Applied Energy 221 (2018) 406–424

Contents lists available at ScienceDirect

Applied Energy

journal homepage: www.elsevier.com/locate/apenergy

# A lifecycle techno-economic model of offshore wind energy for different entry and exit instances

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## HIGHLIGHTS

- A lifecycle techno-economic model of an offshore wind farm is developed.
- Analytical consideration of OPEX linking latest reliability data to ECN O&M tool.
- Sensitivity analysis specified the most sensitive parameters on the investment NPV.
- The model was applied to different investor clusters in the wind energy market.
- Insights regarding potential minimum asking and maximum offered price are derived.

## ARTICLE INFO

*Keywords:*
Offshore wind
Techno-economic model
Lifecycle
Strategic investment decision support
Investor clusters
Entry and exit timing

## ABSTRACT

The offshore wind (OW) industry has reached reasonable maturity over the past decade and the European market currently consists of a diverse pool of investors. Often equity investors buy and sell stakes at different phases of the asset service life with a view to maximize their return on investment. A detailed assessment of the investment returns taking into account the technical parameters of the problem, is pertinent towards understanding the value of new and operational wind farms. This paper develops a high fidelity lifecycle techno-economic model, bringing together the most up-to-date data and parametric equations from databases and literature. Subsequently, based on a realistic case study of an OW farm in the UK, a sensitivity analysis is performed to test how input parameters influence the model output. Sensitivity analysis results highlight that the NPV is considerably sensitive to FinEX and revenue parameters, as well as to some OPEX parameters, i.e. the mean time to failure of the wind turbine components and the workboat significant wave height limit. Application of the model from the perspective of investors with different entry and exit timings derives the temporal return profiles, revealing important insights regarding the potential minimum asking and maximum offered price.

## 1. Introduction

With 92 wind farms in operation across European countries (including sites with partial grid-connected offshore wind (OW) turbines [1]), the OW market and supply chain have been rapidly expanding, attracting a diverse pool of investors that include Utilities, Original Equipment Manufacturers (OEMs), Independent Power Producers, Japanese Trading Houses, Pension Funds and Banks [2]. Broadly speaking, these investors can be segmented based on their attitude to risk (technology readiness level, track record, portfolio diversity, country, and asset phase), return expectations (Internal Rate of Return (IRR) and yield), holding length, and level of engagement [2,3].

Numerous authors have conducted research in the technical and economic feasibility of OW farms [4–9] and related innovative concepts [10,11], and the development of cost models for OW farms [12–15]. In [4], a feasibility study was performed for the development of an OW farm installed in the Northern Adriatic Sea, in order to test the suitability of the region for the development of the technology, while [9] refers to a feasibility study off the Turkish coast. Another study determining the profitability of an OW energy investment across different areas of Chile was performed in [8]. Kaiser and Snyder have developed models for the installation and decommissioning costs of offshore wind farms, based on existing data in European wind farms [13,16]. Myhr et al. developed a lifecycle cost model with the aim to predict the LCOE of a number of offshore floating wind turbine concepts and compare them with their fixed monopile counterparts [5]. One of their

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https://doi.org/10.1016/j.apenergy.2018.03.143
Received 9 November 2017; Received in revised form 15 March 2018; Accepted 28 March 2018

conclusion was that LCOE is particularly sensitive to the distance from shore, load factor and availability. Authors in [7] develop a methodology for the life-cycle costing of a floating OW farm and apply it to analyse a location in the North-West of Spain and indicate the best platform option. Dicorato et al. formulated a general model to evaluate the costs in pre-investment and investment stages of OW farms and then employed this method to indicate the most suitable wind farm layout [12]. A review of offshore wind cost components was performed by [17], summarising parametric expressions and data available in literature including the acquisition and installation of wind turbines and foundations, the electrical system, the predevelopment costs, etc. Shaffie et al. have also developed a parametric whole life cost model of offshore wind farms, which requires less input data in relation to other tools available [14], aiming to provide a simple framework for estimating the LCOE of the investment. Data were also trained in order to provide expressions for the estimation of the cost of materials used in a wind turbine, as well as the cost of the offshore substation. Finally, sensitivity analysis was performed in order to indicate the most impactful parameters of the model on LCOE.

Existing literature on the financial returns from renewable energy projects assumes that there is a single investor who owns the asset (e.g. the wind farm) throughout its entire service life [7,9,18,19]. However, recent research [3], as well as market reports [2,20,21] show that equity investors buy and sell their stakes at different phases of the OW farm life, depending on their investment strategy. To this end, a model that predicts returns over time could be useful for investors and policy makers to check the viability of the investment and to predict the temporal return profile of the investment. Additionally, the analytical consideration of the capital expenditure (CAPEX), operational expenditure (OPEX) and financial expenditure (FinEX) variables could contribute to the identification of input parameters that have the highest impact on the feasibility of the project.

This paper aims at addressing this challenge through developing a lifecycle techno-economic assessment framework for the prediction of lifecycle costs of OW farms, which incorporates up-to-date models for the estimation of key cost components, taking into consideration technical aspects associated with the installation and maintenance of the asset. The model developed takes into account the time that expenses occur as well as the time value of money. The high-fidelity model predicts the different costs of a typical OW farm in a lifecycle-phase-sequence pattern, by:

- adopting the most up-to-date parametric equations found in the literature;
- developing new parametric equations where latest data are available;
- including the use of industry standard ECN O&M Tool [22] for the prediction of operation and maintenance costs in conjunction with latest reliability data from [23].

Compared to existing literature related to the life-cycle cost assessment of OW farms, the novelty of this paper lies on, firstly, the consideration of different equity investors with different investment strategies that buy and sell stakes at different time instances during the life of an OW farm project and the development of a relevant tool that enables such investors to assess the viability of their investment [3]; secondly, the prediction of the maintenance cost of the OW farm by linking the latest reliability data published in literature to the industry standard ECN O&M tool, which can account for site specific details (such as the wind profile of the location which affects the available weather window for maintenance interventions); and, finally the derivation of cumulative cost and revenue curves which can reflect the temporal value of the asset, providing a decision support framework to investors and, deriving insights on expected upper and lower bounds for the OW farm price setting.

Although the focus of this study is placed on Europe and especially the UK, a country with significant technical resource [24], as well as a mature market with significant secondary sales activity, the proposed methodology can be applied to other country contexts (such as Japan, Korea and China which are regarded as significant emerging players in the OW market), provided the corresponding policy regime and cost adjustments (personnel cost, material costs, etc.) are taken into consideration. It, thus, needs to be highlighted that results should be treated with caution as input data have been adopted from wind farms mainly installed in North Europe, while no data currently exist for the USA or Asian offshore wind farms. Furthermore, for regions of Asia and the USA (where the frequency of hurricanes and typhoons is much higher than in Europe), existing design standards should also be potentially adjusted to ensure that extreme weather phenomena are properly accounted for.

## 2. Methodological approach

### 2.1. Investor profiles in the European offshore wind market

Within the existing market, there is a variety of investors with different investment strategies and appetite for risk. OW power plants are subject to a number of uncertainties of both technical and financial nature [25], which can be encountered across the whole life of the asset by means of variability in the energy performance, capital costs, operational costs, and economics of the LCOE model [26]. As such, during the predevelopment phase, investor faces uncertainties associated with the legal, environmental survey and project management costs, among others. During the procurement phase, there is uncertainty in the prediction of the cost of materials of the different components of the wind farm, while during construction, variability in the cost of labour, availability and cost of installation vessels, weather conditions, along with the duration of the installation operations induce additional risk in the evaluation of the investment. Damages to the wind turbines during the operation and maintenance phase result in uncertain repair costs and loss of revenues due to downtime. Finally, variability in the cost of capital can have a significant effect on the LCOE. Acknowledging above uncertainties within the OW energy sector [27], it becomes pertinent to identify means to systematically assess uncertainty with respect to service life valuation, hence supporting decisions of investors [28]. Each investor develops their bespoke assessment and valuation framework projecting revenues and costs, in order to decide effectively their potential entry and exit strategies.

An analysis [3] of investor strategies, based on data from existing OW farms in the UK indicated the existence of three distinct profiles: (i) Pre-commissioning investors, (ii) Build-Operate-Transfer investors, and (iii) Late entry investors.

Late entry investors comprise third party capital investors, who are investors seeking to contribute equity capital without having an involvement on the core activities of the asset, such as corporate investors, infrastructure funds and institutional investors. They undertake exclusively operational risks, entering after the commissioning of the wind farm, thus avoiding construction risks. This strategy is generally consistent with a low risk profile with stable returns. They principally purchase minority stakes in wind farm assets (mean value of 40.7%).

Pre-commissioning investors principally comprise independent energy companies, EPCI (Engineering, Procurement, Construction and Installation) contractors, and Original Equipment Manufacturers (OEMs). They can be considered as turnkey developers entering the venture at an early phase of its lifecycle to get involved in the construction and installation phase. Further, they tend to sell the majority (if not the entirety) of their stake and exit few years after the project is fully commissioned.

Finally, Build-Operate-Transfer investors comprise major utilities and independent power producers, who build and then keep the operating assets in their balance sheet. Further, they tend to divest part of their stake (minority stakes) during the operating phase of the asset.

Accurate prediction of the temporal returns profile of the investment is useful for the different types of investor clusters to conduct the techno-economic assessment of the asset during the specific year of purchase or divestment. To this end, a parametric life cycle techno-economic model was developed to accommodate the different investor

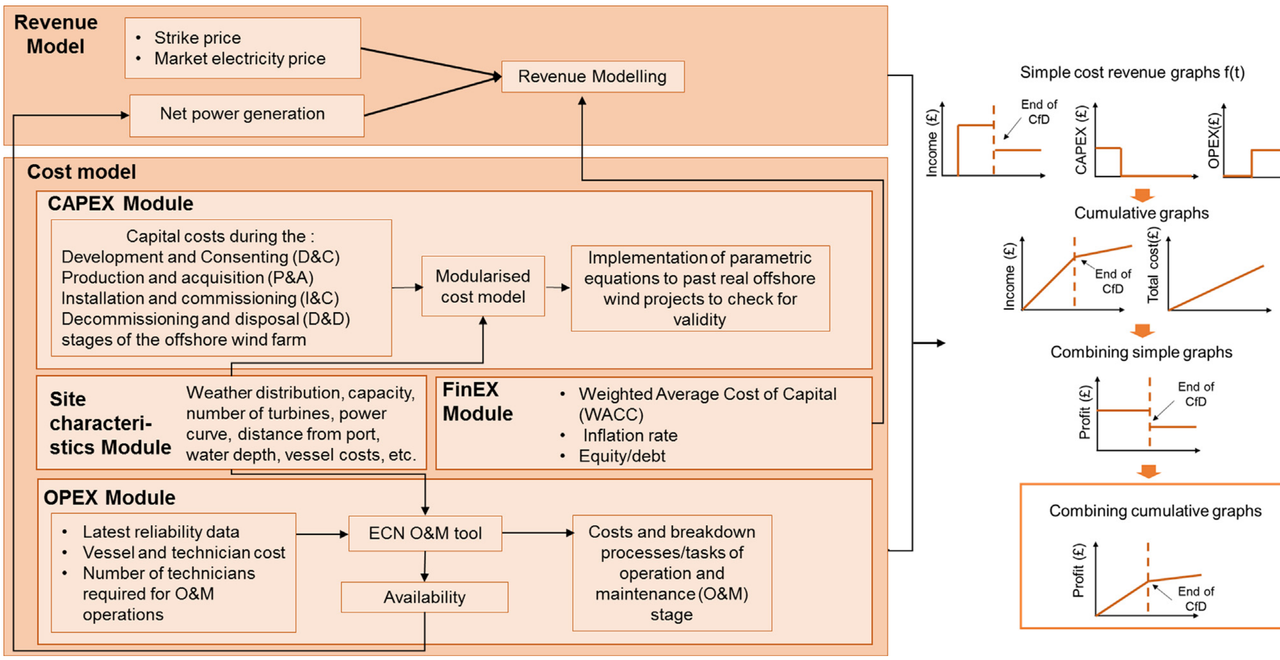


**Fig. 1.** Methodological framework.

strategies with the view to identify temporal return profiles of the asset.

### *2.2. Overview of the developed techno-economic model for the valuation of an offshore wind energy project*

In this section, the different components or programming modules of the techno-economic model of the OW energy farm are presented. The 5 main phases of an OW farm project considered are: Development and Consenting (D&C), Production and Acquisition (P&A), Installation and Commissioning (I&C), Operation and Maintenance (O&M) and Decommissioning and Disposal (D&D).

The methodological approach followed in this paper consists of the modules illustrated in Fig. 1, namely: (i) the CAPEX module, which includes costs during the D&C, P&A, I&C and D&D phases of the OW farm, (ii) the general site characteristics module with details on the weather conditions, site water depth, distance from port, vessels, cost of personnel etc., (iii) the FinEx module with parameters related to the financing expenditures, namely the Weighted Average Cost of Capital (WACC), inflation rate, equity and debt ratio, etc., (iv) the OPEX module considering reliability data from literature, cost of personnel, materials, vessels and related maintenance processes, which will provide availability, and O&M cost estimates pertinent for the cost analysis and (v) the revenue module, which considers the net power generation, the energy policy scheme in place for supporting the technology, namely the Contracts for difference (CfD) scheme, and the market electricity price (the scheme mandates that revenues are calculated on the basis of the strike price during the first 15 years of operation of the asset and the market electricity price over the rest of its life) to derive the revenues yielded by the investment. Outputs of the model are temporal cumulative return profiles of the investment, which can support the appraisal of investment opportunities for different types of investors in various periods of a wind farm service life, taking into account the technical parameters of the problem.

## 3. Case study site characteristics, weather, vessel and personnel data

This section outlines the assumptions and characteristics of the reference wind farm, corresponding to a realistic OW farm in the UK. It also compiles data that apply to multiple phases of the lifespan of the asset, such as the specifications of vessels and the cost of personnel. Key assumptions of the wind farm site are included in Table 1. The 504 MW capacity wind farm is located in the North Sea region, 36 km away from shore. Weather data (3-hourly data over a 3-year period) were retrieved from BTM ARGOSS [29] for modelling the operational phase of the asset. Weather delays during the I&C and the D&D phases were modelled by the use of an adjustment factor (*ADJWEATHER*), which will be described in more detail in Section 4.1.3. A wind farm of approximately 500 MW capacity was considered a reasonable selection, since there is a number of studies that has considered the same wind farm capacity in their baseline scenario, such as [5,14], which could facilitate comparison of results.

### *3.1. Vessel data*

Vessel data encompass the cost (and key characteristics) of vessels chartered for carrying out the I&C, O&M and D&D phases of the project. The specifications of the vessels (for instance, speed, day rates and mobilisation costs) employed for the completion of above phases are integrated in Table 2, while further data regarding the number and the type of vessels used per phase and task is clarified in the respective Sections of the paper. The wind speeds are referenced at 10 m above the mean water level, while the mobilisation and demobilisation activities comprise the

**Table 1**
Case study wind farm specifications.

| Wind farm characteristics | | Values |
|---|---|---|
| Wind farm | Total wind farm capacity, $P_{WT}$ | 504 MW |
| | Projected operational life of the wind farm, $n$ | 25 years |
| | Construction years, $T_{constr}$ | 5 years |
| | Number of turbines, $n_{WT}$ | 140 |
| General Site characteristics | Distance to port, $D$ | 36 km |
| | Water depth, $WD$ | 26 m |
| Wind turbine | Rotor diameter, $d$ | 107 m |
| | Hub height, $h$ | 77.5 m |
| | Pile diameter, $D_{pile}$ | 6 m |
| | Rated power | 3.60 MW |
| | Cut-in speed | 4 m/s |
| | Cut-out speed | 25 m/s |

**Table 2**
General data for O&M vessels and transportation equipment.

| Vessel type | Technician space | Vessel speed (knots) | Weather limits | | Mob./demob. Cost (k£) | Mob./demob. Time (h) | Day rate (k£/day) |
|---|---|---|---|---|---|---|---|
| | | | Sign. wave height (m) | Wind speed (m/s) | | | |
| Crew transfer vessel[i] | 12 | 26 | 1.8[iii] | 16[iii] | – | – | 3.25[ii] |
| Jack-up vessels[iii] | – | 10[iv] | 2 | 10 | 405 | 720/48 | 112.6 |
| Heavy lift vessel[vi] | – | 9 | – | – | 500[ix] | – | 135 |
| Helicopter[v] | 6 | – | 99 | 20 | 4.7 | 8/4 | 4.7 |
| Diving support vessel (DSV)[iii] | – | 16 | 2 | 25 | 185 | 360[v] | 60 |
| Cable laying vessel [iii] | – | 14 | 1 | 10 | 445[iii] | 720[v] | 80 (Array), 100 (Export) |
| Rock dumping vessel | – | 13.5[vii] | – | – | 10.6[viii] | – | 13.8[viii] |

[i] Source: [30].
[ii] Source: [31].
[iii] Source: [32].
[iv] Source: [33].
[v] Source: [22].
[vi] Source: [13].
[vii] Source: [34].
[viii] Source: [35].
[ix] Source: [36].

**Table 3**
Cost breakdown of P&C costs.

| Cost components | Total cost (£ million) | Percentage over total P&C cost (%) |
|---|---|---|
| Legal costs, $C_{legal,pc}$ | 16.7 | 8.1% |
| Environmental survey costs, $C_{surveys,pc}$ | 19.2 | 9.3% |
| Engineering costs, $C_{eng,pc}$ | 1.14 | 0.6% |
| Contingency costs, $C_{cont,pc}$ | 126.4 | 61.4% |
| Project management cost, $C_{proj,pc}$ | 42.3 | 20.6% |

cost and time allocated to the planning, preparing and modifying a vessel for a marine operation (mobilisation), and then to restoring it for release and reassignment to other operations (demobilisation).

### 3.2. Personnel cost

Apart from the vessel crew, additional personnel is hired to perform mechanical/electrical operations for the installation, erection and other services at a rate of £270/day [5,37]. Offshore personnel works on a shift pattern of 2 weeks "on" followed by 2 weeks "off" according to working time regulations for offshore workers [38]. Finally, a total of 12 working hours per day is assumed [5].

## 4. Integrated techno-economic model

### 4.1. CAPEX module

As previously mentioned, the CAPEX module includes costs during the D&C, P&A, I&C and D&D phases of the OW farm, which are further analysed in the following Sections.

#### 4.1.1. Development and consenting phase (D&C)

Development and consenting costs include all costs prior to the point of financial close (i.e. the point when all financing agreements of the project have been signed and the conditions have been met) including project management, surveys (environmental, coastal process, Met station, sea bed, human impact), legal authorisation, front-end engineering and design and contingency costs [14,39]. Costs during D&C of the wind farm vary significantly across different sites; thus, different values of costs can be found in literature. Indicatively, in [39] a total of £60 million for a 500 MW wind farm is reported, while in [14] costs were estimated £202.8 million for a wind farm of the same capacity. Myhr et al. [5] assumed a cost of £89.9 million/500 MW, while in [40] a total cost of £156.5 million/500 MW was estimated, when adjusted to the respective currency and inflation rate. In the examined case study with the total windfarm capacity of 504 MW, the cost breakdown of [14] is adopted as shown in Table 3, as a more conservative scenario.

#### 4.1.2. Production and acquisition phase (P&A)

*4.1.2.1. Wind turbines*. The acquisition of a fully equipped turbine is one of the most expensive cost components of the P&A phase of the wind farm. Cost is usually expressed as a function of the turbine capacity and different parametric models have been developed to predict the cost of different sizes of turbines [11,12,15,17]. Within the context of the reference case study, the following expression has been formulated for the estimation of the wind turbine cost [14]:

$$c_{T,pa} = 3{\cdot}10^6 \ln(P_{WT}) - 662{,}400, \text{in £/turbine} \tag{1}$$

where, $P_{WT}$ is the capacity of the wind turbine (MW). For a wind turbine of 3.6 MW, Eq. (1) results to £3.1804 million/turbine, while by adding the tower cost into the total turbine costs (which according to [39] is of the order of £1 million for a 5 MW turbine), total cost for the acquisition of the turbine and the tower accounts for approximately £3.90 million/turbine.

*4.1.2.2. Foundations*. A monopile configuration was assumed for the reference case study as it remains the most popular substructure up to date with a cumulative amount of 87% of all installed foundations in 2017 [1]. The cost of foundation depends largely on the type of foundation, the depth of the site, the seabed characteristics as well as, to a lesser extent, the turbine capacity, the wave and wind conditions [17]. The cost of foundation, $c_{F,pa}$, was estimated by means of a parametric expression linking the foundation cost to the turbine geometry (hub height, h and rotor diameter, $d$) and the water depth (WD) according to [41]:

$$c_{F,pa} = 320{,}000{\cdot}P_{WT}{\cdot}(1 + 0.02{\cdot}(WD-8)){\cdot}\left(1 + 8{\cdot}10^{-7}{\cdot}\left(h{\cdot}\left(\left(\frac{d}{2}\right)^2 - 100{,}000\right)\right)\right) \tag{2}$$

Application of the above expression to the reference case study resulted in £1.52 million/foundation. Other parametric expressions, found in the literature, link foundation cost with water depth, turbine capacity, as well as cost of material usage and fabrication [5,12,17]. For example, application of [17] to the baseline case study gives £1.14 million/foundation.

*4.1.2.3. Transmission system.* The transmission system of the wind farm consists of: the collection system of the generated power by means of array cables, the integration of the power through an offshore substation, the transmission of the electricity from the offshore substation to shore through the export cables. Two kinds of export cables are distinguished: the offshore export cables transmit the electricity from the offshore substation to the onshore substation, and the onshore export cable which transport the power to the grid connection point.

*4.1.2.3.1. Cables.* Array cables organise turbines in clusters adopting various different grid schemes, such as the radial design according to which, turbines of each cluster are interconnected in a 'string' ending at an offshore substation.

Mean Voltage (MV) submarine cables are most frequently used as array cables, while High Voltage (HV) export cables carry the stepped up voltage from the offshore substation to the grid connection point. MV cable unit costs, similarly to HV cable unit costs vary according to the cable section (i.e. data summarised in Table 4) and nominal voltage (as shown in [12]).

Export cables can be either high-voltage alternating current (HVAC) or high-voltage direct current (HVDC) depending on a number of factors and especially the distance from shore. Generally, if the distance from shore is less than 50 km, AC cables would be preferred while for longer distances and in more remote wind farms, DC cables are used since HVDC cabling has no reactive power requirements resulting in lower power losses [40,43].

In general, the total cost of the cables, $C_{cables,pa}$, is calculated by the product of the unit-length price of the cable, $c_i$ (£/m), with the number of cables, $N_i$, and the average length of each cable, $L_i$ (km). Protective equipment (such as J-tube seals, passive seals, bend restrictors etc.) is required to protect the cables [14].

$$C_{cables,pa} = \sum_{i=1}^{3} (c_i \cdot L_i \cdot N_i) + C_{protection}, \text{in £} \quad (3)$$

where, $i$ denotes the cable type of the wind farm, namely: the MV array cables ($i = 1$), the HV subsea export cables ($i = 2$) and the HV onshore export cables ($i = 3$).

Retrieving data from 4C Offshore [44], a linear equation with two predictors namely, the number of wind turbines, $n_{WT}$ and the rotor diameter $d$ (in m) was produced as follows:

$$L_1 = 1.125 \cdot n_{WT} + 1.055 \cdot d - 122.64 \, (R^2 = 0.959), \text{in km} \quad (4)$$

The length of the subsea export cable, $L_2$, is assumed equal to the distance between the centre of the OW farm (where the offshore substation is located) and the shore (where an onshore substation is located), an assumption also taken in [45], which for the baseline case study is 36 km. Finally, the length of the onshore export cable, $L_3$, is equal to the distance from the onshore substation to the grid connection point (assumed to be 10 km long each). The electrical system is comprised of 33 kV array cables and two offshore substations of 336 MW HVAC transmission system. Further, the transmission assets are connected to the onshore substation by three 800 mm$^2$ 132 kV subsea export cables. The resulting costs of the electric system are summarised in Table 5.

**Table 4**
Unit costs of AC submarine cables from companies A and B.
Source: [42].

| Conductor size (mm$^2$) | 95 | 150 | 400 | 630 | 800 |
|---|---|---|---|---|---|
| | *Collection system unit cost (£/m)* | | | | |
| Company A | 142 | 213 | 356 | 534 | 561 |
| Company B | 426 | 462 | 570 | 594 | 684 |
| | *Transmission system (£/m)* | | | | |
| Company A | | | | 706 | |
| Company B | | | | 805 | |

**Table 5**
Electric system cost components.

| Cost component | Total cost (k£) | Total length of cables (km) |
|---|---|---|
| Array cables | 28,039 | 147.7 |
| Offshore export cables | 84,002 | 108 |
| Onshore export cables | 7,778 | 30 |
| Offshore substation (x2), $C_{off,subst,pa}$ | 121,340 | – |
| Onshore substation, $C_{on,subst,pa}$ | 30,334 | – |

*4.1.2.3.2. Substations.* The most cost efficient electric power transmission method to reduce cable losses is by means of an offshore substation, which is considered appropriate for projects located at a distance of > 20 km offshore [40]. The total offshore substation cost has been estimated by a number of authors [14,17] who derived parametric expressions linking the offshore substation cost to the total installed capacity of the wind farm. In the present study, the offshore substation cost, $C_{offSubst,pa}$, was estimated based on [12], which breaks down the cost of offshore substation to: (1) the MV/HV transformer cost, $C_{TR}$, (2) MV switchgear cost, $C_{SG,MV}$, (3) HV switchgear cost, $C_{SG,HV}$, (4) HV busbar cost, $c_{BB}$, (5) Diesel generator cost, $C_{DG}$ to supply essential equipment when the OW farm is off, and (6) substation platform cost, $C_{offSubst,pa_f}$. The expressions of the individual cost components are the following:

$$C_{TR} = n_{TR} \cdot (42.688 \cdot A_{TR}^{0.7513}) \quad (5)$$

$$C_{SG,MV} = 40.543 + 0.76 \cdot V_n \quad (6)$$

$$C_{DG} = 21.242 + 2.069 \cdot P_{WF} \quad (7)$$

$$C_{offSubst,pa_f} = 2534 + 88.7 \cdot P_{WF} \quad (8)$$

$$C_{offSubst,pa} = C_{TR} + C_{SG,MV} + n_{TR} \cdot (2 \cdot c_{SG,HV} + c_{BB}) + (C_{DG} + C_{offSubst,pa_f}) \quad (9)$$

where, $n_{TR}$ is the number of transformers, $V_n$ is the nominal voltage and $A_{TR}$ is the rated power of the transformers. Using Eq. (5)–(9) the total cost of offshore substation was calculated £60.67 million. In the context of the case study, 2 offshore substations are assumed to be placed in order to transmit the power at 132 kV. Platform 1 contains three transformers each rated 180 MVA, while Platform 3 has two 90 MVA transformers installed. Finally, the export cables connect the offshore substations with an onshore substation which further transforms power to grid voltage (e.g. 400 MW). Onshore substation cost was assumed to be half the cost of the offshore substation according to [14,39].

*4.1.2.4. Control system.* More recent wind farms have integrated supervisory control (including health monitoring) and data acquisition (SCADA) systems, with the view to optimise wind turbine life and revenue generation [39]. Health monitoring of wind turbines is performed by means of sensors and control devices, gathering data that can be used for optimising operation and maintenance operations. Cost of monitoring was estimated $C_{SCADA,pa}$ = 75 k£/turbine [12].

*4.1.3. Installation and commission phase (I&C)*

This phase refers to all activities involving the transportation and installation of the wind farm components, as well as those related to the port, commissioning of the wind farm and insurance during construction.

Once a suitable number of components are in the staging area, the offshore construction starts with installation of the foundations, transition piece and scour protection, followed by the erection of the tower and the wind turbines. Accordingly, the installation of the offshore substation, the array cables and finally the export cables and onshore substation takes place.

*4.1.3.1. Foundation and wind turbine installation.* Installation costs are a function of the vessel day rates, the usage duration and the personnel costs required for carrying out the operations. Vital components of both the wind turbine and the foundation installation cost are the vessel day rates and the duration of the installation processes. The total time per trip of an installation vessel is broken down to: the travel time, the loading time, the installation time and the intra-field movement time.

For the installation of monopiles a jack-up vessel can be employed with an assumed deck capacity of $VC_{F,JU} = 4$ foundations. After foundations are secured, the transition pieces are lifted and placed on the top of the foundation pile and are then grouted. In the context of the present case study, it is assumed that the installation of monopiles and the placement of transition piece can be realised by the same vessel.

The total installation time of foundations was estimated by the following expression:

$$T_{F,Instal} = 2{\cdot}N_{F,voy}{\cdot}T_{j,port} + 2{\cdot}n_{WT}{\cdot}T_{j,site} + n_{WT}{\cdot}T_{F,Load} + T_{porttofarm} + T_{betwtrb,F} + n_{WT}{\cdot}T_{F,Lift} \quad (10)$$

where, $N_{F,voy}$ is the number of voyages, $T_{j,port}$ is the time of jacking at port (up/down), $n_{WT}$ is the number of turbines, $T_{j,site}$ denotes the time of jacking at installation site, $T_{F,Load}$ denotes the monopile foundation loading time, $T_{porttofarm}$ is the travel time from port to farm, $T_{betwtrb,F}$ represents the time to travel between turbines, and $T_{F,Lift}$ is the offshore lift/installation time of the monopile. More details on the calculation steps for the estimation of the foundation installation cost are included in Appendix A.

Turbines are installed after foundations have been placed. The vessel used both transports turbines in the installation site and performs installation. Turbines typically consist of seven components, namely nacelle, hub, 3 blades, and 2 tower sections. Onshore assembly of some of the parts of the OWT is usually performed in order to reduce lifts offshore, which can be considered risky and prone to cause delays due to wind speeds. The installation process of OW turbines is composed by the following time steps: 1. Travel/transportation time, 2. Lifting operation time, 3. Assembly operation time (onshore and offshore), and 4. Jacking up operation time. The pre-assembly (i.e. onshore assembly) strategy followed determines the total time of turbine installation, along with the distance from the port, the number of turbines, the nameplate capacity, etc. Characteristics of different pre-assembly methods are summarised in Table 6.

For this reference case study, preassembly method 5 was used entailing 3 offshore lifts. Total installation time was estimated by the following expression [46]:

$$T_{T,Instal} = \frac{T_{T,Travel} + T_j + T_{T,Assemb} + T_{T,Lift}}{V_{N,JU}} \quad (11)$$

where, $T_{T,Travel}$ represents the travel/transportation time of turbines, $T_j$ is the jacking up operation time, $T_{T,Assemb}$ is the assembly operation time, $T_{T,Lift}$ is the lifting operation time, and $V_{N,JU}$ symbolizes the number of identical jack up vessels. Considering 12 h of total working hours, effective installation time was estimated 264 days, equivalent to 1.89 days/turbine, which is in agreement with mean installation times found in literature [13]. The individual time components of the turbines installation time are presented in Appendix B.Finally, for the installation of the tower and the Rotor Nacelle Assembly (RNA), 30 additional offshore workers are employed, and another 30 for the installation of the foundations and transition pieces. An overview of the results produced by the model on the installation costs of OW turbines and foundations is given in Table 7. A weather adjustment factor of $ADJWEATHER = 0.85$ was assumed in the baseline scenario to account for delays due to unpredictable unfavourable weather conditions.

**Table 7**
Summary of results on foundations and turbines installation.

| Parameter | Value |
|---|---|
| Total effective days of foundations installation, $T_{Effectdays,F}$ | 292 days |
| Total effective days of turbines installation, $T_{Effectdays,T}$ | 264 days |
| Total effective days per foundation + transition piece | $2.08\frac{\text{effective days}}{foundation}$ |
| Total effective days per turbine | $1.89\frac{\text{effective days}}{turbine}$ |
| Cost of personnel employed for the installation of foundations | £2.36 million |
| Cost of personnel employed for the installation of turbines | £2.14 million |
| Total installation cost of foundations, $C_{F,ic}$ | £102.2 million |
| Total installation cost of turbines, $C_{T,ic}$ | £62.6 million |

*4.1.3.2. Scour protection installation.* The scour phenomenon takes place around structures undergoing steady current conditions, and is associated with the increase in the sediment transport capacity and erosion [47]. To ensure structural stability of the wind turbine foundation (as well as protection of cables), scour protection is usually applied. Available options to protect from scour are: placement of geotextile containers/sandbags, concrete armour units/block mattresses, grout bags/mattresses and rock armour (among others), which cover a particular area of the seabed [48]. The scour protection option employed is site-specific, i.e. at some locations the amount of protection varies with sediment and current conditions, while in others scour protection may not be needed. The input data used for the estimated mass of scour protection [49], the vessel leased for installation and the total installation time were adopted from [13,50,51].

The total effective duration for the installation of scour protection takes into account the lead time due to potential adverse weather conditions during the installation operations. As such, the total effective days were calculated by the following equation:

$$T_{Effectdays,Scour} = \frac{T_{Scour,Inst}{\cdot}N_{trips,scour}/24}{ADJWEATHER} \quad (12)$$

The total effective days correspond to the actual number of days that the rock-dumping vessel should be leased to perform the operations. As such, the installation cost of scour was estimated based on the vessel day rate and mobilisation cost (included in Table 2). Table 8 presents inputs and outputs related to the calculation of the total cost and installation time of the scour protection.

*4.1.3.3. Cables installation.* A dedicated Cable Laying Vessel (CLV) needs to be leased for the installation of the inner array and export cables. Average installation rates of inner-array and export cables were

**Table 6**
Pre-assembly methods characteristics.

| Installation method | Sub-assemblies | No of onshore assemblies | No of lifts/assemblies during installation ($N_{Lj}$) |
|---|---|---|---|
| 1 | (Nacelle + hub) + 3 blades + tower in 2 pieces | 1 | 6 |
| 2 | (Nacelle + hub) + 3 blades + tower in 1 piece | 2 | 5 |
| 3 | Nacelle + (hub + 3 blades) + tower in 2 pieces | 3 | 4 |
| 4 | (Hub + nacelle + 2 blades)+ tower in 2 pieces + 1 blade | 4 | 4 |
| 5 | (Nacelle + hub + 2 blades) + 1 blade + tower in 1 piece | 4 | 3 |
| 6 | (Nacelle + hub + 3 blades + tower in 1 piece) | 6 | 1 |

**Table 8**
Input and output data for scour protection installation.
Sources:[16,34,50,51].

| Parameter | Value |
|---|---|
| *Inputs* | |
| Tonnage of scour protection per unit, $SPU$ | 6,890 ton/turbine |
| Rock-dumping vessel capacity, $VC_{scour}$ | 24,000 ton |
| Number of trips required to the installation of scour protection, $N_{trips,scour}$ | 41 |
| Total transportation time of scour protection by rock-dumping vessel, $T_{Scour,Tr}$ | 2.97 h/trip |
| Dumping time per trip, $T_{Scour,Dump}$ | 16 h/trip (4 h/turbine) |
| Loading time per trip, $T_{Scour,Load}$ | 12 h/trip |
| Mobilisation cost of rock-dumping vessel, $V_{scour,Mobil}$ | £10,650 |
| *Outputs* | |
| Total time for scour protection installation, $T_{Scour,Inst} = T_{Scour,Tr} + T_{Scour,Dump} + T_{Scour,Load}$ | 31 h/trip |
| Total effective days for scour protection installation, $T_{Effectdays,Scour}$ | 62 days |
| Installation cost of scour protection, $C_{Scour,ic}$ | £872,600 |

calculated by taking into account historic data from past projects on the total length (in km) of the cables and total installation time (in days) [13]. Average installation rates were estimated approximately 1.6 and 0.6 km/day for export and inner array cables, respectively. For the installation of the subsea cables, a trenching ROV (Remotely Operated underwater Vehicle) was employed for the post–lay burial of the cables with a daily charter rate of 82.5 k£ [39]. The installation cost of export and array cables was, thus, estimated based on the total duration of the installation operation, and the day rates of the CLV and the trenching ROC. As such, the installation cost of array and export cables were calculated by the following expressions:

$$C_{C-array,ic} = T_{C-array,Inst}\cdot(V_{DR,CLV-array} + V_{DR,Trench}) + V_{Mobil,CLV} \tag{13}$$

$$C_{C-export,ic} = T_{C-export,Inst}\cdot(V_{DR,CLV-export} + V_{DR,Trench}) + V_{Mobil,CLV} \tag{14}$$

Input and output data for the cable installation are summarised in Table 9.

*4.1.3.4. Substation installation*. Substation is assumed to be barged on site and get installed by a Heavy-Lift vessel (HL). The installation time is comprised of the jacket foundation installation time, the grout application (if applicable) and, the installation of the substation topside. The voyage time from the port to the installation site and vice versa is estimated by:

$$T_{HL,voy} = 2\cdot\frac{D}{V_{S,HL}} \tag{15}$$

where, $V_{S,HL}$ is the speed of the heavy lift vessel used for the installation of the substation units. The total installation time of the substation is calculated as:

$$T_{Subst,Inst} = (n_{Subst,pile}\cdot R_{Subst,pile}\cdot D_{pile}) + T_{reposit} + T_{Substjacket,Inst} \tag{16}$$

The symbols of Eq. (16), the input data used in the context of the case study, along with the derived results concerning the transportation and installation time of the substation foundation/topside are demonstrated in Table 10. To estimate the weight of a typical substation topside, a dataset from existing OW farms was established consisting of the substation topside weights for various wind farms whose capacities range from 60 to 630 MW (data retrieved from [52] from deployed wind farms) and a linear regression model was trained based on this dataset. As a result, the mass of the topside substation can be approximated by the following linear equation (shown in Fig. 2):

$$W_{Subst,top} = 3.5129\cdot P_{WF} + 388.85 (R^2 = 0.9011) \tag{17}$$

**Table 9**
Input and output data for cables installation.

| Parameter | Description | Value |
|---|---|---|
| *Cables installation – inputs* | | |
| Installation rate of export cable | | 1.6 km/day |
| Installation rate of array cables | | 0.6 km/day |
| *Cables installation – outputs* | | |
| Effective days required for the installation of export cables, $T_{C-export,Inst}$ | | 147 days |
| Effective days required for the installation of array cables, $T_{C-array,Inst}$ | | 537 days |
| Installation cost of export cables, $C_{C-export,ic}$ | | £27.3 million |
| Installation cost of array cables, $C_{C-array,ic}$ | | £87.7 million |

**Table 10**
Input and output data for offshore substation installation.

| Parameter | Value |
|---|---|
| *Offshore substation installation – input* | |
| Number of piles per substation foundation, $n_{Subst,pile}$ | 4 |
| Rate of piling the piles of the substructure, $R_{Subst,pile}$ | 0.115 h/m |
| Depth of pile under the soil, $D_{pile}$ | 36 m |
| Reposition time of the vessel, $T_{reposit}$ | 8 h |
| Installation time of the substation's jacket, $T_{Substjacket,Inst}$ | 20 h |
| *Offshore substation installation – output* | |
| Total effective installation days for one substation, $T_{Subst,Inst}$ | 13 days |
| Total installation cost (for the 2 substations), $C_{OffSubst,ic}$ | £3.99 million |

The weight of the topside substation will determine the vessel that will be required with the appropriate crane capacity as shown in Table 10. Instead of assuming one topside substation of 2160 ton, two identical substations of 1080 ton were assumed. The estimation of the installation cost of the substation was based on the total effective duration of the installation operation, $T_{Subst,Inst}$, and the HL vessel day rate, $V_{DR,HLV}$, and mobilisation cost, $V_{Mobil,HLV}$, as expressed below:

$$C_{OffSubst,ic} = T_{Subst,Inst}\cdot V_{DR,HLV} + V_{Mobil,HLV} \tag{18}$$

Input and output data for the substation installation are summarised in Table 10.

## 4.2. OPEX module

### 4.2.1. Failure modes and latest reliability databases utilised

For the prediction of O&M total cost, an updated database of failure rates, number of technicians required for repairs and cost of repairs was used as input. A number of onshore wind reliability analysis exists in literature, covering the whole onshore turbine as well as its subassemblies

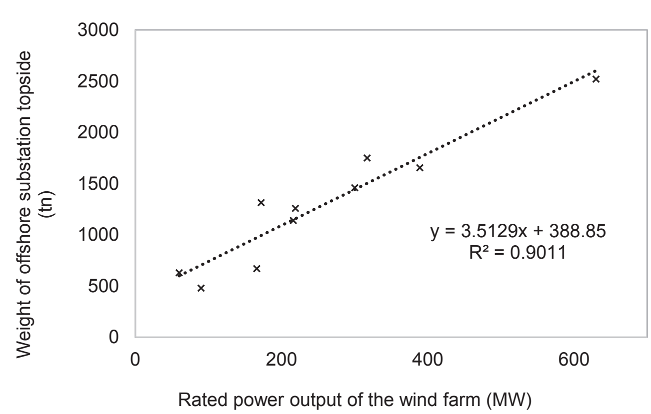


**Fig. 2.** A linear model for offshore substructure topside mass used in a wind farm (data retrieved from [52]).

[53–56]. As far as the reliability analysis of OW turbines is concerned, in [23] authors have gathered information from around 350 OW turbines with nameplate capacities ranging from 2 to 4 MW and ages between 3 and 10 years old. The failure rates used in the present analysis are provided in a per turbine per year format, defined as:

$$\lambda = \frac{\sum_{e=1}^{E}\sum_{k=1}^{K}\frac{n_{e,k}}{N_{T,e}}}{\sum_{e=1}^{E}\frac{T_e}{8760}} \tag{19}$$

where, $\lambda$ denotes the failure rate per turbine per year, $E$ is the number of intervals for which data are collected, $K$ is the number of subassemblies, $n_{e,k}$ the number of failures during the specific interval, $N_{T,e}$ the number of turbines that were examined, and $T_e$ represents the total time period in hours.

$\sum_{e=1}^{E}\sum_{k=1}^{K}\frac{n_{e,k}}{N_{T,e}}$ denotes the total number of failures in all periods per turbine while $\sum_{e=1}^{E}\frac{T_e}{8760}$ is equal to the sum of all time periods in hours divided by the number of hours within a period of a year.

Repairs are classified as minor repairs (repairs that cost up to 1,000€), major repairs (1,000–10,000€) or major replacements (> 10,000€); a categorisation adopted by the Reliawind project which has registered failure rate data for onshore wind turbines [57]. Data on the failure rates, average repair times, number of required technicians and material costs are enclosed in Table 11.The "No cost data" category refers to repairs for whose cost data are not registered.

The mean time between failures (MTBF) is a commonly used reliability metric for repairable items and it can be expressed as the inverse of the failure rate, as follows:

$$MTBF = \frac{1}{\lambda} \tag{20}$$

As demonstrated in Fig. 3, MTBF is connected to the mean time to repair (MTTR) and the Mean Time To Failure (MTTF) as follows [58,59]:

$$MTBF = MTTF + MTTR \tag{21}$$

The MTTF represents the reliability of the system while the MTTR denotes the competence of the maintenance strategy to recover the system back to normal operation (as well as the weather window to perform maintenance operations). The latter is hence a stochastic quantity that available reliability data cannot capture and needs to be processed in detail as will be described in Section 4.2.2. Since wind turbine components undergo failures usually less than once a year (therefore MTBF > 365 days), while the MTTR usually lasts for much shorter time, above expression can be assumed equivalent to $MTBF \cong MTTF$, which is the simplification that needs to be made in the application of the ECN O&M tool as will be described below.

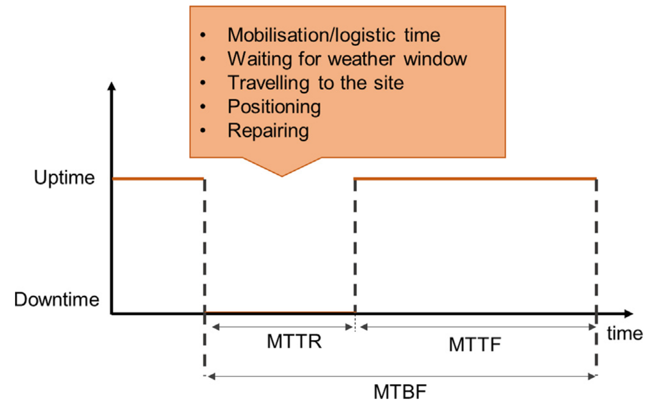


**Fig. 3.** Illustration of the MTTR, MTTF and MTBF.

### 4.2.2. Specification of settings for O&M costs

The detailed estimation of the O&M annual costs, downtime because of O&M activities and revenue losses caused by energy production loses was carried out through the ECN O&M tool [60], which has been used by numerous project developers and turbine manufacturers in the OW industry, and it is considered as the most comprehensive tool for O&M analysis to date [61]. It generates an average yearly estimation of the O&M cost over the lifetime of the wind farm; hence, long term average values of failure rates (as the ones outlined in Table 11) are needed as input to determine annual operating costs.

Apart from the general characteristic values of the wind farm (i.e. the number of turbines, the wind farm capacity, the power curve, etc.), met ocean data were also inserted in the software for an indicative installation site located in North Sea. Software allows for 1-hourly or 3-hourly significant wave height and mean wind speed data to be introduced; to this end, 3-hourly data was supplied by BTM ARGOSS [29].

For framing the maintenance strategy of the reference OW farm, a

**Table 11**
Average repair times (h), number of required technicians, material cost for different turbine components and repair category. FR: Failure rates (failures/turbine/year), ART: Average repair times (h), RT: Required technicians, MC: Material cost (€).
Source: [23].

| | No cost data | | | Minor repair | | | | Major repair | | | | Major replacement | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | FR | ART | RT | FR | ART | RT | MC | FR | ART | RT | MC | FR | ART | RT | MC |
| Pitch/Hyd | 0.072 | 17 | 2.8 | 0.824 | 9 | 2.3 | 210 | 0.179 | 19 | 2.9 | 1900 | 0.001 | 25 | 4 | 14,000 |
| Other Components | 0.15 | 8 | 2.3 | 0.812 | 5 | 2 | 110 | 0.042 | 21 | 3.2 | 2400 | 0.001 | 36 | 5 | 10,000 |
| Generator | 0.098 | 13 | 2.4 | 0.485 | 7 | 2.2 | 160 | 0.321 | 24 | 2.7 | 3500 | 0.095 | 81 | 7.9 | 60,000 |
| Gearbox | 0.046 | 7 | 2.2 | 0.395 | 8 | 2.2 | 125 | 0.038 | 22 | 3.2 | 2500 | 0.154 | 231 | 17.2 | 230,000 |
| Blades | 0.053 | 28 | 2.6 | 0.456 | 9 | 2.1 | 170 | 0.01 | 21 | 3.3 | 1500 | 0.001 | 288 | 21 | 90,000 |
| Grease/oil/cooling liq. | 0.058 | 3 | 2 | 0.407 | 4 | 2 | 160 | 0.006 | 18 | 3.2 | 2000 | 0 | 0 | 0 | 0 |
| Electrical components | 0.059 | 7 | 2.4 | 0.358 | 5 | 2.2 | 100 | 0.016 | 14 | 2.9 | 2000 | 0.002 | 18 | 3.5 | 12,000 |
| Contactor/circuit/breaker/relay | 0.048 | 5 | 2 | 0.326 | 4 | 2.2 | 260 | 0.054 | 19 | 3 | 2300 | 0.002 | 150 | 8.3 | 13,500 |
| Controls | 0.018 | 17 | 3.2 | 0.355 | 8 | 2.2 | 200 | 0.054 | 14 | 3.1 | 2000 | 0.001 | 12 | 2 | 13,000 |
| Safety | 0.015 | 2 | 2 | 0.373 | 2 | 1.8 | 130 | 0.004 | 7 | 3.3 | 2400 | 0 | 0 | 0 | 0 |
| Sensors | 0.029 | 8 | 2.7 | 0.247 | 8 | 2.3 | 150 | 0.07 | 6 | 2.2 | 2500 | 0 | 0 | 0 | 0 |
| Pumps/motors | 0.025 | 7 | 2.5 | 0.278 | 4 | 1.9 | 330 | 0.043 | 10 | 2.5 | 2000 | 0 | 0 | 0 | 0 |
| Hub | 0.014 | 8 | 2.4 | 0.182 | 10 | 2.3 | 160 | 0.038 | 40 | 4.2 | 1500 | 0.001 | 298 | 10 | 95,000 |
| Heaters/coolers | 0.016 | 5 | 2.7 | 0.19 | 5 | 2.3 | 465 | 0.007 | 14 | 3 | 1300 | 0 | 0 | 0 | 0 |
| Yaw System | 0.02 | 9 | 2.4 | 0.162 | 5 | 2.2 | 140 | 0.006 | 20 | 2.6 | 3000 | 0.001 | 49 | 5 | 12,500 |
| Tower/foundation | 0.004 | 6 | 2.3 | 0.092 | 5 | 2.6 | 140 | 0.089 | 2 | 1.4 | 1100 | 0 | 0 | 0 | 0 |
| Power supply/converter | 0.018 | 10 | 2.7 | 0.076 | 7 | 2.2 | 240 | 0.081 | 14 | 2.3 | 5300 | 0.005 | 57 | 5.9 | 13,000 |
| Service items | 0.016 | 9 | 2.2 | 0.108 | 7 | 2.2 | 80 | 0.001 | 0 | 0 | 1200 | 0 | 0 | 0 | 0 |
| Transformer | 0.009 | 19 | 2.8 | 0.052 | 7 | 2.5 | 95 | 0.003 | 26 | 3.4 | 2300 | 0.001 | 1 | 1 | 70,000 |

number of operational decisions (common within the O&M strategies of OW projects) needs to be taken. As such:

- Four workboats (crew transfer vessels, (CTVs)) are available for O&M operations and are permanently leased on a fixed contract. CTVs are used for the transportation of personnel and small components with 26knots maximum speed and maximum capacity of 15 workers.
- One helicopter is chartered to transfer technicians when response time is critical. Typically three technicians plus their equipment can be transferred by helicopter (top speed 245 km/h) [62].
- One jack-up vessel (heavy maintenance vessel) is chartered in the spot market in order to transfer and instal heavy components.
- One diving support vessel is chartered on the spot market to perform underwater inspections.
- One cable laying vessel for replacing any damaged power cables when required.

The site is close enough to shore ($D = 36$ km) and the maintenance activities are staged out of the O&M port; thus, an accommodation vessel (or mother vessel) was not considered necessary in the baseline case study and the access time for minor repairs and inspections as well as the fair weather window were evaluated in reference to the distance from shore.

General data such as maximum wave heights, wind speeds for the transportation equipment and vessel costs are shown in Table 2. Values included in the table have been retrieved and cross checked through a number of references [5,61,63–65], including a report [66] completed by the National Renewable Energy Laboratory (NREL) and the Energy Research Centre of the Netherlands (ECN) as well as from real data retrieved from 4C Offshore website [44].

The ECN O&M tool considers three types of O&M strategies, namely calendar-based, condition based and unplanned corrective. For unplanned corrective maintenance each component of the system (wind turbine and the Balance of the Plant (BOP)) is assigned an annual failure frequency. This may consist of several failure modes (fault type classes, (FTC)) with different severities and frequencies. The failure frequencies of each component of the system are introduced in the software through the MTTF. Annual failure rates from Table 15 are hence transformed on a per hour basis, as follows:

$$MTTF = \frac{8760}{\lambda}, \text{in h} \tag{22}$$

In the context of the baseline scenario, the components of the system considered are the ones summarised in Table 11, while the different FTCs are categorised as minor repairs, major repairs or major replacements (according to the Reliawind categorisation) with relative failure frequencies (RFF) calculated as:

$$RFF_{fc}(\%) = \frac{\lambda_{fc}}{\sum_{fc=1}^{numberofFTC} \cdot \lambda_{fc}} \cdot 100 \tag{23}$$

where, $fc$ denotes the number of FTC. Apart from the RFF defined per FTC, the priority level as well as the repair and spare control strategy need to be defined; we set major repairs and major replacements to be of high priority and the rest to be of normal. Further data used for the definition of the unplanned corrective maintenance strategy constitute the average repair times, number of required technicians and material costs which were retrieved from Table 11. Finally, the logistic time for major replacements for unplanned corrective maintenance was assumed around 250 h. Due to the multiple uncertainties as well as the lack of data for predicting condition based maintenance activities, this maintenance type was ignored.

The period for calendar based maintenance is set between 01-May to 30-September to take advantage of the expected favourable weather conditions. For calendar based maintenance, all wind turbines are assumed to be maintained on an annual basis, through a lower cost maintenance mission, while every 5 year a larger preventive maintenance mission is assumed to take place.

The estimation on the total number of technicians to perform the O&M operations was based on having the maximum number of manpower for 4 workboats, resulting in a total of $4 \cdot 12 = 48$ technicians. The annual fixed technician's salary is 95 k£ for unplanned corrective maintenance, while additional crew for the calendar-based maintenance is hired with hourly wage £120/hour in the base case scenario [67].

#### 4.2.3. Operation and maintenance phase (O&M) cost estimation

The costs for maintaining the OW farm were determined by both unplanned and corrective maintenance. The parameters exported through the tool were, among others, the range of availability of the wind farm, and the average annual repair cost and the power production. Results are summarised in Table 12.

### 4.3. Decommissioning and disposal phase (D&D)

Energy companies are obliged to remove all structures and verify the clearance of the area upon the termination of the lease. Decommissioning activities relate to the removal of the wind turbine (i.e. nacelle, tower and transition piece) as well as the balance of the plant (substation, cables and scour protection). Removal of the wind turbine and tower is done using a reversed installation method while the removal of foundation is carried out by the use of a cutting tool that removes the transition piece, while an ICM (Internal Cutting Manipulator) is used to cut the monopile at 2 m below the mud-line [68]. Cranes are used to lift the cut pieces of the turbine. Removal of mud and internal cutting can be realised by means of a workboat, while the lifting of the structure is performed by a jack up vessel. Two jack up vessels with deck space to load 5 complete WTGs with foundations are assumed. For the removal of the substation topside a heavy lift vessel is required while the jacket support structure of the substation also needs to be cut (the 4 piles) in order to get removed. As far as cables are concerned, they can be partially or wholly removed, depending on whether they are buried or not [69]. Cables can be cut in several sections while they are removed, hence, less expensive vessels can be employed, such as Special Operations Vessels (SOVs) or barges. In this analysis, 50% of the initial length of cables are assumed to be left in situ after the decommissioning of the wind farm (an assumption derived from discussions with wind farm operators). The scour protection may also be left in situ in order to conserve the marine life that would have grown on it. Site clearance is the final stage during decommissioning and it encompasses the removal of the debris accumulated in a specified radius of the structure throughout the 25 years of life of the wind farm. Vessels employed for the decommissioning of the structures are assumed to have similar characteristics to the ones summarised in Table 2. Input and output values of the removal process are included in Table 13.

Further to the removal of the wind turbine components, the balance of the plant and the clearance of the area, removed items need to be transported and disposed. Cost of transportation is a function of the total mass of the wind farm components, $W_{components}$, the cost per ton-mile of the transportation truck, $C_{truckperton-mile}$, the capacity of truck, $W_{truck}$, and the distance of port from the waste facility, $D_{port-facility}$, as follows [14]:

$$C_{transp,dd} = \frac{\sum W_{components}}{W_{truck}} \cdot D_{port-facility} \tag{24}$$

**Table 12**
Summary of OPEX in the baseline scenario.

| OPEX estimation | Values |
|---|---|
| Availability (%) | 92.5/92.2% |
| Repair costs | £28.38 million/year |
| Net annual energy production | 1,734,792 MWh/year |

**Table 13**
Removal costs of wind turbine.

| Parameter | Value |
|---|---|
| *Turbine and foundation removal – inputs* | |
| Remove time per turbine with a self-propelled jack up vessel | 15 h/turbine |
| Complete turbines (including foundations) capacity of a Jack up vessel | 5 turbines/trip |
| Number of jack up vessels for the removal of the wind turbines | 3 |
| Number of workboats employed for the decommissioning of the turbines | 2 |
| Number of technicians per workboat | 5 |
| Offloading time of turbines/monopiles | 8 h/item |
| Time to cut the foundation | 6 h/foundation |
| Time to lift the item and place on the deck | 11 h/item |
| *Turbine and foundation removal – outputs* | |
| Total duration of each trip which equals the sum of the travel time to and from site, the removal time of turbines and monopile, the loading time and the intra-field movement time of the jack up vessel | 244 h |
| Total time per trip (adjusted to weather and working hours) | 26 days |
| Total effective days for turbines and monopiles removal divided by the number of vessels, $T_{Effectdays,TF-Rem}$ | 243 days |
| Total cost of hiring technicians and workboats during the decommissioning of the wind turbines, $C_{vessel,dd}$ | £4.13 million |
| Total cost for removing all wind turbines with monopiles, $C_{TF,dd}$ | £83.5 million |
| *Offshore substation removal – inputs* | |
| Pile diameters of jacket substructure | 2.6 m |
| Cutting rate of the pile | 1 h/m |
| Lifting time of topside substructure | 3 h |
| Cut time of topside | 12 h |
| Reposition time of vessel to each leg of the jacket substructure | 8 h |
| *Offshore substation removal – outputs* | |
| Time to cut the 4 piles | 10.4 h |
| Total time for the removal of the two substations, $T_{Effectday,Substat-Rem}$ | 8.7 days |
| Total cost for removing the two substations, $C_{offSubst,dd}$ | £1.18 million |
| *Cables removal* | |
| Rate of removal of inner-array cables | 600 m/day |
| Rate of removal of export cables | 875 m/day |
| Cost of cables removal, $C_{cables,dd}$ | £11.9 million |
| *Site clearance* | |
| $Area = -51.5 + 0.41{\cdot}d + 0.65{\cdot}n_{WT}$, in km | 83.37 km$^2$ |
| Total cost for site clearance, $C_{clear,dd}$ | £5.38 million |

### 4.4. Revenue module

Levelised cost of electricity (LCOE) models consider the costs throughout the whole life of the asset. However, investors emerging in different phases of the OW farm are interested in the profitability profile of the investment from the purchasing instance until their exit point from the investment. Assessing the profitability of investing in an OW farm in different phases of its service life requires the estimation of the temporal profile of the revenues that the investment yields.

As far as the policy instruments supporting the OW industry are concerned, the Contract for Difference (CfD) scheme is currently in effect in the United Kingdom, which is a private law contract between a low carbon power producer and the Low Carbon Contracts Company (LCCC), a government-owned company. According to the CfD scheme, the low carbon power producer sells the produced electricity, as usual, through a Power Purchase Agreement (PPA), to a licenced supplier or trader at an agreed reference market price. However, in order to reduce investors' exposure to variations in electricity market prices, the CfD mandates that the power producer is paid the difference between a pre-determined "strike price" and the reference market price. If the reference price is lower than the strike price, the power generator receives the difference from LCCC; reversely, if the reference price is higher, the power producer has to pay back the difference. The bottom line is that the power producer always gets the strike price for the electricity generated. CfDs are awarded to power producers in allocation rounds and the amount of the strike price is determined through an allocation process, which is either based on administrative strike prices set by the Government (provided there are sufficient funds) or by means of a competitive auction run by the National Grid. The auctions ensure that the least expensive projects are awarded, reducing, thus, the cost passed to consumers. The scheme lasts for 15 years (while the average lifetime of an OW energy asset is 25 years), after which the electricity output is sold on the average UK electricity market price, hence imposing uncertainty to the revenues yielded by the investment after the 15th year of operation [70]. To this end, appropriate modelling of the cash inflows, along with the taxation imposed to the income needs to be conducted. For the reference case study, the baseline strike price value considered amounts to £140/MWh (which corresponds to the administrative strike price for 2018/19 [71]).

### 4.5. FinEX module

#### 4.5.1. Depreciation and tax

Tax depreciation is available through the capital allowances regime, according to which $d_{rate} = 18\%$ of qualifying expenditure on equipment is reduced [72]. Depreciation is a term used in accounting in order to spread the cost of the capital assets over the life span of the investment, so that the net profit in any year will reflect all the costs required to produce the output. The effect of depreciation is estimated by dividing the equipment cost of the wind farm, $C_{equipment}$, over the total life span of the asset and deducting the 18% of this annual cost from the tax payment. The net tax, $t_{net}$, can then be calculated by deducting the depreciation credit, $d_{credit}$, from the yearly tax payment, $t_{payment}$, as shown below:

$$d_{credit} = \frac{C_{equipment}}{n}\cdot d_{rate} \tag{25}$$

$$t_{net} = t_{payment} - d_{credit} \tag{26}$$

$$t_{payment} = t_c\cdot P_{gr} \tag{27}$$

where, $t_c = 17\%$ is the nominal corporate income tax rate paid every year and $P_{gr}$ represents the gross profit. Accordingly, the Net profit, $P_{net}$, of the investment can be calculated as:

$$P_{net} = P_{gr} - t_{net} \tag{28}$$

#### 4.5.2. WACC and inflation

Inflation and interest rates are used to account for the time value of money. Inflation accounts for the reduction in the purchasing power of a unit of currency between two time periods, while the interest rate is the rate earned from a capital investment. In financial analysis, the nominal interest rate is the interest rate quoted by the banks, stock brokers etc. which includes both the cost of capital and the inflation. Real discount rate (or else real WAAC) integrates the inflation adjustment and the discount of cash flows according to Fisher Equation [73]:

$$WACC_{real} = \frac{1 + WACC}{1 + R_{infl}} - 1 \approx WACC_{nom} - R_{infl} \tag{29}$$

The discount rate is determined by the source of capital as well as the estimation of the financial risks associated with the investment. Projects gather their capital by raising funds through debt and equity. These sources of financing demonstrate individual risk-return profiles; hence their costs also fluctuate. The cost of capital will correspond to the weighted average of cost of its equity and debt, with weights determined by the amount of each financing source. The WACC is calculated by the following expression [74]:

$$WACC = \frac{VE}{V}\cdot RoE + \frac{VD}{V}\cdot Rd\cdot(1-tc) \tag{30}$$

where, $VE$ is the market Value of Equity, $VD$ is the market Value of Debt, $V = VE + VD$, $RoE$ denoted the Return on Equity, and $Rd$ the interest rate on debt. The risk of the project significantly influences the amount of return on investment required by the investor. External capital is cheaper and, thus, it is often desirable to obtain the highest possible amount of debt; however, the cost of debt depends on the specific investment risk, namely the highest the investment risk, the lower the amount that banks will be willing to lend. Average values for the components of WACC were retrieved from [75,76] for OW energy and are summarised in Table 14. Further, the real WACC is calculated by taking into account the inflation rate (inflation rate was estimated equal to 2.5% in the baseline case study, which is a realistic assumption according to UK inflation rate predictions for 2017–2018 [77]).

**Table 14**
Input data for the cost of capital calculation model.
Sources: [74–76].

| | Values (%) |
|---|---|
| Share of equity, $\frac{VE}{V}$ | 30 |
| Share of debt, $\frac{VD}{V}$ | 70 |
| *RoE* | 15.8 |
| *Rd* | 7 |
| $WACC_{nom}$ | 8.8 |

## 5. Results and discussion

### 5.1. Cost breakdown

In this Section, an overview of the case study results is presented. Table 15 summarises the cost estimates of the different lifecycle phases. The total undiscounted CAPEX encompassing costs during the P&C, P&A, I&C and D&C phases amounts to £1.675 billion, while the annual OPEX was estimated £56.6 million.

In Fig. 4, the relative contribution of the 5 different phases of the life cycle to the total LCOE is presented. It is indicated that the costs incurred during the P&A phase have the largest share of the total costs (46%), followed by the O&M costs (30%). These results are consistent with a number of previous studies [14,78].

**Table 15**
Overview of case study results.

| Name | Value |
|---|---|
| *CAPEX in k£* | |
| Total P&C costs, $C_{P\&C}$ | 205,750 |
| Project management cost $C_{proj,pc}$ | 42,327 |
| Legal costs, $C_{legal,pc}$ | 16,698 |
| Environmental surveys costs $C_{surveys,pc}$ | 19,162 |
| Engineering costs, $C_{eng,pc}$ | 1,144 |
| Contingency costs, $C_{cont,pc}$ | 126,419 |
| Total P&A costs, $C_{P\&A}$ | 1,040,230 |
| Wind turbine cost, $C_{T,pa}$ | 546,056 |
| Foundation cost, $C_{F,pa}$ | 212,699 |
| Cables cost, $C_{cables,pa}$ | 120,525 |
| Offshore substation (x2), $C_{offSubst,pa}$ | 121,337 |
| Onshore substation, $C_{onSubst,pa}$ | 30,334 |
| SCADA cost, $C_{SCADA,pa}$ | 9,278 |
| Total I&C costs, $C_{I\&C}$ | 305,742 |
| Installation of wind turbines (tower, hub, nacelle and blades), $C_{T,ic}$ | 62,619 |
| Installation cost of foundations, $C_{F,ic}$ | 102,224 |
| Installation cost of cables, $C_{Cables,ic}$ | 115,070 |
| Installation cost of substation, $C_{offSubst,ic}$ | 3,991 |
| Installation cost of scour protection, $C_{Scour,ic}$ | 873 |
| Insurance cost during installation $C_{insur,ic}$ | 20,966 |
| Total D&D costs, $C_{D\&D}$ | 122,860 |
| Removal cost of turbines and monopile foundations, $C_{TF,dd}$ | 83,526 |
| Cable Removal, $C_{cables,dd}$ | 11,907 |
| Removal of offshore substation, $C_{offSubst,dd}$ | 1,176 |
| Scour Protection removal, $C_{scour,dd}$ | 1,612 |
| Grout removal, $C_{grout,dd}$ | 60 |
| Transportation cost, $C_{transp,dd}$ | 21 |
| Disposal cost, $C_{disposal,dd}$ | 2,452 |
| Site Clearance, $C_{clear,dd}$ | 5,376 |
| Cost of hiring vessels and personnel, $C_{vessel,dd}$ | 4,130 |
| Port preparation, $C_{port,dd}$ | 12,600 |
| *OPEX in k£/year* | |
| Total O&M costs, $C_{O\&M}$ | 56,597 |
| Repair cost, $C_{repair,om}$ | 28,403 |
| Rent cost, $C_{rent,om}$ | 5,040 |
| Insurance cost, $C_{insur,om}$ | 7,338 |
| Project management cost, $C_{proj,om}$ | 15,816 |

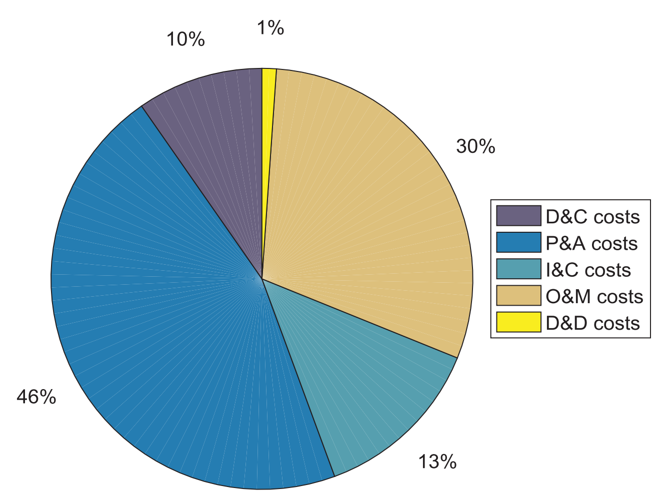


**Fig. 4.** Life cycle cost breakdown.

### 5.2. Sensitivity analysis

For the sensitivity analysis of the model, we have considered the wind farm general specifications, presented in Table 1 as design parameters (parameters that remain unchanged) and we have tested the sensitivity of variables found in the other modules of the model with respect to their influence on the Net Present Value (NPV) of the investment (as opposed to other works testing sensitivity of design parameters on the economic performance of the wind farm [14,79]). This should allow a targeted investigation of the impact of parameters that can be influenced during the lifecycle of a wind farm of a given location.

The results of the sensitivity analysis are illustrated in Fig. 5(a)–(d). The graphs include parameters which have an influence of at least ± 2% (cut-off point) on the NPV upon a 20% increase/decrease in their values. Under the baseline scenario, NPV of the investment was calculated £2.843 million at a real discount rate of 6.15% with an IRR = 10.3%. Further, LCOE was estimated £109/MWh.

Most influential CAPEX parameters appeared to be the wind turbine acquisition cost, the working hours of the personnel and the foundation acquisition cost increasing the NPV by 28% in absolute terms, upon a 20% decrease in their values, followed by the day rate of the jack up vessels and the weather adjustment factor inducing an approximately 9% change in the NPV.

As far as the OPEX parameters are concerned, the MTTF and the workboat wave height limit appeared to have the greatest influence on the NPV of the investment. In fact, a 20% drop of the wave height limit of the workboat, decreases NPV by 16%. Considering the significant effect of this factor on the feasibility of the project, the operator could consider measures to limit this risk; for example, through leasing workboats which could provide safe access at higher wave heights or through hiring other modes of transportation, which would allow rapid access to the WTGs regardless of weather (e.g. helicopters).

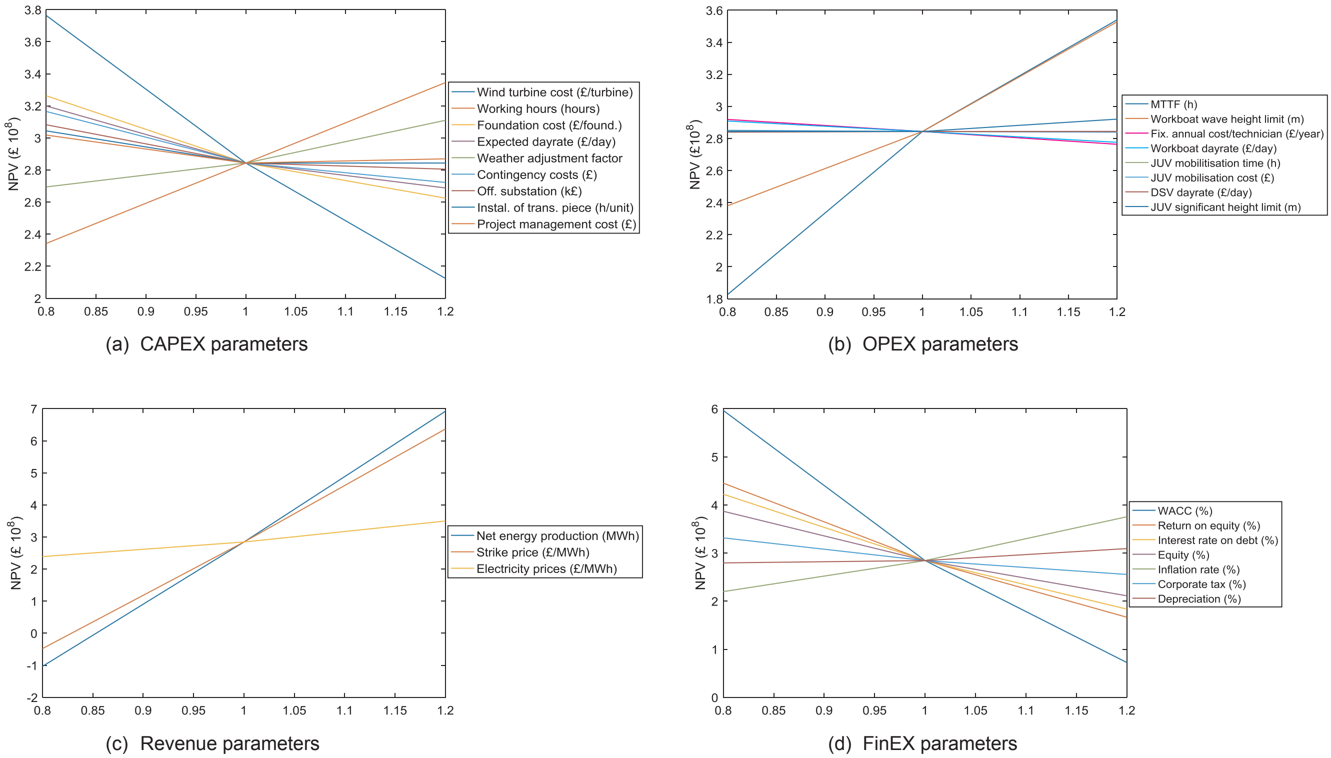


**Fig. 5.** Sensitivity analysis results.

Net present value demonstrated high sensitivity to the WACC value (with a 20% decrease in WACC more than doubling the NPV of the investment) and as a result, to its composing parameters. In fact, a 20% decrease in these parameters, namely the return on equity, the interest rate on debt and the equity ratio increase NPV by 52%, 44% and 32%, respectively. The last observation stresses the importance of financing costs on the feasibility of the investment, indicating that cost of equity is almost always expected to be higher than the cost of debt; thus, as the debt ratio increases, the WACC is expected to drop. Nevertheless, third party financing stakeholders would expect to see a reasonable equity being invested in the project in order to increase confidence in the investment. Hence, the final equity to debt ratio would be a balance of these opposite forces. Further, the inflation rate and the corporate tax appeared to have an effect of up to −26% and +13% in NPN upon a 20% decrease in their values, respectively.

A general observation from the four sensitivity analysis graphs is that FinEX and revenues parameters appear to have the greatest impact on the NPV of the investment in comparison to the other two modules of the model, with WACC, net energy production and strike price having the greatest impact.

### 5.3. Investor specific cost/revenue profiles

As mentioned above, one of the objectives of this paper is to assess the expected financial returns from an OW farm asset for investors investing and divesting the asset at different time instances across the entire lifecycle. Implementation of the model for the respective investment strategies can provide – among other outputs – information regarding the amount of return different investor classes will be looking to earn to get involved in the investment.

Fig. 6(a)–(c) illustrate cumulative cash flow profiles for the three different investor classes (Late entry investors, Pre-commissioning investors, Build-Operate-Transfer investors) identified in [3]. The "Build-Operate-Transfer" (BOT) type of investor suggests that a single investor owns the asset from the D&C up to the D&D phase; hence, this is the typical case that financial appraisal studies usually consider. The temporal cost/revenue profile of the BOT investor is illustrated in Fig. 6(a). In order to account for the range of potential WACC values this investor cluster is likely to accommodate, results for WACCs equal to 8% and 10% are presented. The graph can provide an estimate of the value of the asset across its life; the estimated break-even year can be found in the intersection of the cumulative costs and cumulative revenues curves (highlighted with the purple circle mark). As such, for WACC = 8% break-even year is the 18th year from the initiation of the project (including the pre-commissioning phase), while for WACC = 10% break-even year becomes the 20th year.

Departing from the BOT scenario, the model was, subsequently, applied to the other two investor profiles. "Pre-commissioning" (PC) investors undertake the development and construction of the wind farm, acting as turn-key developers, while they tend to sell the asset once the project is commissioned. Fig. 6(c) illustrates cumulative costs (dashed red and blue lines) and revenues (solid red line) for an investor entering from year 1 of the asset lifecycle (P&C phase) and exiting at the end of year 5. As expected, since PC investors sell the asset following its commissioning (i.e. before energy starts to be produced and injected to the grid), revenues are expected to be zero before the sixth year of the project's life cycle. The setting of the sale price of the asset needs to cover at least the construction cost of the asset plus their financing costs to that point. This cluster of investors comprising OEMs and EPCI contractors have generally weaker balance sheets in comparison to big power producers (belonging to the BOT cluster of investors), and hence, they have less financial strength to provide corporate finance to the project. Considering a WACC in the region of 12–15% [21], their cost/revenue profile for the construction period of the wind farm (from year 1 to year 5) is illustrated in Fig. 6(c) for the lower and upper bounds of potential WACC values. Assuming a 100% ownership, the PC investor is anticipated to balance the cost spent for the development of the asset and the financing cost (determined by the WACC values), in order to assess the minimum selling price of the asset. The application of the model indicated that the seller should ask for a minimum price of £1,078 million for a WACC = 15% under the baseline scenario, while the minimum asking price when WACC = 12% should be £1,170.5 million.

On the other hand, "Late entry" (LE) investors should consider future

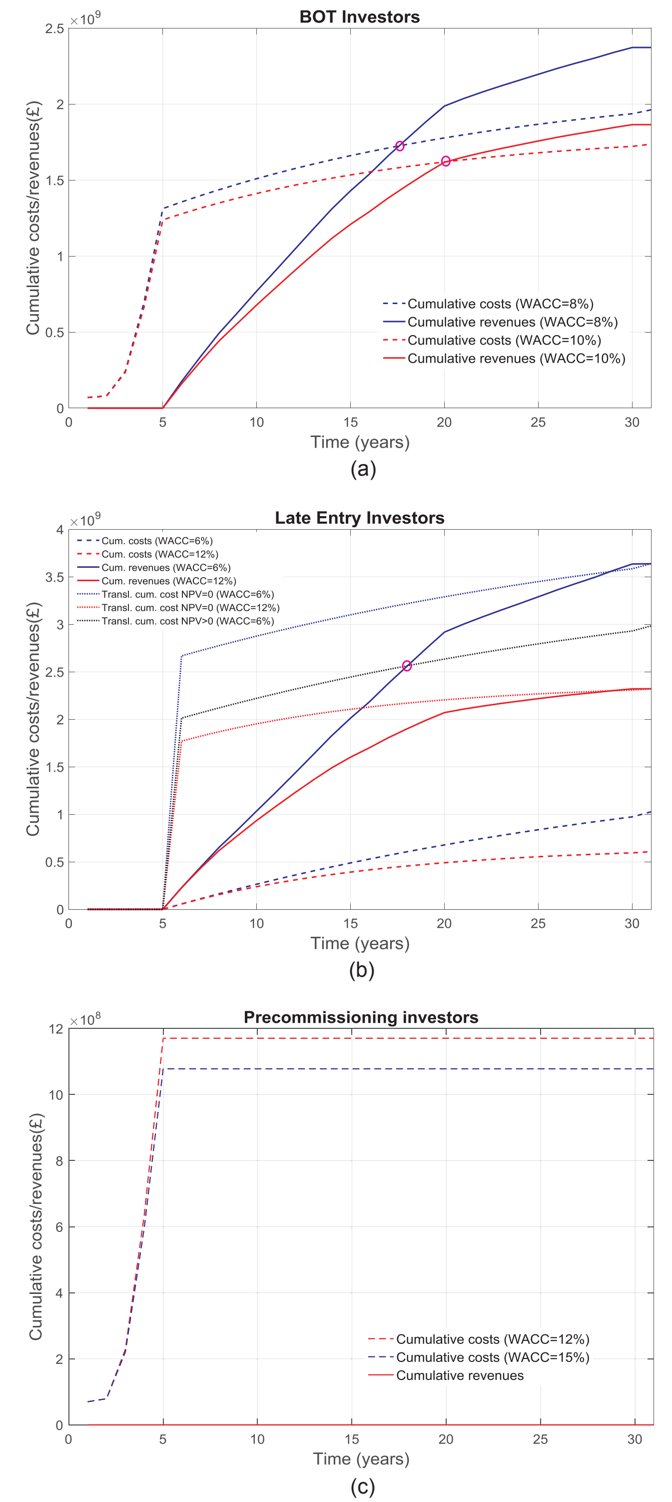


**Fig. 6.** Cumulative cost return profiles of the asset from the different investor perspectives.

expected costs and revenues, in order to evaluate the maximum price they can purchase the asset for. Taking into account the fact that this class of investors have more liquidity and stronger balance sheets, their WACC range is lower, approximately between 6% and 12% [21]. In Fig. 6 (b), the cost/revenue profiles of the asset from year 6 (commissioning year) up to the D&D phase are outlined for WACC values 6% and 12%. Further, the cumulative costs (denoted with the dotted lines) have been translated, so that they intersect with the cumulative revenues (solid lines) at the end of the service life of the asset (i.e. year 31st). This means that the break-even point is found at the extreme end of the service life and, hence, the NPV of the investment equals to zero. The blue dotted line corresponds to the translated cumulative costs for WACC = 6%, while the red dotted line represents the translated cumulative costs for WACC = 12%. Correspondingly, the blue and red solid lines reflect the cumulative revenues for the lower and upper WACC limit, respectively. Cumulative costs are discounted to the year of acquisition (i.e., beginning of year 6). The translation of the cumulative costs enables the identification of the extreme purchase price of the asset at the commissioning point, which will allow the late entry investor to make marginal profit. The translation of the cumulative cost is realised by the following expression:

$$DCC_{translated,t} = DCC_t + (DCR_{t=31} - DCC_{t=31}),\ \forall\ t = 6,7,8,\ldots,31 \tag{31}$$

where, $DCC_{translated,t}$ is the discounted translated cumulative cost at year $t$, $DCC_t$ is the discounted cumulative cost and $DCR_t$ is the discounted cumulative revenues at time $t$. If the acquisition price, at the point of the purchase, is less than this extreme, the two curves will be intersecting to a time earlier than the service life of the asset (i.e. the 31st year) and the profit margin will increase. For example, as illustrated in Fig. 6(b), if the acquisition price of the asset at year 6 (or else the discounted translated cumulative cost at year 6) amounts to £2 billion, the breakeven point will be reached during the 18th year, which is the intersection of the cumulative cost (black dotted line) with the cumulative revenues denoted by the blue solid line, assuming that WACC = 6%. The intersection point of the two lines is indicated by the purple circle mark. As such, the maximum acquisition price at the commissioning year of the wind farm (namely, the 6th year) can be calculated by subtracting the cumulative revenues of the asset from the translated cumulative costs at that year. Taking into account the upper and lower WACC bounds considered for this type of investor, the maximum price of purchase is £1,770 for WACC = 12% and 2668 million for WACC = 6%, as indicated by the red and blue dotted lines at the beginning of year 6, respectively. Therefore, it is deemed that the final price of the asset would, most probably, lie in the region between the minimum selling and the maximum purchase price, estimated by the PC and the LE investors, respectively. For the above mentioned example, the price of the wind farm is, thus, expected to lie in the region £1,078–£2,668 million, depending on the cost of capital of both investors.

However, it must be highlighted that the "price" and the "value" of the asset represent different concepts, with the price of the asset being determined by supply and demand, while the value is estimated by accounting for the cost and the return of an investment. In general, it is deemed that the price of an asset should be a result of adding a reasonable profit to a cost, which, however, is not always the case. Setting a price for an asset simply on the basis of its costs and revenues can, therefore, be considered a simplistic approach, although it makes sense to assume that the price is set by the value. The demand for investing in OW energy assets is influenced by a number of factors, in example the stability of the regulatory framework for the promotion of the technology, the lack of grid availability (particularly in markets where project sponsors are not in charge of the grid connection), etc. [21].

## 6. Conclusions

Offshore wind investments have reached reasonably maturity over the past decade. With 92 wind farms in operation in European countries, distinctive clusters of investors can be observed with new clusters expected to focus on the second half of the operational life of wind farms; in example, investors who will purchase assets approaching the end of their commercial life, at a low cost and extend its life in expense of higher O&M costs [80]. A detailed assessment of the returns is pertinent towards understanding the real cost and opportunity of investing in new or existing operational wind farms. Such an assessment could facilitate fair valuation of assets, supporting relevant investment/divestment decisions.

This paper has developed a methodological framework for the techno-economic analysis of a wind farm allowing for the assessment of the investment value from the perspective of different classes of investors. To this end, a life cycle cost/revenue model, which is decomposed further into CAPEX, OPEX and FinEX components, has been developed and applied for different investor classes.

The sensitivity analysis of the model has revealed that financial and revenue parameters have greater influence on the NPV of the investment in comparison to CAPEX and OPEX parameters. More in specific, the WACC along with the strike price and the energy production were found to cause the highest deviation, while the mean time to failure and the workboat wave height limit were the OPEX parameters with the highest impact. As far as CAPEX is concerned, reduction in the acquisition cost of wind turbines and foundations can yield the highest increase in the NPV of the investment.

Although several previous studies focus on the life-cycle cost assessment of OW farms and their economic feasibility, the consideration of different equity investors with different investment strategies that buy and sell stakes at different time instances during the life of an OW farm project, and the development of a relevant tool that enables such investors to assess the viability of their investment has not been previously investigated. Furthermore, in relation to other academic models in literature, the present study provides an integrated lifecycle cost revenue model of high fidelity aiming to increase accuracy of results, while there is, currently, no study to date to link the cost model to investment decisions. This is an element that is addressed from operators who have developed their own cost tools, but these are not included in the current body of literature.

Implementation of the lifecycle cost/revenue model from the perspective of different investors can contribute towards the fairer temporal evaluation of the wind energy asset. As such, the BOT class of investors (typically consisting of Major Utilities like DONG Energy, RWE, etc.), tend to keep the (majority stake of the) operating assets in their balance sheets. The temporal cost/revenue profile of the project can be used to estimate its value throughout its lifespan and derive the breakeven year. The PC investor cluster typically consists of OEMs and EPCI contractors with relatively higher costs of capital (in the range of 12–15%) than the BOT cluster. They would normally seek to sell the asset at a higher price in comparison to its construction cost to compensate for the risk to carry out the procurement and construction works. On the one hand, LE investors typically comprising third party capital investors, such as pension funds, are more likely to seek for a low risk investment with stable returns. When it comes to appraising the asset, they will need to assess the expected future costs and revenues and come up with an offer that will be lower than the breakeven point derived from the cash flow model. Above analysis, takes into account the different cost of capital values applicable to each investor class.

## Acknowledgements

This work was supported by grant EP/L016303/1 for Cranfield University and the University of Oxford, Centre for Doctoral Training in Renewable Energy Marine Structures (REMS) (http://www.rems-cdt.ac.uk/) from the UK Engineering and Physical Sciences Research Council (EPSRC).

## Appendix A. Installation of foundations

The number of voyages (from the staging port to the installation site and vice versa) is calculated as:

$$N_{F,voy} = \frac{n_{WT}}{VC_{F,JU}} \tag{A.1}$$

where, $VC_{F,JU}$ is the jack up vessel capacity of foundations. The time of jacking at port can be estimated as:

$$T_{j,port} = \frac{WD_{port}}{V_j} \tag{A.2}$$

where, $WD_{port}$ denotes the water depth at the port (m) and $V_j$ the jacking up speed (in m/h). The jacking (up/down) time at the wind farm site is estimated as:

$$T_{j,site} = \frac{WD}{V_j} \tag{A.3}$$

where, $WD$ is the water depth at wind farm site (m). The time to travel from port to farm can be found as:

$$T_{port\ to\ farm} = 2\cdot T_{JU,voy}\cdot N_{F,voy} \tag{A.4}$$

The voyage time, $T_{j,voy}$ is estimated by taking into account the vessel speed, $V_{S,JU}$ (in km/h), and the distance, $D$ (in m), between the wind farm site and the port:

$$T_{JU,voy} = \frac{D}{V_{S,JU}} \tag{A.5}$$

The time to travel between turbines can be estimated as:

$$T_{F,mov} = (VC_{F,JU}-1)\cdot T_{betwtrb,F}\cdot N_{F,voy} \tag{A.6}$$

The travel between turbines time is estimated by:

$$T_{betwtrb,F} = \frac{d_{trb}}{V_{S,JU}} \tag{A.7}$$

where, $d_{trb}$ is the mean distance between consecutive turbines. Assuming 12 working hours per day, $T_{workhrs}$, along with a time adjustment factor for the consideration of potential adverse weather conditions during the offshore operations ($ADJWEATHER$), the number of effective days was estimated as:

$$T_{effectdays,F} = \frac{T_{F,Instal}}{T_{workhrs}\cdot ADJWEATHER} \tag{A.8}$$

Input data that were used for the calculation of installation time of foundations are summarised in Table A.1.

**Table A.1**
Parameters used for the calculation of installation time of foundations.

| Parameter | Value |
|---|---|
| $VC_{F,JU}$ | 4 Units/trip |
| $V_{N,JU}$ | 3 |
| $WD_{port}$ | 20 m |
| $V_j$ | 30 m/h |
| $T_{F,Load}$ | 2 h/turbine |
| $T_{workhrs}$ | 12 h |
| $T_{F,Lift}$ | 4 h/turbine |
| $R_{F,pile}$ | 0.65 h/m |
| $D_{F,driv}$ | 30 m |
| $ADJWEATHER$ | 0.85 |
| $d_{trb}$ | 800 m |
| $n_{workers}$ | 30 |

## Appendix B. Installation of wind turbines

The cost components throughout the turbine installation are outlined in this Appendix. Calculations were based on the work of [46] under the conditions described below. The total travel time for transporting the turbines was calculated by the following expression:

$$T_{T,Travel} = \frac{n_{WT}}{V_{S,JU}\cdot V_{N,JU}}\left[(2\cdot D - d_{trb} + t_{PL}\cdot V_{S,JU})\cdot\left(\frac{A_{Tj}\cdot e^{q_1\cdot(P_{WT}-2)}}{A}\right) + 2V_{N,JU}\cdot d_{trb} + t_{FS}\cdot V_{N,JU}\cdot V_{S,JU}\right] \tag{B.1}$$

where, $n_{WT}$ represents the number of wind turbines, $V_{S,JU}$ is the vessel speed (km/h), $V_{N,JU}$ is the number of vessels, $t_{PL}$ symbolizes the pre-loading time in the port (h), $t_{FS}$ is the pre-loading time at site, $A_{Tj}$ is the area required for one reference turbine with rated power 2 MW during transport (m$^2$), $A$ is the free deck area for transportation of components (m$^2$), and $q_1$ is the constant coefficient (0.1019). The total lifting time was estimated by the following expression:

$$T_{T,Lift} = \frac{2^b\cdot(n_{WT}\cdot N_{Lj})^{1+b}\cdot e^{q_2\cdot(P_{WT}-2)}}{R_L}(\alpha_1\cdot P_{WT}^2 + b_1\cdot P_{WT} + c_1 + H_{JU}) \tag{B.2}$$

where, $b = \frac{\log(L_R)}{\log 2}$ with the learning rate $L_R = 0.95$, $b < 0$, $N_{Lj}$ is the number of lifts for each turbine during loading or installation, $q_2$ is a constant (0.3214), $R_L$ is the lifting rate $\left(40\frac{\text{m}}{\text{hour}}\right)$, $\alpha_1$ is a constant (0.5714), $b_1$ is a constant (0.7714), $c_1$ is also a constant (77.12), and $H_{JU}$ represents the jack up height [m]. The total assembly (onshore and offshore) time is further described below:

$$T_{T,Assemb} = \frac{n_{WT}^{1+b}e^{q_2(P_{WT}-2)}}{R_A}((M - N_{Lj})^{1+b} + W\cdot N_{Lj}^{1+b}) \tag{B.3}$$

where, $R_A$ is the rate of assembly $\frac{1 assembly}{2h}$, $M$ is the number of parts in each turbine (7) and $W$ is the weather multiplier for offshore lift. Finally, the total jack up time is calculated by the following equation: (See Table B1)

$$T_{JU} = \frac{n_{WT}\cdot \mathrm{H_{JU}}}{V_{S,JU}}\left(\frac{A_{Tj}\cdot e^{q_1(P_{WT}-2)}}{A} + 4\right) \tag{B.4}$$

**Table B.1**
Parameters used for the calculation of installation time of wind turbines.

| Parameter | Value |
|---|---|
| $M$ | 7 |
| $W$ | 2 |
| $V_{N,JU}$ | 2 |
| $A$ | 7000 m$^2$ |
| $A_{Tj}$ | 550 m$^2$ |
| $N_{Lj}$ | 3 |
| $t_{PL}$ | 5 h |
| $t_{FS}$ | 1 h |
| $R_L$ | $40\frac{m}{h}$ |
| $R_A$ | $1\ \frac{assembly}{2\ h}$ |
| $H_{JU}$ | 35 m |
| $L_R$ | 0.95 |
| $q_1$ | 0.1019 |
| $q_2$ | 0.3214 |
| $\alpha_1$ | 0.5714 |
| $b_1$ | 0.7714 |
| $c_1$ | 77.12 |

## Appendix C

(See Table C1).

**Table C.1**
List of symbols.

| | |
|---|---|
| $A$ | Free deck area for transporting equipment ($m^2$) |
| $A_{Tj}$ | Area required for one reference turbine with rated power 2 MW during transport ($m^2$) |
| $A_{TR}$ | Rated power of transformer (MVA) |
| $\alpha_1$ | Constant |
| $ADJWEATHER$ | Weather adjustment factor |
| $b_1$ | Constant (0.7714) |
| $C_{Cables,ic}$ | Total installation cost of cables (£) |
| $C_{cables,dd}$ | Total cost of cables removal (£) |
| $C_{cables,pa}$ | Total cost of cables (£) |
| $C_{C-export,ic}$ | Installation cost of export cables (£) |
| $C_{C-array,ic}$ | Installation cost of array cables (£) |
| $C_{clear,dd}$ | Total cost for site clearance (£) |
| $C_{cont,pc}$ | Contingency costs (£) |
| $C_{DG}$ | Diesel generator cost (£) |
| $C_{disposal,dd}$ | Disposal cost (£) |
| $C_{eng,pc}$ | Engineering costs (£) |
| $C_{equipment}$ | Cost of equipment (capital assets) over the lifetime of the investment (£) |
| $C_{F,ic}$ | Total installation cost of foundations (£) |
| $C_{grout,dd}$ | Grout removal cost (£) |
| $C_{insur,ic}$ | Installation insurance cost (£) |
| $C_{insur,om}$ | Operation insurance cost (£) |
| $C_{legal,pc}$ | Legal costs (£) |
| $C_{offSubst,ic}$ | Total installation cost of the two substations (£) |
| $C_{offSubst,pa_f}$ | Substation platform cost (£) |
| $C_{offSubst,pa}$ | Cost of offshore substation (£) |
| $C_{onSubst,pa}$ | Cost of onshore substation (£) |
| $C_{offSubst,dd}$ | Total cost for removing the two substations (£) |
| $C_{proj,pc}$ | Project management cost during predevelopment and consenting (£) |
| $C_{proj,om}$ | Project management cost during operation of the wind farm (£) |
| $C_{D\&D}$ | Total disposal and decommissioning costs (£) |
| $c_{F,mat}$ | Cost of materials for foundations (£/foundation) |
| $c_{F,manuf}$ | Cost of manufacturing of foundations (£/foundation) |
| $c_{F,pa}$ | Unit cost of foundation (£/foundation) |
| $C_{I\&C}$ | Total installation and commission costs (£) |
| $C_{P\&A}$ | Total production and acquisition costs (£) |
| $C_{P\&C}$ | Total predevelopment and consenting costs (£) |
| $C_{protection}$ | Cost of protective equipment for cables (£) |
| $C_{port,dd}$ | Cost of port preparation (£) |
| $C_{repair,om}$ | Repair costs (£/year) |
| $C_{rent,om}$ | Rent costs (£/year) |
| $C_{SG,HV}$ | HV switchgear cost (£) |
| $C_{SG_{MV}}$ | MV switchgear cost (£) |
| $C_{SCADA,pa}$ | Cost of monitoring (£/turbine) |
| $C_{Scour,ic}$ | Total installation cost of scour (£) |
| $C_{Scour,dd}$ | Scour protection removal cost (£) |
| $C_{surveys,pc}$ | Environmental survey costs (£) |
| $C_{TF,dd}$ | Total cost for removing all wind turbines with monopiles (£) |
| $C_{TR}$ | MV/HV transformer cost (£) |
| $C_{vessel,dd}$ | Total cost of hiring technicians and workboats during the decommissioning of the wind turbines (£) |
| $C_{transp,dd}$ | Total cost for the transportation of decommissioned parts (£) |
| $C_{truckperton-mile}$ | Cost per ton-mile of the transportation truck (£/ton/mile) |
| $C_{T,ic}$ | Total installation cost of turbines (£) |
| $c_{T,pa}$ | Unit cost of wind turbine (£/turbine) |
| $C_{TF,dd}$ | Removal cost of turbines and monopile foundations (£) |
| $c_{BB}$ | HV busbar cost (£) |
| $c_i$ | Unit cost of the cable (£/km) |

(continued on next page)

**Table C.1** (*continued*)

| | |
|---|---|
| $c_1$ | Constant |
| $D$ | Distance of installation site from port (km) |
| $D_{pile}$ | Depth of pile under the soil (m) |
| $D_{port-facility}$ | Distance of port from the waste facility (km) |
| $D_{F,driv}$ | Distance of monopile driven into the seabed |
| $DCC_{translated,t}$ | Discounted translated cumulative cost at year $t$ (£) |
| $DCC_t$ | Discounted cumulative costs at year $t$ (£) |
| $DCR_t$ | Discounted cumulative revenues at year $t$ (£) |
| $d$ | Rotor diameter (m) |
| $d_{credit}$ | Tax depreciation credit reduced from the total tax payment (£) |
| $d_{rate}$ | Tax depreciation rate (%) |
| $d_{trb}$ | Mean distance between consecutive turbines (m) |
| $E$ | Number of intervals for which reliability data are collected |
| $FTC$ | Fault type classes |
| $H_{JU}$ | Jack up height (m) |
| $h$ | Hub height (m) |
| $K$ | Number of subassemblies |
| $L_i$ | Length of cable of type $i$ (km) |
| $L_1$ | Length of array cables (km) |
| $L_2$ | Length of export subsea cables (km) |
| $L_3$ | Length of export onshore cables (km) |
| $L_R$ | Learning rate |
| $M$ | Number of parts comprising each turbine |
| $MTBF$ | Mean time between failures (h) |
| $MTTF$ | Mean Time To Failure (h) |
| $MTTR$ | Mean time To Repair (h) |
| $N_i$ | Number of cables of type $i$ |
| $N_{F,voy}$ | Number of voyages for the transportation of foundations |
| $N_{Lj}$ | Number of lifts for each turbine during loading or installation |
| $N_{T,e}$ | Number of turbines that were examined for deriving the failure rates |
| $N_{trips,scour}$ | Number of trips required for the installation of scour protection |
| $n$ | Lifetime of the investment (years) |
| $n_{e,k}$ | Number of failures |
| $n_{Subst,pile}$ | Number of piles per substation foundation |
| $n_{TR}$ | Number of transformers |
| $n_{WT}$ | Number of turbines |
| $n_{workers}$ | Number of workers |
| $P_{WF}$ | Capacity of the wind farm (MW) |
| $P_{WT}$ | Capacity of the wind turbine (MW) |
| $P_{gr}$ | Amount of gross profit (£) |
| $P_{net}$ | Amount of net profit of the investment (£) |
| $q_1$ | Constant coefficient 1 (0.1019) |
| $q_2$ | Constant coefficient 2 (0.3214) |
| $RFF_{fc}$ | Relative failure frequencies (%) |
| $R_A$ | Assembly rate (assembly/hour) |
| $Rd$ | Interest rate on debt (%) |
| $R_{infl}$ | Inflation rate (%) |
| $R_L$ | Lifting rate (m/hour) |
| $RoE$ | Return on Equity rate (%) |
| $R_{Subst,pile}$ | Rate of piling the piles of the substructure (h/m) |
| $R_{F,pile}$ | Rate of piling the monopile (h/m) |
| $SPU$ | Tonnage of scour protection per unit (ton/turbine) |
| $T_{C-array,Inst}$ | Effective days required for the installation of array cables (days) |
| $T_{C-export,Inst}$ | Effective days required for the installation of export cables (days) |
| $T_{Effectdays,F}$ | Number of effective days for the installation of the foundations (days) |
| $T_{Effectdays,Scour}$ | Total effective days for scour installation (days) |
| $T_{Effectdays,Substat-Rem}$ | Total effective days for the removal of the substations (days) |
| $T_{Effectdays,TF-Rem}$ | Total time effective days for the removal of turbines and monopiles (days) |
| $T_{Effectdays,T}$ | Total effective days of turbines installation (days) |
| $T_{F,Instal}$ | Total installation time of foundations (h) |
| $T_{F,Lift}$ | Offshore lifting time (h) |
| $T_{F,Load}$ | Pile loading time (h) |
| $T_{reposit}$ | Reposition time of the vessel (h) |
| $T_{HL,voy}$ | Voyage time of heavy-lift vessel from the port to the installation site (h) |

(*continued on next page*)

**Table C.1** (*continued*)

| | |
|---|---|
| $T_{JU}$ | Total jack up time (h) |
| $T_{Scour,Inst}$ | Total time for scour installation (h) |
| $T_{Scour,Tr}$ | Travel time from/to port (h) |
| $T_{Scour,Dump}$ | Dumping time per trip (h/trip) |
| $T_{Scour,Load}$ | Loading time per trip (h/trip) |
| $T_{Subst,Inst}$ | Total installation time of the substation (days) |
| $T_{Substjacket,Inst}$ | Installation time of the substation's jacket (h) |
| $T_{T,Assemb}$ | Assembly time of wind turbine (h) |
| $T_{T,Instal}$ | Total installation time of turbines (h) |
| $T_{T,Lift}$ | Lifting operation time of wind turbine (h) |
| $T_{T,Travel}$ | Travel/transportation time of turbines (h) |
| $T_{betwtrb,F}$ | Travel time from one turbine to the next (h) |
| $T_e$ | Total time period during which failures are counted (h) |
| $T_j$ | Total jacking up operational time (h) |
| $T_{j,port}$ | Time of jacking of the jack-up vessel at port (h) |
| $T_{j,site}$ | Time of jacking of the jack-up vessel at installation site (h) |
| $T_{porttofarm}$ | Travel time from port to farm (h) |
| $T_{workhrs}$ | Working hours (h) |
| $t_c$ | Nominal corporate income tax rate (%) |
| $t_{net}$ | Amount of net tax (£) |
| $t_{FS}$ | Pre-loading time at site (h) |
| $t_{PL}$ | Pre-loading time in the port (h) |
| $t_{payment}$ | Amount of tax payment over the gross profit (£) |
| $V$ | Sum of Equity and Debt (£) |
| $V_{DR,CLV-array}$ | Day rate of Cable Laying Vessel for the installation of array cables (£/day) |
| $V_{DR,CLV-export}$ | Day rate of Cable Laying Vessel for the installation of export cables (£/day) |
| $V_{DR,Trench}$ | Day rate of trenching ROV (Remotely Operated underwater Vehicle) for the installation of subsea cables (£/day) |
| $V_{DR,HLV}$ | Day rate of Heavy Lift Vessel (HLV) for the installation of the substation units (£/day) |
| $V_{Mobil,CLV}$ | Mobilisation cost of Cable Laying Vessel (£) |
| $V_{Mobil,HLV}$ | Mobilisation cost of Heavy Lift Vessel (£) |
| $V_{N,JU}$ | Number of identical jack up vessels used for the installation of the wind turbines |
| $V_n$ | Nominal voltage (kV) |
| $V_{scour,Mobil}$ | Mobilisation cost of rock-dumping vessel (£) |
| $V_{S,HL}$ | Speed of heavy lift vessel (km/hour) |
| $V_{S,JU}$ | Speed of jack-up vessel (km/hour) |
| $V_j$ | Jacking speed (m/hour) |
| $VC_{F,JU}$ | Deck capacity of jack-up vessels for foundations (number of foundations per voyage) |
| $VC_{Scour}$ | Rock-dumping vessel capacity (ton/trip) |
| $VD$ | Market Value of Debt (£) |
| $VE$ | Market Value of Equity (£) |
| $W$ | Weather Multiplier for offshore lift |
| $W_{components}$ | Total mass of the wind farm components (ton) |
| $W_{Subst,top}$ | Mass of the topside substation (ton) |
| $W_{truck}$ | Load capacity of truck (ton) |
| $WACC$ | Weighted average cost of capital (%) |
| $WACC_{nom}$ | Nominal weighted average cost of capital (%) |
| $WACC_{real}$ | Real weighted average cost of capital (%) |
| $WD$ | Water depth at the installation site (m) |
| $WD_{port}$ | Water depth at the port (m) |
| $\lambda$ | Failure rates per turbine per year |

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