Offshore Renewable Energy Installation Decommissioning Study

Final Report

Climate Change Capital

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GLOSSARY AND DEFINITIONS

ATF	Approved Treatment Facilities
Credit Rating	A published ranking, based on detailed financial analysis by a credit bureau, of a company's financial history. It relates to the company's ability to meet its financial obligations. The highest rating is usually AAA, and the lowest is D.
DEA	Danish Energy Authority
Decommissioning	The complete removal of an offshore renewable energy device including foundations and cables 1-2 metres below the sea bed.
Decommissioning Plan	A costed decommissioning programme setting out the measures to be taken to decommission the installations and estimating the potential costs and timing.
DTI	Department of Trade and Industry
ELV	End of Life Vehicle
EPC	Engineering, Procurement and Construction
FSA	Financial Security Agreement
HMG	Her Majesty's Government
IPCC	Integrated Pollution Prevention and Control
NDA	Nuclear Decommissioning Authority
NLF	Nuclear Liabilities Fund
NRC	US Nuclear Regulatory Commission
OOAG	Offshore Oil and Gas
OREI	Offshore Renewable Energy Installation
PCG	Parent Company Guarantee
PPA	Power Purchase Agreement - a bilateral contract between a generator and a supplier for the provision of electricity for a defined period at defined price conditions.
Risk Adjusted Exposure	The magnitude of the decommissioning defaulted liability, adjusted by the likelihood of the event of default of the liable entity.
RO	Renewables Obligation
ROC	Renewables Obligation Certificate
REZ	Renewable Energy Zone
SEA	Strategic Environmental Assessment
SPV	Special Purpose Vehicle
UKCS	UK Continental Shelf

Turnkey contract	An agreement under which a contractor agrees to complete an infrastructure of a particular type at an agreed price, quality standards and deadlines.
WEEE	Waste Electric and Electronic Equipment

1. Executive summary

1. The Department for Trade and Industry (DTI) has commissioned Climate Change Capital (CCC) to undertake a Study to advise on a range of suitable approaches to protect the Government against default on decommissioning liabilities by developers and owners of Offshore Renewable Energy Installations (OREIs), without inhibiting unnecessarily the development of the offshore renewables industry.

2. The Study has been structured in five parts:
    - Generic Review
    - Contact Programme
    - Estimate of the magnitude of decommissioning costs
    - Circumstances of default on decommissioning costs
    - Analysis of financial securities for risk management.

3. The Study recognised the differences between commercial offshore wind and presently pre-commercial marine technologies. These differences are reflected in our approach to each of the key components described above for offshore wind and marine.

1.1. Generic Review

4. The Study was initiated with a 'Generic Review' of relevant techniques deployed in the UK to secure long term liabilities arising in different sectors, and an analysis of schemes addressing the decommissioning of offshore wind in Denmark and the Netherlands.

5. The UK Government's approach to decommissioning across a range of different sectors has been to require the producer to pay for the disposal of its own waste. The Government has required some companies in the offshore oil and gas sector to provide financial securities (usually annually renewable letters of credit) for meeting the costs of decommissioning in the event of default.

6. The Dutch Government requires that owners/operators of offshore wind farms must pay monies into a segregated decommissioning fund for a minimum of 10 years, starting from the first year of operation of the project. Recent Danish regulations have also introduced the requirement for a financial 'guarantee' from offshore wind developers, although thus far no financial security is known to have been provided.

1.2. Contact Programme

7. The Contact Programme was devised to identify those groups of stakeholders that may have a direct interest or valuable contribution to make to the effective conduct of the study.

8. The Contact Programme found that a transparent, certain and flexible mechanism for allocating decommissioning liabilities is key to the effective management of decommissioning risk.

9. Flexibility amongst a range of acceptable financial securities to cover decommissioning liabilities is desirable so that companies at different stages of development, as well as companies producing different technologies or with different capital structures, may

provide instruments that are both affordable and sufficient to satisfy Government requirements.

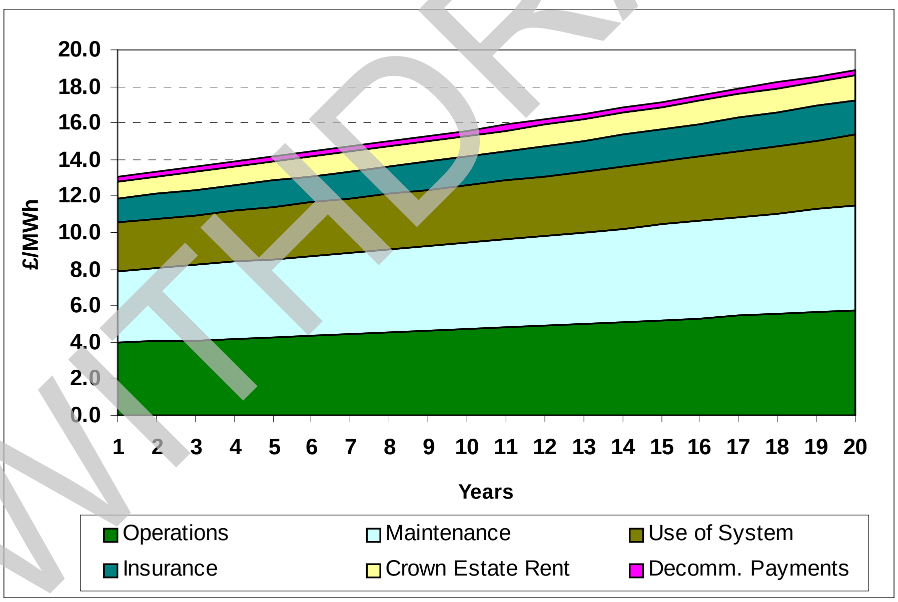
10. Several interviewees were of the opinion that projects would be more likely to face insolvency because of problems arising from technical failure rather than financial risk, due to protection from the latter afforded by a power purchase agreement (PPA) and the Renewables Obligation.

11. Technical risk refers to the risk of underperformance of offshore technologies. This risk is particularly relevant by the end of life of the installation when, because of obsolescence and increased technical failures, the cost of repairing the installation may be higher than the expected future revenues. However, default would require both the installation to be abandoned, because of lower future revenues than combined future operation and decommissioning costs, and for the owner to be insolvent. The Study is therefore interested in the circumstances under which both these conditions may be satisfied.

1.3. Magnitude of decommissioning costs

12. Interviews within the Contact Programme suggested that the average decommissioning[1] costs for offshore wind would be around £40,000/MW . These would make up around 2.5% (undiscounted) of the total project cost (assuming £1.5 million per MW) or 2% of operating costs when spread over the lifetime of the project (as if paid into a segregated fund).

Decommissioning costs as proportion of operating costs

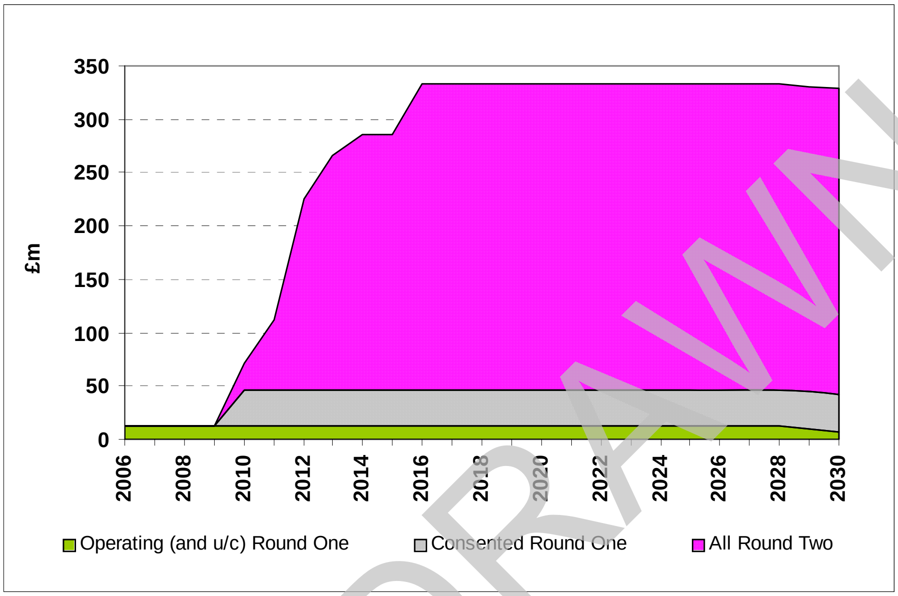


13. Construction of offshore renewables until 2020 could create a maximum £288 million of offshore wind decommissioning liabilities based upon decommissioning costs of

[1] For the purposes of this Study, decommissioning is defined as the complete removal of an offshore renewable energy device, including foundations and cables 1-2 metres below the sea bed.

£40,000/MW and 7.2 GW of installed Round Two capacity. If decommissioning of currently operating/under construction Round One projects is included, this would add an additional liability of £12 million, based upon decommissioning costs of £40,000/MW and 300 MW of installed Round One capacity. Finally, if all consented Round One is included in the calculation the magnitude of decommissioning costs would increase to £335 million[2].

Estimated offshore wind decommissioning costs



14. Estimates of decommissioning costs may change once experience of decommissioning is gained, the extent of decommissioning required is better defined, and future technological capabilities are better understood.

1.4. Circumstances of default

15. Typically different types and magnitudes of risk arise during the lifetime of an offshore installation. Default risk has therefore been considered during three distinct phases: construction, operation and the decommissioning phase itself.

1.4.1. Construction

16. The most relevant source of risk during construction is geological or geotechnical risk. This risk refers to the circumstances in which the location proves to be inadequate to support the foundations of the offshore device. However, it is extremely unlikely that this event would trigger abandonment of the whole construction. Rather, it is probable that some devices would be moved to another location.

[2] Round One unconsented capacity is 568MW, which would add £23 million of decommissioning liability. However, for the purposes of this Study we do not include unconsented Round One capacity because we consider our estimate already to be a 'high' scenario.

17. There are two categories of risk holders during the construction phase: the developer and the EPC contractor. The risk that each party bears will depend upon the nature of the contractual arrangements for the construction process. Early offshore wind development is likely to see the developer manage construction via a multi-contract arrangement with several contractors. In this case, the developer would be responsible for removing any incomplete construction. However, as the sector expands and matures, construction under turnkey contracts is expected to become a more common practice, thereby transferring risk to EPC contractors.

18. The Government's risk adjusted exposure[3] to default during construction is relatively low, because installations are unlikely to be abandoned at such an early stage and the probability of default of the liable entities over their liabilities is also low, given the financial profiles of the companies that have been awarded Crown Estate leases and the short period of time over which their financial profiles could erode.

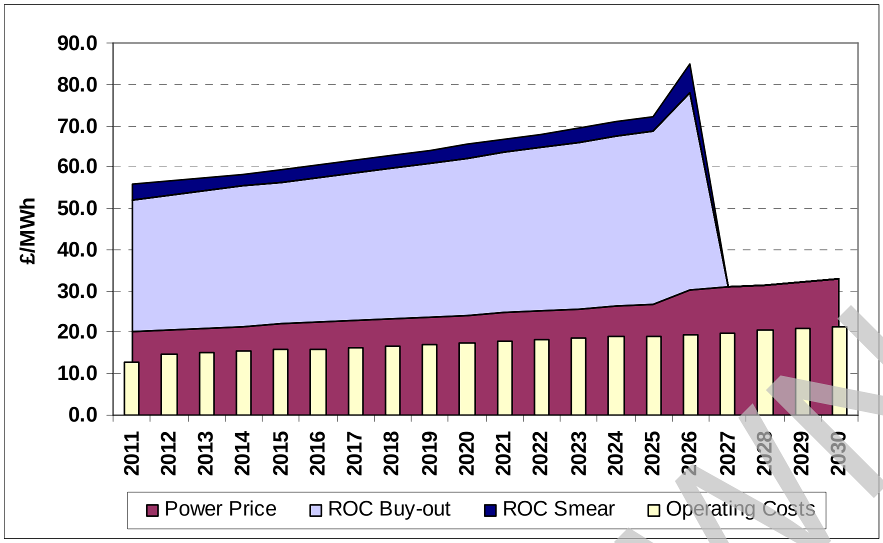
1.4.2. Operation

19. Risk of default during the operation phase relates to financial risk – the risk that revenues are lower than expected because of falling green power prices – and technology risk – the risk that the technology does not perform as expected.

20. Financial default could occur if decommissioning costs are larger than future cash generated by the plant, after debt is serviced. However, given the economics of offshore wind, it is expected that an installation would ordinarily be able to cover the cost of decommissioning for the whole life of the plant. Even by the end of life, when the difference between the present value of future cash flows and decommissioning costs shrinks, the offshore wind farm operating margins should be large enough to cover decommissioning costs.

[3] The risk adjusted exposure is equal to the magnitude of the decommissioning defaulted liability, adjusted by the likelihood of default by the liable entity

Estimated offshore wind farm project economics



21. In order to estimate technical failure rates, the Study used failure statistics for operating onshore wind farms, since long-term statistics on offshore wind farms are not available. Data have been adjusted in order to account for the more difficult and aggressive marine environment.

22. The Study then looked at the installation's ability to cover decommissioning costs in the instance of these estimated technical failure rates. Technical failure would reduce the operating margins of an installation and thus the expectations about future revenues. The likelihood of revenues being insufficient to cover decommissioning costs would therefore be much higher.

23. The Study looked at the credit rating of the asset owner as a way to estimate the probability that the owner might default on decommissioning liabilities during the operation phase. The risk adjusted exposure to the Government depends on the magnitude of decommissioning costs and the probability of insolvency of the developer. This cost could vary anywhere between a few £ millions and more than £100 million (in the case of a high rate of insolvency).

24. Developers that are currently involved in Round One and Round Two offshore wind projects typically have very solid credit ratings, suggesting that the cost to the Government would be in the low range of the previous estimate. However, there are two factors that can substantially jeopardise the credit rating of the developer and thus increase the risk adjusted exposure to the Government; (i) the company operating the offshore wind farm is usually a limited liability company with limited recourse on the parent's assets and potentially with a different credit rating from the parent company; (ii) assets can be sold over the lifetime of the installation and the new owner can potentially have a different and lower rating than that of the initial owner.

25. During the first 3 to 5 years of operation the risk of technical failure is typically covered by warranties and performance guarantees from the technology providers, giving the potential for an additional layer of protection to the Government.

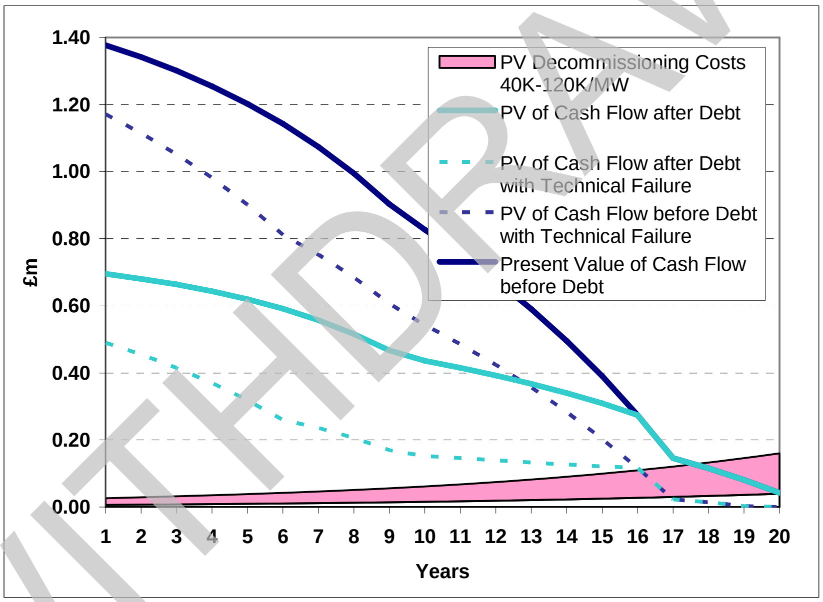
1.4.3. Decommissioning

26. The risk during the decommissioning phase is primarily due to an unexpected increase in decommissioning costs, such that the installations are not able to fund decommissioning as required. The risk adjusted exposure to the Government would increase proportionally with such an increase and be dependent upon the credit rating of the developer.

27. Lack of experience in decommissioning offshore renewable installations increases the risk that developers are unable to provide a fair valuation of decommissioning costs. Finally, experience in the offshore oil and gas sector and in the nuclear sector (somewhat less relevant) suggests that decommissioning costs can increase substantially beyond initial estimates.

28. The larger the increase in decommissioning costs the higher the probability of default. The Figure below shows how an increase in decommissioning cost could bring forward decommissioning during the lifetime of an installation.

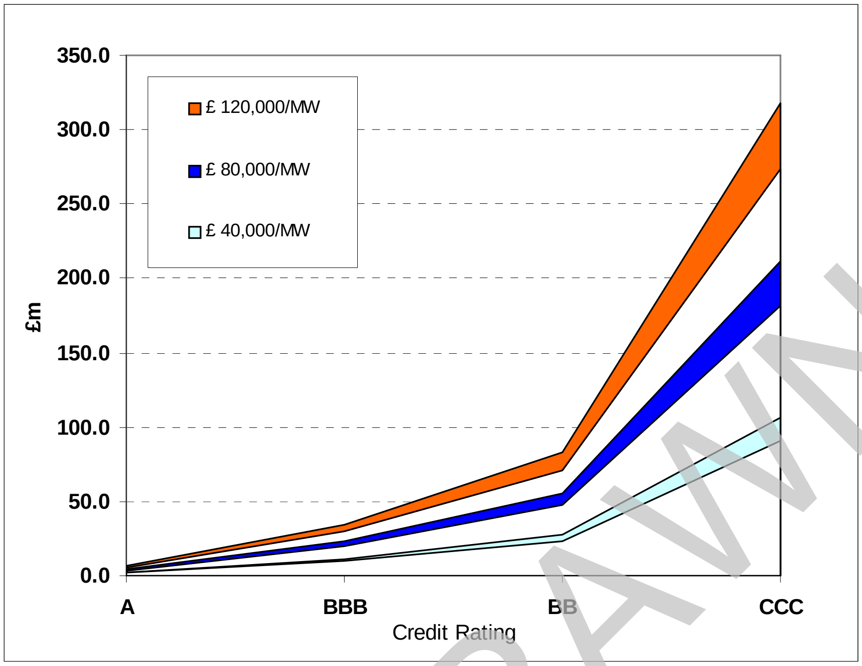
Present value of future cash flows and future decommissioning costs in the event of unforeseen increase in decommissioning costs



29. The Figure shows how an increasing future decommissioning cost (discounted to present value) could exceed the present value of future cash generated by an offshore wind installation both with and without technical failure. In this instance decommissioning would occur earlier in the lifetime of the installation (i.e. in the graph above by Year 16 in the case of technical failure and decommissioning costs of £120,000/MW, the top of the pink band).

30. The risk adjusted exposure to the Government would be affected by an increase in decommissioning costs. The Study therefore looked at different scenarios of unit decommissioning costs under different scenarios of offshore wind capacity and developer credit ratings. An increase in decommissioning cost would most probably be realised when the decommissioning plan is actually executed. In the case of default, the Government's risk adjusted exposure would increase proportionately and be highly dependent upon the creditworthiness of the owner.

Potential cost to the Government under different scenarios of offshore wind capacity and developer credit ratings



(Upper line of each scenario represents all Round Two and consented Round One wind farms, the lower line represents all Round Two alone)

1.4.4. The need for financial securities

31. An offshore wind installation will probably be able to cover decommissioning costs given the operating margins that characterise the industry (high capital costs but very low operating costs). The financial viability of offshore wind is not a major concern since it is reasonable to assume that if the installed capacity of offshore wind reaches the target of 7-8GW, it would be because the investment community perceives the sector as profitable and performs due diligence to secure that the financial risks are minimized.

32. However, notwithstanding these considerations, a few critical factors would suggest that a financial security that does not impose a significant burden on the sector would be advisable in order to manage the uncertainty of the risk adjusted exposure to the Government.

33. The Government's risk adjusted exposure is very dependent upon the magnitude of decommissioning costs (see previous graph). Estimates of those costs have been provided by the industry during the course of the Contact Programme. However, there is an incentive for developers to underestimate these costs. As a consequence the real size of the decommissioning liability and the risk adjusted exposure to the Government is uncertain and will only be resolved once installations start to be decommissioned.

34. Technical failure during operation is a significant source of risk. Typically estimates of the cash flows generated by offshore wind farms are based on a technology performance that is uncertain. Early experience from offshore wind farms shows that the technical failure rate is high. The difficulty of the marine environment reduces performance and makes maintenance slow and expensive. Revenue losses because technology does not perform as expected could increase beyond the asset owner's worst case scenario, exposing the Government to unforeseen liabilities. In addition, at this stage there are only a few

companies providing wind turbines, hence the risk that the technology underperforms could be spread across a number of installations simultaneously.

35. The risk adjusted exposure to the Government is dependent upon the credit worthiness (i.e. credit rating) of the asset owner. Companies that are sponsoring offshore wind development at this stage are financially solid companies. However, in 20 year's time, assets might have been transferred to smaller companies with balance sheets that are not so robust and that are less concerned about the reputational impact of default.

36. A financial security may therefore be required to ensure the risk of default to which the Government is exposed does not escalate under conditions of trade of offshore assets. Any requirement for a security would need to be structured in such a way that it moves with the transfer of ownership of the asset. For example, in the case of a segregated decommissioning fund, previously accrued monies and the requirement to make payments into the fund would need to move with the decommissioning liability to any new owner.

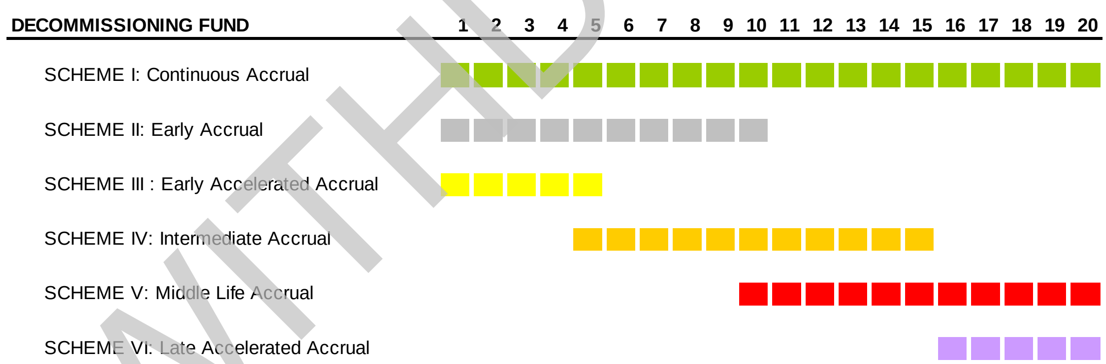
1.5. Analysis of Financial Securities

37. The Study looked at financial securities potentially available to reduce the Government's exposure to default on OREI decommissioning liabilities. The Study looked both at the financial securities mentioned in the Energy Act 2004 and additional ones used in other sectors.

Decommissioning Fund

38. The Government could require the establishment of a decommissioning fund that accrues early or late into the life of the installation, accruing slowly or quickly (Figure below):

Possible decommissioning fund schemes



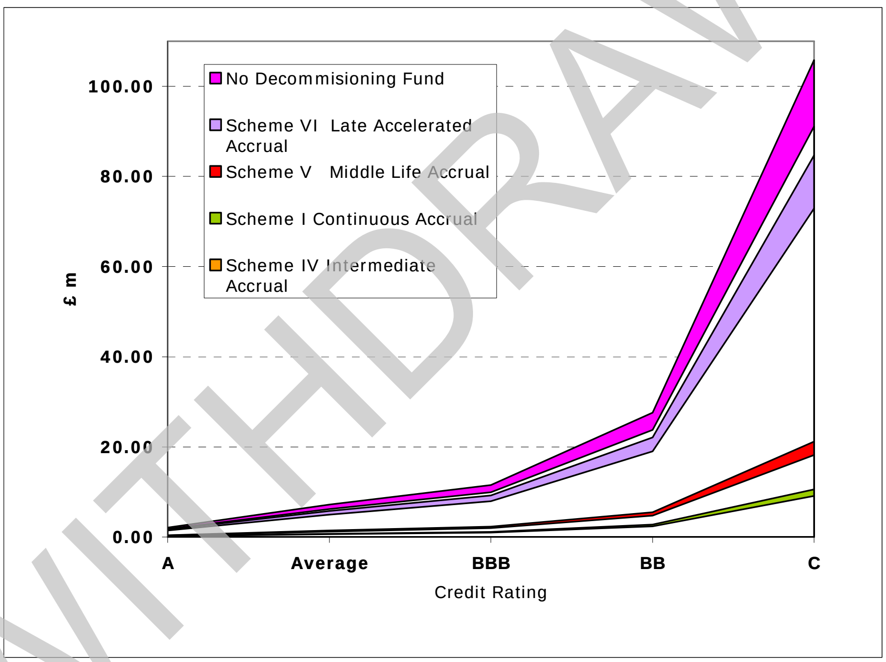
39. Decommissioning fund schemes have only a limited impact upon the investors' returns and would therefore have a minor effect on the development of the technology. However, the Study acknowledges that offshore wind is already financed on tight margins and even small changes to returns can have an impact upon investment decisions. For this reason, the Study focused the analysis on four decommissioning fund schemes (Scheme I Continuous Accrual, Scheme IV Intermediate Accrual, Scheme V Middle Life Accrual and Scheme VI Late Accelerated Accrual) characterized by their minimal impact upon equity returns.

Impact of different decommissioning fund schemes on annual IRR to equity

	Scheme I	Scheme II	Scheme III	Scheme IV	Scheme V	Scheme VI
No Fund	Continuous Accrual	Early Accrual	Early Accelerated Accrual	Intermediate Accrual	Middle Life Accrual	Late Accelerated Accrual
10.56%	10.33%	10.16%	10.03%	10.33%	10.48%	10.53%

40. Each of the selected schemes has been appraised on the basis of their effectiveness in providing security against default on decommissioning, on the impact that the security might have upon the future development of the industry and on the effectiveness in mitigating unforeseen increases in decommissioning costs. In general terms, a scheme that requires a decommissioning fund to be accrued during the early years of operation would significantly reduce the Government's exposure, but would have a larger financial impact upon the sector.

Government's risk adjusted exposure under different decommissioning fund schemes



N.B. Scheme IV Intermediate Accrual does not appear in the Figure above because the Government's exposure is zero under the scenarios envisaged.

41. Other securities mentioned in the Energy Act 2004, such as letters of credit, parent company guarantees and bonds, all have specific disadvantages. Main concerns include; (i) the tenor of the instrument does not match the tenor of the decommissioning liability, thus providing only partial coverage; (ii) some instruments, such as bonds, are not presently available or affordable for offshore wind; (iii) other instruments, such as parent company guarantees, would require the Government to assess periodically the viability of the instruments and would not provide certainty.

1.6. Middle life accrual is the preferred mechanism

42. Depending on the level of risk the Government is prepared to accept, the Study recommends the use of a decommissioning fund structured in a similar way to Scheme V Middle Life Accrual.

43. A decommissioning fund scheme that starts accruing in the second half of the life of the installation would reduce the risk adjusted exposure and its uncertainty to the Government and would not impose an excessive burden upon the industry.

44. The asset owner would not have to pay into a fund during the first years of operation, when debt (if any) is serviced. Payments would also be spread over 10 years to minimise the exposure during the last years of operation when the installation is most vulnerable (because of obsolete technology and uncertainty of green power prices).

45. The industry would have to bear an increase of decommissioning costs in present value terms, but this would have a very limited impact upon the returns provided to equity investors.

46. This scheme would allow for adjustments to respond to an increase in estimated decommissioning costs. Once the funds start accruing the sector would probably have better knowledge of decommissioning costs and the fund could be adjusted accordingly. Secondly the Government could require a mid term review of the fund (for example, after 5 years of accrual) to verify its adequacy (or more frequent reviews if considered appropriate).

1.7. Marine Technologies

Size of the Liability

47. The marine sector is currently much more diverse than the offshore wind sector because it is several years behind in terms of technological development. It is expected some of the diversity of marine technologies will fall in years to come as devices move into the commercial stage.

48. Marine technologies under development currently have limited capacity because they are at the demonstration stage and only a few such devices have thus far been deployed. Most individual units are currently less than 500kW in size, while the largest currently planned are no larger than a few MWs.

49. Further development of the marine renewables market from demonstration to commercial deployment will require substantial cost reductions or continuing Government support. Total project costs of £1.7−4.3 million/MW (according to Carbon Trust) of marine renewables are higher than for offshore wind, which is in the region of £1.5 million/MW. However, higher levels of output per MW of capacity (higher load factors) are expected to reduce this disparity over project lifetimes. Learning curve effects are also likely to lower costs with the deployment of additional devices.

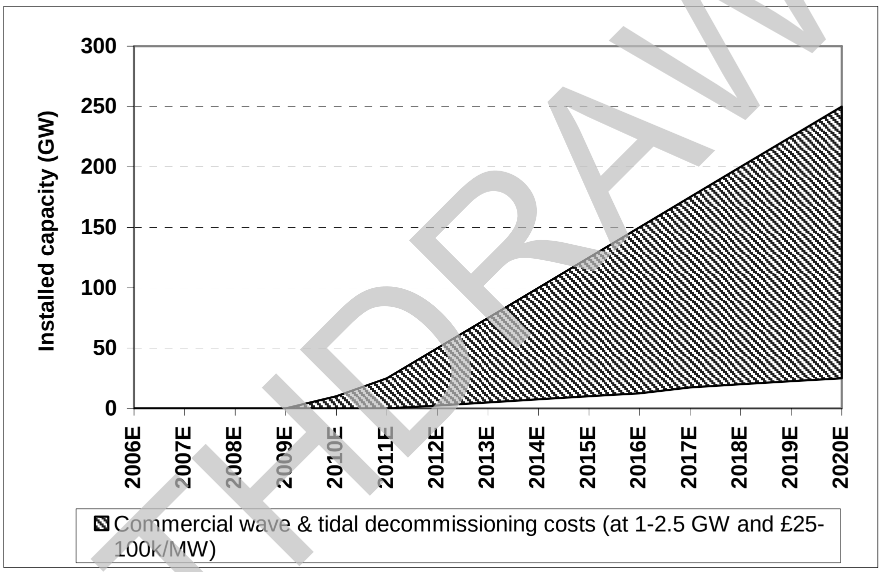
50. Marine development scenarios have been extracted from the Carbon Trust report, Future Marine Energy (2006), which postulates 1−2.5 GW of commercial wave and tidal capacity could be available by 2020 (see Figure overleaf).

Cost of decommissioning

51. Decommissioning cost estimates for marine technologies are more uncertain than those for offshore wind because few marine technologies have been deployed so far, and none have been deployed at a commercial scale. The future size and number of marine developments is also uncertain.

52. Discussions with project developers and technology providers within the Contact Programme suggested decommissioning costs for marine technologies could vary from as little as £25,000/MW up to £100,000/MW. This could generate a decommissioning cost range of £25-250 million based on 1-2.5 GW of marine capacity deployed by 2020, although as the diversity of devices falls with time the estimated costs of decommissioning are likely to become less variable. The high-end of this range may be considered an extreme scenario given the current pre-commercial status of marine technologies and the likely reduction in decommissioning costs with economies of scale.

Estimated marine decommissioning costs



Default of Marine Technologies

53. Our analysis indicates that decommissioning costs for pre-commercial marine devices are likely to be, on an average per MW basis, higher than for offshore wind farms. These costs will probably fall as marine devices become commercialised and the scale of deployment increases, although they may vary considerably depending upon the number and type of offshore marine devices that become commercialised.

54. The Study is unable to provide estimates of default rates over the lifetimes of the projects (and therefore the risk adjusted Government exposure), given the lack of data regarding technical failure rates and developer company credit ratings. However, we would expect them to be higher on a like-for-like basis than for offshore wind, particularly while marine technologies are still at a very early stage of development.

Financial Securities

55. Marine technologies would at present struggle with the provision of any financial securities, because of a lack of certain revenues at the pre-commercial, demonstration stage and because the lifetime of these devices is shorter than, and in some case incompatible

with, the tenor of the decommissioning fund. The cost of marine decommissioning payments might therefore need to be ring-fenced as a condition of any grants or further support from Government. However, future commercial marine devices may reasonably be expected to provide the same level of security as commercial offshore wind devices.

2. Background

2.1. Regulatory Framework of OREI Decommissioning

56. Decommissioning of Offshore Renewable Energy Installations (OREIs) in the UK is regulated under Chapter 3 of Part 2 of the Energy Act 2004 which, as far as the Renewable Energy Zone is concerned (see below), implements the UK's obligations on decommissioning under the United Nations Convention on the Law of the Sea. The Act enables the Secretary of State to require developers of OREIs to submit a costed decommissioning programme to the DTI, setting out the measures to be taken to decommission the installations and estimating the potential costs and timing. This programme must be executed by the liable entity whenever decommissioning is necessary.

57. The Energy Act 2004 defines the 'Renewable Energy Zone' (REZ) as an area beyond territorial waters, in principle out to 200 nautical miles (370 Km) from the baselines (usually the low water mark). The scheme also applies to waters around Great Britain further inshore, from the mean low water mark to the seaward boundary of the territorial sea. The Crown Estate has the right to provide leases or licenses for the installation of renewable energy installations. The DTI has identified three strategic areas for offshore (wind) development: the Greater Wash, the Thames Estuary and the North West (Liverpool Bay). Future rounds of offshore wind farm developments are currently planned for these three areas.

58. The Energy Act 2004 refers to the use of financial securities aimed at guaranteeing delivery of the decommissioning programme. The requirement for financial securities is discretionary. Submitted decommissioning programmes are subject to periodic review "from time to time" and modification to the programme is subject to the approval of the Secretary of State. The review includes the suitability of any current financial securities.

59. Under the Energy Act 2004, if the liable entity defaults in carrying out the decommissioning programme the Government, as a last resort, may carry it out itself and where possible will recover the cost incurred from the liable entity. Criminal penalties are available if a liable entity fails to carry out the decommissioning programme.

2.2. Generic Review

60. The scope of the Generic Review was to identify the financial securities that have been used in the UK and other countries to secure long-term liabilities incurred by the private sector. The Review has looked at a number of sectors and activities where decommissioning represents a significant phase or cost component in the project lifecycle.

61. In particular, the Review has looked at the way Government addresses decommissioning in two highly regulated and capital-intensive sectors: offshore oil and gas and nuclear power.

62. The analysis was further broadened to include contaminated land, the disposal of electrical and electronic equipment (WEEE) and the treatment of so-called end-of-life vehicles (ELVs). The examination of these sectors provided a useful overview of the policies and financial securities available to address environmental liabilities in less-regulated and more fragmented sectors. Finally, this section looked at the approach adopted in Denmark and the Netherlands to address the decommissioning of offshore wind installations.

63. Key outcomes from the Generic Review are as follows:

"Polluter pays principle"

64. The Government's approach to decommissioning across a range of different sectors has been to require the producer to pay for the disposal of its own waste. In the offshore oil and gas industry a decommissioning programme has to be submitted, funded and executed by the owner of the installation. Contaminated land legislation requires the entity that causes or knowingly permits contamination to sustain the remediation costs.

65. Even in the nuclear industry, where the Government has borne the public sector cost of decommissioning and has underwritten private sector liabilities, it was always the intention that the polluter pays for waste disposal.

Liabilities may be assumed by new/previous owners or related companies

66. In the case of the offshore oil and gas sector, Government may require previous owners of an asset to bear liability for decommissioning upon asset transfer, if the new owner is deemed to be of inadequate financial standing. An approved Financial Security Agreement (FSA), which spreads the decommissioning risk across each of the parties involved, might otherwise be required.

67. Similarly the cost of remediation of land contamination is borne by those who carried out the polluting activity. In the event it is not possible to identify the polluter, the liable entity would ultimately be the owner of the land. Producers of WEEE and ELVs may also be required to bear the cost of treatment on behalf of another producer, in the instance of the latter's default.

Government support is evident in many sectors

68. Government support has been available to varying degrees in each of the sectors studied herein. The OREI sector, which for example will benefit from the UK Renewables Obligation, is no exception to this rule. Yet the polluter pays principle applies in all five sectors analysed, no matter the level of Government support.

Financial Securities

69. For the offshore oil and gas industry, in some instances, the DTI has required a financial security to be provided (usually an annually renewable letter of credit), or an approved FSA between asset holders, if a developer is of insufficient financial standing to provide certainty over its ability to meet decommissioning liabilities.

70. Under the Pollution Prevention and Control (PPC) Regulations, a waste management operator cannot commence any activity without demonstrating that an installation is solvent and that they can financially operate the site in accordance with its permit conditions. When an operator stops or intends to stop operating an installation or part of it, they need to submit a surrender application, including a site report identifying any changes from the original site report (which must accompany a permit application). This is designed to ensure their obligations (including remediation obligations) are discharged as necessary.

71. In the nuclear industry, payments into the Nuclear Liabilities Fund are required from British Energy (BE), the sole private owner/operator of nuclear plants in the UK. ELV regulations require producers to enter into contracts with dismantlers and scrappers to ensure that treatment of their own brands of vehicles is carried out without charge to owners (from January 2007), but no financial securities are required.

Tax incentives

72. Payments into the Nuclear Liability Fund (NLF) are allowable against tax, but this is not the case for decommissioning payments into a fund or insurance-based decommissioning agreements in the offshore oil and gas sector.

Decommissioning in other countries

73. Decommissioning in other countries has been dealt with in a similar manner to decommissioning in the UK. The predominant approach has again been to require the 'polluter to pay'. This is true for the US nuclear industry as well, where companies are required to pay into segregated decommissioning funds over the course of power plant operations.

74. Denmark and the Netherlands are two of the leading countries in the offshore wind sector, with over 3 GW of installed capacity (the vast majority in Denmark). Both countries require the owner of an offshore installation to be liable for decommissioning. The Netherlands requires that offshore owners/operators must pay monies into a segregated decommissioning fund for a minimum of 10 years, starting from the first year of operation of the project. Danish regulations also state a guarantee may be required from developers, but to the best of our knowledge this requirement has not yet been enforced.

75. Appendix A provides additional information on the Generic Review.

2.3. Contact Programme

76. The Contact Programme was devised to identify those groups of stakeholders that may have a direct interest or valuable contribution to make to the effective conduct of the Study. Interviews were sought with representatives of companies or associations falling into the categories set out below:

- Early stage and 'commercialising' technology/project developers (marine technologies);
- Late stage and 'mature' technology/project developers (offshore wind);
- Equipment, Procurement and Construction (EPC) contractors and technology providers;
- Operators
- Equity and Debt investors;
- Insurers;
- The Crown Estate; and
- Renewable energy trade associations.

77. The Contact Programme asked interviewees for their opinions on the magnitude of decommissioning costs, the most relevant sources of risk and views on possible Government requirements for financial securities.

Views on financial securities

78. It was apparent that a financial security regime for OREIs must be clear, transparent and certain. The common view of interviewees was that any uncertainty over the required provisions for financial securities would be harmful to project development in terms of attracting investment.

79. Flexibility amongst a range of acceptable financial securities to cover decommissioning liabilities is desirable so that companies at different stages of development as well as

companies producing different technologies or with different corporate structures may provide instruments that are both affordable and sufficient to satisfy Government requirements.

80. The industry as a whole was ready to accept its liabilities for decommissioning, but reluctant to provide financial securities given the fact that offshore energy is already financed on tight margins. Interviewees were aware that current legislation (the Energy Act 2004) requires owners/operators to bear full liability for decommissioning. They were also cognisant of the requirements of the Crown Estate that guarantors are responsible for complete removal of OREIs.

81. A typical view was that a PCG (if one could be obtained) might be acceptable to developers but a letter of credit or insurance bond (again, if either could be obtained) that required up-front costs would be unwelcome. However, most interviewees were prepared to accept the suggestion that a segregated decommissioning account be created into which decommissioning payments could be made over the lifetime of a project (perhaps starting 5 or 10 years after commissioning). If such payments were allowable this could become an attractive proposition for developers.

82. Interviewees were generally unsupportive of the suggestion that liability for decommissioning could be pooled through a collective or insurance-based scheme, perhaps with DTI as the insurable entity. In the latter instance, this may encounter further difficulties in that DTI is probably not an 'insurable entity' given it does not have a direct financial interest in the offshore developments. In response to a further suggestion, EPC contractors and equipment suppliers revealed they were unwilling to accept any liability for decommissioning over and above current warranties associated with construction and operation of the asset (which may last for up to the first 5 years of an OREI operational lifetime). However, financiers mentioned this might be a possibility later in the development of offshore turbines, perhaps becoming incorporated into the Operation and Maintenance (O&M) contract.

83. A common view shared by the interviewees was that financial securities in the form of cash, bonds or letters of credit would tend to favour larger developers over smaller ones because of their stronger balance sheets.

Source of risk

84. The major source of risk during the construction period would be geological and geotechnical risk. Due to inaccurate site investigation some piles might be required to be reallocated, increasing construction costs and delaying completion. However, interviewees stressed that few of all the piles of a wind farm would have to be moved because of unforeseen geological difficulties.

85. Several interviewees were of the opinion that default would largely be technical and not financial, that is, that the developing companies would be unlikely to face insolvency in the event projects did not fulfil revenue expectations.

86. Technical risk can arise from underperformance of offshore technologies. This risk is particularly relevant by the end of life of the installation when, because of obsolescence and increased technical failures, the cost of repairing the installation may be higher than the expected future revenues.

87. Detailed information about the Contact Programme is provided in Appendix B.

3. Magnitude of decommissioning costs

3.1. Summary

88. This section of the Study estimates the potential scale of OREI decommissioning[4] liability and the associated cost.

89. Our analysis indicates that the offshore wind market could reach 7.5 GW by 2016. This figure includes operating and under construction Round One projects and implies that all consented Round Two projects proceed to construction and operation. The Study also found that marine technologies could deliver 1GW-2.5 GW by 2020. These projections are very optimistic and provide an estimate of the maximum size of the cost of decommissioning renewable offshore installations.

90. The second part of this section provides estimates of the decommissioning costs based upon these projections of the size of the offshore renewables sector.

91. Key findings of this section are:

- Interviews within the Contact Programme provided a useful indication of current expectations of the industry on decommissioning costs equal to £40,000/MW. These would make up around 2.5% (undiscounted) of the total project cost (assuming £1.5 million per MW) or 2% of operating costs when spread over the lifetime of the project (as if paid into a segregated fund).
- Construction of offshore renewables up until 2020 could create a maximum £288m of offshore wind decommissioning liabilities based upon decommissioning costs of £40,000/MW and 7.2 GW of installed Round Two capacity. If decommissioning is included also from currently operating/under construction Round One projects, this would add an additional liability of £12 million, based upon decommissioning costs of £40,000/MW and 300 MW of installed Round One capacity. Finally if all consented Round One is included in the calculation the magnitude of decommissioning costs increases to £335 million.
- Future construction of commercial marine technologies could create a decommissioning liability anywhere between £25 million to £250 million depending upon the unit decommissioning cost and the future size of the sector.
- Estimates of decommissioning cost could change substantially once experience of decommissioning is gained, the extent of decommissioning is better defined, and future technological capabilities are better understood.

4 For the purposes of this Study, decommissioning is defined as the complete removal of an offshore renewable energy device, including foundations and cables 1-2 metres below the sea bed.

3.2. Size of the Liability

3.2.1. Offshore wind Round One

92. In December 2000, Crown Estate initiated "Round One" of the process to allocate sites and leases for offshore wind farms. 18 sites with up to 30 turbines each lodged successful applications.

93. The UK's first commercial-scale offshore wind farm, located off the North Wales coast at North Hoyle, commenced operations in November 2003. There are now three projects operating under Round One (Scroby Sands, North Hoyle and Kentish Flats), which represent a capacity of 210 MW from a total of 90 turbines. This is set to grow to 300 MW when construction of Barrow is completed (as expected) in 2006. A further seven projects have been consented by DTI at the time of writing, which would deliver up to an additional 864 MW of capacity, equal to some 240 turbines. Another four projects are under consideration, which would bring the Round One development to a maximum total of 1,732 MW of capacity. However, this is likely to be an optimistic figure compared to actual construction.

94. Round One was intended to act as a 'demonstration' round, enabling prospective developers to gain technological, economic and environmental expertise. The Crown Estate's procedures limited the area of sea bed to be developed under each license to 10 km^2 and a maximum of 30 turbines to generate a minimum installed capacity of 20 MW.

95. At the time of Round One consents, the submission and execution of a decommissioning programme was not a statutory requirement. However, the Crown Estate required, as part of the lease submission, a costed plan for decommissioning the proposed wind farm sites one year before expiration of the lease. The use of financial securities was limited because the Crown Estate's enforcement ability was itself restricted.

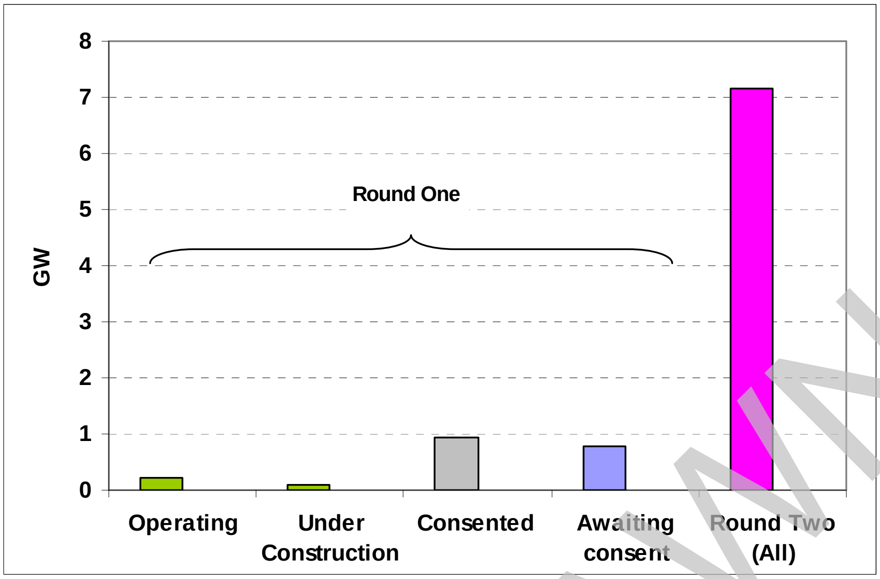
3.2.2. Offshore Wind Round Two

96. A second round of offshore leases offered by the Crown Estate ("Round Two") was more ambitious in scale. 15 projects, totalling approximately 1800 turbines and delivering a possible 7.2 GW of capacity, were approved. Round Two has developed under a more defined regulatory environment, although it has foregone the favourable capital grants available to Round One developments. Developments were restricted to three strategic areas (the Greater Wash, the Thames Estuary and the North West, Liverpool Bay) following a DTI strategic environmental assessment (SEA) completed in May 2003.

97. The Crown Estate required prospective developers to bid in a competitive tender process for Round Two offshore leases. The highest bid was favoured for site approval, assuming that other requirements, such as a minimum level of financial strength, undertaking of environmental impact surveys and the provision of construction, operation and decommissioning plans, were satisfied.

98. The concept of a decommissioning sum was also introduced in Round Two leases, supported by the statutory obligation for decommissioning within the Energy Act 2004. Developers and the Crown Estate must agree a decommissioning sum to be deposited with the Crown Estate five years before termination of the lease. The decommissioning sum is defined under the approval of a jointly appointed third party expert. The Crown Estate will refund the decommissioning sum once the decommissioning plan (which may be revised under joint agreement) has been executed satisfactorily.

Figure 1 Rounds One and Two offshore wind projects by stage



(Source: CCC, BWEA, Crown Estate and DTI)

3.2.3. Marine (Wave and Tidal)

99. The marine sector is currently much more diverse than the offshore wind sector because it is several years behind in terms of technological development. It is expected some of the diversity of marine technologies will fall in years to come as devices become commercialised.

100. A common characteristic of marine developers is the relatively small size of the companies involved (except for some like Scottish and Southern Energy). Of these, perhaps 10 to 15 would be capable of developing a commercial-stage device in the UK during the next decade. At present there are no commercial-scale devices delivering power into the UK grid.

101. Marine technologies under development currently have limited capacity because they are at the demonstration stage and only a few such devices have thus far been deployed. Most individual units are currently less than 500kW in size, while the largest currently planned are no more than a few MWs.

102. Commercial marine devices could be deployed in arrays of up to 15−20 MW over the next decade. However, this will be unlikely if current costs do not decline significantly. A recent Carbon Trust report, Future Marine Energy (2006), states project costs for marine technologies are currently in the range of £1.7−4.3 million/MW. The Study therefore makes a distinction for the purposes of analysis between currently pre-commercial marine devices and future commercial devices.

3.2.4. Future development of offshore renewables

103. The 2002 Renewables Obligation Order established a 10.4% obligation for electricity supply from renewables sources in the UK by 2010/11, later extended to 15.4% in 2015/16. The contribution of offshore renewables to the Government's 10% target is generally expected to be delivered by some 3 GW of offshore wind capacity. Marine renewables, on

the other hand, are not expected to make a significant contribution to the UK's energy mix by this time.

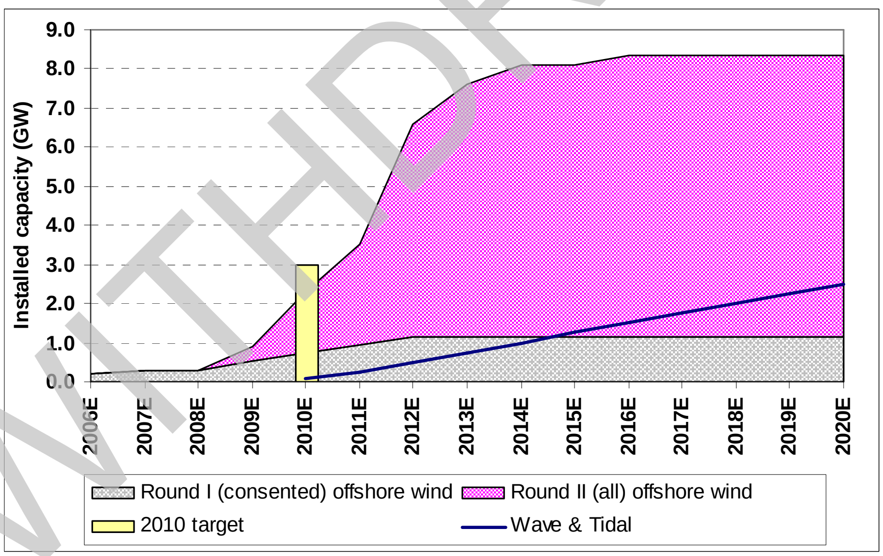
104. The Study identified maximum capacity projections for offshore wind and marine technologies, given that the size of any decommissioning liability to Government would be affected by the scale of the market.

105. If all consented Round One projects move into construction, they could potentially deliver 1.2 GW by 2020 (currently only 300MW are available). If all consented Round Two offshore wind is constructed an additional 7.2 GW would be available and in total 8.4 GW of capacity would become available by 2020. This is a high-case scenario since currently only three consented Round One wind farms are operating and one is under construction.

106. Further development of the marine renewables market from demonstration to commercial deployment will require substantial cost reductions or continuing Government support. Total project costs of £1.7−4.3 million/MW of marine renewables are higher than for offshore wind, which is in the region of £1.5 million/MW. However, higher load factors are expected to reduce this disparity over project lifetimes. Learning curve effects are also likely to lower costs with the deployment of additional devices.

107. Marine development scenarios have been extracted from the Carbon Trust report, Future Marine Energy (2006), which postulates 1−2.5 GW of commercial wave and tidal capacity could be available by 2020. Figure 2 shows this high marine target and high offshore wind scenario.

Figure 2 Offshore wind and marine capacity projections to 2020



(Source: CCC and Carbon Trust)

3.2.5. Factors affecting size of liability

108. Future development of offshore wind and marine technologies is likely to be influenced by Government policy, development of renewable technologies, competing generation sources and the prices of fossil fuels.

Government policy

109. Continuing renewables support in the form of the Renewables Obligation (RO), European Union Emissions Trading Scheme (EU-ETS) targets and sector-specific support will be important determinants of the future deployment of offshore technologies.

Other renewables development

110. The support of the RO to offshore developments will be reduced if Government targets for renewables (like onshore wind and solar) are exceeded, causing the recycle payment to disappear and the price of ROCs to fall below the buy-out price.

Technological development

111. Future design and process improvements, efficiency gains and economies of scale may all lead to learning curve reductions of total project costs. Learning curve reductions are well-established patterns of declining costs that occur as a result of experience gained as new technologies are deployed. Costs should fall for offshore wind and marine as new capacity is installed.

112. However, the development of clean coal technologies in response to high carbon prices may introduce another important competitor for new low-carbon capacity investment.

Prices of fossil fuels

113. High prices for fossil fuels will spur further Government efforts to reduce reliance on carbon-emitting technologies. They will also bring greater investment in renewable technologies including offshore wind and marine.

Financing gap for offshore renewables

114. Development is currently constrained by high capital costs (including rising steel prices and turbine costs) and the inaccessibility of long term power purchase agreements (PPA), as well as the more difficult conditions offshore. Unless some additional support is forthcoming, the deployment of OREIs (and the potential liability) will be constrained in the short to medium term, under current market conditions.

3.3. Cost of the Liability

3.3.1. Cost estimates for decommissioning offshore wind farms

115. Interviews within the Contact Programme provided a useful indication of current expectations in the industry of decommissioning costs. In Table 1, data obtained from a Round Two offshore wind developer are reported.

Table 1 Estimated decommissioning costs

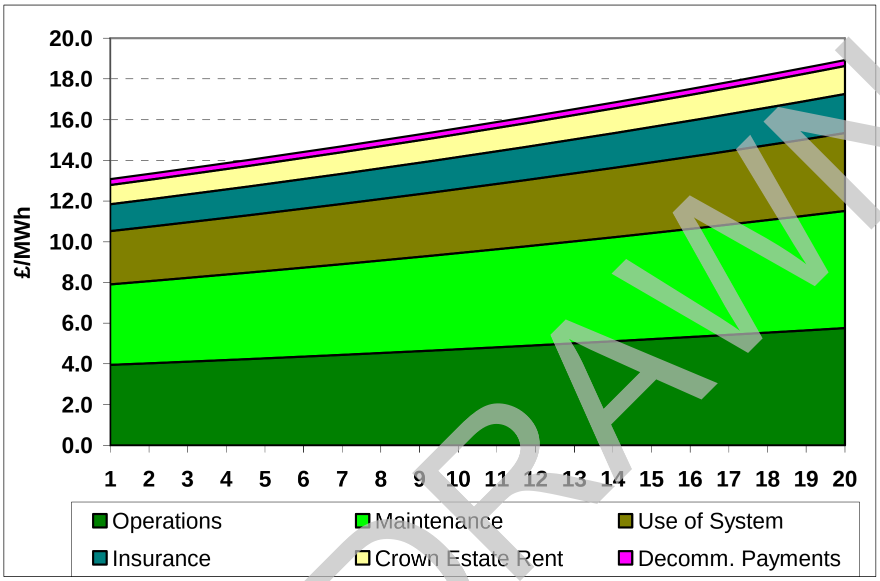
Monopile	Per turbine	Per MW
Cables left in situ	£108,000	£31,000
Cables removed	£122,000	£35,000

Gravity base	Per turbine	Per MW
Cables left in situ	£121,000	£35,000
Cables removed	£135,000	£39,000

(Source: CCC & Contact Programme)

116. These data are consistent with decommissioning costs previously estimated by Enron Wind in 2001[5]. A 240 MW offshore wind farm would have a decommissioning cost of £8.4 − 9.3 million, depending upon the type of foundation. This would make up around 2.5% (undiscounted) of the total project cost (assuming £1.5 million per MW) or 2% of operating costs when spread over the lifetime of the project (as if paid into an accumulating segregated fund). Figure 3 shows the scale of these decommissioning costs in proportion to project operating costs.

Figure 3 Decommissioning costs as proportion of operating costs



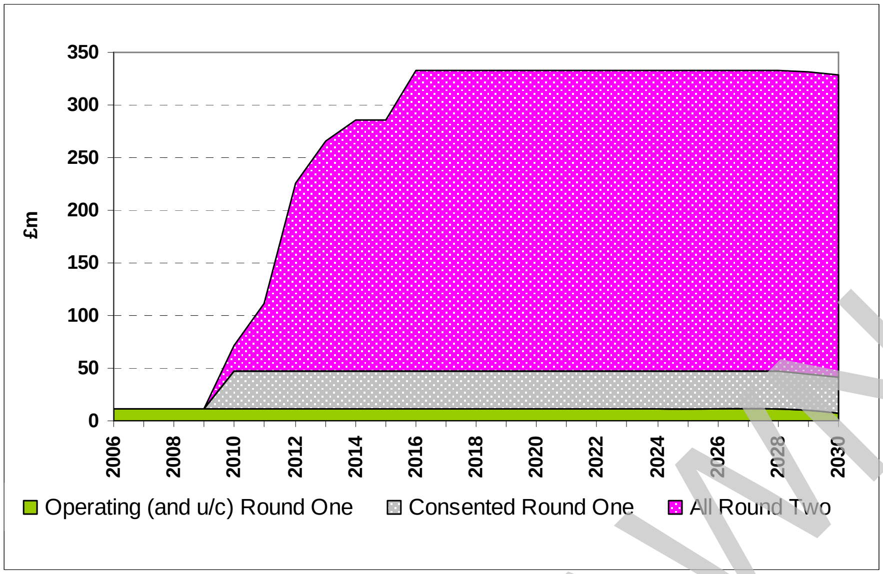
(Source CCC)

117. However, some interviewees in the Contact Programme believed the figures shown in Table 1 might underestimate the actual decommissioning costs. They stressed the variability of different installations and future technological developments as two major reasons for doubting current decommissioning cost estimates. Finally the sources of the estimates provided in Table 1 were developers, who might have an incentive to underestimate decommissioning costs in order to reduce the size of their decommissioning liability. There will also be a better understanding of decommissioning costs once experience is gained (in OREI and offshore oil and gas) and future technological capabilities are better defined.

118. For the reasons mentioned above, the data reported in Table 1 represent the best estimates of decommissioning costs available at the time of writing. On the basis of these estimates, it is possible to estimate decommissioning costs associated with current and projected offshore wind installation constructed up to 2020.

[5] Dan Pearson, Enron Wind (2001): Decommissioning Wind Turbines In The UK Offshore Zone

Figure 4 Estimated offshore wind decommissioning costs



(Source CCC)

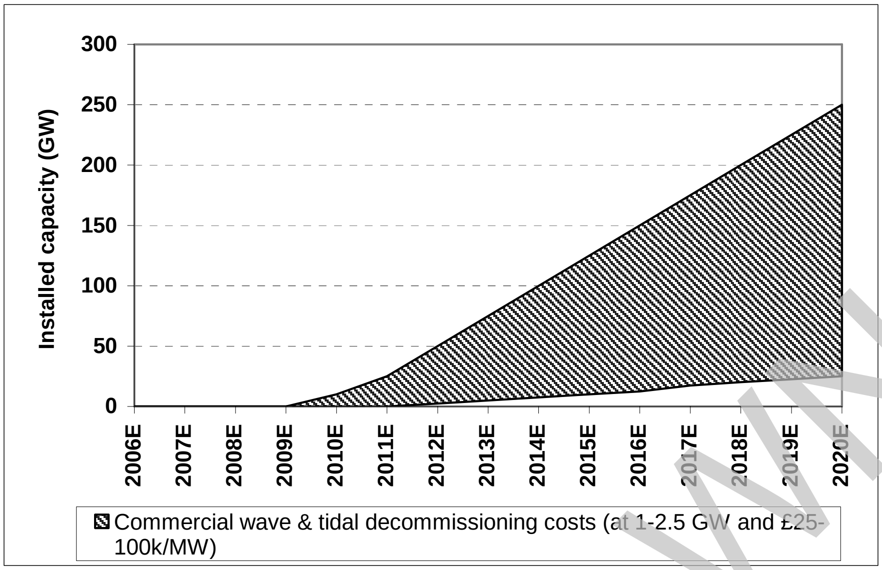
119. Based upon the assumption that full Round Two capacity (7.2 GW) is installed by 2020, the cost of decommissioning (based on cost assumptions reported in Table 1) would be £288 million. Note that these estimates are entirely dependent upon the projections of future offshore wind development and expected decommissioning costs per MW. If decommissioning of currently operating and under construction Round One projects is included, this would add an additional liability of £12 million. If all operating and consented Round One and Round Two are also included in the calculation, the total magnitude of decommissioning cost would be £335 million.

3.3.2. Cost estimates for decommissioning marine technologies

120. Decommissioning cost estimates for marine technologies are more uncertain than those for offshore wind because few marine technologies have been deployed so far, and none have been deployed at a commercial scale. The future size and number of marine developments is also uncertain.

121. Discussions with project developers and technology providers within the Contact Programme suggest decommissioning costs for marine technologies could vary from as little as £25,000/MW up to £100,000/MW. This could generate a decommissioning cost range of £25-250 million based on 1-2.5 GW of marine capacity deployed by 2020 (Figure 5), although as the diversity of devices falls with time the estimated costs of decommissioning are likely to become less variable. The high-end of this range may be considered an extreme scenario given the current pre-commercial status of marine technologies and the likely reduction in decommissioning costs with economies of scale.

Figure 5 Estimated marine decommissioning costs



(Source CCC)

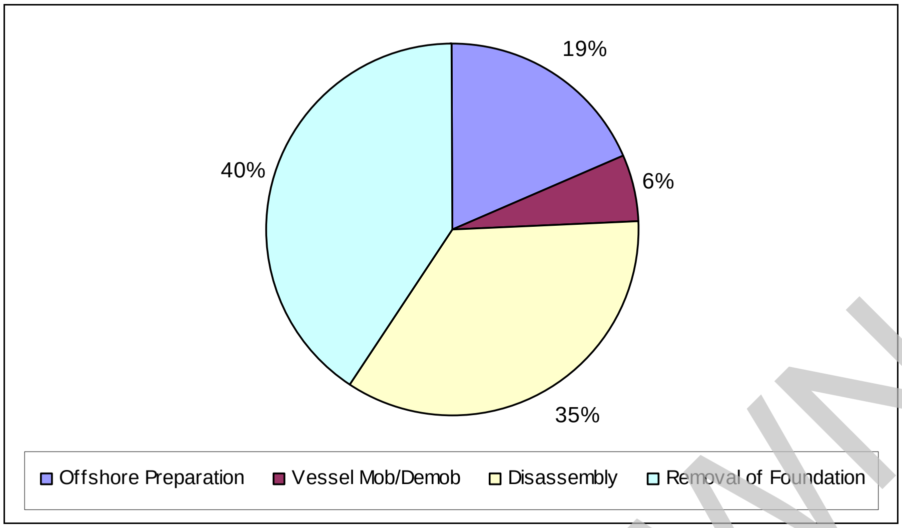
3.3.3. Factors affecting decommissioning cost

122. The expected costs and challenges of decommissioning an OREI differ depending upon the size of the installation, its type of foundation, location, electrical cables and the availability of technical expertise and equipment.

Technical expertise and equipment

123. Relevant technical expertise and equipment are available for decommissioning, given experience in the offshore oil and gas sector and the expectation of relatively simple means of OREI removal. The expected process of removing an offshore wind installation includes site preparation ahead of the main lifting activity, vessel mobilisation (and eventual demobilisation), cutting and lifting the monopile or foundation and dismantling the installation on its return to the shore. Figure 6 shows the proportion of decommissioning cost at each stage.

Figure 6 Breakdown of decommissioning costs



(Source: Contact Programme)

124. While there is currently very little experience of decommissioning offshore wind farms, there are expectations that the foundations will be the most difficult, and therefore most expensive, part of the offshore structures to remove. A lifting vessel, barges and tugs will all be needed. Mobilisation and demobilisation of the vessels is an expensive and variable element of the cost, since the availability of specialist vessels will change depending upon the pattern of decommissioning and even development of other offshore renewables and oil and gas structures. On the other hand, it can be expected that better technology will be available in the future and, after the first installations are decommissioned, costs will decline with learning.

125. The nature and scale of future commercial marine devices is uncertain and could vary considerably if multiple technologies are successful (although this is thought unlikely to be the case). Experience in decommissioning marine devices is also extremely limited because very few have yet made it past the demonstration stage.

Scale and location

126. Decommissioning costs are likely to vary between OREIs in a broad pattern that reflects their relative stages of development and location. At present, many marine devices are small in scale. In contrast, offshore wind developments are likely to be increasingly large in scale – both in terms of the size of individual turbines and the size of collective wind farms.

127. The location of devices is important with regards to the type of sea bed (and hence foundation), the depth of the water and the local currents and tides. Marine devices, such as tidal turbines, are specifically placed in regions with powerful currents and a fast tidal race, which would limit recovery to specific seasons and times of day. Offshore wind farms may be placed in regions of the sea that are very deep and therefore relatively inaccessible (although offshore oil and gas platforms provide experience of dealing with these challenges). Transport to and from the decommissioning site will therefore be a more difficult and expensive prospect for some OREIs than for others.

Type of foundation

128. The most difficult and expensive process for offshore wind decommissioning, and possibly for decommissioning many marine devices, will be the removal of the foundation. This is especially true for monopiles embedded in hard rock. However, if monopiles only need to be cut away 1−2 m below the sea bed, this might not be overly burdensome. But piles embedded in sand banks may need to be cut away at perhaps 5−10 m below the sea bed because of the potential for sands to shift over long periods of time.

Cables

129. Electrical cables delivering power from the offshore site to the mainland may be laid on to the surface of the sea bed or buried, typically 1−2 m below the surface. Initial estimates suggest the cost of removing offshore array and transmission cables is £4,000/MW, although this figure (calculated for a large offshore wind farm) may rise as the scale of offshore installation decreases. However, available information indicates a trend towards deeper burial of cables because of environmental regulations. Deeper burial of cables would lead to increased removal costs, but only if such removal were necessary. This is therefore an uncertain variable at present.

4. Circumstances of Default

4.1. Summary

130. In this section the Study looked at the circumstances under which owners of OREI installations might default on decommissioning liabilities.

131. Typically different types of risk arise during different phases of the project, and their magnitude varies across the lifetime of the installation. It is therefore helpful to consider default risk during three distinct phases: construction, operation and the decommissioning phase itself.

132. In each of the three phases the Study highlighted the sources of risk, the risk holders, the magnitude of the risk, the probability that default can occur and the resulting risk adjusted exposure of the Government. The risk adjusted exposure is equal to the maximum size of the liability (as identified in section 3) adjusted by the likelihood of default of the liable entity.

133. Key findings of this section are:

- During construction the decommissioning[6] risk holder is either the developer or the EPC contractor. The Government's risk adjusted exposure to default during construction is relatively low because installations are unlikely to be abandoned at such an early stage and the probability of default of the liable entities over their liabilities is also low, given the financial profiles of the companies that have been awarded Crown Estate leases and the short period of time over which their financial profiles could erode.
- Risk of default during the operation phase relates to technology risk (the risk that the technology does not perform as expected) and financial risk (the risk that revenues are lower than expected because of falling green power prices). Financial default could occur if decommissioning costs are larger than future cash generated by the plant. However, if offshore wind is successfully financed it is expected that an installation would be able to cover the cost of decommissioning at every point in the life of the plant. Even near the end of life, when the difference between the present value of future cash flows and decommissioning costs shrinks, the offshore wind farm operating margins would be large enough to cover decommissioning costs.
- Default would be more likely because of technology risk. A rate of technical default that is beyond the asset owner's expectations would reduce the operating margins of the installation and thus future revenues.
- The risk during the decommissioning phase is primarily related to an unexpected increase in decommissioning costs such that the installations are unable to fund decommissioning. The risk adjusted exposure to the Government would increase proportionally with such an increase and be dependent upon the credit rating of the developer.

[6] The authors are aware that the term 'decommissioning' implies an installation must first be 'commissioned' (operations must begin). However, for the purposes of simplicity, decommissioning here refers both to installations that have already been commissioned and those that have not yet been commissioned.

- The proportion of decommissioning cost that could be borne by the Government depends on the probability of insolvency of the asset owner. This cost could vary widely depending upon the credit rating of the developer. Developers that are currently involved in Round One and Round Two typically have very solid credit ratings suggesting that the cost to the Government would be minimized. However, there are two factors that can substantially jeopardise the credit rating of the developer and thus increase the risk adjusted exposure to the Government; (i) the company operating the offshore wind farm is usually a limited liability company with limited recourse on the utility's assets and potentially with a different credit rating from the parent company; (ii) assets can be sold over the lifetime of the installation and the new owner can potentially have a different and lower rating than that of the initial owner.
- Uncertainty over decommissioning costs and the possibility of asset transfer to less creditworthy companies suggest that the use of a financial security would be appropriate to safeguard the Government against decommissioning liabilities.
- Marine devices should be treated separately from offshore wind because they are currently in the pre-commercial phase. However, once commercial marine devices become available there should be no impediment to addressing their decommissioning liabilities in the same manner as offshore wind.

4.2. Construction Phase

4.2.1. Circumstances of default during construction

134. Default during construction might occur if the installation cannot be completed because of technical difficulties or construction cost overrun. Default occurs if the risk holder goes bankrupt and defaults on decommissioning liabilities and there is no remaining asset for another party to buy and continue construction.

Risk holders

135. There are two categories of risk holder: the developer and the EPC contractor. The risk that either party bears will depend upon the nature of the contractual arrangements for the construction process. Early offshore wind development is likely to see the developer manage construction via a multi-contract arrangement with several contractors and to be responsible for removing any incomplete construction. However, as the sector expands and matures, construction under turnkey contracts is expected to become more common practice.

136. In the event that the project developer is responsible for starting and testing the installation, the responsibility for decommissioning, in the case of failure during construction, is with the developer. In contrast, the EPC contractor, under a typical turnkey contract structure, is responsible for delivering a fully operational facility by an agreed deadline, compliant with certain operating standards and at a fixed price. If the EPC contractor does not deliver according to the agreed terms, it will be financially responsible for providing compensation to the developer, including the cost of removing the installation.

Source of risk

137. As pointed out during the Contact Programme, the most relevant source of risk during construction is geological or geotechnical risk. This risk refers to the circumstances resulting from insufficient site investigation, in which the location proves to be inadequate to support the foundations of an offshore device. However, it is extremely unlikely that this event could trigger the abandonment of construction. Rather, it is probable that some devices would be moved to another location. For the same reason it is unlikely that an installation would be abandoned despite an increase in construction cost or delays.

4.2.2. Cost of default during the construction phase

138. To provide a reference example of the potential cost to the Government in the event of default during construction, the Study looked at the construction of the largest Round Two installation, consisting of 286 turbines for an installed capacity of approximately 900 MW. In case of abandonment, assuming that the total decommissioning cost has to be incurred, the size of the liability would be £36 million. The risk adjusted exposure to the Government on this specific project would be equal to the total size of the liability, adjusted by the probability of default of the developer.

Probability of default

139. A method of appraising the probability of default of the liable entity is to look at its credit rating. Credit ratings are publicly available data that serve as a measure of a company's ability to honour its financial obligations. They therefore provide a useful proxy for the probability of default on financial obligations such as decommissioning. Historical default probabilities, published by credit rating agencies such as Fitch (similar ratings are provided by other agencies), are reported in the table below.

Table 2 Average cumulative default rates: 1990–2004.

Credit rating	Historical default
AAA	**0%**
AA	**0.07%**
A	**0.63%**
BBB	**3.45%**
B	**5.47%**
CCC to C	**31.63%**
All corporate bonds	**2.16%**

(Source: Fitch Ratings Global Corporate Finance 2004 Transition and Default Study)

140. The Crown Estate required prospective developers to bid in a competitive tender process for Round Two offshore leases. The highest bid was favoured for site approval, assuming that other requirements, such as a minimum level of financial strength, were satisfied. Developers that have been awarded licenses in Round One and Two are mostly utility companies with a credit rating of BBB and above.

Government's risk adjusted exposure to decommissioning liabilities

141. In order to calculate the risk adjusted exposure to the Government, decommissioning cost has to be adjusted by the probability of default of the developer. Assuming that the company would have a low credit rating, such as BBB (this is the lowest credit rating

observed amongst rated utilities bidding in Round Two), the associated probability of default would be approximately 3.45%. The resulting risk adjusted exposure to the Government would be £1.2 million or approximately £1300/MW.

142. Publicly available credit ratings do not exist for most offshore EPC contractors. However, as interviewees pointed out in the Contact Programme, turnkey contracts are very expensive and companies would look only at financially solid EPC contractors to bear construction risk. Finally, in the case of default of the EPC contractor, the developer would still be liable for removing a partially built installation. Hence from the Government's perspective, the creditworthiness of the developer remains the critical concern.

Financial securities are not required for construction phase

143. The Government's risk adjusted exposure to default during construction is relatively low because installations are unlikely to be abandoned at such an early stage and the probability of default of the liable entities over their liabilities is also low, given the financial profiles of the companies that have been awarded Crown Estate leases and the short period of time over which their financial profiles could erode.

144. Offshore projects will undergo considerable site surveys and preparation prior to installation. Any major problems encountered during construction would therefore tend to result from inadequate surveying work, but given the experience and skills-base in this area, it is very unlikely that more than a small portion of an offshore development would be affected. Historical experience from offshore sectors indicates construction difficulties are unlikely to occur.

145. Finally, standard construction insurance contracts entered into by project developers and/or EPC contractors would protect the developer against acts of 'force majeure', and could cover problems arising from 'defective' design. Insurance pay-outs would also normally cover debt repayments and lost revenues further decreasing the risk of default of the developer.

4.3. Operation Phase

4.3.1. Circumstances of default during operation phase

146. Risk of default during the operation phase of an OREI[7] relates to financial risk (the risk that revenues are lower than expected because of falling green power prices) and technology risk (the risk that the technology does not perform as expected).

Financial risk

147. Financial risk varies during the operation phase and depends upon the financing structure. It is minimal during the first 10-15 years of the life of the plant, during which time debt is paid down, Power Purchase Agreements (PPAs) are in place to match the tenor of the debt, and revenues are supported by ROCs. Given that the lifetime of the installation is 20 years

[7] For the purposes of this analysis, the Study assumed that the useful lifetime of an offshore wind farm is 20 years. This assumption is consistent with the lifetime assumed by debt and equity investors when valuing an investment. This is relevant in the case of default since assets cannot be used as collateral when their value, at the end of life of the installation, is close to zero.

(if not more), by the end of life of the plant financial risk increases because of exposure to the variability of electricity prices and uncertainty over the existence of ROCs (currently guaranteed till 2027).

Technology risk

148. There are two types of technology risk: (i) systemic technology failure, being a general and fundamental failure of the technology of a specific provider; (ii) persistent minor failure that erodes revenues because of lower output and/or higher than expected operating costs.

149. The Contact Programme revealed that it is likely that a number of the major components (such as gearboxes, generators and transformers) will fail during the operation of offshore renewable devices and require repair or replacement. In some cases this may occur more than once. However, the chances of systemic technology failure are considered very low, because offshore turbine suppliers are major companies with considerable experience of onshore wind turbine design. The challenges associated with the marine environment are expected to cause an increase of technical failures rather than a systemic failure.

150. Since long term statistics on technical failure of offshore wind farms are not available, the Study estimated failure rates based on the recorded failure statistics for operating onshore wind farms. The failure rates represent the chance of a turbine experiencing a fault in any of its components each year (i.e. of 100 turbines, with a 3% fault rate for gearboxes, three turbines would be expected to develop gearbox faults each year). In order to account for the more difficult and aggressive marine environment, which might make failure rates higher than for onshore wind, it has been assumed that the total probability of failure is the summation of each individual event and 87% of the full cost of installation would be incurred to repair a failure.

151. Table 3 estimates that, on average, an offshore wind farm could incur a failure rate of approximately 17% per year. The associated cost of repair has been estimated to be equal to £43/kW, based on total equipment cost of £520/KW, installation cost of £286/KW and cost of the single components provided by the industry within the Contact Programme.

Table 3 Estimated technical failure rates and costs of repair for offshore wind

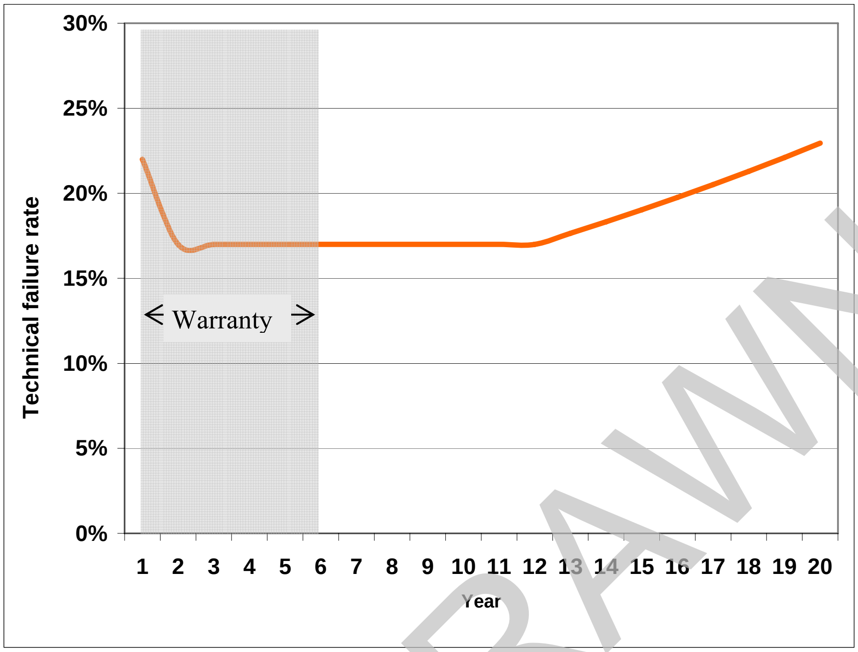
	£/kW	Failure rate per turbine
Equipment Cost (£/kW)	**520**	
Installation Cost (£/kW)	**286**	
TOWER		0.4%
GEARBOX		3.0%
GENERATOR		9.0%
MAIN SHAFT		1.3%
TRANSFORMER		1.4%
ROTOR		2.0%
TOTAL PROBABILITY OF TECHNICAL FAILURE	**17%**	
ESTIMATED MAINTENANCE COST (£/kW)	**43.4**	

(Source: CCC and Contact Programme)

152. Over the lifetime of the plant, the rate of technical failure is expected to have a 'bath-tub' profile (Figure 7). It is expected to be highest in the initial stages of operation, when it has been assumed that a technology provider warranty is in place (usually for the first 5 years), such that the developer would not incur any repair costs for this period. A 17% failure rate then holds for the first years of an onshore project's lifetime, after which time it rises

linearly to 23% by Year 20. This latter rise coincides with financial risk as the ROC period ends and uncertainty about green power prices increases.

Figure 7 Estimated failure rate profile for offshore wind



(Source: CCC and Contact Programme)

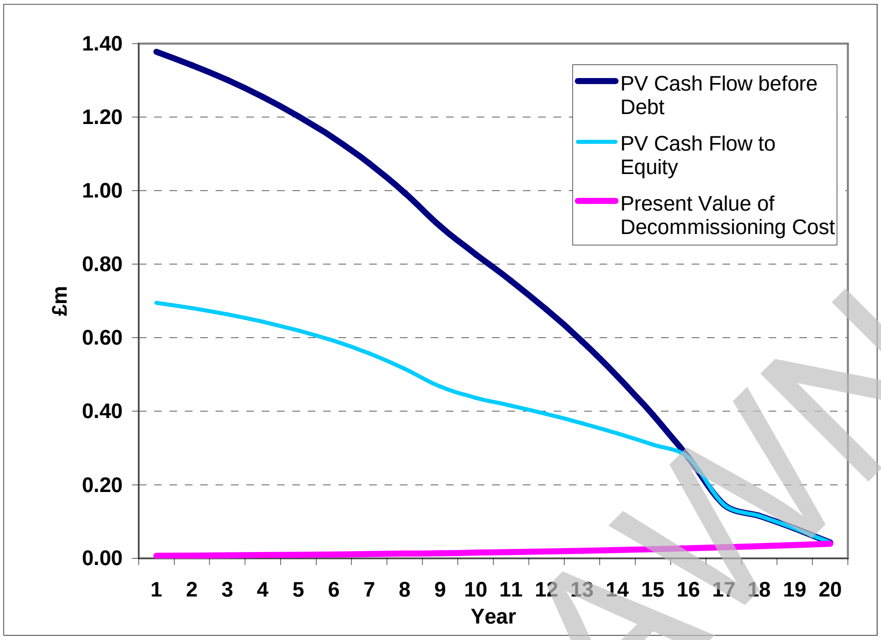
Financial default

153. Default refers to the instance in which cash flows generated by the plant decline and the installation defaults on its decommissioning obligations. This circumstance could be triggered by a revenue reduction (collapse in power and/or ROC prices) that reduces the cash flows generated by the installation.

154. To illustrate this situation the Study looked at a hypothetical offshore wind farm whose physical characteristics, financing and market conditions are reported in Appendix C. The Study appraised the offshore installation owner's ability to cover decommissioning costs based on the difference between expected future cash flows and expected decommissioning costs. Since decommissioning costs are expected to be paid after debt, both the cash before and after debt service is reported. Default could occur if decommissioning costs are larger than future cash generated by the plant. As reported in Figure 8, based on the assumption of a 20-year life time, the hypothetical installation would be able to cover the cost of decommissioning at every point in the lifetime of the plant.

155. By the end of life, the difference between the present value of future cash flows and decommissioning costs shrinks, but even under these conditions the offshore wind farm operating margins would be large enough to cover decommissioning costs.

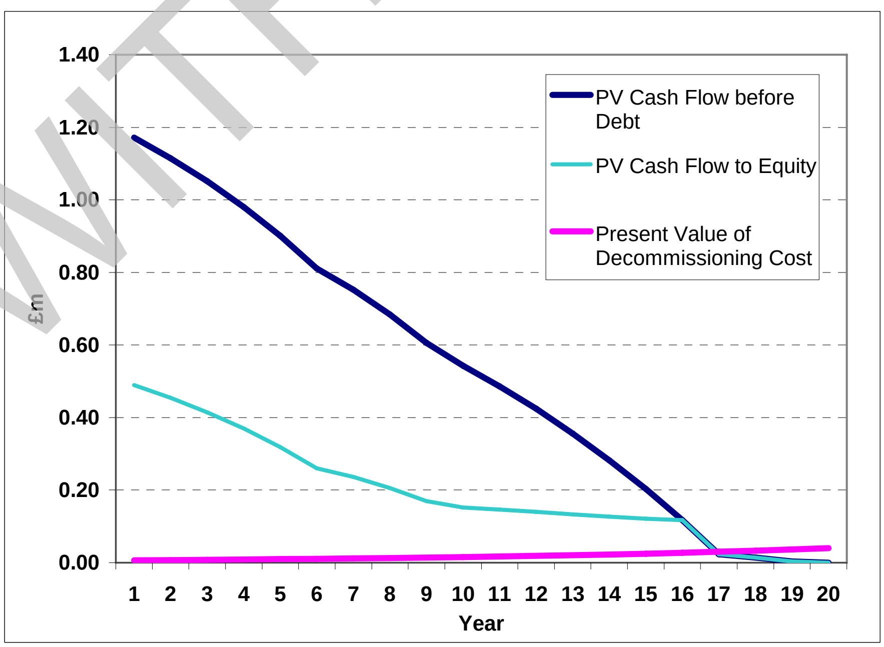
Figure 8 Present value of future cash flows and future decommissioning costs



Technical default

The Study carried out the same analysis performed in Figure 8, but it included the additional costs derived from assuming a 17% annual technical failure rate. Under these circumstances, an operator would take the decision not to repair any damaged devices if the cost of repairing is higher than the corresponding loss of revenues. The installation would continue to operate at a lower output and would begin to accumulate failed devices that are uneconomic to repair.

Figure 9 Present value of future cash flows and future decommissioning costs in the event of technical failure



156. Technical failure would reduce the operating margins of the installation and thus the expectations about future revenues. Under this scenario, revenues would be further reduced because of technical failures that are uneconomical to repair and the event of revenues being insufficient to cover decommissioning costs would be more likely.

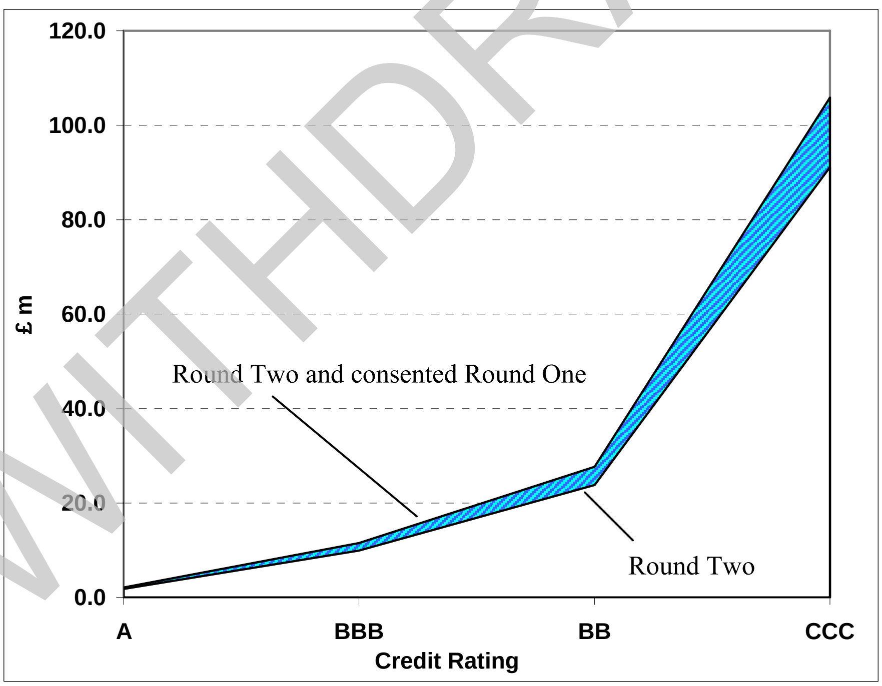
4.3.2. Cost of default during the operation phase

157. To quantify the Government's risk-adjusted exposure to default on decommissioning liabilities during the operational phase of an offshore asset, the Study adopted the same credit ratings approach used to calculate the Government's exposure during the construction phase.

158. Estimates reported in Figure 10 are provided as a reference to compare the impact of the asset operator's creditworthiness on the Government's risk adjusted exposure, rather than to provide a precise estimate of the Government's exposure to decommissioning liabilities.

159. The magnitude of cost is calculated under different scenarios of offshore wind capacity, based on the assumption that the full decommissioning cost is defaulted since no financial securities are in place. The upper line in each scenario corresponds to construction of all consented Round One and all Round Two wind farms (8.4 GW) and the lower line to all Round Two consented capacity alone (7.2GW).

Figure 10 Risk adjusted cost to the Government under different scenarios of offshore wind capacity and developer credit ratings



160. The cost to the Government is related to the probability of insolvency of the developer. This cost could vary anywhere between a few £ millions and more than £100 million (in the case of a high rate of insolvency).

161. To determine the credit rating of the developer is not a straightforward task. Credit ratings of utilities that build Round One and Round Two projects are solid (they vary between AAA and A-, with only one utility having a BBB rating). Under this scenario the risk

adjusted cost to the Government would be lower. However, a few factors could increase this risk:

- The company operating the offshore wind farm is usually a limited liability company with limited recourse on the utility's assets. The credit rating of the SPV is therefore not necessarily the same as that of the parent company.
- Assets can be sold over the lifetime of the installation and the new owner can potentially have a different and lower rating than that of the initial owner.

4.4. Decommissioning Phase

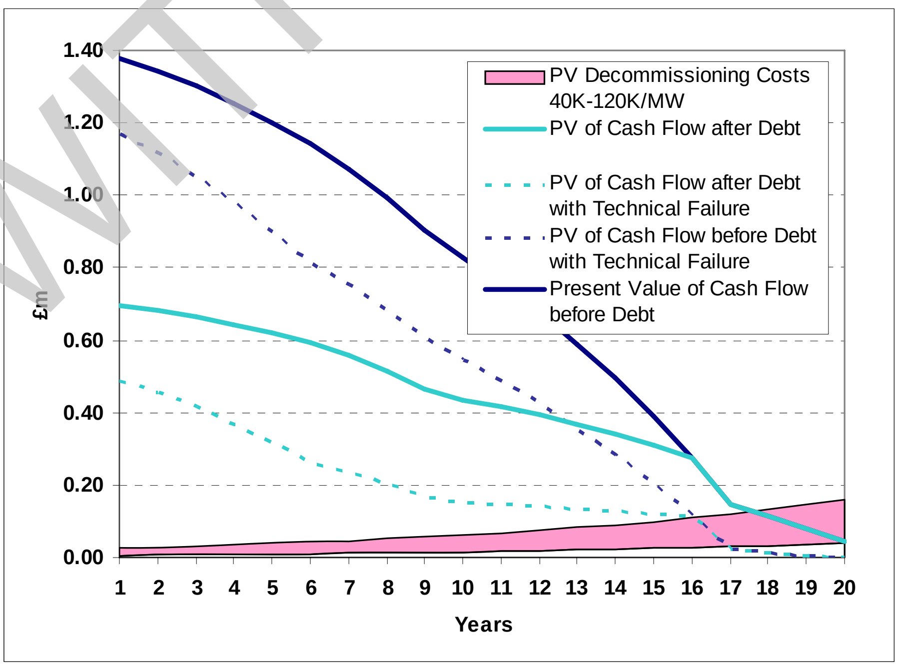
4.4.1. Circumstances of default during the decommissioning phase

162. The risk of default during the decommissioning period relates to the fact that real decommissioning costs are higher than expected and the asset owner does not have enough funds to cover the entire cost.

163. Lack of experience in decommissioning offshore renewable installations increases the risk that developers are unable to provide a fair valuation of decommissioning costs (see paragraph 3.3). This risk increases further because developers might have an incentive to underestimate decommissioning cost in order to reduce the size of their liability. Finally experience in the offshore oil and gas sector and in the nuclear sector (somewhat less relevant) suggests that decommissioning cost can increase substantially beyond initial estimates.

164. The larger the increase in decommissioning costs, the higher the probability of default. Figure 11 shows how an increase in decommissioning cost could cause default earlier during the lifetime of an installation. The impact of the increase in decommissioning cost is even more relevant if technical risk is factored in as well.

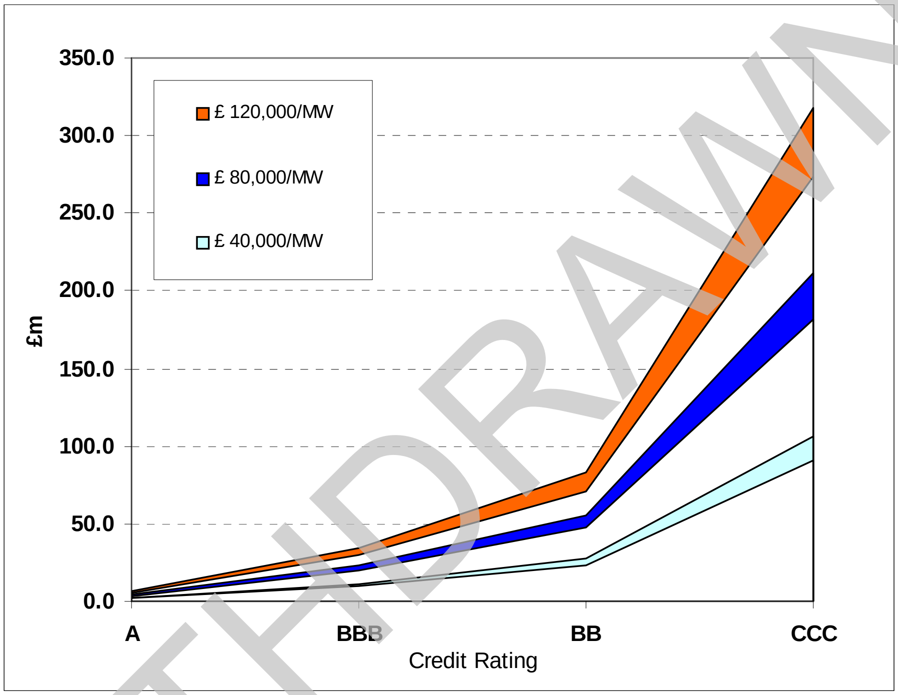
Figure 11 Present value of future cash flows and future decommissioning costs in the event of unforeseen increase in decommissioning costs



4.4.2. Cost of default during the decommissioning

165. To analyse how the risk adjusted exposure of the Government would be affected by an increase in decommissioning costs, the Study looked at different scenarios of unit decommissioning costs under different offshore wind capacity and developer credit ratings. An increase in decommissioning cost would most probably be realised when the decommissioning plan is actually executed. In the case of default, the Government's risk adjusted exposure would increase proportionately (Figure 13) and be dependent upon the creditworthiness of the developer.

Figure 12 Risk adjusted cost to the Government under different scenarios of offshore wind capacity, credit rating of the developer and decommissioning costs



(Upper line of each scenario represents all Round Two and consented Round One wind farms, the lower line represents all Round Two alone)

4.4.3. The need for financial securities

166. As noted in the previous analysis, an offshore wind installation will probably be able to cover decommissioning costs given the wide operating margins that characterise the industry (high capital costs but very low operating costs). As noted previously, the financial viability of offshore wind is not a major concern with regards decommissioning, since it is reasonable to assume that if the installed capacity of offshore wind reached the target of 7-8GW, it would be because the investment community perceives the sector as profitable and performs due diligence to secure that market risks (PPA and ROCs) are minimized.

167. However, notwithstanding these considerations, a few critical factors suggest that a financial security that does not impose a significant burden on the sector would be advisable to manage the size and uncertainty of the risk adjusted exposure to the Government:

Uncertainty of technology performance

168. As reported in Figure 9 and confirmed in the Contact Programme, technical failure during the last years of operation is a relevant source of risk. Typically, estimates of the cash flows generated by offshore wind farms are based on a technology performance that is uncertain. Early experience from offshore wind farms shows that the technical failure rate is high, although expected to decline with time. The difficulty of the marine environment reduces performance and makes maintenance slow and expensive. Revenue losses because technology does not perform as expected could increase beyond the asset owner's worst case scenario, exposing the Government to unforeseen liabilities. In addition, at this stage there are only few companies providing wind turbines, hence the risk that the technology underperforms could be spread across a number of installations simultaneously.

Asymmetric information

169. The Government's risk adjusted exposure is very dependent on the magnitude of decommissioning costs (Figure 11 and Figure 12). Estimates of those costs have been provided by the industry during the course of the Contact Programme. However, there is an incentive for developers to underestimate these costs. As a consequence the real size of the decommissioning liability and the risk adjusted exposure to the Government is uncertain and will only be resolved once installations start to be decommissioned.

Asset Transfer

170. Figure 10 and Figure 12 show how the risk adjusted exposure of the Government is dependent upon the creditworthiness (i.e. credit rating) of the asset owner. Companies that are sponsoring offshore wind development at this stage are financially solid companies. However, in 20 year's time, assets might have been transferred to smaller companies with balance sheets that are not so robust and that are less concerned about the reputational impact of default. A financial security may therefore be required to ensure the risk of default to which the Government is exposed does not escalate under conditions of trade of offshore assets.

4.5. Default of Marine Technologies

171. The development of marine technologies, which are still at a pre-commercial stage (with perhaps one or two very limited exceptions), is very uncertain, both in terms of the type and scale of marine devices and the extent of their future deployment. Decommissioning cost estimates obtained from the Contact Programme fell in the range of £25,000-100,000/MW. This generates a decommissioning cost range for 1-2.5 GW of marine capacity by 2020 of £25-250 million (Figure 5).

172. Thus our research indicates that decommissioning costs for pre-commercial marine devices are likely to be, on an average per MW basis, higher than for offshore wind farms. These costs will probably fall as marine devices become commercialised and the scale of deployment increases, although they will vary considerably depending upon the number and type of offshore marine devices that become commercialised.

173. The Study is unable to provide estimates of default rates over the lifetimes of the projects (and therefore the Government's risk adjusted exposure), given the lack of data regarding technical failure rates and developer company credit ratings. However, we would expect them to be higher on a like-for-like basis than for offshore wind, particularly while marine technologies are still at a very early stage of development.

174. However, once marine technologies have reached the fully commercial stage, they should be required to provide the same level of financial security for decommissioning as offshore wind.

5. Analysis of Financial Securities

5.1. Summary

175. The Study looked at financial securities potentially available to reduce the Government's exposure to default on OREI decommissioning liabilities. The Study looked both at the financial securities mentioned in the Energy Act 2004 and to additional securities used in other sectors.

176. Key findings of this section are:

- The Government could require the establishment of a decommissioning fund that accrues early or late into the life of the installation, accruing slowly or quickly. Different decommissioning fund schemes have only a limited impact upon the investors' return and thus would have a minor effect on the development of the technology. However, the Study acknowledges the fact that offshore wind is already financed on tight margins and even small changes to investor's returns could have a significant impact upon investment decisions. For this reason, the Study focused the analysis on four decommissioning fund schemes (Figure 13): Scheme I Continuous Accrual, Scheme IV Intermediate Accrual, Scheme V Middle Life Accrual and Scheme VI Late Accelerated Accrual, characterized by their minimal impact upon equity returns.
- Depending on the level of risk the Government is prepared to accept, a scheme in which accruals start by the mid life of an installation would be our recommended form of security, offering risk mitigation to the Government at a contained cost to industry. Other schemes, such as a Continuous Accrual Scheme (Scheme I) and an Intermediate Accrual (Scheme IV), would significantly reduce the risk to the Government of default on decommissioning liabilities but at some cost to the industry. A Late Accrual scheme accruing during the last years of operation would in contrast be very inexpensive, but would not significantly reduce the Government's risk adjusted exposure.
- Decommissioning fund schemes would provide some insulation to the Government from an increase in decommissioning costs depending upon how early in the project lifetime cash is accrued. The most important aspect of a fund would be to provide a defined mechanism by which decommissioning payments could be obtained from OREI owners. The earlier and the longer payments are made, the better the insulation provided to Government.
- To further protect against this risk, the Government might also require periodic review of the fund payments to verify they are sufficient to cover expected decommissioning costs. However, this would be of little benefit if the increase in costs is only identified when experience of decommissioning accumulates.
- A decommissioning fund would provide limited protection in the case of systemic technical failure across a range of offshore installations, although the likelihood of this occurring, given current experience in onshore wind, is thought to be low.
- Other securities mentioned in the Energy Act 2004, such as letters of credit, parent company guarantees and bonds, all have specific disadvantages. Main concerns include; (i) the tenor of the instrument does not match the tenor of the decommissioning liability, thus providing only partial coverage; (ii) some instruments, such as bonds, are not presently available or affordable for offshore wind; (iii) other instruments, such as parent

company guarantees, would require the Government to assess periodically the viability of the instruments and would not provide certainty.

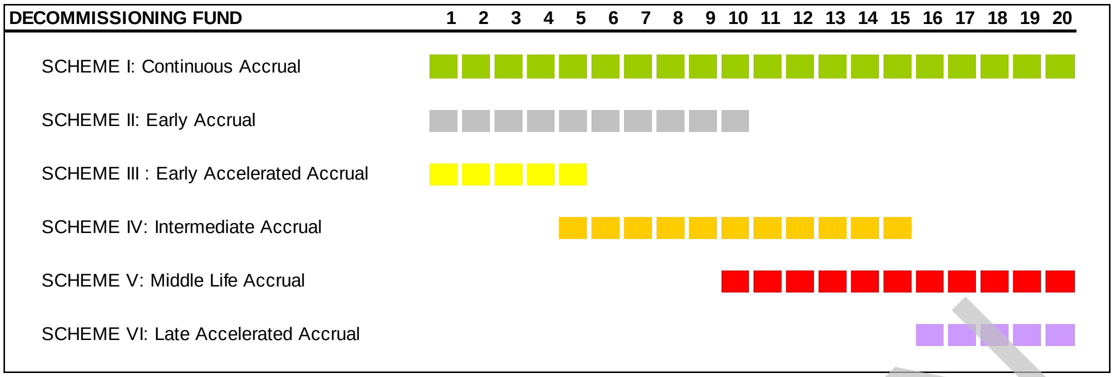
- A collective scheme could be designed to cover only the risk of that portion of companies that are likely to default, thereby minimising the cost to industry. The quantification of this risk is not straightforward and poses some significant challenges. A collective scheme would also not provide insulation in the case of an increase in decommissioning costs, leaving the Government with a potential liability whose magnitude is uncertain. Finally a collective scheme could encourage ‘free-riding’ amongst its participants and is therefore unlikely to gain widespread acceptance from the offshore industry.
- An insurance scheme as a stand alone security would be unable to mitigate the risk of default. The Contact Programme revealed that the main factors limiting the use of insurance schemes are the tenor of the liability, the uncertainty of the technology and the unclear nature of decommissioning cost and timing.
- Tax incentives on fund payments would make a decommissioning fund scheme more attractive to developers. Additionally tax incentives could be offered on any capital expenditures aiming to prolong the lifetime of the installation. OREIs often have a nominal lifetime of 20 years, which according to technology providers could be extended significantly.
- Marine technologies would at present struggle with the provision of any financial securities, because of uncertain revenues at the pre-commercial, demonstration stage and because the lifetime of these devices is shorter than, and in some case incompatible with, the tenor of an affordable decommissioning fund. The cost of marine decommissioning might therefore need to be ring-fenced as a condition of any grants or further support from Government. However, future commercial marine devices may reasonably be expected to provide the same level of security as commercial offshore wind devices.

5.2. Decommissioning Funds

177. Decommissioning funds have been used in other countries aswell as the UK to provide security against environmental and decommissioning liabilities. In the nuclear industry, payments into the Nuclear Liabilities Fund are required from BE (the UK’s sole private owner/operator of nuclear assets) to cover decommissioning costs as well as certain other nuclear liabilities. Payments are annual and based on the revenues produced by the installation. At the international level, the Netherlands requires that offshore owners/operators must pay monies into a segregated decommissioning fund for a minimum of 10 years, starting from the first year of operation of the project. The US Environmental Protection Agency Brownfield Superfund requires operators to set aside monies through annual payments into a fund in order to accrue clean-up costs.

178. In a similar fashion, the UK Government could require the establishment of a decommissioning fund that accrues continuously over the whole lifetime of an OREI installation. Alternatively it could require funds to be set aside early or late into the life of the installation, accruing either slowly or quickly. In this section, the Study appraised the effectiveness of different decommissioning fund schemes (reported in Figure 13) to mitigate the risks identified in Section 4.

Figure 13 Decommissioning fund schemes



179. Sensitivity analysis of the impact of different decommissioning fund schemes on the return to equity investors is shown in Table 4 (based upon an offshore wind farm with characteristics as described in Appendix C). This analysis shows that the choice of different decommissioning fund schemes has only a limited impact upon the investor's returns and thus would have a minor effect on the development of the technology. However, the Study acknowledges the fact that offshore wind is already financed on tight margins and even small changes to returns can have a significant impact upon investment decisions. For this reason, the Study focused the analysis on four decommissioning fund schemes (Scheme I, IV, V and VI) characterized by their minimal impact upon equity returns.

Table 4 Impact of different decommissioning fund schemes on annual IRR to equity

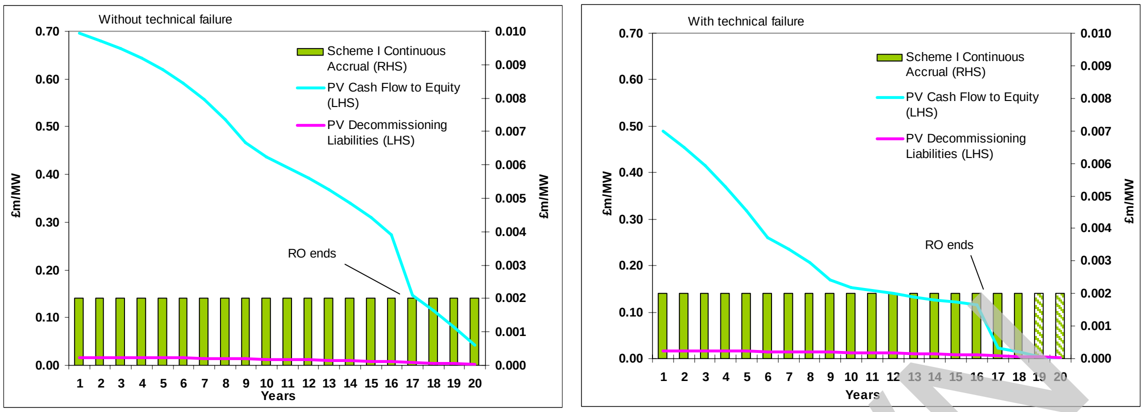
	Scheme I	**Scheme II**	**Scheme III**	**Scheme IV**	**Scheme V**	**Scheme VI**
No Fund	Continuous Accrual	Early Accrual	Early Accelerated Accrual	Intermediate Accrual	Middle Life Accrual	Late Accelerated Accrual
10.56%	10.33%	10.16%	10.03%	10.33%	10.48%	10.53%

180. Each of the selected schemes has been appraised on the basis of their effectiveness in providing security against default on decommissioning, and on the impact that the security might have upon the future development of the industry. The developer could default on decommissioning payments into the fund, making the security ineffective, if the cost of outstanding decommissioning obligations is larger than the installation's future expected cash flows, after debt is serviced. In general terms, a scheme that requires a decommissioning fund to be accrued during the early years of operation would significantly reduce the risk of default on the payment into the decommissioning fund, but would have a larger financial impact upon the sector.

Scheme I: Continuous Accrual into a decommissioning fund

181. In a continuous accrual scheme, payments into a decommissioning fund would be made for the whole life of the installation. The ability of the asset owner to pay into a continuous accrual scheme has been analysed both assuming that the technology will perform as expected and including technical failure (Figure 14).

Figure 14 Scheme I: Continuous Accrual – Remaining decommissioning liabilities



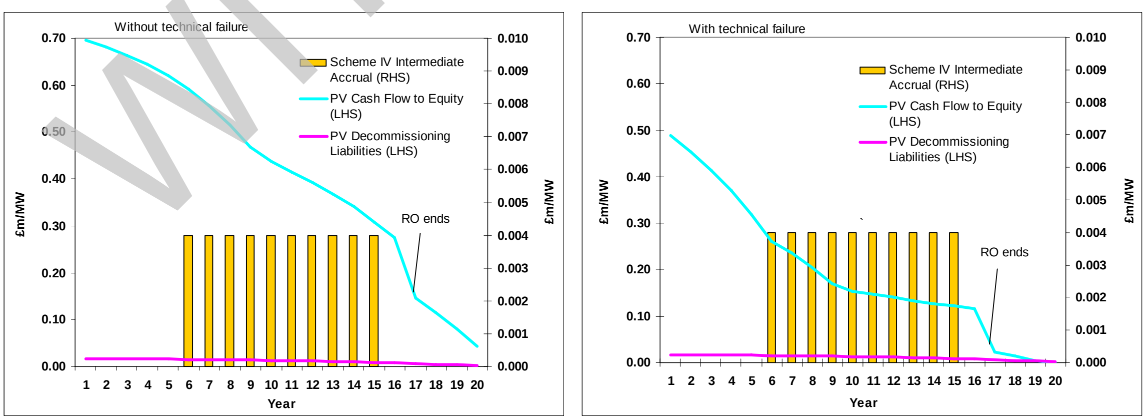
182. Figure 14 shows the present value of future cash flows to equity investors (after debt is serviced), with and without a high technical failure rate. Even after the period of the PPA expires and the ROCs support may end, the present value of cash flows with technical failure exceeds the present value of decommissioning liabilities. Thus the offshore wind farm would continue to operate and payments into a continuous accrual scheme would continue to be made. However, the final two payments in the event of technical failure (shaded bars in right graph of Figure 14) would be lost under the hypothetical scenario developed.

183. The Study applied this analysis to the hypothetical offshore wind farm described in Appendix C. Default would be on the last two payments into the decommissioning fund. The magnitude of defaulted payments in case of insolvency of the owner would therefore be £4,000/MW (i.e. 10% of the total decommissioning cost).

Scheme IV: Intermediate Accrual into a decommissioning fund

184. This scheme is designed to account for the fact that the technology is most likely to be guaranteed during the first 3-5 years of operation, and so the risk of technology default is mostly mitigated during this period.

Figure 15 Scheme IV: Intermediate Accrual – Remaining decommissioning liabilities



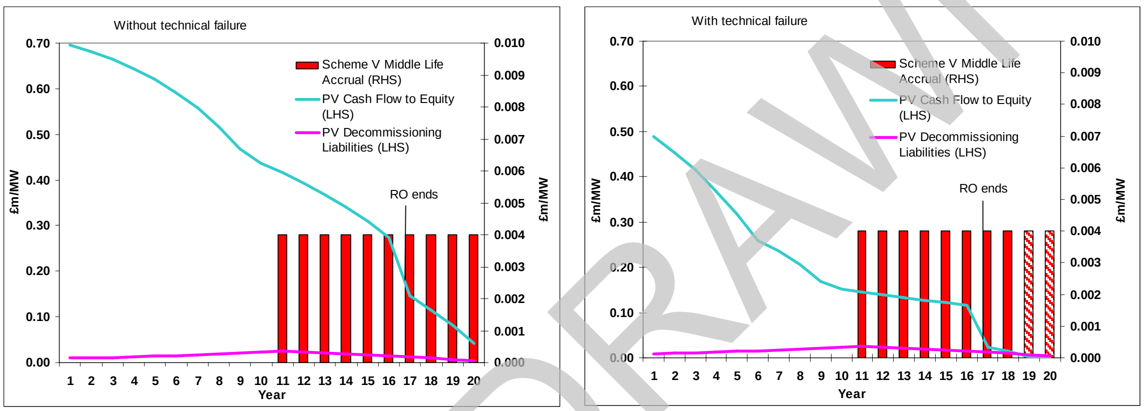
185. This scheme would expose the Government to virtually zero risk of default on decommissioning, since payments are made during the early operational phase when the installation's revenues are high enough to cover decommissioning costs. The owner would

not default on decommissioning payments even when technology risk is accounted for. The scheme also gives time for additional funds to be accrued in the event of foreseen decommissioning cost increases. The down side with this scheme is that the decommissioning fund is accrued several years before the decommissioning plan has to be executed, and is therefore relatively inefficient in terms of use of capital.

Scheme V: Middle Life Accrual into a decommissioning fund

186. This scheme is designed to account for the fact that the technology is most likely to be guaranteed during the first 3-5 years of operation, and so the risk of default is partially mitigated during the first half of the life of the plant. In addition, delaying payments into the decommissioning fund would reduce the burden to the developer, especially in the event that debt needs to be serviced for the first 10-15 years of operation.

Figure 16 Scheme V: Middle Life Accrual – Remaining decommissioning liabilities



187. Even under a decommissioning fund scheme in which accruals begin in the middle of the installation's life, the owner is very unlikely to default on decommissioning costs because of financial risk. If technology risk is included in the analysis, the installation is more financially vulnerable and the owner could default on the last payments into the decommissioning fund (shaded bars in Figure 16).

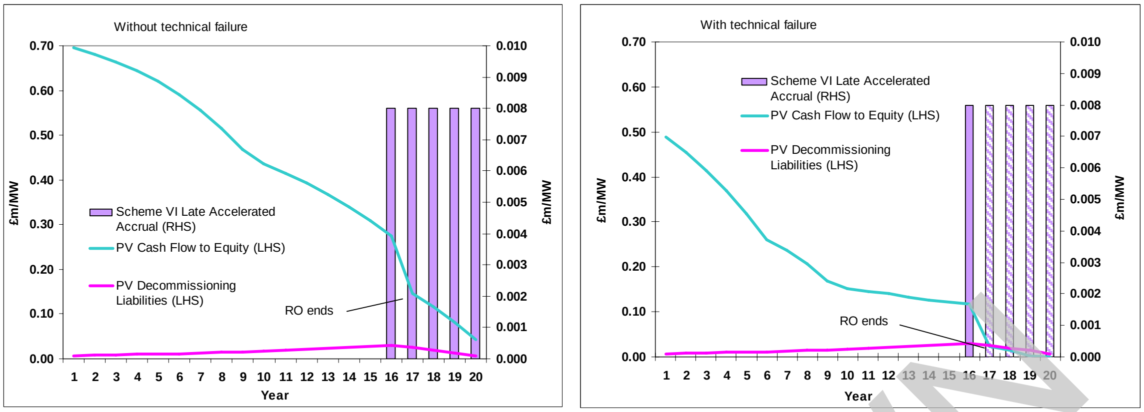
188. The magnitude of defaulted payments into the decommissioning fund in this case is larger. Because the accrual period is shorter, the size of the annual payment is larger, and if those payments are delayed till the end of life, they increase the portion of the decommissioning fund that could potentially be defaulted.

189. The Study applied this analysis to the hypothetical offshore wind farm described in Appendix C. Default would be on the last two payments. The magnitude of defaulted payments in case of insolvency of the owner would be £8,000/MW (i.e. 20% of the total decommissioning cost).

Scheme VI Late accelerated accrual into the decommissioning fund

190. This scheme would require the developer to build the decommissioning fund only during the last 5 years of operation. The rationale behind such a scheme is that, based on the revenues generated by the offshore wind farm, the developer would be able to cover the cost of decommissioning by relying solely on the cash generated during the last 5 years of operation (Figure 17 left). However, if technology risk is included in the analysis, the risk of default increases significantly.

Figure 17 Scheme VI: Late Accelerated Accrual – Remaining decommissioning liabilities



191. The magnitude of the defaulted payments into the decommissioning fund is larger because the accrual period is very short, and the amount paid annually into the decommissioning fund is larger and concentrated in the last years of operation, when the amount of cash generated by the installation is smaller and more uncertain.

192. We applied this situation to the hypothetical offshore wind farm described in Appendix C. Default would be on the last four payments into the decommissioning fund. The magnitude of defaulted payments in case of insolvency of the owner would be £32,000/MW (i.e. 80% of the total decommissioning cost).

5.2.1. Appraisal of decommissioning fund mechanisms

193. The Study appraised the extent to which a decommissioning fund would encourage and facilitate the development of the offshore renewable energy industry while providing appropriate safeguards against the possible absence of funds to cover decommissioning.

General applicability to commercial offshore wind technologies

194. As shown in Table 4, a decommissioning fund that builds over the whole life of an installation, or is delayed towards the end, has a limited impact upon equity returns. The Study acknowledges that offshore wind is already financed on tight margins and a small variation in returns can compromise the financial viability of an investment. For this reason, only four decommissioning fund schemes have been considered for further screening, being those with only minimal impacts upon equity returns.

195. The cost of decommissioning is expected to be in the order of 2-3% (undiscounted) of the initial capital cost. Thus decommissioning cost is not expected to be a 'deal-breaker'. This result is consistent with information gained from the Contact Programme, where equity investors stated that decommissioning costs would be factored into the initial investment decision and would not be a significant obstacle to capital flowing into offshore renewable developments.

Limited applicability to pre-commercial marine technologies

196. Marine technologies would at present struggle with any accrual schemes, because of a lack of revenues at the pre-commercial, demonstration stage and because the lifetime of these devices is shorter than, and in some case incompatible with the tenor of an affordable decommissioning fund. Very early stage commercial devices might also suffer due to

marginal profitability. The cost of marine decommissioning might therefore need to be ring-fenced as a condition of any grants or further support from Government.

197. However, future commercial marine devices may reasonably be expected to provide the same level of security as commercial offshore wind devices.

Quality and robustness

198. The mechanism of setting aside cash could be implemented via the establishment of a separate escrow account or trust fund for each project. The DTI or a bank could be the beneficiary of these accounts.

199. A decommissioning fund would also provide an effective way of enforcing transfer of the liability along with the asset, since decommissioning fund payments would be required from the new owner. In addition, since the trustee would be an entity distinct from the company, the decommissioning fund would be protected from administrators and investors in case of insolvency.

Transparency

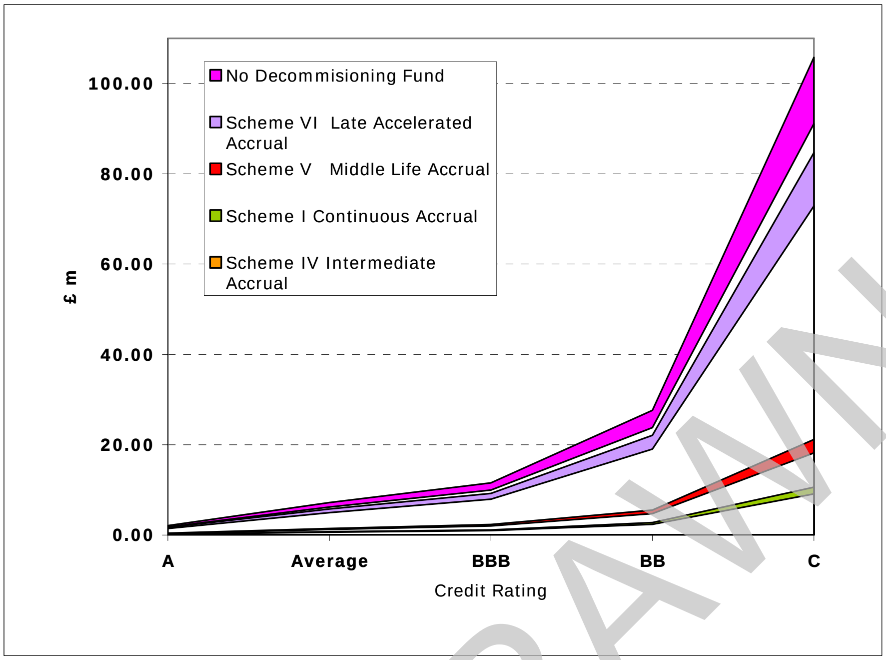
200. A cash fund is a transparent instrument that provides a clear indication of the residual liability to the Government over the lifetime of the whole portfolio of offshore renewable energy.

Cost in relation to risks covered

201. The Government has the option either to minimize its risk by passing costs sooner to the offshore wind sector (requiring early accruals) or to postpone the establishment of the decommissioning fund to the last years of operation, thereby increasing the Government's exposure.

202. Figure 18 summarizes the risk adjusted exposure to the Government under different decommissioning fund regimes, and under the same scenarios of company credit ratings and installed offshore wind capacity used previously. The upper line in each scenario corresponds to construction of all consented Round One and all Round Two wind farms (8.4 GW) and the lower line to all Round Two consented capacity alone (7.2GW).

Figure 18 Government's risk adjusted exposure under different decommissioning fund schemes



N.B. Scheme IV Intermediate Accrual does not appear in the Figure above because the Government's exposure is zero under the scenarios envisaged.

203. Figure 18 shows that both a continuous accrual scheme and a scheme in which accruals start during the middle of the life of an installation would significantly reduce the risk to the Government and the uncertainty of the magnitude of the risk. A late accrual scheme accruing during the last years of operation would not significantly reduce the Government's risk adjusted exposure. An intermediate accrual would almost entirely eliminate the risk of default but at some cost to the industry.

204. Table 5 below compares the range of potential cost of providing the financial security to the industry and the associated risk adjusted exposure to the Government. Figures are provided as a reference to compare different schemes with each other, rather than a precise estimate of costs.

205. The first column of Table 5 shows the present value of the decommissioning cost under the different decommissioning fund accrual schemes. The later payments are made into the decommissioning fund, the lower the cost to the developer. In the second column the impact of the decommissioning fund on returns to equity investors is reported. The case in which financial securities are not required is assumed as the reference case. The third and fourth columns compare the cost to the industry with the corresponding risk adjusted exposure to the Government. The last column provides a qualitative analysis of the decommissioning fund schemes' effectiveness in addressing an increase in decommissioning costs.

Table 5 Cost to the industry and residual risk adjusted exposure to the Government

	Industry			Government	
Scheme	PV Decommissioning fund	Impact on return to Investors	Cost to the industry (7.2-8.4GW)	Max risk-adjusted exposure (7.2-8.4GW)	Robustness against increase in decommissioning costs
No Fund	£6000/MW	-	£40-50m	£2-100m	LOW
Scheme I Continuous Accrual	£17,000/MW	30bps	£120-145m	£0-10m	MEDIUM
Scheme IV Intermediate Accrual	£15,000/MW	30bps	£110-130m	£0	MEDIUM
Scheme V Middle Life Accrual	£9,500/MW	10bps	£70-80m	£ 0-20m	MEDIUM/LOW
Scheme VI Late Accrual	£ 7,000/MW	5bps	£50-60m	£1-80m	LOW

100 basis points (bps)=1%

Efficiency of the use of capital

206. The main concern with segregated cash funds is that they do not provide an efficient use of capital. Concerns regarding the inefficient use of capital would be stronger when the accrual period is earlier (and quicker) in the life of the installation. In order to address this issue, the Study looked at the cost in present value terms of the different accrual schemes compared with the case in which no financial security is required (No fund case in Table 5). Schemes V and Scheme VI would be preferable in terms of the efficient use of capital since their cost, in present value terms, is only marginally higher than the base case in which no financial securities are provided. In addition, Scheme IV could be challenging to implement because the fund would completely accrue several years before decommissioning is due, though the same could be true of Scheme V and VI if the life of the installation is extended.

Increase in decommissioning cost

207. Decommissioning fund schemes would provide some insulation to the Government from an increase in decommissioning costs depending upon how early in the project lifetime cash is accrued. The most important aspect of a fund would be to provide a defined mechanism by which decommissioning payments could be obtained from OREI owners. The earlier and the longer payments are made, the better the insulation provided to Government, since payments would occur when expected revenues are high and the installation would be able to accommodate larger payments if necessary.

208. To further protect against this risk, the Government might also require periodic review of the fund payments to verify they are sufficient to cover expected decommissioning costs. However, this would be of little benefit if the increase in costs is only identified when experience of decommissioning accumulates, although fund payments for later projects would be able to respond to information acquired from earlier projects.

Tax implications

209. The Study assumed that decommissioning payments accumulate after tax, hence no tax benefit is provided to the developer. Inefficient tax treatment has been one of the causes of resistance to decommissioning funds encountered in the offshore oil and gas sector. HM

Treasury could make a decommissioning fund accrual scheme more acceptable to industry by making the payments allowable against tax, thus compensating for the reduction in investor's returns.

Systemic technical failure

210. Systemic technical failure relates to the fact that the number of commercial technology providers or equipment suppliers is small, and if a particular technology were to malfunction it may well affect more than one installation at any one time. This would be particularly true if the offshore renewables market develops very quickly.

211. In contrast, because of high capital costs in the offshore sector, there is an incentive to continuously deploy new technologies in order to decrease capital costs. Under these circumstances the technology would hardly provide confidence about its performance.

212. Financial securities would provide limited protection in the case of systemic failure. However, the likelihood of this occurring, given current experience in onshore wind, is thought to be low.

5.2.2. Middle life accrual is the preferred mechanism

213. Depending on the level of risk the Government is prepared to accept, the Study recommends the use of a decommissioning fund structured in a similar way to Scheme V. A decommissioning fund scheme that starts accruing in the second half of the life of the installation would reduce the risk adjusted exposure to the Government and would not impose an excessive burden upon the industry.

214. The asset owner would not have to pay into a fund during the first years of operation, when debt (if any) is serviced. Payments would also be spread over 10 years to minimise the exposure during the last years of operation when the installation is most vulnerable (because of obsolete technology and uncertainty on green power prices). The industry would have to bear an increase of decommissioning costs in present value terms, but this would have a limited impact upon the returns provided to equity investors.

215. This scheme would also be able to adjust to an increase in expected decommissioning costs. Firstly, by the time funds start accruing, the sector would have gained a better knowledge of decommissioning costs and the fund could be adjusted accordingly. Secondly, the Government could require a mid term review of the fund (after 5 years of accrual or more frequently) to verify its adequacy.

5.3. Collective Schemes

216. Collective schemes operate in certain industries where businesses working in the same sector face the same risks. However, this has typically been as a result of Government legislation; for example the UK's implementation of the ELV and WEEE Directives has arranged for collective (producer) responsibility, and a collective scheme is under discussion amongst landfill operators.

217. Companies that are part of an OREI collective scheme would pay an annual fee to provide partial coverage against default by any member(s) of the scheme on their decommissioning liabilities.

218. The problem with the former option is that stand-alone collective schemes might result in 'free-riding', where some developers do not adequately address the risks in their projects, or fail to take account of them in design and construction, because they know a pooled

decommissioning fund exists. Developers themselves expressed resistance to a collective scheme for this reason.

219. Free riding would stem from the fact that, by the end of a plant's life, the installation is more exposed to uncertainty over the revenue support mechanism, ageing of the plant and an increased technical failure rate. In addition, assets may have been transferred to smaller companies that are less concerned about the reputational impact of default. Companies would therefore be incentivised to rely excessively on the collective scheme, making this instrument ineffective.

220. Finally, a collective scheme would be designed to cover only the risk of that portion of companies that are likely to default, thereby minimising the cost to industry. The quantification of this risk is not straightforward and poses some significant challenges. In particular, in order to quantify the size of the collective scheme, the Government would need to quantify the creditworthiness of the participants in the scheme, monitor their creditworthiness for the whole life of the installations and review in the instance that assets are transferred.

221. However, the collective scheme would not provide insulation of risk to the Government in case of an increase in decommissioning costs. The instrument would also be relatively opaque and the Government would be left with a potential liability whose magnitude is uncertain over a long period.

5.4. Insurance Schemes

222. Insurance schemes could be used to insure against the uncertainty in the size of decommissioning costs (but not to cover the decommissioning liability itself which is a certain, not unexpected, event). Similar insurance schemes have been applied in the field of environmental liabilities, such as landfill remediation.

223. An insurance scheme as a stand alone security would be unable to mitigate the risk of default. The Contact Programme revealed that the main factors limiting the use of insurance schemes are the tenor of the liability, the uncertainty of the technology and the unclear nature of decommissioning cost and timing.

224. However, insurance schemes would be suitable for covering unexpected increases in decommissioning costs at a specific site. The cost of the premium is hard to quantify since such insurance schemes are not presently available and the tenor of the liability is long.

5.5. Bonds

225. An underwriter (either a bank or an insurance company) could guarantee the developer an amount equal to the decommissioning sum in return for an arrangement fee plus a premium paid upfront or in annual instalments. The tenor of such a bond would probably be shorter than the length of the liability. However, feedback received through the Contact Programme suggests something longer than 5-10 years is not currently available in the market.

226. This instrument is not suitable for mitigating decommissioning liabilities over the whole lifetime of the installation. The tenor of the liability and uncertainty about the associated risk make this instrument expensive and difficult to obtain. Additionally, compared to other sectors, such as offshore oil and gas where reserves can be provided as collateral to the bond underwriter, offshore renewables can provide only the asset itself as collateral, and in case of default the asset itself might have lost most of its value.

5.6. Letters of Credit

227. A letter of credit would be underwritten by a bank to cover partially or in full the risk of default, using as collateral either the assets of the developer or those of a parent company. Companies tend to resist this form of security because it has an impact on their borrowing ability.

228. A letter of credit would be renewed on an annual basis (longer terms may be available under special circumstances), although some may have a 'draw-down facility' which will operate if the instrument cannot be renewed. This has been used previously in the offshore oil and gas industry to secure decommissioning liabilities, but it is only available at significant expense and may therefore cause difficulties for the nascent offshore renewables industry.

5.7. Parent Company Guarantees

229. Traditionally, PCGs have been used to meet decommissioning obligations for ELV regulations and to some extent under the WEEE Directive.

230. The Crown Estate required PCGs for Round One leases, although they recognised that they would offer only limited protection against default, because the Crown Estate would find it relatively difficult to assess the financial viability of the parent company on a regular basis. The implementation of a PCG in the case of default may be more of an issue for the Crown Estate and indeed the Government if the parent company is registered overseas. Similar conclusions have been reached in the offshore oil and gas sector.

6. Conclusions

231. The Government's plan to encourage the development of offshore renewable energy faces many challenges. One such challenge is the management of the potential liability associated with decommissioning offshore renewable energy installations. The DTI commissioned CCC to undertake this Study to advise on a range of suitable approaches to protect the Government against the potential incidence of default on decommissioning liabilities, without inhibiting unnecessarily the development of the offshore renewables industry.

232. Given the economics of offshore wind characterized by high capital cost (as of today in the range of £1.5million /MW) and very low operating costs (approximately £70,000/MW), the crucial component to offshore wind development is the availability of long term PPAs at prices sufficiently high to allow developers to build, finance and operate OREIs. However, financial viability was a starting assumption of the Study since, without an attractive power price and revenue support mechanism (such as the RO), offshore wind would not be built in the first place.

233. The Study analysed the circumstances under which an asset owner could default on its decommissioning liabilities and the sources of risk that would trigger the event. Typically different types of risk arise during different phases of the project, and their magnitude varies across the lifetime of the installation. It is therefore helpful to consider default risk during three distinct phases: construction, operation and the decommissioning phase itself.

234. The most relevant source of risk during construction is geological or geotechnical risk. This risk refers to the circumstances in which the location proves to be inadequate to support the foundations of an offshore device. However, it is extremely unlikely that this event could trigger abandonment of the entire construction. Rather, it is probable that some devices would be re-located within the project. Risk could be further mitigated by the fact that, depending upon the contractual arrangements, the EPC contractor will bear some of the decommissioning liability if construction is unsuccessful.

235. The Government's risk adjusted exposure to default during construction is relatively low, because installations are unlikely to be abandoned at such an early stage and the probability of default of the liable entities over their liabilities is also low, given the financial profiles of the companies that have been awarded Crown Estate leases and the short period of time over which their financial profiles could erode.

236. Risk of default during the operation phase relates to technology risk (the risk that the technology does not perform as expected) and financial risk (the risk that revenues are lower than expected because of falling green power prices). Financial default could occur if decommissioning costs are larger than future cash generated by the plant. However, given the economics of offshore wind, it is expected that an installation would be able to cover the cost of decommissioning at every point in its lifetime. By the end of life, the difference between the present value of future cash flows and decommissioning costs shrinks, but even under these conditions the offshore wind farm operating margins would be large enough to cover decommissioning costs.

237. Default would be more likely because of technology risk. Technical failure would reduce the operating margins of the installation and thus expectations about future revenues. Typically estimates of the cash flows generated by offshore wind farms are based on a technology performance that is uncertain. Early experience from operating offshore wind farms shows that the technical failure rate is high. The difficulty of the marine environment

reduces performance and makes maintenance slow and expensive. Revenue losses because technology does not perform as expected could increase beyond the asset owner's worst case scenario, exposing the Government to unforeseen liabilities.

238. The risk during the decommissioning phase is primarily due to an unexpected increase in decommissioning costs such that the installations are unable to fund decommissioning. The risk adjusted exposure to the Government would increase proportionally with such an increase and be dependent upon the credit rating of the developer. Estimates of those costs have been provided by the industry during the course of the Contact Programme. However, there is an incentive for developers to underestimate these costs and costs may rise as a result of increased environmental obligations, for example. As a consequence the real size of the decommissioning liability and the risk adjusted exposure to the Government is uncertain and will only be resolved once installations start to be decommissioned.

239. The cost to the Government is related to the probability of insolvency of the developer in case of default. This cost could vary widely depending on the credit rating of the developer. Developers that are currently involved in Round One and Round Two typically have very solid credit ratings, suggesting that the cost to the Government would be minimized. However, there are two factors that can substantially jeopardise the credit rating of the developer and thus increase the risk adjusted exposure to the Government; (i) the company operating the offshore wind farm is usually a limited liability company with limited recourse on the utility's assets and potentially with a different credit rating from the parent company; (ii) assets can be sold over the lifetime of the installation and the new owner can potentially have a different and lower rating than that of the initial owner.

240. Uncertainty over technology performance, decommissioning costs and the possibility of asset transfer to less creditworthy companies suggest that the use of a financial security would be appropriate to safeguard the Government against decommissioning liabilities.

241. The use of financial securities for OREIs would be consistent with the UK Government's approach to decommissioning across a range of different sectors and the way other Governments in the EU have dealt with offshore wind decommissioning. Also, as emerged from the Contact Programme, the industry and the investment community would not offer significant resistance to a flexible mechanism for providing security against decommissioning liabilities, if applied only to those technologies that are commercially viable.

242. The Study therefore looked at financial securities potentially available to reduce the Government's exposure to default on OREI decommissioning liabilities.

243. The Government could require the establishment of a decommissioning fund that accrues early or late into the life of the installation, accruing slowly or quickly. Different decommissioning fund schemes have only a limited impact upon returns to investors and thus would have a minor effect on the development of the technology. However, the Study acknowledges the fact that offshore wind is already financed on tight margins and even small changes to investors' returns could have a significant impact upon investment decisions. For this reason, the Study focused the analysis on four decommissioning fund schemes (Continuous Accrual, Intermediate Accrual, Middle Life Accrual And Late Accelerated Accrual) characterized by their minimal impact upon equity returns.

244. Depending upon the level of risk the Government is prepared to accept, the Study recommends the use of a decommissioning fund that starts accruing in the second half of the life of the installation.

245. This form of security would reduce the Government's risk adjusted exposure and its uncertainty at an acceptable increase of the cost to industry. The asset owner would not have to pay into a fund during the first years of operation, when debt (if any) is serviced. Payments would also be spread over 10 years to minimise the exposure during the last years of operation when the installation is most vulnerable (because of obsolete technology and uncertainty of green power prices).

246. The industry would have to bear an increase of decommissioning costs in present value terms, but this would have a very limited impact upon the returns provided to equity investors. The scheme would allow for adjustments in payments to respond to an increase in estimated decommissioning costs. Once the funds start accruing the sector would probably have better knowledge of decommissioning costs and the fund could be adjusted accordingly. Secondly the government could require a mid term review of the fund (for example, after 5 years of accrual) to verify its adequacy (or more frequent reviews if considered appropriate).

247. Marine technologies would at present struggle with the provision of any financial securities, because of a lack of certain revenues at the pre-commercial, demonstration stage and because the lifetime of these devices is shorter than, and in some case incompatible with, the tenor of the decommissioning fund. The cost of marine decommissioning payments might therefore need to be ring-fenced as a condition of any grants or further support from Government. However, future commercial marine devices may reasonably be expected to provide the same level of security as commercial offshore wind devices.

APPENDIX A Generic Review

A.1 UK Offshore Oil and Gas Decommissioning

248. UK offshore oil and gas operations are highly regulated, primarily through the UK Petroleum Act 1998. The DTI is the regulatory body. The sector plays a significant role in the UK economy, exporting oil and gas products worth £2 billion in 2004 and generating some £5 billion in 2004/2005 in taxation for HM Treasury.

249. The Petroleum Act 1998 mandates that the costs of decommissioning offshore oil and gas installations and pipelines should lie with the operators and owners of such facilities. Section 29 of the Act requires submission of a costed decommissioning programme to the DTI that must eventually be arranged and financed by the persons that submitted the programme. This can include current and previous owners (both partial and full) and operators of the installation.

250. Offshore oil and gas installations are primarily developed by some of the world's largest and best capitalised companies, such as BP and Shell. Financial viability has therefore not usually been a concern with regards to decommissioning costs. Reputational risk to developers from neglecting to fulfil their obligations is also high. The DTI has therefore not traditionally required financial securities (such as bonds) from developers before consenting offshore oil and gas developments.

251. In recent years the trend has been for the transfer of mature UK continental shelf (UKCS) oil and gas assets from large companies to smaller ones. Free trade of offshore assets has been encouraged by the Government to extend field lives and maximize economic recovery. This has brought a consequent higher risk of default in meeting the costs of decommissioning if insufficient assets under UK jurisdiction are available (it is timely and expensive to pursue financial liabilities through international courts).

252. The DTI ensures that adequate provision is in place to secure the liabilities associated with decommissioning. At asset transfer the liability does not automatically transfer. In the case of an asset sale DTI will place the liability on the new company but may also retain liability on the departing company. In some instances the DTI has required a financial security to be provided (usually a guaranteed-renewable letter of credit), or an approved Financial Security Agreement (FSA) between asset holders, if a new developer is of insufficient financial standing to provide certainty over its ability to meet decommissioning liabilities. Other liabilities have been left with the previous owner of the asset, but with the liability able to be distributed on a private basis amongst the companies involved. In any event, the financial provisions for decommissioning of offshore oil and gas assets are subject to ongoing review in order to ensure protection for the Government in the event of default.

253. The Government assists in meeting the costs of decommissioning by making them allowable (deductible from profits before tax), although this does not extend to payments into a decommissioning fund or an insurance-based decommissioning agreement.

254. In the UK, implementation of the OSPAR Decision 98/3 requires complete removal of the installation (except for parts of the very largest installations). By contrast, in the US about 10% of all installations decommissioned are disposed of by simply toppling sections of a structure or removing the platform to form an artificial reef, which has enabled decommissioning costs to be minimized.

A.2 Nuclear

255. Nuclear power stations in the UK were constructed before privatization of the electricity industry and were therefore solely owned by the Government until partial privatisation of the industry in the 1990s.

256. The Nuclear Decommissioning Authority (NDA) was established on 1 April 2005 under the Energy Act 2004. The NDA are now the owners of the plant and facilities of BNFL (the Magnox stations, Sellafield, THORP/SMP and Springfields), and took responsibility for managing clean-up at the UKAEA sites. The NDA is charged with cleaning up the UK's historic civil public sector nuclear legacy at its sites safely, securely, cost effectively and in ways that safeguard the environment for this and future generations. In creating the NDA, the UK's aim is to provide a more effective means of dealing with the legacy than has previously existed, by driving forward greater efficiencies and through the introduction of competition for site clean up. This is a significant change to Government's approach to the clean up of the historic civil nuclear legacy, providing for the first time a national strategic direction to managing the UK's nuclear clean up programme under a single body. It is a considerable long-term, resource-intense challenge, with civil liabilities currently calculated (2004 figures) to be some £56 billion.

257. Under the privatisation deal of 1996, British Energy (BE) was required to establish a segregated fund, the Nuclear Generation Decommissioning Fund (NGDF), into which decommissioning payments were to be paid annually. Contributions were designed to fully meet BE's decommissioning costs, the Fund undergoing Quinquennial Reviews to revise contributions if necessary. Following BE's financial difficulties, the NGDF has now been renamed as the Nuclear Liabilities Fund (NLF) whose remit is expanded to cover decommissioning costs as well as certain other BE nuclear liabilities. BE will continue to make payments into the fund, both fixed and variable, but there is no longer a requirement for the Fund to be fully funded; the DTI has underwritten the Fund so that should the assets fall short of the liabilities, DTI will make good any shortfall. In order to minimise the liability to UK taxpayers, the NDA will review BE's decommissioning plans and approve payments out of the NLF. In addition, measures have been placed on BE to ensure the liabilities are minimised as far as possible (to replicate the incentive to reduce liabilities that are removed through the underwriting). BE is required by law to undertake decommissioning work at each of its facilities, but the UK Government may exercise its right to intervene at any stage if it considers the provisions to be inadequate.

258. The US Nuclear Regulatory Commission (NRC) similarly requires financial assurances from nuclear power plants that sufficient funds will be available when decommissioning is required. In the US, most nuclear companies have established segregated decommissioning funds, which accrue at rates established by the Federal Energy Regulatory Commission (FERC) or state regulatory authorities. Nuclear companies contribute to a \$25 billion (currently) Nuclear Waste Fund collected by the Treasury from a US\$0.1 /kWh charge on all nuclear-generated electricity.

259. Key lessons from the nuclear industry are the advantages of dealing with decommissioning strategy and costs on a case-by-case basis, and that they will evolve over time as new research and decommissioning facilities come on-line.

A.3 Contaminated Land Remediation

260. In the UK, Part IIA of the Environmental Protection Act 1990 provides the framework for the identification and remediation of contaminated land. The primary enforcing authorities in England are the local authorities, except where contaminated land (as defined in the Act) is also a special site (as defined in the Contaminated Land (England) Regulations 2000), in which case it is the Environment Agency. The enforcing authorities will then establish the appropriate person(s) who are liable for the remediation of the land. In the first instance, this will be the entity(s) that caused or knowingly permitted the contamination, but if they cannot be found then it is the owner or occupier of the land.

261. Legislation is based upon the 'polluter pays principle', which applies whether the appropriate entity is a public corporation, a limited company or an individual. In the case of a small or medium-sized enterprise the enforcing authority will consider whether recovery of the full cost would mean that the enterprise is likely to become insolvent and thus cease to exist. If so, the authority will also consider the cost to the local economy of such a closure. Where the cost of closure appears to be greater than the costs of remediation, the enforcing authority should consider waiving or reducing its cost recovery to the extent necessary to avoid making the enterprise insolvent.

262. At the European level, the EU Directive on Environmental Liability sets the regulatory framework for environmental liabilities. The Directive aims to prevent environmental damage by forcing industrial polluters to pay for prevention and remediation costs.

263. The Directive does not oblige operators to ensure coverage of their potential liabilities by appropriate financial security products such as insurance. However, Member States are required under the Directive to encourage the gradual development of such security instruments in the market and their use by operators.

264. Under the Pollution Prevention and Control (PPC) Regulations, which implement the Integrated Pollution Prevention and Control (IPPC) Directive, an operator cannot commence any activity without submitting a site report along with the IPPC permit application to the regulator. The operator of a PPC waste management activity has to demonstrate that the installation is solvent and can financially operate the site in accordance with the permit conditions. When an operator stops or intends to stop operating an installation or part of it, the operator needs to submit a surrender application. This should include a site report describing the site conditions and identifying any changes from the condition described in the original site report. This is designed to ensure that the obligations (including aftercare provisions) arising from a PPC permit in relation to that activity are discharged and any closure procedures required are followed.

265. There are many different technical approaches to remediation of contaminated land. These can be categorised as either civil engineering or process-based approaches. Each of the different approaches may be capable of treating a wide range of contaminants so the remedial strategy needs to be carefully selected on a site-specific basis. Historically, the most common form of remediation has been to remove the contaminated soil and dispose of it at a licensed landfill site.

A.4 Treatment of End-of-Life Vehicles

266. UK policy regarding End-of-Life Vehicles (ELVs) implements the EU Directive on End-of-Life Vehicles (Directive 2000/53/EC) and does so in an "own marque" manner. "Marques" or brands of vehicle are declared by producers to the relevant authority (the DTI) and producers then become liable for their recovery, reuse and recycling, in line with established targets, should those ELVs be brought back to treatment facilities with whom the manufacturer has a "take-back" contract. ELVs can also be dealt with voluntarily by "uncontracted" facilities, which pick up responsibility for the recovery targets.

267. The Government does not require vehicle manufacturers to have in place any specific security to fund the cost of ELV disposal. However, by the end of August 2005, producers were required to submit their proposals to form collective networks (with dismantlers) to the DTI for approval. These networks must meet convenience and treatment-capacity criteria. Vehicle manufacturers have recently been entering into long-term contracts with approved vehicle dismantlers/recyclers, known as approved treatment facilities (ATFs).

268. The ELV (Producer Responsibility) Regulations 2005 provide that, in the event of producer default on decommissioning liabilities, the Government may require new or previous owners of a particular brand, or a collective group of producers, to take over the decommissioning responsibilities. It is unlikely the taxpayer would face this cost.

269. In the event of asset transfer, it is expected the new owner of a brand would bear the cost of ELVs arising from previous production (although this may not always be the case). Any vehicles produced by a company that is no longer in business are known as "orphan" vehicles. When these producer-responsibility regulations were drafted, the number of orphan cars was estimated to be comparatively small, roughly 2.5% of all ELVs.

270. The net cost of decommissioning ELVs fluctuates with the price of scrap metal (amongst other factors), which is heavily influenced by the price of steel. At present high values for scrap, vehicle dismantlers and recyclers are able to make good margins and have been willing to enter into contracts with little or no charge to vehicle manufacturers for decommissioning. However, in an era of lower scrap prices, ELV producers may find themselves required to provide part of the funds to ensure compliance with ELV regulations, since they must always maintain "convenient" networks of facilities from which last owners can receive free "take-back" from January 2007.

A.5 Waste Electrical and Electronic Equipment

271. The EU Directive on Waste Electrical and Electronic Equipment (WEEE) (2002/96/EC) was agreed on 13 February 2003 and imposes obligations upon the producers of WEEE to arrange and finance its recovery, reuse and recycling up to specific targets (in the range 50−80% by average product weight). The Directive encourages the use of collective schemes to cover the costs of decommissioning, which the UK is seeking to encourage through a scheme of its own design.

272. The Directive requires national legislation to implement the WEEE Directive to be in place by the 13 August 2005, but the UK Government (like many other EU Member States) has postponed its implementation to permit more detailed analysis to be undertaken. As a result the UK's WEEE regime has not yet been finalised.

273. Enough is known of the likely substance of the UK's WEEE regulations to determine that producers will ultimately be responsible for decommissioning liabilities and will bear the costs through annual payments into a collective scheme. In addition, companies must provide a 'financial guarantee' to ensure that decommissioning costs are not borne by the taxpayer in the event of insolvency. However, the precise make-up of this guarantee is still to be determined.

274. Government could decide upon a form of insurance-based product or collective scheme to achieve compliance with the WEEE Directive. In the event of default by one or more participant in a collective scheme, other participants could be required to cover the defaulting participants' liabilities. This might in the first instance be the producers within the same "marque" or brand/product types, a subset or even the whole of the industry (in the manner of the historic liability provisions).

275. It is estimated WEEE decommissioning under the new Directive will cost UK industry between £217 million and £455 million per year. The European Commission has estimated this will raise the average cost of small to medium-sized WEEE products by 1−2%, and the average cost of larger and more complex products by 3−4%.

A.6 Offshore Wind Decommissioning Regimes: Denmark and the Netherlands

6.2.1. Denmark

276. There are currently six offshore wind farms in Denmark, totalling some 3.1 GW of capacity in 2004. Both offshore and onshore wind farms receive subsidies from the Danish Government in the form of a premium for electricity supplied. New wind farms connected to the grid from 1 January 2005 receive a fixed premium of 10ore/KWh [€0.013/kWh] for 20 years – with a ceiling on market price plus subsidy of 36ore/KWh [€0.048/KWh] – and 2.3ore/KWh [€0.003/kWh] for offset costs etc.

277. Danish Government policy on offshore wind decommissioning holds the owner/operator (the permit holder) of an installation legally liable for returning the site of the installation to its original state, once the permit expires or the installation is irreparably damaged or disused. Partial decommissioning may be permitted; however, if removal is considered to present an environmental or physical hazard, only certain types of foundation structure may be left in place.

278. Danish regulations state that, before a developer can bid to build a wind farm (approval to build is granted to the lowest bidders for the feed-in tariff – amongst other considerations), it must provide a financial guarantee to the Danish Energy Authority (DEA) for fulfilment of decommissioning costs, including cable connections between turbines (but not between land and the offshore arena). However, according to our discussions with Elsam, a leading offshore wind developer and the largest power producer in Denmark, no financial guarantee in the form of a bond or letter of credit has thus far been provided.

279. The permit holder must also provide a decommissioning plan (not costed, although the DEA may impose further requirements) to the DEA for approval at least 2 years before expiry of the permit, or in the case of irreparable damage or disuse of the installation. Any new owner must provide the same level of financial guarantee as the previous owner.

6.2.2. The Netherlands

280. In the Netherlands there was considerable debate between developers and the Government regarding the use of securities for decommissioning liabilities. Developers were typically small companies, unwilling or unable to provide a bank guarantee for 20 years.

281. The latest information available indicates the Government has decided that developers of wind farms must make payments for a minimum of 10 years into a segregated fund from the start of the operation of the wind farm. The Government would have access to this fund in the event of insolvency of the owner/operator.

282. In addition, the developer is required to prepare a decommissioning plan, which is based upon the presumption that monopiles must be cut at least 4 m below the sea level. However, no consideration need be made for cables. The Government must approve the decommissioning plan and the owner/operator of the installation will then be liable for its execution after the final operation of the wind farm.

APPENDIX B Contact Programme

B.1 Early stage and pre-commercial technology/project developers

283. Decommissioning is a relevant issue for early stage developers, although more so for those developing projects several miles offshore than for those with devices on or near the shore. Early stage developers were aware of their liabilities under the Energy Act 2004 and the requirements of the Crown Estate for offshore leases. However, some expressed concern that the additional costs imposed by decommissioning could jeopardise the financial viability of offshore renewables in the UK.

284. Other developers were more concerned with the form of security that would be required by Government. They claimed that a financial security requiring up-front costs or payments within the first few years of operation would be financially damaging and would tend to favour larger developers over smaller ones. It was unclear whether developers have assumed a requirement for insurance bonds or other up-front securities (letters of credit) within their financial models. However, there was no evidence that an insurance bond is currently available in the market to cover the 10+ year liabilities of some Round One projects.

B.2 Late stage and 'mature' technology/project developers

285. It was noted that no offshore renewable technology could be described as 'mature' at this stage, but it was accepted that some are more mature than others. Nevertheless late stage or 'mature' technology developers had concerns similar to those of early stage developers. Developers again made the point that currently there are no insurance bonds available to cover decommissioning liabilities for the 20–50 year lifetimes of Round Two offshore wind projects.

286. Some developers also remarked that many of the larger companies involved in the offshore business, such as the well-known utilities, would face substantial reputational risk were they to walk away from their decommissioning obligations.

B.3 Engineering procurement and construction contractors and technology providers

287. Engineering, Procurement and Construction (EPC) contractors and technology providers did not see any extraordinary technical difficulties or challenges with decommissioning, despite the fact that no large-scale commercial OREIs have yet been decommissioned anywhere in the world. However, this lack of experience means that any cost estimates are uncertain and might change considerably given the technological developments that are likely in the future. Current cost estimates vary depending on the type of installation and its location. However, a working assumption is that decommissioning costs are very unlikely to be more expensive than installation of the OREIs and are likely to be considerably less.

288. Technology providers and EPC contractors were willing, in general, to undertake decommissioning when necessary. For monopile foundations they presumed it would be somewhat akin to installation, but in reverse, although the pile would simply require cutting 1−2 m below the sea bed (depending upon the conditions – moving sands might require 5 m depth) rather than the entire section being extracted. Drilling might be required for piles inserted into hard rock and this would be a more expensive operation. Gravity-based foundations would be harder again, given the extreme difficulty in removing what is essentially a very large block of concrete. In this instance removal might cause more disruption of the sea bed than leaving the foundation in place and costs could therefore be

substantially lower. This, and the extent to which electrical cables must be removed, is an ongoing question that has yet to be resolved.

B.4 Operators

289. Operators contacted were typically eager to see decommissioning addressed in as simple and timely a fashion as possible. Round Two projects, which have not received grants, will require decommissioning on a larger scale than Round One projects and probably at a later date. Operators expressed their belief that renewal/re-powering of offshore sites would be likely at the end of current quoted lifetimes and that decommissioning could potentially be postponed by as much as 10 years or more.

B.5 Equity investors

290. Equity investors in offshore renewables are mostly utilities at present because the private equity houses and banks are unwilling to invest in what they perceive to be very risky or at least relatively unknown projects. This is partly due to the fact that onshore wind has been growing rapidly in the UK and is a more secure and proven technology. It may also be because they cannot currently see a large upside to the projects. It is likely that equity investors will think seriously about investing in offshore renewables in as little as 1 or 2 years and definitely in less than 10 years. In terms of technologies, offshore wind is further ahead in this developmental pathway than marine (tidal or current), at least on today's reckoning.

291. However, equity investors revealed that they were not overly concerned with decommissioning. In this sense it is not a decisive issue affecting their investments, although they were keen to point out that it would be one of several factors on which they would perform due diligence (such as seeking independent advice on costs) and account for the costs in their estimates of future cashflows. One contact mentioned they did not attribute a value to onshore wind farms after 20 years and decommissioning costs become small when discounted over this entire period, but bringing forward decommissioning cashflows would have an impact on investors.

292. Equity investors were unenthusiastic when it was suggested decommissioning costs could be shared across the sector, largely because they would rather not pay for another project's mistakes or misfortune. A final key message was that any system imposed by the Government to ensure against default on decommissioning liabilities must be clear, transparent and long-lasting, so as to provide the certainty that equity investors require.

B.6 Debt providers

293. Debt investors that responded to the Contact Programme had been involved in financing offshore renewables and oil and gas installations as well as onshore wind farms. However, OREI decommissioning was not an issue they had considered in any great detail because they have been more concerned with other economic issues surrounding offshore projects. These included recent increases in turbine costs (both capital and installation) and the availability of off-take contracts from credit-worthy electricity suppliers at competitive prices. In terms of marine OREIs, the banks contacted were not involved in any project finance because of the greater risk perceived for the technologies.

294. It was therefore apparent that decommissioning would have less of an impact on the debt providers than equity investors because banks could simply readjust the amount they were willing to lend and possibly the required return on capital. However debt provider's

primary concern was to ensure decommissioning liabilities did not have recourse over the priority of project cashflows (i.e. they did not take seniority over debt repayments). The timing of decommissioning costs was also important given that debt might be paid off within the first 10 years of the project, perhaps before any decommissioning payments occur (depending upon the level and type of security required).

B.7 Insurers/Underwriters

295. Insurance-based products to cover decommissioning liabilities have been proposed (in both offshore renewables and oil and gas) but none have yet been implemented. There are three key problems. First, the tenor of such instruments is often incompatible with OREI lifetimes; projects may last 20−50 years, whereas renewable insurance contracts may only be available for up to 2−3 years. Second, the renewable element of the contract means that there is no guarantee that the instrument will last sufficiently long to cover decommissioning liabilities. Third, the decommissioning liabilities are insufficiently known both in magnitude and timing.

296. Specialist insurers stated they were eager to develop products that cover the full lifetime of an OREI, which could be non-renewable and account for the variability of risk throughout the project. However, they might be unable to provide the level of cover that the Government requires because the projects are sufficiently risky that conditions such as limited coverage for external damages would be required. Insurers expressed concern that any requirements for financial guarantees that were too inflexible would preclude innovative insurance products that might otherwise be developed. A collective scheme was regarded as a difficult solution to agree with the different companies in this sector and there would be a problem since the DTI is not an "insurable entity" (i.e. having no financial interest in OREI developments) and therefore would not be able to take a central role in the insurance scheme.

B.8 Crown Estate

297. The Crown Estate is very supportive of the DTI establishing a decommissioning regime that requires companies to provide a financial guarantee on decommissioning obligations. For Round One leases, the Crown Estate required developer companies to provide a PCG covering decommissioning liabilities. For Round Two they have not, because the Energy Act 2004 established legislation on decommissioning that provides a firm legal basis for securing decommissioning costs. Nevertheless, a form of 'back-end' security is required in Crown Estate leases for Round Two projects; decommissioning costs must be set aside 5 years prior to the end of operational life and repaid as decommissioning work is undertaken. The Crown Estate expressed concern over the perceived behaviour of some parent companies to distance themselves financially from their related development companies through the creation of special purpose vehicles (SPVs).

B.9 Renewable Energy Trade Associations

298. The trade associations' views were that, while most of the wind turbines placed offshore would see a successful operational life, some might face technical difficulties. However, they were less concerned about the likelihood of financial default by owners/operators in this space because of the observed trend towards consolidation in the sector, the primary players being large utilities with strong balance sheets.

299. On marine technologies, the trade associations were in broad agreement that costs would be highly variable and, while a few developers out of the current 15 or so might default, the

imposition of a financial security requirement at this stage would place unnecessarily burdensome obligations upon the sector.

APPENDIX C Offshore Wind Farm Model Assumptions

Installed capacity	240MW
Expected annual output	Approx 700,000MWh
Load factor	33%

Capital cost (£ / MW)	
Development costs	45,000
Preliminary and Management	75,000
Wind turbine supply	600,000
Foundation supply	255,000
Monitoring systems	30,000
Installation	330,000
Total CAPEX (ex grid) (£ / MW)	1,335,000

Annual Operating costs (£/MW)	
Operations cost	20,000
Maintenance cost	20,000
Use of system	15,000
Insurance	6,600
Crown Estate lease	3,000
Total OPEX (ex grid) (£/MW year)	64,600

Minimum return on equity	10%
Equity financing	45%
Debt financing	55%
Return on debt	7.5%
Debt tenor / years	15
PPA tenor / years	15
ROCs	Until 2027

Tax Regime	
Corporation tax rate	30%
CAPEX allowable / %	90%
Capital allowances / %	25%
Years of tax holiday	0