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Levelised cost of energy for offshore floating wind turbines in a life cycle perspective

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ABSTRACT

This report presents a comprehensive analysis and comparison of the levelised cost of energy (LCOE) for the following offshore floating wind turbine concepts: Spar-Buoy (Hywind II), Tension-Leg-Spar (SWAY), Semi-Submersible (WindFloat), Tension-Leg-Wind-Turbine (TLWT) and Tension-Leg-Buoy (TLB). The analysis features a generic commercial wind farm consisting of 100 five megawatt turbines, at a far offshore site in a Life Cycle Analysis (LCA) perspective. Data for existing bottom-fixed turbines, both jacket and monopile concepts are used as reference values for adaptation to the generic wind farm parameters. The results indicate that LCOE values are strongly dependent on depth and distance from shore, due to mooring costs and export cable length, respectively. Based on the findings, depth is the dominant parameter to determine the optimal concept for a site. Distance to shore, Load Factor and availability are amongst the significant factors affecting the LCOE. The findings also indicate that LCOE of floating turbines applied in large scale and in intermediate depths of 50–150 m is comparable to bottom-fixed turbines. Floating turbines for increasing depths generally experience increased LCOE at a lower rate than bottom-fixed turbines. An optimal site, situated 100 km offshore would give LCOE in the range of € 82.0–€ 236.7 per megawatt-hour for the conceptual designs in this paper.

1. Introduction

During the last decade, the European wind energy sector has grown from an annual energy capture of 23 TWh in 2000 to 177 TWh in 2010 [1]. A significant part of this production is land-based. However, over the last few years, the number of offshore wind farms is increasing. Important drivers for this include increased wind potential and environmental aspects [2].

The offshore commercial wind farms are, as of yet, constructed with bottom-fixed wind turbines. Depending on depth and soil conditions, various concepts are utilised, but most common is the monopile. However, at increasing depths, typically around 30 m, the monopile design reaches engineering limits with respect to pliable diameters and wall thicknesses. For deeper waters, the more expensive jacket foundation is a valid option. It is limited to depths of less than 50 m, not due to engineering limitations, but economic viability [3].

One may argue that the depth limitations for bottom-fixed turbines exclude the possibility to utilise the vast quantities of offshore wind resources. For deeper waters, one will need to approach different foundation concepts such as floating platforms. New concepts deployed in new territories may imply increased costs, but floating platforms may also at the same time offer beneficial aspects with respect to improved wind conditions, reduced wave loading, reduced installation cost and less visual impact.

The main barriers for installation of floating wind turbines are high capital- and operating expenditures (CAPEX, OPEX), but there has also been a lack of accurate simulation tools capable of analysing and optimising these complex systems. Nevertheless, increased offshore knowledge through experience with bottom-fixed turbines and recent development of simulation codes have led to the development of several different floating platforms.

The scope of this work is not to assess the mechanical properties and viability of each concept, but rather to investigate the LCOE of current state-of-the art offshore floating concepts. We assume deployment in a large-scale, both for the floating and bottom-fixed wind farms. We use the term 'floating' also for concepts where the floater elevation is given by the taut mooring system rather than the mean sea level, such as the TLS, TLP, TLWT and TLB.

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2. Approach

This work is based on the master thesis of Catho Bjerkseter and Anders Ågotnes [4], graduating summer 2013 at the University of Life Sciences, Norway. Their work consisted mainly in gathering data and the development of a computer tool to aid in the comparison of different floating offshore wind turbine concepts. A thorough review of their work has been conducted and the scope of this work is to present updated findings and results. Much of the same approach is employed; including the complex calculation methods, but with revised and updated values based on recent reviews and newly acquired experience. Some new features and boundary conditions are also included, in addition to a new concept.

There are several important parameters to consider when trying to determinate an optimal source for energy production. Local resources, national commitments, emissions and environmental impacts are all important. One may discuss the importance of each of these factors, but when considering large-scale deployment, a project is not likely to be completed if at an economic disadvantage. Thus, the cost of energy production should presumably be a dominant factor. The approach to obtain this cost of energy is similar to the one described in Ref. [4] and only the main important aspects and edited features will be presented in this work.

When considering the cost of energy, there are several perspectives and approaches to consider. OPEX and CAPEX are the main features examined to evaluate the economic potential of the project. These factors are often used for initial review of larger investment projects, but are not suited for distinguishing between several concepts with significant discrepancies concerning the mentioned features. This is especially apparent when evaluating capital-intensive projects that will accumulate the income over a longer period – much like the common offshore wind farm. When considering a wide time span, in example 20–30 years, quantification of the expenses in different phases of the project becomes important due to capital costs and risk placement. This is often referred to as a Life Cycle Cost Analysis (LCCA) or Cradle to Grave (CG) and is both a convenient way and widely used method to evaluate the potential economic performance [5,6].

For this work, an LCCA analysis will be conducted on each of the concepts. The LCCA is divided into five main phases, distinguished by the different operating conditions and capital intensity;

1. Development and consenting (D&C)
2. Production and acquisition (P&A)
3. Installation and commissioning (I&C)
4. Operation and maintenance (O&M)
5. Decommission (DECOM)

To increase the significance of the LCCA concerning concept comparison it is advisable to utilise a levelised cost in order to define a similar reference for value of money at different stages of a project. It is convenient to level the LCCA results by expected energy production. This allows for a better analysis and evaluation of risk and total cost during the life span is often referred to as a Levelised Cost of Energy (LCOE) Analysis. The similar reference value of money is obtained by discounting the costs to a given date[1] by the annuity method. Once obtained, the LCOE may be interpreted as the minimum unit price of energy and is a suitable variable in order to evaluate the performance of different concepts. The following equation is used to calculate the LCOE and is derived from Ref. [7]:

$$\mathrm{LCOE} = \frac{\sum_{t=0}^{n} \frac{I_t + M_t}{(I_0+r)^t}}{\sum_{t=0}^{n} \frac{E_t}{(I_0+r)^t}} \tag{1}$$

where I_t denotes investments at time t; M_t denotes operation and maintenance costs at time t; E_t denotes energy generation at time t; r denotes the evaluation discount rate; t denotes the time, ranging from zero to n.

The discount rate should reflect the market value of both equity and debt. In addition, project risk and return yield should be considered. This combination is often referred to as Weighted Average Cost of Capital (WACC). For this work, the WACC is set to a base case of 10%, with high- and low cases at 8% and 12%, respectively, in addition to an assumed inflation interest of 2.5%. Momentary values are stated in Euros and PV and converted to 2013-Euros (1st of January) before inflation by the Industrial Producer Price Index (PPI). No contingency is used in the analyses of the concepts.

Future cost reduction potential was not covered. The model was compared to existing literature, from both onshore [8,9] and offshore [10–12], in Ref. [4] and produced satisfying results. Additional comparison to Ref. [13] resulted in limited discrepancies, especially for the production cost estimations.

Six conceptually different floating concepts are investigated in this work. Variation in underlying conditions typically makes comparison difficult. Two bottom-fixed wind turbine setups are therefore included for increased value and comparability to similar work.

It is likely that the different concepts are under different stages of development, ranging from small prototypes to conceptual phase with full-scale deployment. In this analysis it is assumed that all the concepts are fully developed. Cost of development and scaling effects are included. Further, a reference case, consisting of 100 5 MW turbines localised in a 10 by 10 km grid with a sub-station in its centre, placed 200 km offshore is used as a benchmark. The reference case also features a given turbine tower and topside[2]. The reference turbine is rated at a power of 5 MW.

The calculation of steps one to three, in addition to step five, is handled internally by the developed simulation tool. Step 4, O&M is partially solved by utilising external software, in example the Operation and Maintenance Cost Estimator (OMCE-Calculator) developed by the Energy Research Centre of the Netherlands (ECN) (reference). This simulation tool computes the results prior to performing sensitivity analysis on high- and low scenarios to identify the main contributions to risk and uncertainty in each of the proposed concepts. This results in an optimised suggestion for which turbine concept that is the most suitable under given conditions when differentiated by LCOE.

3. The concepts

In total, nine different wind turbine concepts are investigated. The floating concepts consist of four spar concepts, a semi-submersible and a tri-floater. Ballast, displacement, mooring lines or a combination of these may stabilise a floating system. Floating systems become available in waters from 30 to 40 m and deeper.

[1] Also known as present value (PV).

[2] Refers to installation above tower level, usually interpreted as hub-height, and include nacelle, hub and rotor. Power electronics inside the turbine tower is also taken as included.

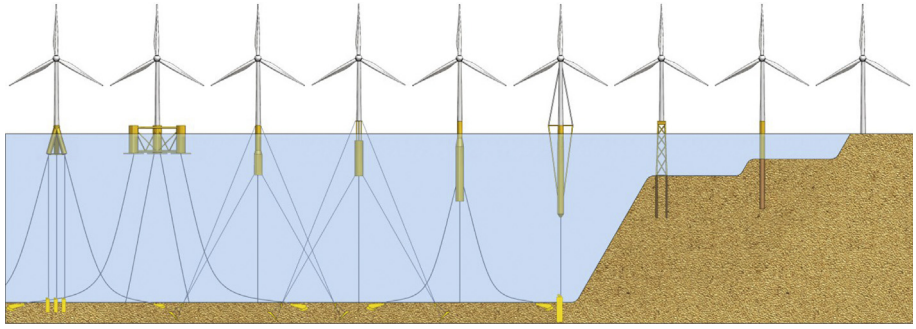

Fig. 1. Illustration of the different concepts, from left to right; TLWT, WindFloat, TLB B, TLB X3, Hywind II, SWAY, Jacket, Monopile and the onshore reference. The mooring systems are not to scale in the horizontal direction.

The bottom-fixed foundation concepts consist of a jacket, utilised at intermediate depths (30–50 m of water), and a monopile suitable for shallower water. All of the systems are illustrated in Fig. 1 and then explained briefly.

The conceptual Tension-Leg-Wind-Turbine (TLWT) utilised in this work achieves stability through displacement and mooring lines. It is developed by the International Design, Engineering and Analysis Service (I.D.E.A.S) [13] and in based on the Tension-Leg-Platform (TLP) system, a favoured solution in the offshore oil-sector. The TLP concept is well known for its performance, utilising vertical tendons to constraint motion along the vertical axis, and several similar concepts have been investigated [14]. However, the TLWT features a reviewed and optimised structure and spaced tri-floater sub-structure. The TLWT may utilise a set of three inclined tendons under specific conditions, but the setup used in this work features three vertical tendons held by suction anchors. A second catenary mooring system is used for horizontal station keeping and redundancy.

The WindFloat [15] system by Principle Power was successfully deployed with a full-scale 2 MW turbine off the coast of Portugal in late 2011. The prototype uses buoyancy for stabilisation, implying a complex and steel-intensive sub-structure with a mass of about 2500 tons, but the concept is favoured for its good towability.[3] A catenary mooring system of four mooring lines, comprising of both steel wire and chain, held by four Drag-Embedded Anchors (DEA), provide the station keeping.

The Tension-Leg-Buoy (TLB) systems benefit from a stabilising system consisting of six taut Dyneema fibre robes held by three Vertical Load Anchors (VLA). The high axial stiffness mooring lines are kept taut by excess buoyancy. The high stiffness results in minimal motion, comparable to or even less than for onshore turbines, but also increased mooring cost – especially for increased depths. TLB B and TLB X3 [16,17], developed at the University of Life Science in Norway, are based on the original works presented in Ref. [18]. The revised versions utilised in this work are derived from Ref. [16]. The reason for implementing two different TLB concepts is to identify if one can justify measures to reduce the wave loading on the structure in order to reduce the total load on the anchors. Not shown in Fig. 1 TLB X3 features a slim lattice transition piece, with an increased complexity factor, located in the wave action zone. In comparison, the TLB B utilise a more traditional conical transition. The total steel mass of the platform is about the same (445 and 521 tons respectively).

[3] Towability: A factor used to describe how easily a concept may be transported at sea. This factor will take into account the need for support vessels, impact of weather conditions, towing resistance and total draft under transportation.

The Hywind II system is an optimised version of the original Hywind system that has been operating off the coast of Norway since 2009. Data used for the Hywind II in the analysis is based on engineering work performed in Refs. [17,19,20] and personal communication with representatives from Statoil ASA [21]. The solution features proven technologies, but with a large mooring footprint with a three line catenary system similar to WindFloat, in addition to a relatively high sub-structure steel mass of about 1700 tons to accommodate ballast and sufficient stability.

In 2011, SWAY AS deployed a 1:6 scaled prototype of the coast of Norway. The SWAY concept features a tension-leg-spar (TLS) construction with one tendon attached to a suction anchor. Excess buoyancy ensures tension and acceptable motions for the downwind rotor assembly. There is no apparent transition from tower to floater, and the tower–floater construction is reinforced by an external wiring system. This allows for optimisation of the body to save materials resulting in a total steel mass of about 1100 tons for the supporting body [19,22].

The chosen bottom-fixed reference system is the well-known jacket structure developed in OC4, the follow up project of Offshore Code Comparison Collaboration (OC3) managed by the International Energy Agency (IEA) Wind Task 27 [23]. Typical jacket structures are complex and labour-intensive due to the lattice construction. It is suited for intermediate water depths, beyond the reach of monopiles.

The second bottom-fixed reference is the monopile. It is a simple design compared to the jacket substructure. The steel mass rises sharply for water depths beyond 30 m, affecting the costs and installation procedures. A simplified generic system based on several existing wind farms is developed to obtain an approximation of total substructure mass at a given depth.

4. Underlying conditions

To compute the LCOE for each of the concepts we split the common set of underlying conditions and boundaries into three

Table 1
Site assumptions for the reference wind farm.

Years of development	2013–2018
Year of commissioning	2018
Years of operation	20
Number of turbines	100
Installed capacity	500 MW
Water depth – floating concepts	200 m
Water depth – bottom-fixed concepts	30 m
Distance to port and grid connection	200 km
Average wind speed at hub height	10 m/s
Soil conditions	Homogenous medium clay

categories; 1) The general reference wind farm, 2) General resources and 3) Vessel specifications.

4.1. General reference wind farm assumptions

It is assumed that installation takes place on a large scale, and that a resourceful company with general offshore experience, able to handle the entire supply chain, rich in both capital and general offshore experience, will handle large parts of the supply chain and operate the wind farms when completed.

Assumptions in Table 1 are used to define the general reference wind farm. The location used is taken as a generic Northern European site. A Weibull probability distribution, derived from Ref. [24] and illustrated in figure 30 of Ref. [4] is utilised to quantify wind speed. Wave loading conditions, where appropriate, is based on the generalised site conditions for the northern parts of the North Atlantic described in Ref. [25].

The 5 MW reference turbine is derived from the well-known generic 5 MW offshore turbine developed by the National Renewable Energy Laboratory (NREL) [26]. A quantification of materials was performed by Raadal et al. [27]. The summarised results are shown in Table 2. The power production is assumed similar to the Repower 5 MW offshore turbine [28] in which the NREL-reference is partly based on and the Power Capacity Factor (PCF) is set to 53 ± 3% for the high- and low sensitivity.

Power output to the grid is substantially less than what one can expect from the capacity factor alone. This is due to several sources of loss, such as wake losses, losses in the power electronics and downtime. The resulting grid output factor is calculated to 44.0%, corresponding to 3859 annual hours of maximum load, based on the values displayed in Table 3, as discussed in Ref. [4], and often referred to as the net Load Factor (LF).

4.2. General resources

The overall consumed resources are simplified and quantified to steel- and fuel consumption as well as needed personnel and commodity resources. One of the main assumptions is that costs for the floater and tower structure can be calculated by evaluating the steel mass only as this covers the majority of the mass in the different structures. However, power electronics, electric cabling and mooring are added separately to the cost calculation.

Steel prices are volatile and vary greatly between countries, locations and other various factors. A base price of € 775 per ton for bulk steel is assumed. Adding to the complexity, there is a variety of different grades, quality and transport options. The base case price, including transport cost, is increased by € 225 per ton to account for Marine quality treated S355 quality steel. The resulting base price is set to € 1000 per ton, accordingly. To account for volatility, the high- and low scenarios are set to ±40%. [4].

During the recent years, bunker fuel cost has experienced as much as 100% fluctuation compared to the average baseline and should be considered as particular volatile. However, the overall fuel consumption cost is found low compared to the operating day-rates of the offshore vessels in question and thereby of less significance. Variation is thereby assumed included in the high- and low scenarios for the vessel costs. A flat fuel cost of € 640 per ton is therefore used in the analysis [4].

Offshore personnel is assumed to work 182.5 days per year with an annual cost of € 67k, resulting in day-rates of € 370 based on discussion in Ref. [4]. High- and low scenarios are set to ±8%.

Table 2
Properties for the generic 5 MW turbine.

Rotor diameter	126 m
Hub height	90 m
Rotor mass	110 tons (of which 54% steel)
Nacelle mass	240 tons (of which 82% steel)
Tower mass	250 tons (of which 93% steel)
Rated speed	11.4 m/s
Operational wind speed limits	3.5–30 m/s
Generator type	Double-fed, asynchronous, 6-pole

Table 3
Overview of the quantified losses to form LF based on the chosen PCF.

Wind farm availability	93.8%
Aerodynamic array losses (wake effects)	7.0%
Electrical array losses	1.8%
Other losses	3.0%

4.3. Vessel specification

Specific vessel costs are limited to vessels in direct use for the three last steps of the project, installation, O&M and decommission. Thus, vessels for weather surveys etc. are not quantified. Due to the contract-based nature of each stage, one distinguishes between installation- and service vessels and appropriate tables listing each category are displayed in Tables 4 and 5 respectively. Installation vessels are also assumed used for the decommission phase.

Additionally, crane vessels for larger maintenance work where larger turbine components are resupplied, Cable-laying vessels or AHTS vessels for cable maintenance, PSVs for component and helicopters for special transport are assumed to be used, but chartered at shorter contracts and are not evaluated as fixed costs [4].

5. Basis for life cycle cost analysis

LCA results for each given phase of the project are calculated before the LCOE approach is applied. Each phase has several quantifiable sub categories presented in Ref. [5]. This section will mainly present the results of the discussion and resulting values from Ref. [4]. Changes and reviewed evaluations will also be presented.

5.1. Development and consenting

The base case D&C was set to an averaged value of € 104,106k, with high- and low scenarios of +20% and −27%, respectively, for the reference wind farm of 500 MW. As there are no available data for deep offshore wind farms, the averaged values were derived from several sources of bottom-fixed sites and will thereby pose some uncertainty. Nevertheless, Fig. 2 shows the assumed distribution of costs for this initial phase.

Table 4
Approximate day-rates, in thousand €, of the different vessels suitable for installation purposes, including mean fuel consumption, excluding labour as discussed in Ref. [4].

Vessel type	Low-case	Reference base-case	High-case
Crane vessel	431	531	631
Inshore crane barge	45	55	65
Jack-up vessel	161	196	231
Anchor handling, tug and supply (AHTS)	81	91	101
Tug boat	16	17	18
Platform supply vessel (PSV)	43	46	49
Onshore mobile crane	5	6	7

Table 5
Annual fixed costs, in thousand of €, for maintenance vessels, including mean fuel consumption, excluding labour as discussed in Ref. [4].

Vessel type	Low-case	Reference base-case	High-case
Specialised maintenance vessel	1850	1900	1950
Mother vessel	12,800	13,100	13,500

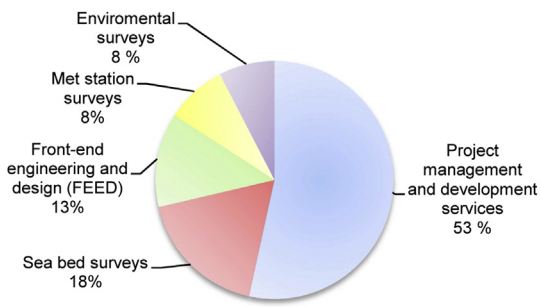

Fig. 2. Development and consenting cost breakdown for the 500 MW base-line farm [4].

For the sensitivity study, it is reasonable to assume that D&C is influenced by the number of turbines to be constructed. Fig. 3 illustrates the utilised cost to number of turbine dependency.

Contingencies are not included for this analysis as this is regarded more of a tool when taking the Final Investment Decision, rather than a basis for the LCOE. The contingency level will also be dependent on the available information. The quality of the available information is described through the sensitivity study and the high- and low scenarios that directly influence the LCOE. For lowered risk, a construction phase insurance is assumed to € 50k per MW based on estimations from Ref. [10]. High- and low scenarios are set to ±10%.

5.2. Production and acquisition

One of the major cost driving components is the turbine. An averaged value of € 7475k is used for the tower and the turbine combined. All of the concepts are in general assumed to use identical turbines and tower configurations. The exceptions are TLB X3, SWAY and the bottom-fixed concepts. The interface between floater and tower is 15 m above the water line for SWAY and 10 m for the other concepts. Correction for changes in zero level for the tower is made by volumetric interpolation with respect to height and is based on the reference turbine tower. The SWAY concept consists of a combined floater and tower. A reduced turbine cost of € 6405k, where the tower is deducted, is employed. High- and low scenarios are set to ±20%.

Table 6
Production cost estimates for the bottom-fixed substructures [4].

	Monopile	Jacket	
		Lattice structure	Piles
Material consumption [tons]	1200	510	315
Material cost [€]	1200k	510k	315k
Manufacturing complexity factor	100%	400%	100%
Manufacturing cost [€]	1200k	2040k	315k
Total production cost [€]	2400k	3180k	

5.2.1. Substructures

Substructures for the bottom-fixed reference systems are based on interpolation of available empirical data as it would require substantial efforts to design specific solutions for the different scenarios in this work. For monopiles, it is obvious that both depth and soil conditions influence the cost substantially. Scaling of available empirical data, with respect to turbine size, is solved by estimated peak thrust forces expected for the relevant rated power. Thus, reference values are all with 5 MW turbine size to obtain an equal reference scenario. The reference monopile-substructure is calculated to a mass of 1200 tons, including the transition piece. The reference jacket at 30 m is developed for the 5 MW turbine with a total mass of 825 tons, where of 510 tons is in the main lattice work and 315 tons is from piles. Costs for the secondary steel components and the transition piece for the jacket are not quantified, but assumed to be included through the complexity factor influencing the fabrication costs [4,29].

In this work, manufacturing costs are evaluated through a complexity factor and related to the bulk steel price. The value reflects not only the complexity with respect to fabrication, but how suitable the design is for mass production. Secondary elements and equipment are also to be included in this factor. Justification and evaluation of these factors for each of the concepts are thoroughly discussed in Ref. [4] and an overview is displayed in Tables 6 and 7. These tables also feature the assessed material masses per floating concept. The masses are results from computations, personal consultations, reverse engineering, experience or a combination of these [4]. It is not possible to disclose all of the material used in the evaluation, but it may be mentioned that no negative feedback has been received from the contacted stakeholders to indicate that any of the concepts are deviating from its specifications.

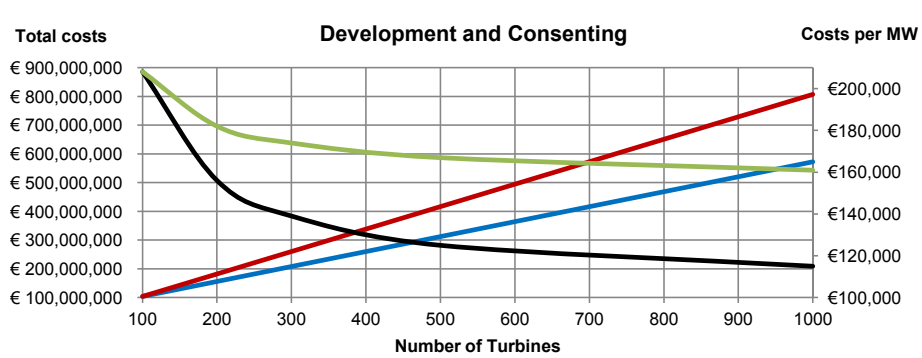

Fig. 3. Illustrating the dependency between farm size and D&C, where the total cost is shown in red (Bottom-fixed) and blue (Floating) (left *y*-axis) and cost per MW is shown in green (Bottom-fixed) and black (Floating) (right *y*-axis). (For interpretation of the references to colour in this figure legend, the reader is referred to the web version of this article.)

Table 7
Production cost estimates for the floating substructures [4].

	TLB B	TLB X3	Hywind II	WindFloat	SWAY	TLWT
Material consumption [tons]	445	521	1700	2500	1100	417
Material cost [€]	445k	521k	1700k	2500k	1100k	417k
Manufacturing complexity factor	110%	130%	120%	200%	150%	130%
Manufacturing cost [€]	489.5k	677.3k	2040k	5000k	1650k	542.1k
Total production cost [€]	934.5	1198.3k	3740k	7500k	2750k	959.1k

5.2.2. Mooring

The perspective of this work is large-scale deployment in soil conditions consisting of medium clay. This somewhat restricts the mooring options. For instance, for one-off constructions, dead-weight anchors may be container shaped and filled with scrap steel as a cheap alternative. This may be acquired at costs down to a tenth of the cost of a high capacity suction anchor. However, the sheer amount of scrap metal needed to moor a wind farm of more than 100 turbines, where the vertical holding capacity is in the range of 500–1000 tons per anchor, is unrealistic. Advanced anchor systems are therefore assumed for all of the concepts. The taut moored TLB concepts each utilise three Vryhof Stevmanta VLAs while the catenary systems of Hywind II and WindFloat make use of similar simpler DEAs of the Vryhof Stevshark type. The TLB X3 features approximately 10% less resulting anchor force compared to TLB B and is adjusted by linear interpolation. The redundant station-keeping system of the TLWT also uses a similar anchor technology. The vertical tendons of SWAY and the TLWT are held by high capacity suction anchors. All of the systems are further described and evaluated in Ref. [4] while the base case for mass estimation and cost is displayed in Table 8. High- and low values are ±25%.

Different mooring lines are utilised for each concept. All of the catenary mooring systems utilise a combination of steel wire and chain while SWAY uses a steel cylinder. Mooring line consumption is dependent not only on the number of anchors and mooring lines, but also depth. Calculating the respective mooring line lengths of the different systems is a complex operation. Thus, some simplifications are utilized. For instance, a linear approximation for growth in wall thickness of vertical tendons is assumed for SWAY. Cost is estimated by bulk price and a complexity factor of 150% ± 25% is used.

For the catenary systems, cost of the chain is approximated to € 250 and 126.5 kg/m at a diameter of 76 mm suitable for both Hywind II and the WindFloat. Correspondingly, a 6 × 41 strand steel wire with a diameter of 61 mm and a mass of 29 kg/m is utilised for these concepts. The estimated base cost of this wire is € 45 per meter. Vertical tendons for the TLWT are assumed of similar type for at a depth of 50 m and are increased linearly in order to maintain vertical stiffness with increasing depth.

Table 8
Baseline costs for the anchors utilised for each concept.

Concept	Type	Mass [tons]	Complexity	Count [n]	Total cost [€]
TLB B	Stevmanta VLA	40	870%	3	1042.5k
TLB X3	Stevmanta VLA	36	870%	3	938.4k
Hywind II	Stevshark Mk5	17	670%	3	342k
WindFloat	Stevshark Mk5	17	670%	4	456k
SWAY	Suction pile	140	1025%	1	1435k
TLWT – taut	Suction pile	50	1025%	3	1537.5k
TLWT – catenary	Stevpris Mk6	3	1833%	3	165k

Table 9
Calculated line lengths for the base case at 200 m depth.

Concept	Total line length [m]	Total line cost [€]
TLB B – upper fibre rope	956	433,987
TLB B – lower fibre rope	811	440,864
TLB X3 – upper fibre rope	956	421,031
TLB X3 – lower fibre rope	811	599,804
Hywind II – steel wire	1800	81,000
Hywind II – chain	150	37,500
WindFloat – steel wire	2640	118,800
WindFloat – chain	200	50,000
SWAY – steel cylinder	101	191,313
TLWT – vertical steel wire	528	35,505
TLWT – catenary steel wire	1980	44,550
TLWT – chain	150	18,750

The TLB systems make use of synthetic fibre ropes that are neutrally buoyant in water. Exponential approximation is utilised to estimate the cost per length of the fibre mooring ropes. The baseline cost per meter is estimated at € $91.681^{0.0113D}$ where D is the desired diameter and assumed applicable in a range of 90–300 mm. At 75 m the following line thickness is used for the upper and lower lines of TLB B and TLB X3 respectively; 0.1416, 0.1495, 0.1388 and 0.1754 m.

The reduced anchor loads for TLB X3 could indirectly lead to a lower mooring line cost, but at significant depths the minimum line stiffness due to eigen frequency requirements governs the line diameter. The TLB system is mainly dependent on the line axial stiffness, thus both the length and cross sectional area scale linearly with depth. The result is a quadratic increase in cost. For the catenary systems, maintaining the stiffness is not as important, and no scaling of the cross section is applied. However, calculating the necessary mooring line length to avoid anchor uplift complicates the calculations severely also for catenary systems. Some approximations are performed to achieve a realistic prediction of the mooring line length for all concepts as further explained in Ref. [4]. Total mooring line lengths and base case costs for the reference wind farm in 200 m of water are shown in Table 9. All high- and low cases for the mooring systems is set at ±25%. The total line length of the TLB system is calculated with a fixed angle of the upper mooring lines of 45°. An additional 25 m per line is added to account for the distance between the seabed and anchor. One may expect that the lower mooring lines would be reduced somewhat in size with increasing depth, due to an increasing vertical component, but this is not accounted for.

5.2.3. Grid connection

It is natural to distinguish between export cables and inter-array cables. The inter-array grid is divided into 20 strands, each accommodating 5 turbines with a 33 kV 300 mm^2 copper core conduction cable. The distance in the reference grid is 1 km between each turbine. Connecting inter-array cable lengths are assumed to be 1.4 km in length. To adjust for the operating water depth, this is added to the length. Based on the evaluation and grid description in Ref. [4] the base case inter array cable cost is set to € 281k/km with high- and low cases at ±15%. Total inter-array cable length for the base case of 100 turbines is approximated to 191.6 km, resulting in a maximal power loss of 0.68% with an average theoretical loss of 0.31%.

The export cables are substantially larger and more expensive than the inter-array cables. This analysis focus on larger distant offshore wind farms and Direct Current (DC) is arguably the better option. For the sensitivity study, the distance to shore is reduced, but Alternating Current (AC) transition will not be considered in order to maintain the overall scenario as argued in Ref. [4]. For the

Table 10
Estimated installation cost for monopile concept wind turbines [4].

Component	Operation	Count	Duration	Unit cost [€]	OW	Total cost [€]
Substructure installation	Quay-side lifts	2.00	0.13	196k	75%	65k
	Transportation	0.22	0.82		75%	47k
	Substructure installation	1.00	2.00		50%	784k
	Stationed personnel	30.0	2.95	370	52%	63k
Turbine installation	Quay-side lifts	1.00	0.17	196k	80%	42k
	Transportation	0.11	0.82		80%	22k
	Turbine installation	1.00	1.20		50%	470k
	Stationed personnel	30.0	2.19	370	54%	45k
Total installation cost per monopile wind turbine utilising a specialised jackup-vessel						1538k

Table 11
Estimated installation cost for jacket-type wind turbines [4].

Component	Operation	Count	Duration	Unit cost [€]	OW	Total cost [€]
Substructure installation	Quay-side lifts	2.00	0.13	196k	75%	65k
	Transportation	0.22	0.82		75%	47k
	Substructure installation	1.00	3.00		50%	1176k
	Stationed personnel	30.0	3.94	370	52%	84k
Turbine installation	Quay-side lifts	1.00	0.17	196k	80%	42k
	Transportation	0.11	0.82		80%	22k
	Turbine installation	1.00	1.20		50%	470k
	Stationed personnel	30.0	2.18	370	54%	45k
Total installation cost per jacket wind turbine utilising a specialised jackup-vessel						1951k

benchmark test, a single 320 kV 1500 mm^2 High-Voltage DC system is used with a baseline cost of € 443k/km. Appropriate cross sections and/or dual cables are chosen for the sensitivity analysis, depending on the optimal solution with respect to optimal values for the LCOE. High- and low values for grid cables are set to ±20%.

When using HVDC, the current is transformed from AC to DC in a substation. There is also a need for stepping up the current to a suitable voltage in order to minimise the losses, in this case from 33 kV of the inter array to the 320 kV in the export system. The total offshore substation cost for a 500 MW unit, not including installation, is approximated to € 143.0 M and € 161.7 M for bottom-fixed and floating wind farms, respectively, as discussed in Ref. [4]. The equivalent onshore recipient is added a cost of € 71.5 M regardless of concept. Where suitable, a 1000 MW unit with an estimated cost of € 235.6 M and € 271.7 M for bottom-fixed and floating solutions is applied, respectively.

5.3. Installation and commissioning

A thorough exploration of the economic aspects of several approaches to installation of the different wind turbine systems was performed in Ref. [4]. For this work, only the approach identified as the optimal solution for each concept will be commented. Wind farm commissioning costs, e.g. the costs associated with finalisation and testing of the wind farms, are assumed included in the presented results.

Table 12
Offshore OW and time consumption for components in the lifting strategies [4].

Component	Time consumption [h]	Maximum operational wind speed [m/s]	OW [%]
Individual rotor blade	4	8	43
Assembled rotor	5	8	43
Nacelle	4	10	58
Tower	6	12	59
Complete turbine	12	7	35

5.3.1. Bottom-fixed installation

The installation operation features a high-capacity jack-up vessel with 4 days of mobilisation time. 15 employees, working 12-h shifts, are assumed required to perform the installation, resulting in a total of 30 workers stationed on the vessel in addition to the vessel crew. Estimated total installation costs for both monopiles and jackets in the benchmark wind farms are shown in Tables 10 and 11, where number of operations, duration in days and Operational weather Windows (OW) are also shown. A vessel capacity of nine main turbine components, i.e. pile, substructure component[4] or turbines is assumed. Three hours per quay-side lift and a transit speed of 11 knots are also assumed.

5.3.2. Floating installation

Several horizontal transportation methods have been suggested to reduce the installation cost of offshore wind power. This includes horizontal transportation of the nacelle and the pre-joining of tower and nacelle [13,19]. It is not evaluated as this is still uncertain concepts and require turbine manufacturers to adapt the turbines significantly. Two main installation strategies were evaluated in Ref. [4]; 1) Assembly inshore, towing of complete turbine and 2) Towing of substructure and assembly offshore. Strategy 2 features both pre-joined turbines and a strategy where floater and tower is pre-joined, and only the turbine is installed offshore. The options of strategy 2 are denoted 2.1 and 2.2 respectively. The main strategies 1 and 2 are further expanded by evaluating five different lifting strategies for each of the components. Appropriate OWs for the components in the expanded set are shown in Tables 12 and 13.

[4] By substructure component it is referred to either pile, transition piece and jacket. The minor foundation piles for the jacket are taken as one substructure component.

Table 13
Concept-depending towing speed and OW for AHTS vessels. Similar assumptions are made for the TLB B, TLB X3 and the TLWT.

	TLB & TLWT		Hywind II		WindFloat		SWAY	
	Speed [knots]	OW [%]	Speed [knots]	OW [%]	Speed [knots]	OW [%]	Speed [knots]	OW [%]
Self-transport	15	90	15	90	15	90	15	90
Towing complete turbines	4.5	45	3	50	5	55	3.5	45
Towing pre-joined floater and turbine	5.4	50	4.2	55	6	65	3.9	60
Towing only floater horizontally	5.9	65	4.6	60	6.5	70		

The most economical viable option was chosen for each concept. Common assumptions for the analysis are the same as for the bottom-fixed concepts in addition to the following remarks:

1. Quay-side launch of floaters treated as one qua-side lift though with an OW of 80%
2. Up-ending of floaters take 12 h with 60% OW, applying to all concepts except WindFloat
3. One AHTS can tow either one complete turbine or two floaters
4. All towing operations are assisted by two tug boats
5. PSV transit speed is 18 knots with OW of 70% with a capacity of three turbines
6. Loading of solid ballast for Hywind II, SWAY and WindFloat is performed inshore by a minor crane vessel with an OW of 60%
7. In general inshore OW are increased by 20% compared to operations performed offshore
8. Time consumption to attach the mooring system is assumed to six hours per line, OW 55%
9. Four hours of mobilisation for the offshore crane vessel between turbines, OW 65%
10. Two hours of mobilisation for the inshore crane vessel between turbines, OW 75%

For all of the concepts, inshore assembly, and turbine assembly in two parts is advantageous. The two-part turbine lift is by complete tower and assembled nacelle with rotor. This implies that it is convenient to assemble most of the major parts on ground level, minimising lifts and the need for larger crane facilities. In general, offshore assembly of the turbines is three to four times more expensive than inshore assembly and towing of the complete structure. The total cost to mount the turbine on the TLB- and TLWT concepts is calculated to € 768k. For Hywind II, WindFloat and SWAY the corresponding cost is € 786k, € 644k and € 655k, respectively.

5.3.3. Mooring system installation

Logistical operation challenges concerning several vessels operating within the wind farm at the same time are not considered and anchors are assumed installed prior to the arrival of each turbine. Turbines are not allowed to share anchors in the economical model.

Anchors for both catenary- and taut mooring systems are installed by a sole AHTS. The detailed process of installing each specific anchor type is described in Ref. [4]. Key assumptions are as follows;

1. Eight hours of installation time for each of the DEA
2. Nine hours of installation time for each of the VLA
3. 12 h of installation time to place one suction anchor
4. 30 min per 100 m of depth is added to the installation time
5. AHTS available deck space for storage of anchors is 630 m^2
6. Available deck space is assumed to decrease by 1 unit per 100 m of depth
7. OW for transit is 75%, while anchor installation OW is set to 60%

One assumes that the DEA and VLA anchors are more suitable for stacking on deck than the cylindrical suction pile anchors. The suction anchors for the TLWT is somewhat smaller than the single large version used for SWAY. However, it also requires three smaller drag embedded anchors. For convenience, it is assumed that the occupied space of one small drag embedded anchor, in addition to the smaller suction pile, equals about half the space occupied by the larger suction pile fitted for SWAY. Further elaboration on the consumption of deck space for each anchor type is discussed in Ref. [4].

5.3.4. Electrical Infrastructure Installation

Electrical infrastructure is quantified in three sub sections; export cables, inter-array cables and the offshore substation. A single trenched export cable is assumed at the high- and low case cost estimations of € 354k/km to € 826k/km. Minimum distance to the wind farm in the sensitivity analysis is 100 km, hence no scale economics are either expected nor implemented in the analysis. The inter-array cables are set to a cost of € 190k/km with high- and low cases at ±10%.

The offshore substation installation is dependent on the choice of foundation. Base cost for the 500 MW units are approximated to € 23.8 M for bottom-fixed wind farms and € 18.6 M for floating, when assuming jacked- and WindFloat (semi-submersible) type foundations. The corresponding values for the 1000 MW unit are € 36.6 M and € 28.5 M, respectively. Assumptions for high- and low cases are discussed in Ref. [4].

5.4. Total capital expenditures

Total CAPEX results for the reference scenario is summarised in Fig. 4.

Total CAPEX for the bottom-fixed turbines in the reference scenario is € 1750–1875 M for the base case. This result is in line with existing generic sources, ranging from € 1800 to 1900 M [30–32]. However, these sources are for wind farms closer to shore than the reference scenarios used for this work, but may feature different interest rates and do also include contingencies, which are not included in this work. Thus, the analysis results seem reasonable with respect to the total CAPEX.

5.5. Operation and maintenance

Calculation and optimisation of O&M and downtime are performed using the OMCE-Calculator, and described in detail in Ref. [4]. One distinguishes between the floating- and bottom-fixed wind farms, but the foundation variation of each is not assumed to influence costs significantly and thereby not evaluated. Three types of O&M-strategies are used in the optimisation; 1) calendar based preventive, 2) condition based preventive and planned

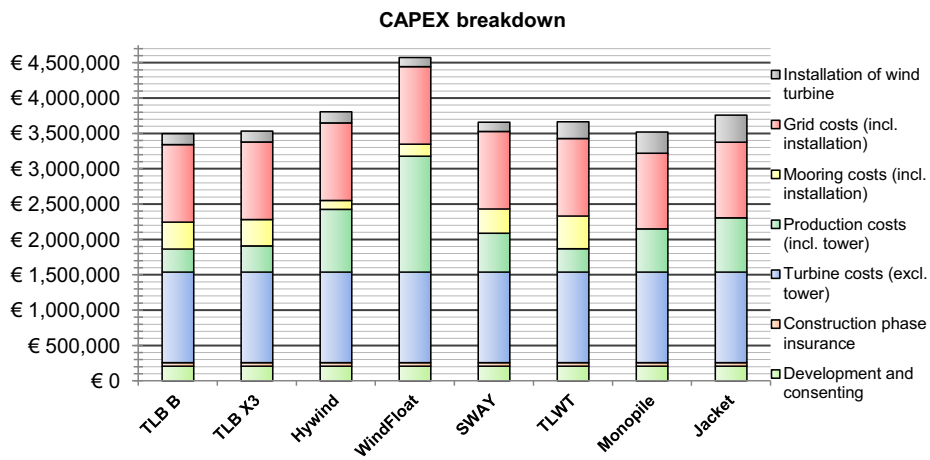

Fig. 4. Base case CAPEX quantification per MW for each concept in the reference scenario.

Table 14
Fixed annual labour cost for the benchmark wind farm [4].

Category	Number of employees	Fixed annual cost [€]	Total annual cost [€]
Offshore O&M technician	60	67k	4020k
Offshore O&M managers	2	118k	236k
Offshore O&M administrative	6	60k	360k
Onshore technical	3	50k	150k
Total annual	82		4766k

corrective, and 3) unplanned corrective. The OMCE-calculator implements opportunity based maintenance strategies.[5] The following assumptions were applied;

1) Annual maintenance of 24 h per turbine with three technicians assisted by small maintenance vessel. A larger preventive maintenance every 10 years is also assumed, requiring twice the time. In addition subsurface inspection every 3 years assisted by a diving vessel is required.
2) Condition based replacement of smaller components with predictable wear is expected to take eight hours by three technicians. Replacement of larger parts is assumed to take twice the resources.
3) All of the operations are expected performed at site. Minor incidents can be repaired without the assistance of a crane vessel, opposed to major repairs, which do. Corresponding expected repair time is 4 and 48 h with the aid of three and six technicians respectively.

The failure rate of subsea cables is expected to 0.1 per 100 km/year, resulting in a wind farm total availability of 97% and 0%, if either an inter-array- or export cable fails, respectively. Based on the results of the OMCE-Calculator, an average of about 870 events per year in category 1 is expected to occur for bottom-fixed and floating respectively. Categories 2 and 3 are independent of foundation and contribute 4 and 120 occurrences, respectively. The total downtime accounts for 54,082 and 58,070 h per year for floating and bottom-fixed wind farms respectively. The total corresponding availability is 93.8% and 93.4% and loss of power production is 143,621 and 155,585 MWh.

[5] Opportunity based maintenance allows maintenance in all categories on several turbines simultaneously, thus reducing the mobilization costs of external vessels.

Table 15
Decommissioning cost in relation to installation cost.

Description	% of installation cost
Complete wind turbine – floating	70
Complete wind turbine – bottom-fixed	80
Subsea cables	10
Substation	90
Mooring systems	90

Insurances for the operating phase are also added to the O&M costs. High- and low cases of € 15–20k/MW are chosen while the base case is set to € 17.5k/MW [4].

5.5.1. Personnel, accommodation and port facilities

This analysis features the choice of a mother vessel, operating within the wind farm through the operational phase. A team of 60 technicians and two managers, in addition to the vessel crew, work rotating shifts on fixed contracts to man the mother vessel. Shifts are 6:00 am to 6:00 pm and maintenance is only initiated if technicians can spend a minimum of 2 h on site. For peak workload scenarios, similar to when performing condition-based maintenance, one assumes additional crew at the rate of € 70 per hour. In addition, an onshore staff of six administrative personnel and three technicians is assumed for the benchmark wind farm. Estimated costs for the different personnel are shown in Table 14.

Short-term storage of supplies and crew accommodation is solved by the mother vessel, though additional port facilities are needed. This cost is assumed to € 2.3 M/year as described in Ref. [4] with high- and low cases at ±11%.

5.5.2. Vessel and equipment requirements

To maintain the offshore wind farm, the following assumptions are made;

Table 16
Distribution of CAPEX, in percent, with respect to year 0 of commissioning [4].

Phase	−4	−3	−2	−1	0	1
Development and consenting	56%	10%	11%	11%	12%	1%
Construction phase insurance	0%	25%	25%	25%	25%	0%
Turbine cost, excluding tower	0%	0%	19%	39%	42%	0%
Production cost, including tower	0%	0%	19%	39%	42%	0%
Mooring costs, including installation	0%	0%	0%	40%	60%	0%
Grid costs, including installation	0%	20%	75%	5%	0%	0%
Installation of wind turbine	0%	0%	0%	36%	64%	0%

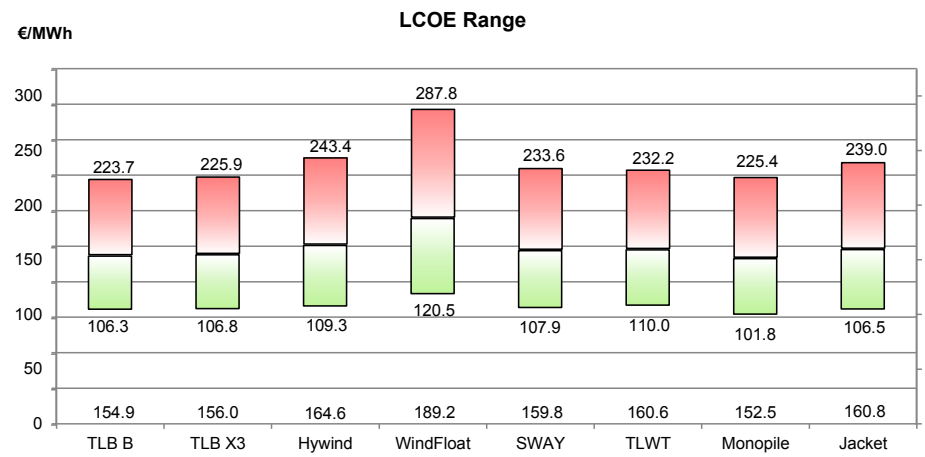

Fig. 5. LCOE for the reference wind farm for each of the concepts with indications on both best- and worst-case scenarios.

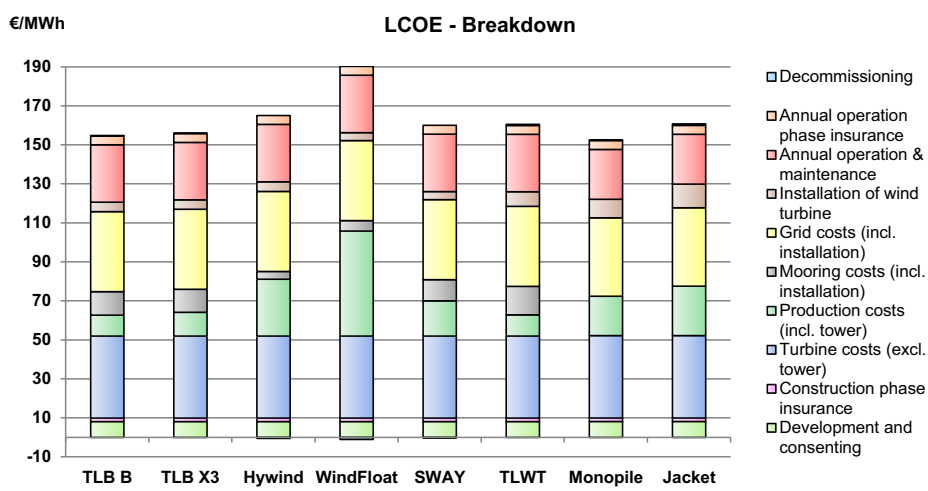

Fig. 6. LCOE cost breakdown for the base case of the reference case.

1. Two specialised maintenance vessels stationed on the mother vessel. Average travel time to turbine is set to one hour and the vessel is able to transport parts of up to 2 tons. Additional similar vessels are chartered, if required, to perform condition based maintenance.
2. Replacement of larger parts requires a larger crane vessel, assumed chartered on the spot market. A specialised maintenance vessel is assumed to assist the operation.
3. Repair of cables is performed by chartering a cable-laying vessel on the spot market. Preventive maintenance on cables is performed with an ATHS that features diving support and ROV.
4. Subsurface inspection and repairs are assumed performed by a diving support vessel chartered on the spot market.
5. Helicopter is chartered to transport technicians when required

The cost of the specialised maintenance vessels is assumed to have a base case price of € 1.9 M/year with ±2.4% as high- and low case. The larger crane vessels needed for maintenance operations is assumed to be somewhat smaller than the ones required for

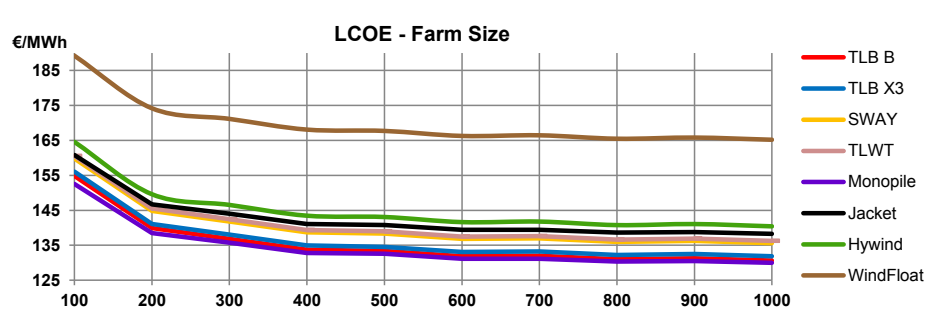

Fig. 7. LCOE changes with increasing number of turbines with the reference wind farm as basis.

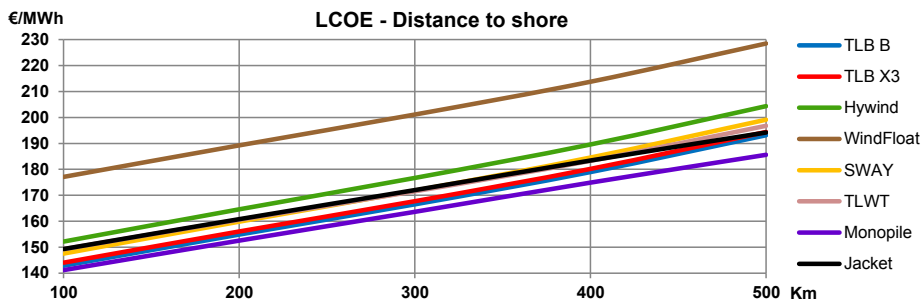

Fig. 8. Change in LCOE with respect to the distance to shore for the reference scenario with base case values.

installation. The cost is assumed to be € 196k/day and € 300k/day for jack-up and a floating crane vessel, respectively. One month of mobilisation is estimated for the larger maintenance vessels and the cost is set to four day-rates.

The total OPEX, including operation phase insurances, are calculated to € 131 and 115k/MW for the floating and bottom-fixed turbines, respectively. Vessel rates for unplanned maintenance seem to account for the majority of the difference. Jack-up vessels, used in the bottom-fixed wind farm, may be chartered for approximately two thirds of the day-rates of comparable floating cranes. The calculated values are somewhat higher than the € 45–50 M/year indicated in Refs. [30–32]. The difference is likely to be a result of the increased distance, influencing maintenance on the export cable, increased transport costs and the introduction of a mother vessel.

5.6. Decommissioning

To simplify the analysis, one assumes that the substructures are not reused, but rather recycled and sold for scrap. Cables are cut below the sea-bed and the remaining inter-connecting lengths are left. A reverse installation process is used to estimate the cost of bringing the components ashore. However it is assumed that this process can be performed simpler and faster. The matrix in Table 15 indicates the assumed decommissioning cost by comparison to the installation.

Linearization of the steel scrap price over the last 13 years result in an averaged estimation of 323.4 €/ton in 2013, and a linearized increase of 17.4 €/year is used to estimate the scrap value at the time of decommissioning. It is apparent that some of the more steel intensive structures may have a negative decommissioning cost.

6. Levelised cost of energy results

The LCOE results are based on the discounted values of CAPEX, OPEX and DECEX before being distributed relative to the energy generation. Additionally, ranges of the high- and low cases are presented. As mentioned earlier it was assumed that the final investment decision is to be taken in 2013 and the operating phase to start five years later, in 2018. CAPEX values are distributed according to Table 16, derived from Ref. [4], where year zero denotes the year of commissioning.

O&M costs are assumed evenly distributed over the 20 years of operation and DECEX are assumed to be distributed 100% at year 21 after commissioning. The following ranges, shown in Fig. 5, for LCOE can then be calculated for the reference wind farm, including the high- and low cases to indicate best- and worst-case scenarios.

For the reference wind farm, where bottom-fixed concepts at 30 m are compared to the floating concepts in 200 m of water, SWAY, TLWT and the TLB concepts are virtually at the same LCOE, considering the analysis accuracy. The large ranges of each high- and low case result in LCOE ranges that span beyond ±50% of the expected base case. Thus, the current spans are too large if one are to get a more reliable prediction to the final LCOE. A review of the high- and low cases is performed to identify which factors contribute the most to the uncertainties. The cost breakdown of the LCOE for the base case values in the reference wind farm is shown in Fig. 6.

The aim of this work was to differentiate the concepts, though a significant part of the breakdown indicates costs that are not concept dependent, such as turbine, grid and O&M.[6] This leaves the production, mooring and installation cost. The more expensive mooring systems of the TLB, TLWT and SWAY indicate similar cost as the installation of bottom-fixed systems. Basically, this implies that installation and production cost of floating concepts should be equal or lower than production cost of bottom-fixed in order to compete. Steel mass, being one of the major contributors to the production cost along with complexity, should therefore be minimised as one can notice for the concepts that are able to compete with the bottom fixed-concepts.

Decommissioning costs are relatively insignificant in perspective to the total LCOE. For Hywind, WindFloat and SWAY they reduce the LCOE as the scrap value outweighs the decommissioning cost and thereby shown in the lower end of the columns in Fig. 6.

It should be emphasised that this is for a site located far offshore which contribute significantly to increase the LCOE through increased grid costs. Further analyses on the sensitivities regarding the reference scenario are conducted in the following sections.

6.1. Farm Size

Fig. 7 shows that increasing the number of turbines to 200 would lower the LCOE by approximately 10% and that semi convergence is achieved from about 600 turbines, resulting in an LCOE reduction of 10–15%. The analysis resolution is per 100 turbines and shifts are observed with change in the utilisation and number of mother vessels and required chartering of vessels. In addition the configuration of substations(s) somewhat influence the result.

6.2. Offshore distance

An increasing distance to shore implies a nearly linear increase in LCOE as shown in Fig. 8. Slight shift in the trend is observed due to the change in transportation distance during installation and

[6] Distance to shore is excluded. In future work, one should strive to distinguish the concepts also with respect to O&M. It is likely that the different geometries will experience independent challenges with respect to availability, specific maintenance, fatigue on turbine, etc.

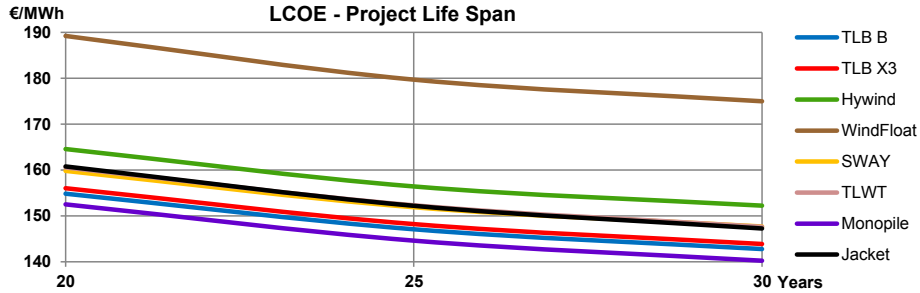

Fig. 9. LCOE changes with offshore distance for the reference scenario with base case values.

rotation of the labour force. Mobilisation times of chartered vessels are not affected by the change in distance. A minimum distance of 100 km is set to maintain a realistic perspective when assuming HVDC connection. The bottom-fixed concepts are less affected by the increasing distance as the installation vessels carry several turbines per trip while the floating concepts need to be towed individually.

6.3. Project life span

Based on the assumptions of this analysis, one expects to find an economical advantage with respect to LCOE when increasing the turbine lifetime to 30 years. The result is plotted in Fig. 9 and the analysis account for increased maintenance, but no increased turbine cost to accommodate the increased lifetime. A reduction is observed with increasing lifetime, though the effect is reduced when closing up to 30 years. The amount of increase in the wind turbine cost is uncertain, but not likely to outweigh the advantages of an increased lifetime to 25 years. When increasing the lifetime to 30 years, it is reasonable to assume that there will be no gain when accounting for the increased investment cost. It should also be noted that increased lifetime also increases the probability of severe weather conditions, which in turn may also influence the overall material consumption in the substructures. A more thorough assessment is necessary in order to evaluate if increased lifetime is beneficial.

6.4. Water depth

One of the parameters expected to distinguish the different floater concepts is the change in water depth and the corresponding changes of the mooring systems. Especially the TLB systems are sensitive to depth, as the effective stiffness at the fairleads and angle of the mooring lines have to be maintained. The results are shown in Fig. 10.

The catenary mooring systems produce an increased LCOE when moving into shallower waters as the mooring line length increases [4]. The mooring system of the TLWT should be more robust than the SWAY system as the depth increases. This is not showing in the analysis due to simplifications in the mooring system of SWAY. The dimensions of the mooring column for SWAY are not likely to be a result of maintaining the stiffness conditions, but also increasing loads. Another issue, not being addressed, is increasing installation complexity for SWAY as this rigid column increases in length and thickness. Using only stiffness determined mass growth by depth and no additional modification to installation cost is considered severely conservative, especially for increasing depths above 200 m.

When comparing with monopiles, the TLB systems are the only floating concepts being able to produce a competitive LCOE. The LCOE of the floating systems all increase with depth, but at a far slower rate than for the bottom-fixed systems. In general, concepts with low steel-mass perform the best in shallow depths, while concepts of larger steel mass become more optimal with increasing depths. This indicates positive trade-offs for more complex mooring systems in shallower waters in order to reduce total production cost.

Both TLB concepts, SWAY and the TLWT perform better than the comparable jacket concepts in waters below about 250 m. The Hywind system is also comparable, but at a slightly higher level before achieving an advantage in deeper waters of 4–500 m. Due to large steel mass and high production costs, the WindFloat concept is relatively expensive, but also experience minimal increase in cost with increasing depths. The TLB X3 system has 10% reduced anchor

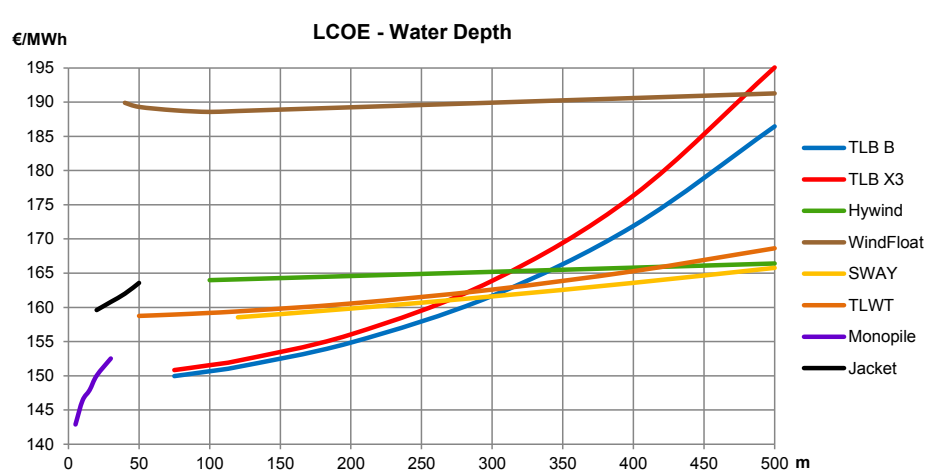

Fig. 10. LCOE changes with depth for the reference scenario with base case values.

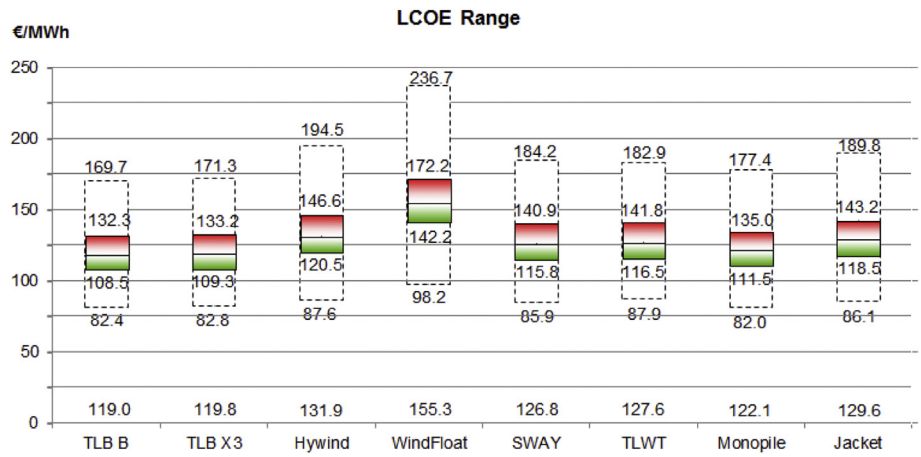

Fig. 11. LCOE for the optimised reference wind farm. All high- and low cases included (dotted lines), while the reduced intervals are shown in colour.

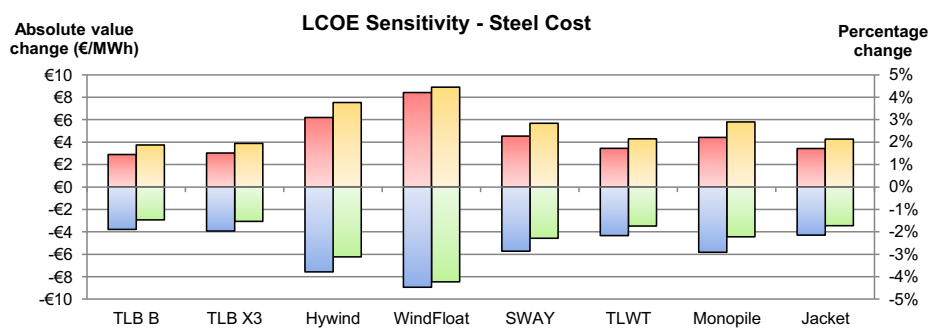

Fig. 12. Indicates influence of the high- and low cases of steel cost on each concept. Columns in yellow and blue are represented in percentage on the *y*-axis on the right side. (For interpretation of the references to colour in this figure legend, the reader is referred to the web version of this article.)

loads compared to TLB B. However, this does not reduce the mooring costs enough to accommodate the additional complexity featured by its space-frame section. Additionally, the TLB X3 demands somewhat higher mooring line stiffness as a result of reduced stiffness in the space-frame. Due to the scaling effects with depth to maintain the correct axial mooring line stiffness, the distance between LCOE of TLB B and TLB X3 increase with increasing depths.

6.5. Optimised results

The reference case is not particularly suitable to estimate the LCOE of wind energy. Optimised site conditions for each of the concepts are therefore utilised to better describe this, and to further quantify the sensitive cost contributors. An optimised reference wind farm is assumed, consisting of 300 turbines with 25 years lifetime and a location 100 km offshore. Monopile depth is 5 m, jacket depth is 20 m, while the TLWT, TLB systems, SWAY and catenary systems are located at depths of 50, 75, 120 and 100 m, respectively. The LCOE is lowered by 30–40%, compared to the base scenario, and is shown in Fig. 11. The following assumptions were made:

1. D&C, insurances, turbine cost, production cost, mooring system acquisition cost and electrical component costs are expected to be known, thus kept at base case level.
2. The high- and low cases of capacity factors and availability is reduced to ±1%
3. Short term vessel contracts can be acquired at fixed price, i.e. installation costs are fixed at base case values, while O&M- and decommission costs are unchanged

The monopoles and TLBs have the lowest costs. The differences up to the other concepts are small, considering the remaining uncertainty of roughly ±10%. Only a minor part of these are concept dependent, as shown when cost drivers are quantified further in the next section.

6.6. Quantified cost drivers

The results of the reference wind farm analyses indicate that the cost of the export cable is a major component of the LCOE. High- and low cases, altering the cost per meter, indicate a potential increase of about 6% or a reduction of about 13%. The overall vessel cost contributes surprisingly little, much due to the fact that the installation step contribute relatively little to the overall LCOE. High- and low cases result in changes of about 2–2.5% change in LCOE. The influence on steel cost is dependent on concept, where the steel intensive are more sensitive and shown in Fig. 12.

The overall influence of the steel price is still relatively low, at around 2% for the concepts with low steel mass. Figs. 13 and 14 show that the importance of accurate prediction of the load factor and the set discount rate sensitivities influence the LCOE in the range of about ±10% for the high- and low cases. The high- and low cases for Load Factor indicate a corresponding increase of 9.8–10.7% or a decrease of 7.3–7.9% of the LCOE. However, it is

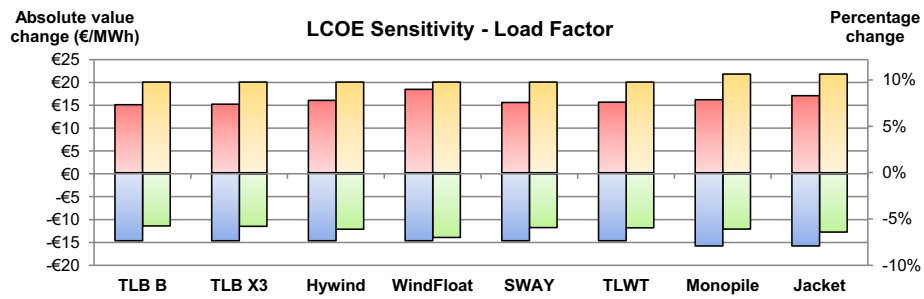

Fig. 13. Indicates influence of the high- and low cases for change in load factor on each concept. Columns in yellow and blue are represented in percentage values on the *y*-axis on the right side. (For interpretation of the references to colour in this figure legend, the reader is referred to the web version of this article.)

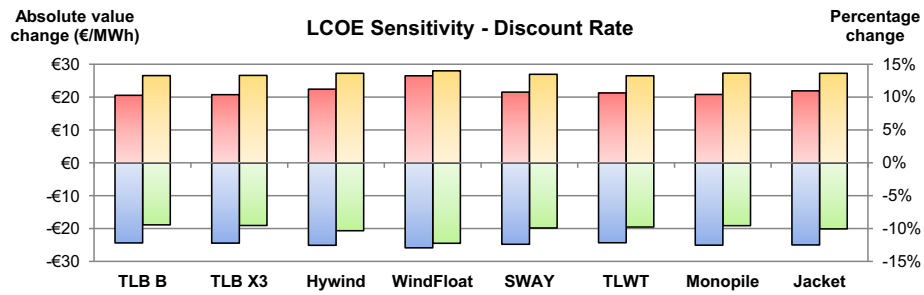

Fig. 14. Indicates influences of the high- and low cases for the discount rate of each concept. Columns in yellow and blue are represented in percentage values on the *y*-axis on the right side. (For interpretation of the references to colour in this figure legend, the reader is referred to the web version of this article.)

important to keep in mind that, the suggested high- and low cases for the load factor is based on both low quality supplier details and scarce weather information. In a realistic case, local weather surveys and detailed supplier contracts will reduce the variation considerably.

The discount rate is pre-set and in such terms not a subject of uncertainty. However, it is an interesting point that the initial high- and low cases of ±2% contribute with an increase of 13.3–14.0% or and decrease of 12.2–12.9% of the LCOE, making the capital intensive and long lifetime offshore wind farms sensitive to expected capital return.

7. Concluding remarks

The results indicate that energy from floating wind turbines, in comparison to bottom-fixed concepts, may be produced at equal or lower LCOE. Several key cost driving aspects have been identified for both bottom-fixed and floating wind farms. One can distinguish between site dependent and thereby predictable aspects and uncertain aspects. Of the predictable aspects, discount rate, distance from shore, farm size and depth is of the highest sensitivity to the LCOE. Of the more uncertain aspects, accuracy of load factor and variation in steel price is two of the main factors most influential to distinguish the foundation concepts.

Optimised conditions for all the concepts were identified. General aspects indicate that farm sizes of 400–500 turbines as close to shore as possible is beneficial. This is due to the fact that the sheer size allows for larger specialised support and maintenance vessels to operate solely in the wind farm. Based on the optimised results, one can also assume the optimal turbine concept for each water depth. The current findings indicate that the TLWT should be used in its deployable operating depth of 40 m and up to 75 m where the TLB systems can be installed. The increasing mooring costs with depth for the TLB system allow the TLWT and SWAY to be more cost effective solutions from about 300 m of depth. SWAY and the TLWT are comparable at all depths, but there are reasons to assume that the mooring costs of SWAY, especially for depths exceeding 200 m, to be optimistic.

In general, the concepts with the lowest steel mass have the best performance with respect to LCOE. This is also apparent with increasing depth, where the concepts of lowest mass reach optimum at an early stage, before a concept of larger mass takes over with increasing depth. This may indicate a trade-off between steel mass and mooring costs.

It is apparent that even if the lattice cross-section of TLB X3 reduces the anchor loads, there is no reduced cost for the mooring lines as they are determined by stiffness conditions rather than peak loads. Thus, there is no significant reduction in LCOE by initiating this measure. However, this may not be the case for a different site or turbine size, but indicates that the focus should be to reduce the demand for line axial stiffness in order to compete in deeper waters.

The overall performance of the analysis is robust, and the reference results for the bottom-fixed concepts are found in line with available literature. However, improvements are needed in order to further quantify anchor costs, and one should implement different mooring options and soil conditions. Further work is suggested on the implementation of cost saving potentials and scaling effects, especially for mass produced components like turbines, mooring lines and anchors. Further investigation is also suggested on effects such as turbine lifetime extension.

Additionally, further work should be considered in order to ensure that each of the compared concepts is optimised for equal weather and site conditions. This is especially important for the concepts of low steel mass, where small changes separate the results of each concept.

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