Department of Business, Energy and Industrial Strategy

Cost Estimation and Liabilities in Decommissioning Offshore Wind Installations

Public Report

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Executive summary

The Energy Act (2004) grants The Department of Business, Energy and Industrial Strategy (BEIS) discretionary powers to request decommissioning programmes and financial securities for offshore renewable energy installations (OREIs). These powers provide a mechanism to ensure that OREIs are:

- appropriately decommissioned at the end of their useful life, and
- that funds are available to ensure costs do not default to the public sector

In addition, BEIS may be required to execute the role of decommissioner of last resort for offshore wind farms (OWF). In order to quantify the potential liability to BEIS, a cost model has been developed to estimate the total cost of decommissioning OWF in the UK.

To support development of the cost model Arup consulted with the offshore wind industry, gathering stakeholder views and considering future scenarios that may influence the decommissioning costs.

The cost model has been used to estimate a range of decommissioning costs for 37 OWFs at various stages of development (either operating, in construction or pre-construction). The total estimated decommissioning cost is £1.28bn to £3.64bn of which the liability to BEIS is estimated to be of £1.03bn to £2.94bn. The Crown Estate and The Scottish Government are potentially liable for the balance.

The range of costs considers a range of factors which may impact cost outturn including:

- Potential for change in regulation which may affect whether some infrastructure can be left in situ;
- Uncertainty in the decommissioning methodology, i.e. what processes, tools and techniques are used to carry out the work; and
- Uncertainty in a number of key cost drivers, e.g. future vessel charter rates.

As a result of the nascent nature of the industry and these uncertainties the estimated decommissioning cost range is wide. However, as more information becomes available these uncertainty bounds will reduce. Arup recommends:

- Appropriate, periodic reviews of the total decommissioning costs;
- Review of decommissioning plans and proposed costs prior to and during the accrual of securities.

These reviews will allow the cost model assumptions to be updated, increasing the certainty of the cost estimate and ensuring that sufficient funds will be available at the time of decommissioning.

1 Introduction

The Energy Act (2004) grants The Department of Business, Energy and Industrial Strategy (BEIS) discretionary powers to request decommissioning programmes and financial securities for offshore renewable energy installations (OREIs). These powers provide a mechanism to ensure that OREIs are:

- appropriately decommissioned at the end of their useful life, and
- that funds are available to ensure costs do not default to the public sector.

In order to quantify the total liability for decommissioning OREIs, specifically offshore wind farms (OWFs), in the UK now and in the future BEIS commissioned Arup to investigate the forecast costs presented by asset owners and developers to understand the range of costs to decommission projects individually and collectively. There is inherent uncertainty in the costs of decommissioning OWFs, as limited activity has been undertaken. There are a range of scenarios that may impacts negatively or positively on the costs of decommissioning. As such a review was also undertaken on the potential sensitivities and their impact on cost outcomes.

Also in accordance with the Energy Act (2004), BEIS may be required to execute the role of decommissioner of last resort in the event that the owner or developer of an OREI is unable to organise and fund decommissioning of the asset. Hence BEIS also required Arup to assess a range of potential security mechanisms to ensure funds for decommissioning are secured by developers. In addition to providing an understanding of the risk of owners or developers not being able to fully fund decommissioning activities and for the decommissioning liability consequently to transfer to BEIS.

Finally, it was acknowledged that earlier studies on the Levelised Cost of Energy from offshore wind (1) did not account for decommissioning costs, or the cost of procuring securities. BEIS required that Arup consider this impact.

The aim of this report is to summarise the findings of this study including the total overall liability for government in relation to OWF decommissioning. The figures provided in this report are to give BEIS an indication of the total liability. It is not intended to suggest the level of security that developers should hold.

This document is a summary report of the findings of the project. The document is structured as follows:

Section 1. Description of Methodology and Cost Modelling

Section 2. Findings

Section 3. Sensitivity Studies and Future Scenarios

Section 4. Transfer or Risk

Section 5. The impact on Levelised Cost of Energy

Section 6. Conclusions and Recommendations

1.1 Project methodology

To meet BEIS' objectives of understanding the total decommissioning cost and the likelihood of the decommissioning liability transferring Arup undertook several work streams:

- Building a cost model (2) to estimate the total decommissioning cost for UK OWFs. This model provides both a database of costs forecast by developers/owners and a benchmark cost built up by Arup. As input material into the work streams. BEIS provided the decommissioning plans and cost estimates for several OWFs, listed in Appendix 1.
- Arup reviewed these plans and costs and used these to inform the design of the cost model, as outlined in section 1.2.
- Consulting with industry to gain stakeholders' views on the decommissioning costs, appropriate security and risk of liability transfer between parties. Arup and BEIS hosted an industry workshop to gain input from developers, Offshore Transmission Owners (OFTOs), investors and regulators on decommissioning costs. This workshop included discussions on decommissioning cost estimates, future scenarios that may impact on costs and decommissioning securities. More information about this consultation can be found in the consultation report (3).
- Using the model to examine how future scenarios will impact on the cost of decommissioning, and the key sensitivities that will have the most significant impact on outturn costs. These scenarios were devised as a result of Arup internal review, conversations with BEIS and with input from the industry consultation. The scenarios are discussed in more detail in section 2.6.
- Examining the risk of liability transfer described in section 4.

1.2 Model design

The OWF decommissioning cost model contains a build-up of the total estimated decommissioning cost across the 37 installed, in construction and pre construction OWFs across the UK. The cost model contains benchmark costs developed by Arup, based on an assumed decommissioning process and several input variables, described in sections 1.2.2 and 1.2.3. Arup benchmarks are based on equivalent operation benchmarks from OWF construction and oil and gas construction and decommissioning. The model gives a cost estimate for decommissioning generation assets (WTG, intra-array cables and foundations) and a cost estimate for decommissioning the OFTO assets (offshore substations and offshore export cables) which can be added to the estimate for the generation assets. This is illustrated in section 2.

The model also contains data provided by BEIS from OWF developers of their estimated decommissioning costs at a project level. The output of the cost model includes a comparison between the Arup benchmark data and developer data.

1.2.1 OWF developer data

BEIS provided confidential OWF developer decommissioning cost data for 17 OWFs. Information was not provided by the developers in a standard format using a consistent methodology and assumptions. As such it was challenging to provide direct comparisons between projects, but attempts were made to normalise cost data where possible. For each of these 17 OWFs the developer data was analysed and the following points should be noted:

- If a decommissioning cost for the OFTO assets was included, this was removed;
- The contingency added by developers to the total decommissioning cost was found to vary between developers. Where contingency had been added as a simple percentage of the total, this cost was separated; and
- Some developers had included a revenue from waste as part of their decommissioning cost calculation. This revenue was not included in the developer estimate used in the cost model.

It should also be noted that some developers provided more information than others in their decommissioning cost estimates, and where it was not possible to identify separate cost elements the total decommissioning cost could not be adjusted. Therefore, some developers' costs may include contingency and OFTO costs which adds some uncertainty in terms of the comparison to Arup's benchmarks. However, the sum of these elements is a small proportion of the overall cost and well within the wider uncertainty.

1.2.2 Arup benchmark cost model logic

The Arup benchmark cost model has been built up based on an assumed decommissioning process, which includes various decision points and input data.

The model performs the required calculations to calculate the cost of the vessel-based activities and then adds additional cost for weather risk and overhead costs.

The decommissioning cost estimate is built up in the same way for each OWF, ensuring each cost estimate is based on the same set of assumptions for vessels and decommissioning activities.

There are a number of decision points included in the model logic. Some are based on an input to the model and some are based on individual OWF characteristics. For example, there is a binary toggle (Yes or No) for whether cables are removed, and the vessel size (a high, medium or low range jack up) used for wind turbine generator (WTG) removal is based on the hub height and the nacelle weight of the WTG for each OWF.

1.2.3 Arup benchmark cost model inputs

The model contains several sets of input variables:

- Inputs related to vessels and duration of activities e.g. vessel day rate and vessel speed;
- Inputs which are specific to individual OWFs e.g. number of WTGs, water depth; and
- Inputs related to various scenarios e.g. whether cables (intra-array and export cables) are assumed to be removed or left in place.

These inputs have been derived from a variety of sources and peer reviewed to ensure they are representative of the current market.

1.3 Outputs

The primary output of the model displays the total cost of decommissioning the installed and planned OWFs over time from now until 2045. The graphical output displays the total cost the developers have estimated and the total cost for all the installed and planned OWFs adjusted using Arup's benchmark estimate.

The model allows the user to select and change a number of parameters to observe how these affect the total decommissioning costs, including:

- filtering for selected OWFs,
- adding in inflation, and
- applying cost reduction learning curves

The model has a number of high level filters that allow the user to view data for specific groups of projects. These filters include:

- Decommissioner of last resort, i.e.:
    - Crown Estate – for a number of round 1 projects;
    - BEIS – for all English and Welsh OWFs from Round 2 onwards and certain Round 1 farms; and
    - Scottish Government – for Scottish OWFs.
- Display only those projects where the developer estimates are included.

The 37 OWFs that are included in the Arup benchmark estimate, referred to throughout this report, are found in Appendix 1.

2 Total cost of decommissioning

In this section the total forecast cost of decommissioning is presented, both as forecast by Arup's benchmark cost model, and as forecast by OWF developers. Inherent assumptions are discussed and suitable uncertainty bounds are applied. The impact of applying inflation is examined, and the cost of decommissioning OFTOs is also considered and put in the context of the overall costs.

2.1 Cost forecasts

Arup estimate the cost of decommissioning across 37 OWFs currently operating or under construction in the UK (see list in Appendix 1) totals £1.82bn. This has been calculated using the decommissioning cost model described earlier and is based on the assumptions outlined in section 2.2. This total is in 2017 values and does not include inflation. The anticipated spend profile in nominal terms is shown in Figure 1 below. This cost will be referred to as the *baseline estimate* for subsequent discussion in this report.

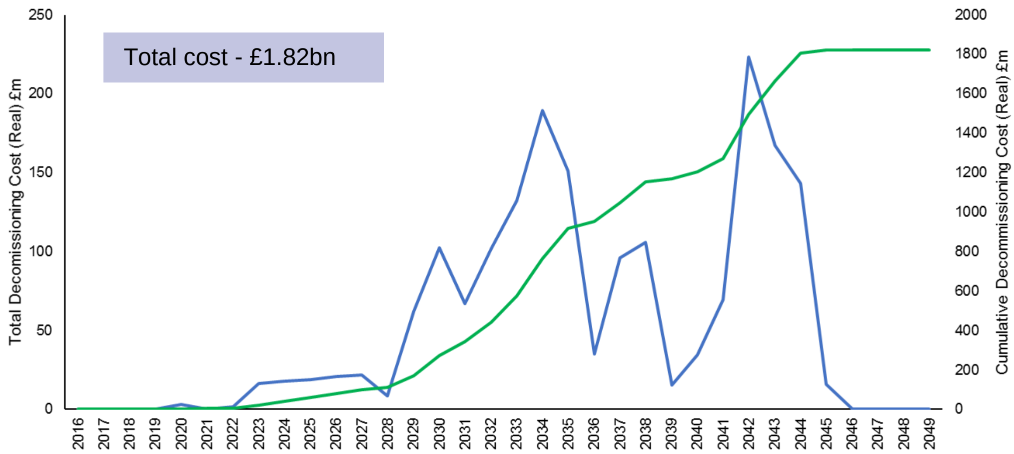

Figure 1: Total decommissioning cost model estimate for 37 OWFs

As described in section 1.2.1, BEIS were able to share confidential decommissioning estimates submitted by developers for 17 OWFs. These 17 OWFs represent 59% of the total capacity (in MW) of the 37 OWFs in the model. The total cost forecast by developers to decommission these OWFs is £822m, including contingency and £737m excluding contingency. The total cost to decommission these 17 OWFs, as forecast by Arup's benchmark model is £980m. Both these costs are illustrated in Figure 2 below.

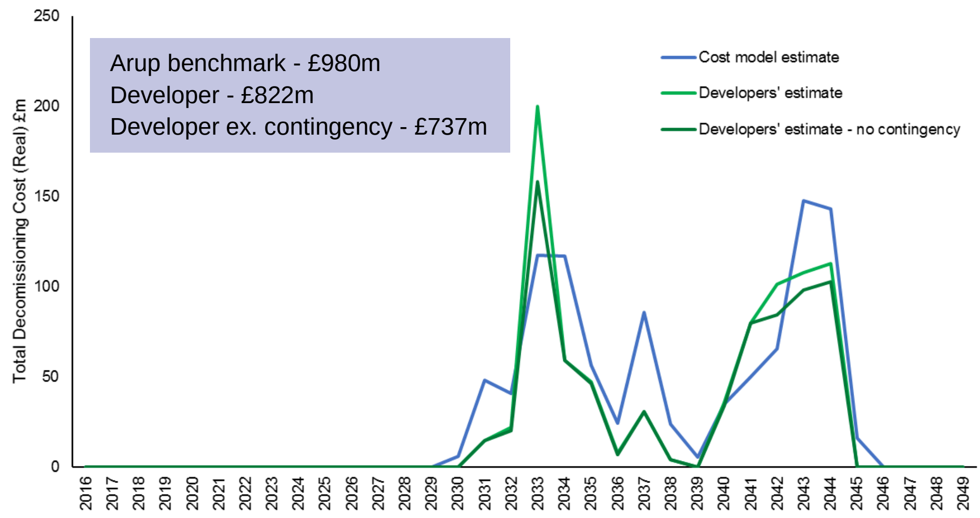

Figure 2: Comparison between cost model and developers' estimate for 17 OWFs

The cost model estimates are generally higher than the developers' estimates. The cost model uses a more conservative approach to estimating the decommissioning costs than most of the developer cost estimates. However, there are a number of instances where the developers' costs are higher as a result of their approach being even more conservative than the cost model. This illustrates the general uncertainty in the decommissioning cost estimation.

These 17 OWF should not be assumed to be representative of all 37 OWF included in the model. The cost estimates from developers vary greatly and are understood to be based on differing assumptions. The Arup decommissioning cost model uses an independent range of input data and, although comparisons are made, the model does not extrapolate from the available developer estimates.

2.2 Assumptions

Arup's baseline estimate of total decommissioning cost produced by the decommissioning cost model shown in Figure 1 is based on the following key assumptions about the decommissioning methodology:

- OFTO costs are excluded (see section 2.4 for details on the OFTO costs);
- The intra-array cables are decommissioned (disconnected from WTGs, ends buried) and left in situ (see section 3.3.1 for a comparison with removing the cables);
- The WTGs are dismantled and transported to shore by the same jack-up vessel;
- A separate jack-up vessel is used to remove and transport the foundations; and
- The foundations are cut below the seabed and the top section removed.

There are also other supporting assumptions used in the model inputs, including estimated vessel day rates and estimated duration of activities.

The vessel day rates have great influence on the total estimate and are a source of considerable inherent uncertainty. Vessel day rates can vary greatly based on the time of year, vessel demand, contract lengths etc. The vessel day rate used in the model includes an estimate of the cost of the spread of tooling and personnel required to carry out the vessel's task. For example, the day rate for the foundation removal vessel includes the cost of cutting equipment, the crew cost and any support vessels which may be required.

The durations of activities have also been estimated and input to the model. Vessel transit times from shore are determined by selecting a potential decommissioning port and the distance of the OWF from that port. The durations for discrete activities are based on Arup's knowledge of offshore operations.

Durations for specialist tasks such as cutting of monopile foundations have the benefit of actual timings known from decommissioning that has been completed to date, e.g. Yttre Stengrund (4). The Yttre Stengrund decommissioning involved cutting a 3.5m diameter monopile. In the model, cutting durations for larger piles are scaled according to the diameter of the monopile being cut.

Other assumptions regarding costs such as overheads (project management, design and engineering, port fees etc.) and waiting on weather have been added as a percentage of the total marine operations.

2.3 Uncertainties

The model is sensitive to vessel day rates and to certain activity durations. These are dealt with as specific scenarios in section 3.2. The model is also subject to uncertainties in decommissioning methodology and the decommissioning philosophy outlined in guidance and regulation, these effects are dealt with in section 3.3.

These uncertainties result in a multitude of scenarios, each resulting in a different estimate for the total decommissioning cost. While specific scenarios are considered in section 3, it is useful to visualise the inherent uncertainty on the overall cost forecasts in the form of likely high/low ranges.

In order to visualise the likely cost range, independent of any future scenario that may occur, a high and low cost range can be assigned to the central estimate.

Arup recommend considering the cost range in line with the AACE (Association for the Advancement of Cost Engineering). This is commonly used in the oil and gas industry when considering the cost of decommissioning oil and gas installations in the North Sea. The AACE classification of estimates is shown in Table 1 below.

Table 1: AACE classification estimates (5)

Cost estimate classification	**Level of definition**	**Cost estimating description**	**Expected accuracy range**
Class 5, Order of magnitude	0% to 2%	Stochastic, most parametric, judgement (parametric, specific analogy, expert opinion, trend analysis)	L: -20% to -50% H: +30% to +100%
Class 4, Budget	1% to 15%	Various, more parametric (parametric, specific analogy, expert opinion, trend analysis)	L: -15% to -30% H: +20% to +50%
Class 3, Preliminary	10% to 40%	Various, more definitive (detailed, unit cost, or activity-based; expert opinion; learning curve)	L: -5% to -15% H: +5% to +20%
Class 2, Intermediate	30% to 70%	Various, more definitive (detailed, unit cost, or activity-based; expert opinion; learning curve)	L: -5% to -15% H: +5% to +20%
Class 1, Definitive	50% to 100%	Deterministic, most definitive (detailed, unit cost, or activity-based; expert opinion; learning curve)	L: -3% to -10% H: +3% to +15%

Until more OWF decommissioning projects have been executed, and more acitvity-based estimating of costs becomes possible, it is reasonable to assume that cost estimates could be Class 5 or Class 4. Therefore, considering a cost range of -30% to +100% would be appropriate.

The conservative upper estimate recognises the high degree of uncertainity involved in estimating the decommissioning cost, given that no large scale projects have yet been executed and the majority of work is planned for 10 to 30 years in the future. This uncertainty can be attributed to uncertatinty in vessel rates and decommissioning methodologies, particularly the timing of activities and the decommissioning philosophy. These are all explored futher in section 3.

The lower estimate acknowledges that there may be some conservatism in the central estimate and that thereare opportunities for cost reduction. These opportunities include the development of new technologies, techniques and efficiencies over the period of the decommissioning works. These scenarios are considered in Section 3.3.

When this range is applied to the decommissioning cost model output, the total estimated decommissioning cost ranges from £1.28bn to £3.64bn. This is illustrated in Figure 3 below.

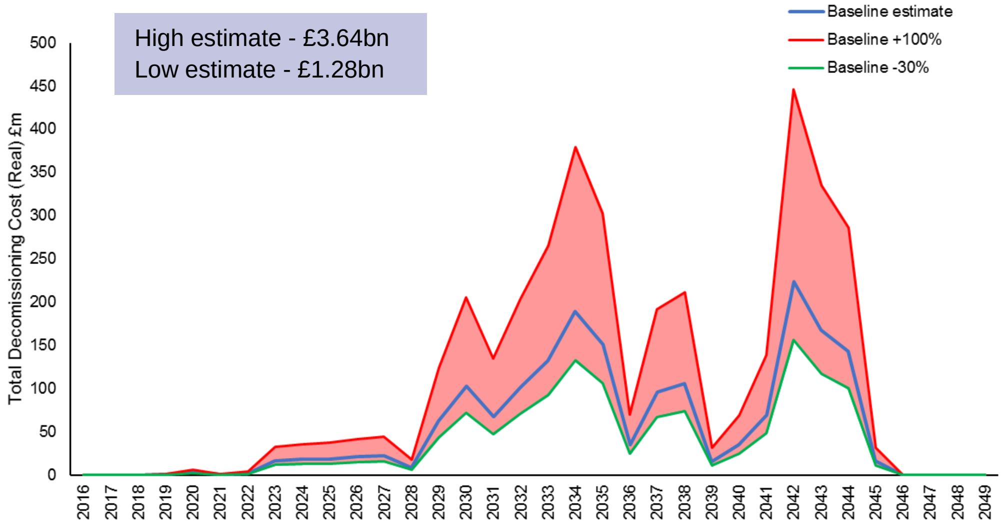

Figure 3: Estimated decommissioning cost range based on AACE cost classifications

2.4 OFTO costs

The cost of decommissioning the OFTO assets, i.e. the offshore substation and the offshore export cable, has been calculated separately for each OWF. The OFTO cost has been calculated based on the following assumed methodology:

- A heavy lift vessel is used to remove the substation topside and foundation; and
- The export cable is decommissioned and left in situ (see section 3.3.1 for a comparison with removing the cables).

The decommissioning cost model estimate for the total cost of decommissioning the OFTO assets of the 37 OWFs listed in Appendix 1 is £158m. The cost of decommissioning the OFTO assets is illustrated in Figure 4 below and a comparison between the decommissioning costs of the generation assets (i.e. WTGs, their foundations and intra-array cabling) and the OFTO assets is shown in Figure 5.

Only two OFTO decommissioning cost estimates were available from OFTO operators for comparison. Little information as to how these costs were calculated was available, and given the very small scope of this dataset, no comparisons have been made with the Arup cost model.

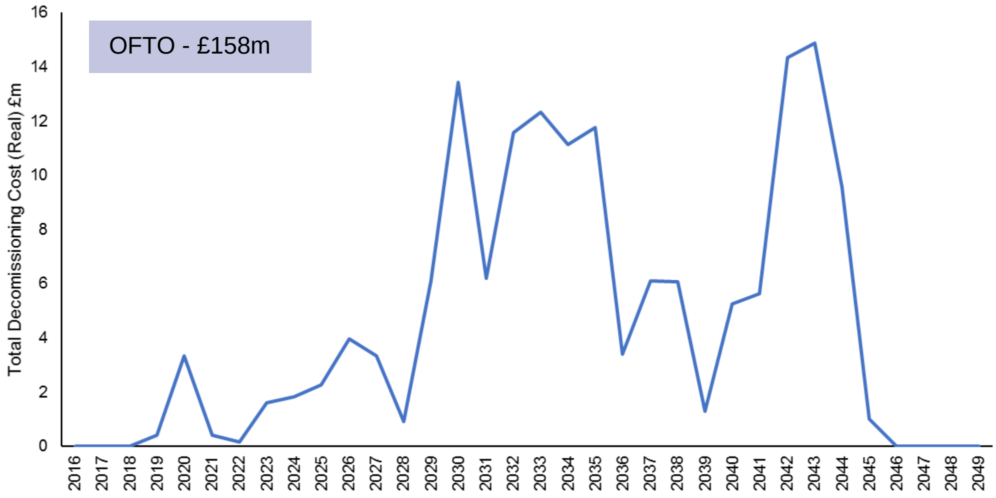

Figure 4: Decommissioning cost model estimate for the OFTO assets for 37 OWFs

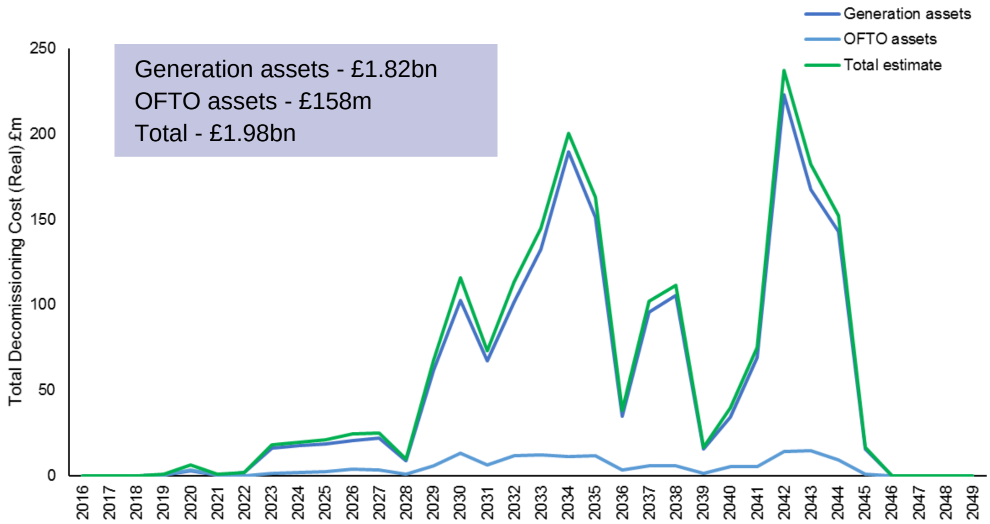

Figure 5: Comparison between the decommissioning cost model estimates for generation and OFTO assets

2.5 Inflation

Three inflation indices have been considered and can optionally be applied in the model:

- RPI – Retail price index;
- RPIX – RPI excluding mortgage interest; and
- CPI – Consumer price index.

The three indices include different items with the key difference between RPI and RPIX being the inclusion of mortgage interest payments (hence they converge except during the financial crisis), however they generally are similar in level and pattern. CPI and RPI, on the other hand, diverge quite significantly with CPI inflation being consistently lower than RPI. RPI has been used to index prices in the majority of regulated infrastructure sectors in the UK. However, policy makers and regulators have slowly been moving away from RPI to CPI as a more reliable statistic. Contracts for Differences (CfDs), for example, are indexed to CPI. Additionally, the Bank of England targets CPI inflation as part of its monetary policy. However, there are still a number of infrastructure sectors that use RPI cost and revenue indexation, e.g. OFTOs and regulated energy networks. We have therefore provided the choice in the model.

The figure below shows historical inflation indices over the past seven years as well as the ONS inflation forecast until 2022.

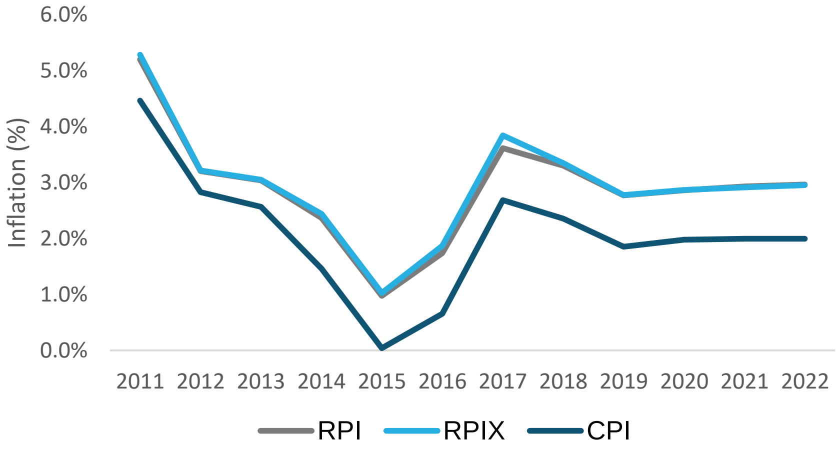

Figure 6: Inflation indices (historical and forecast)

The impact of these inflation indices on the decommissioning cost estimate (excluding OFTO assets) is shown in Figure 7 below.

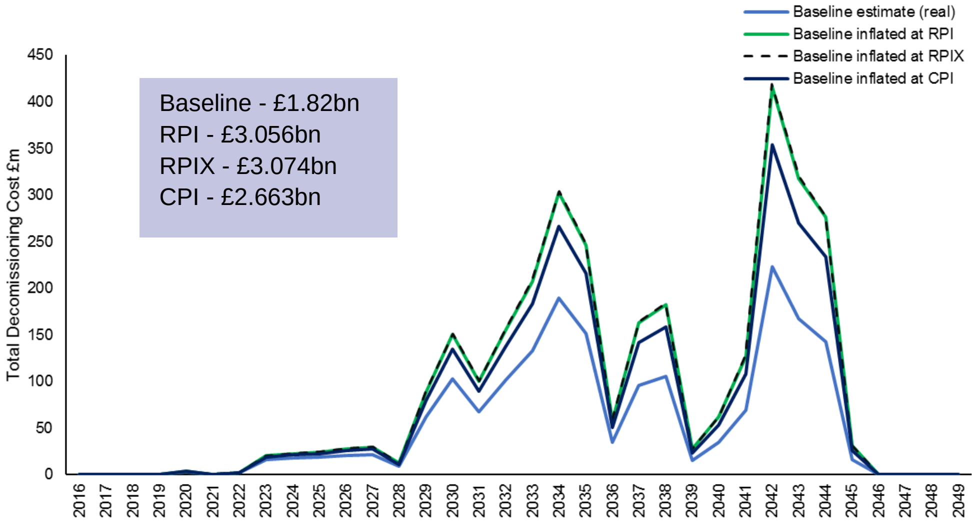

Figure 7: Impact of inflation on the baseline decommissioning cost model estimate

The impact of RPI inflation on the total decommissioning cost is an increase of 68% compared to the baseline estimate, CPI inflation equates to an increase of

46% compared to the baseline estimate. This can clearly be seen in the cumulative cost figure below.

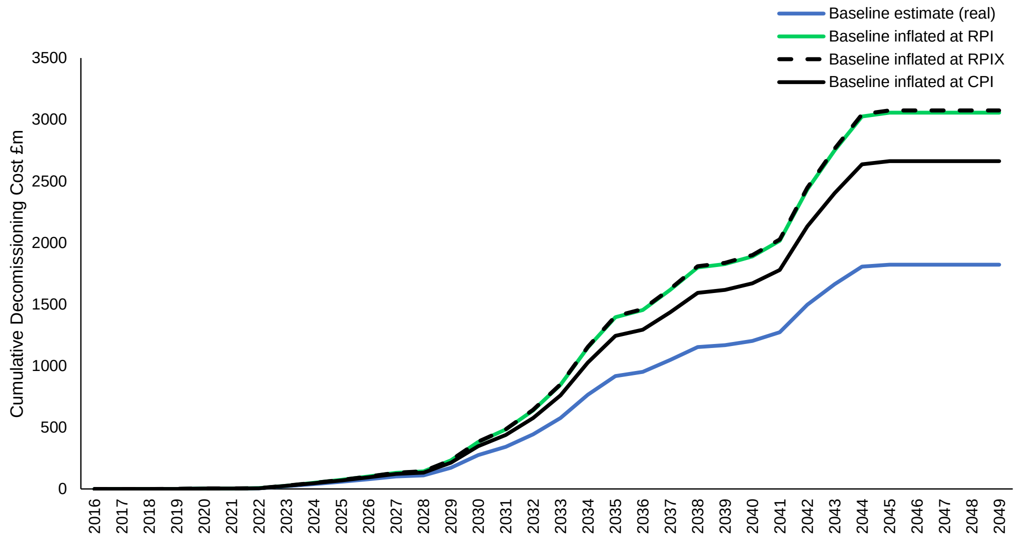

Figure 8: Cumulative impact of inflation

The model reflects the Bank of England's index forecasts to 2022. Beyond this, no official forecast is available and the model rolls forward the average inflation rate over the period 2017-2022. This equates to c. 3% for RPI and c. 2% for CPI.

2.6 Total range of costs

Figure 9 below shows the impact on the on the total cost range when inflation, calculated using CPI, is included. Compared to the total cost range shown in Figure 3, the high estimate has increased £1.69bn to £5.33bn.

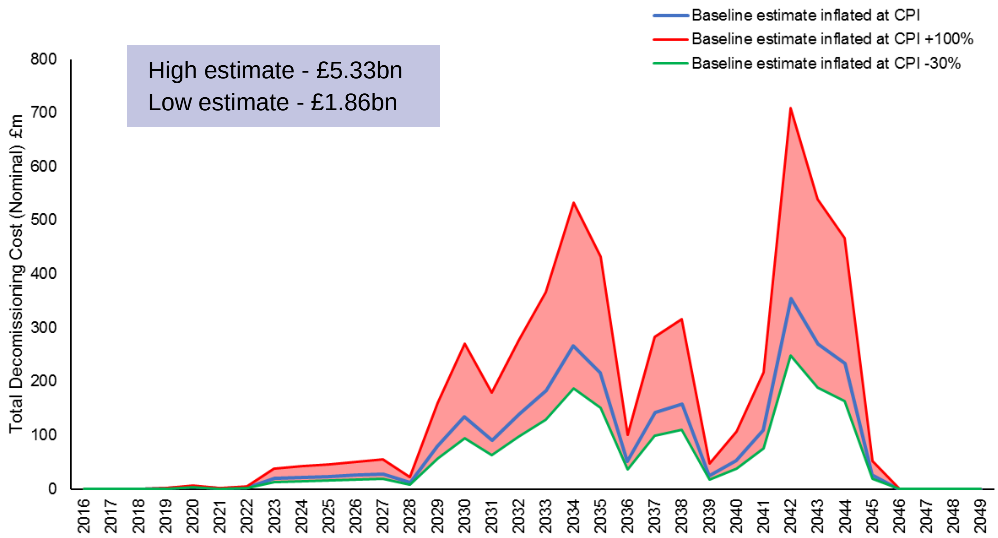

Figure 9: Estimated decommissioning cost range including CPI inflation assumption

This range of costs is intended to give BEIS an indication of the potential decommissioning costs, based on the available information and uncertainties that currently exist. It is expected that these costs will reduce over time as more information is available. The figures shown throughout this section are not intended to provide a suggested level of securities that developers should hold. It is expected that BEIS will agree with individual developers the required level of security based on the circumstances of each project.

2.6.1 BEIS liabilities

The costs outlined above are for all 37 OWFs currently included in the model. The responsibilities for ensuring these OWFs are decommissioned as required under the Energy Act (2004) are distributed between BEIS, The Crown Estate and the Scottish Government.

Of the 37 OWF included in the model, 25 are BEIS' responsibility. The total decommissioning liability for BEIS, based on the assumptions outlined above is £1.47bn, applying the cost range discussed in section 2.3 gives a range of £1.03bn to £2.94bn. This cost, as with all the costs estimated in the model, is excluding VAT.

3 Sensitivity analysis and scenarios

There are a number of inputs to the model which have a significant influence on the output costs. The model allows a number of scenarios to be visualised by making changes to the model inputs or assumptions. In this section, these are described and the results of sensitivity analyses are presented.

3.1 Cost drivers

The key inputs in the model which drive the total decommissioning cost are:

- The vessel day rates;
- The duration required to complete various activities;
- The choice the vessel used to complete various tasks; and
- The assumptions for overhead costs and wait on weather.

The total decommissioning cost is heavily dependent on vessel day rates and vessel mobilisation cost (which is itself a multiple of day rates).

The duration required to complete activities dictates how long the vessel is required on site and therefore drives the total cost of the vessel activities. Activities completed by the jack-up vessels have the highest cost. Therefore, the time taken to complete these activities, e.g. removing the WTG, cutting and removing the foundation, has a large impact on the overall decommissioning cost.

Within the model vessels are selected for each activity. There are three decision points:

- WTG removal vessel – a low-, medium- or high-end jack-up vessel is selected based on hub height and nacelle weight.
- WTG transport vessel – either the same vessel as for WTG removal is selected or a separate cargo barge is chosen. The user can select either. The baseline estimate assumes the same vessel is used for WTG removal and transport. This is an assumption in many developers' decommissioning plans, but in many cases it is possibly more cost-effective to use a separate cargo barge.
- Foundation removal vessel – either the same vessel as for WTG removal is selected or a separate, additional, jack-up vessel is chosen. The user can select either. The baseline estimate assumes that different vessels are used to allow foundation removal and WTG removal in parallel. This is an assumption in many developers' decommissioning plans.

An overhead cost for engineering, project management, port fees etc. is added as a percentage of the marine operations cost. A cost for waiting on weather is added in a similar way. The percentage applied for these costs has a direct impact on the total cost.

3.2 Cost sensitivities

In this section, vessel day rates and certain activity durations are adjusted to examine the impact on the total cost.

3.2.1 Vessel day rates

As described earlier the vessel day rate is a key driver to the total cost. To examine the sensitivity of the model to the vessel day rate the total decommissioning cost was calculated with all vessel rates adjusted up and down. The results are shown in the graph below.

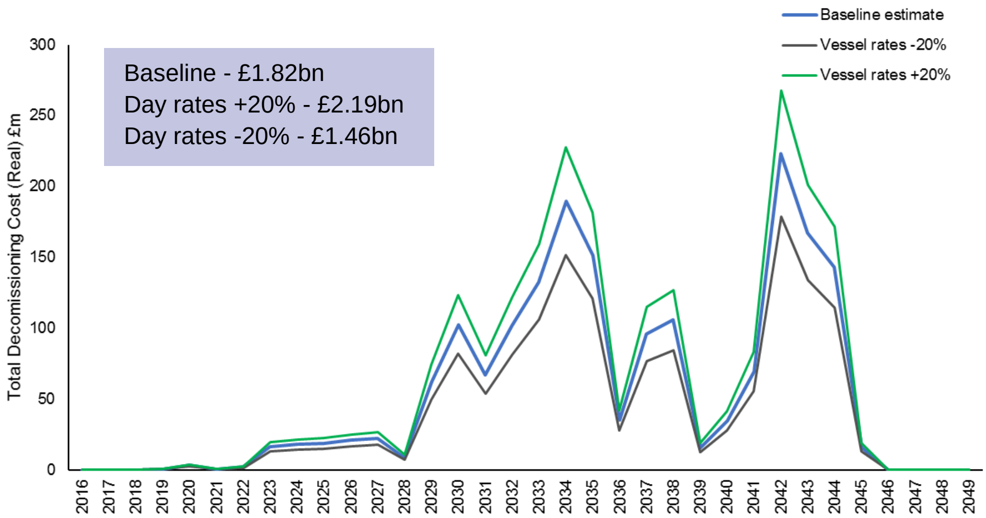

Figure 10: Impact of adjusting vessel rates on the decommissioning cost estimate

A very direct impact is observed. A change in vessel rates across all vessels utilised in the model results in the total decommissioning cost being scaled by the same percentage, i.e. a 20% reduction in vessel costs equates to a 20% reduction in the total decommissioning cost estimate. This highlights the need to make reasonable, well-informed assumptions around vessel day rates when estimating decommissioning costs and accepting the consequences of the inherent uncertainty.

Figure 10 demonstrates the relationship between vessel rate and estimated decommissioning costs. Vessel charter rates can vary significantly over time, and are influenced by mobilisation requirements, location, work scope, duration of charter as well as wider market supply and demand.

This market volatility is regularly seen in the oil and gas vessel market. Figure 11 below demonstrates how rates for chartered offshore assets can vary. In the short term the market is extremely volatile, with the highest and lowest contracting rates varying by around 300%. Even in the medium and longer term, there are significant, order of magnitude changes in contracting rates.

For offshore wind decommissioning it is likely that developers will be competing for vessels with offshore wind installation projects, oil and gas projects and potentially other marine developments. It is reasonable to expect high volatility in vessel rates, and longer terms changes beyond the 20% represented above, are very possible.

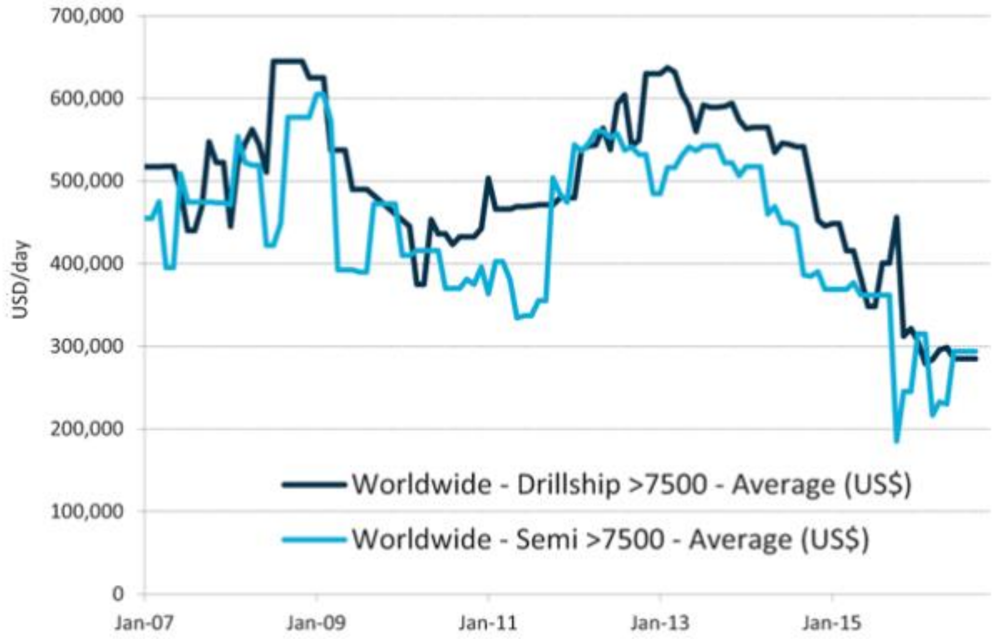

Figure 11: Variability in vessel day rates for drilling vessels in the oil and gas industry (6)

3.2.2 Activity durations

The time require to complete some of the decommissioning activities is more uncertain that others. For example, the time to cut foundations prior to removal is highly uncertain as the technology required to cut through large diameter monopiles is not currently available off the shelf. There will also be differences in cutting time for internal versus external cutting operations. Seabed conditions will also affect the operation. The impact of changes in cutting duration (including preparation of the tool and excavation or pumping to access the foundation) is shown in Figure 12 below.

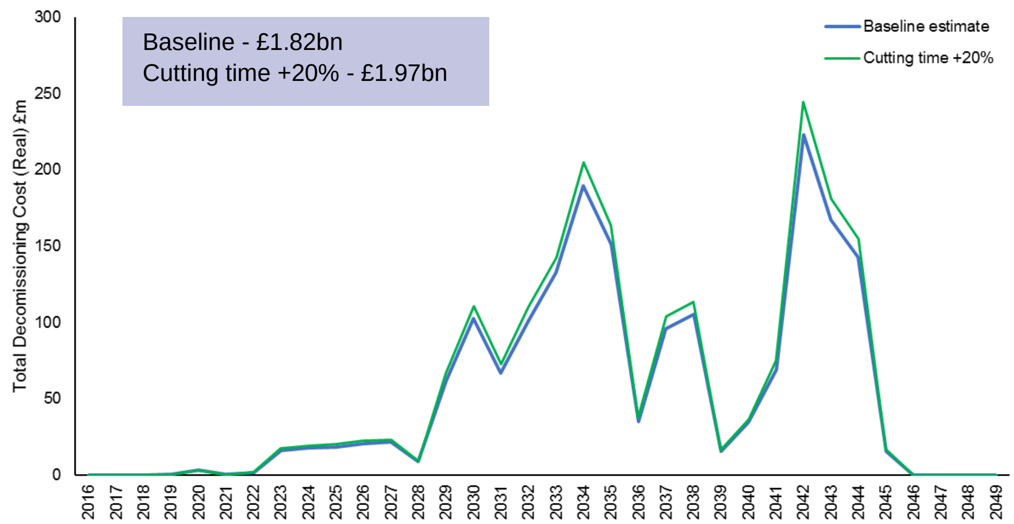

Figure 12: Impact of increasing the foundation cutting duration on the decommissioning cost estimate

An increase of 20% in cutting duration (including preparation) increases the total decommissioning cost by 8% compared to the baseline estimate. This is a significant impact and is expected. Cutting is a time-consuming activity requiring a high end jack up vessel (e.g. a vessel similar to the Geoseas Innovation which has been modelled as the foundation removal vessel).

Another activity for which timing is uncertain is the burial of cable ends. This would be required task if the intra-array cables are to be left in situ. This activity is not considered in many developers' decommissioning programmes reviewed so the methodology and equipment required appears not to be well considered. In the model it is assumed that an ROV is able to locate, cut (if necessary) and bury the cable ends. The impact of changes in the duration to decommission the cable in situ is shown in the graph below.

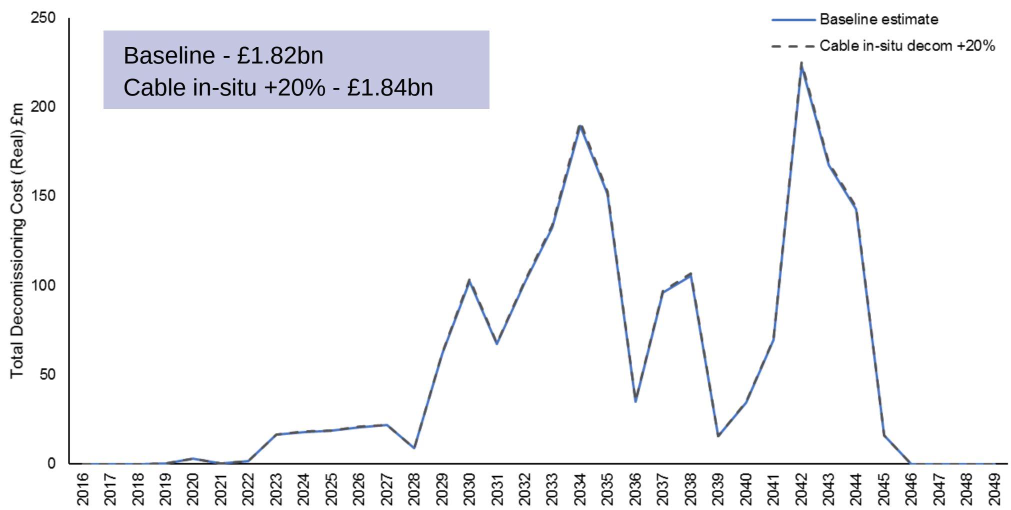

Figure 13: Effect of increasing the duration of decommissioning the cables in situ on the decommissioning cost estimate

As shown in the graph above, an increase of 20% in the time taken to decommission the cable in situ results in increase of 1% for the total decommissioning cost. This is a much smaller impact than the effect of reducing the foundation cutting times shown in Figure 12. This is because the assumed ROV and support vessel used in the cable decommissioning operation being around one third the cost of the jack up vessel used for the foundation cutting operations. An important point to note is that if the ROV and support vessel is not able to complete the cable burial task and other vessels and equipment are required, then a substantial cost increase could be incurred.

3.3 Future scenarios

The model allows various future scenarios to be considered, including:

- Changing guidance and regulatory requirements;
- Learning curve effects i.e. a gradual reduction in costs as a result of improved efficiencies; and
- Innovation i.e. cost reductions as a result of development of new methodologies.

A number of scenarios have been modelled and the results compared to the baseline estimate. This section describes the scenarios modelled and the effect on the decommissioning cost estimate.

3.3.1 Changing guidance and regulatory requirements

The decommissioning of offshore installations is governed by United Nations Convention on the Law of the Sea (UNCLOS) as implemented by the International Maritime Organization (IMO) and OSPAR guidance (7) which state that OWF installations on the UK Continental Shelf[1] should be removed except in certain specified circumstances (as outlined in the IMO Standard).

Based on these international obligations the UK government has produced guidance on the decommissioning of OREI (8). This states that decommissioning:

‘starts with a general presumption in favour of the whole of disused installations being removed and subsequently taken back to land for reuse, recycling, incineration with energy recovery or disposal at a licensed site’.

The guidance describes some examples of potential exemptions to complete removal noting that decisions will always be made on a case-by-case basis. This list of potential exemptions includes:

- ‘Foundations and structures below sea-bed level’ and
- ‘Cables buried at a safe depth below the sea-bed’.

[1] Under UNCLOS the obligation to remove installations only applies in the Exclusive Economic Zone (12nm to 200nm from the coast), not the territorial sea (0nm to 12nm). However, as there are obligations under UNCLOS for marine protection in the territorial sea, the UK Government applies the same approach to OWF removal in the territorial sea and Exclusive Economic Zone.

Many OWF developers, as reflected in their decommissioning plans, have interpreted this to mean that cutting foundations below sea-bed level will be acceptable, as will be leaving buried cables in situ. Both these assumptions have been reflected in the baseline estimate in the cost model.

During the industry consultation (3) it was made clear by stakeholders that there is some uncertainty around whether or not intra-array and export cables can be left in situ. The cost model allows for a scenario of removing the intra-array cables to be modelled. The impact on the decommissioning cost estimate is shown in Figure 14 below.

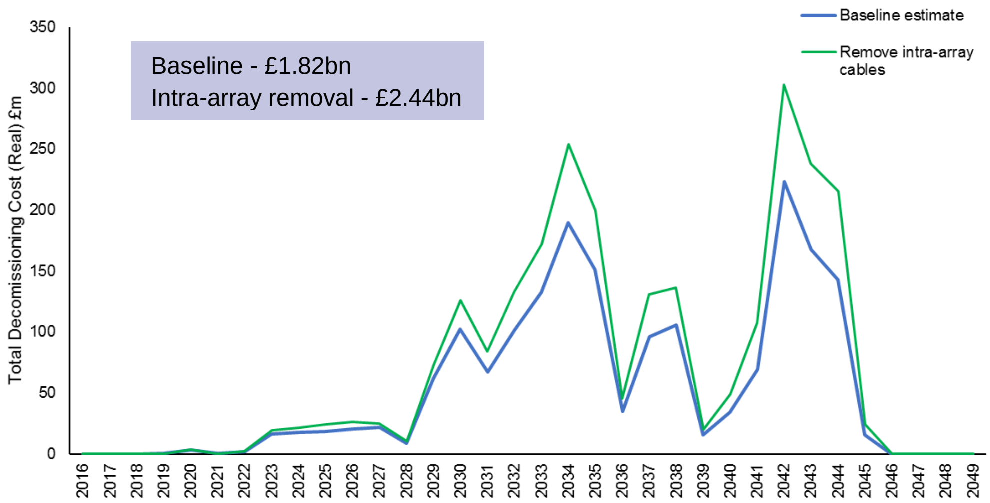

Figure 14: Impact of removing the intra-array cable

The cable removal has been modelled assuming a removal rate of 300m per day. This reflects circumstances where the cable removal is somewhat challenging and may require the use of ploughing or jetting equipment to aid the removal. While faster work rates may be achieved in practice, given the variability in seabed conditions, burial depths, etc. across UK OWFs, this rate of removal is considered reasonable to represent a conservative scenario.

A similar comparison has been conducted for the OFTO assets. As the total cost of removing the OFTO assets is much lower than the cost of removing the generation assets, there is a significant impact on the total cost of OFTO decommissioning when considering cable removal. Considering a removal rate of 300m per day results in a fourfold increase in the OFTO decommissioning cost. This is illustrated in Figure 15.

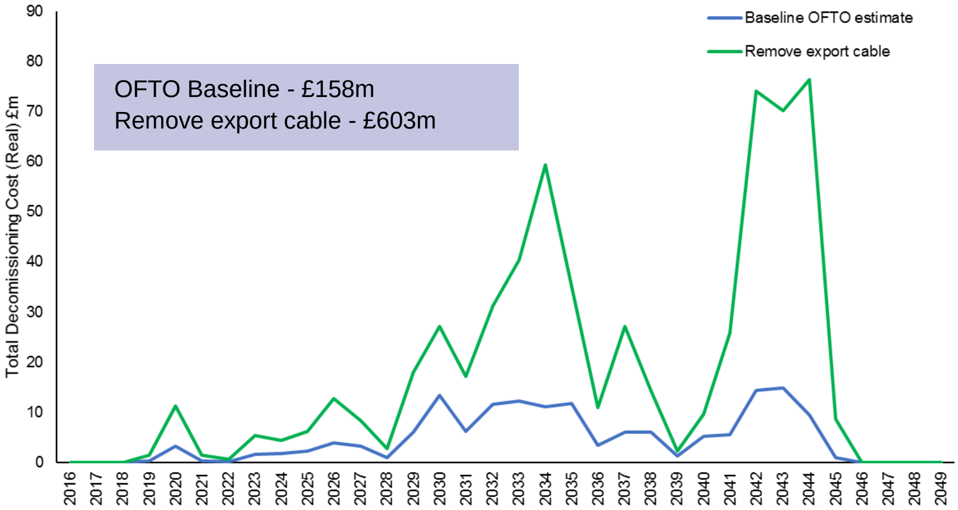

Figure 15: Impact of removing the export cable on the cost of OFTO decommissioning

In addition to changing the assumption that buried intra-array and export cables can remain in situ, changing the assumption that foundations can be cut below the sea-bed could also have a significant effect on the decommissioning costs for OWFs. If the complete removal of monopiles or jacket foundation piles was required this would mean significant excavation around the foundation, or the development of new removal technologies such as high capacity vibratory hammers. As these options are currently considered technologically and economically challenging for large-diameter piles, there is a high degree of uncertainty as to how complete foundation removal could be achieved in practice. This high uncertainty and limited visibility around future technology development in this area makes it difficult to quantify the impact of this scenario. It is however reasonable to assume that complete foundation removal is likely to significantly increase the decommissioning cost.

An alternative scenario to consider is challenging the assumption that foundations are cut around 2 to 3m below the sea-bed, as stated in the majority of decommissioning plans. If, in the future, the required depth of removal below the sea-bed increases, this would require additional removal of internal material from piles for an internal cut, or deeper excavation around piles for an external cut. Longer operational times, additional equipment, further technology development and increased vessel capability are likely to be required to facilitate a deeper foundation removal. All of these which would lead to an increase in decommissioning costs. Again the high degree of uncertainty and limited visibility regarding the operational specifics make it challenging to quantify this scenario. However, the decommissioning cost increase could be significant if a deeper foundation removal depth was required.

3.3.2 Learning curve cost reduction

Reduction in costs due to learning as projects are executed is a phenomenon observed in many industries, and learning rates/curves are utilised to predict future cost reductions. The learning rate/curve is conventionally defined as the percent cost reduction achieved with each doubling of the cumulative number of units of the technology that have been constructed/delivered. For example, a learning rate of 20%, implies a 20% reduction in the unit cost of the technology for each doubling of cumulative installed capacity. A broad range of energy technologies including onshore and offshore wind, solar, biomass and gas combustion technologies have demonstrated a range of learning rates of up to 35%.

The decommissioning cost model allows learning to be modelled by reducing the duration of certain activities over time.

Demonstrable learning rates are most prevalent in manufacturing where repetitive manufacturing steps can be automated, but is generally evident in any area where repetitive tasks are executed in large volumes. In general, learning curve/rate approaches are most likely to be relevant for complex technologies, involving many subcomponents, with a wide range of opportunities for incremental improvement.

Arguably decommissioning of OWF projects will have less opportunity for dramatic learning when compared to energy technology delivery, as the project costs are not dominated by delivery of manufactured plant, i.e. the WTG. Instead cost reductions will have to rely on the efficiencies in and innovations relating to offshore operations, which are the main cost contributors. There are analogous examples from offshore wind construction and O&G decommissioning where offshore operations have been delivered with increasing efficiencies to allow for the reduction of costs as experience has been gained. A number of cost reduction contributors in these industries are as follows:

- An analysis in 2012 (9) found that repetitive OWF construction tasks such as tower assembly and nacelle installation took on average four vessel-days. By 2016 (10), vessel capacities and installation methodologies had improved to reduce this to one vessel-day per WTG.
- Looking ahead, research in 2014 (11) included offshore wind industry consultation which suggested that installation costs could decrease by 6.6% to 2019, driven primarily by economies of scale and a robust pipeline of work allowing vessel operators to amortise vessel debt over a greater number of projects.
- Market competition (12) is also thought to be a major cost reduction driver. In 2011 it was observed that nine offshore contractors were operating 32 vessels offering some form of lifting capability (13). By 2017 this number had increased to over 50. Increased market competition encourages cost reduction as new market entrants bring new, cheaper techniques to the marketplace.
- In oil and gas decommissioning economies of scale and on-the-job learning have been seen particularly in the area of plugging and abandoning of wells. Operators engaged on long campaigns with repeat work have seen significant reduction in task durations during these campaigns as tools and procedures have been improved (14). This is comparable to offshore wind decommissioning where a small number of specific tasks will be repeated.

This was reflected by stakeholders in the consultation (3) who shared the view that learning during removal of the first large OWFs (where tasks would be repeated a large number of times) will be notable.

To reflect the opportunities above, two learning rates are available in the model to visualise the impact of efficiency improvements:

- Low: a modest learning curve of 5% for every doubling of effort[2].
- High: same pattern as above but with double the rate, i.e. 10%.

These are illustrated in Figure 16 below.

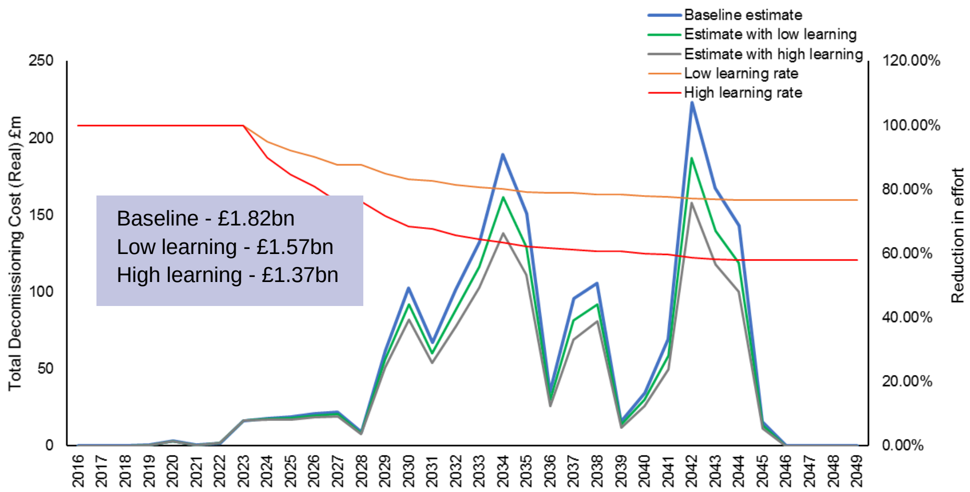

Figure 16: Effect of learning rates on the total decommissioning

3.3.3 Cost reduction through specific innovations

The model also allows specific innovations to be considered. This is distinct from the learning curves discussed earlier and allows step changes in how specific activities are carried out to be visualised. For example, for WTG dismantlement the baseline assumption is that the majority of WTGs will be dismantled in six lifts (one lift for each blade, one lift for the nacelle and rotor and two lifts for the tower), unless otherwise stated in a developer's decommissioning plan. Innovations that reduce the number of lifts, such as innovative crane technologies may allow the lifts to be reduced.

The impact of reducing the number of lifts from six to three is shown in Figure 17 below.

[2] For this analysis we assume that decommissioning an OWF is one unit of effort, starting with the first non-demonstrator OWF in 2023, and concluding with a total of 36 OWFs by 2045.

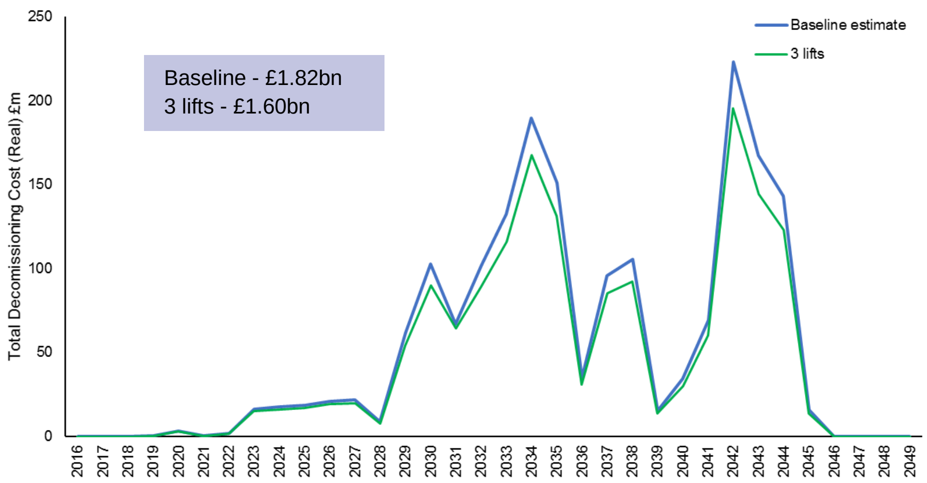

Figure 17: Effect of innovation – reducing the number of lifts for WTG dismantlement from 6 to 3

The effect of reducing the number of lifts from six to three is a cost reduction of 12% of the total decommissioning cost. This is a material cost impact and is to be expected given that lifting operations form a substantial proportion of the total WTG removal duration. There is the potential for further cost reductions through other innovations, for example reducing the foundation cutting time would have a cost upside. A completely novel methodology could also have a profound impact on cost, such as cutting a foundation and towing a complete WTG and foundation back to shore.

3.3.4 Future scenarios conclusions

In this section a number of factors that have the potential to have a negative or positive impact on the total outturn costs of decommissioning the UK's OWFs have been reviewed in turn. This analysis gives an understanding of the sensitivities of the overall cost outcomes to a range of individual factors. Clearly there are some factors which have the potential to have a more significant impact on outturn costs, and which have higher uncertainty.

Understanding the overall impact of these range of factors on the outturn costs is extremely complex. It is likely that a range of factors will contribute at different rates, to create positive and negative impacts. There will also be a difference in how those factors will be realised across different projects. For example,

- certain innovations may only be applicable to certain OWFs due to limitations such as water depth or WTGs size, or
- there may be specific circumstances which influence a specific OWF decommissioning programme such as high demand for vessels forcing up vessel rates at the time of decommissioning.

These cost ranges are compared to the overall cost analysis undertaken in section 2, which considers an overall uncertainty range of a class 4 or 5 estimate as plus 100% and minus 30%. Given the potential for individual factors to impact the costs, and the overall uncertainty of the future scenarios, this is considered to be an appropriate range.

4 Transfer of risk

As decommissioner of last resort, BEIS are exposed to the risk of default by developers. This was a discussion point in the consultation with industry (3). This section provides stakeholders' views, provides a mechanism for identifying at-risk cost estimates from OWF developers and illustrates the relative benefits and drawbacks of different forms of security.

4.1 Default scenarios

The scenarios for default considered were as follows:

- Default during operation which may have an impact on the accrual of securities;
- A significant gap between the provision for decommissioning and the outturn decommissioning cost which causes the developer to default prior to, or during decommissioning;
- The financial impacts after decommissioning, e.g. from infrastructure left in situ.

During consultation, the developers did not see a high risk of default in either of the first two scenarios. They felt that in each of these scenarios, it is expected that there would be other development partners who would step in and continue to manage the OWF should one of the partners find themselves in financial difficulty. However, any OWF consortium agreement would have to be structured in a such a way to ensure this is the case, and that the regulator had a route to ensuring remaining partners had appropriate obligations. As consortium agreements can be complex, and the partners may vary over the life of the OWF. BEIS may wish to consider:

- The entities who are served a Section 105 notice and how joint and several liabilities are applied to all interested parties; and
- If joint and several liabilities expire when assets transferred or if decommissioning obligations remain in perpetuity.

The developers did identify a number of situations where their revenue could be significantly impacted, potentially resulting in them not being able to meet decommissioning obligations. However, these situations were considered to have a low likelihood. Situations which could impact developers' revenue, which were raised during the consultation, include:

- Change in Contracts for Difference (CfD) support policy or major fluctuations in energy prices;
- Major changes in seabed conditions affecting scour protection and foundation integrity;
- Major structural integrity issues or degradation of plant that increases late life operating costs, reduces energy production leading to decreased revenue; and

- Conflict with oil and gas exploration licences being granted in the same area.

The developers felt that a significant gap between the decommissioning security and eventual decommissioning cost should not be a problem if decommissioning costs are being reviewed at appropriate intervals. Suggestions from industry include:

- before decommissioning accrual starts,
- during accrual, and
- following the accrual.

It was also suggested that decommissioning costs should be reviewed when more information becomes available, for example after a number of OWF decommissioning projects have been completed and the supply chain develops knowledge to provide quotations for the offshore operations with less uncertainty.

Ongoing monitoring of, and dealing with issues in relation to, infrastructure left in situ following decommissioning is the most likely scenario where costs could fall to BEIS. Following the decommissioning of OWFs, developers will no longer have a revenue stream from a particular asset which may impact the funding for post decommissioning monitoring, remedial works and dealing with incidents.

BEIS may wish to consider how the current legislation obliges a developer to take enduring responsibly for any impacts that occur beyond the execution of the decommissioning plan. It is understood that developers will complete a survey of the OWF area post decommissioning and BEIS can use this to identify any residual issues.

In the short term following decommissioning it is likely that the developer will have some obligation to monitor the site and will have funds set aside for this, as part of the decommissioning budget. However, the if an issue develops many years after the decommissioning has taken place, the OWF owners responsible for the in situ infrastructure may have ceased to operate. Hence government may be more likely to be required to deal with any issues. It is difficult to estimate this liability as there are many unknowns, however BEIS should consider how it wishes to handle this potential future liability.

4.2 Securities

The following types of securities are available and are deemed acceptable by the Government (15) to be used for decommissioning costs. Some securities are funded securities, essentially setting aside funds for future use, whereas others purely provide security that the operator will make funds available in the future at the point of decommissioning.

- Upfront cash: this is cash set aside upfront to cover expected decommissioning liabilities.
- Letter of credits: An irrevocable letter of credit issued by a Prime Bank (banks established in an OECD country which have an A-, A3 or equivalent rating).

This is essentially a promise by the Bank that they will pay the amount at the agreed date in the future if the operator does not.

- Performance bonds: whereby an underwriter (either an appropriate Prime Bank or insurance company) guarantees an amount equal to the decommissioning sum in return for an arrangement fee and premium, assuming they can be relinquished in a similar manner to letters of credit.
- Early/Mid-life and continuous accrual funds: a secure, segregated decommissioning fund that accrues early in, during the middle of, or over the life of an installation, provided the fund is completed ahead of the end of life of the installation.
- Insurance: Insurance, for example, to cover the uncertainty element of decommissioning costs. Could be used but it is unlikely as a security given the long-term nature.

Currently, BEIS does not consider parent company guarantees as providing appropriate cover despite them being low cost, as they are unlikely to be enforceable if the parent company is outside the UK.

When assessing the acceptability of the proposed securities BEIS may wish to take into account the financial robustness of the companies who have decommissioning obligations. There was a process set out by BEIS for oil and gas to determine the appropriate security for a given field and operator. This considered both the nature of the field license holder(s) in the context of their decommissioning obligations. This guidance is currently under review to ensure it adequately reflects the potential future financial robustness of licensees. Once agreed, this guidance may be applicable to OWF decommissioning as well.

Each of these securities carry a different cost. They also vary in terms of trade-offs between ease of access, ring-fencing, certainty of funds and cost. The table below assesses at a high level the securities against our selected criteria.

Table 2: Comparison of securities

Security	Cost of financial security (Interest Rate or Opportunity Cost)	Cash Flow Impact	Counterparty Default Risk	Ease of Access to Security/ Ring-Fencing of Financial Assets	Provision for Cost Escalation	Provision for Asset Transfer	Likely impact on LCoE*
Upfront cash	Opportunity cost = Cost of capital of the operator (high as it includes both cost of equity and debt) and provided at the outset therefore cost incurred through the duration of the project	Upfront cash impact (Day 1)	Counterparty: Bank holding the deposited cash	Typically not ring-fenced (if retained in project) In case of operator default, creditors may be able to draw on it before BEIS. Potential to restrict account for BEIS use in decommissioning in operator insolvency (e.g. escrow account)	Amount set upfront (and not varied) Need additional mechanism to add cash when reforecasting decommissioning costs	No need as cash held by the project or BEIS, not by parent	5 (see estimate in Section 5)
Early/ Mid-life & Continuous Accruals	Cost of capital of operator (like ‘cash’) on deferred basis as provisioned through the life of the project, therefore cost is minimised compared to ‘cash’	Regular payments to accrual fund (lower NPV than ‘cash’) BEIS has required for mid-life accrual to span: ROCs (year 10 to 20) CfDs (year 10 to 15) OFTOs (year 10 to 20)	Counterparty: Bank holding the deposited funds	Accruals are secure and segregated, ring-fenced from the project and there is potential to restrict account for BEIS similar to ‘cash’	Provisions need to be made for adjustments in case of cost escalations Easier to adjust for reforecast than ‘cash’ given the annual nature of accrual	No need as cash held by the project or BEIS, not by parent	4 (deferred ‘cash’)

Security	Cost of financial security (Interest Rate or Opportunity Cost)	Cash Flow Impact	Counterparty Default Risk	Ease of Access to Security/ Ring-Fencing of Financial Assets	Provision for Cost Escalation	Provision for Asset Transfer	Likely impact on LCoE*
Letter of Credit (LoC)	Fee for providing letter of credit for decommissioning cost. Fee linked to credit risk of operator/ parent, rating; ongoing fee. Bank is likely to periodically monitor the operator/ parent From an operator perspective funds still need to be reserved/ provided for to cover the actual cost of decommissioning	Ongoing arrangement fee	Counterparty: Prime Bank providing the letter	Beneficiary of the credit letter should be BEIS	Amount agreed at start Need additional provisions for cost escalation/ reforecasting Bank is likely to require accumulation of some cash reserve – as cash reserve increases, the amount in the LoC should decrease	The limit on any asset sale needs to be that the new owner provides an equivalent LoC	3 (but has to go in hand with accrual)
Performance bonds	Similar to Letter of Credit Arrangement fee plus premium on top of decommissioning costs	Arrangement fee & premium payments on ongoing basis	Counterparty: Underwriter of the bond (Prime Bank or Insurance Company)	Ring-fenced so BEIS can draw on it	No provision for cost escalation	Dependent on company the bond is linked to within the corporate structure - if ability to transfer to different owners on transfer (e.g. if linked to HoldCo and HoldCo is transferred), then no additional provision needed	3 (similar to LoC)

Security	Cost of financial security (Interest Rate or Opportunity Cost)	Cash Flow Impact	Counterparty Default Risk	Ease of Access to Security/ Ring-Fencing of Financial Assets	Provision for Cost Escalation	Provision for Asset Transfer	Likely impact on LCoE*
Parent Company Guarantee	Typically limited cost passed to the project. Cost of capital of Parent Company If risk cannot be absorbed into parent company's current portfolio without changing its risk profile Parent Company can borrow at corporate level - cheaper than at project level	No impact on operator cash flow for specific security	Counterparty: Parent Company These companies usually have a portfolio of similar assets, geographically diversified. Dependent on credit rating of parent may carry the highest risk	Ring-fenced from project Likely no ring-fenced funds in the parent company	Can include headroom at start or adjust the guaranteed amount when reforecast closer to the date of decommissioning	As asset transfer assumes change of parent company, the sale needs to be contingent on a similar guarantee provided by the new parent	1 (no security cost but decommissioning cost still incurred)

* Likely impact on LCoE is ranked from highest, 5 to lowest, 1

5 Effect of security cost on LCoE

As well as understanding the total cost of decommissioning OWF, BEIS require an understanding of the impact decommissioning and security costs have on the Levelised Cost of Energy (LCoE).

In November 2016 BEIS published its Electricity Generation Cost study (16) as part of a periodic review, looking into the cost and technical performance of different generation technologies. The report estimated the LCoE of building and operating an 'average' generation technology. The LCoE represents the average cost of generating energy over the lifecycle of a plant, expressed on a per MWh basis. The data used to generate the estimates was based on evidence collected from industry stakeholders.

It should be noted that the LCoE is not the same as the CfD strike price. Strike prices take into account market conditions, policy considerations and other factors in addition to the LCoE. The 2016 BEIS LCoE study (16) used data and analysis carried out by Arup (1). Summary results are provided in the table below.

Table 3: LCoE estimates for 'nth of a kind' projects commissioning in 2020, technology-specific hurdles, £/MWh. Source: BEIS electricity generation costs (16), p. 36, Table 8

	Reciprocating engines (gas) 2000hrs	Reciprocating engines (gas) 500hrs	Dedicat-ed biomass <50MW	Biomass Convers-ion	Biomass CHP	Onshore Wind >5MW UK	Offshore Wind Round 2	Offshore Wind Round 3
Pre Development	1	4	2	2	7	4	3	5
Construction	29	115	41	5	93	44	69	73
Fixed O&M	-11	-37	12	6	41	10	17	24
Variable O&M	2	2	8	1	11	5	3	3
Fuel Costs	53	53	33	72	41	0	0	0
Carbon Costs	18	18	0	0	0	0	0	0
CCS Costs	0	0	0	0	0	0	0	0
Decommissioning/Waste	0	0	0	0	0	0	0	0
Steam Revenue	0	0	0	0	-24	0	0	0
Total	92	155	96	87	170	63	92	106

The cost of decommissioning and securities was not taken into account in this analysis. For example, the 2016 study estimated that the LCoE from OWF (Round 3) to be £106/MWh (in 2014 prices), but excluded decommissioning costs. In this study, the LCoE figure represents an average OWF (based on data provided by industry stakeholders).

To illustrate the impact of decommissioning on LCoE, Arup has used the same model from the 2016 BEIS study, keeping all assumptions constant. Assuming no scrap value and taking into account that the costs will be incurred 26 years after the start of construction[3], the cost of decommissioning increases the LCoE for offshore wind by £0.86/MWh (in 2014 prices), which is less than 1%. A key driver of the relatively small impact on LCoE is that the costs take place nearly 30 years in the future, and are therefore heavily discounted to present values. We note that the discount rate used in the LCoE model, which was provided by BEIS, is around three times higher than the Green Book (17) value. In addition to discounting, the result appears reasonable given that it strips out inflation and the

[3] The original LCoE model assumed an average construction period of a R3 OWF of three years plus 23 years of operation to generate the £106/MWh – assumptions approved by BEIS.

relative size of OWF investment compared to decommissioning costs. While we have not estimated the impact on Round 2 OWFs, we consider that the Round 3 results are illustrative of the relative magnitude.

While this cost does not include the cost of procuring and administering the security itself, the relative magnitude of total decommissioning costs to financial security costs indicate that the overall impact would remain around 1% of LCoE. This assumes that costs are incurred towards the end of the life of the asset and would apply to letters of credit, performance bonds or parent company guarantees. As discussed in the previous section, cash sits at the other end of the spectrum as it is set aside upfront. As such, cash would have a greater impact on levelised cost as it is not discounted. The equivalent impact of an ‘upfront cash’ financial security is £4.65/MWh or 4.4% of LCoE. This is about five times higher than the back-ended securities. Cash therefore gives the upper bound of the impact of securities on the LCoE and we expect the remainder of the securities to lie within the range of 1 to 4.4%, with the specific value dependent on timing.

The choice of developer decommissioning cost estimate or the Arup decommissioning cost estimate does not have a material impact on the LCoE.

6 Conclusions and recommendations

- This project has reviewed OWF decommissioning cost estimates from 17 UK OWFs, and benchmarked these costs against a cost model developed by Arup. Four of these projects have been identified as having low cost estimates, compared to Arup's benchmarks, and it is recommended that the relevant developers review these and provide updates.
- The cost model generates decommissioning cost estimates for a total of 37 UK OWFs. This model includes up-to-date cost assumptions, appropriate inflation indices and a standardised mechanism for modelling uncertainty.
- The total decommissioning liability in real (2017) terms, based on the base line assumptions in the cost model, is forecast to be £1.82bn. However, applying a range of uncertainty commensurate with a class 4/5 estimate a range of £1.28bn to £3.64bn is anticipated.
- There are many factors that have the potential to influence the outturn decommissioning cost including:
    - Vessel rates – The decommissioning cost is highly dependent on the vessel rates available at the time of decommissioning. The offshore vessel market is highly volatile and is difficult to predict with high certainty.
    - Decommissioning methodology – The cost model presented is based on an assumed reverse installation process however no large scale projects have been carried out to date, and as such different approaches may be undertaken in practice.
    - Decommissioning regulatory approaches – The estimated cost range assumes leaving the intra-array cables in situ and removing the foundations at a shallow depth (2 to 3m) below the sea-bed. If these assumptions change there will be a significant impact on the decommissioning cost.
- The decommissioning of OFTO assets is estimated to be £158m, giving a range of £111m to £316m (-30%, +100%). This is a small fraction of the generation asset decommissioning cost but could be significantly impacted by requirements to remove the export cable. Including cable removal costs increases the modelled OFTO decommissioning cost fourfold and brings it significantly beyond the + 100% cost range suggested in the sensitivity analysis.
- There is uncertainty around the timing of OWF decommissioning. This will have an impact on the nominal decommissioning cost due to inflation effects and could impact some security arrangements. This uncertainty also makes it more difficult for BEIS to predict the periods of high decommissioning activity, when default by developers could be more significant. Although developers have indicated specific dates for decommissioning, it is likely that improved late life management and repowering could extend the operational life of many OWFs. This uncertainty can be managed through regular review of proposed OWF decommissioning dates.

- The impact of decommissioning costs on LCoE has been modelled and is considered likely to be less than 1%[4].
- Appropriate reviews of the decommissioning costs should be undertaken, the results of the reviews should be used to update the model assumptions to increase the certainty of the cost estimates.
- It is recommended that a review of decommissioning plans and proposed costs takes place prior to and during the accrual of securities to ensure sufficient funds will be available at the time of decommissioning.

[4] This is based on 2016 BEIS figures for LCoE for offshore wind, the LCoE is understood to have reduced since then and so the decommissioning cost will be a slightly higher proportion of the current LCoE.

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Appendix 1 – List of OWFs

	Included in Arup baseline cost estimate
Barrow	Yes
Beatrice Demonstrator	Yes
Beatrice	Yes
Blyth Offshore	Yes
Blyth Demonstrator Array 2	Yes
Burbo Bank	Yes
Burbo Bank Extension	Yes
Dudgeon	Yes
Galloper	Yes
Greater Gabbard	Yes
Gunfleet Sands 1 & 2	Yes
Gunfleet Sands 3	Yes
Gwynt y Môr	Yes
Humber Gateway	Yes
Kentish Flats	Yes
Kentish Flats Extension	Yes
Lincs	Yes
London Array	Yes
Lynn	Yes
Inner Dowsing	Yes
North Hoyle	Yes
Ormonde	Yes
Race Bank	Yes
Rampion	Yes
Rhyl Flats	Yes
Robin Rigg	Yes
Scroby Sands	Yes
Sheringham Shoal	Yes
Teesside	Yes
Thanet	Yes
Walney	Yes
Walney Phase 2	Yes
Walney Extension	Yes
Westermost Rough	Yes
West of Duddon Sands	Yes
East Anglia One	Yes
Hornsea Project One	Yes
Total	**37**