

Review of offshore wind farm cost components

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Abstract

This paper reviews the data available in the bibliography relative to most important economical factors in an offshore wind farm, including the acquisition/installation of wind turbines and foundations, electrical infrastructure, design and project management, and operation/maintenance. These data are necessary to carry out any profitability analysis, or optimization procedure. In order to establish a common reference, prices have been translated into an unique currency and taken to the present year. Taking into account these considerations, the paper presents an estimation of the different costs as a function of the farm size. Finally, the main cost drivers affecting the capital and operating expenditures are presented and discussed.

Keywords: offshore wind farms, costs, electrical infrastructure, CAPEX, levelized cost of energy

1. Introduction

A large number of studies have been conducted in order to optimize the design of onshore wind farms. The objective in these studies is to select and place the components that optimize a specific economic indicator, such as the internal rate of return, the net present value, or mainly, the levelized cost of energy (LCOE). These economic figures takes into account the investment, decommissioning cost, the revenues derived from the energy sold, and the operation and maintenance cost. Latelly, similar studies are being performed for Offshore Wind Farms (OWFs).

Accordingly, before addressing the problem of optimizing an OWF, consistent data are required on the most significant aspects involved in the planning, construction, operation and decommissioning of the wind farm. Many aspects of the engineering related to this technology can be easily found. There is therefore sufficient information regarding the foundation techniques [Vølund][Kaiser and Snyder][Loman], electrical infrastructure, [ODIS] (Offshore Development

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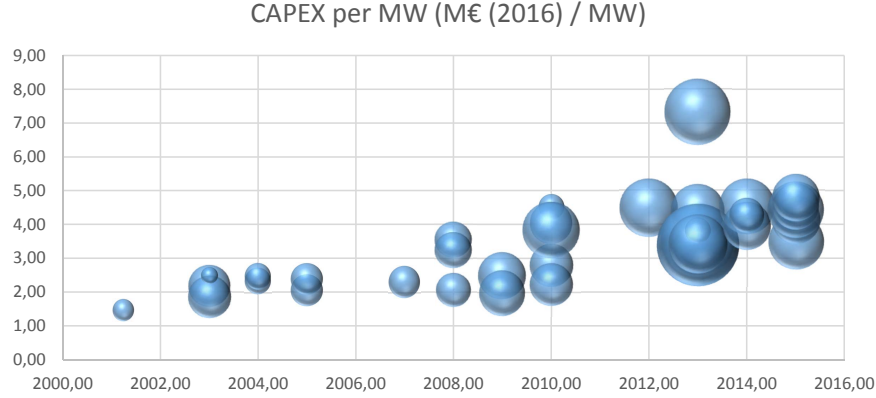


Figure 1: Investment per MW translated into present euros (2016) of commissioned OWFs. The bubble size represents the park capacity.

15 Information Statement) [Nikolaos], availability and reliability [Larsen et al.], or wakes in offshore power plants [Frandsen et al.].

However, the theoretical, qualitative, or heuristic study of the factors influencing the profitability of a site is worthless if it fails to include realistic data on the economic costs of each concept involved in the analysis. Unfortunately, the number of sources and their dependability are very reduced. These are important factors that contribute to the uncertainty in the profitability assessment of an OWF. Additional sources for this uncertainty come from the following factors:

- variable competitiveness in the supply chain,
- 25 • volatility in the commodities prices, with a strong influence on turbines, cables and foundations,
- prices given at different currencies and years,
- different metocean and seabed conditions, which modify the characteristics of the foundations and the downtime periods due to rough weather, and
- 30 • different distances from the park site to the nearest harbor with enough staging and manufacturing facilities.

These factors will be explained in Section 7, but we can anticipate that the first two ones are responsible of the variability over time in the main components of Capital Expenditure (CapEx) and Operating Expenditure (OpEx). The price evolution of the main components in an OWF is presented in [Ernst & Young]. This report shows that the overall cost of acquisition plus installation per MW has markedly increased in recent years. The same is presented in Fig. 1 which represents the investment cost per installed MW of a number of wind farms in operation in the North Sea. Data have been mainly obtained from 4coffshore.com, and prices have been normalized into the same reference (in this paper euros at 2016), as usual for comparison purposes [Kaiser and Snyder]. To this end, the reviewed values have been converted into euros and increased according to the accumulated inflation (see Fig. 2).

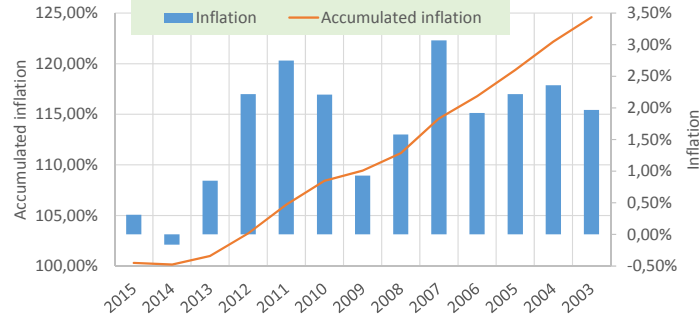


Figure 2: Inflation and accumulated inflation over the past twelve years. The accumulated inflation is calculated taken 2016 as reference (100 %).

The observed ascending price trend of Fig. 1 has gone against the convention
of decreasing costs usually achieved through economies of scale, learning curves
and supply chain improvements [Douglas-Westwood]. Factors for this trend
included exploring deeper waters and higher commodity prices, reduction and
centralization of supply chain competition, and increasing demand for common
supply from onshore wind EWEA (2009). Recent years have seen a descending
trend in the commodities prices and a lower vessel demand from the oil and gas
sector. This is balanced by the competition with onshore wind turbine supply,
and exploration of deeper waters, thus resulting in the price stagnation observed
in Fig. 1.

In order to reduce the commented uncertainty to a minimum, and to provide
a LCOE estimator with relatively dependable values, it is necessary to gather
as much data as available. In this sense, it is possible to find valuable reports
compiling the sources relative to investment costs [Rosenauer], [Gooch et al.],
with a thorough study of different foundation techniques, although the electrical
infrastructure is not generally dealt with in the same profusion. Therefore, it is
necessary to complete these data with information about the inter-array cables
and their characteristics in order to evaluate the power losses of each cable and
allow a designer to choose the most suitable cable as a function of its price and
the expected power flow. In addition, present paper reviews the bibliography
in order to complete previous reports with additional sources and new values
in order to take into account other important items in the profitability analy-
sis of an OWF: design and project management, operation and maintenance,
mobilization/demobilization, and decommissioning.

Table 1 presents a list of commissioned OWFs from which useful economic
values have been extracted. Since all economic data are translated into €_{2016} ,
the last column represents the normalization factor that must multiply the origi-
nal cost in order to obtain its normalized value in €_{2016} .

In Table 2, the reviewed OWFs are planned, under construction, or they are
hypothetical projects that are used as case studies (CS) by the authors. Last

Ref.	Wind Farm	Fnd.	Capacity	Date	CAPEX	Dist. km	Depth m	Curr.	Norm. Factor
1.Md	Middelgrunden	GB	20x2MW	Mar-01	47.7 M€	3.5	3-6	€ ₂₀₀₁	1.301 ¹
2.SS	Scroby Sands	MP	30x2MW	Dec-04	79.8 M£	3 ¹	3-12	£ ₂₀₀₄	1.797 ¹
3.PA	Prinses Amalia	MP	60x2MW	Jun-08	383 M€	30	19-24	€ ₂₀₀₈	1.111 ¹
4.NH	North Hoyle	MP	30x2MW	Mar-04	82 M£	10	7-11	£ ₂₀₀₄	1.797 ²
5.KF	Kentish Flats	MP	30x3MW	May-05	105 M£	12.5	5	£ ₂₀₀₃	1.790 ²
6.HR	Horns Rev	MP	80x2MW	Jul-03	278 M€	55	6-14	€ ₂₀₀₃	1.246 ¹
7.HR2	Horns Rev2	MP	92x2.3MW	May-09	407 M€	98	9-17	DKK ₂₀₀₉	0.147 ¹
8.Ny	Nysted	GB	72x2.3MW	Dec-03	269 M€	6 ¹	6-9	€ ₂₀₀₃	1.246 ³
								\$ ₂₀₀₇	0.8432 ³
9.BB	Burbo Bank	MP	25x3.6MW	Oct-07	181 M€	19	8	\$ ₂₀₀₇	0.8432 ⁴
10.AB	Arklow Bank	MP	7x3.6MW	Dec-03	47.4 M€	12	15	\$ ₂₀₀₇	0.8432 ⁴

¹ The value corresponds to the distance to shore.

² Costs for these OWFs are given in the corresponding currency.

³ Costs for Nysted are given by [Gerdes et al.] in €₂₀₀₃
and by [Bellone and Dale] in \$₂₀₀₇.

⁴ Costs for these OWFs are given by [Bellone and Dale] in \$₂₀₀₇.

Table 1: Commissioned OWFs in which actual costs are available. The first column lists the reference used along the paper. Following columns are: OWF name, type of foundation (monopile or gravity based), number of turbines and their capacity, commissioning date, CAPEX, distance to the grid, water depth, the currency in which the costs were expressed, and the normalization factor to convert the available cost into present (2016) €.

rows are related to estimated costs of components obtained from experienced
75 companies (Est).

The study obtained from the review of these parks and sources is aimed to
provide the programmer of layout optimization algorithms with the information
necessary to execute it in a coherent way. Such data are realistic but they can-
not be considered reliable for a complete, accurate and thorough study of the
80 cost of investment, operation and decommissioning. However, since those costs
where there is a greater unavailability are fixed costs, such as in management,
finance and administration, then they are considered as a secondary factor in
the optimization analysis. Alternatively, these values can be used as a first esti-
mation of the investment cost and the profitability of an OWF to be projected
85 in a particular location.

Following sections breaks down the most important components affecting
the LCOE, compiled from a number of sources. The extracted data are pre-
sented in the following groups, one per section: design and project management,
and SCADA, in Section 2; turbine and foundation, in Section 3; electrical in-
90 frastructure, in Section 4; operation and maintenance costs, in Section 5; and
decommissioning costs and residual price, in Section 6. Section 7 discusses the
main cost drivers affecting the installation and operation of OWFs, and the
sources of the variability in the observed costs.

Finally, the conclusions, scope and limitation of this study are presented in

Ref.	Wind Farm	Fnd.	Capacity	CAPEX	Dist.	Depth	Curr.	Norm.
					km	m		Factor
11.Du	Dudgeon	MP	67x6MW	1300M£	35	12-24	\$ ₂₀₁₄	0.737
12.Wi	Wikinger	Jk	70x5MW	1350 M€	35	36-40	\$ ₂₀₁₄	0.737
13.No	Nordsee One	MP	54x6.15MW	1200 M€	45	28	\$ ₂₀₁₄	0.737
14.CW	Cape Wind	MP	130x3.6MW	2620 M\$	11	3-15	\$ ₂₀₁₀	0.879
15.BW	Bluewater Wind	MP	150x3MW	1000 M\$	24	10-33	\$ ₂₀₁₀	0.879
16.CP	Coastal Point	Jk	60x2.5MW	360 M\$	8	15	\$ ₂₀₁₀	0.879
17.GS	Garden State	Jk	96x3.6MW	1500 M\$	33	21-30	\$ ₂₀₁₀	0.879
CS-1	[Nikolaos]	TL	110x4.5MW		50		€ ₂₀₀₄	1.222
CS-2	[Douglas-Westwood]	MP	120x5MW	16.2GNOK	15	20	NOK ₂₀₁₀	0.135
CS-3	[Kaiser and Snyder]		83x3.6MW		19		\$ ₂₀₁₀	0.879
CS-4	[Green et al.]		167x3MW		15	20	\$ ₂₀₀₇	0.843
CS-5	[Clasadonte et al.]		8x3MW	52.9 M€		13	€ ₂₀₀₉	1.094
CS-6	[ODE] ¹		30x3.6MW				£ ₂₀₀₇	1.696
CS-7	[Nielsen]		80x3MW		12	10	€ ₂₀₀₃	1.246
Est-1	[EWEA] ²						€ ₂₀₀₉	1.094
Est-2	[Ernst & Young]						£ ₂₀₀₉	1.278
Est-3	[Garrad Hassan]		100 MW				£ ₂₀₀₃	1.790
Est-4	[Smith et al.]						\$ ₂₀₁₄	0.737
Est-5	[ODIS] ³						£ ₂₀₀₉	1.278

¹ ODE, for Offshore Design Engineering Ltd, UK

² EWEA, for European Wind Energy Association

³ ODIS, for Offshore Development Information Statement, UK

Table 2: Planned or hypothetical OWFs in which costs are estimated. First column lists the reference used along the paper. Following columns are: OWF name, type of foundation (Monopile, Jacket or Tension Leg), number of turbines and their capacity, estimated CAPEX, distance to the shore, water depth, currency in which the costs were expressed, and normalization factor.

Park	Source	Cost	$\frac{k\text{€}_{2016}}{MW}$
CS-1	[Nikolaos, page 98]	2.9 M€/495MW	7
3.PA	[Slengesol et al., page 93]	10 M€/120 MW	92
CS-6	[ODE, page 38]	5.6 M£/108MW ¹	88
2.SS	[Gerdes et al., page 127]	1.737 M£/60 MW	52
4.NH	[Slengesol et al., page 91]	80 k£/MW	144
1.Md	[Slengesol et al., page 89]	4 M€/40 MW	130
1.Md	[Larsen et al., page 2]	2.98 M€/40MW	89
Est-1	[EWEA, page 217]	100 k€/MW	109
CS-2	[Douglas-Westwood, page 15]	2.7MNOK/MW	365

¹ Project management + FEED + Engineering phase

Table 3: Design and project management

95 Section 8.

2. Design and project management, and SCADA systems

There are several methods of extrapolating these costs from the reference data. As an example, [ODE] indicates that many of the design/management costs are proportional to the square root of the size. This is a reflection of the economies of scale.

2.1. Design and project management

This activity consists of a variety of items: geophysical and bathymetric surveys, meteorological mast and wind monitoring, insurance, cost of finance, licences, public relations and marketing, environmental-impact assessment, design engineering, and construction management. Detailed costs for them can be found in [Garrad Hassan] and [ODE]. Table 3 shows the compiled values.

2.2. SCADA system

The value of 1 M£/30 turbines (56 k€₂₀₁₆) has been found in [ODE, page 38], and 25 k£/turbine (45 k€₂₀₁₆) in [Garrad Hassan, page I.3].

3. Turbines and foundations

3.1. Turbine cost

As represented in [Douglas-Westwood, page 15], the overall turbine cost consists of: the acquisition cost (AC = 85%); the shipping and assembling (SA = 5%); and the electrical installation (EI = 10%). The shipping depends on the distance to the wind farm, although it constitutes the least significant item.

With regard to only the acquisition cost, a trended cost (in GBP) for turbines as a function of their capacity is given in [ODE, page 47]

$$AC_t = -255016 + 2E6Ln(MW) \quad (1)$$

which for 3.6MW, results 2.7 M£.

Most of the sources do not split the overall turbine cost into these three items, and therefore only the overall cost is presented. Table 4 lists the available data for these costs, together with the base currency, the base capacity (in MW), and the normalized overall cost in €₂₀₁₆. The curve that best fits these data was

$$Cost = 1081 \cdot Cap^{0.9984} \quad (2)$$

where the *Cost* of the turbines is expressed in k€₂₀₁₆ and *Cap* is the OWF capacity in MW. The coefficient of correlation (CoC) was 0.85. The exponent close to 1 might suggest that a linear trend is preferable. The resulting expression is

$$Cost = 1527 \cdot Cap - 38\,303 \quad (3)$$

with *CoC* = 0.997. Despite this fair correlation, the negative independent term (−38 303) discredits this expression. Disregarding the last four rows, corresponding to the year 2014, the dependence is given by

$$Cost = 1374 \cdot Cap^{0.87} \quad \text{with } CoC = 0.968 \quad (4)$$

significantly different to (2) or (3), which indicates the importance of the acquisition year on the turbine cost. The fairly high CoC and the exponent lower than the unity reflects the presence of economies of scale on this item.

3.2. Foundation cost

This cost includes transport, installation, and scour protection to prevent the erosion of sediment around the foundation. In case of GBS foundation, it should also include seabed preparation. The cost is strongly dependent on the type of foundation (gravity, monopile, jacket, or tripod), and in the case of steel solutions, on the price of this commodity. The type of foundation depends, in turn, on the water depth and the seabed characteristics, and to a minor extent, on the turbine capacity and the wave conditions. [Nielsen, page 10] highlights that the increase per m of additional water depth is roughly 2%.

Table 5 presents the information extracted from the reviewed sources.

Following expression is the regression curve that best fits these data, after suppressing two outliers

$$CoF = 363 P^{1.06} \quad \text{with } CoC = 0.9975 \quad (5)$$

with the cost of foundation *CoF* and capacity *P* expressed in k€₂₀₁₆ and MW, respectively. The exponent close to 1 does not reflect any economy of scale.

In addition to these data, Tab. 6 extracted from [Loman] and [Douglas-Westwood] lists the cost of various solutions for a 5MW turbine at a reference

Park	Source	Curr.	MW	AC	SA	EI	$\frac{k\text{€}_{2016}}{MW}$
Est-4	[Smith et al., page 71]	k\$	1494	1494 · 2053			1513
CS-2	[Douglas-Westwood, page 15]	MNOK	600	11.9	0.7	1.1	1850
11.Du	[Smith et al., page 71]	k\$	402	402 · 2112			1557
12.Wi	[Smith et al., page 71]	k\$	350	350 · 1645			1212
13.No	[Smith et al., page 71]	k\$	332	332 · 1998			1473
8.Ny	[Bellone and Dale, page 7]	M\$	165.6	94.9	11.1		540
Est-3	[Garrad Hassan, page I.5]	M£	100	52.5			940
9.BB	[Bellone and Dale, page 6]	M\$	90	69.6	8.1		728
10.AB	[Bellone and Dale, page 6]	M\$	25.2	16.3	1.9		609
CS-5	[Clasadonte et al., page 106]	k€	24	30.400			1386
CS-6	[ODE, pages 40-47]	k£	3.6	2700	216	135	1437
CS-7	[Nielsen, page 34]	k€	3.5	2975			1059
Est-1	[EWEA, page 217]	k€	1	815			892
Est-2	[Ernst & Young, page 29]	k£	1	1500			1917

Table 4: Cost of the turbine acquisition, shipping and assembling, and electrical installation

Park	Source	Curr.	MW	Acq	Inst	$\frac{k\text{€}_{2016}}{MW}$
CS-2	[Douglas-Westwood, page 15]	mNOK	600 MP	4.33	1.8	828
CS-1	[Nikolaos, page 198]	m€	495 TL	520		1163
8.Ny	[Bellone and Dale, page 7]	m\$	165.6 GB	33.84	32.58	338
8.Ny	[Gerdes et al., page 103]	m€	165.6 GB	45		339
8.Ny	[Vølund, page 3]	m€	165.6 GB	0.26		324
Est-3	[Garrad Hassan, page I.5]	m£	100 MP	22.5	12	618
9.BB	[Bellone and Dale, page 6]	m\$	90 MP	24.83	23.91	457
1.Md	[Larsen et al., page 8]	m€	40 GB	9.92		592
1.Md	[Vølund, page 3]	m€	40 GB	0.32		416
10.AB	[Bellone and Dale, page 7]	m\$	25.2 MP	5.8	5.58	381
CS-6	[ODE, pages 20,39]	m£	3.6 MP	0.67	0.33	471
CS-7	[Nielsen, page 31]	k€	1 GB	359		447
Est-1	[EWEA, page 217]	k€	1	350		383
Est-2	[Ernst & Young, page 29]	k£	1	700		895

MP: monopile GB: gravity based TL: tension leg

Table 5: Foundation costs

Depth (m)	Gravity based	Steel monopile	Steel jacket	Tripod
	520 -875	678	665	842
< 20 m	365	581	486	729
$\in [20, 29]$	513	729	608	972
$\in [30, 39]$	864	972	918	1094

Table 6: Cost in k€₂₀₁₆/MW for different foundation techniques, as extracted from [Loman] and [Douglas-Westwood, page 26].

Cross Area (mm ²)	Fixed losses (W/m)	Variable losses (mW/m/A ^{1/2})	I_{max} (A)	Price (\$/m)	Norm. price (€ ₂₀₁₆ /m)
A95	0	0.714	380	152	128
A150	6	0.435	430	228	192
A400	24	0.192	680	381	321
A630	34	0.123	780	571	481
A800	50	0.0862	900	600	506
B95	0	0.833	260	455	384
B150	6	0.5	360	494	416
B400	8	0.172	640	609	513
B630	10	0.111	790	635	535
B800	12	0.0862	900	731	616

Table 7: Characteristics and price for inner array cables, extracted from [Green et al.].

water depth of 35 m for a number of technologies. The costs have been translated
150 into k€₂₀₁₆ and they include design, fabrication and installation. An additional
cost of 252 –383 k€/5MW must be included for gravity-based structures due
to seabed preparation.

4. Electrical infrastructure

4.1. Cables

155 4.1.1. Inner Array cables

Table 7 has been obtained from information provided by [Green et al.]
with respect to 2 manufacturers, designated as *A* and *B*. Prices were given
in \$₂₀₀₆/m, and are normalized into €₂₀₁₆/m.

160 These data can be used for the selection of the most suitable cable in terms
of the purchase cost and the energy losses throughout the lifespan of the instal-
lation.

Additional data are found:

- in [Nielsen, page 14] with a cost of 85€/m (106 €₂₀₁₆/m) for Cu sections
of 150 mm²

Park	Source	Original Price	Norm. Price ($\text{€}_{2016}/\text{m}$)
CS-3	[Kaiser and Snyder, page 170]	166 $\$/\text{m}$	146
CS-4	[Green et al., page 3]	94 $\$/\text{m}$	79
CS-4	[Green et al., page 3]	103 $\$/\text{m}$	87
Est-5	[ODIS, page 46]	276 $\text{£}/\text{m}^*$	59
CS-6	[ODE, page 40]	195 $\text{£}/\text{m}$	331
CS-7	[Nielsen, page 13]	50 $\text{€}/\text{m}$	62
CS-2	[Douglas-Westwood, page 35]	1MNOK/km	135

¹ Assuming a cable laying rate of 400 m/day.

Table 8: Installation cost of inner array cables.

- in [Douglas-Westwood, page 35] with a cost of 1.4 MNOK/km (189 $\text{€}_{2016}/\text{m}$) for Cu sections of 250 mm^2 , or a cost of 3.8 MNOK/km (513 $\text{€}_{2016}/\text{m}$) for Cu sections of 380 mm^2 , and
- in [Nikolaos, page 95] with a cost of 100 $\text{€}/\text{m}$ (122 $\text{€}_{2016}/\text{m}$).

A supplementary cable extension of 40 m must be added to each turbine for connections.

4.1.2. Installation cost of inner array cables

Cable lay activity is one of the most challenging aspect of construction. Table 8 presents the compiled data for this cost including transport, and laying/burying operations. Except in bedrock seafloors, this cost can be lower than in the case of export cables, because, thanks to a lower shipping transit cost, the burial depth is lower. [Green et al., page 5] propose that only laying is enough. However, insurers statistics show that cables are responsible of over fifty percent of damages paid [Slengesol et al.]. As an example given by [Gerdes et al.], the anchor of a construction vessel destroyed one of the interconnection cables in Horns Rev park when it was laid unprotected on the seabed. Since repair and remedial works are very expensive, it is advisable to bury the cables to a depth that depends on the seabed subsidence.

4.1.3. Export cables

[ODIS, page 29] provides the values of Tab. 9 for 3-core 132 kV and 220 kV subsea cables, in which a J-tube de-rating factor of 0.88 has been applied.

Additional data are found in:

- [Green et al., page 5], with 755 $\$/\text{m}$ (636 €_{2016}) for a 630 mm^2 cable, 170 kV, and 860 $\$/\text{m}$ (725 €_{2016}) for a 630 mm^2 cable, 150 kV.
- [Nielsen, page 13], with 500 $\text{€}/\text{m}$ (623 €_{2016}) for a 630 mm^2 cable, 150 kV.
- [Nikolaos, page 98], with 260 $\text{€}/\text{m}$ (318 €_{2016}) for a 150 kV cable.

Voltage (kV)	Section (mm^2)	Capacity (MVA)	Price ($\text{£}/m$)	Norm. price ($\text{€}_{2016}/m$)
132	500	138	405	518
132	630	151	463	592
132	800	177	540	690
132	1000	189	630	805
220	500	250	660	843
220	630	273	740	946
220	800	295	830	1061
220	1000	314	950	1214

Table 9: Characteristics and price of export cables.

Park	Source	Original price	Norm. price ($\text{€}_{2016}/m$)
CS-3	[Kaiser and Snyder, page 170]	179 $\text{\$/m}$	157
Est-5	[ODIS, page 29]	500 $\text{£}/m$	639
Est-5	[ODIS, page 46]	552 $\text{£}/m$ ¹	705
CS-6	[ODE, page 40]	195 $\text{£}/m$	331
CS-7	[Nielsen, page 13]	50 $\text{€}/m$	62
CS-1	[Nikolaos, page 95]	70 $\text{€}/m$	86

¹ Assuming a cable laying rate of 200 m/day .

Table 10: Installation cost of export cables.

4.1.4. Installation cost of export cables

This cost is presented in Tab. 10.

4.1.5. Acquisition cost of onshore HV cable

Table 11 presents the prices and capacity regarding 1-core copper cables (XLPE insulated, corrugated aluminium armoured cable), obtained from a manufacturer.

4.1.6. Excavation and Installation of onshore HV cable

[ODIS, page 29] establishes an interval from 300 $\text{£}/m$ in agricultural land to 530 $\text{£}/m$ in roads (383 $\text{€}_{2016}/m$ –677 $\text{€}_{2016}/m$).

Voltage (kV)	Section (mm^2)	Capacity (MVA)	Cost ($\text{\$/m}$)	Cost ($\text{€}/m$)
220	500	273	315	232.8
220	630	297	360	266.0
220	800	314	405	299.3
220	1000	348	497	367.3

Table 11: Acquisition cost of onshore HV cables.

Park Source	Cost	$\frac{k\text{€}_{2016}}{MW}$
CS-2 [Douglas-Westwood, page 38]	0.7 MNOK/MW @ 600 MW ¹	95
CS-4 [Green et al., page 4]	40.52 M\$/500MW	68
CS-1 [Nikolaos, page 98]	25 M€/495MW	61
CS-7 [Nielsen, page 13]	15 M€/ 240MW	78
Est-5 [ODIS, page 44]	28 M£/160MW ²	224
CS-6 [ODE, pages 38,40]	(7.5+1.5) M£/108MW	141
Est-3 [Garrad Hassan, page I.5]	5 M£/100MW	90
1.Md [Slengesol et al., page 89]	4.4 M€/40MW	143
1.Md [Larsen et al., page 2]	4.51 M€/40MW	135

¹ Estimated from a HVDC substation.

² For a 1200-tonne substation, which is the weight of Horns Rev's substation [Gerdes et al., page 73].

Table 12: Cost of the offshore substation.

[ODE, page 40] indicates a value of 125 £/m (212 €₂₀₁₆/m) plus disruption downtime of 25%, and [Garrad Hassan, page I.5] a value of 300 £/m (537 €₂₀₁₆/m).

4.2. Substations

4.2.1. Offshore substation

As pointed out by [Douglas-Westwood] and [Slengesol et al.], it is possible a cost effective grid connection at medium voltage to existing onshore substations if the OWF is small, or it is close to the shore. It is the case of Middelgrunden, Egmond aan Zee, Scroby Sands or Kentish Flats. Otherwise, an offshore substation must be included with the electrical equipment to transform the medium inter-array voltage (typically 30-34 kV) to the transmission network high voltage. This equipment will be supported on a jacket or monopile (for smaller platforms) foundation. The substation capacity determines the cost and weight of the electrical equipment (mainly transformer and gas insulated switchgears), and in turn the weight and cost of the substructure, which also depends on the water depth. The cost for both components, electrical equipment and platform, are approximately equal for HVAC substations. In the case of HVDC, [Douglas-Westwood] increases the former cost in 500%, and [ODIS] in about 50%.

Table 12 lists the available data. The cost of the offshore substation CoS can be expressed as:

$$CoS = 539 P^{0.678} \quad \text{with } CoC = 0.861 \quad (6)$$

with the cost CoS and capacity P expressed in $k\text{€}_{2016}$ and MW , respectively. The exponent lower than the unity reflects the presence of economies of scale on this component.

Park	Source	Cost	$\frac{k\text{€}_{2016}}{MW}$
CS-4	[Green et al., page 4]	29.37 M\$/500MW	50
CS-1	[Nikolaos, page 98]	30 M€/495MW ¹	75
CS-7	[Nielsen, page 13]	34 M€/240MW ¹	177
CS-6	[ODE, page 38]	3 M£/108MW	47

¹ Including onshore cables

Table 13: Onshore substation.

4.2.2. Power factor compensating devices

225 It may be necessary to include HVAC shunt reactors in three core cables to compensate for the reactive power of AC transmission networks. Its price is not significant: 2 k£/100MVar at 132 kV (2556 €₂₀₁₆) [ODIS, page 36].

HVAC static VAR compensators (SVC) and STATCOM can compensate either reactive or capacitive characteristics, to regulate the local voltage at the interface point. From [ODIS, pages 40-42], $C_{SVC} = 5 \text{ k£} + 50 \text{ £/MVar} =$
230 $6390\text{€}_{2016} + 63\,900\text{€}_{2016}/\text{MVar}$ and $C_{statcom} = 100 \text{ £/MVar} = 128\text{k€}_{2016}/\text{MVar}$.

4.3. HV connection

Regulations in some countries like Denmark and Germany dictate that the acquisition and installation of export cable supply, as well as the onshore grid connection is covered by the grid operator [Slengesol et al.]. Consequently, these
235 costs are frequently gathered in a single item.

4.3.1. Shoreline transitions

A barge of around 1.3 M£ (1661 k€₂₀₁₆) is given in [ODIS, page 52], mainly for the horizontal directional drilling, from land to sea.

4.3.2. Onshore substation

240 The available data is presented in Tab. 13.

4.3.3. Connection to the grid

Grid connection can be highly variable, depending on whether the grid is sufficiently strong or if it needs reinforcement. It can be covered by subsidies
245 [Gerdes et al., page 144] or by the grid operator [Slengesol et al., pages 11-12].

The expression relating the cost of the connection to the grid and the park capacity, after extracting an outlier, is:

$$CCG = 8.047P^{1.66} \quad \text{with CoC} = 0.82 \quad (7)$$

with the cost CCG and capacity P expressed in $k\text{€}_{2016}$ and MW , respectively. The exponent higher than the unity contradicts the economy of scale, and it is
250 due to other important issues, like the necessity of reinforcing the grid in case of large OWFs.

Park	Source	Cost	$\frac{k\text{€}_{2016}}{MW}$
7.HR2	[Slengesol et al., page 83]	824 MDKK / 209MW	580
8.Ny	[Bellone and Dale, page 7]	32.8 M\$ / 165.6 MW	167
6.HR	[Slengesol et al., page 82]	40 M€ / 160MW	312
6.HR	[Gerdes et al., page 79]	40 M€ / 160MW	312
CS-6	[ODE, page 40]	185 k£ / 108 MW	314
Est-3	[Garrad Hassan, page I.4]	5 M£/100MW	90
9.BB	[Bellone and Dale, page 6]	19.3 M\$ / 90 MW	180
4.NH	[Slengesol et al., page 91]	4 M£ / 60MW	120

Table 14: Cost of the connection to the grid.

Park	Source	Cost	$\frac{\text{€}_{2016}}{MWh}$
CS-2	[Douglas-Westwood, page 40]	0.7 MNOK/MW ¹	31
CS-5	[Clasadonte et al., page 107]	11 €/MWh	12
CS-6	[ODE, page 28]	4 M£/108MW ¹	21
5.KF	[Slengesol et al., page 85]	10.31–12.20 £/MWh	18 –22
4.NH	[Slengesol et al., page 91]	2.75 M£/186GWh	27
2.SS	[Slengesol et al., page 95]	10.05–11.31 £/MWh	18 –20
1.Md	[Larsen et al., page 5]	8.2 €/MWh	10
1.Md	[EWEA, page 218]	12 €/ MWh	13
1.Md	[Slengesol et al., page 89]	8.2 €/MWh	11
Est-1	[EWEA, page 218]	16 €/ MWh	18
Est-2	[Ernst & Young, page 9]	45 k€/MW ¹	18

¹ Assuming a load factor of 35%.

Table 15: Operation and maintenance costs.

5. Yearly cash flow

5.1. Operation and maintenance costs

Available data are presented in Tab. 15, and include insurance, regular main-
255 tenance, repair, spare parts and administration. This value is usually given as
per MWh and they increase as the equipment is ageing. In the case that it is
given in currency per MW, it can be translated to currency per MWh by mul-
tiplying by 8766 hours/year, and by a load factor (typically 0.35 [ODE][Garrad
Hassan][Slengesol et al.]). Depending on the source, they can include land rent
260 and internal electricity consumption. Table 15 lists the reviewed values.

Although its increase throughout the lifespan is not linear, an annual slope
of 5% can be assumed.

5.2. Price of MWh and expected increase

The selling price of energy greatly depends on the environmental policy of
265 the country and the energy price in the general market. The type of support

Park	Source	d-port	Fnd.	MW	Cost	$\frac{k\text{€}_{2016}}{MW}$
14.CW	[Kaiser and Snyder, page 215]	60 nm	MP	468	63.8 M\$	120
15.BW	[Kaiser and Snyder, page 215]	100 nm	MP	450	59.7 M\$	117
17.GS	[Kaiser and Snyder, page 215]	80 nm	Jk	350	45.3 M\$	114
16.CP	[Kaiser and Snyder, page 215]	20 nm	Jk	150	23.4 M\$	137
CS-5	[Clasadonte et al., page 110]			13.2	2.11 M€	175
CS-6	[ODE, page 41]	10 km		3.6	343 k£	162

Table 16: Decommissioning cost for different parks, including data of the distance to the nearest port (in nautical miles or km), the foundation type (monopile or jacket), original cost as presented in the referenced source, and normalized cost per MW

mechanisms established in Europe (mainly feed-in tariff and quota obligations based on green certificates), and the current subsidies to be applied are listed in [EWEA, page 231], [Douglas-Westwood, page 87], [Slengesol et al., page 11].

Price can evolve over the lifetime of the wind park. As shown in [Larsen et al., page 4] for Middelgrunden wind farm, this is 80 €/MWh in the first 6 years, 57 €/MWh in the following 5 years, and finally is subject to the market price plus 13 €/MWh.

5.3. Subsidies, depreciation and annual taxes

Other data such as investment subsidies, depreciation allowances and taxes on the cash flows, must also be computed in an accounting analysis, although this inclusion has not been carried out due to either unavailability or because certain data remains unspecified for every country: fiscal policy, preferential courses of action, and capital amortization tables.

Particularly, with regard to the grants, the revenues for different wind farms are listed in [Slengesol et al.]: 10 M£ for Barrow, Burbo, Kentish Flats, and Scroby Sands, or 207 MSEK in Lillgrund. The value of 27 M€ is given in [Gerdes et al., page 144].

6. Decommissioning costs and residual price

Offshore decommissioning relates to removal of the superstructure (i.e. blades, nacelle, towers and transition piece), foundation, scour protection and offshore cables. Residual price depends on whether the foundations are made of concrete or steel, although, in general, this is a minor value in comparison to the decommissioning cost (around 10%) [Kaiser and Snyder, page 214].

Available data are summarized in Tab. 16, which includes the distance to the nearest port and the type of foundation. Nevertheless, this table does not show a strong influence of these factors on the cost.

A linear expression reasonably fits the obtained data, with a fixed cost of 1606 k€₂₀₁₆, and a slope of 114 k€₂₀₁₆/MW (CoC = 0.99).

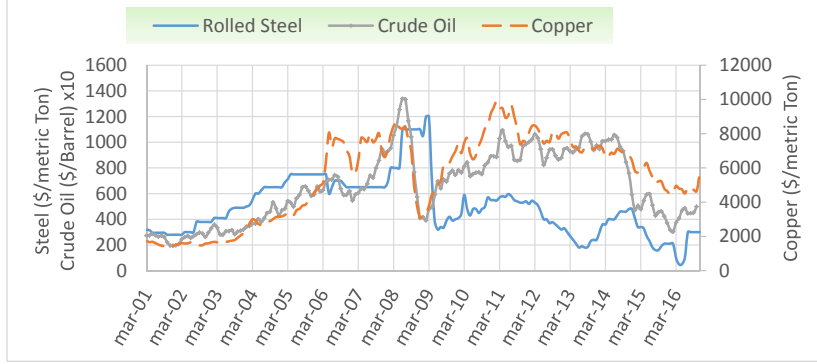


Figure 3: Evolution of price for steel and Copper in \$/metric tonne, and crude oil in \$/barrel. This last price has been multiplied by ten for a better resolution.

7. Factors affecting the economic data

7.1. Unavailability of prices and costs

It is difficult to find documentation regarding the main Cost Drivers for key offshore wind cost components, since the involved companies usually protect their knowledge in the form of confidential data. At best, reports include a generalist breakdown of costs which is not sufficient to analyse the variation in LCOE when modifying the structure, position or the layout of the OWF. Even the reports elaborated by experienced companies advise that the presented Capital Expenditure information have not been verified or audited.

This lack of transparency leads to disparity of costs presented by different authors for the same concept or park, and it is necessary to collect data from several sources in order to obtain more dependable values.

7.2. Evolution of Commodities

The rolled steel is the main raw material used in the manufacture of towers, but also monopile and tripod foundations, and transition pieces. Copper is used in cabling, and to a lesser extent in generators and transformers. These metals make up approximately 6% and 5% of total LCOE respectively [CrownState], and their price have significantly fluctuated in the past years due to the infrastructure growth in China, and, on the other hand, by the recent economic downturn. As a significant example, the price of copper has quadrupled in value in the last fifteen years [Index Mundi], although it is currently decreasing. Figure 3 shows the evolution of steel, crude oil and copper over this period. The price for steel was obtained from [TradingEconomics] and [Quandl], oil crude from [FRED], and copper from [Index Mundi] and [Quandl].

7.3. High demand and lack of competitiveness

7.3.1. Vessels

320 The oil price is also an important factor, not only as a commodity influencing the travelling costs of vessels, but mainly because a high oil price increases the demand of vessels used in the gas and oil sector [Skoko et al.].

The rental price of vessels had doubled in past years [Douglas-Westwood][Kaiser and Snyder][Skoko et al.] resulted from a lack of competition amongst vessel
325 owners/operators as well as a lack of fit for purpose vessels. The recent collapse in crude oil prices has triggered a decline in offshore oil and gas exploration and construction activities, which has led to reduced vessel day rates, albeit a significant vessel demand is maintained for retrofit work and maintenance activities.

330 Different types of vessels are used for the transport and installation/laying of foundations, turbines, cables and substations. Four types of vessels are used: liftboats, Jackup barges, self-propelled installation vessels (SPIV) and heavy-lift vessels. A detailed study into each type of vessel, its date rate, its main use, the installation times as a function of the performed task, and its mobilization
335 costs can be found in [Kaiser and Snyder][CrownState][Garra Hassan][Skoko et al.] and [Gerdes et al.].

7.3.2. Wind Turbine Supplies

With regards to the wind turbines, the market is dominated by two manu-
340 facturers, which also supply onshore wind turbines. Nevertheless, a decline in wind turbine prices is being observed that reflects a lower steel price and the fact that new turbine suppliers are seeking to gain market share and offering turbines at lower prices.

7.4. Meteorological conditions and weather downtime

345 Metocean conditions play an important role in the schedule of the installation works and scour protection. In general, locations with good wind conditions are more likely to be unavailable for assembling, laying, or installation. As noted by some project owners [Slengesol et al.] from experiences at Lillgrund and Scroby Sands, some tasks like cable installation or pile driving should be avoided in winter due to high waves. A sheltered site such as Nysted will have little weather
350 downtime compared to a more exposed site like Barrow (and other projects in the Irish Sea, which have challenging wave conditions). The days in which these operations are not possible entails an additional cost, which can be alleviated through an appropriate task schedule. Table 17 presents the available data.

355 With large new-generation jack-ups the operational weather window can be increased, but on the other hand, they are unsuitable for some sites with soft seabed conditions.

Maintenance plans must also designed accordingly to the location accessibil-
360 ity. In the North Sea, the high waves complicate the access by boat, and some tasks (cable laying, pile driving) should be avoided in the weather window in which these conditions are expected. Accessibility can be drastically increased

Park	Source	Installation downtime	Laying downtime
CS-6	[ODE, page 32]	25%	10%
Est-3	[Garrad Hassan, page I.3]	20%	
CS-1	[Nikolaos, page 112]		20%
Est-5	[ODIS, page 46]		up to 40%

Table 17: Weather downtime.

by including helicopter platforms or if boat landings can be performed in high waves. These extras increase the wind turbine cost.

In addition to the increased downtimes, bad weather conditions also affect the design of foundations. In colder sites such as in the Baltic Sea, foundations must withstand the ice pressure, and thus, ice-breaking cones are installed in top of the foundation or in the transition piece, and oversizing may also be required. A more approximated estimation of the necessary foundation weight and the scour protection should then include the soil type, turbine capacity, depth, wave height, maximum wind speed, or the tidal current [ODE][Nielsen].

7.5. Tidal currents, seabed conditions and biologically sensitive areas

Soil type can impact installation procedure. If rocks exist below the mudline, piles must be drilled rather than driven, which is more time consuming. Other example of this influence is given by [Gerdes et al.] which stated that the seabed consisting of sorted glacier deposit (especially moraine clays) at Nysted made not feasible the option of monopile foundations in favour of gravity based ones.

Tidal currents must also be taken into consideration because they can limit the diver intervention, but mainly because, in conjunction with an erodible seabed, they can make scour protection necessary and bury the cables at enough depths. As indicted in [Douglas-Westwood], GBS foundations are not suitable for sites with heavy erosion. Scroby Sands (located on an huge sand bank formed by the strong tides) and Arklow Bank represent examples of large seabed subsidence due to the tides. At Arklow Bank, sediment shifted post-construction, exposing the export cable that was subsequently damaged by a ship anchoring.

Another aspect to be taken into account is the ecological impact of the OWF. In this sense, monopile installation is noisy, produces water turbulence and damage to macro-fauna, and can scare maritime animals [Gooch et al.]. Onshore transition type in biologically sensitive areas can increase the export cable installation [Kaiser and Snyder]. The visual impact was considered in Humber Gateway OWF, near Spurn Head, moving a possible location 2 km farther from the coast of Spurn Head, which is a Heritage Coast site [Renewable East]. The assessment of the visual impact, as in [Gonzalez-Rodriguez], may be required in order to avoid social rejection.

7.6. Distances

When analyzing the investment cost, four distances must be taken into account: distance from the OWF to the shore; distance to the grid; distance to

Ref	Source	Cost	$k\text{€}_{2016}$
CS-4	[Green et al., page 3]	7 M\$	5901
CS-6	[ODE, pages 39–41]	0.96 M£ ¹	1628
Est-3	[Garrad Hassan, page I.5]	0.75 M£	1343
CS-7	[Nielsen, page 13]	0.5 M€	547

¹ 0.24 M£ for each of the installation/laying activities.

Table 18: Mobilization and demobilization costs.

the holding port; and distance traveled by the vessels for their mobilization and demobilization.

The first one determines the visual impact, influences the water depth, and serves as a proxy for the length of export cable required. It was dealt with in previous sections, mainly Section 4.

The second one refers to the distance to a nearby harbor with enough manufacturing facilities, and staging area for the turbine assembly or the gravity based foundation construction. This distance determines the time for marine vessels to pick-up material and equipment at port and return to the work site. Therefore, it affects the installation time/cost, and is an important factor for the estimation of the vessel rental cost. Nevertheless, it has only been taken into account in few sources [Gerdes et al.][ODE][Kaiser and Snyder]. The following distances have been gathered: Middelgrunden, 3.5 km; Nysted, 10 km from Gedser (service work), 85 km from Nyborg (logistics) and circa 240 km from Swinoujscie (manufacture); Greater Gabard, 20 nm; Horns Rev, 10 – 15 km from Esbjerg; Scroby Sands, 5-8 km from Great Yarmouth, 25 km from Lowestoft (turbine pre-assembling); Cape Wind, 60 nm; BlueWater Wind, 100 nm; Coastal Point, 20 nm; Garden State, 80 nm.

Finally, the last distance to be taken into account corresponds to the travel d from the vessel origin port to the work site, and determines the mobilization and demobilization fee. As presented in [Kaiser and Snyder, page 166], this cost can be roughly obtained as a function of this distance through the expressions

$$\begin{aligned}
C_{mob+dem}^{SPIV}(k\text{€}_{2016}) &\sim 369 \cdot d(km) \\
C_{mob+dem}^{Jackup}(k\text{€}_{2016}) &\sim 272 + 369 \cdot d(km) \\
C_{mob+dem}^{heavy-lift}(k\text{€}_{2016}) &\sim 472 \cdot d(km).
\end{aligned} \tag{8}$$

The figures of Tab. 18 have been extracted from the literature.

8. Conclusions

This paper reviews the sources with useful data about prices and costs that are needed to deduce the LCOE. It cannot be seen as a thorough study of the main Cost Drivers for key offshore wind cost components, nor it presents all the

expressions required to obtain the exact LCOE. Nevertheless, it provides the most important economical data to undertake the programming of optimum layout algorithms for OWFs.

Obtained information shows a big variability in prices over the years, with a increasing trend which has been finally stagnated, mainly in the turbine acquisition and the vessel rental.

Starting from the available data, a regression curve has been obtained for certain components to show how the park capacity affects the cost of certain components. This analysis has lead to deduce that economies of scale are not present in some of the expenditures, like the turbine or the decommissioning. Just on the contrary, higher park capacities increase the specific cost in some of the components, like the grid connection. On the other hand, the components that benefit from the economies of scale are: design and project management, vessel mobilization/demobilization, offshore substation, and export cables.

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