21 Wind Turbines, Offshore - Annex

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Annex to Performance and cost development

This annex supplements the description in the Technology Catalogue for offshore wind and explains the underlying assumptions and calculations behind the estimates of the datasheet. By changing geographical characteristics and other parameters of an offshore wind farm site, the central datasheet estimates can be adjusted with the same underlying assumptions behind.

New in this 2022 update of the Technology Catalogue is a more refined prediction of future performance and costs. Also, LCOE (Levelized Cost of Energy) is calculated. In previous versions and in most other publications the learning rate theory has been dominating for future cost predictions as an "all in one" learning rate.

In the following a more refined approach is used. Future projects are designed based on:

- Expectations of future larger WTG sizes, which is assumed to increase to 30 MW in 2050.
- Expectations of future longer distances to shore and deeper water depths, which are larger the longer the outlook with most suited sites taken first.
- Expectations of larger projects (measured in installed MW) which decrease project development costs per MW.

There are further dependencies to offshore wind farm design than what has been possible in the scope of this work. All calculations are deemed overall representative on a system level and are discussed by benchmarking them to known cost characteristics of current representative Danish offshore wind farms. Main focus of the Technology Catalogue is the overall system level, and individual assessments of specific projects and their characteristics can result in other dependencies and cost breakdown variations than what is presented in the following.

Prediction of performance

An energy production and cost function calculator in Excel has been created and applied based on the following input and calculations.

The mean wind speed 100m above sea level has been unified and set to a default value of 10 m/s corresponding to what is seen in the North Sea (Horns Rev area). For other areas, like near Bornholm or Hesselø, lower wind speeds are expected, round 1 m/s less. The used wind speed is extrapolated to hub height by a shear[1] of 0.11. Based on generic

[1] Shear is a constant used as input to an expression telling how much the wind speed changes by height.

power curves for modern WTGs and reflecting the selected values for specific power, the production per m^2 rotor area is calculated (W/rotor area), as presented below.

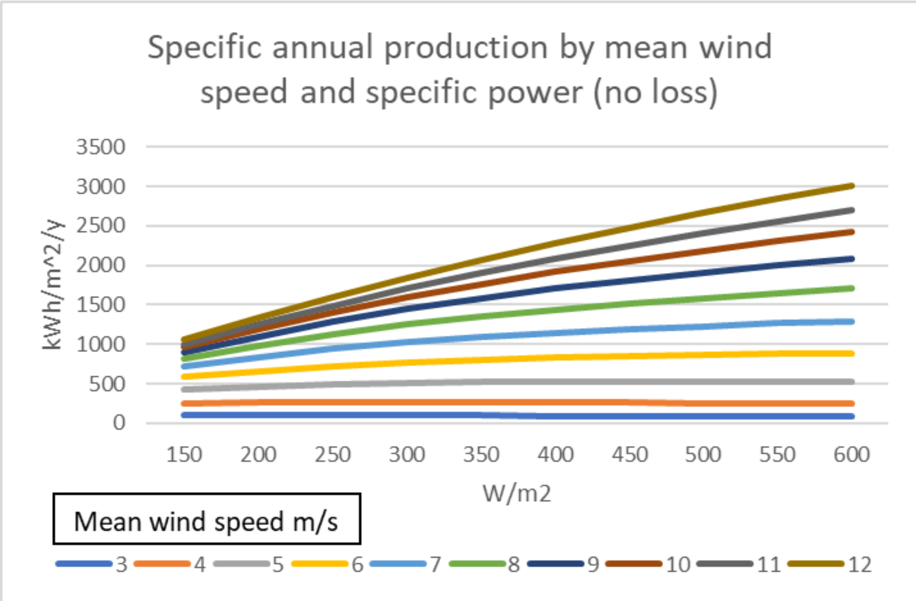

Figure A.1 Production based on mean wind speed and specific power.

It is not assumed that there will be improved power curves for future turbines and that current state of the art turbines will be able to reflect power curve characteristics for future turbines as well.

Wake losses are calculated by a formula calibrated based on several real wake loss calculations where the impact of different parameters is investigated. These are all based on a square layout with Danish wind direction distribution. The wake losses can therefore be considered to be conservative assumptions, as the impact of wake issues is slightly increased in a squared layout compared to a wake-optimized layout. The average distance between the turbines is set to eight rotor diameters, which might be lower for an optimized layout of a real project, which might utilize the available areas more efficiently. Thereby wake losses might also be higher. Similarly, near neighbour wind farms can increase wake losses/reduce wind speeds available.

The parameters that impact the wake losses with these limitations are:

- RD (Rotor Diameter spacing),
- number of turbines, and
- mean wind speed.

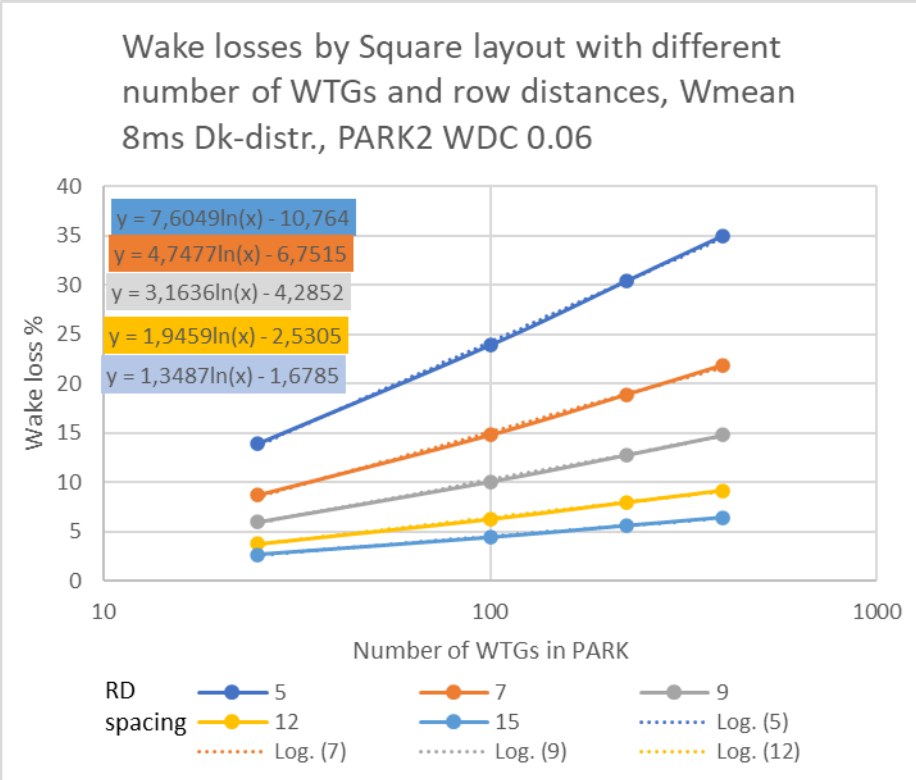

Figure A.2 Example of wake loss by number of WTGs and RD spacing by given mean wind speed.

Figure A.2 is constructed by running several Wake loss calculations with windPRO software and PARK2 wake loss model from DTU. Trendline constants are used to establish curves for finding constants for any RD spacing (figure A.3):

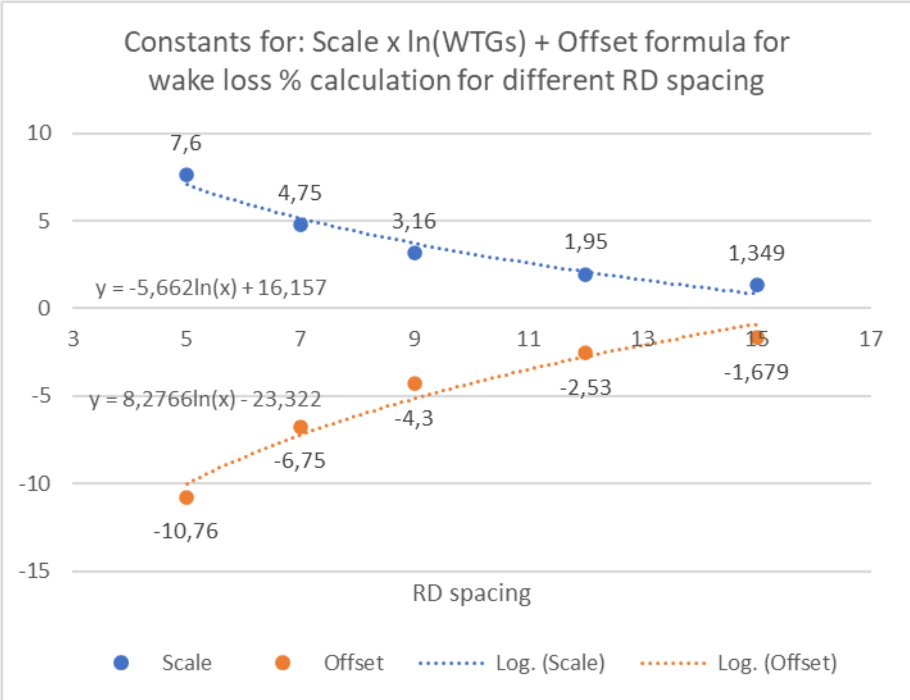

Figure A.3 Constants for simulating trendlines for any RD spacing for a given mean wind speed.

These constants are then found for different mean wind speeds, and a formula set is established for any mean wind speed and RD spacing and number of WTGs in the wind farm. The formula is the following.

Wake loss for square layout, DK offshore wind:

$$Wake\ loss = (((Wlc_1 * \ln(ED) + Wlc_2) * \ln(No)) + (Wlc_3 * \ln(ED) + Wlc_4))/100$$

ED: Equivalent rotor diameter distance in park

No: Number of turbines

$Wlc_{1...4}$: Wake loss constants calculated from:

$Wlc = A * U_{mean} + B$

A and B for the 4 constants are:

Slope (A)	*Intercept (B)*
1.07	*-14.19*
-3.10	*40.96*
-1.39	*19.43*
3.99	*-55.21*

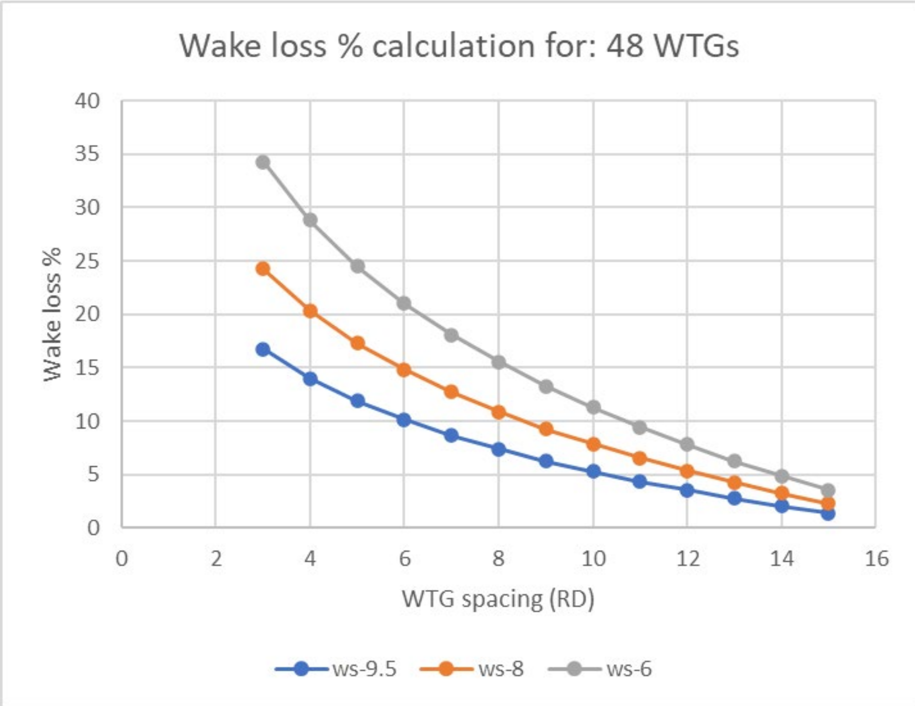

Figure A.4 Example of the use of the formula sets for 48 WTGs (Lillgrund) with different wind speeds and RD spacing.

The Lillgrund (Swedish offshore wind farm in Øresund) has very dense spacing of roughly 4 RD on average with an average wind speed of round 8 m/s. The wake loss is somewhat underpredicted by the formula seen with roughly 20 pct. wake loss, whereas detailed model validations show roughly 25 pct. wake loss. There are two explanations to this:

1. The site density is large compared to other more representative offshore wind farms. The spacing of 4 RD is outside the calibration range of 5-10 RD, which is the expected spacing range for current and future wind farms.
2. The Turbulence intensity at Lillgrund site is lower (roughly 6 pct.) than a typical DK offshore site (roughly 7 pct.). When turbulence is lower, wake losses are higher. The model is calibrated for “normal” DK offshore turbulence.

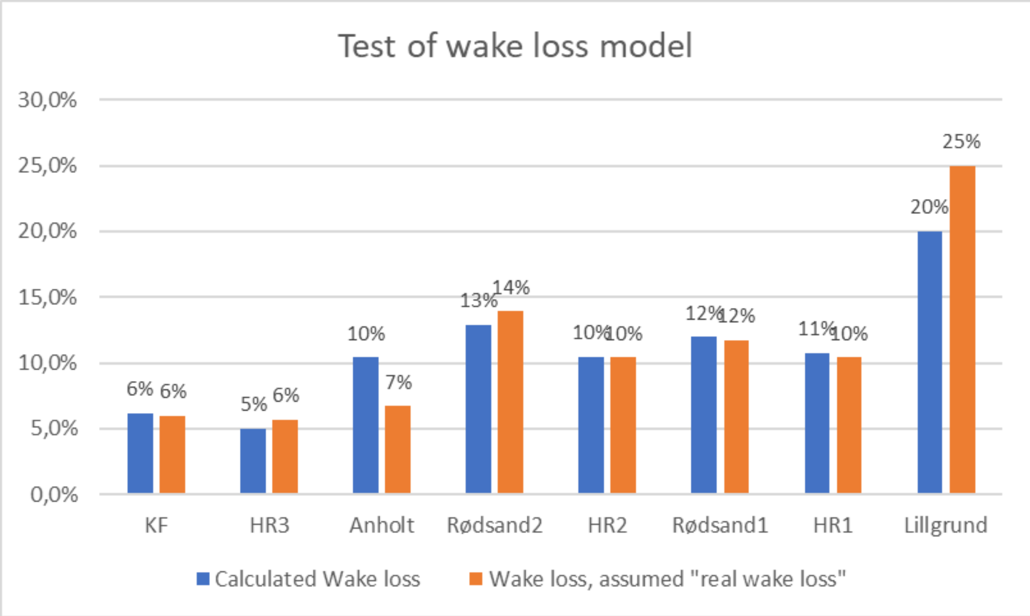

Figure A.5 The wake loss model tested on different wind farms.

That the model calculates a higher wake loss for Anholt is due to the fact that the wind farm has a layout that is far from a square layout. With a long side perpendicular to the main wind direction, there is less wake loss than what the model predicts based on a square layout.

Apart from wake losses, there are other losses. These are mainly availability and grid losses, which are set to a default value of 5 pct.

Table A.1 Losses for selected farms.

	Expected *) AEP (MWh/y)	Per WTG (MWh/y)	Realised from Table 3 [6] shown in chapter (before external grid loss)	Loss excl. external grid loss	Detail calibrated calculation #) AEP (MWh/y)	"Real loss" based on detail calibrated calc.
Horns Rev 1	654,414	8,180	7,031	14.1%	662,600	15.1%
Rødsand 1	602,218	8,364	7,475	10.6%	586,700	8.3%
Horns Rev 2	928,587	10,204	9,686	5.1%	938,281	6.1%
Rødsand 2	827,346	9,193	8,873	3.5%	824,791	3.2%
Anholt	1,811,999	16,324	15,294	6.3%	1,834,560	7.5%

The losses based on all operation years until end 2020. The commissioning year is not included. With external grid losses in the sizeorder of 2 pct., it seems reasonable to expect 5 pct. losses in addition to wake losses for future wind farms, whereof roughly 2 pct. is internal grid losses and 3 pct. is outage losses. Rødsand 2 is the only wind farm out of the above in table 5, where no major grid failure has occurred. Major grid failures had an impact on the production and increased the losses for the other wind farms.

With the deducted losses, the AEP is calculated, as presented in Figure A.6 below.

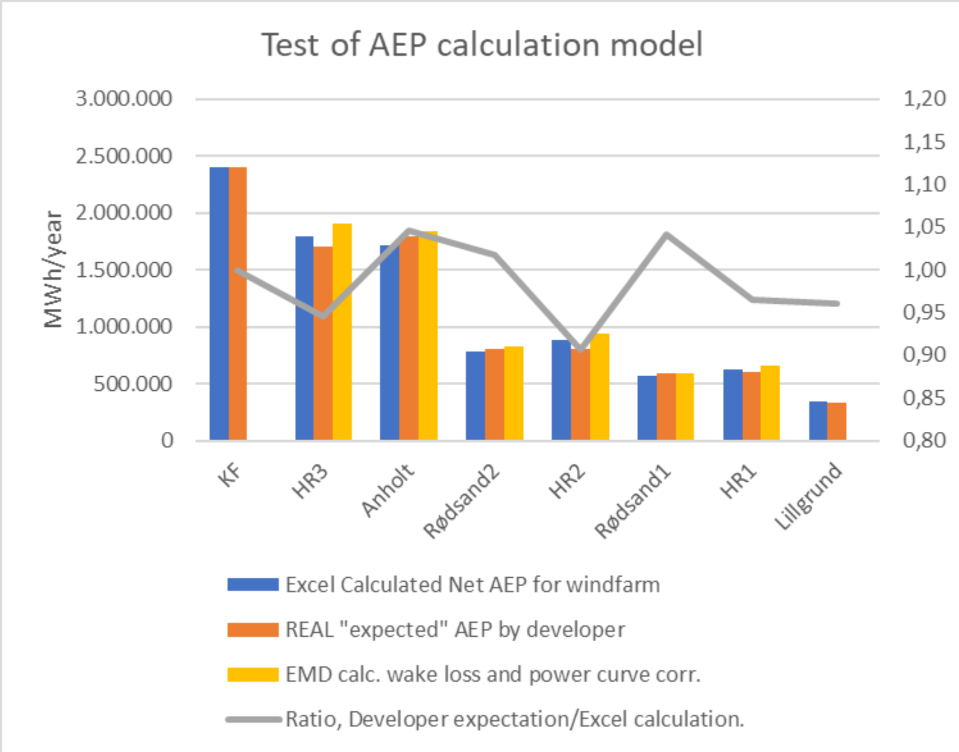

Figure A.6 Estimated AEP tested on selected offshore wind farms.

One reason for predicting future wind farms' output is to be able to calculate LCOE. The established Excel model used for is assumed sufficiently accurate to do this. A major pitfall is that a "wake friendly" layout will have less wake losses than calculated, and a low turbulence site will have higher losses. It shall also be noted that the model is considered for Danish offshore wind climate only. For Nearshore wind farms, more simplified assumptions are used considering the assumed one-row layout of those farms.

Prediction of costs based on cost functions and constants

The full cost budget for an offshore wind farm in 2020 cost level is shown below in table A.2.

Table A.2 Cost budget for offshore wind farm in Denmark. Bolded with formulas, orange input fields with constant cost/MW or MWh.

Devex	**In year -1**	**Output unit**
	Development #)	kEUR/MW
2%	Permitting, EIA etc. (% of Capex)	kEUR/MW
Capex	All in year 0	
	Turbine #)	kEUR/MW
50	Turbine transport	kEUR/MW
	Turbine installation #)	kEUR/MW
	Foundations #)	kEUR/MW
	Foundation install. etc. #)	kEUR/MW
	Array cable #)	kEUR/MW
250	Substation offshore	kEUR/MW
	Offshore export cable #)	kEUR/MW
50	Onshore export cable *)	kEUR/MW
0	Sea rights fee	kEUR/MW
100	Insurances	kEUR/MW
100	Finance cost	kEUR/MW
50	Contingences	kEUR/MW
	#) Formula based *) Very site specific	
		kEUR/MW
Opex	Per year from year 1 to end	US$/kW
45	Service, pr. MW	kEUR/MW/y
5	Service, pr. MWh	EUR/MWh
5	Other, pr. MW	kEUR/MW/y
0	Other, pr. MWh	EUR/MWh

Abbreviations used in cost formulas:

- MW_t – Turbine power (MW)
- MW_f – Farm power (MW)
- RD – Rotor diameter (m)
- RA – Rotor Area (m^2)
- HH – Hub Height (m)
- SP – Specific power (W/m^2)
- IA – Inter Array distance (m)
- No – Number of turbines
- WD – Water Depth
- DS –Distance to shore

FORMULAS: (some of the formula backgrounds and validations are presented later)

Project development

$$Project\ development\ costs = (-0.021*\ln(MW_f) + 0.1804)*Capex \qquad [\%\ of\ Capex]$$

In figure A.7, a simple regression of expected lower development cost per MW over different wind farm sizes in MW is shown:

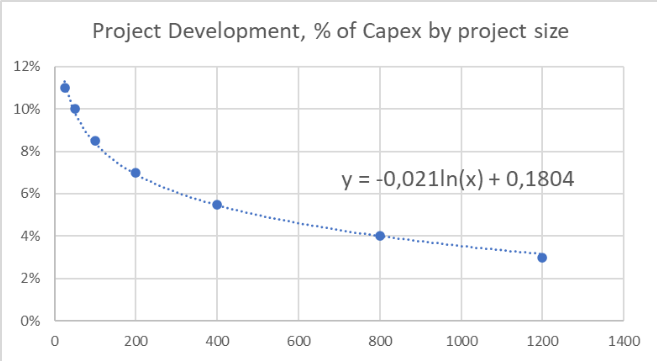

Figure A.7 Expected decrease in project development costs by project size.

Wind turbines

$$WTG\ cost = (A*SP+B+(C*HH*RA+D)/(1000*MW_t))*E \qquad [kEUR/MW]$$

A: -0.5 $\left[\frac{\frac{kEUR}{MW}}{\frac{W}{m^2}}\right]$

B: 750 $\left[\frac{kEUR}{MW}\right]$

C: 0.53 $\left[\frac{EUR}{m^3}\right]$

D: 5,500 $[EUR]$

E: 1.1 $[-]$

The above formula is developed based on onshore wind turbines. For offshore wind turbines, a factor E of 1.1 is multiplied while offshore turbines are assumed more costly due to added corrosive protection, safety equipment, air filtering etc. This assumption is based on interview with Vestas several years ago.

Turbine installation

$$WTG\ installation\ costs = B*MWt\text{^}C \qquad [kEUR/MW]$$

B: 300 $\left[\frac{kEUR}{MW^2}\right]$

C: -0.6 $[-]$

Foundations offshore (equipment)

$Foundation\ costs = (A*WD+B)*(1+(c*(350\text{-}min(D;SP)))\quad [kEUR/MW]$

$A: 8 \qquad \left[\frac{\frac{kEUR}{MW}}{m}\right]$

$B: 30 \qquad \left[\frac{kEUR}{MW}\right]$

$C: 0.003 \qquad \left[\frac{m^2}{W}\right]$

$D: 400 \qquad \left[\frac{W}{m^2}\right]$

Foundation installation

$Foundation\ installation\ cost = A *WD + B*MWt\text{^}C \qquad [kEUR/MW]$

$A: 2{,}5 \qquad \left[\frac{\frac{kEUR}{MW}}{m}\right]$

$B: 600 \qquad \left[\frac{kEUR}{MW^2}\right]$

$C: \text{-}0.6 \qquad [-]$

Offshore export cable

$Export\ cable\ costs = A * DS \qquad [kEUR/MW]$

$A: 2{,}8 \qquad [kEUR/MW/km]$

Array cables offshore

$Array\ cable\ costs = \ IA * A \quad [EUR]$

$A: 500 \qquad \left[\frac{EUR}{m}\right]$

In reality, array cable costs are dependent on the cable capacity and thus turbine size. But with larger turbines, higher voltage levels will be expected and thereby more power can be handled by same cable dimensions. Another reason for the choice of fixed cost per meter array cable is that the cost share stemming from the installation of cables is a rather high share (see table A.3 below) [15]. Due to missing quantitative data a more simplistic estimate has been chosen. A more project-specific investigation should be done in order to qualify this value further and in a project-specific setup. On an overall system perspective, the estimation is deemed sufficient. Worth to notice is that by increased voltage level, cables become more expensive, not included in the simple formula.

For subdivision of cables into equipment and installation, these factors are used:

Table A.3 Subdivision of array cables and export cables in Equipment and installation.

	Array cables	Export cables
Equipment	0.333	0.667
Installation	0.667	0.333

These formulas are expected to work for wind turbines from round 2.5 MW and up. For smaller turbines, higher costs must be expected.

Table A.4 Formula test on Kriegers Flak.

Kriegers Flak Check	Model (€/kW)	Real	Model/real
WTG's	722	833	87%
WTG installation	134	119	112%
Foundations	207	143	145%
Internal cabling	35	36	98%
Installation of foundation + cabling	300	298	101%
Project development, financing etc.	387	357	108%
Total excl. export cable grid connection	**1784**	**1786**	**100%**

With an assumed cost distribution for Kriegers Flak, the formulas are tested. There is not a full match for each component, but there is a match in terms of the total specific cost per MW. An interview with Vattenfall [15] indicates that foundation cost is probably higher than the number indicated as "real" in the table above and likewise WTG cost is probably lower, but full transparency of these data is not available.

The cost functions are not just calibrated with Kriegers Flak, but several other projects and data. The total costs for Kriegers Flak are nevertheless confirmed. At the Vattenfall homepage there are similar costs for the Hollandse Kust Zuid 1–4 of 2,600 MEUR corresponding to round 1,733 EUR/kW, 2 pct. lower than Kriegers Flak. This suggests that Kriegers Flak is not an outlier, but instead reflects the real present cost level.

A shortcoming with the present approach is that unforeseen technological developments are not observable through historic data, but this engineering bottom-up approach is considered robust in terms of a description of current state of the art projects. There is however uncertainty concerning whether the specific shares of cost will continue to develop in the way as they are outlined here.

In Figure A.8 below, the cost functions are tested on several other projects. The functions are not supposed to work well for Anholt and HR3, because these were built when costs were driven up for other reasons, some mentioned in the main chapter where this appendix belongs to. For the older wind farms, the cost functions result in slightly higher costs than what is known as real cost for most of the projects that were matched against, as seen above.

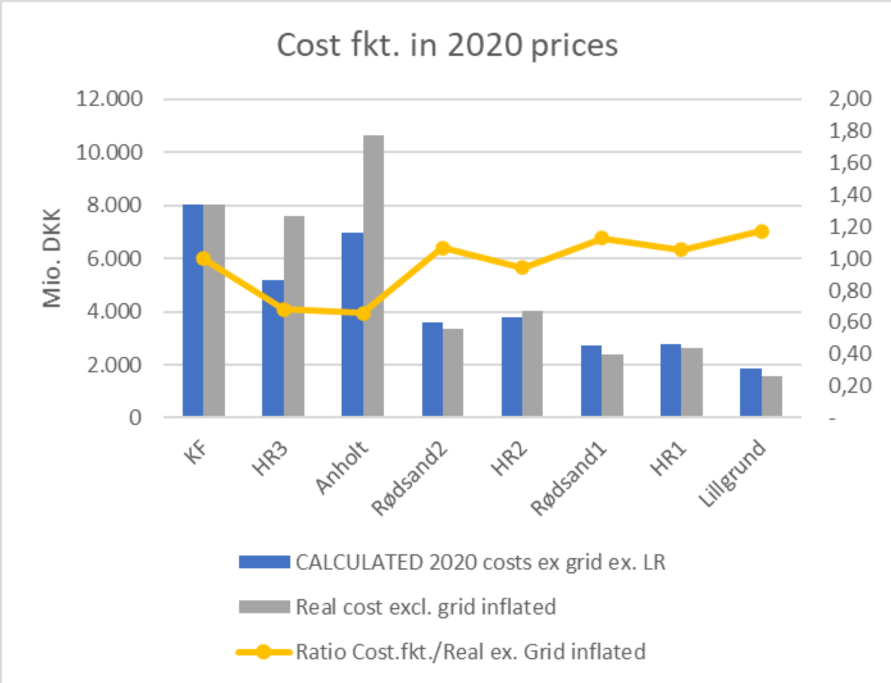

Figure 8 Cost function validation for other projects.

Turbine cost's function background

The turbine cost function is developed based partly on manufacturer list prices and partly on realized Danish project cost from 2018.

The two main drivers for WTG costs are specific power and tower height, as shown below in figure A.9. The tower costs are extracted based on a linear regression representing the tower cost function to give a precise picture of the specific power dependency for all other turbine costs than tower cost, i.e. costs for nacelle, hub, blades, and controller. The graph is based on 3-5 MW WTGs.

It is assumed this cost level also will be valid for very large offshore WTGs.

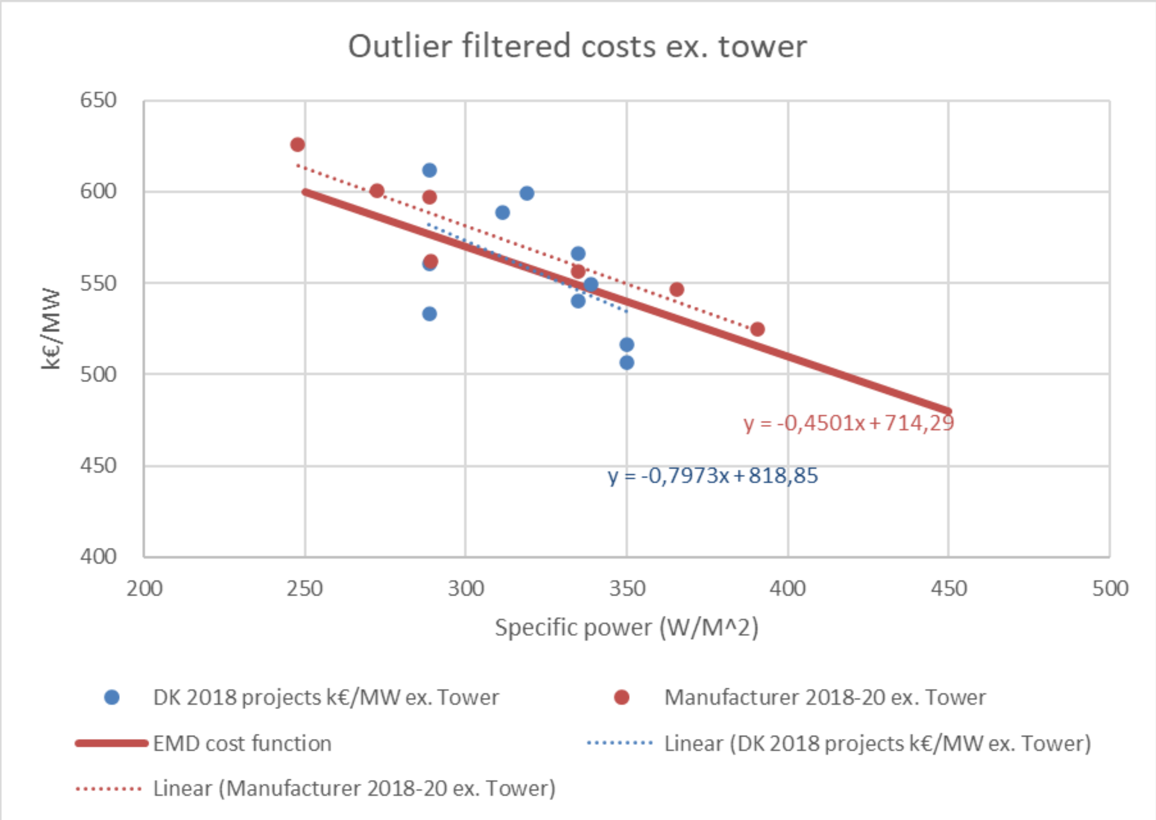

Figure A.9 WTG costs vs specific power.

Foundations and water depths, cost function validation

In most cases, the foundation costs are presented as total costs. Figure A.10 illustrates this by showing identical costs for cost function and Cowi data from a presentation from Ea Energianalyse [16]. This example assumes a 4 MW turbine. The cost function includes the turbine size, which makes it more refined than just a simple cost per MW. This is illustrated further below in Figure A.11.

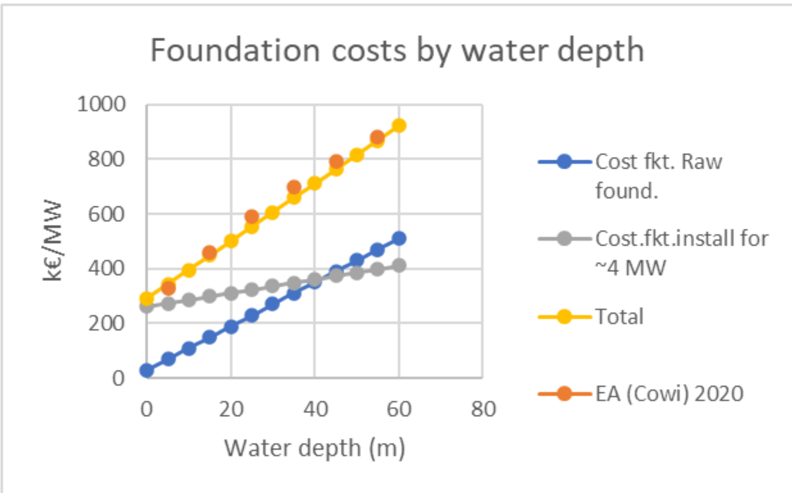

Figure 9 Validation against Ea Energianalyse/Cowi data.

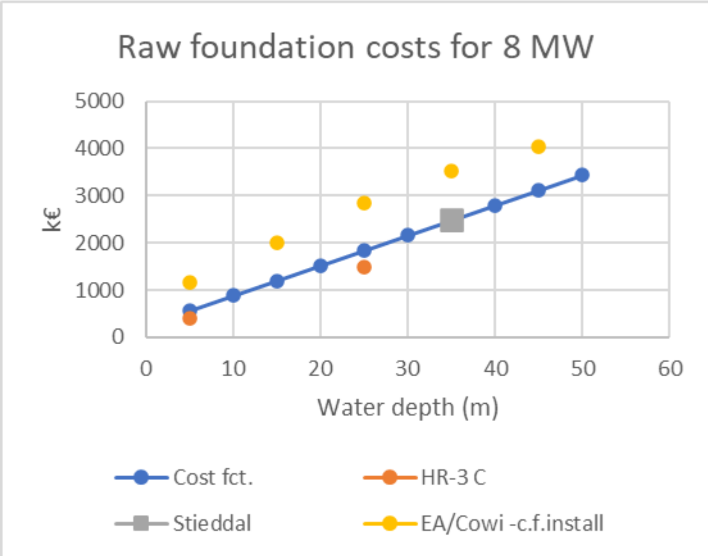

Figure A.11 Foundation costs without installation.

Here, the cost function is used on an 8 MW turbine with comparison to alternative sources in order to secure the correct level. When the calculated installation costs are subtracted from previous shown Ea Energianalyse (Cowi) data, this source comes out with some higher foundation equipment costs. But this is due to the simplicity of not taking MW size into account.

It is found within more data sources, that installation cost for doubling WTG size only increase to 120 pct., meaning 60 pct. cost per MW. Below in Figure A.12 an example from Crown Estate illustrates this point.

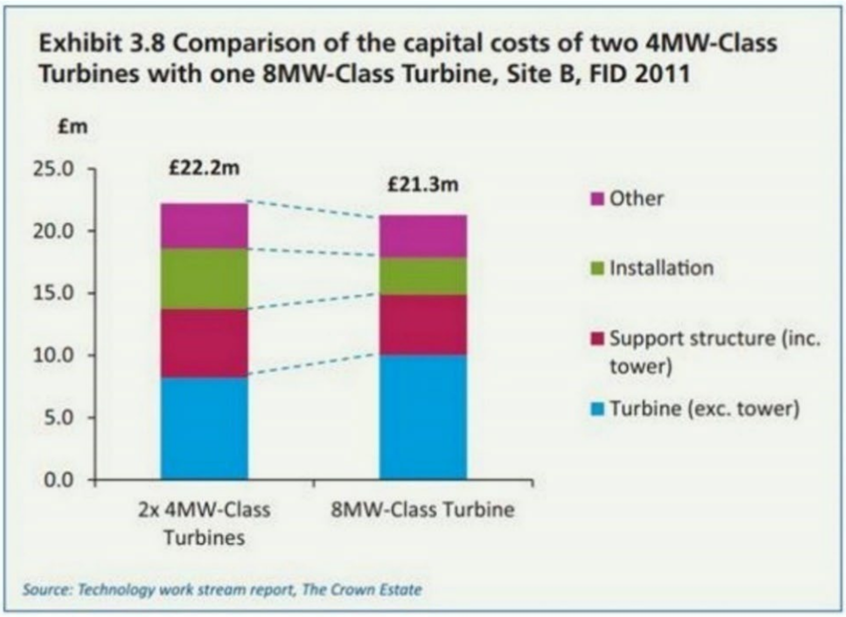

Figure 10 More sources pinpoint a large installation cost reduction by increased WTG size.

A special consideration built into the foundation costs is the specific power. Having larger rotor per MW will make cost pr MW higher. Based on 350 W/m^2 as "base cost", it is found from onshore cost functions that a change in 1 W/m^2 gives a change of 0.3 pct. in cost. The function is capped at 400 W/m^2, because unrealistic input, i.e. very high specific power, could result in negative foundation costs.

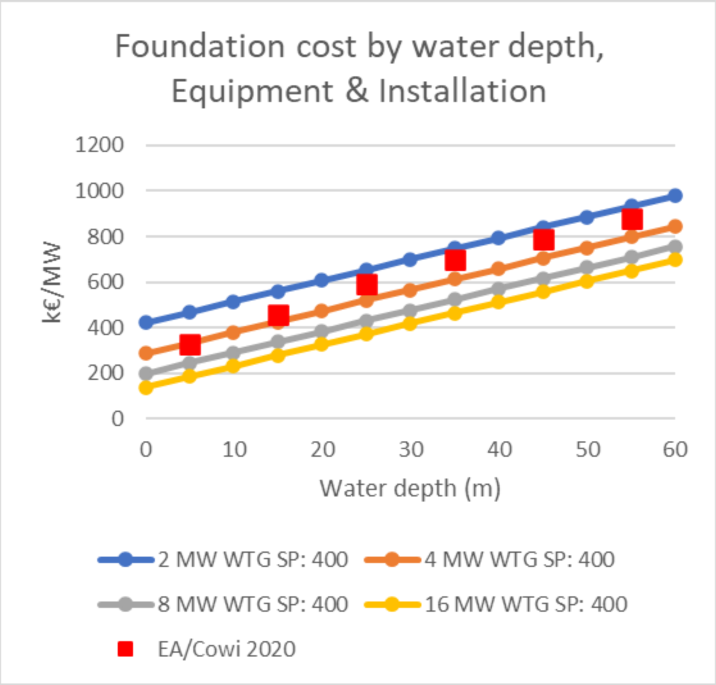

Figure A.13 Illustration of foundation cost calculation by water depth and WTG size, all for a specific power of 400 W/m².

The foundation equipment costs pr. MW increases with lower specific power due to larger rotor area/MW (figure A.14). This is not assumed to affect the installation costs.

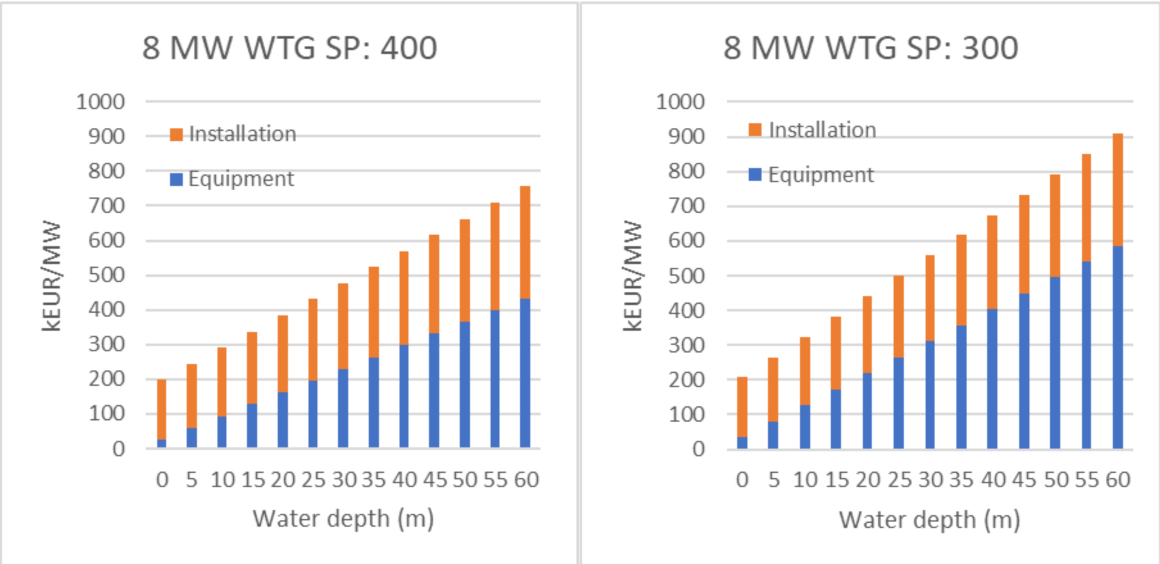

Figure A.14 Illustration of the impact of specific power on the foundation costs (left: 400 W/m²; right: 300 W/m²).

Export cable cost function validation and outlook

Based on data for the latest three large offshore wind farms commissioned in Denmark, the relatively simple cost functions are compared to realized costs, which are published based on a request from the Danish parliament (Figure A.15) [17].

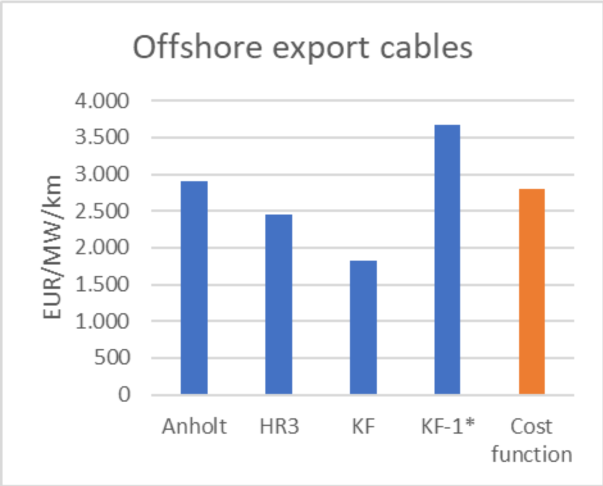

Figure A.15 Cost of offshore export cables.

The cost of Kriegers Flak's offshore export cables, named KF-1*, is based on the real distance to shore, while KF is based on double distance accounting for two cables installed. Overall, the cost function seems to have a realistic level, as shown in Figure A.16.

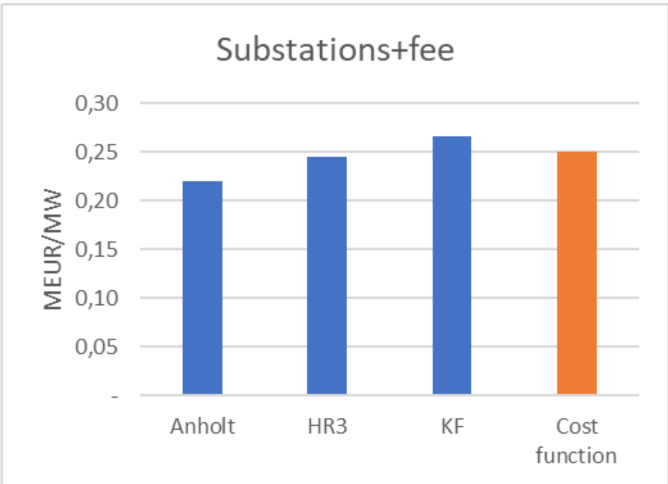

Figure A.16 Cost of offshore substation.

Similar for offshore substations, the cost function value is at a similar level to realized costs, as seen in figure A.17.

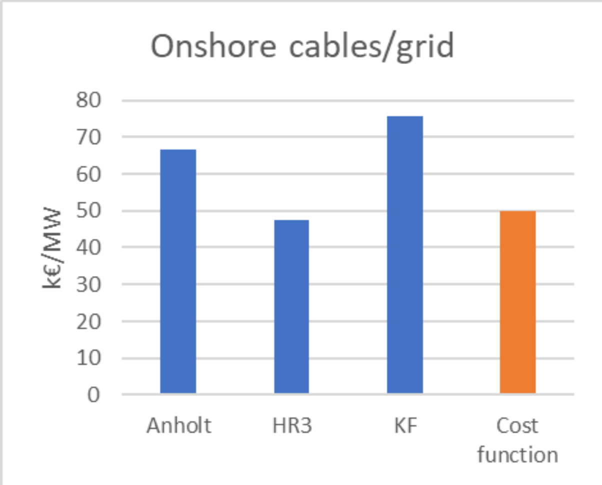

Figure A.17 Cost of onshore export cables.

For the onshore export cable, there is a high dependency between location and grid costs. The cost function for this part is within a realistic level from a system perspective, as seen in figure A.17, but might diverge for individual projects.

A potential cost reduction is the fast development of power electronics, making DC (Direct current) an alternative to AC (Alternating current) for offshore wind farms being located far from shore at distances to shore of above around 100 km. Therefore, it seems not to be relevant for Danish radial offshore wind farms, but this might of cause change. Likewise, DC connection will play a role for the energy hubs that will not only be connected to Denmark, but also neighbouring countries. In Figure A.18, there is a cost illustration from the IEA.

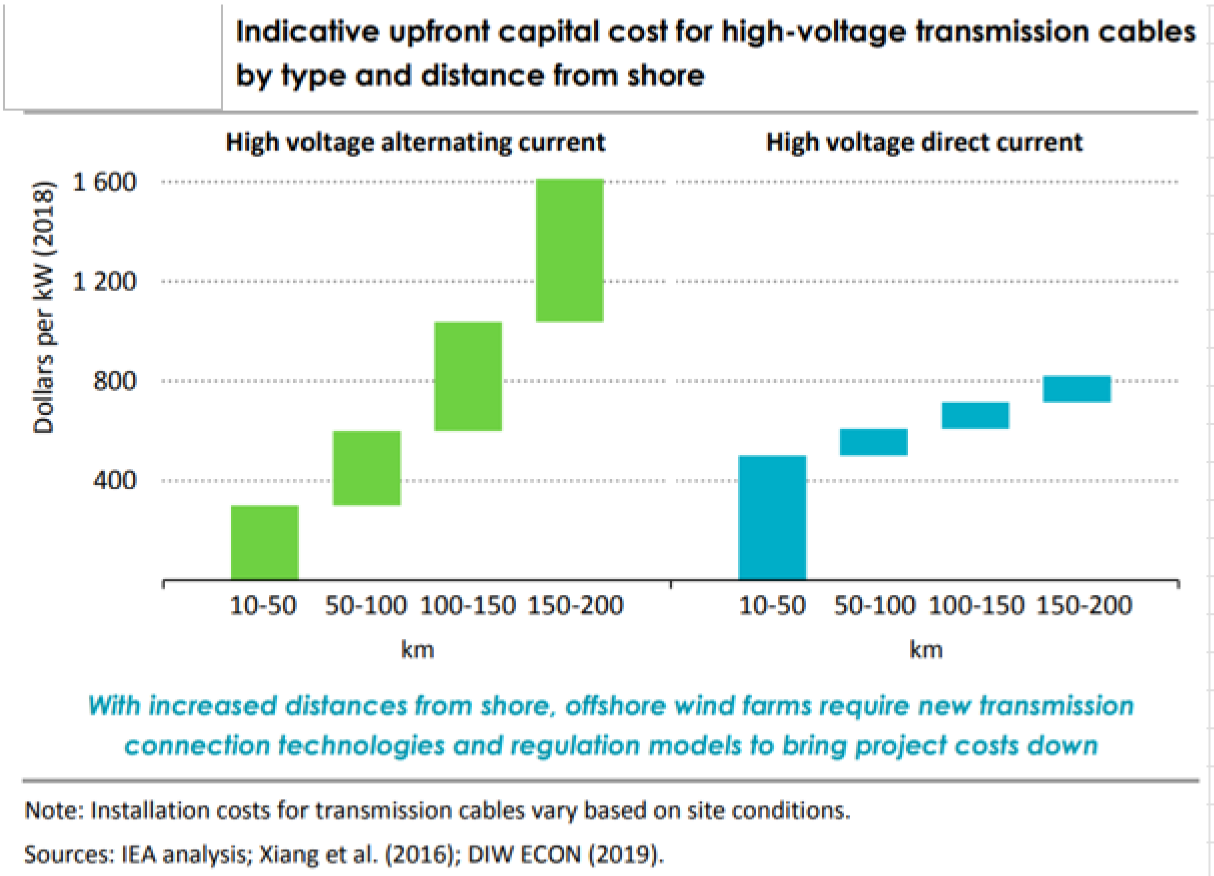

Figure A.18 Indicative upfront capital cost for high-voltage export cables by type and distance to shore

As seen, there are large potentials in cost reduction by deploying DC export cables, when the distance to shore is high. The higher cost for DC converters partially offsets the savings from the lower cost for the DC export cables and will need to be taken into account as well. While this is a R&D area with much effort recent years, the DC is expected to be even more competitive to AC today than the graph illustrates.