Offshore Wind
Programme Board

Transmission Costs for Offshore Wind

Final Report

April 2016

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ABBREVIATIONS USED

Initials	Definition
CRMF	Cost Reduction Monitoring Framework
CfD	Contract for Difference
CPI	Consumer Price Index
FID	Final Investment Decision
kV	Kilo Volt
kW	Kilo Watt
LEC	Levy Exemption Certificate
LCoE	Levelised Cost of Energy
MW	Megawatt
MWhr	Megawatt Hour
OFTO	Offshore Transmission owner
O&M	Operations & Maintenance
ORE Catapult	Offshore Renewable Energy Catapult
OWPB	Offshore Wind Programme Board
pa	Per annum
PPA	Power Purchase Agreement
RPI	Retail Price Index
TRS	Tender Revenue Stream

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1 SUMMARY CONCLUSIONS

The purpose of this report is to calculate transmission tariffs (in £/MWhr LCoE-equivalent terms) for in-service offshore wind projects, and to estimate transmission tariffs for future offshore wind farms up to projects with FID in 2020.

The author of this report is Transmission Excellence Ltd. The report has been commissioned by the Grid Group of the Offshore Wind Programme Board (OWPB), and has benefited from discussions among the members of the group. However, the OWPB Grid Group accepts no responsibility for the accuracy and completeness of the report. The reader's attention is also drawn to the Disclaimer on page 2 of this report.

It should be noted that the report only considers costs that form part of the transmission tariff. In particular, it does not include the cost impact of fault outages that may reduce power deliveries to consumers, and hence increase the cost of the energy that can be delivered. It also does not consider the cost of any energy losses on transmission assets, or costs associated with balancing supply and demand.

The report concludes that:

i) Per-MWhr transmission tariffs for offshore wind have been held (and can continue to be held) within a £10-12/MWhr range. This is despite the distance between offshore and onshore substations increasing almost nine-fold from c. 2006 to 2020.

ii) The primary reasons why per-MWhr transmission tariffs have not previously risen with transmission distances are lower OFTO revenues relative to asset values (a 25% reduction in £/MWhr transmission tariffs), higher wind farm capacity factors (a 30% reduction), and upgrading from 132-150kV export cables to 220kV cables (a 12-28% saving for two sample projects).

iii) For the 2020 scenarios a further reduction of 23%[1] in transmission tariffs for far-offshore wind farms is estimated to be possible by employing two technical advances that are currently under investigation by the OWPB Grid Group: lightweight offshore substations and large-conductor dynamically-rated 275kV cables.

iv) Taken together, the various sources of improvement equate to a reduction of more than 70% in the per-MWhr transmission tariff of a far-offshore wind farm relative to the same wind farm with the technical approach to transmission, capacity factor and OFTO revenue levels seen on projects that reached FID in 2006-8.

v) While transmission tariffs have been broadly constant, the overall costs of offshore wind have steadily fallen. This combination means that transmission tariffs represent an increasing proportion of total offshore wind costs: rising from around 8% in 2006 to 12-15% by 2020.

[1] An indicative value based on specific scenarios and a 170km transmission distance. See Section 4.5.

2 OFFSHORE WIND – TOTAL COST

2.1 The Cost Reduction Monitoring Framework

The total cost of offshore wind (i.e. the cost of the generation element and the transmission[2] element combined) has been tracked by the Cost Reduction Monitoring Framework (CRMF). CRMF is a set of studies commissioned by the Offshore Wind Programme Board[3] (OWPB) from the Offshore Renewable Energy Catapult (ORE Catapult). The first such study started in February 2014 and the results were published in February 2015. A further study was undertaken in 2015, but as this was purely qualitative in nature it is not relevant here.

The CRMF has measured the total cost of offshore wind in terms of its Levelised Cost of Energy (LCoE), which seeks to quantify the average cost over the life of a wind turbine. LCoE is calculated using a discounted cash flow analysis as follows:

i) All development, construction, operating and decommissioning costs of a wind farm are discounted at the (real, pre-tax) investment hurdle rate used by the wind farm's owner. This provides a net present cost.

ii) An annual cost is then found such that when you have this cost fixed over the whole operating life of the wind farm, and then discount this cost at the same discount rate as in step (i) above, you get the same net present cost as was calculated in step (i) above.

iii) The fixed annual cost calculated in step (ii) above is then divided by the expected annual energy output of the wind farm to yield the LCoE in £/MWhr.

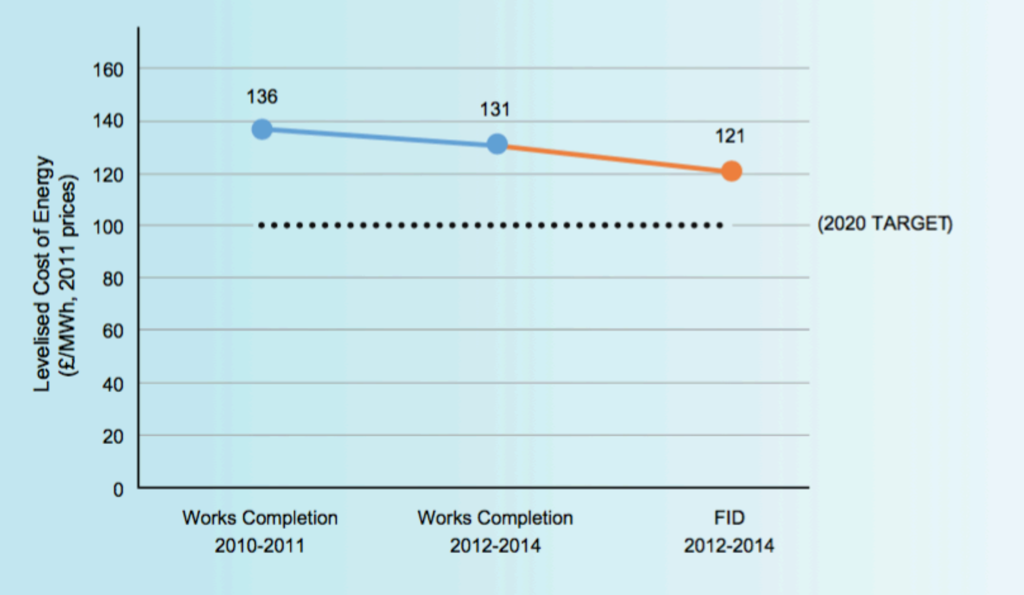
To ensure that the data used in the CRMF is consistent, ORE Catapult provides wind farm owners with a standardised spreadsheet to calculate LCoE, but the input values – including the operating life of the wind farm and the discount rate – are decided by the wind farm owners themselves.

The report published in February 2015 found the pattern of reduction in the total cost of offshore wind shown in Figure 1 below.

[2] For the purposes of this study "transmission" is defined as being those assets which are transferred to the OFTO (offshore transmission owner). Costs associated with array cables, turbine step-up transformers and tower-base switchgear are defined as being part of generation costs.

[3] The OWPB is a joint initiative of the UK government and the UK offshore wind industry which aims to reduce to the cost of offshore wind.

Figure 1: trend in total offshore wind costs



Source: CRMF Summary Report to the Offshore Wind Programme Board, Feb 2015

Figure 1 divides the set of wind farms analysed into three categories which map[4] to the groups of actual projects shown in Table 1 below. Each category collects projects which were built at around the same time, and each category is approximately 2 years after the preceding category

Table 1: Allocation of wind farms to categories in February 2015 CRMF report

Category	Projects
Works completion 2010-11[5]	Gunfleet Sands (complete 2010)
	Robin Rigg (complete 2010)
	Thanet (complete 2010)
Works completion 2012-14	Walney (complete 2012)
	Sheringham Shoal (complete 2012)
	Ormonde (complete 2012)
	Greater Gabbard (complete 2012)
	Teesside (complete 2013)
	London Array (complete 2013)
	West of Duddon Sands (complete 2014)

[4] The CRMF report indicates which projects are in a "works completion" category and which are in an "FID" category. Specific knowledge of the projects is needed to know which of the two "work completion" categories, or which of the two FID categories, a project is in.

[5] The works completion dates are taken from the Crown Estate Operational Wind Report (2013) and have been used to sort projects between the two works-completion categories.

FID 2012-14[6]	Humber Gateway (FID 2012) Westermost Rough* (FID 2013) Dudgeon* (FID 2014)
	*These projects use 6MW class turbines

According to the CRMF report the downward trend in total cost seen in Figure 1 is driven primarily by the economies of scale available from larger wind turbines. The report notes that:

> *"One factor that does stand out is that the 2012-2014 FID projects group is dominated by projects using 6MW turbines, whilst the other LCoE figures reflect projects with an average turbine size of 3.4MW – 3.6MW. It may be inferred that the estimated reduction to £121/MWh for these projects is due to some extent (possibly a large extent) to the anticipated capex and O&M reductions from fewer installations and maintainable units plus improvements in output and reliability. "*

Other secondary factors referred to in the CRMF report include "XL monopile foundations, improvements in operation & maintenance and extended design life". The authors of the CRMF report also note that "progress is also being made in finance (cost of debt, equity and insurance) and across the supply chain".

2.2 CfD Strike Prices

ORE Catapult expect to undertake an updated analysis in 2016 which will extend the graph shown in Figure 1 to include more recent projects. Unfortunately, the results of this work will not be published until early 2017.

In the absence of this update, an *approximate* view of the latest total costs of offshore wind can be obtained from the winning offshore wind bids for Contracts for Difference (CfDs) announced in February 2015. These are:

i) The East Anglia 1 windfarm at a strike price of £119.89/MWhr (in 2012 pounds). This equates to £116.5/MWhr in 2011 pounds (the unit used in the LCoE figures).

ii) The Neart na Gaoithe windfarm at a strike price of £114.39/MWhr (in 2012 pounds). This equates to £111.2/MWhr in 2011 pounds.

It is assumed that competition will mean that any excess returns will be eliminated, so that prices become synonymous with costs. Even with this assumption, however, strike prices are

[6] The CRMF report provides a set of projects in two "FID" categories: 2010-11 and 2012-14. The results from the FID 2010-11 category were not used in the final graph: it included the Gwynt y Mor (2010), Teesside (2011) and West of Duddon Sands (2011) project; of these only Gwynt y Mor was not already contained in one of the categories in table 1. As actual FID dates are not always publicly available, the date of placing the export cable order – which is frequently one of the first major orders placed – was used instead to provide the indicated FID dates.

not directly equivalent to LCoE. DECC indicates the following differences[7]:

i) The CfD strike prices apply for a period of 15 years, while the LCoE is calculated over the life of the generating asset. After the CfD expires the wind farm will receive the wholesale electricity price, so the level of this will affect the LCoE calculation.

ii) The CfD strike price does not necessarily reflect the amount of money that the generator will receive. If the generator sells its power through a power purchase agreement (PPA), then a "PPA discount" will apply. This has been estimated to be 5%[8], or roughly £5-6/MWhr. In other words, this factor would reduce the LCoE by £5-6/MWhr relative to the strike price.

iii) A further reduction in the price for energy actually achieved by the wind farm results from the transmission loss multiplier, i.e. the fact that the wind farm will have to pay for its share of grid losses. This will reduce the effective price received by the wind farm by around 0.8%[9], and reduce the LCoE by around £1/MWhr relative to the strike price.

iv) At the time that bidding took place wind farms were expected to have an additional revenue stream from Levy Exemption Certificates (LECs). Although LECs have since been abolished they presumably played a role in determining the value of the bids made for the CfD's awarded in early 2015. Since LECs represent an additional income source for the wind farm, their effect would have been to reduce the strike price bids by £5-6/MWhr[10] relative to the LCoE.

Taking these factors together, it appears that LCoE can be estimated from strike price with reasonable accuracy if only factor (i) above – the relatively short duration of the CfD – is considered; the other factors above are minor or approximately cancel each other out. Differences in indexation (i.e. RPI versus CPI) have not been considered – given the small number of years involved and the generally low level of inflation any differences in indexation are unlikely to accumulate to a large discrepancy.

Since the wind farm will receive the strike price for 15 years, and following this the wholesale electricity price for the balance of the wind farm's life, calculating the LCoE from the strike price requires that assumptions are made regarding the market price and the wind farm's life. This then gives a per-MWhr revenue stream whose present value (calculated using the developer's cost of capital – which must also be estimated) is the same as that from receiving the LCoE over every year of the wind farm's life.

For the purposes of this study, the following values are assumed for the parameters referred to above:

[7] From "Consultation on the draft Electricity Market Reform Delivery Plan. Annex B - Strike Price Methodology", July 2013
[8] From National Grid Analytical Report (supporting document to 2013 EMR consultation).
[9] Elexon estimate of transmission loss multiplier for 2014/15.
[10] From April 2015 until their abolition LECs were worth £5.54/MWhr.

i) The post-CfD wholesale price was assumed to be £60/MWhr in 2011 pounds. This is higher than current forward-market prices, which equate to less than £54/MWhr in 2011 pounds[11]. On the other hand it is lower than the forecast for prices in the 2020s of roughly £70±5/MWhr (in 2011 pounds) produced by National Grid in 2013 using DECC scenarios[12].

ii) The life span of a wind farm has been assumed to be 25 years. In the Cost Reduction Pathways Study[13] a 20 year operational life is assumed, but it is noted that "feedback from project participants suggested that the lifetime of wind farms could be increased, and this could be a driver of cost reduction". It seems likely, therefore, that over the period since this study was completed developers will have extended their expected lifetimes to 25 years. This appears to be confirmed by recent Decommissioning Programmes and by the CRMF report of progress extending asset life.

iii) The developer cost of capital was set to 8.7% (pre-tax real) based on advise from ORE Catapult that costs of capital were only part-way through the reductions forecast in the Cost Reduction Pathways Study[14].

Applying these parameters, it is found that the LCoE for East Anglia 1 and Neart na Gaoithe are £106.1/MWhr and £101.3/MWhr respectively (in 2011 pounds).

The author understands that some forecasters now believe that annual baseload prices in the 2030s and 2040s will be much lower than suggested above: perhaps on the order of £40-50/MWhr. These forecasts are based on an assumption that there will be very high levels of renewable penetration by this time, which would depress market prices and cause them to regularly collapse to zero at times of high wind and/or low demand. A sensitivity study was therefore undertaken which had a post-CfD price of £40/MWhr; this was found to reduce the LCoE values by about £5/MWhr.

[11] The EnergyUK Wholesale Market Report, January 2016, gives the price for a two year ahead annual baseload contract as £58/MWhr in nominal pounds.
[12] From section 6.1.5 of the National Grid EMR Analytical Report, July 2013. This price range applies to most of the scenarios.
[13] Published in 2012 by The Crown Estate, but the outcome of an industry-wide analysis process.
[14] Footnote 3 in the Cost Reduction Pathways Study indicates that the baseline cost of capital for projects with FID in 2011 was 9.2% pre-tax real (footnote 3). The Cost Reduction Pathways Study also forecasts that the cost of capital "will drop by around one percentage point" by 2020 (see page 32 of the study and exhibit 3.28). It has been assumed for the purposes of this report that the cost of capital for East Anglia 1 (reached FID in early 2016) and Neart na Gaoithe (due to reach FID in 2016) would be roughly midway through this process of reduction, i.e. 9.2% - (1% / 2) = 8.7%.

2.3 Summary of Total Offshore Wind LCoE Data

The table below summarises the offshore wind LCoE values obtained from the 2015 CRMF report and from the 2015 CfD bids. It also includes the target set by the Offshore Wind Programme Board of an LCoE of £100/MWhr for a project reaching FID in 2020.

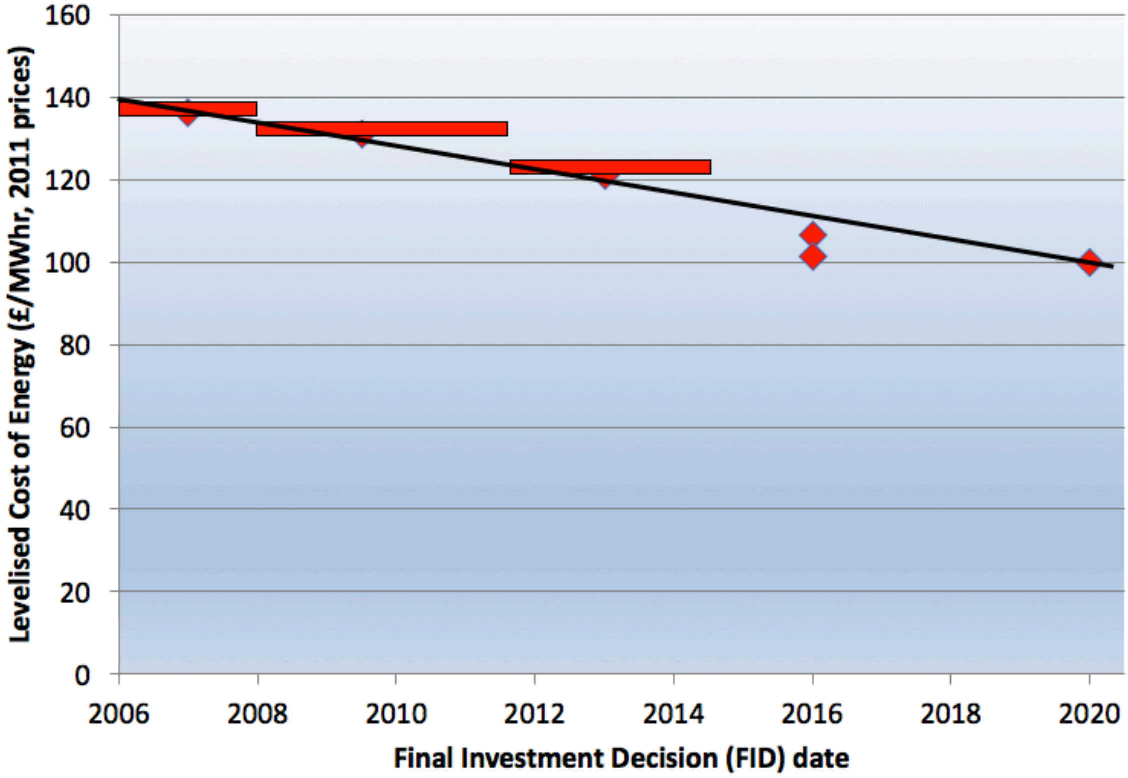
Table 2: Projects and LCoE - listed by date

Project	FID date (approx[15])	LCoE (2011 pounds)
Robin Rigg	2006	£136/MWhr (weighted average)
Gunfleet Sands	2007	
Thanet	2008	
Walney	2008 & 2010[16]	£131/MWhr (weighted average)
Sheringham Shoal	2008	
Greater Gabbard	2008	
Ormonde	2009	
London Array	2009	
Teeside	2011	
West of Duddon Sands	2011	
Humber Gateway	2012	£121/MWhr (weighted average)
Westermost Rough	2013	
Dudgeon	2014	
East Anglia 1	2016	£106.1/MWhr
Neart na Gaoithe	2016[17]	£101.7/MWhr
OWPB target	2020	£100/MWhr

The data shown in Table 2 is also represented below in Figure 2.

[15] As actual FID dates are not always publicly available, the date of placing the export cable order – which is frequently one of the first major orders placed – was used instead to provide the indicated dates for all but the last two projects.
[16] Walney was built in two phases
[17] Neart na Gaoithe has not reached FID yet, but its CfDs is based on it doing so in 2016.

Figure 2: LCoE plotted as a function of project FID date.



3 OFFSHORE WIND – TRANSMISSION COST OF IN-SERVICE WIND FARMS

This section examines the transmission cost faced by offshore wind farms. For the purposes of this report, “cost of transmission” is the defined as the transmission tariffs that must be paid by a wind farm. It does not include:

i) Any costs relating to the array cables, as these are not classed as transmission.

ii) Costs that are not passed through to the wind farm as part of their transmission tariff. (As will be explained below, the OFTO receives all of its revenue from National Grid, but not all of this revenue is passed-through to the wind farm through the tariffs that the wind farm pays to National Grid).

iii) Costs that are incurred by the wind farm when it builds the project’s transmission assets, but which Ofgem subsequently does not allow the wind farm developer to recover through the Transfer Value paid by the OFTO. (i.e. costs disallowed on the grounds of not being efficiently incurred).

iv) The cost impact of fault outages on cables or other transmission equipment that may reduce power deliveries to consumers, and hence increase the cost of the energy that can be delivered.

v) The cost of energy losses on transmission assets, since these costs are socialised (paid by all generators and demand customers across Britain).

vi) Costs associated with balancing supply and demand.

The transmission tariffs for those offshore wind farms that have already transferred their transmission assets to OFTOs are disclosed through the Statement of Use of System Charges, published annually by National Grid. This provides four tariffs, all measured in £/kW pa, which are added together to give a wind farm’s total tariff:

i) The local circuit tariff. This is different for every wind farm and represents a full[18] pass-through of the portion of the charge levied on National Grid by the OFTO that relates to the export cable (whether onshore and offshore) and any reactive compensation or harmonic filters owned by the OFTO (whether onshore or offshore).

ii) The local substation tariff[19]. This is also different for every wind farm and represents a partial (typically[20] 65±5%) pass-through of the remainder of the charge levied on National Grid by the OFTO.

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[18] There may be a small tariff discount in cases where wind farms are connected by a single circuit.

[19] The “local substation tariff” is primarily to pay for the offshore substation. The cost of onshore substation is either included in the circuit tariff (the reactive compensation and harmonic filters part) or not paid by the offshore generator at all (the transformers and switchgear part). Further complexity arises because not all of the offshore substation costs will be passed through if there is excess transformer capacity, and because of a so-called “civil works” discount which exists so that offshore generation is not treated unfairly relative to onshore generation.

[20] There are a few wind farms where the proportion passed through differs substantially from the typical level. Lower

iii) The onshore tariff. This varies depending on the onshore generation zone where the wind farm connects. The onshore tariff can be further divided into an element that is independent of the wind farm's capacity factor[21] and an element that is proportional to it[22].

iv) Some older offshore wind farms have 132kV assets belonging to onshore distribution networks lying between the OFTO assets and the National Grid. These wind farms (all of which reached FID before 2010) must pay an additional tariff for use of the distribution networks[23].

In order to convert this tariff data into a form comparable to LCoE values, the following conversions are necessary:

i) The OFTOs have licences that allow them the levy essentially the same[24] annual charge on National Grid for 20 years. At the end of this period the annual charge is assumed to fall to 10% of its original value[25], reflecting the fact that the asset would then be fully depreciated. Over the 25-year life assumed for the wind farm LCoE calculation, therefore, there will be 20 years of full tariff and 5 years of reduced tariff. Using a discounted cash flow analysis at the generator's cost of capital, it is found that – from the generator's point of view – the expected 20-years-high-then-5-years-low tariff pattern is equivalent to a flat 25-year tariff about 7% lower than the current tariffs reported by National Grid.

ii) All values reported by National Grid in their most recent Statement of Use of System Charges are in 2015 pounds. These need to be converted to 2011 pounds to be comparable with the LCoE values. This has the effect of reducing the values by a further 7%.

iii) The tariffs need to be converted from £/kW pa to £/MWhr. For this the capacity factor of the wind farm needs to be estimated. Capacity factors were taken from the graph shown as Figure 3 below, with the first power date of each project assumed to be 2 years after FID. This capacity factor is also used to compute the capacity-factor-dependent part of the onshore transmission tariff.

percentage pass-through occurs in situations where the non-reactive-compensation part of the onshore substation is a large proportion of the project's total substation cost and/or where the offshore transformers are oversized.

21 The "year round non-shared element" plus the "residual element"

22 The "year round shared element"

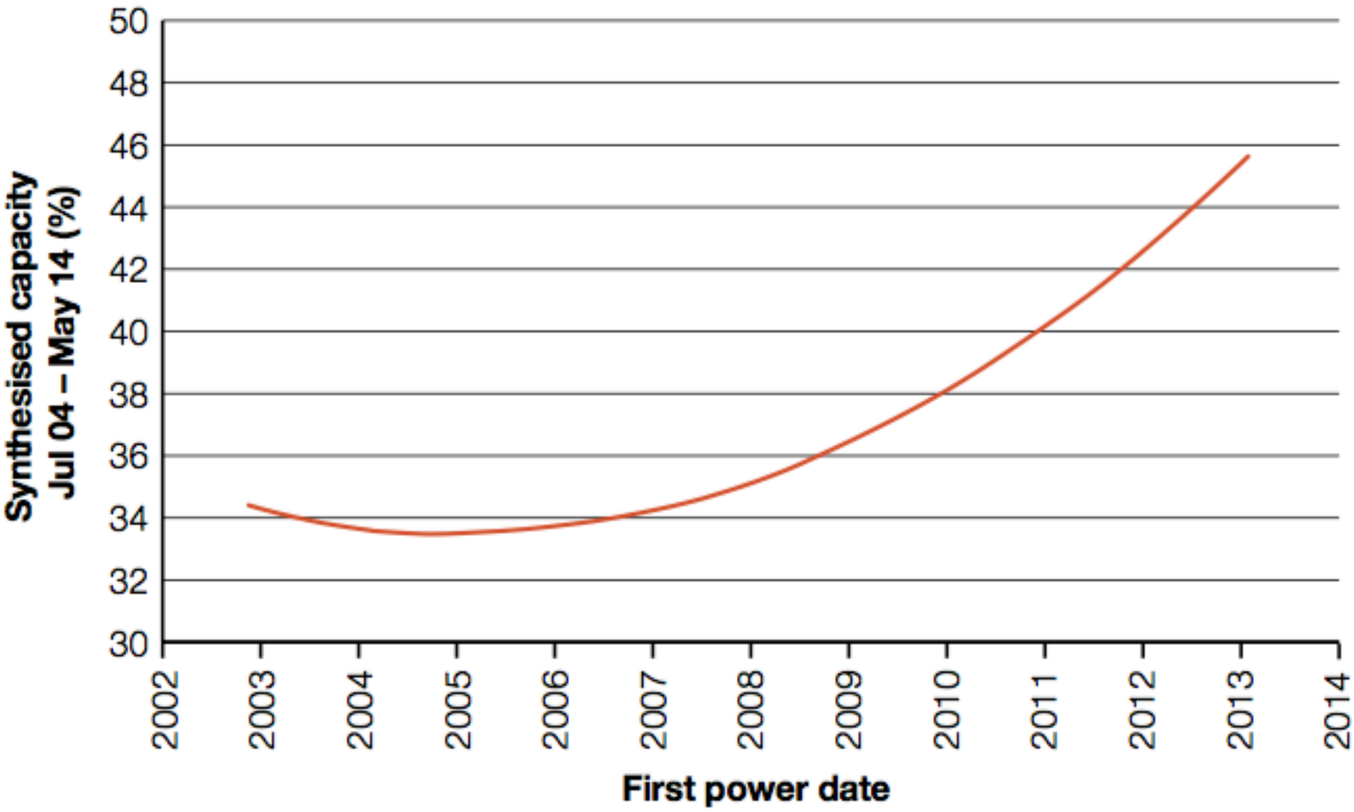
23 In addition, there is currently a discount for small 132kV-connected generation. This has been neglected as it is to be discontinued shortly.

24 With inflation indexing.

25 Ofgem has not announced how it will deal with OFTO revenues after the end of the initial 20 year period. However, if the wind farm is due to be decommissioned at the end of 25 years (the LCoE assumption) then it would seem likely that the OFTO would receive a significantly reduced amount over this period: as the cost of acquiring the assets would be fully amortised this amount would only need to support extended maintenance, repair and asset management of the assets. Note that the 10% figure is approximate and is not based on a detailed analysis of OFTO costs.

iv) For later years the graph was extrapolated up to a maximum capacity factor of 50%[26].

Figure 3: Assumed Capacity Factors



Source: 2015 Operational Wind Report, The Crown Estate. Based on a study that corrects actual wind energy outputs to their values given long-term expected average wind speeds.

[26] The Cost Reduction Pathways report suggests a yearly average wind speed of 10.0m/s for far-offshore wind farms ("site D"). With modern turbines this equates to a gross capacity factor in excess of 50% (for instance the published data for the V164 shows 10m/s at hub height equating to a 54% gross capacity factor) – however real-world factors such as wake losses, equipment breakdowns and array losses will limit real-world net capacity factors to be a level likely to be around 50%.

This then yields the results shown in table 3 below:

Table 3: £/MWhr transmission costs of in-service wind farms with published tariffs

Project	FID date (approx.)	Transmission Tariffs (2011 £/MWhr)	Average Transmission Tariffs (2011 £/MWhr)
Robin Rigg	2006	na[27]	£11.8/MWhr (weighted-by-MW average)
Gunfleet Sands	2007	£9.4/MWhr	
Thanet	2008	£13.2/MWhr	
Walney-1	2008	£16.2/MWhr	£12.4/MWhr (weighted-by-MW average)
Sheringham Shoal	2008	£12.8/MWhr	
Greater Gabbard	2008	£12.0/MWhr	
Ormonde	2009	£17.0/MWhr	
London Array	2009	£10.7/MWhr	
Walney-2	2010	£14.7/MWhr	
West of Duddon Sands	2011	£10.9/MWhr	

[27] Robin Rigg did not transfer its offshore substation to an OFTO, so its transmission tariffs are not comparable to other wind farms.

4 OFFSHORE WIND – FUTURE TRANSMISSION COST ESTIMATES

4.1 Derivation of Formula for Transmission Costs Using Existing Technology

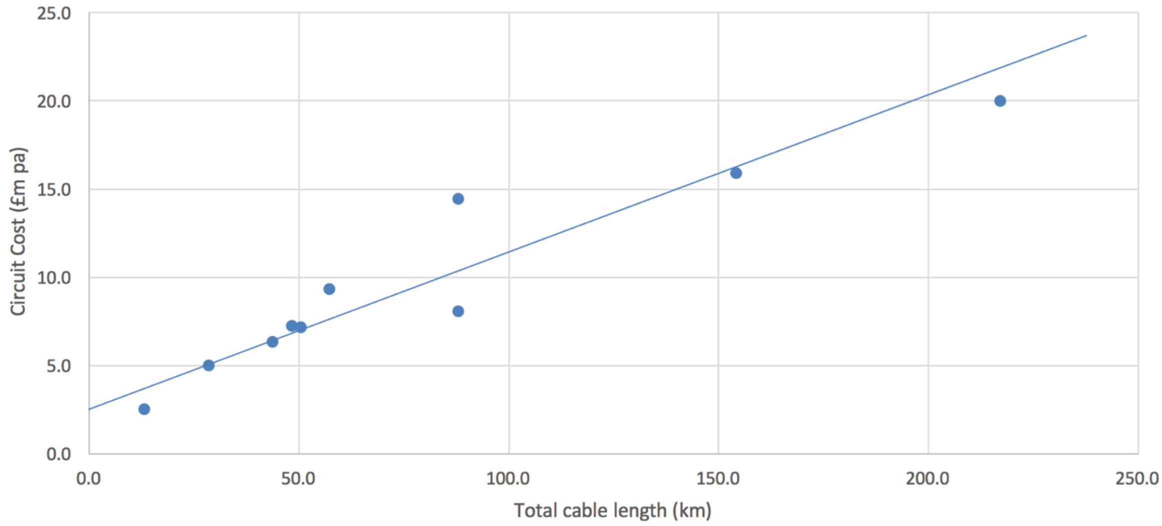
In order to facilitate the estimation of future transmission costs, an analysis was undertaken of the data available from in-service projects. As noted above, the money that the OFTO charges to National Grid (also called the Tender Revenue Stream, or TRS[28]) can be broken down into two components.

i) "Circuit Cost". This portion of the TRS is supposed to relate to cables, harmonic filters and reactive compensation. As mentioned above, the value of the local circuit tariff (in £/kW pa) is published by National Grid; multiplying by the wind farm capacity gives the value in millions of pounds per annum.

ii) "Substation Cost". This is the remaining portion of the TRS, relating to the offshore platform(s), the transformers and HV switchgear on the platforms, and the onshore transformers, HV switchgear and civil works. The Substation Cost (in £m pa) can be reasonably approximated by taking the full TRS value – which is published by Ofgem – inflation-adjusting it to current pounds, and then subtracting the Circuit Cost.

The Circuit Cost and the Substation Cost are then plotted against their primary cost drivers: the Circuit Cost is plotted against the length of export cable[29] in km, and the Substation Cost is plotted against the wind farm's MW capacity.

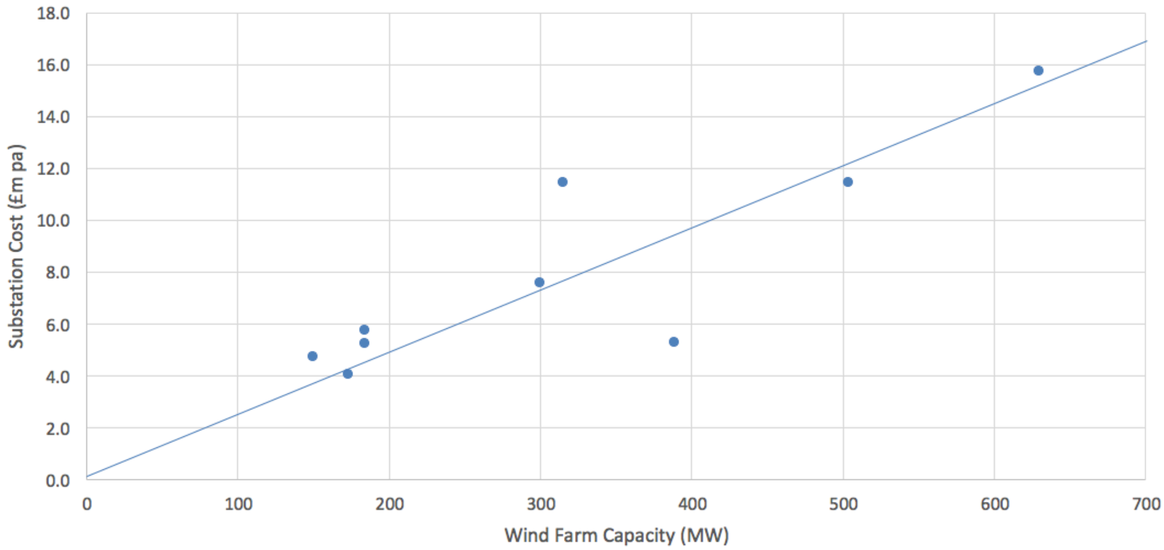
Figure 4: Estimated Circuit Cost a function of cable length



[28] The amount charged to National Grid actually includes some other elements in addition to the TRS, but the TRS is dominant and it alone is considered here.

[29] The length used is the total length of both onshore and offshore cable circuits. On most projects the onshore cable length is relatively low, and even where there are significant lengths of onshore cable, onshore and offshore per-km costs were found to be close enough that considering both together did not give rise to large errors.

Figure 5: Estimated Substation Cost a function of wind farm capacity



The data points shown in Figures 4 and 5 were then converted into formulae by fitting the lines shown on each Figure. The lines were fitted manually in order to avoid the result being impacted by outliers[30] and in order to ensure that the line gives a good match for long cable lengths and high power levels as these are the areas most relevant for estimating the cost of future projects.

The resulting formulae (both in which yield results in 2015 pounds) are:

i) Annual Circuit Cost = £2.5m pa + ((£90k pa per km) x (cable length in km))

ii) Annual Substation Cost = (£24k pa per MW) x (wind farm capacity in MW)

Note that the good correlation of Circuit Cost to cable length shown in figure 4 above, despite cable ratings that vary between 90MW and 200MW, suggests that cable rating is not a major cost driver. This is as expected given that all of the cables in the dataset have a similar design (all are 3-core cables in the 132-150kV voltage range), and all are installed in the same way by the same type of vessel.

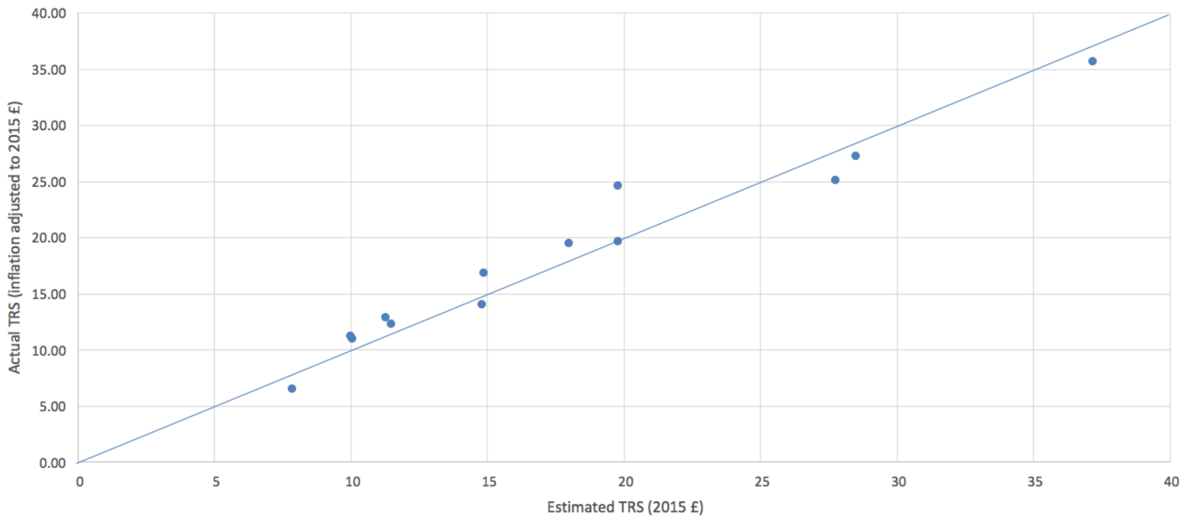
4.2 Validation of Formulae for Transmission Costs Using Existing Technology

The formulae set out above were tested by using them to predict the tender revenue stream (TRS) for all of the projects listed in Table 3 above, plus four additional projects: Lincs, Gwynt y Mor, Westermost Rough and Humber Gateway[31]. Figure 6 shows the good agreement between the estimated and actual TRSs: on all but two of the thirteen wind farms examined the actual TRS (OFTO revenue) level was within ±12% of the estimated amount.

[30] The notable outlier above the line in Figure 4 and below it in Figure 5 is the West of Duddon Sands project. The fact that the cost is unexpectedly high in one case and low in the other suggests that it is the cost allocation between "circuit" and "substation" on this project that is unusual rather than the actual costs.

[31] The TRS for Humber Gateway has yet to been published by Ofgem, but it has been estimated based on the estimated transfer value (which has been published by Ofgem) and the ratio of TRS to transfer value seen on recent projects.

Figure 6: Estimated and actual TRS



4.3 Estimated Transmission Costs for Existing-Technology Future Projects

Using the formulae derived above, transmission tariffs can now be estimated for existing-technology projects that have yet to be completed, along with projects which are complete but for which National Grid has yet to publish tariff figures. This is done as follows.

i) Export cable lengths and wind farm capacities are found from public-domain sources (typically the developer's website).

ii) Using the formulae derived in 4.3 above above, the annual circuit and substation costs are estimated.

iii) The offshore circuit tariff is assumed to be equal to 100% of the annual circuit cost and the offshore substation tariff is assumed to be 65% of the annual substation cost. (The 100% and 65% values are based on the typical pass-through portions discussed at the start of Section 3).

iv) The onshore tariff is then added, based on the zone where the wind farm connects and the 2016/17 tariffs set out for each zone in National Grid's publications.

v) Further conversions are applied to yield a result based on a 25-year tariff, in 2011 pounds, and in £/MWhr terms. The conversion to a "25-year tariff" is done by levelising a tariff stream that is based on the OFTO's revenue being at 100% of the published TRS value for 20 years followed by 10% for 5 years.

Table 4 below shows the estimated transmission tariffs, in 2011 £/MWhr terms, for all projects using existing technology that are either in-service or under construction but whose tariffs have yet to be published by National Grid.

Table 4: Estimated £/MWhr transmission costs for wind farms using existing 132-150kV transmission technology but without published tariffs

Project	Capacity	Export cables total length	FID date approx.	Transmission Tariffs (2011 pounds)
Humber Gateway	219 MW	78 km	2012	£13.1/MWhr
Westermost Rough	210 MW	27 km	2013	£8.1/MWhr
Dudgeon	402 MW	178 km	2014	£12.4/MWhr
Rampion	400MW	85km	2015	£8.1/MWhr
Galloper	336MW	92km	2015	£9.6/MWhr

4.4 Estimated Transmission Costs for New-Technology Future Projects

The projects listed in Table 4 above all use "existing" technology. The remaining projects introduce one or more of the following new approaches:

i) The export cable voltage is increased from the 132-150kV range seen on existing projects to 220kV.

ii) The offshore substation platforms are reduced in weight so that they can be installed on the same type of foundation as the wind turbines. The lighter weight also allows them to be installed, using a single lift operation, by the same vessel that installs the turbines. The OWPB has previously published a report that explores such lightweight substations in more detail[32].

iii) Placing shunt reactors on an offshore platform at the midpoint of the export cables in order to allow AC cables to be used over longer distances than previously.

To estimate the cost of such projects assumption must be made regarding the cost impact of these changes. As a result, any costs presented in this section are inevitably more speculative than those shown previously.

For the purposes of this report, the following assumptions are made regarding the cost impact of the three new technologies described above:

i) Based on a simplified analysis[33] the annual circuit cost for a km of 220kV cable is assumed to be 16% higher than the equivalent cost for 132-150kV cables.

[32] OWPB report "Lightweight Offshore Substation Designs", January 2016.

[33] This is based on generic cable cost estimating relationships, and it assumes that reactive compensation costs rise broadly in proportion to the installed cable costs. It should therefore be regarded as an initial approximation.

ii) The OWPB report into lightweight substations undertakes a cost analysis that verifies the feasibility of the contract cost reduction of £23.5m figure put forward by a substation vendor as the saving available by converting a 500MW wind farm to use standalone[34] lightweight substations rather than a heavy conventional platform. Using the approach set out in section 8.6 of that report, this reduction in contract costs is found to equate to a reduction in annual substation cost of £2.3m pa for 500MW, or £4.6/kW pa.

iii) The cost of a midpoint shunt reactor platform is conservatively[35] assumed to be the same as the cost of a conventional transformer platform serving the same amount of generation. The report "A Guide to an Offshore Wind Farm"[36] suggests that a 500MW offshore transformer platform would cost £50m to fabricate and £10m to install. Assuming the same £60m cost for a shunt reactor platform serving a 500MW wind farm, and applying the calculation methodology described in (ii) above, yields an annual cost of £11.7/KW pa. This is then added to the project's annual circuit cost.

Using these assumptions, Table 5 below was calculated. It shows the estimated transmission tariffs, in 2011 £/MWhr terms, for projects are using one or more of these new approaches.

Table 5: Estimated £/MWhr transmission costs for wind farms using new technology

Project	Capacity and export cable length	New technologies included	FID date approx.	Transmission Tariffs (2011 pounds)
Burbo Extension	256MW 36km	220kV	2014	£8.3/MWhr
Race Bank	546MW 172km	220kV	2014	£11.1/MWhr
Walney Extension	649MW 167km	220kV	2015	£10.3/MWhr
Hornsea 1 *	1200MW 513km	220kV Shunt platform	2016	£15.5/MWhr
East Anglia 1 *	714MW 244km	220kV	2016	£11.5/MWhr
Beatrice	580MW 160km	220kV Lightweight sub	2016?	£12.3/MWhr
Neart na Gaoithe	448MW 90km	220kV Lightweight sub	2016?	£9.3/MWhr

* the connection arrangements for these projects have yet to be made public; for the purpose of this report they are assumed to be at the current state of the art for AC offshore wind farm connections: 220kV cables of up to 400MW capacity each.

[34] A "standalone" lightweight substation is one that sits on its own jacket or monopile, as opposed to the "integrated" lightweight substation where a substation and a turbine share the same substructure.

[35] No information on the cost of shunt reactor platforms was available, but it is likely that their cost (per cable) is between 50% and 100% of the cost of the associated transformer platform(s). If cost is at the low end of this range then the savings described in section 4.5 below would be reduced by approximately £0.5/MWhr.

[36] Written by BVG for The Crown Estate, 2010. This document is not intended to provide precise cost estimation data, but it does provide a useful, and public-domain, source for approximate capital cost information.

4.5 Cost reduction approaches investigated by OWPB Grid Group

The 2015 action plan of the OWPB Grid Group focussed in particular on the two areas which the group believed to have a high potential for cost reduction: reducing cable cost by using higher-capacity cables and reducing offshore substation cost by using lightweight offshore substations.

In order to quantify the potential benefits of the approaches being investigated by the OWPB Grid Group relative to the state of the art in wind farm connection the following scenarios were investigated for an offshore wind farm 170km from its onshore connection point.

i) The "State of the Art" scenario employed three 220kV cables each capable of carrying 400MW with dynamic ratings and a shunt reactor platform.

ii) The "OWPB-Investigated Technologies" scenario employed a pair of 275kV cables with enlarged conductors[37], each capable of carrying 550MW with dynamic ratings. The shunt-reactor platform(s) are of the "lightweight" design discussed in section 4.4 above, and the transformer platforms are of the "integrated lightweight" design where a single wind-turbine-type substructure carries both a lightweight substation *and* a wind turbine.

Costs for the "State of the Art" scenario were based on the same assumption as were set out in section 4.4 above. Costs for the "OWPB-Investigated Technologies" scenario were assumed to be as follows:

i) The large-conductor 275kV cable was assumed to cost 37% more than a 132-150kV cable. This was based on the same generic cable cost estimation approach as was used in Section 4.4.

ii) The cost reduction from using a lightweight design for the shunt-reactor platform was assumed to be £4.6/kW (the same as is estimated for standalone lightweight transformer platforms; see Section 4.4 above).

iii) The cost reduction from using integrated lightweight substations for the transformers was taken from the OWPB's lightweight substation report: this calculated a contract cost saving of £34.1m by using integrated lightweight substations on a 500MW wind farm rather than a heavy conventional substation platform. Using the same approach as previously, this equates £6.8/kW pa.

The results for each scenario are shown in Table 6 below.

[37] The OWPB Grid Group has commissioned studies of a 275kV 2000mm^2 cable.

Table 6: Alternative scenarios for far-offshore wind farm connection.

Scenario Name	Scenario description	New technologies included	Transmission Tariffs (2011 pounds)
State of the Art	1200MW wind farm 170km from connection point 3x400MW cables	220kV Shunt-reactor platform	£15.5/MWhr
OWPB-investigated technologies	1100MW wind farm 170km from connection point 2x550MW cables	275kV Large conductor cables Integrated lightweight transformer platforms Lightweight shunt-reactor platforms	£12.0/MWhr

It is worth noting that the two scenarios above involve slightly different wind farm sizes, each intended to minimise transmission cost by ensuring that the wind farm capacity would be an integral multiple of the largest cable capacity available in each scenario. While the practice of sizing wind farms to minimise transmission cost has not been noted previously, it seems likely that it will become increasingly evident as the competitive CfD process prioritises cost minimisation over output maximisation, and as transmission costs grow as a proportion of total offshore wind costs (see Section 6 below).

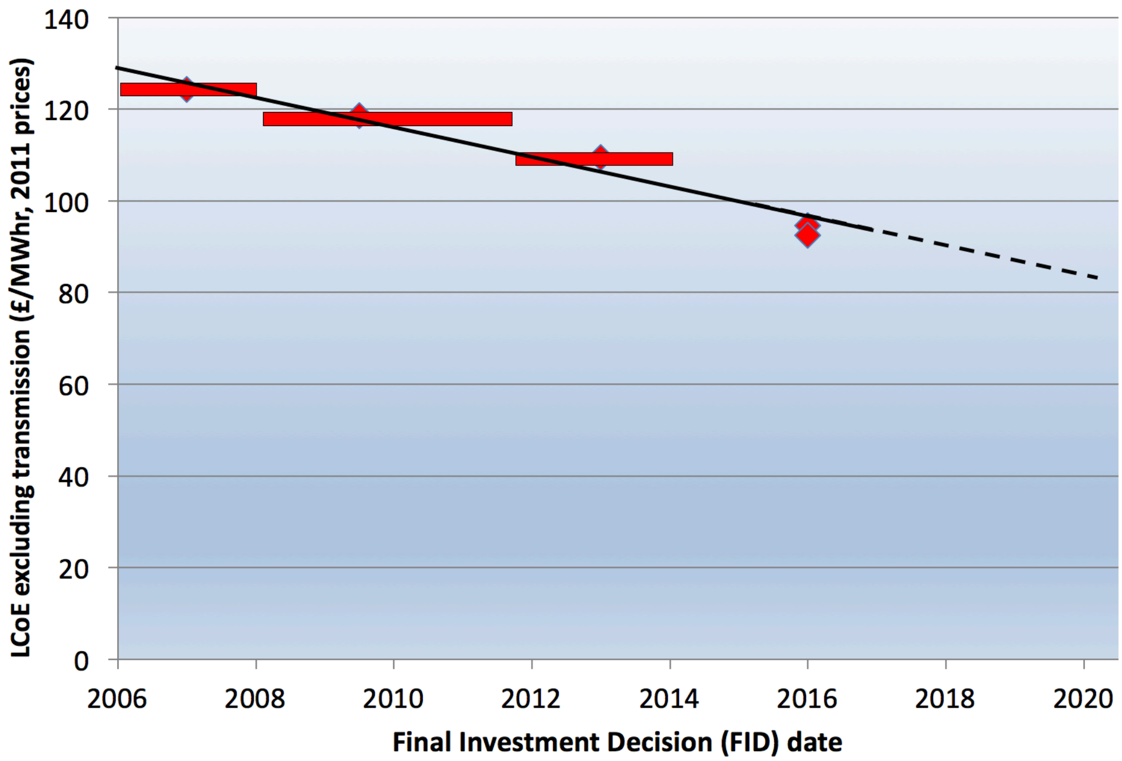
5 GENERATION-ONLY COSTS

A benefit of being able to calculate the cost of transmission in the same terms as the total cost of offshore wind (i.e. as the levelised cost over the turbine life, in 2011 pounds per MWhr) is that by subtracting the cost of transmission from the total cost of wind the cost of generation is obtained.

Figure 7 below shows how the cost of generation (which includes the cost of the array cables) has changes over time. The three horizontal bars on the left are the three groups of projects whose costs are presented in the February 2015 report of the CRMF (see figure 1). The pair of diamonds in 2016 represent the two projects that were successful in the 2015 competitive CfD round and are scheduled to reach FID in 2016.

As can be seen the cost of generation is already in the £90-100/MWhr range and, on current trends, should be in the £80-90/MWhr range by 2020.

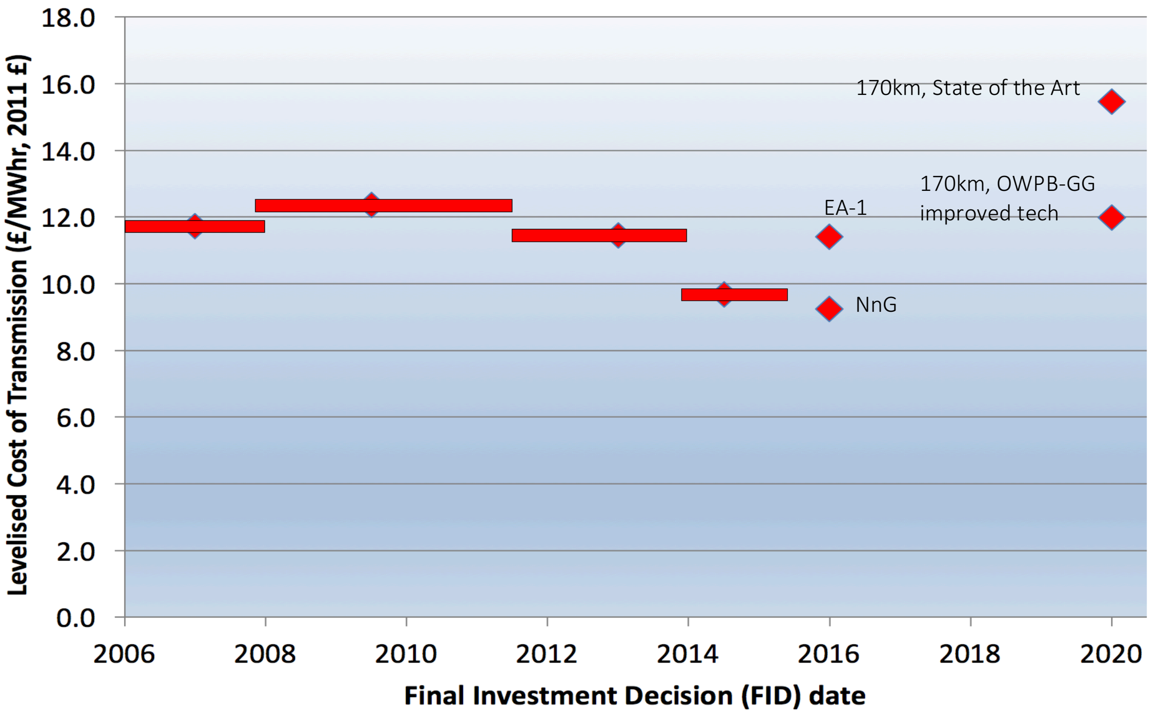
Figure 7: Estimated cost of offshore wind generation (excludes transmission)



6 CONCLUSIONS

Figure 8 below show summarises the transmission tariff calculations and estimates previously presented. The three horizontal bars on the left are the three groups of projects whose costs are presented in the February 2015 report of the CRMF. The fourth bar represents the set of projects that reached FID in 2014-2015 (Dudgeon, Burbo-2, Race Bank, Walney Extension, Rampion and Galloper). For 2016 the two competitive-CfD projects are shown. Finally, for 2020, the two scenarios for a 170km connection are shown.

Figure 8: Transmission tariffs as a function of project FID date



It is noteworthy that the cost of transmission has generally been held (and can continue to be held) within the £10-12/MWhr range despite transmission distances increasing by almost an order of magnitude from an an an average of 20km for the leftmost bar to 170km for the 2020 scenarios. The primary reasons why this has been achieved are as follows:

i) The revenues received by OFTOs have declined from over 10% of the asset value[38] on early projects to around 7%[39] of the asset value (see figure 9). This has the effect of reducing transmission tariffs by over 25%. This reduction in revenues reflects increased competition between OFTOs, lower interest rates in the economy generally, economies of scale in the financing and operation of larger projects, and the introduction of more efficient financial structures.

[38] The value of an OFTO's assets are decided by Ofgem and published as the Final Transfer Value (or Final Capital Value). This is the amount that an OFTO pays to acquire the transmission asset built by and for a particular wind farm.

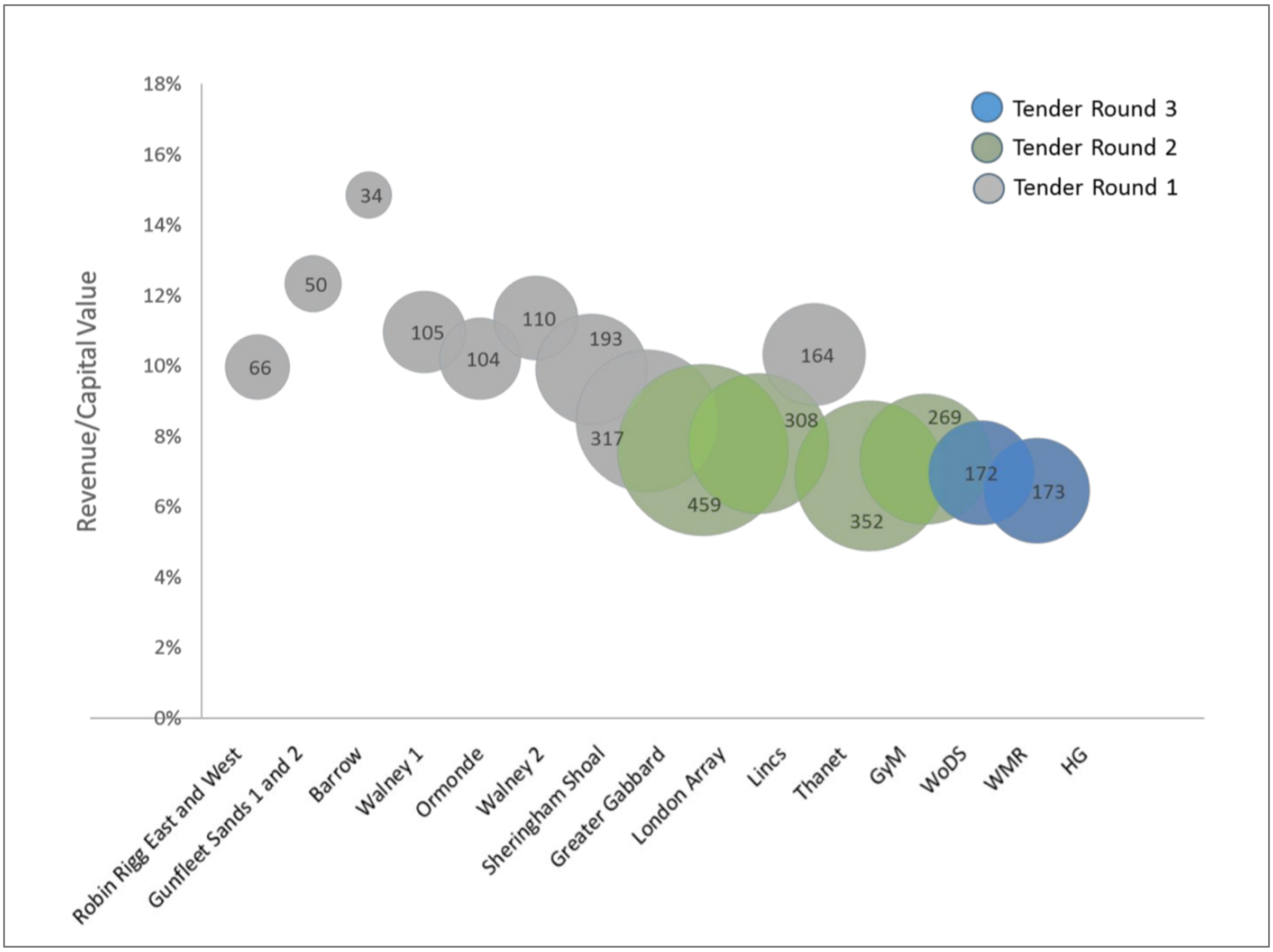
[39] Note that this is the OFTO's 20-year annual revenue expressed as a percentage of the transfer value, *not* the rate of return (which will be lower).

ii) Increasing generation capacity factors, which have risen from 35% for projects with an FID in 2006 to 50% for the latest projects with 7-8MW wind turbines. This has the effect of reducing transmission costs by over 30%.

iii) Upgrading from cables with voltages in the 132-150kV range to 220kV cables allows the number of cables to be reduced, although this is somewhat offset by the increased cost per cable. For instance, using the cost estimation assumptions set out in this report, it was estimated that by using a pair of 220kV cables rather than three 132kV cables the Race Bank wind farm would have reduced its transmission tariffs by 12%. The benefits of using 220kV increase as projects go further offshore and cables get longer: for instance, on the East Anglia-1 project using two 220kV cables in place of four 132kV cables was estimated to reduce tariffs by 28%.

iv) For the 2020 scenarios a further tariff reduction of 23% is estimated to be possible by employing two technical advances that are currently under investigation by the OWPB Grid Group: lightweight offshore substations and large-conductor 275kV cables.

Figure 9: OFTO Projects Revenue/Capital Value and Capital Value



Source: Ofgem. Bubble size and the number on each bubble are the capital value. Projects are shown from left to right in the order in which their transmission assets were transferred to OFTOs.

Taken together all of these sources of improvement equate to a reduction of more than 70% in the per-MWhr transmission costs of a far-offshore wind farm relative to a scenario where OFTO efficiency, capacity factor and technology had never improved. In other words, without these improvements the cost of transmission – far from remaining broadly stable between 2006 and 2020 – would have increased more than threefold.

Over this 2006-2020 period the total cost of offshore wind should have fallen, according to Figure 2, from £140/MWhr to a target level of £100/MWhr. Since transmission tariffs are expected to stay broadly constant over this period, it follows that the scale of transmission *relative* to the total cost of offshore wind will rise from around 8% in 2006 to 12-15% by 2020.