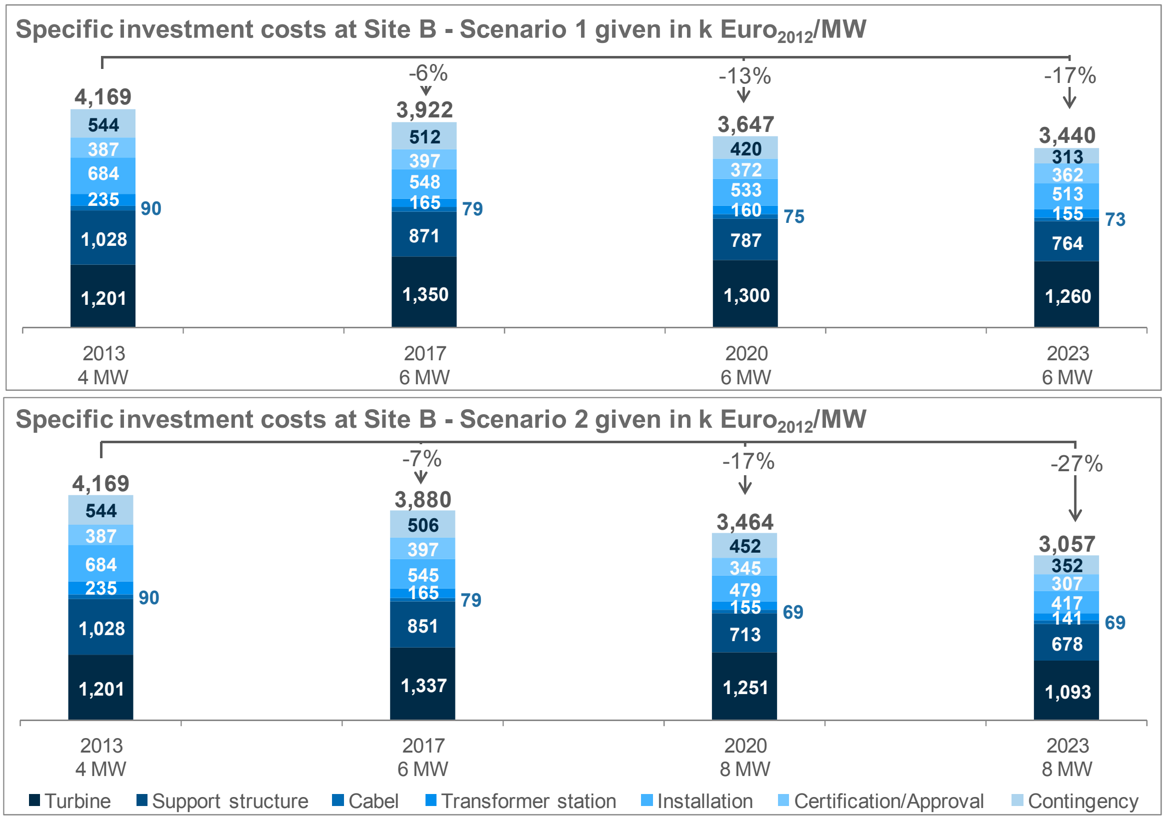
(1) Due to the more complex **site conditions at Site B**, **total investment costs at Site B** are higher than those of **Site A**, both short- and long-term.

For Site B, the specific total investment costs in **Scenario 1** will altogether decrease from about 4,170k Euro/MW in 2013 to 3,440 k Euro/MW in 2023. This corresponds to a decrease of specific investment costs by 17 %.

By 2023, increased competition and a steeper learning curve will have reduced specific investment costs in **Scenario 2** by as much as 27 % to about 3,060k Euro/MW.

The **larger reduction** of specific investment costs **in comparison to Site A** is particularly due to an improved maritime logistics, but also to economies of scales regarding the support structure. Even though deeper waters will result in increased costs for foundation materials, optimisation and learning curve effects regarding the production will overcompensate the increased costs of the required additional steel. In addition, for the longer distance to port at Site B improved logistics concepts and faster ships have a larger effect than for Site A. Figure 12 summarises the development of the specific total investment costs for both scenarios.

Figure 12: Development of specific investment costs at Site B



Source: [Prognos/Fichtner]

Technology costs

(2) Technology costs include investment costs - presented in Figure 12 - for turbine (generator, rotor, etc.), substructure/ support structure of the wind turbine generator (foundation and tower), cabling between wind turbine generator and wind farm transformer platform as well as the costs of the transformer platform.

(3) **Turbine**

As **turbine costs** are independent of the generator site, they **do not differ from the costs at Site A**.

The specific investment costs per turbine in **Scenario 1** will increase from today's 1,200k Euro/MW to 1,260k Euro/MW in 2023.

In **Scenario 2**, after an intermediate peak specific investment costs will decrease to about 1,090k Euro/MW. Also in this scenario, economies of scales and optimisation as well as the manufacturing utilisation rate compensate the more complex technology.

(4) **Support structure**

As investment costs for foundation and tower depend on **water depth**, among others, the absolute investment costs for the support structure at Site B differ from those at Site A. In the reference year, they amount to 1,028k Euro/MW and are thus more than **30 % higher than the costs at Site A**. For water depths of 40 m at Site B, currently **only jackets** are included in the assumptions for foundations. Medium-term from 2020 onwards however, the industry expects other substructure concepts for 6 MW generators to be available.

In **Scenario 1**, the specific investment costs for the support structure will decrease from about 1,030k Euro/MW in 2013 to about 764k Euro/MW in 2023. Short-term, economies of scales due to switching from 4 MW to 6 MW will have a positive impact on specific costs. It applies also to this site that a continuous production of foundations will result in an additional cost reduction. In Scenario 1, **from 2020** the model assumes the use of **monopiles** for 6 MW generators. Until 2020, in spite of the larger amount of material required for monopiles with such dimensions, they still show a slight cost advantage over jackets. Also at this site hub height will increase and thus even the tower from a current 90 m to 105 m in 2023; the larger amount of material required will be compensated by production learning curve effects, though.

In **Scenario 2**, specific investment costs for the support structure will have decreased to about 680k Euro/MW by 2023. Particularly in 2020, this scenario once again benefits from economies of scales due to the switch from 6 MW to 8 MW generators. The market entrance of new manufacturers will result in a further cost decrease until 2023. In Scenario 2, the hub height increases for 8 MW generators to 115 m in 2023. The use of 8 MW generators from 2020 onwards will **still** require **jackets** as foundations. Additional costs due to larger material requirements will be compensated by optimised production processes.

(5) **Cable**

In Scenario 1, the specific investment costs for cables that connect the generators to the wind farm transformer platform will decrease from about 90k Euro/MW in 2013 to about 73k Euro/MW in 2023. This means that cabling costs **at Site B** always will be **slightly higher than costs at Site A**. This is mainly due to the larger water depth.

In Scenario 2, specific investment costs will have decreased to about 69k Euro/MW by 2023 and will therefore be slightly lower than in Scenario 1. Larger learning effects, increasing utilisation of production capacity for a larger number of installations and increased competition in Scenario 2 also in this case characterise the development in relation to Scenario 1.

(6) **Wind farm transformer platform**

Specific investment costs for the wind farm transformer platform for Site B are here **slightly higher** than the costs **at Site A**. Due to deeper waters, foundations at Site B have to have larger dimensions.

In **Scenario 1**, the specific costs will decrease from about 235k Euro/MW in 2013 to 155k Euro/MW in 2023.

In **Scenario 2**, specific investment costs will have decreased to 141k Euro/MW by 2023.

Installation costs

(7) At **Site B** due to the larger distance to port and deeper waters, installation costs will be higher than at Site A over the entire considered period of time. In **2013**, specific costs amount to 684k Euro/MW and are thus more than **20 % higher than the costs at Site A**.

In **Scenario 1**, specific installation costs will decrease from about 684k Euro/MW in 2013 to slightly below 513k Euro/MW in 2023.

In **Scenario 2**, specific costs will have decreased substantially more - to 417k Euro/MW by 2023. In the following, we will present the reasons for this decrease.

(8) Turbine

Improved logistics also have a positive impact on Site B. In the future, larger and faster installation ships will reduce installation times; and more generators will be installed during one trip. Also regarding rotor installation concepts, horizontal single blade assembly, among others, will make it possible to mount substantially more rotor blades at a faster rate in comparison to the transport and assembly of entire rotor stars. These concepts contribute a large part to cost savings. In addition, the specific costs per MW of installed capacity will decrease due to economies of scales for larger turbines. In **Scenario 1**, the specific installation costs for the turbine will decrease from 158k Euro/MW in 2013 to 124k Euro/MW in 2023.

In **Scenario 2**, the stronger development will lead to an even steeper learning curve. At the same time by 2023, 8 MW turbines will be used. In spite of the increase in absolute costs to 850k Euro per generator, over the same period of time specific costs will decrease to 107k Euro/MW due to a higher generator capacity.

(9) Support structure

Installation costs for the support structure will also be positively affected by the development of maritime logistics. In **Scenario 1**, the specific installation costs for the support structure will decrease from 350k Euro/MW in 2013 to about 260k Euro/MW in 2023. In addition to the already mentioned economies of scales that are due to a capacity increase from 4 MW to 6 MW, the main driver is more powerful ships. There will also be available improved installations processes, such as optimised drilling and vibration processes for monopiles. Until 2020, the large number of installed monopiles is very likely to produce large learning curve effects.

In **Scenario 2**, specific costs will have decreased to about 200k Euro/MW by 2023 and thus will be lower than the costs in Scenario 1. Further cost reductions are achieved by another capacity increase from 6 MW to 8 MW generators and the larger competition in Scenario 2.

(10) **Cable**

Due to the larger water depth, total costs for cabling are also higher at Site B than at Site A. A future cost decrease will originate from the same effects as at Site A.

In **Scenario 1**, the specific costs for cabling will decrease from about 120k Euro/MW in 2013 to 92k Euro/MW in 2023.

In **Scenario 2**, specific costs will have decreased to 77k Euro/MW by 2023.

(11) **Wind farm transformer platform**

In **Scenario 1**, due to larger wind farms - and the corresponding capacity increase of the wind farm transformer station in 2017 - the specific installation costs will decrease from 56k Euro/MW to 39k Euro/MW. Long-term, the improved logistics due to faster ships will also substantially reduce absolute costs.

In **Scenario 2**, due to the introduction of design standards and new platform concepts specific costs will have decreased slightly more to 32k Euro/MW by 2023. Shorter installation times reduce the utilisation periods of special ships and thus the corresponding costs.

Certification and approval costs

(12) At Site B, specific certification and approval costs are **slightly higher than at Site A**. For soil examinations, due to the longer distance to port, it takes the ships longer to arrive at the sites. Rental time and the corresponding costs increase. The same applies to explosive ordnance removal. In **Scenario 1**, the specific certification and approval costs will decrease from 387k Euro/MW in 2013 to 362k Euro/MW in 2023.

In **Scenario 2**, specific costs will go down further to 307k Euro/MW.

Project contingencies

(13) In **Scenario 1**, specific provisions will decrease from about 540k Euro/MW in 2013 to slightly less than 310k Euro/MW in 2023. This decrease is caused, on the one hand, by the absolute reduction of investment costs and by the decrease of the proportional provisions from 15 % to 10 % of the investment sum total. Due to higher investment costs at Site B, specific contingency provisions are slightly higher than for Site A.

The same applies to **Scenario 2**. Specific contingency provisions will have decreased to about 350k Euro/MW by 2023. In Scenario 2, the provisions develop less progressively due to more frequent technology switches to larger generators. As a consequence, contingency provisions for unplanned risks during project implementation will be slightly higher.

3.2.2 Operating costs

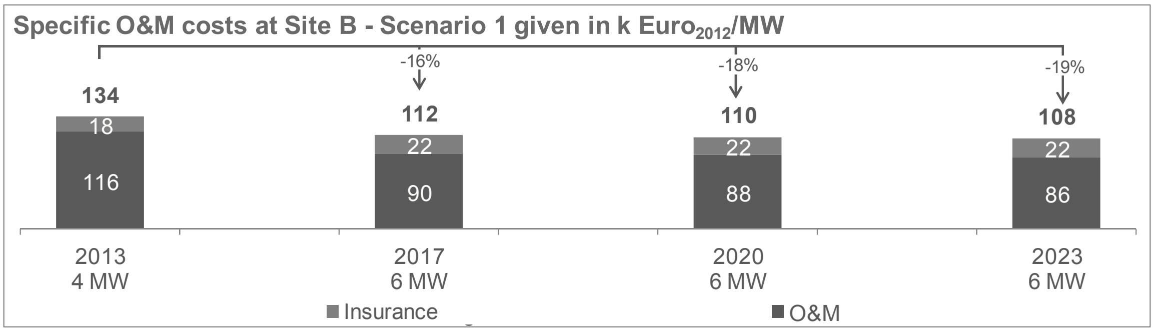
(1) With a distance to port of 80 km for Site B, land-based concepts for generator maintenance are economically disadvantageous in comparison to sea-based concepts. Due to the large distance, sea-based maintenance concepts with accommodation vessels or residential platforms will be used. After a thorough analysis, both sea-based maintenance concepts show a similar discounted value of total costs over the entire lifespan of a wind farm. For the sake of comparison, we have used residential platforms for this operating cost approach, even though they trigger a higher portion of investment costs. Due to the permanent use of ships, **maintenance costs** are **higher** than at **Site A**.

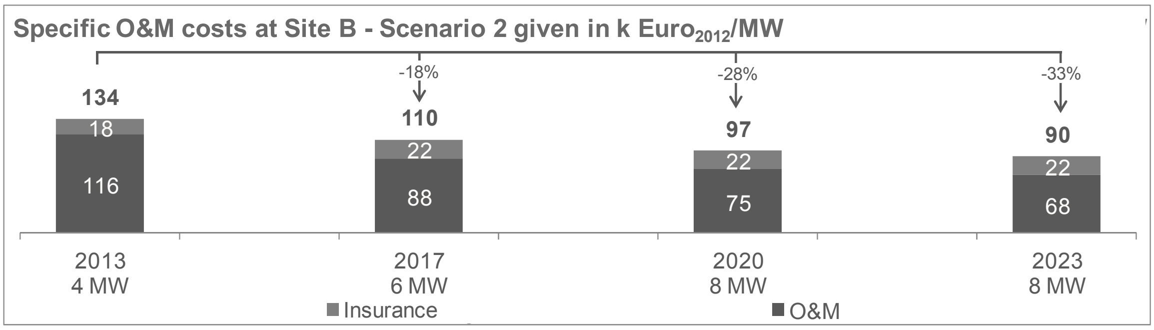
(2) Switching from 4 MW to 6 MW generators also will reduce specific operating costs at Site B with this effect being repeated in Scenario 2 when in 2020 turbine capacity will increase from 6 MW to 8 MW. The larger the distance between wind farm and shore, the more efficient the use of inter-operator maintenance concepts will become. Scenario 2 shows a stronger long-term decrease of specific operating costs due to the use of such concepts.

In **Scenario 1**, the specific operating costs will decrease from 134k Euro/MW in 2013 to 108k Euro/MW in 2023 which corresponds to a reduction of almost 20 %.

In **Scenario 2**, due to stronger competition and the faster development of joint concepts for several wind farms, operating costs will have decreased to 90k Euro/MW by 2023. Figure 13 shows the development of annual operating costs.

Figure 13: Development of specific annual operating costs at Site B





Source: [Prognos/Fichtner]

3.2.3 Electricity generation

(1) Electricity generation is more advantageous at Site B than at Site A. With 10 m/s, the average **wind speed at Site B is slightly higher than at Site A** with 9.9 m/s. Thus both gross and net **electricity production** at Site B are about 2 % **higher**.

Due to the uniform wind farm design, the assumed wake losses (see Table 7) correspond to those at Site A.

Table 7: Wake losses wind farm B

	Scenario 1						
Windpark B Initial operation	Number of WTG	Rotor diameter	WAKE losses				
			Total	Internal	External	Surrounded area
2013	80	120 m	13.50%	9.75%	3.75%	1.25
2017	75	145 m	14.50%	9.75%	4.75%	1.50
2020	75	154 m	16.50%	10.25%	6.25%	2.00
2023	75	164 m	17.75%	10.75%	7.00%	2.25
	Scenario 2						
Windpark B Initial operation	Number of WTG	Rotor diameter	WAKE losses				
			Total	Internal	External	Surrounded area
2013	80	120 m	13.50%	9.75%	3.75%	1.25
2017	75	145 m	14.50%	9.75%	4.75%	1.50
2020	56	164 m	17.25%	9.25%	8.00%	2.50
2023	56	178 m	19.50%	10.00%	9.50%	3.00

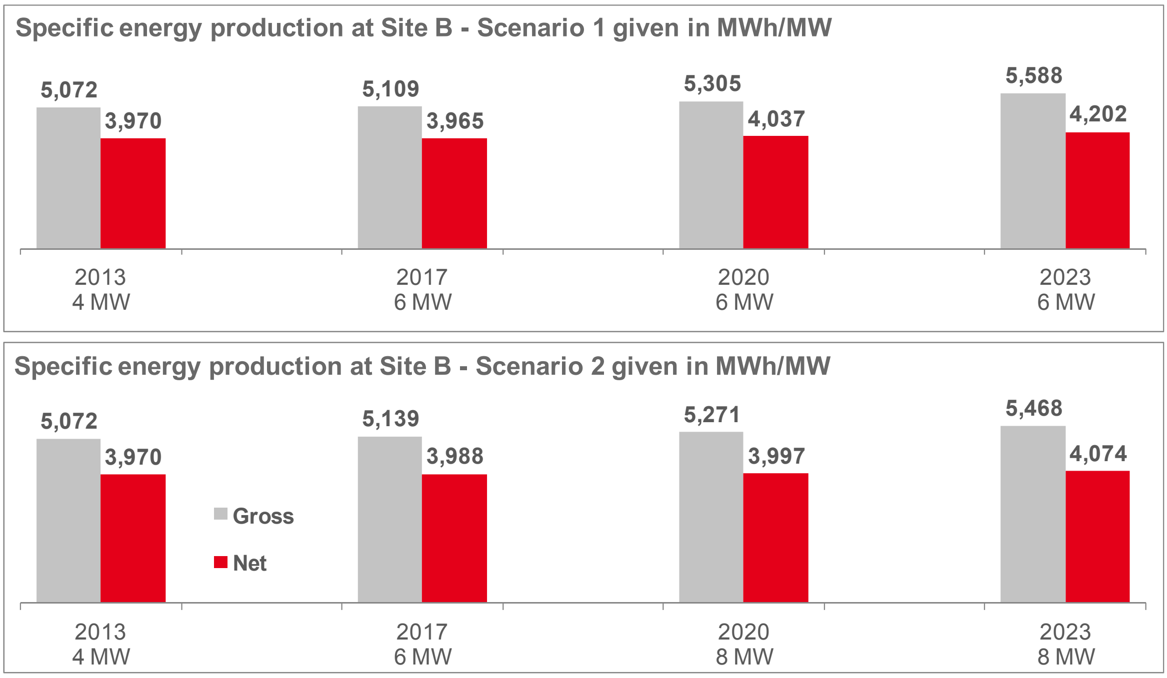
Source: [Prognos/Fichtner]

(2) Similar to Site A, the switch from 4 MW to 6 MW generators with simultaneously increased rotor diameters short-term only results in a slightly higher specific gross electricity generation.

In 2017, due to the switch from 4 MW to 6 MW generators, the specific net electricity generation in **Scenario 1** marginally decreases. According to our model assumptions, the rotor-to-generator ratio deteriorates in spite of enlarged rotor diameters. As rotor diameters will further increase to 164 m until 2023, the average gross electricity generation will go up from 5,072 MWh/MW in 2013 by approximately 10 % to 5,588 MWh/MW in 2023. Larger external wake losses though result in an increase of only 6 % in the annual net electricity generation for the same period from 3,970 MWh/MW in 2013 to 4,202 MWh/MW.

Also in **Scenario 2**, the lower rotor-to-generator ratio affects gross and net electricity production. Due to the continuous improvement of all generator components, already in 2017 both gross and net electricity generation short-term slightly exceed the values in Scenario 1. Medium-term until 2020, due to the switch from 6 MW to 8 MW generators, the specific net electricity generation only marginally increases. The absolute net electricity generation per generator goes up substantially, though. As rotor diameter will further increase to 178 m, the specific gross electricity generation in 2023 will have gone up - in comparison to the base year 2013 - by approximately 8 % to 5,468 MWh/MW. At the same time, the external wake losses in Scenario 2 will increase due to the stronger development of offshore wind power in the North Sea und the resulting higher degree of wind farm clusters. The net electricity generation will therefore increase by only 3 % to 4,074 MWh/MW. Figure 14 presents the development of the specific electricity generation for both scenarios.

Figure 14: Development of the specific electricity generation at Site B



Source: [Prognos/Fichtner]

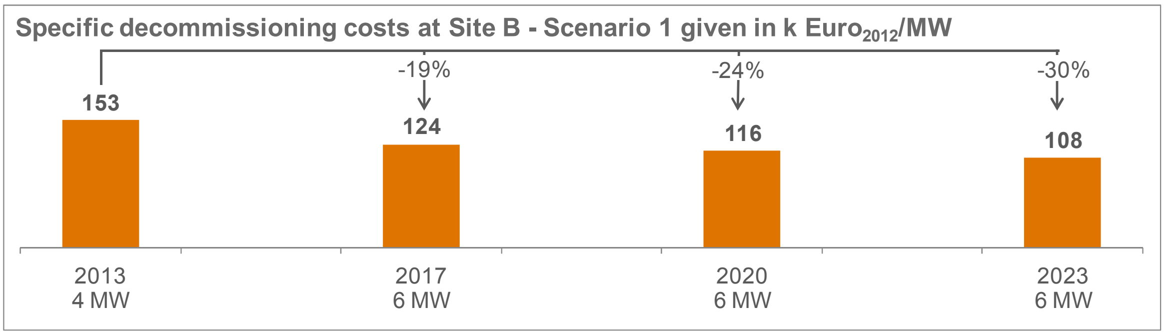
3.2.4 Provisions for dismantling

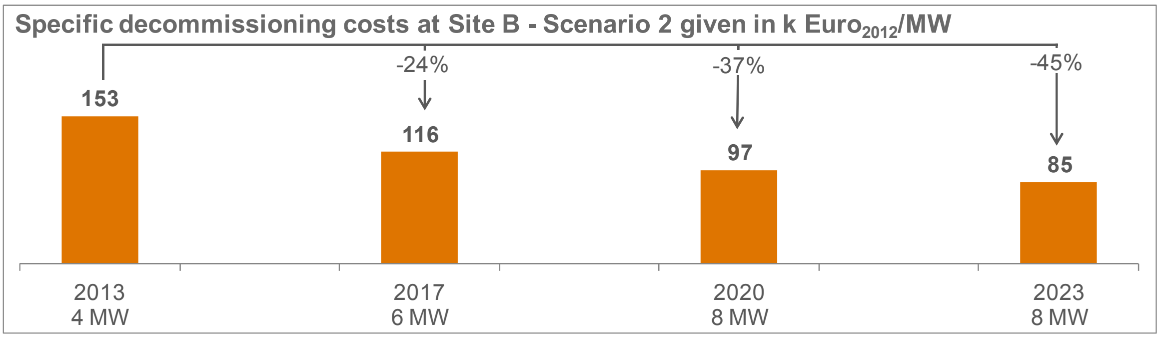
(1) Due to larger distances to port and deeper waters, the **dismantling costs** for a generator **at Site B** are higher **than those at Site A**; this means that we have to assume higher provisions for dismantling.

In **Scenario 1**, the specific dismantling costs will in total decrease from 153k Euro/MW in 2013 to slightly less 110k Euro/MW in 2023 due to the same learning curve effects as at Site A.

In **Scenario 2**, specific costs will have decreased to 85k Euro/MW by 2023. Figure 15 summarises the development of both scenarios.

Figure 15: Development of specific decommissioning provisions for Site B





Source: [Prognos/Fichtner]

(2) Similar to Site A, also at Site B the specific decommissioning costs will decrease in the future because of the switch to larger turbines. Once there is experience from dismantling the first wind farms, absolute costs will decrease. Cost advantages in Scenario 2 are once again the result of a steeper learning curve due to an increased number of dismantled wind farms.

3.3 Site C

(1) For Site C, there are currently no wind farms that are under construction or have been approved that could be used as a comparison. Therefore, all results for the year 2013 are rather theoretical. With a water depth of 50 m and a distance to port of 120 km, it is the most advanced site for a wind farm project within the framework of our analysis. The first wind farms in such deep waters will become operational in 2020, at the earliest. The average annual wind speed of 10.1 m/s is the highest of this study. Table 8 summarises the site characteristics. It differs from the configurations of Site A and B described in Chapters 3.1 and 3.2 regarding the type of substructure used and its maintenance concept (O&M). The adjustments result from the distance to port and the water depth at the site.

Table 8: Site configuration wind farm C

	Scenario 1						
Site C Initial operation	Number of WTG	Capacity WTG	Size wind farm	Hub height	Rotor diameter	Foundation	O&M Concept
2013	80	4 MW	320 MW	90 m	120 m	JK	SB
2017	75	6 MW	450 MW	100 m	145 m	JK	SB
2020	75	6 MW	450 MW	100 m	154 m	JK	SB
2023	75	6 MW	450 MW	105 m	164 m	JK	SB
	Scenario 2						
Site C Initial operation	Number of WTG	Capacity WTG	Size wind farm	Hub height	Rotor diameter	Foundation	O&M Concept
2013	80	4 MW	320 MW	90 m	120 m	JK	SB
2017	75	6 MW	450 MW	100 m	145 m	JK	SB
2020	56	8 MW	450 MW	110 m	164 m	JK	SB
2023	56	8 MW	450 MW	115 m	178 m	JK	SB

Source: [Prognos/Fichtner]; MP – Monopile, JK – Jacket

(2) The presentation of costs and electricity generation at Site C follows the systematics of Site A. The different results are due to diverging site conditions and the interaction of different factors that affect costs.

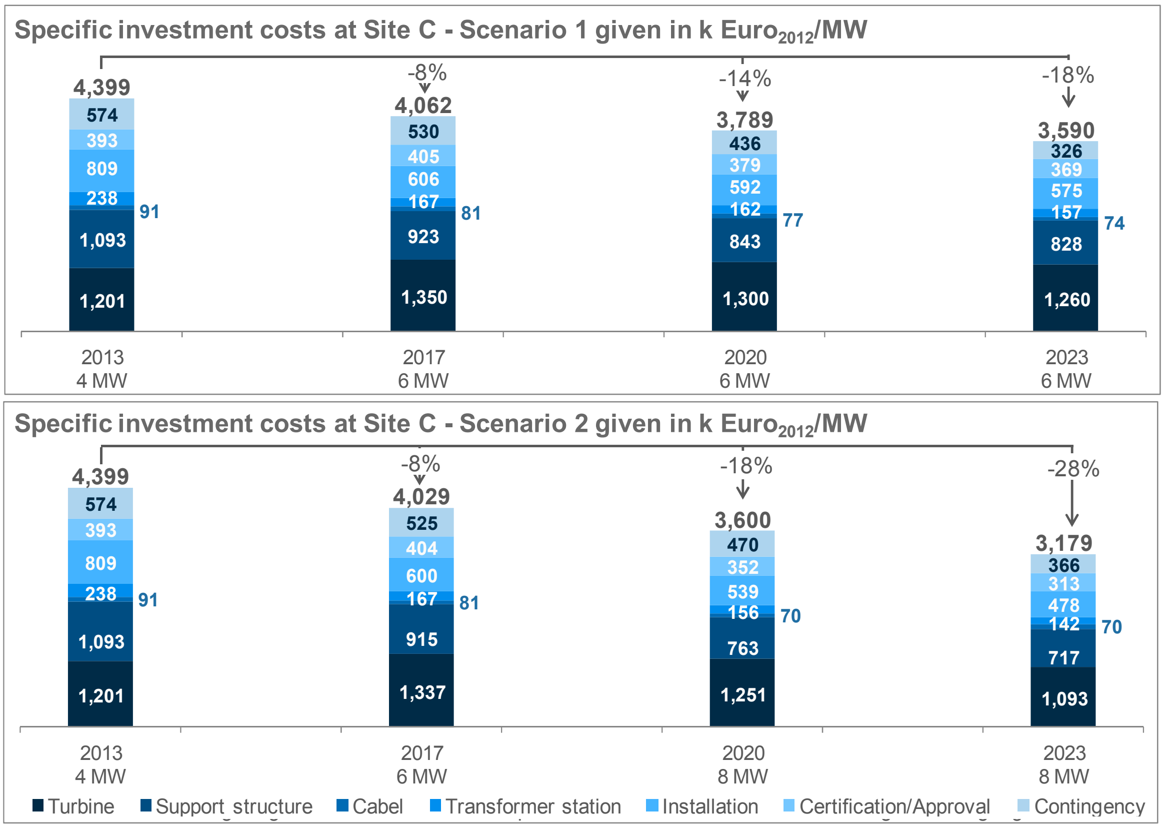
3.3.1 Investment costs

(1) Due to deeper waters and a longer distance to port, investment costs at Site C exceed those for the other two sites. On the one hand, material costs for support structures will be substantially higher. On the other hand, the distance to port increases the rental periods for installation ships and thus increases costs. In addition, meteorological conditions on the open sea are much more demanding resulting in shorter weather slots with favourable conditions for a successful installation. Due to the complex framework conditions, the specific **total investment costs** at Site C in the (theoretical) base year 2013 amount to 4,399 k Euro/MW and thus **exceed** those at **Site B by more than 5 %** and those of **Site A by over 25 %**. Independent of that, we can assume a future decrease of investment costs also for Site C.

The specific total investment costs in **Scenario 1** will altogether decrease from about 4,400k Euro/MW in 2013 to 3,590 k Euro/MW in 2023. This corresponds to a decrease of 18 %.

In **Scenario 2**, due to stronger competition and a steeper learning curve from the faster development of offshore wind power, by 2023 specific investment costs will have decreased by a total of 28 % to about 3,180k Euro/MW. Also to this site applies that the optimisation of installation and logistics concepts as well as cost advantages regarding the support structure are the main reasons for the cost reduction. Figure 16 summarises the development of the investment costs for both scenarios.

Figure 16: Development of specific investment costs at Site C



Source: [Prognos/Fichtner]

Technology costs

(2) Similar to Sites A and B, technology costs include investment costs - presented in Figure 12 - for turbine, support structure, cabling between wind turbine generator and wind farm transformer platform as well as the costs for the transformer platform.

(3) **Turbine**

Turbine costs at Site C do not differ from the costs **at Site A and B**.

The specific investment costs per turbine in **Scenario 1** will increase from 1,200k Euro/MW in 2013 to 1,260 k Euro/MW in 2023. In **Scenario 2**, after an intermediate peak specific investment costs will decrease to about 1,090k Euro/MW.

(4) Support structure

Because of a water depth of 50 m, at Site C **jackets** are used **consistently** for all times of initial operation, independent of generator capacity. At the same time due to water depth, specific investment costs for the support structure exceed costs at Site A (+ 38 %) and B (+ 6 %).

In **Scenario 1**, costs for the support structure will decrease from about 1,090k Euro/MW in 2013 to slightly less than 830k Euro/MW in 2023. Similar to the other sites, switching from 4 MW to 6 MW generators will have a positive impact on costs. The reasons of the cost reduction are comparable to those for Site A and B.

In **Scenario 2**, specific costs for the support structure will have decreased to about 720k Euro/MW by 2023. When switching from 6 to 8 MW generators in 2020, also Site C will show a larger cost decrease for Scenario 2 than for Scenario 1. Long-term, the same learning curve effects and increased competition as for the other two sites will apply.

(5) Cable

Due to deeper waters and the correspondingly required longer cables **costs at Site C** will be **slightly higher than costs at Site B**.

In **Scenario 1**, the specific cabling costs for connecting the generators to the wind farm transformer platform will decrease from 91k Euro/MW in 2013 to 74k Euro/MW in 2023.

In **Scenario 2**, specific investment costs for cabling will have decreased to 70k Euro/MW by 2023. The drivers of the cost development coincide with those at Sites A and B.

(6) Wind farm transformer platform

The investment costs for the wind farm transformer platform are **slightly higher at Site C than at Site B.** The necessary foundations have to have larger dimensions because of the deeper waters.

In **Scenario 1**, the specific costs will decrease from about 238k Euro/MW in 2013 to 157k Euro/MW in 2023.

In **Scenario 2**, specific investment costs will have decreased to 142k Euro/MW by 2023. Cost reduction is due to the same effects as at Sites A and B - such as competition, standardisation and optimisation of the foundations.

Installation costs

(7) As Site C is located even further away from the port and in deeper waters, installation costs at **Site C** on average are **substantially higher** than costs at **Site A** (+ 41 %) **and B** (+ 18 %).

In **Scenario 1**, specific installation costs will decrease from about 810k Euro/MW in 2013 to 575k Euro/MW in 2023.

In **Scenario 2**, specific costs will have decreased substantially more - to 478k Euro/MW by 2023. In the following, we will present for the individual components the reasons of the decrease.

(8) **Turbine**

For Site C, turbine installation as a portion of total installation costs amounts to almost 25 %. The larger water depth results in that the support structure is more important than at the other sites. Optimised logistics concepts and future larger and faster installation ships bring about a shorter installation time for the generators also for Site C. This has a cost-reducing effect on the specific installation costs. In 2017, with the switch from 4 MW to 6 MW generators, economies of scales produce a short-term effect.

In **Scenario 1**, the specific installation costs for the turbine will decrease from 190k Euro/MW in 2013 to 140k Euro/MW in 2023.

In **Scenario 2**, the stronger development will lead to an even steeper learning curve. In addition by 2023, 8 MW turbines will be used. In spite of the increase in absolute costs to over 960k Euro per generator, over the same period of time specific costs relating to higher generator capacity will decrease to 120k Euro/MW.

(9) **Support structure**

At Site C, the support structure corresponds to more than 50 % of total installation costs and therefore is of **utmost importance**.

In **Scenario 1**, the specific installation costs for the support structure will decrease from 420k Euro/MW in 2013 to about 290k Euro/MW in 2023. Also here, improved logistics concepts as well as larger and faster ships are the key drivers of the cost reduction.

In **Scenario 2**, specific costs will have decreased to about 236k Euro/MW by 2023 and thus will be 19 % lower than the costs in Scenario 1.

(10) **Cable**

Specific cabling costs correspond to 15 % of total installation costs. In **Scenario 1**, they will also decrease from 140k Euro/MW in 2013 to about 100k Euro/MW in 2023 due to improved logistics concepts and installation infrastructure.

In **Scenario 2**, specific costs will have decreased to 87k Euro/MW by 2023. The reduction in both scenarios is due to the same reasons as at Sites A and B. This means that also in Scenario 2 the larger decrease is caused by a stronger competition between installation companies.

(11) **Wind farm transformer platform**

With clearly less than 10 %, the wind farm transformer platform contributes the smallest portion to total installation costs. In **Scenario 1** they will decrease from 60k Euro/MW to 40k Euro/MW.

In Scenario 2, due to the introduction of design standards and optimised installation methods as well as the availability of appropriate installation ships specific costs will have decreased slightly more to 34k Euro/MW by 2023.

Certification and approval costs

(12) As at **Site C** the distance to port is even larger, specific certification and approval costs will be **higher** than the costs at **Sites A and B**. In **Scenario 1**, the specific certification and approval costs will decrease from 393k Euro/MW in 2013 to 369k Euro/MW in 2023.

In **Scenario 2**, specific costs will have decreased to 313k Euro/MW.

Project contingencies

(12) Due to the proportional calculation in percent and higher total investment costs at Site C, specific contingency provisions are **higher than for Site B**.

In **Scenario 1**, provisions will decrease from over 570k Euro/MW in 2013 to slightly less than 330k Euro/MW in 2023.

In **Scenario 2**, contingency provisions will have decreased to about 370k Euro/MW by 2023. It will go down less than in Scenario 1 as more frequent switches from one technology to another results in higher project risks during project implementation. This requires a higher proportional provision.

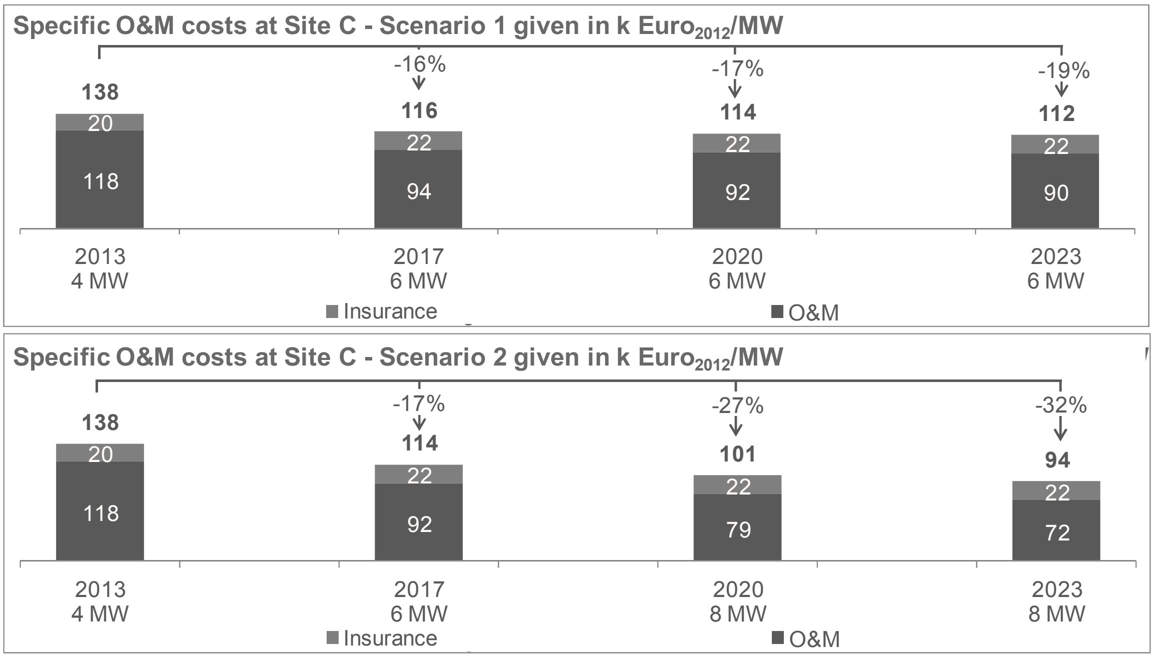
3.3.2 Operating costs

(1) Due to the large distance to port of 120 km, only sea-based maintenance concepts with accommodation vessels or residential platforms can be used for Site C. The larger distance to port - in comparison to Site B - results in 5 % higher costs due to longer transport distances for maintenance staff and material. As the maintenance concept changes in comparison to Site A, costs will be almost 20 % higher at Site C.

In **Scenario 1**, the specific operating costs will decrease from 138k Euro/MW in 2013 to 112k Euro/MW in 2023.

In **Scenario 2**, specific annual operating costs will have decreased to 94k Euro/MW by 2023. Figure 17 summarises the development of the specific annual operating costs for Site C.

Figure 17: Development of specific annual operating costs at Site C



Source: [Prognos/Fichtner]

(2) The reasons for the reduced operating costs coincide with those at Sites A and B. They are mainly due to economies of scales of larger generators, faster ships and joint maintenance concepts of the operators. In addition, improved access systems and corresponding maintenance options that are independent of the weather contribute to cost reductions.

3.3.3 Electricity generation

(1) Similar to Site B, the larger distance to port at Site C results in an additional advantage regarding electricity generation. With 10.1 m/s, the average wind speed at Site C slightly exceeds that at Sites A and B. Thus both gross and net **electricity production at Site C** are about 2 % **higher than at Site B and more than 3 % higher than at Site A**.

Due to the uniform wind farm design, the assumed wake losses (see Table 9) correspond for all studied sites to those of Site A.

Table 9: Wake losses wind farm C

	Scenario 1					
Windpark C Initial operation	Number of WTG	Rotor diameter	WAKE losses			
			Total	Internal	External	Surrounded area
2013	80	120 m	13.50%	9.75%	3.75%	1.25
2017	75	145 m	14.50%	9.75%	4.75%	1.50
2020	75	154 m	16.50%	10.25%	6.25%	2.00
2023	75	164 m	17.75%	10.75%	7.00%	2.25
	Scenario 2					
Windpark C Initial operation	Number of WTG	Rotor diameter	WAKE losses			
			Total	Internal	External	Surrounded area
2013	80	120 m	13.50%	9.75%	3.75%	1.25
2017	75	145 m	14.50%	9.75%	4.75%	1.50
2020	56	164 m	17.25%	9.25%	8.00%	2.50
2023	56	178 m	19.50%	10.00%	9.50%	3.00

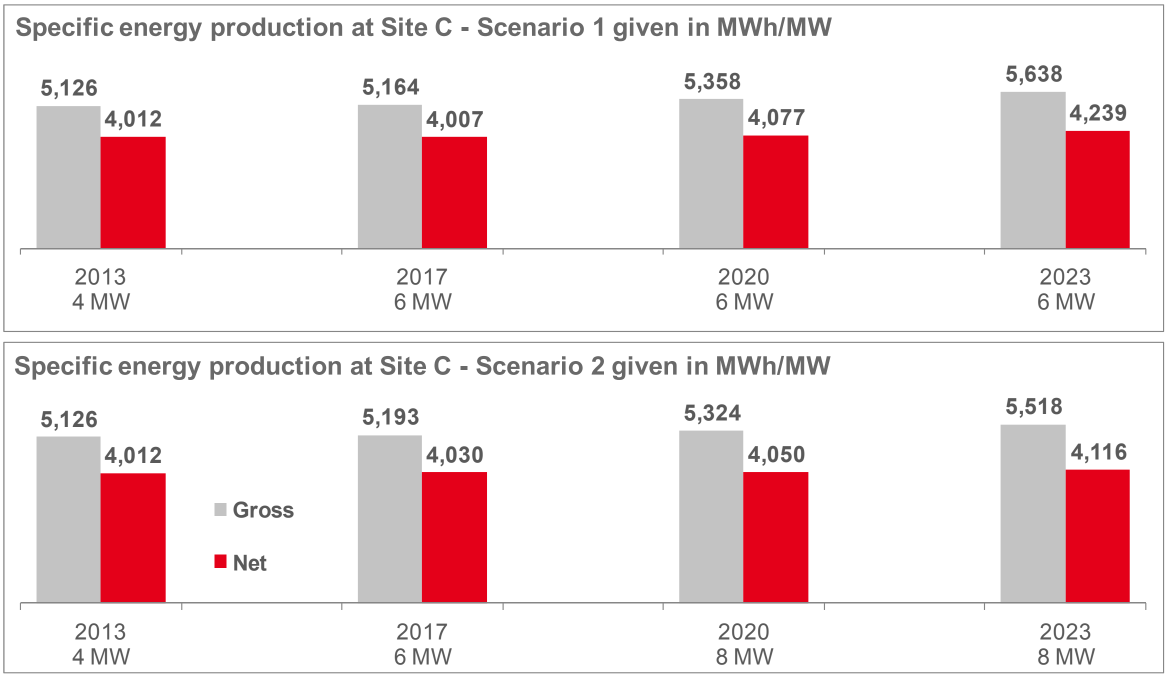
Source: [Prognos/Fichtner]

(2) The reasons for the change in electricity production in both scenarios corresponds to those at the other sites: The switch from 4 MW to 6 MW generators between 2013 and 2017 with simultaneously increasing rotor diameters in both scenarios results in a below-average increase in specific gross electricity generation as this generator configuration has a less favourable rotor-to-generator ratio.

In **Scenario 1**, the specific gross electricity generation increases from 5,126 MWh/MW in 2013 by approximately 10 % to 5,638 MWh/MW in 2023. Due to higher internal wake losses, net electricity generation increases only by slightly less than 6 % from 4,012 MWh/MW to 4,239 MWh/MW. In 2017, due to the switch from 4 MW to 6 MW generators, the specific net electricity generation marginally decreases. After that, with rotor diameter increasing to 164 m until 2023, net electricity generation will continuously increase.

Also in **Scenario 2**, the lower rotor-to-generator ratio will have a short-term impact on gross and net electricity production. Similar to Sites A and B, both gross and net electricity generation at Site C will already short-term slightly exceed the values in Scenario 1. In this scenario, the trigger is the continuous development of all generator components. Also medium-term until 2020, the additional switch from 6 MW to 8 MW generators will hardly affect the specific net electricity generation. The absolute net electricity generation per generator goes up substantially, though. As rotor diameter will further increase to 178 m, the specific gross electricity generation in 2023 will go up - in comparison to the base year 2013 - by approximately 8 % to 5,518 MWh/MW. At the same time, the external wake losses in Scenario 2 will increase due to the stronger development of offshore wind power in the North Sea und the resulting higher degree of wind farm clusters. The net electricity generation will therefore increase by only 3 % to 4,116 MWh/MW. The following Figure 18 presents the development of the specific electricity generation for both scenarios.

Figure 18: Development of specific electricity generation at Site C



Source: [Prognos/Fichtner]

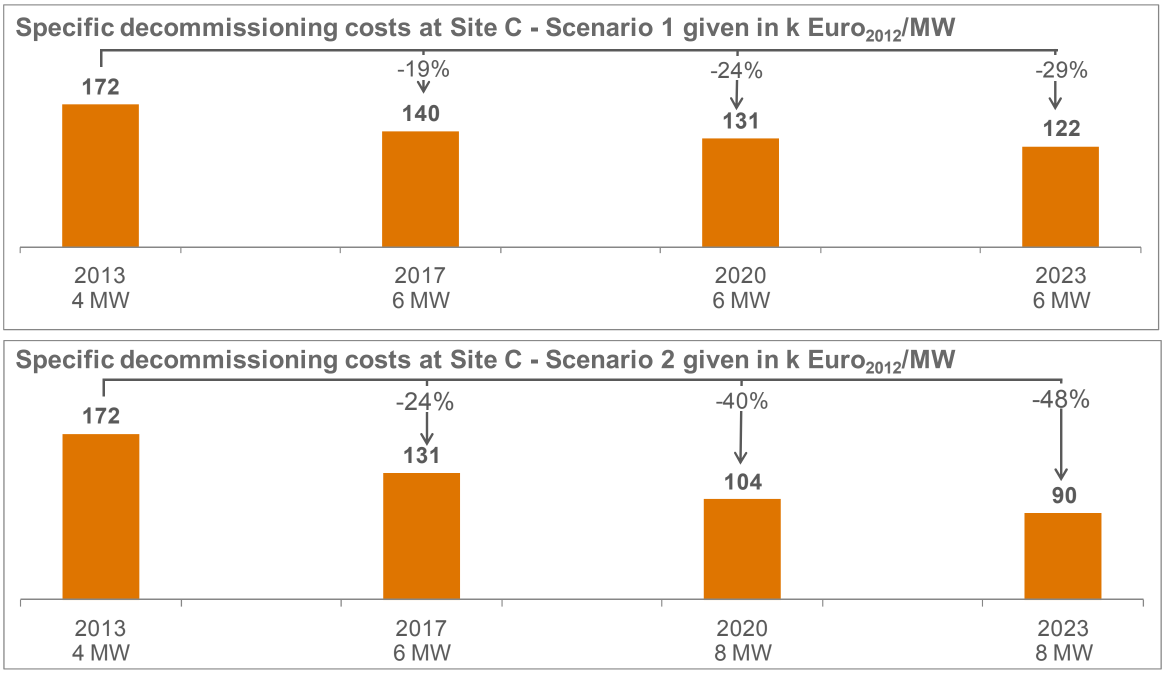
3.3.4 Provisions for dismantling

(1) Due to larger distances to port and deeper waters, the **dismantling costs** for a generator at Site C are higher **than those at the other sites**. The proportional provisions for dismantling and decommissioning at Site C are therefore correspondingly higher than those at Sites A and B. Similar to the other sites, the specific decommissioning costs at Site C will decrease due to increased generator capacity. In addition, there will be efficiency gains from experience gathered from the dismantling the first wind farms.

In **Scenario 1**, the specific dismantling costs will decrease from about 170k Euro/MW in 2013 to slightly less than 120k Euro/MW in 2023.

In **Scenario 2**, specific costs will have decreased to 90k Euro/MW by 2023. Stronger reductions in Scenario 2 are the result of a steeper learning curve due to a faster specialisation of companies and more competition. Figure 19 summarises the development of both scenarios.

Figure 19: Development of specific decommissioning provisions for Site C

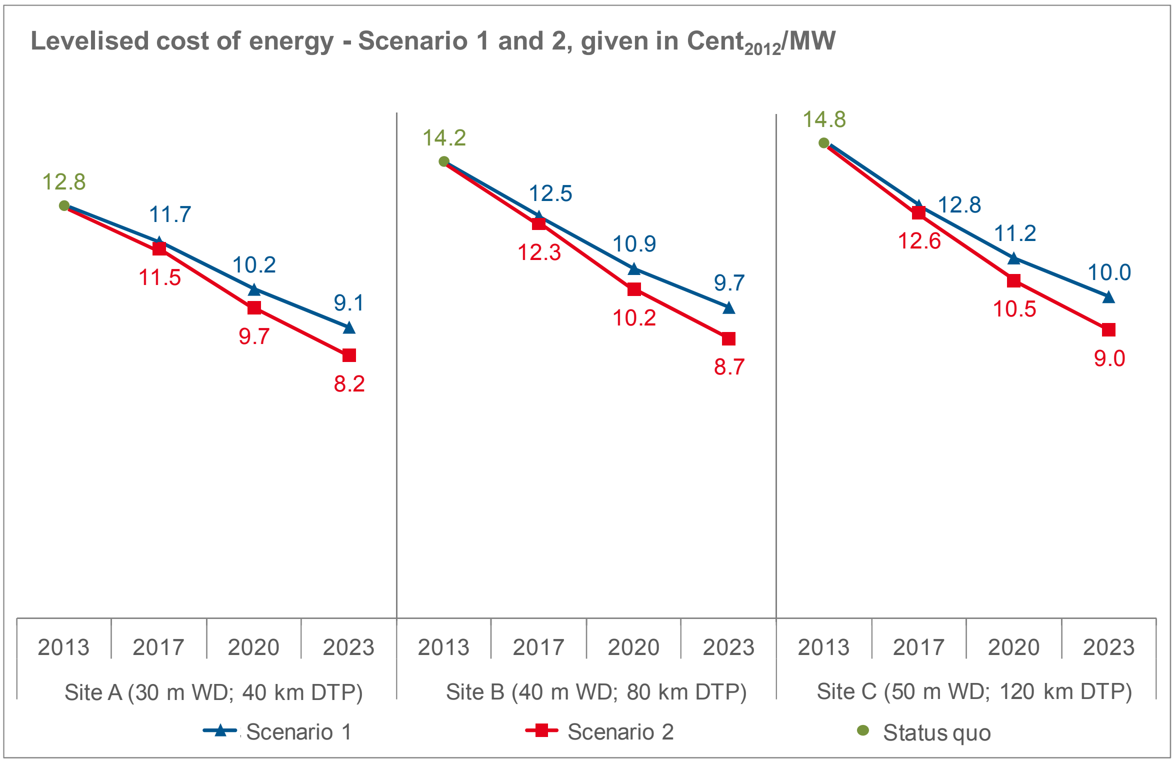


Source: [Prognos/Fichtner]

3.4 Development of the levelised cost of energy (LCOE)

(1) For the **base year**, the costs of offshore wind power at site A amounts to 12.8 $Cent_{2012}$/kWh – calculated over an operational life of 20 years. At the other sites, due to deeper waters and larger distances to port costs amount to 14 $Cent_{2012}$/kWh. For the year 2013, the levelised cost of energy (LCOE) of the wind farms at sites B and C are rather theoretical as there are no wind farms with these parameters that will become operational by the end of 2013. Wind farms in such deep waters and at such distances are increasingly expected to be completed until 2017 or 2020, respectively. The levelised cost of energy (LCOE) is not equivalent to the revenue and compensation levels (feed-in tariffs) that are necessary for projects to become profitable.

Figure 20: Comparison of the scenario results



Source: [Prognos/Fichtner]; WD = water depth; DTP = distance to port

(2) In **Scenario 1**, the levelised cost of energy for offshore wind power decreases on average by about 30 % at all sites until 2023. In 2023, at Site A they will amount to 9.1 Cent/kWh, at Site B to 9.7 Cent/kWh and at Site C to 10.0 Cent/kWh. Short-term, this cost reduction is caused by savings in the areas of logistics, installation as well as maintenance and operations. Medium-term, the optimisation of existing generator types will largely contribute to the cost

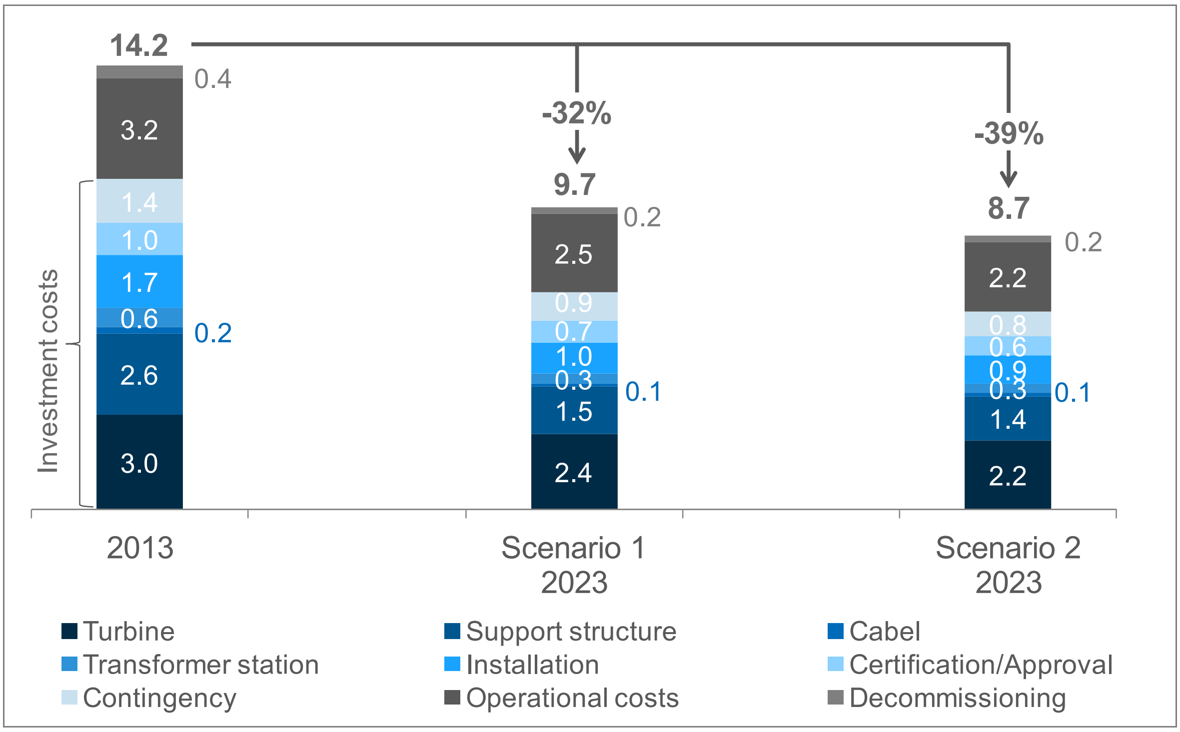
reduction. Long-term, new technologies resulting in larger turbines will dominate the cost development.

In **Scenario 2** assuming optimum conditions, cost reductions of 40 % are achieved. In 2023, at Site A they will amount to 8.2 Cent/kWh, at Site B to 8.7 Cent/kWh and at Site C to 9.0 Cent/kWh. In addition to a faster technological development, the increased competition due the sustainable market entrance of a large number of companies under stable framework conditions will be the main driver for the additional cost reduction. The differentiation of the scenarios will become significant only after 2017.

(3) Currently the **development of the offshore wind industry** is characterised by projects that correspond to the configuration of Site A. Between 2017 and 2020, the development will be dominated by the construction of wind farms at Site B. After 2023, sites with a longer distance to port and deeper waters according to the configuration of Site C will determine the market. This means that for interpreting the results, the short-term focus must be on Site A, medium-term on Site B and long-term on Site C.

(4) Offshore wind power is a **capital-intensive technology**. Therefore, the structure of the levelised cost of energy (LCOE) is mainly determined by the investment costs. For optimum market conditions, the costs of offshore wind power can decrease by up to 40 % until 2023. 75 percent of costs can be attributed to investment costs, the remainder to operations and decommissioning. The structure of the levelised cost of energy (LCOE) does not change; for an illustration, we will use the example of wind farm B in the following Figure 21. The reduction of the levelised cost of energy from 14.2 $Cent_{2012}$/kWh to 8.7 $Cent_{2012}$/kWh at site B is substantially determined by these costs.

Figure 21: Development of LCOE in real terms according to segments for the example of wind farm B



Source: [Prognos/Fichtner]

(5) The **reduction of the cost of capital** in real terms from 7.85 % in 2013 to 5.68 % in 2023 (see Table 3) directly and evenly affects all parts of the investment costs. That means that the **LCOE structure** changes only slightly between 2013 and 2023.

In Scenario 2, **more competition** through new market entrants under optimum conditions results in a larger decrease of costs for turbines and support structures than in Scenario 1.

The **operating costs** in Scenario 2 show a larger decrease than in Scenario 1 due to joint inter-operator operating and maintenance concepts. The generator capacity increase from 6 MW to 8 MW leads to additional economies of scales for the operating costs and thus to a larger cost reduction than in Scenario 1.

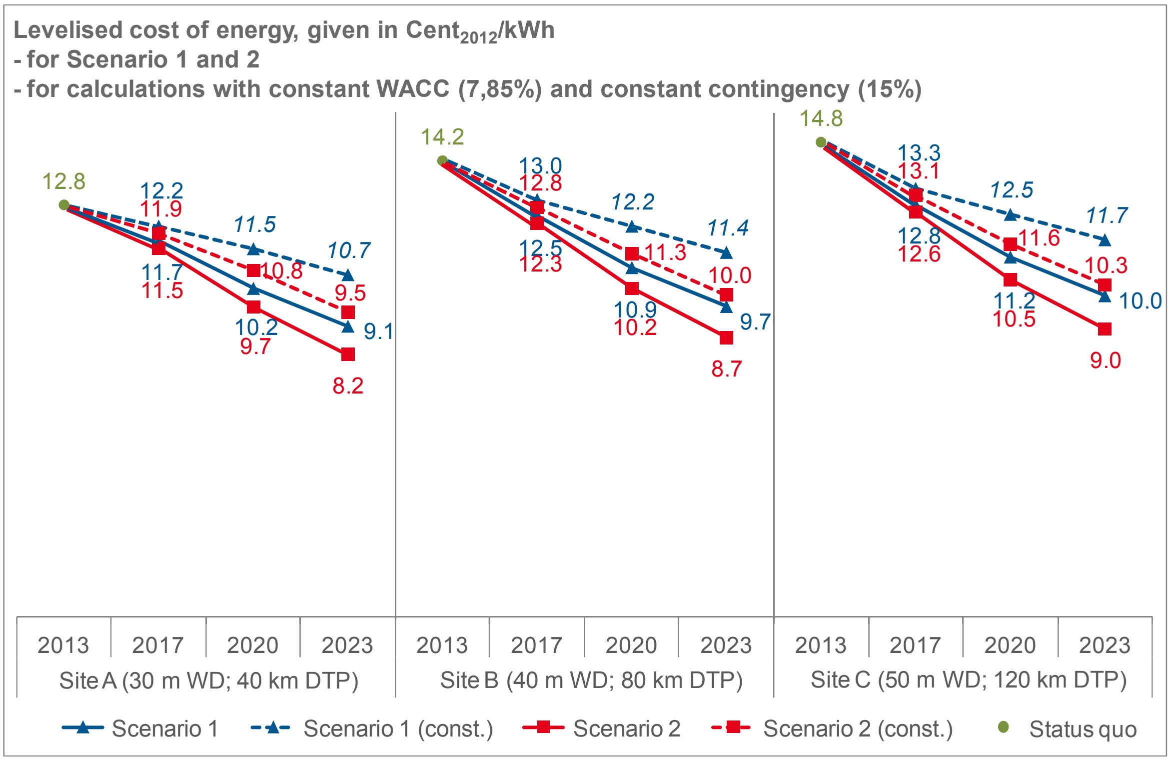
3.5 Impact of risk evaluation on the cost of capital

(1) As **risk evaluations** affect cost of capital they have a strong impact on the levelised cost of energy (LCOE). Offshore wind power is a capital-intensive technology; therefore changes in the rate of return have an immediate effect on the levelised cost of energy. If the real calculatory rate of return (WACC; see Chapter 2.5)

increases by one percentage point, LCOE will go up by about six percent.

In a joint **workshop** with more than 20 industry representatives and institutions (operators, manufacturers, financial service providers), we comprehensively discussed the financing and risk conditions of the technology. The results of the workshop were directly incorporated into the modelling of the levelised cost of energy (LCOE). Figure 22 shows for the studied period until 2023 the effect that decreasing weighted average costs of capital and contingency provisions have on the levelised cost of energy (LCOE). Here, we compare the results of Scenarios 1 and 2 that include reduced risk premia due to the increasing experience with offshore wind power (full lines) and the corresponding results for constant risk premia and provisions (dotted lines).

Figure 22: Impact of the rate of return and provisions on the levelised cost of energy (LCOE)



Source: [Prognos/Fichtner]; WACC = weighted average cost of capital; WD = water depth; DTP = distance to port

(2) **Technical cost reduction potentials** vary between sites depending on water depths and distance to port. Additional cost reduction potentials due to **risk control and financing** have a similar effect at all sites; they vary, however, between the scenarios due to the absolute volume of investment costs.

(3) Until 2023, in **Scenario 1** (dotted lines) technical cost reduction potentials at Site A on average amount to 17 %, at Site B to 20 % and at Site C to 21 %. In **Scenario 2**, purely technical cost reduction potentials until 2023 are between 26 % for Site A and 31 % for Site C.

At Sites B and C, purely **technical cost reduction potentials** are higher than at Site A as cost reductions for support structure and foundations as well as for the installation at the sites with longer distances to port and deeper waters have a larger impact.

(4) For Scenario 2, an additional **9 percentage points** can be achieved at all sites just because risk-handling costs for financing and project implementation are expected to go down. In Scenario 1, due to higher investment costs an additional average of **12 percentage points** will be achieved. That means that the impact of financing and risk handling on total cost reduction becomes less the more technology costs decrease.

3.6 Sensitivity regarding further important parameters

3.6.1 Adding other generator sizes to the two scenarios

(1) In addition to the wind farm design presented in Chapters 3.1 to 3.3 - including **assumptions regarding additional generator sizes** at the time of initial operation for the two scenarios - this analysis will calculate two diverging sensitivities.

Scenario 1a will - as opposed to Scenario 1 with generator capacity increasing from 4 MW to 6 MW in 2017 - study the effect of a delay in introducing the new generators. Scenario 1a assumes that 4 MW generators are kept operational in 2017 and generator capacity will switch to 6 MW only in 2020. It shows the impact of a delayed market-wide introduction of 6 MW generators.

Scenario 2a examines the effect that a continued use of 6 MW generators will have on the levelised cost of energy (LCOE). As opposed to Scenario 2, there will be no 8 MW generators introduced into the market. Table 10 shows the exact configuration within the sensitivities. The characteristics of the three sites remain constant.

Table 10: Configuration with delayed introduction of new generator sizes for the sensitivities

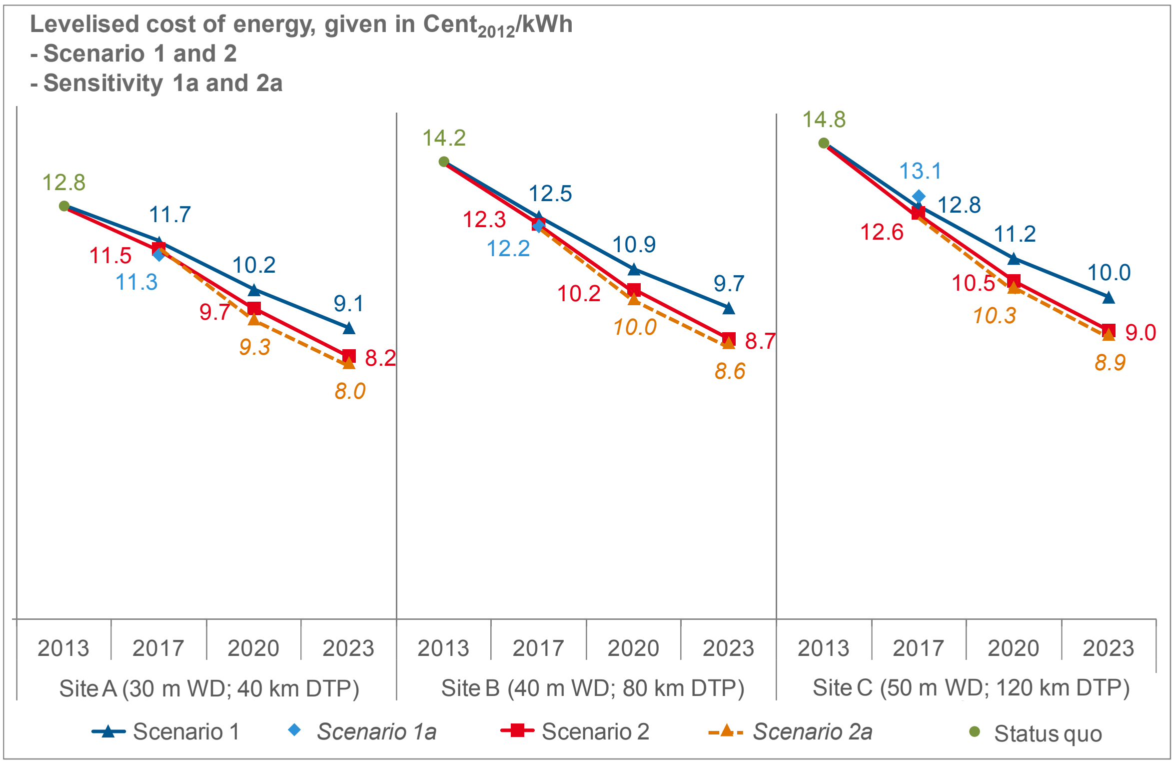
	Sensitivity - Adding other generator sizes								
	Scenario 1a, 4 MW in 2017								
Initial operation	Number of WTG	Capacity WTG	Size wind farm	Hub height	Rotor diameter	WAKE losses			
						Total	Internal	External	Surrounded area
2013	80	4 MW	320 MW	90 m	120 m	13.50%	9.75%	3.75%	1.25
2017	80	4 MW	320 MW	95 m	135 m	15.00%	10.25%	4.75%	1.50
2020	75	6 MW	450 MW	100 m	154 m	16.50%	10.25%	6.25%	2.00
2023	75	6 MW	450 MW	105 m	164 m	17.75%	10.75%	7.00%	2.25
	Scenario 2a, 6 MW in 2020/2023								
Initial operation	Number of WTG	Capacity WTG	Size wind farm	Hub height	Rotor diameter	WAKE losses			
						Total	Internal	External	Surrounded area
2013	80	4 MW	320 MW	90 m	120 m	13.50%	9.75%	3.75%	1.25
2017	75	6 MW	450 MW	100 m	145 m	14.50%	9.75%	4.75%	1.50
2020	75	6 MW	450 MW	100 m	160 m	18.50%	10.50%	8.00%	2.50
2023	75	6 MW	450 MW	105 m	170 m	20.50%	11.00%	9.50%	3.00

Source: [Prognos/Fichtner]

(2) For a constant wind farm size of 320 MW, in 2017 Scenario 1b keeps on using 4 MW generators instead of 6 MW generators. The rotor diameter increases from 120 m to 135 m and the hub height reaches 95 m. Scenario 2b keeps on installing 6 MW generators between 2020 and 2023. These replace the 8 MW generators that are used in the original scenario. The rotor diameter will have increased to 170 m by 2023.

The calculations of sensitivities 1b and 2b show that diverging assumptions regarding the development of generator sizes - depending on the wind farm site - can have both advantages and disadvantages. Figure 23 shows the result for the levelised cost of energy for the sensitivities. For detailed assumptions on investment and operating costs as well as regarding annual energy generation and provisions, see Table 11 to Table 16 in Appendix6.3.

Figure 23: Results of Scenarios 1 and 2 as well as of Sensitivities 1a and 2a



Source: [Prognos/Fichtner]; WD = water depth; DTP = distance to port

(3) With the continued use of 4 MW generators in 2017, the sensitivity **Scenario 1a** shows in 2017 **varying effects** on the levelised cost of energy (LCOE) for the analysed sites.

For **Site A**, LCOE amounts to 11.3 Cent/kWh for a 4 MW generator and thus is slightly lower than the LCOE of 11.7 Cent/kWh for a 6 MW generator in Scenario 1. At this site, the somewhat lower investment costs and a substantially higher specific net electricity generation have a **positive** impact.

In comparison to Site A, the configuration 1a shows a slightly weaker positive impact for **Site B**. The levelised cost of energy (LCOE) amounts to 12.2 Cent/kWh for a 4 MW generator and thus also is lower than the LCOE of 12.5 Cent/kWh for a 6 MW generator in Scenario 1. The advantage of slightly lower specific investment costs and higher net electricity production is almost compensated by the higher specific annual operating costs for a 4 MW generator. Particularly these short-term effects due to the switch from 4 MW to 6 MW together with a sea-based maintenance concept - and also for these specific investment costs - are hardly noticeable at all in case of a continued use of 4 MW generators.

For **Site C**, a continued use of 4 MW generators is not beneficial at all. With 13.1 Cent/kWh, the levelised cost of energy (LCOE) of a 4 MW generator in 2017 exceeds the LCOE of 12.8 Cent/kWh for a 6 MW generator. As capacity does not increase from 4 MW to 6 MW, specific investment costs are higher than those of 6 MW generators, particularly regarding support structure, installation and annual operating costs. Not even the substantially higher net electricity generation can compensate these **additional costs**.

(4) In **Scenario 2a**, **only for Site A** the continued use of 6 MW generators has **clear advantages until 2020**. For **Sites B and C**, the **advantage** is **almost negligible**.

With 9.3 Cent/kWh, in 2020 the levelised cost of energy at **Site A** is **0.4 Cent/kWh** lower than that of an 8 MW generator at the same site. This corresponds to about 4 %. Similar to Sensitivity 1a, this is due to the lower specific investment costs and the higher specific net electricity production.

With 10.0 Cent/kWh at **Site B** and 10.3 Cent/kWh at **Site C**, the levelised cost of energy of a 6 MW generator is in both cases only **0.2 Cent/kWh** lower than the LCOE of an 8 MW generator at the same site. The higher specific annual operating costs of this generator almost compensate the advantage of a higher specific net electricity production. Long-term until 2023, at all sites the levelised cost of energy of a 6 MW generator approaches those of an 8 MW generator. Even though the specific net electricity generation (in MWh/MW) of a 6 MW generator exceeds that of an 8 MW generator at all sites, the larger number of generators - when using 6 MW generatos - will increase internal wake losses. Due to less economies of scales, the specific annual operating costs of a 6 MW generator exceed those of an 8 MW generator and almost compensates the advantages of the higher net electricity generation of 6 MW generators.

(5) We arrive at the **result** that in Scenario 1a the use of 4 MW generators may be reasonable even in 2017, if rotor diameters are maximised. The higher electricity generation will over-compensate the also increased specific annual operating costs. The longer the distance to port, the more advantageous it becomes to benefit from the positive effects of an increased capacity due to optimised distance-related costs such as installation and operating costs.

The same applies to the long-term use of 6 MW generators in **Scenario 2a**. The longer the distance to port and the deeper the waters, the more feasible it becomes to optimise the maximum wind yield with the largest possible generator capacity.

3.6.2 Prolonging operating life to 25 years

(1) The results of Scenarios 1 and 2 as well as of Sensitivities 1a and 2a are based on a technical wind farm life of 20 years. It might be possible though that - with regular maintenance - a wind farm can be operated more than 20 years. In order to calculate the effects of a prolonged operational life of these wind farms at Sites A, B and C, the levelised cost of energy (LCOE) was also computed for an operational life of 25 years.

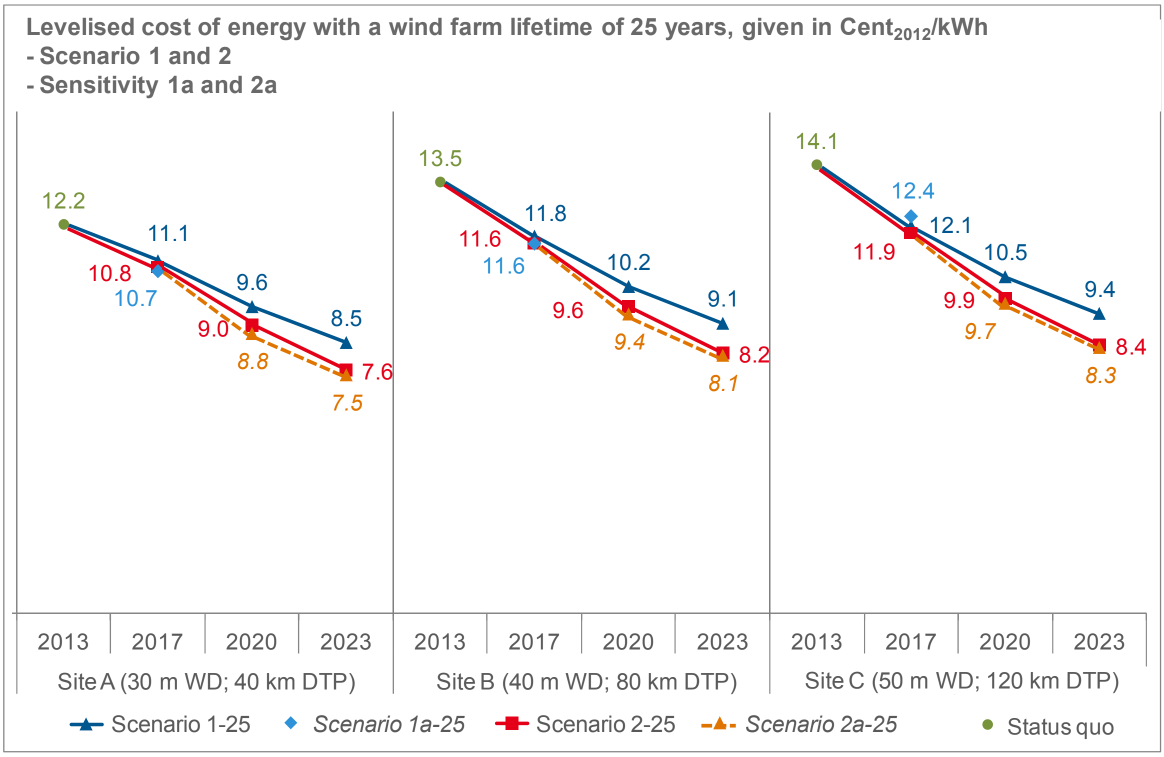
(2) If the generators are **operated for an additional five years**, the operating and maintenance costs of the last five years will increase due to higher costs of keeping the old generators operational. Due to wear-and-tear, generator downtime is expected to increase. Subsequently, also the specific net electricity generation of the generators will decrease during that period.

A wind farm owner will only repair a generator if the incurred costs can be recovered and produce profit over the remaining operating life. The owner will therefore gradually disconnect individual generators from the grid before they reach 25 years. Thus, frequent downtime or the complete failure of individual generators will further reduce the average specific net electricity production.

(3) Figure 24 shows the results of the levelised cost of energy (LCOE) for an operational life of 25 years. For wind farms that become operational in 2013, a **prolonged** operational life of five years will - due to the aggregated higher energy generation for constant investment costs - result in a 5 % **lower levelised cost of energy (LCOE)** (see Figure 23). For wind farms that become operational between 2017 and 2023, the levelised cost of energy will decrease by up to 7 %.

This result highlights the importance of high-quality, robust generator components as well as operating and maintenance concepts that are designed for the entire lifetime of a generator.

Figure 24: Results of Scenarios 1 and 2 as well as of Sensitivities 1a and 2a for an operating life of 25 years



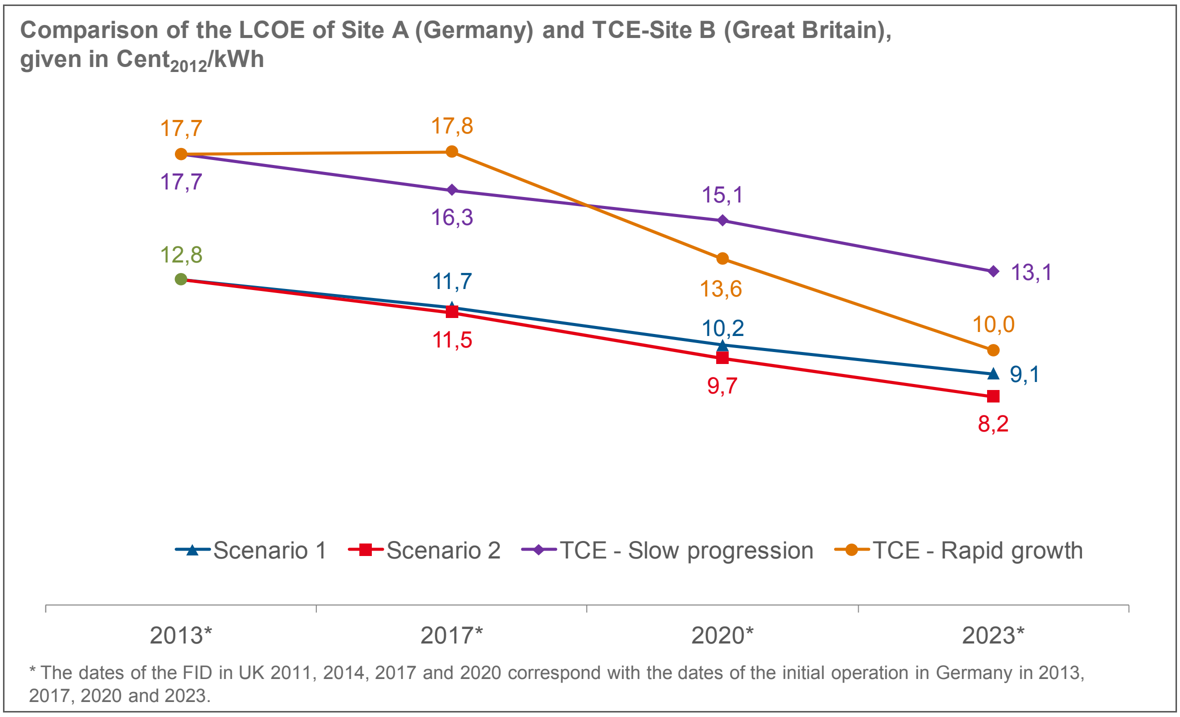
Source: [Prognos/Fichtner]; WD = water depth; DTP = distance to port

3.7 Positioning the results in comparison to the TCE study

(1) As mentioned in Chapter 1, the current study uses a similar methodology as the analysis presented by The Crown Estate (TCE) in 2012. In this chapter, we will briefly position the results of our analysis for the German market in relation to the TCE study.

We will use Site A (Germany) and B (TCE study) in order to illustrate the comparison. Site A of the present analysis corresponds most closely to the site parameters water depth, distance to port and average wind speed of the configuration of Site B in the TCE study. The data from the TCE study refer to generators with final investment decisions (FID) being taken in 2011, 2014, 2017 and 2020. Assuming a construction time for an offshore wind farm (including construction preparation) of two to four years, we can approximately compare the results of the TCE study with the present study for Germany that analyses initial operation in 2013, 2017, 2020, and 2023. The following Figure 25 compares the development of the levelised cost of energy for Site A in Scenarios 1 and 2 with the results of the TCE study in the scenarios “Slow progression” and “Rapid growth” at Site B. The assumed market conditions in the scenario „Slow progression“ (>31 GW of installed capacity in Europe in 2023) are similar to those in Scenario 1 of our study; our Scenario 2 corresponds to the development in the scenarios „Rapid growth“ (>43 GW of installed capacity in Europe in 2023). Both studies use in the compared scenarios the same average generator capacity at the corresponding points in time.

Figure 25: Comparison of the levelised cost of energy (LCOE) between Germany and the United Kingdom for Site A



Source*: [TCE 2012; Prognos/Fichtner]; own conversion and presentation*

(2) The **TCE study** of the British offshore market arrives at a levelised cost of energy that exceeds the costs in the present study for Germany because it **includes the complete transmission costs** to shore for the offshore generated electricity. In the TCE study, the levelised cost of energy (LCOE) decreases at Site B (40 km distance to port, 35 m water depth) from almost 17.7 Cent/kWh to 13.1 Cent/kWh in the scenario „Slow progression“ and to about 10 Cent/kWh in the scenario „Rapid growth“ with an optimum market development.[10]

10 According to Deutsche Bundesbank, the assumed average exchange rate for the year 2012 amounts to 1 GBP = 1.23 Euro. Source: www.bundesbank.de

(3) The cost reduction in the scenario “Slow progression” of the TCE study amounts to 26 % and for the scenario “Rapid growth” to 44 % and thus lies at a similar level as in the Scenarios 1 and 2 of our study. However, in spite of comparable technological developments it is based on two fundamentally different effects regarding financing costs and electricity yield.

(4) Over the entire project duration, the **financing rate** of the British offshore projects, i.e. the weighted average cost of capital, exceeds in real terms with a 9 % before tax for FID 2011 and over 8 % before tax (FID 2020) those in Germany. In addition, financing costs decrease less than assumed in the study for Germany.

The German study assumes that due to lower risks the weighted average cost of capital over the entire project duration decreases from 7.85 % (initial operation 2013) to 5.68 %. The main driver for the higher financing costs in the UK is the different financing structure that is assumed. Due to the expected lower liquidity in the British market, financing includes bonds with higher return requirements that increase the weighted average cost of capital. In addition, the British study assumes a higher equity portion which is typical of the British market.

In the scenario “Slow progression” this leads to a lower cost reduction potential in the financing part. Therefore, with 26 % the cost reduction potential in the UK is altogether slightly lower than the potential in German Scenario 1 (29 % to 32 %). In the scenario “Rapid growth” a substantially increased weighted average cost of capital to 12 % in real terms results in constant cost levels for 2017 in relation to 2013.

(5) In the TCE study **net electricity generation** is up to 10 % higher, in spite of lower average wind speeds in comparison to Germany. The assumed higher wake losses for German wind farms cause this difference.

In Germany, for 2023 at Site A (distance to port 40 km, water depth 30 m, wind speed 9.9 m/s) **wake losses** amount to 17.75 % (Scenario 1) and 19.5 % (Scenario 2). As compared to this, wake losses in the TCE study (FID 2020) for the UK at its Site B (distance to port 40 km, water depth 35 m, wind speed 9.4 m/s) amount to 8.5 % in the scenario “Slow progression” and 7.7 % in the scenario “Rapid growth”. This results in that - in spite of a substantially higher gross generation due to higher wind speeds - the net electricity generation of German offshore wind farms is up to10 % lower than the yields in the UK.

The main reason for the significantly different evaluation of the wake losses between Germany and the UK is the different **availability of space** for wind farms. As in Germany wind farms will be arranged in already approved clusters, in the UK there is a substantially higher flexibility regarding the space available for developments after 2017. This way, both the distance between individual generators within a wind farm and the distance between wind farms can be enlarged. Both lead to a clearly better utilisation of the increasing generator capacity and lower internal and external wake losses. Mainly therefore, the cost reduction potential in the scenario “Rapid growth” - which basically corresponds to Scenario 2 with optimum market condition in our study - is with 44 % larger in the UK than in Germany (39 %). The substantially higher wind yield in the UK exceeds the advantages of the more favourable financing conditions in Germany that also apply to this scenario.

4 Cost Reduction Potentials

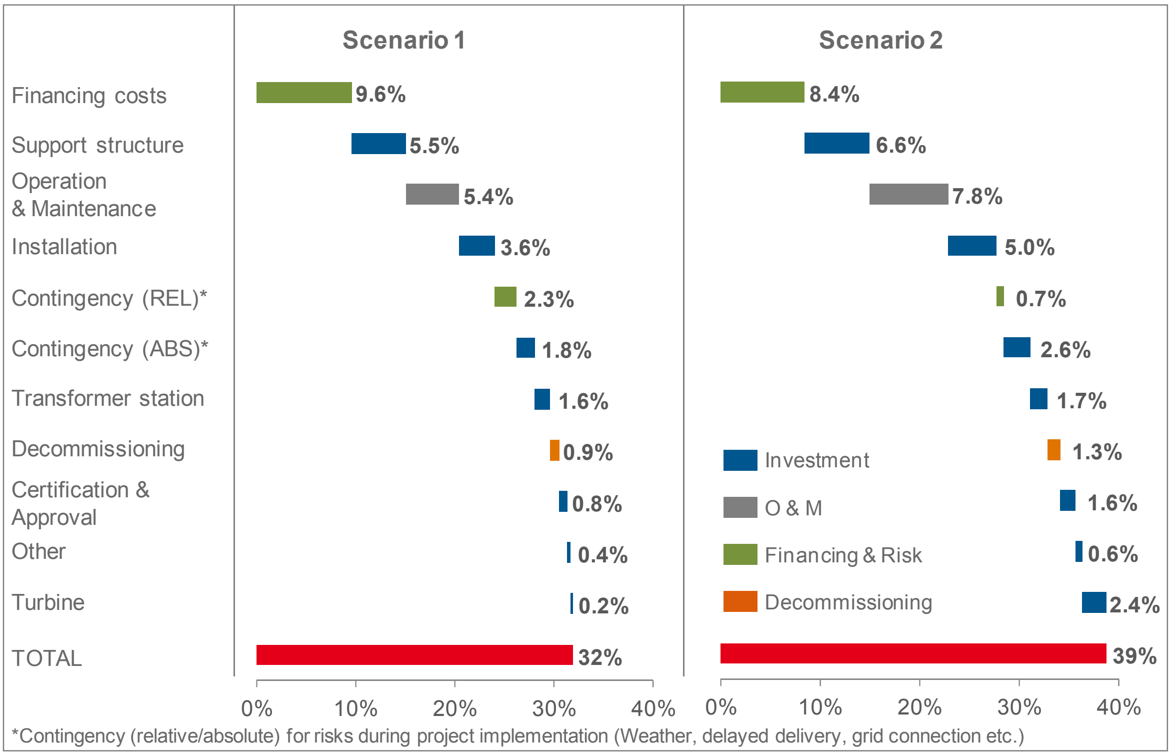
In the following, we will present the **reasons for the decrease** of the levelised cost of energy (LCOE). The largest cost savings result from reduced investment costs and lower financing costs due to changes in the risk evaluation. For this study, the calculated costs of both scenarios were verified through interviews with individual companies. Due to its large importance for the considered period, unless otherwise stated Site B will be used as the exemplary site for the following presentation of the results. Because of the large amount of data, a verification of the results was only carried out for Site B. After that, the results were transferred to Sites A and B taking into consideration site characteristics such as water depth and distance to port.

4.1 Summary

(1) In Scenario 2 with its fast development path, the **maximum cost reduction potential** of the individual components of investment and operating costs results from comparing the levelised cost of energy for a wind farm with initial operation in 2013 and one that becomes operational in 2023. Due to the slower development, the values of Scenario 1 are lower than those in Scenario 2. For Sites A and C, cost reduction potentials are similar to those for Site B.

The cost reduction potentials of offshore wind power over the next ten years amount to between **32 % in Scenario 1 and 39 % for optimum market conditions (Scenario 2)**. The main part can be attributed to the direct technical potential. The remaining reduction potentials (financing and risk) can be related indirectly to potentials that are triggered by technology. Figure 26 describes the effect of individual cost reduction potentials in Scenarios 1 and 2 for Site B.

Figure 26: *Individual cost reduction potentials for the example of wind farm B*



Source: [Prognos/Fichtner]

4.2 Technical cost reduction potentials

The following subchapters will present the main factors regarding **investment, operating** and **decommissioning costs** that affect the technical cost reduction potential.

4.2.1 Turbine

(1) In spite of increasing technical requirements for larger generators and rotor diameters, in Scenario 2 the **turbine** provides with 2.4 percentage points a significant contribution to cost reduction. The gross electricity yields increase from about 5,070 MWh/MW to 5,470 MWh/MW. The increasing gross yield is, however, partially compensated by larger wake losses. In the long run, new market players enter the market and the increased competition contributes to cost reduction. With 0.2 percentage point, the cost reduction is significantly lower in Scenario 1. The reason is less competition and economies of scales as generator size increase to only 6 MW as compared to 8 MW.

(2) At first glance, the specific investment costs for the turbine with 8 % (Scenario 2) of total cost reduction potential offer only lit-

tle technical cost reduction potential in comparison to other options. We have to keep in mind, though, that increasing costs due to optimised technology result in improved energy yields, decreased installation costs and less maintenance. The main reasons are the two technology switches regarding capacity from 4 MW via 6 MW to 8 MW. Even though the product platform may be similar, the necessary development costs during this short period of time will lead to increasing absolute costs for the turbine. Due to the capacity increase from 4 MW to 8 MW, the specific costs are somewhat lower. At the same time, rotor diameter increases from 120 m in 2013 to 164 m (Scenario 1) or 178 m (Scenario 2) in 2023. Development and material costs for rotor blades of this size prevent a palpable cost degression for the turbine. A similar cost development occurs for onshore wind turbine generators.

4.2.2 Support structure

(1) In both scenarios, an increased generator size and capacity results in substantial economies of scales for **substructures** and **support structures**. It reduces the specific costs of this large cost item and thus decreases the levelised cost of energy (LCOE). In the long run serial production and increased competition additionally contributes to a cost reduction of another 6.6 percentage points in Scenario 2. In Scenario 1, the cost reduction potential is 5.5 percentage points and thus slightly lower. Lower volumes due to a slower development in the whole of Europe reduce the technological progress.

(2) The support structure offers the largest cost reduction potential regarding investment costs. The main driver for the cost reduction is the **continuous production** of jackets or monopiles, respectively. This requires a stable political and legal framework though. Otherwise investment decisions can be further delayed. If there is a constant demand of foundations though, manufacturers can reduce costs due to a continuous production. If downtime can be avoided, there will be less staff fluctuation in these companies. Employee fluctuation often causes quality deterioration and high transaction costs. Steady demand could avoid such fluctuations. Production quality may thus remain at a constantly high level; thus reject and transaction costs could be reduced.

(3) At the same time, **improved or optimised production processes** result in decreasing production costs. An important factor for the cost reduction is an optimised foundation design. In this area, there are a number of options for improvement in order to be able to switch from project-specific foundations to uniform industrial standards and to use standard products of suppliers, particu-

larly in jacket manufacturing. In addition, increased generator capacity can contribute to decreasing specific costs. Due to the increased material requirements, the foundation of an 8 MW generator will be more expensive in absolute terms. However, the specific costs per MW will be substantially lower than for a 4 MW generator. The same applies to the manufacturing of towers. An increased generator capacity results - in spite of a larger hub height and higher material requirements - in decreasing specific costs.

(4) In total, the described effects as **portion** of the total cost reduction potential amount to 17 % in Scenario 1 and Scenario 2.

4.2.3 Wind farm transformer platform

(1) In Scenario 2, the standardisation of the technical dimensions of the wind farm **transformer platforms** accounts for a cost reduction potential of 1.7 percentage points. In addition, an intensified competition will contribute to cost reduction and to that the development in Scenario 2 is slightly faster than that in Scenario 1.

(2) In spite of an increase in connected capacity from 320 W to 450 MW, the **absolute costs** of the wind farm transformer platform can be reduced by about **15 %** until 2023 due to the introduction of a standardised design. This decrease is enhanced by additional learning curve effects and new market entrants. In addition, the various installation concepts, such as suction bucket, self-installing etc. will have to reach market maturity and then contribute to reduced installation costs. The major cost portion of the transformer platform corresponds to the foundation and steel structure and only a smaller part to electrical components. This means that an increased connected capacity will not result in an increase of absolute costs. At the same time, the specific costs will decrease due to the reduced absolute costs and the capacity increase from 320 MW to 450 MW.

(3) The **portion** that the transformer platform contributes to the total cost reduction potential amounts to between 5 % in Scenario 1 and about 4 % in Scenario 2.

4.2.4 Installation costs

(1) In Scenario 2, an improved **installation logistics** due to larger, faster ships and the adaptation of installation processes reduces costs by 5.0 percentage points. Larger ships increase

transport capacities and allow for utilising favourable weather slots. In addition, more powerful installation ships and improved logistics concepts are required in order to be able utilise the economies of scales of larger turbines. Due to a weaker growth of the European market, in Scenario 1 the cost reduction potential of 3.6 percentage points is lower as there will be a the limited number of specialised market players and less competition.

(2) In the future, the **installation costs** for turbine, support structure, wind farm transformer platform as well as cable laying will decrease, mainly due to improved **logistics concepts** and increased **competition** from new market entrants. This way, faster and larger installation ships and the introduction of special ships (e.g. for the installation of cables) will lead to shorter installation times. The shorter rental duration for special ships and installation equipment will reduce costs. For appropriate sites, the use of jack-up vessels with dynamic positioning systems will have an additional positive effect on rental periods. These systems make it possible to install components without time-consuming hoisting processes that are required by jack-up vessels. The ships are computer-controlled and automatically remain at the same spot and can carry out the installation process. In heavy seas, jack-up vessels have the advantage though, that by applying hoisting equipment they are better protected from the waves. These concepts have to be optimised and used in a project-specific, efficient and cost-efficient way. Another optimisation potential regarding installation concepts is to replace the grout connection between monopile and transition piece with flanges. There are also new technologies such as vibration or drilling that can be used instead of the noisy and time-consuming ramming methods.

(3) In addition, the specific costs for the installation will decrease due to **increased generator capacity**. The time it takes to install a foundation is hardly affected by generator capacity. The absolute costs are therefore hardly dependent on generator size. The capacity increase from 4 MW to 8 MW will result in substantially reduced specific costs. Learning curve effects will also contribute to decreasing costs. Over time, the gathered experience will reduce problems with installation.

(4) Long-term, installation costs can be even further reduced by new **support structures** (floating foundations, gravity base foundations, etc.) In Germany, a large-scale use of such foundations is expected to take place only after 2023.

(5) The **portion** that the installation contributes to the total cost reduction potential until 2023 amounts to 11 % in Scenario 1 and about 13 % in Scenario 2.

4.2.5 Reduction of absolute project contingency provisions

(1) In order to calculate the cost reduction potential of the **contingency provisions**, we will keep its portion as part of total investment costs at a constant level of 15 %. Reduced investment costs will already decrease the portion of the provisions which is kept constant.

(2) The reduction of the absolute **contingency provisions** for project implementation and installation risks due to decreased total investment costs brings down the levelised cost of energy by 1.8 percentage point in Scenario 1 and 2.6 percentage points in Scenario 2. It is directly triggered by the technical development and the correspondingly decreasing investment costs.

(3) Until 2023, in both scenarios the reduction of provisions contributes a **portion** of 6 % to 7 % to total cost reduction potential.

4.2.6 Development of operating and maintenance costs

(1) In Scenario 2, improved **operating and maintenance logistics** contribute with 7.8 percentage points the largest technological potential. In Scenario 1, with 5.4 percentage points the potential is lower due to less economies of scales for the 6 MW generators and a slower development of joint maintenance concepts. In the short term, particularly faster and larger ships as well as an improved infrastructure determine the reduction potential. In the long run, especially inter-operator sea-based maintenance concepts result in decreasing costs.

(2) Here, the introduction of **inter-operator maintenance and logistics concepts** is essential. Using a joint fleet and logistics infrastructure (landing and fuelling facilities for helicopters, ships, material storage, rescue and safety concepts) can result in a reduction of absolute annual operating costs. At the same time, faster ships and more competition will have a positive impact on operating costs.

(3) In Scenario 2, also the **increased turbine capacity** from 4 MW to up to 8 MW has a large effect on specific operating costs. Travelling time to a generator for maintenance purposes is independent of generator size. Thus the absolute costs for the travelling time are the same. If instead of a 4 MW generator an 8 MW generator is maintained, specific operating costs per MW of installed capacity will automatically decrease.

(4) The **portion** that operating costs contribute to the total cost reduction of the levelised cost of energy until 2023 amounts to about 17 % in Scenario 1 and 20 % in Scenario 2.

4.2.7 Other technical cost reduction potentials

(1) In Scenario 2, uniform **approval and certification standards** as well as a growing experience regarding project planning contribute a cost reduction potential of 1.6 percentage points. In Scenario 1, it amounts to 0.8 percentage points. In both scenarios, the increase of wind farm capacity from 320 MW to 450 MW contributes to a short-term decrease of specific costs. Uniform standards are particularly required for certification in order to not only decrease costs in this specific area, but also to enhance serial production of components and consequently the related costs.

(2) As specialisation regarding the **dismantling of offshore wind farms** increases over time, the levelised cost of energy can be reduced by 1.3 percentage points in Scenario 2 and by 0.9 percentage points in Scenario 1. The dismantling of offshore wind turbine generators is expected to be substantially less expensive than their installation and thus result in clearly lower costs. In the long run, increasing income from selling dismantled generators - in addition to the mere steel price - will contribute to a further cost decrease.

(3) In Scenario 2, an improved availability and a more efficient **cable production** due to increasing competition will result in a cost reduction of 0.6 percentage points. Today cable production is clearly determined by availability issues. Here we assume that the market - if there is a continuous market development in connection with the establishment of manufacturing capacity - will change towards a buyer´s market and contribute noticeable cost reduction potentials.

4.3 Indirect technical cost reduction potentials

The additional cost reduction potentials result from the **reduced weighted average cost of capital** as well as from **adjustments** of proportional **provisions** during the installation phase. These potentials go up with increasing investment costs. In the following, we will describe these two effects on the cost reduction potentials.

4.3.1 Reduction of risk premia for financing

(1) In Scenario 1, the substantial **decrease of risk premia** for financing due to **increased** planning, construction and operating **experience** and the higher reliability of the generators contributes 9.6 percentage points to cost reduction; and thus reduces costs to a larger extent than in Scenario 2 (8.4 percentage points). In addition, banks will require less equity. As debt usually requires less return than equity, financing costs further decrease. In total, the reduction of the cost of capital due to a changed risk profile of the technology together with more experience is one of the main drivers of cost reduction. In Scenario 1, the improved risk profile due to more experience with the technology contributes one third of the total cost reduction potential.

(2) Even though reduced risk premia for wind farm financing results in a changed weighted average cost of capital (WACC), they are indirectly attributed to the **technological development** of the industry. Growing experience with offshore technology regarding planning, installation and also operation reduces both risk premia for debt financing and return requirements for equity. For this purpose, the technology has to be continuously developed and a clearly reduced error rate along the entire value-added chain has to be achieved. In addition to a stable regulatory framework, also technological development, standardisation and sufficient experience in operating the generators are essential prerequisites for that.

(3) This cost reduction potential will become effective particulary **from 2020** as by that time Germany with an optimum market development (Scenario 2) will have implemented 10 GW of generator capacity. Europe-wide, more than 20 GW of generator capacity will be installed by 2020; in Scenario 2, it will be even more than 40 GW.

In this context, also the operation of generators in other countries such as Denmark or the UK will contribute experience and result in lower risk premia. By 2020, these countries will have almost 15 years of experience in operating such generators.

(4) In Scenario 1, the portion that financing costs contribute to the total cost reduction amounts to about 30 %. We assume that by 2023 in Scenario 2 the cost reduction potential due to lower risk premia will correspond to about 1.1 Cent/kWh of the levelised cost of energy (LCOE). With a **portion** of about 22 % of the total cost reduction potential of 5.5 Cent/kWh, minimising risk premia through technological development and larger industrial experience also in this scenario constitutes one of the key drivers of cost reduction.

4.3.2 Reduction of relative project contingency provisions

(1) In addition, for offshore wind power the **relative provisions for covering** potential risks during project implementation will decrease. Growing experience with handling approval, wind farm design and installation reduces the necessity of provisions for project risks. Medium- and long-term, the scheduled additional costs can be reduced this way. It will result in a relative reduction of provisions as a portion of total investment costs from 15 % to 13 % in Scenario 2 and from 15 % to 10 % in Scenario 1. Reduced provisions thus reduce the levelised cost of energy (LCOE).

(2) Altogether this contributes 0.7 percentage points to cost reduction in Scenario 2. In Scenario 1 with the majority of generator capacity being 6 MW even in 2020, provisions go down to 10 % of total investment. This corresponds to a cost reduction of 2.3 percentage points.

(3) The **portion** that this effect contributes to the total cost reduction potential amounts to 2 % in Scenario 2 and slightly less than 7 % in Scenario 1.

4.4 The importance of the wind farm design

(1) In Germany, offshore wind farms will be built in assigned and already approved areas. During the preparation of this study it has become clear that minimising both internal and external **wake losses** contribute a large potential to increasing the energy yield of a wind farm and thus decreasing the levelised cost of energy (LCOE).

(2) The following Figure 27 illustrates the internal and external wake **effects** of wind farms. Individual, single wind turbine generators are obviously not affected by any wind farm losses. The wind yield correlates to hub height and is the result of average wind speed, rotor-swept area and generator capacity. The theoretical gross generation of the individual generator is then only reduced by the availability of the wind turbine generator and electrical transmission losses.

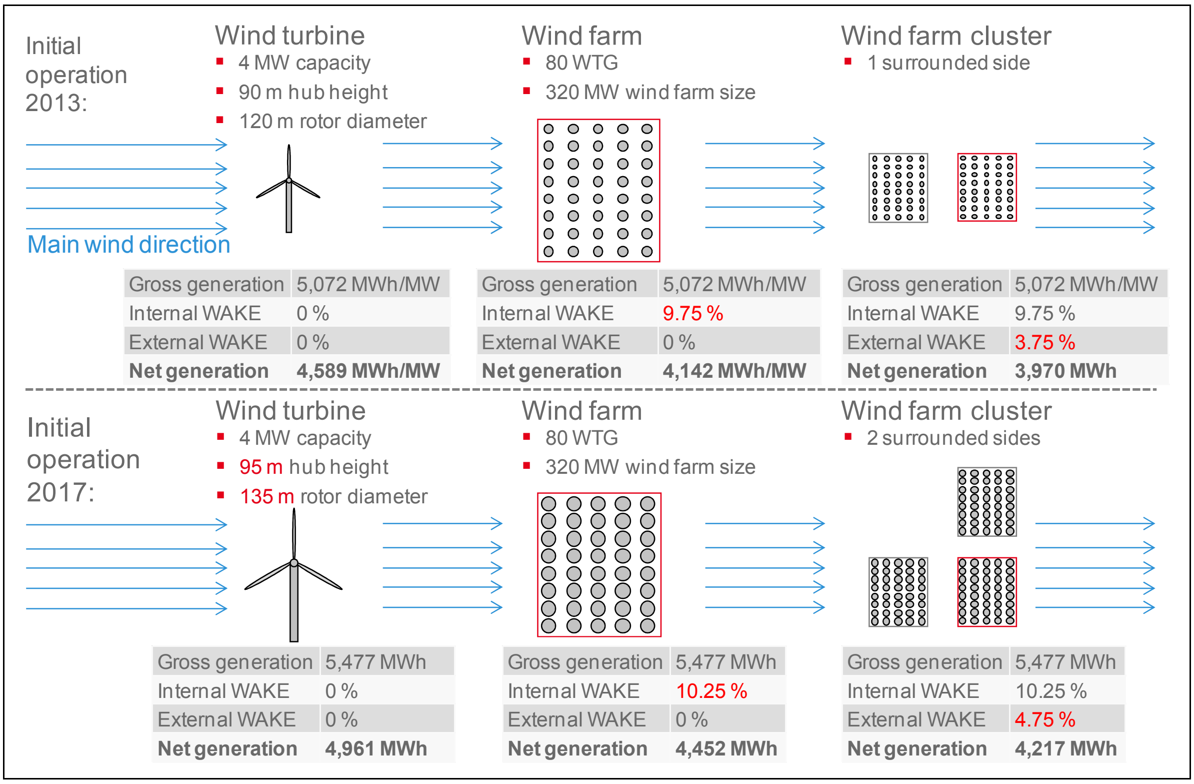
(3) If a wind farm comprises several generators the average wind yield per generator is already reduced by 8 to 10 %. This depends on the distance between generators in relation to rotor diameter. This study assumes that in the main wind direction 4 MW

generators with a rotor diameter of 120 m are installed at a distance that corresponds to 8 times the rotor diameter; for secondary wind directions, it is only at a 5-fold distance. This results in **internal wake losses** of 9.75 % and a further reduced net generation. If an existing wind farm is surrounded by other wind farms, i.e. a cluster configuration, in addition to the wind farm wake losses there will be **external wake losses** from the other wind farms. Currently, assumptions regarding external losses are only based on modelling, as there are hardly any wind farms operated in clusters yet. For wake effects in the main wind direction, we assume an additional external loss of 3.75 % of an individual generator´s net production.

(4) For a constant generator capacity, larger rotor diameters and hub heights increase the **utilisation** of the generator. The calculation of the wind yield includes the squared rotor diameter. In larger heights, in addition average wind speed goes up which even increases the wind yield with the third power. For a constant number of generators and a constant surface area, however, larger rotor diameters also increase internal wake losses. The relative distance between the generators in relation to rotor diameter will decrease; and internal wake losses increase to 10.25 %. Here we assume that the so called spacing method slightly mitigates the effect of the reduced generator distance in relation to rotor diameter in the main wind direction. Spacing means that wind turbine generators are placed in the gap in relation to the previous line of generators.

(5) If the wind farm is additionally **surrounded** on several sides, external wake losses further increase. Wind farm configurations in specific clusters that are advantageous for grid connection will increase external wake losses in the future. In the following example (Figure 27) wake losses increase to 10.25 % (internally) or 4.75 %, respectively, due to the mentioned effects. Together with the other technological losses of 8 % a total of almost 23 % of gross yield is lost. This means that only about 77 % of the gross electricity yield reaches the feed-in point at the external transformer platform.

Figure 27: Schematic presentation of wake effects of an offshore wind farm



Initial operation 2013 – Wind turbine:

Gross generation	5,072 MWh/MW
Internal WAKE	0 %
External WAKE	0 %
Net generation	**4,589 MWh/MW**

Initial operation 2013 – Wind farm:

Gross generation	5,072 MWh/MW
Internal WAKE	9.75 %
External WAKE	0 %
Net generation	**4,142 MWh/MW**

Initial operation 2013 – Wind farm cluster:

Gross generation	5,072 MWh/MW
Internal WAKE	9.75 %
External WAKE	3.75 %
Net generation	**3,970 MWh**

Initial operation 2017 – Wind turbine:

Gross generation	5,477 MWh
Internal WAKE	0 %
External WAKE	0 %
Net generation	**4,961 MWh**

Initial operation 2017 – Wind farm:

Gross generation	5,477 MWh
Internal WAKE	10.25 %
External WAKE	0 %
Net generation	**4,452 MWh**

Initial operation 2017 – Wind farm cluster:

Gross generation	5,477 MWh
Internal WAKE	10.25 %
External WAKE	4.75 %
Net generation	**4,217 MWh**

Source: [Prognos/Fichtner]; *WAKE = wake losses*

(6) As already described in Chapter 2.5, the **first offshore wind farms** in the German North Sea, in particular the generators of the wind farm alpha ventus, reach about a number of full-load hours that exceeds expectations. However, there are no other wind farms adjacent to these ones. With only 12 generators, alpha ventus is a small wind farm with low internal wake effects. These two advantages will not be valid in a future with wind farms of 80 generators.

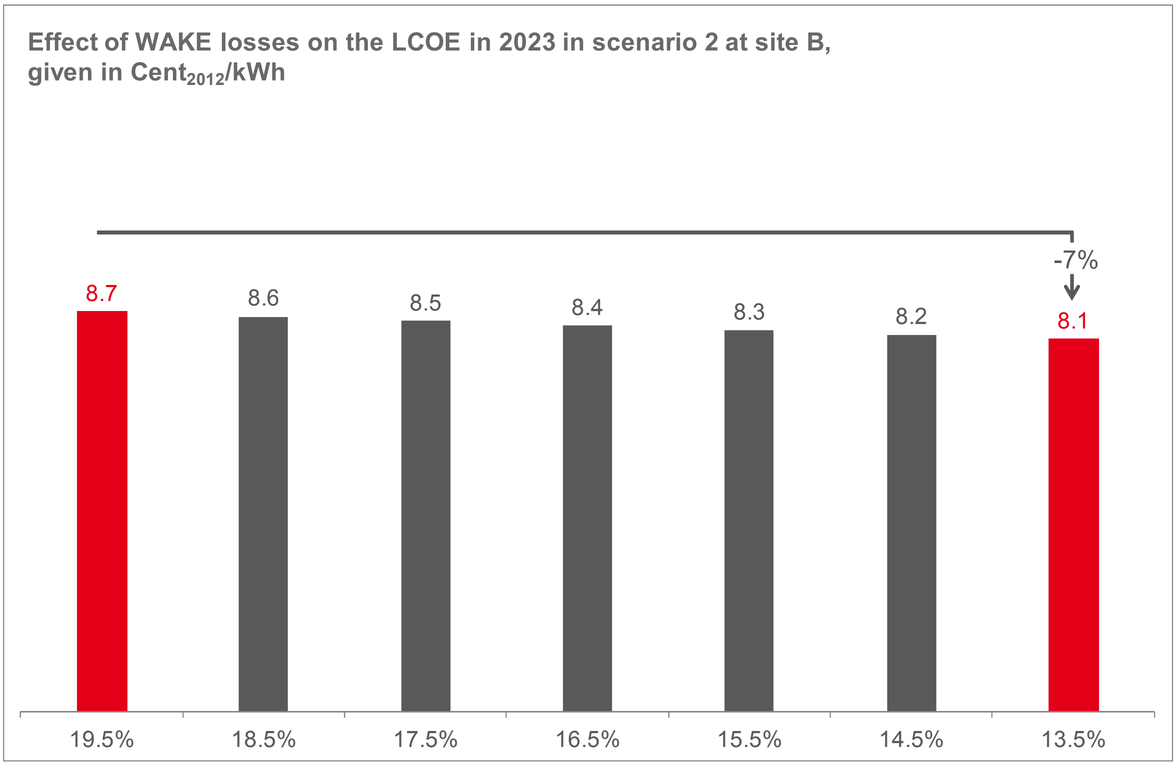
(7) The **wake losses assumed** in this study over an average of 20 years of operational wind farm life are based on **typological assumptions** regarding wind farm design and surrounding wind farms in the expected clusters. Adjusted wind farm designs with larger specific distances, less generators per surface area and less surrounding wind farms can result for specific wind farms in other assumptions regarding wake effects.

(8) The **reduction of wake losses** through an adjusted **wind farm design** is a key task for the future dimensioning of wind farms. The optimum number of generators per surface area will be the result of an economic optimisation of the number of genera-

tors, wind farm yield and specific investment costs. Due to the scenario assumptions, this optimisation is not comprehensively reflected in this study. Optimising the wind farm design in relation to internal wake losses constitutes an additional cost reduction potential. Regarding external losses, operators have a limited optimising potential as the arrangement in clusters is basically fixed by the regulatory framework.

(9) The **impact the optimisation** of a wind farm design could have is illustrated in the following considerations: When modelling the levelised cost of energy for Site B in Scenario 2, total wake losses due to larger rotors (internal wake losses) and more surrounding wind farms (external wake losses) will increase from 13.5 % in 2013 to 19.5 % in 2023. If total wake losses in 2023 would be kept constant at the 2013 level (13.5 %), this would correspond to a theoretical cost reduction potential of approximately 7 %. The levelised cost of energy for 2023 could be reduced from currently 8.7 Cent/kWh to 8.1 Cent/kWh (see Figure 28).

Figure 28: Effect of wake losses on the levelised cost of energy for the example of wind farm B



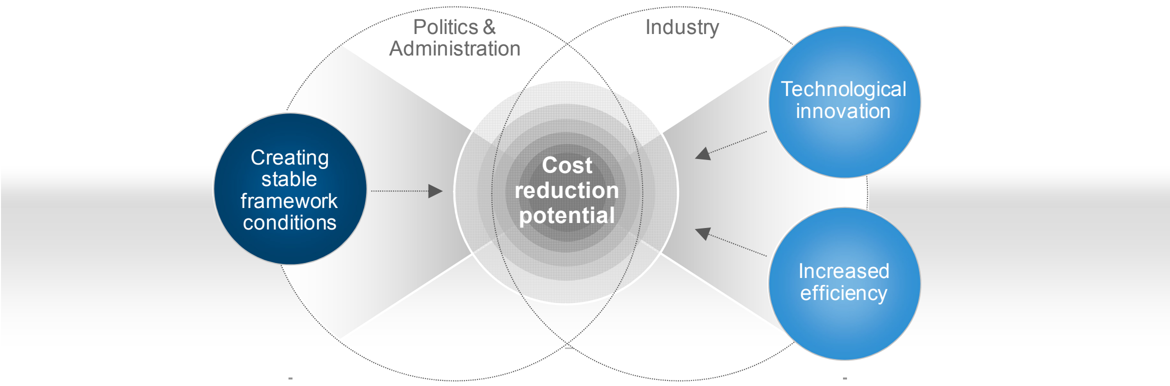
Source: [Prognos/Fichtner]

5 Conclusions: How to exploit the potentials

(1) It is essential that all **affected parties** in industry, politics and administration **contribute** in order to be able to exploit the presented cost reduction potentials of offshore wind power over the next ten years. Not only the technical areas such as investment, operating and decommissioning costs, but also the minimisation of risk premia provide significant reduction potentials. A stable regulatory framework provided by the political environment is a prerequisite for this. For the offshore industry itself, technological innovations and a more efficient use of technology are key variables.

(2) Figure 29 summarises the three fields of action. In the following, the areas for exploiting the potentials are described in more detail.

Figure 29: Factors that affect the implementation of cost reductions



Source: [Prognos/Fichtner]

All fields of action presented in the following also affect project risks. For offshore wind power projects, the **active risk management** is an important part of cost reduction. An improved **management of the interface** between wind farm operators, manufacturers, installation companies, grid operators and authorities can further reduce the risks.

Recommendations regarding the political and regulatory conditions

- **Creating stable legal and political framework conditions**
  Stable framework conditions constitute the basis for a reliable investment climate. In addition to stable refinancing options stated in the EEG (Renewable Energy Act), this also refers to the exemption of already carried-out investments and investment decisions ("Bestandsschutz"). It is of particular importance to keep up the development pace even after the first development phase runs out in 2017. A long-term perspective regarding the regulatory environment helps the offshore industry with its long-term planning horizons to adapt to it.
- **Defining technical standards for generator components and grid connection**
  The introduction of technology standards for components and grid connections can substantially decrease the costs of installation and maintenance. It would be useful to develop these standards in close cooperation with the industry and throughout Europe in order to further minimise the costs of offshore wind power in all of Europe.
- **Simplifying certification and approval criteria**
  A joint review of certification and approval standards by the industry, operators, certifying entities and the Federal Maritime and Hydrographic Agency can optimise processes and standards. Uniform certification standards simplify the complex situation and reduce the current costs. It is recommended to use experience regarding certification processes gained by the powerstation and plant construction industry as well as other industries outside the classical offshore segment.

Recommendations to the industry regarding technological innovation

- **Optimising generator technology in order to maximise utilisation and wind yield**
  Depending on the site, both optimising generator technology in order to reach a high utilisation and maximising the wind yield offer potentials for decreasing energy production costs. For close-to-shore sites, a higher plant utilisation through larger rotors will be advantageous. The higher the installation and maintenance costs due to larger distances to port, the more reasonable it becomes to maximise wind yield by economies of scales that larger turbine capacities contribute.

- **Optimising existing support structures and developing new ones**

  Optimising the foundation design provides an opportunity for standardisation. Particularly jacket fabrication can become more efficient with higher volumes. In the short to medium term, processes for installing support structures can be optimised by drilling or vibration, for instance. In the long run, new substructure concepts such as gravity or floating substructures can lead to further improvements.

- **Improving installation logistics**
  Installation logistics should be improved by more powerful ships and ports as well as the adjustment of processes. The larger transport capacities that are achieved this way allow for a better utilisation of favourable weather slots. This is a prerequisite for utilising the economies of scales of larger turbines.

- **Intensifying research and development**
  Development, testing and market introduction of innovative generator concepts and support structures should be intensified. Supported by the political environment, the creation of test fields and use of demonstration facilities could be useful in this context.

Recommendations to the industry regarding an increased efficiency

- **Developing inter-operator maintenance and installation concepts**
  In the medium term, substantial cost benefits could be achieved by joint concepts for the operation and maintenance of wind farms. The goal should be to jointly use fleet and logistics infrastructures (landing and fuelling facilities for helicopters, ships, material storage, joint rescue and safety concepts). Offshore logistics centre where replacement components of various manufacturers are stored would reduce downtime of wind farms. In the long run, operators of adjacent wind farms using the same type of generator could develop joint concepts and thus achieve cost benefits also during the installation phase.

- **Accelerating serial production**
  Regarding turbine and support structure technology as well as grid-connection components, serial production offers substantial cost reduction potentials. The further development of serial production will, however, only be successful if there is a dynamic market development and a far-reaching implementation of technology standards.

6 Appendix

6.1 List of interview partners

The results are based on independent expert analyses. In addition, interviews and data provided by companies representing the entire spectrum of the offshore wind power industry (operators, manufacturers, suppliers and financing institutions) were included. The contents of this study do not represent the opinion of individual companies.

ALSTOM Deutschland AG Alstom Power	**Markus Rieck**	Country Sales Director Germany
Ambau GmbH	**Holger Müller**	Head of Sales Department
AREVA Wind GmbH	**Aurélien Petitot**	Investment Solutions Manager
BARD Engineering GmbH	**Dr. Daniel Brickwell**	Head of Sales and Project Development
Bundesamt für Seeschifffahrt und Hydrographie	**Christian Dahlke**	Head of Unit M 5 Management of the Oceans
Commerzbank Renewable Energies	**Klaus Bornhorst**	Director Project Finance Germany & Offshore
Deutsche WindGuard GmbH	**Dr. Knud Rehfeldt**	Managing Director
DONG Energy	**PhD Katja Birr-Pedersen**	Lead Regulatory Advisor
DONG Energy	**Manfred Dittmer**	Head of Regulatory /Stakeholder Management
DONG Energy	**Scott Urquhart**	Head of Business Analysis, Cost of Energy & Business Development
E.ON Climate & Renewables Central Europe GmbH	**Dr. Arno Buysch**	Program Manager - Cost Reduction Offshore Wind
E.ON Climate & Renewables GmbH	**Uta von Thomsen**	Risk and Investment Analyst
EnBW Erneuerbare und Konventionelle Erzeugung AG	**Thomas Augat**	Head of Controlling and Finance
EnBW Erneuerbare und Konventionelle Erzeugung AG	**Jörn Däinghaus**	Project Manager Offshore Wind
EnBW Erneuerbare und Konventionelle Erzeugung AG	**Michael Boll**	Head of Offshore Wind Operations and Maintenance
EnBW Erneuerbare und Konventionelle Erzeugung AG	**Nikolaus Elze**	Head of Engineering
GL Garrad Hassan Offshore	**Peter Frohböse**	Head of Department Offshore Germany
HOCHTIEF Solutions AG Civil Engineering Marine and Offshore	**Bernd Löhden**	Head of Marine and Offshore Technology
HOCHTIEF Solutions AG Civil Engineering Marine and Offshore	**Stefan Müller**	Head of Marine and Offshore Technology
KfW	**Carlos Christian Sobotta**	Department Director KfW Program Offshore Wind energy

Marguerite Adviser S.A.	**Bruno Erbel**	Vice President
MEAG MUNICH ERGO AssetManagement GmbH	**Stefan Schweikart**	Investment Manager Renewable Energy and New Technologies
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NORD/LB Norddeutsche Landesbank Girozentrale	**Ulrich Winkelmann**	Director
Nordwest Assekuranzmakler GmbH & Co. KG	**Thomas Haukje**	Managing Director
REpower Systems SE	**Norbert Giese**	Vice President Offshore Development
RWE Innogy GmbH	**Holger Gassner**	Head of Markets and Political Affairs
RWE Innogy GmbH	**Udo Reher**	Head of Procurement
RWE Innogy GmbH	**Tobias Schneider**	Controlling
Siemens AG Energy, Wind Division	**Matthias Bausenwein**	Head of Business Development, Offshore Germany
Siemens AG Energy, Wind Division	**Peter Gregersen**	Head of Sales Offshore
Siemens AG Energy, Wind Division	**Horst Hakelberg**	Head of Sales Service Offshore Germany
Siemens AG Energy, Service Division	**Christian Leffringhausen**	Service Proposal Manager Offshore
Siemens Financial Services GmbH	**Christian Grenz**	Senior Advisor, Financial Advisory & Structuring, Energy Finance EMEA
Siemens Financial Services GmbH	**Marcus Turnwald**	Senior Advisor, Financial Advisory & Structuring, Energy Finance EMEA
Siemens Wind Power A/S	**Morton Vindbjerg**	Head of Operational Marketing
UniCredit Bank AG	**Brad McAboy**	Director
Vattenfall Europe Windkraft GmbH	**Dr. Johannes Kammer**	Program Manager LEC Reduction
Vattenfall Europe Windkraft GmbH	**Bastian Scheele**	Risk Manager
WeserWind GmbH Offshore Construction Georgsmarienhütte	**Dirk Kassen**	Managing Director
Windkraftwerk Borkum GmbH & Co. KG	**Linda Wehle**	Manager Project Finance
WindMW GmbH	**Sebastian Schmidt**	Chief Financial Officer

6.2 Glossary

CAPEX	Investment costs (Capital Expenditure)
EEG	Renewable Energies Act
E	Equity
D	Debt
GW	Gigawatt (1,000 megawatt)
HVDC	High-voltage direct-current transmission
Jacket	Type of foundation with four piles
kWh	Kilowatt per hour
Monopile	Type of foundation with one pile
MW	Megawatt (1,000 kilowatt)
MWh	Megawatt per hour
O&M	Operation & Maintenance
OPEX	Operating costs (Operating expenditure)
Spacing	Wind turbine generators are placed in the gap in relation to the previous line of generators
TCE	The Crown Estate
Tripod	Type of foundation with three piles
WACC	Weighted Average Cost of Capital
WAKE	Wake losses
WTG	Wind turbine generator

6.3 Detailed results of the individual scenarios

Table 11: Wind farm A – Scenario 1 and 1a

	Unit	Scenario / Initial operation	1: 2013	1: 2017	1: 2020	1: 2023	1a: 2017
Investment costs							
Certification and approval costs	in thou. $Euro_{2012}$/MW		377	385	361	351	376
Turbine	in thou. $Euro_{2012}$/MW		1,201	1,350	1,300	1,260	1,190
Support structure (inc. tower)	in thou. $Euro_{2012}$/MW		793	757	717	683	732
Array cables	in thou. $Euro_{2012}$/MW		89	77	74	72	89
Substation	in thou. $Euro_{2012}$/MW		232	163	158	154	234
Installation	in thou. $Euro_{2012}$/MW		571	431	414	401	561
Support structure	in thou. $Euro_{2012}$/MW		*286*	*212*	*205*	*198*	*277*
Turbine	in thou. $Euro_{2012}$/MW		*130*	*104*	*100*	*95*	*128*
Cables	in thou. $Euro_{2012}$/MW		*101*	*77*	*75*	*73*	*105*
Substation	in thou. $Euro_{2012}$/MW		*54*	*37*	*35*	*35*	*50*
Contingency	in thou. $Euro_{2012}$/MW		489	475	393	292	414
Share of contingency	in thou. $Euro_{2012}$/MW		*15%*	*15%*	*13%*	*10%*	*13%*
Total investment costs	in thou. $Euro_{2012}$/MW		**3,753**	**3,638**	**3,417**	**3,213**	**3,596**
Operating and maintenance costs (O&M)							
Operation and maintenance costs	in thou. $Euro_{2012}$/MW p.a.		97	76	74	72	96
Operating phase insurance	in thou. Euro2012/MW p.a.		15	22	22	22	18
Total O&M costs	in thou. Euro2012/MW p.a.		**112**	**98**	**96**	**94**	**114**
Annual energy production							
Gross energy production	in MWh/MW		**4,967**	**5,000**	**5,193**	**5,471**	**5,364**
Gross Load Factor	in %		*56.7%*	*57.1%*	*59.3%*	*62.5%*	*61.2%*
Wind farm availability	in %		94.5%	94.7%	94.9%	95.0%	94.5%
Aerodynamic array losses (WAKE-Losses)	in %		13.5%	14.5%	16.5%	17.8%	15.0%
Electrical array losses	in %		2.3%	2.2%	2.1%	2.0%	2.2%
Other losses	in %		2.0%	2.0%	1.9%	1.8%	2.0%
Net energy production	in MWh/MW		**3,888**	**3,880**	**3,952**	**4,114**	**4,129**
Capacity factor	in %		*44.4%*	*44.3%*	*45.1%*	*47.0%*	*47.1%*
Decommissioning costs							
Dismantling	in thou. Euro2012/MW		135	110	102	95	135
Weighted average cost of capital (WACC)	in %		7.85%	7.19%	6.17%	5.68%	7.19%
Levelised cost of energy 20 years	in $Cent_{2012}$/kWh		**12.8**	**11.7**	**10.2**	**9.1**	**11.3**
Levelised cost of energy 25 years	in $Cent_{2012}$/kWh		**12.2**	**11.1**	**9.6**	**8.5**	**10.7**

Source: [Prognos/Fichtner]

Table 12: Wind farm A – Scenario 2 and 2a

	Unit	Scenario / Initial operation	2013	2017	2020	2023	2a 2020	2a 2023
Investment costs								
Certification and approval costs	in thou. $Euro_{2012}$/MW		377	386	333	296	337	307
Turbine	in thou. $Euro_{2012}$/MW		1,201	1,337	1,251	1,093	1,180	1,075
Support structure (inc. tower)	in thou. $Euro_{2012}$/MW		793	748	671	635	668	599
Array cables	in thou. $Euro_{2012}$/MW		89	77	68	68	74	72
Substation	in thou. $Euro_{2012}$/MW		232	163	154	140	150	142
Installation	in thou. $Euro_{2012}$/MW		571	425	397	365	378	353
Support structure	in thou. $Euro_{2012}$/MW		*286*	*209*	*194*	*175*	*179*	*167*
Turbine	in thou. $Euro_{2012}$/MW		*130*	*102*	*96*	*90*	*92*	*84*
Cables	in thou. $Euro_{2012}$/MW		*101*	*76*	*71*	*69*	*74*	*71*
Substation	in thou. $Euro_{2012}$/MW		*54*	*37*	*36*	*31*	*33*	*32*
Contingency	in thou. $Euro_{2012}$/MW		489	470	431	337	362	255
Share of contingency	in thou. $Euro_{2012}$/MW		*15%*	*15%*	*15%*	*13%*	*13%*	*10%*
Total investment costs	in thou. $Euro_{2012}$/MW		**3,753**	**3,606**	**3,305**	**2,934**	**3,149**	**2,802**
Operating and maintenance costs (O&M)								
Operation and maintenance costs	in thou. $Euro_{2012}$/MW p.a.		97	74	58	51	70	63
Operating phase insurance	in thou. Euro2012/MW p.a.		15	22	22	22	22	22
Total O&M costs	in thou. Euro2012/MW p.a.		**112**	**96**	**80**	**73**	**92**	**85**
Annual energy production								
Gross energy production	in MWh/MW		**4,967**	**5,029**	**5,158**	**5,352**	**5,368**	**5,566**
Gross Load Factor	in %		*56.7%*	*57.4%*	*58.9%*	*61.1%*	*61.3%*	*63.5%*
Wind farm availability	in %		94.5%	94.7%	95.0%	95.5%	95.5%	96.0%
Aerodynamic array losses (WAKE-Losses)	in %		13.5%	14.5%	17.3%	19.5%	18.5%	20.5%
Electrical array losses	in %		2.3%	2.2%	1.8%	1.5%	1.8%	1.5%
Other losses	in %		2.0%	2.0%	1.8%	1.6%	1.8%	1.6%
Net energy production	in MWh/MW		**3,888**	**3,903**	**3,912**	**3,988**	**4,031**	**4,117**
Capacity factor	in %		*44.4%*	*44.5%*	*44.7%*	*45.5%*	*46.0%*	*47.0%*
Decommissioning costs								
Dismantling	in thou. Euro2012/MW		135	102	85	74	95	87
Weighted average cost of capital (WACC)	in %		7.85%	7.19%	6.17%	5.68%	6.17%	5.68%
Levelised cost of energy 20 years	in $Cent_{2012}$/kWh		**12.8**	**11.5**	**9.7**	**8.2**	**9.3**	**8.0**
Levelised cost of energy 25 years	in $Cent_{2012}$/kWh		**12.2**	**10.8**	**9.0**	**7.6**	**8.8**	**7.5**

Source: [Prognos/Fichtner]

Table 13: Wind farm B – Scenario 1 and 1a

	Unit	Scenario / Initial operation	1 2013	1 2017	1 2020	1 2023	1a 2017
Investment costs							
Certification and approval costs	in thou. $Euro_{2012}$/MW		387	397	372	362	388
Turbine	in thou. $Euro_{2012}$/MW		1,201	1,350	1,300	1,260	1,190
Support structure (inc. tower)	in thou. $Euro_{2012}$/MW		1,028	871	787	764	869
Array cables	in thou. $Euro_{2012}$/MW		90	79	75	73	91
Substation	in thou. $Euro_{2012}$/MW		235	165	160	155	237
Installation	in thou. $Euro_{2012}$/MW		684	548	533	513	678
Support structure	in thou. $Euro_{2012}$/MW		*350*	*275*	*268*	*258*	*340*
Turbine	in thou. $Euro_{2012}$/MW		*158*	*135*	*131*	*124*	*157*
Cables	in thou. $Euro_{2012}$/MW		*120*	*97*	*95*	*92*	*125*
Substation	in thou. $Euro_{2012}$/MW		*56*	*41*	*39*	*39*	*56*
Contingency	in thou. $Euro_{2012}$/MW		544	512	420	313	449
Share of contingency	in thou. $Euro_{2012}$/MW		*15%*	*15%*	*13%*	*10%*	*13%*
Total investment costs	in thou. $Euro_{2012}$/MW		**4,169**	**3,922**	**3,647**	**3,440**	**3,902**
Operating and maintenance costs (O&M)							
Operation and maintenance costs	in thou. $Euro_{2012}$/MW p.a.		116	90	88	86	113
Operating phase insurance	in thou. Euro2012/MW p.a.		18	22	22	22	18
Total O&M costs	in thou. Euro2012/MW p.a.		**134**	**112**	**110**	**108**	**131**
Annual energy production							
Gross energy production	in MWh/MW		**5,072**	**5,109**	**5,305**	**5,588**	**5,477**
Gross Load Factor	in %		*57.9%*	*58.3%*	*60.6%*	*63.8%*	*62.5%*
Wind farm availability	in %		94.5%	94.7%	94.9%	95.0%	94.5%
Aerodynamic array losses (WAKE-Losses)	in %		13.5%	14.5%	16.5%	17.8%	15.0%
Electrical array losses	in %		2.3%	2.2%	2.1%	2.0%	2.2%
Other losses	in %		2.0%	2.0%	1.9%	1.8%	2.0%
Net energy production	in MWh/MW		**3,970**	**3,965**	**4,037**	**4,202**	**4,217**
Capacity factor	in %		*45.3%*	*45.3%*	*46.1%*	*48.0%*	*48.1%*
Decommissioning costs							
Dismantling	in thou. Euro2012/MW		153	124	116	108	153
Weighted average cost of capital (WACC)	in %		7.85%	7.19%	6.17%	5.68%	7.19%
Levelised cost of energy 20 years	in $Cent_{2012}$/kWh		**14.2**	**12.5**	**10.9**	**9.7**	**12.2**
Levelised cost of energy 25 years	in $Cent_{2012}$/kWh		**13.5**	**11.8**	**10.2**	**9.1**	**11.6**

Source: [Prognos/Fichtner]

Table 14: Wind farm B – Scenario 2 and 2a

	Unit	Scenario / Initial operation	2: 2013	2: 2017	2: 2020	2: 2023	2a: 2020	2a: 2023
Investment costs								
Certification and approval costs	in thou. $Euro_{2012}$/MW		387	397	345	307	347	317
Turbine	in thou. $Euro_{2012}$/MW		1,201	1,337	1,251	1,093	1,180	1,075
Support structure (inc. tower)	in thou. $Euro_{2012}$/MW		1,028	851	713	678	728	670
Array cables	in thou. $Euro_{2012}$/MW		90	79	69	69	75	73
Substation	in thou. $Euro_{2012}$/MW		235	165	155	141	152	143
Installation	in thou. $Euro_{2012}$/MW		684	545	479	417	486	457
Support structure	in thou. $Euro_{2012}$/MW		*350*	*273*	*239*	*201*	*235*	*220*
Turbine	in thou. $Euro_{2012}$/MW		*158*	*134*	*119*	*107*	*120*	*110*
Cables	in thou. $Euro_{2012}$/MW		*120*	*97*	*84*	*77*	*94*	*90*
Substation	in thou. $Euro_{2012}$/MW		*56*	*41*	*37*	*32*	*37*	*37*
Contingency	in thou. $Euro_{2012}$/MW		544	506	452	352	386	274
Share of contingency	in thou. $Euro_{2012}$/MW		*15%*	*15%*	*15%*	*13%*	*13%*	*10%*
Total investment costs	in thou. $Euro_{2012}$/MW		**4,169**	**3,880**	**3,464**	**3,057**	**3,354**	**3,009**
Operating and maintenance costs (O&M)								
Operation and maintenance costs	in thou. $Euro_{2012}$/MW p.a.		116	88	75	68	85	78
Operating phase insurance	in thou. Euro2012/MW p.a.		18	22	22	22	22	22
Total O&M costs	in thou. Euro2012/MW p.a.		**134**	**110**	**97**	**90**	**107**	**100**
Annual energy production								
Gross energy production	in MWh/MW		**5,072**	**5,139**	**5,271**	**5,468**	**5,483**	**5,685**
Gross Load Factor	in %		*57.9%*	*58.7%*	*60.2%*	*62.4%*	*62.6%*	*64.9%*
Wind farm availability	in %		94.5%	94.7%	95.0%	95.5%	95.5%	96.0%
Aerodynamic array losses (WAKE-Losses)	in %		13.5%	14.5%	17.3%	19.5%	18.5%	20.5%
Electrical array losses	in %		2.3%	2.2%	1.8%	1.5%	1.8%	1.5%
Other losses	in %		2.0%	2.0%	1.8%	1.6%	1.8%	1.6%
Net energy production	in MWh/MW		**3,970**	**3,988**	**3,997**	**4,074**	**4,118**	**4,205**
Capacity factor	in %		*45.3%*	*45.5%*	*45.6%*	*46.5%*	*47.0%*	*48.0%*
Decommissioning costs								
Dismantling	in thou. Euro2012/MW		135	116	97	85	108	99
Weighted average cost of capital (WACC)	in %		7.85%	7.19%	6.17%	5.68%	6.17%	5.68%
Levelised cost of energy 20 years	in $Cent_{2012}$/kWh		**14.2**	**12.3**	**10.2**	**8.7**	**10.0**	**8.6**
Levelised cost of energy 25 years	in $Cent_{2012}$/kWh		**13.5**	**11.6**	**9.6**	**8.2**	**9.4**	**8.1**

Source: [Prognos/Fichtner]

Table 15: Wind farm C – Scenario 1 and 1a

	Unit	Scenario / Initial operation	1 2013	1 2017	1 2020	1 2023	1a 2017
Investment costs							
Certification and approval costs	in thou. Euro$_{2012}$/MW		393	405	379	369	396
Turbine	in thou. Euro$_{2012}$/MW		1,201	1,350	1,300	1,260	1,190
Support structure (inc. tower)	in thou. Euro$_{2012}$/MW		1,093	923	843	828	1,089
Array cables	in thou. Euro$_{2012}$/MW		91	81	77	74	93
Substation	in thou. Euro$_{2012}$/MW		238	167	162	157	240
Installation	in thou. Euro$_{2012}$/MW		809	606	592	575	801
Support structure	in thou. Euro$_{2012}$/MW		*421*	*309*	*302*	*293*	*412*
Turbine	in thou. Euro$_{2012}$/MW		*191*	*150*	*146*	*141*	*187*
Cables	in thou. Euro$_{2012}$/MW		*138*	*104*	*102*	*101*	*143*
Substation	in thou. Euro$_{2012}$/MW		*59*	*42*	*41*	*40*	*58*
Contingency	in thou. Euro$_{2012}$/MW		574	530	436	326	495
Share of contingency	in thou. Euro$_{2012}$/MW		*15%*	*15%*	*13%*	*10%*	*13%*
Total investment costs	in thou. Euro$_{2012}$/MW		**4,399**	**4,062**	**3,789**	**3,590**	**4,304**
Operating and maintenance costs (O&M)							
Operation and maintenance costs	in thou. Euro$_{2012}$/MW p.a.		118	94	92	90	117
Operating phase insurance	in thou. Euro2012/MW p.a.		20	22	22	22	18
Total O&M costs	in thou. Euro2012/MW p.a.		**138**	**116**	**114**	**112**	**135**
Annual energy production							
Gross energy production	in MWh/MW		**5,126**	**5,164**	**5,358**	**5,638**	**5,528**
Gross Load Factor	in %		*58.5%*	*58.9%*	*61.2%*	*64.4%*	*63.1%*
Wind farm availability	in %		94.5%	94.7%	94.9%	95.0%	94.5%
Aerodynamic array losses (WAKE-Losses)	in %		13.5%	14.5%	16.5%	17.8%	15.0%
Electrical array losses	in %		2.3%	2.2%	2.1%	2.0%	2.2%
Other losses	in %		2.0%	2.0%	1.9%	1.8%	2.0%
Net energy production	in MWh/MW		**4,012**	**4,007**	**4,077**	**4,239**	**4,256**
Capacity factor	in %		*45.8%*	*45.7%*	*46.5%*	*48.4%*	*48.6%*
Decommissioning costs							
Dismantling	in thou. Euro2012/MW		172	140	131	122	172
Weighted average cost of capital (WACC)	in %		7.85%	7.19%	6.17%	5.68%	7.19%
Levelised cost of energy 20 years	in Cent$_{2012}$/kWh		**14.8**	**12.8**	**11.2**	**10.0**	**13.1**
Levelised cost of energy 25 years	in Cent$_{2012}$/kWh		**14.1**	**12.1**	**10.5**	**9.4**	**12.4**

Source: [Prognos/Fichtner]

Table 16: Wind farm C – Scenario 2 and 2a

	Unit	Scenario / Initial operation	2 2013	2 2017	2 2020	2 2023	2a 2020	2a 2023
Investment costs								
Certification and approval costs	in thou. $Euro_{2012}$/MW		393	404	352	313	353	323
Turbine	in thou. $Euro_{2012}$/MW		1,201	1,337	1,251	1,093	1,180	1,075
Support structure (inc. tower)	in thou. $Euro_{2012}$/MW		1,093	915	763	717	801	703
Array cables	in thou. $Euro_{2012}$/MW		91	81	70	70	77	74
Substation	in thou. $Euro_{2012}$/MW		238	167	156	142	154	144
Installation	in thou. $Euro_{2012}$/MW		809	603	539	478	540	514
Support structure	in thou. $Euro_{2012}$/MW		*421*	*306*	*273*	*236*	*267*	*254*
Turbine	in thou. $Euro_{2012}$/MW		*191*	*150*	*134*	*120*	*134*	*127*
Cables	in thou. $Euro_{2012}$/MW		*138*	*104*	*92*	*87*	*99*	*96*
Substation	in thou. $Euro_{2012}$/MW		*59*	*43*	*39*	*34*	*39*	*38*
Contingency	in thou. $Euro_{2012}$/MW		574	526	470	366	404	283
Share of contingency	in thou. $Euro_{2012}$/MW		*15%*	*15%*	*15%*	*13%*	*13%*	*10%*
Total investment costs	in thou. $Euro_{2012}$/MW		**4,399**	**4,032**	**3,600**	**3,179**	**3,508**	**3,116**
Operating and maintenance costs (O&M)								
Operation and maintenance costs	in thou. $Euro_{2012}$/MW p.a.		118	92	79	72	89	82
Operating phase insurance	in thou. Euro2012/MW p.a.		20	22	22	22	22	22
Total O&M costs	in thou. Euro2012/MW p.a.		**138**	**114**	**101**	**94**	**111**	**104**
Annual energy production								
Gross energy production	in MWh/MW		**5,126**	**5,193**	**5,324**	**5,518**	**5,534**	**5,733**
Gross Load Factor	in %		*58.5%*	*59.3%*	*60.8%*	*63.0%*	*63.2%*	*65.4%*
Wind farm availability	in %		94.5%	94.7%	95.0%	95.5%	95.5%	96.0%
Aerodynamic array losses (WAKE-Losses)	in %		13.5%	14.5%	17.3%	19.5%	18.5%	20.5%
Electrical array losses	in %		2.3%	2.2%	1.8%	1.5%	1.8%	1.5%
Other losses	in %		2.0%	2.0%	1.5%	1.5%	1.8%	1.6%
Net energy production	in MWh/MW		**4,012**	**4,030**	**4,050**	**4,116**	**4,156**	**4,241**
Capacity factor	in %		*45.8%*	*46.0%*	*46.2%*	*47.0%*	*47.4%*	*48.4%*
Decommissioning costs								
Dismantling	in thou. Euro2012/MW		172	131	104	90	122	113
Weighted average cost of capital (WACC)	in %		7.85%	7.19%	6.17%	5.68%	6.17%	5.68%
Levelised cost of energy 20 years	in $Cent_{2012}$/kWh		**14.8**	**12.6**	**10.5**	**9.0**	**10.3**	**8.9**
Levelised cost of energy 25 years	in $Cent_{2012}$/kWh		**14.1**	**11.9**	**9.9**	**8.4**	**9.7**	**8.3**

Source: [Prognos/Fichtner]

6.4 Other appendices

Table 17: Explanation of cost components

Certification/Approval	Approval		Includes all required approval costs for a wind farm (e.g. soil survey, bomb disposal, environmental and wind speed surveys)
	Certification		Total costs of certification
	Project development		All project development costs until FID
	Project management		All project management costs until the end of the installation phase
	Insurance		Insurance cover for the whole construction phase (liability insurance and Construction All Risks (CAR) insurance)
Turbine		Inclusive	Supply of the turbine (Rotors, hub, nacelle and electrical system)
			Delivery to the next port
			Warranty
			Cost of initial operation
		Exclusive	Tower
Foundation		Inclusive	Supply of the foundation (Piles, transition piece, boat landing and technical equipment)
			Delivery to the next port
			Tower
			Warranty
		Exclusive	Foundation substation
Cable		Inclusive	Delivery to the next port
Installation		Inclusive	Transport of turbine, foundation and substation from the port to the site
			Required preliminary works at the port
			All relevant costs of installation (e.g. vessels, scour protection, noise mitigation)
			Cable protection
			Initial operation
Substation		Inclusive	Supply of the substation (incl. foundation, electrical components and topside)
			Delivery to the next port
			Warranty
Operation and maintenance		Inclusive	Operating phase starts with the initial operation of the first turbine
			Implementation of all required measures and monitoring to ensure the operating lifetime
			All planned and unplanned O&M
			Insurance over lifetime
Energy production	Gross energy production	Inclusive	Average energy production over lifetime of the wind farm
			Calculation based on different power curve calculations assuming cut-in and cut-out wind speed in line with the market, Weibull parameters (site A: 2,17; site B and C: 2,25), adjustment of rotor diameter and hub height
		Exclusive	Losses through:
			Turbine availability
			Electrical losses
			WAKE losses and other losses
	Turbine availability	Inclusive	Average availability of turbine, foundation, substation and cable over the lifetime of a wind farm
	WAKE losses	Inclusive	Internal and external WAKE losses depending on wind farm layout, numbers of WTG, rotor diameter, hub height and the number of surrounding offshore wind farms
	Electrical losses	Inclusive	Average electrical losses of a wind farm incl. the unavailability of the substation
	Other losses	Inclusive	Includes losses over lifetime through hysteresis
	Net energy production	Inclusive	Average net energy production over lifetime including all losses
Decommissioning		Inclusive	Planning and design of measures
			All required environmental measures
			Decommissioning of turbine, foundation, cable and substation
			Resale of relevant components (e.g. steel scrap with 250 Euro/t)

Source: [Prognos/Fichtner]

Table 18: General technical assumptions for the calculation

General technical assumptions for the sites A-B-C in scenario 1 and 2					
				min	max
Foundation					
	Monopiles		[$Euro_{2012}$/t]	1,680	1,950
		Tonnage	[t]	750	1,500
		Length	[m]	57	86
		Diameter	[m]	5.5	8.0
	Transition piece		[$Euro_{2012}$/t]	2,250	2,780
		Tonnage	[t]	185	475
		Length	[m]	17	31
		Diameter	[m]	4.8	6.7
	Jackets		[$Euro_{2012}$/t]	3,650	4,100
		Tonnage	[t]	580	1,025
		Length	[m]	43	67
	Jacket - Piles		[$Euro_{2012}$/t]	1,150	1,375
		Tonnage	[t/item]	85	255
		Length	[m]	35	68
		Diameter	[m]	2.20	3.10
Installation	Foundation				
		Monopile	[days/item]	1.2	3.2
		Jacket incl. Jacket-Piles	[days/item]	1.4	3.9
		Scour protection	[k $Euro_{2012}$/item]	150	300
		Noise mitigation	[k $Euro_{2012}$/item]	180	250
	Turbine (incl. tower)		[days/item]	1.1	5.4
	Cabel		[km/day]	0.1	0.9
	Substation		[days/item]	15	42

Source: [Prognos/Fichtner]

Table 19: Cont. General technical assumptions for the calculation

General technical assumptions for the sites A-B-C in scenario 1 and 2					
				min	max
Vessel prices	DP - Vessels				
		Medium	[k $Euro_{2012}$/day]	185	220
		Large	[k $Euro_{2012}$/day]	215	250
	Jack-Up: Self propelled				
		Medium	[k $Euro_{2012}$/day]	100	150
		Large	[k $Euro_{2012}$/day]	135	200
	Jack-Up: Non self propelled				
		Medium	[k $Euro_{2012}$/day]	40	65
		Large	[k $Euro_{2012}$/day]	60	135
	Heavy-lift vessel				
		Medium	[k $Euro_{2012}$/day]	105	215
		Large	[k $Euro_{2012}$/day]	200	625
	Cable layer				
		Medium	[k $Euro_{2012}$/day]	65	107
		Large	[k $Euro_{2012}$/day]	100	145
	PSV/Feeder - Vessels				
		Medium	[k $Euro_{2012}$/day]	25	45
		Large	[k $Euro_{2012}$/day]	40	80
	Tugboat				
		Medium	[k $Euro_{2012}$/day]	5	10
		Large	[k $Euro_{2012}$/day]	10	25
	Barge				
		Medium	[k $Euro_{2012}$/day]	3	5
		Large	[k $Euro_{2012}$/day]	8	20
O&M					
	Accomodation vessel (Seabased)				
		Medium	[k $Euro_{2012}$/day]	20	35
		Large	[k $Euro_{2012}$/day]	30	50
	Crew transfer vessel				
		Medium	[k $Euro_{2012}$/day]	3	6
		Large	[k $Euro_{2012}$/day]	5	15
	Helicopter operation		[k $Euro_{2012}$/day]	7	10

Source: Prognos AG / Fichtner

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