Independent evaluation of the Electricity Market Reform

Final Report to the Department of Energy and Climate Change

15 October 2015

Contents

1 Disclaimer

Audience and disclaimer

1.1 This report is provided in accordance with our appointment under the contract for the provision of services for the evaluation of the first round of EMR delivery and the FID Enabling for Renewables process dated 13 October 2014 to the Department of Energy and Climate Change ('DECC').

1.2 We have satisfied ourselves, so far as possible, that information presented in our report is consistent with other information which was made available during the course of our work in accordance with the terms of our appointment. We have not verified the accuracy of the data or the information and explanations provided by the third parties and therefore accept no liability in relation to this.

1.3 This report has been prepared exclusively for DECC. To the fullest extent permitted by law, we do not accept or assume responsibility to anyone other than DECC for our work, our report and other communications, or for any opinions we have formed. We do not accept any responsibility for any loss or damages arising out of the use of the report by DECC for any purpose other than in connection with this project. We draw your attention to the limitation of liability in our appointment.

2 Executive summary

Introduction

2.1 In its Delivery Plan (December 2013) the Government's stated objectives for Electricity Market Reform (EMR) were to (i) keep the lights on; (ii) decarbonise electricity generation; (iii) whilst at the same time ensure energy bills remain affordable. EMR would provide the means to meet these objectives by:

- **Ensuring a secure electricity supply** through having sufficient capacity to meet demand, a diverse portfolio of generation technologies and a reduced reliance on fossil fuels.
- **Ensuring sufficient investment in sustainable low-carbon technologies** to provide the necessary support and stable revenues to decarbonise electricity generation. This will allow the UK to continue to drive toward its EU 2020 renewables target and its longer term aim to reduce carbon emissions by at least 80% of 1990 levels by 2050.
- **EMR will do so in a way which maximises benefits and minimises costs** to the UK economy and to taxpayers and consumers. EMR will use the power of the markets and competition to deliver affordable electricity bills alongside unprecedented investment in energy infrastructure.

2.2 It has two main strands:

- **Capacity Market (CM)**, which has been designed to secure sufficient electricity supplies to meet a defined reliability standard at an affordable cost by remunerating capacity providers investing in reliable plants; and
- **Contract for Difference (CfD)**, which has been designed to:
  - be an investable instrument, which is attractive to a wider pool of capital sources;
  - mitigate key risks of renewables projects, which allows investment to come forward at a lower cost of capital;
  - introduce competition as a conduit for cost reduction and eliciting project efficiencies;
  - ensure diversity across technologies and companies; and
  - keep spending within the Levy Control Framework and enabling support to be approved under the EU State Aid guidelines.

These are supported by the Carbon Price Floor (CPF), the Emissions Performance Standard (EPS), measures to incentivise Electricity Demand Reduction (EDR), measures to support market liquidity and access to market for independent renewable generators and the transitional arrangements from the Renewables Obligation and the CfD, ie the Final Investment Decision (FID) Enabling for Renewables. It was recognised that these would be necessary to deal with the inevitable tension between decarbonisation goals and having security of supply, and achieving these at least cost.

2.3 Following the Energy Bill in 2013, DECC moved into implementation and then allocated Investment Contracts – the early version of the CfD – under the FID Enabling for Renewables programme. It then ran CM and CfD auctions over the period to February 2015.

2.4 DECC asked Grant Thornton and Pöyry to conduct an independent early-stage review of the CM and CfD process and outcomes with widespread stakeholder research so that early lessons can be identified and, where necessary, remedies implemented. This also allows Government to gain further insight into both the short term and longer term policy outcome. These are covered in this report, while our parallel investigation into FID Enabling for Renewables is reported separately. Field work and analysis was carried out in the period November 2014 to June 2015 and the text in the report is consistent with the programme situation during this period.

Capacity Market performance

Introduction

2.5 Taking the Capacity Market from policy concept to functioning policy instrument in the timeframe from 2011 to 2014 is a major achievement. The auction ran smoothly and secured capacity for 2018/19 within the target range established by the administered demand curve.

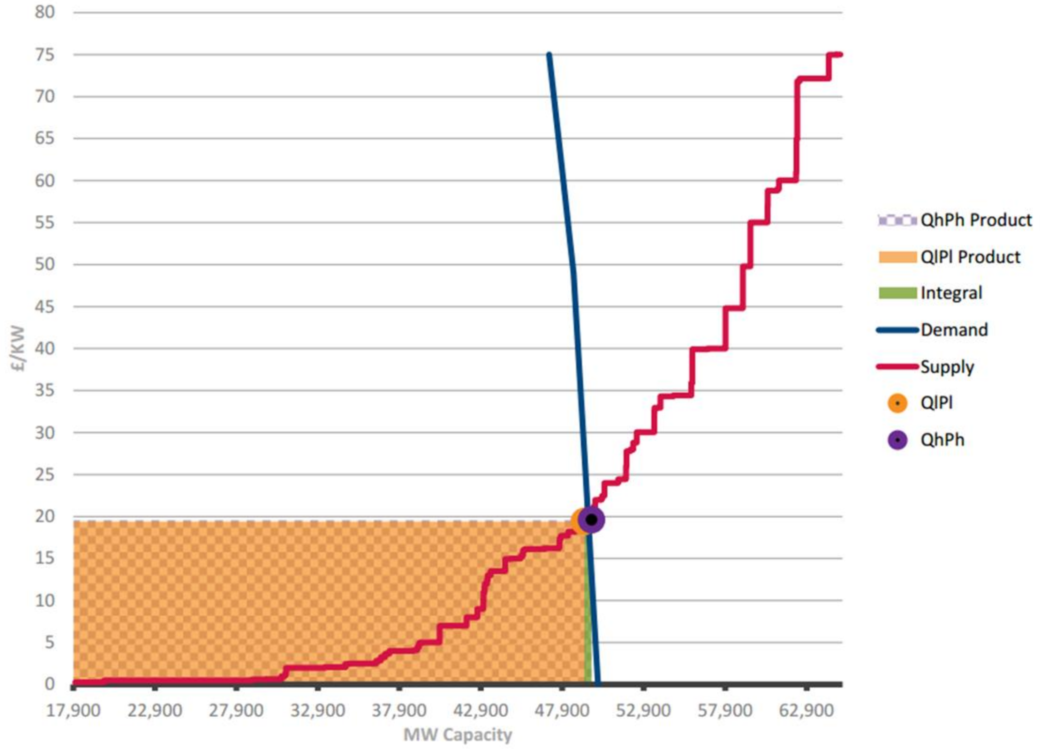
2.6 However, we have had only one Capacity Market auction, giving a single data set in terms of results. We remain 3 ½ years from the start of the 2018/19 delivery period and 1 year from the Financial Commitment Milestone for 2018/19, which will be an important staging post for assessing the delivery of new build projects. As such, it is too early to draw conclusions about the effectiveness of the Capacity Market in delivering long-term security of supply.

Outcome

2.7 National Grid, in its capacity as the Delivery Body (DB), identified a target of 53.3GW de-rated capacity being needed to meet the reliability standard for 2018/19, based on which the Secretary of State set a target capacity of 48.6GW for the first four year-ahead auction. Auctions for this capacity were held in December 2014 on schedule; the auction process ran smoothly and secured capacity within the target range established by the administered demand curve, structured around a Net Cost of New Entry (CONE), which was calculated at £49/kW (2012 prices).

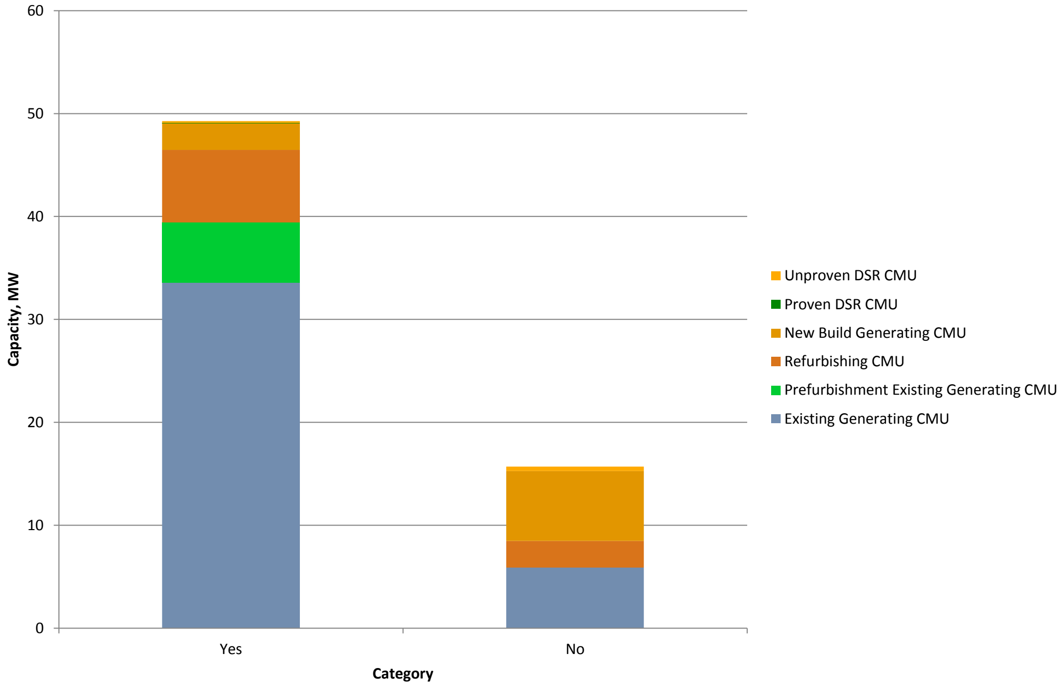
2.8 The auction cleared at £19.40/kW, as shown in Figure 1. However, it is noteworthy that the outcome is highly sensitive to decisions on capacity requirement and shape of the administered demand curve: an increase of 1GW required capacity would have resulted in a clearing price closer to £24/kW, other things being equal.

Figure 1 – Outturn supply curve (source: National Grid auction report)



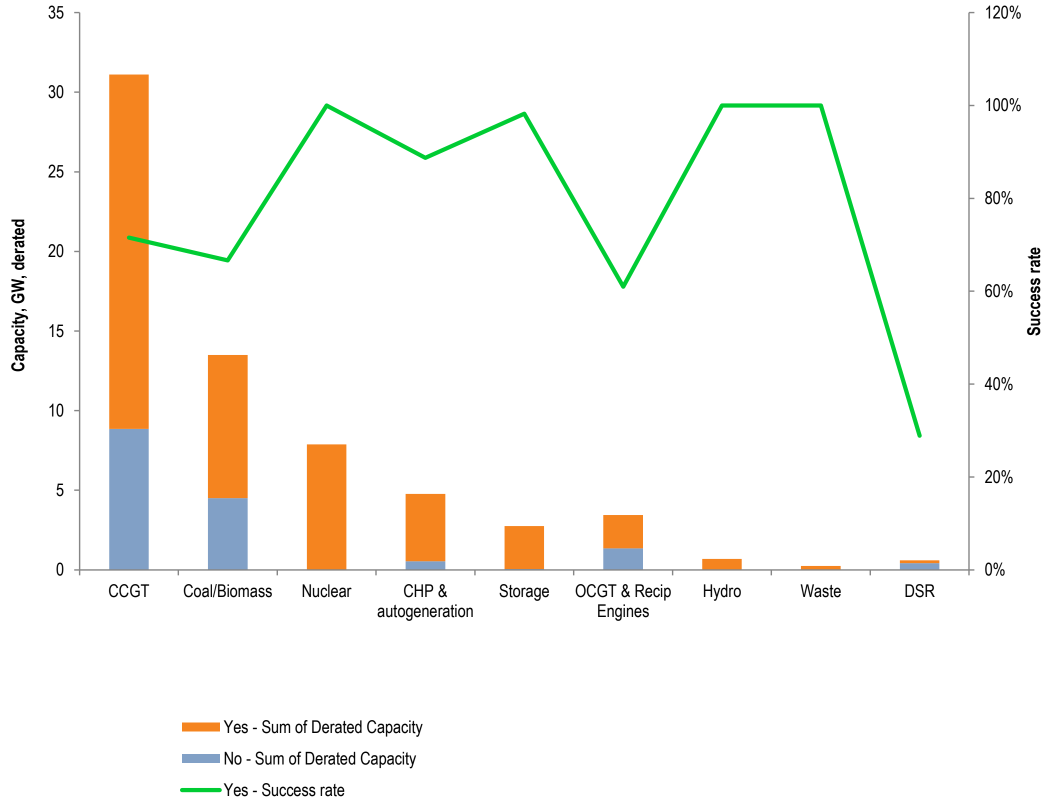
2.9 As summarised in Figure 2, the auction attracted 65GW of capacity, providing significant surplus capacity relative to the target of 48.6GW. Of the participating capacity, ~49.3GW was awarded Capacity Agreements. Existing capacity accounted for nearly 95% of awarded Capacity Agreements, with 2.6GW of new build projects also securing Agreements.

Figure 2 – Split between successful and unsuccessful capacity in auction



2.10 Several different technology types applied for the auction with varying degrees of success, as shown in Figure 3. While the technology mix was generally in line with our expectations, the success of reciprocating engines is worthy of note.

Figure 3 – Capacity Agreement success rate by technology



Observations

2.11 At face value, therefore, the first CM auction delivered many of its objectives. However, there are learning points to be drawn from it, and it is important to note that we should not infer too much from the outcome of the first auction alone. We remain 3½ years from the start of the 2018/19 delivery period and 1 year from the Financial Commitment Milestone which will serve as an indicator of the actual delivery of new build that secured Capacity Agreements. As such, it is too early to draw conclusions about the CM's effectiveness in delivering security of supply in the long run, particularly as a high proportion of the current generation fleet is nearing the end of its operational life.

2.12 In the following paragraphs we comment on areas that are worth attention. However, there is also need for some stability to allow the system to bed-in and for a track-record to be established over several years. There is scope for fine-tuning of details or enhancements to procedural or administrative aspects of the arrangements but the system in place is the one that must be worked with and it would be counter-productive to seek major reform.

2.13 The administered demand curve hinges on pricing parameters, particularly the Net CONE and the Price Cap. But the derivation of these parameters lacks a transparent methodology. As these values set the expectations of the maximum willingness to pay for capacity it is important that they are transparent with full explanation of methodologies and data ranges. With more transparency, the boundaries of discretion of the Secretary of State would be clearer, increasing certainty for participants in future.

2.14 Providing new generation projects with access to longer term Capacity Agreements has a clear rationale, helping to provide access to finance to support project delivery and to pay for capital expenditure. While tenure of 15 years is long relative to international experience, it is compatible with typical debt finance and re-finance timescales. Some stakeholders expressed a preference for rolling annual arrangements, but recognised that this will only be practical when the CM is well established. For the time being, in the interests of providing stability and certainty for participants, retaining 15 years as the maximum Capacity Agreement duration appears an appropriate course of action.

2.15 Non-availability of longer-term Capacity Agreements for new DSR has attracted criticism and a number of stakeholders consider this to be discriminatory, creating a non-level playing field that disadvantages DSR relative to generation technologies. But there is some evidence to support the adoption of one year agreements for DSR. For example, the Capacity to Customers[1] project suggests that one year arrangements are the optimal length required to secure a contract with DSR providers[2]. There is a clear tension here. To take this forward, the DSR community should continue to be invited by DECC to supply evidence in relation to the implications of 1 year only agreements on DSR deployment and the potential effects of longer-term agreements on this, as well as assessment of delivery risk issues associated with longer-term agreements. This will allow an evidence-based review of this issue.

2.16 With over 15GW of plant qualifying for refurbishment status and the consequent optionality afforded to it in the auction, the inclusion of the refurbishment category complicates the auction outcome. The refurbishment eligibility criteria and/or the ongoing need for the category more generally should be reviewed.

2.17 Prequalification was hampered by many of the teething troubles associated with the delivery and commissioning of new IT systems and to some extent the concurrent development of rules during the process. Nevertheless it reached a successful conclusion in this first year. Looking forward we believe there is potential for streamlining the process to reduce the administrative burden without losing necessary controls.

2.18 National Grid and DECC's efforts to provide training and supporting material for the auction process itself were endorsed by industry stakeholders with wide praise for the functionality and effectiveness of the auction platform and supporting IT infrastructure. The effectiveness of actual auction operation counts as a success.

2.19 Although many types of generation technology were successful in the auction, we note two areas of particular interest.

- Trafford was the only successful large scale project securing a 15 year agreement, and we believe that this may not be indicative of a wider trend – several specific factors linked to the project may not be replicable by other projects. There is a need for focus on prospects for replicability in other projects.
- Reciprocating engines were far more successful than many expected, and it may be that their technical and cost characteristics will be highly advantageous in the future. Yet they run on hydrocarbon fuels, prompting concern that this outcome contradicts wider EMR objectives in pursuit of decarbonisation. There is a need for greater understanding of the underlying characteristics of engine options, implications for running patterns and their potential impact on emissions and costs to consumers in providing security of supply.

1 The Capacity to Customers project run by Electricity North West tested innovative network management technologies in conjunction with new customer commercial arrangements to release capacity on the distribution network as an alternative to traditional reinforcement.

2 http://www.enwl.co.uk/docs/default-source/c2c-key-documents/customer-segmentation-report.pdf?sfvrsn=4

2.20 Finally, linked to the points above, 2.6GW of new capacity will now need to be delivered for 2018/19 and the effectiveness of monitoring schemes and incentives will be critical. While there is no evidence of non-delivery of new build to date, the prospect is highlighted by developments at two existing stations. Already one existing project (Aylesford[3]) has been cancelled and, if press releases are to believed, there is a distinct possibility that Longannet will close before the delivery year. Robust monitoring of the potential for non-delivery is important in this context.

CM recommendations

2.21 We recommend the following steps in relation to the CM:

- Given the over-riding desire for some stability to allow the system to bed-in and for a track-record to be established, the overarching framework and design of the Capacity Market should remain stable wherever possible.
- Improve transparency of demand curve pricing parameters. Having a clear methodology for the determining these parameters will increase certainty for participants in future.
- DECC should continue to invite the DSR community to supply evidence in relation to the implications of 1 year only agreements on DSR deployment and the potential effects of longer-term agreements on this, as well as assessment of delivery risk issues associated with longer-term agreements. This will allow an evidence-based review of this issue.
- The arrangements for qualifying for refurbishment status need revision. Notably, the capital expenditure threshold is imprecise and historical expenditure can qualify as eligible spending. Beyond these enhancements, the ongoing need for the refurbishment category should be reviewed.
- Concerns regarding non-delivery risk create uncertainty for the market and its ability to respond in the event of non-delivery. There is a need for regular monitoring and communication of non-delivery risk to provide transparency to the market.

CfD performance

Introduction

2.22 In general the CfD process has delivered well against its objectives although we have some concerns about its longer term performance.

2.23 We recognise that the CfD and its process of award by auction represented a very new approach to renewable investment. In this context, it is a noteworthy achievement that apart from some minor delays, the associated set up and auction processes have been delivered thus far.

2.24 As we discuss below, quantitative analysis of the inputs and outputs of the auction process was limited by the restrictions placed on National Grid, and we drew considerably on in-house industry knowledge and a widespread stakeholder research.

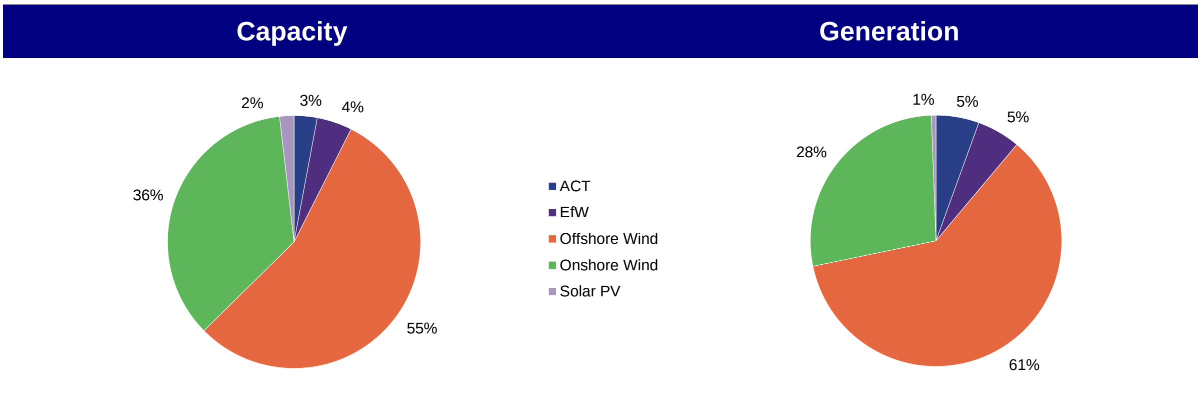
Outcome

2.25 The first CfD allocation round opened in October 2014 and concluded in February 2015 with the award of a CfD Contracts to 27 projects equating to 2,138MW of renewable capacity. The total capacity was distributed as follows: five projects for an equivalent capacity of 1,224MW were secured by less established technologies in Pot 2, while 22 projects for an equivalent capacity of 915MW were awarded to established technologies in

[3] As the capacity contribution from Aylesford Newsprint is ~3.5MW, the impact on the Capacity Market is small. However, the same would not be the case if there is a sizeable accumulation of capacity that pulls out and/or the withdrawal of a larger scale capacity provider.

Pot 1, two of which[4] withdrew leaving 882MW after the signature stage. These are as shown in Figure 4 expressed in capacity and generation terms.

Figure 4 - Capacity and generation by technology (first CfD allocation round)



2.26 The first competitive allocation was successful both in terms of the number of awarded contracts and the number of applicants. While the total number of applications made in the first allocation round was not made public, National Grid disclosed that the total value of all applications received was £1,176.3 million based on the Administrative Strike Prices (ASPs). This suggests that only around 36% of the projects[5] were successful in securing a CfD Contract. Although it is not known how this ratio changes at pot level, based on our conversation with stakeholders and our understanding of the pipeline, we are comfortable to conclude that both pots were oversubscribed.

Observations

2.27 A final judgement of the success of the October 2014 allocation round will need to wait until the projects have commissioned so some caution in reaching conclusions is needed. However, we believe that the outcome of the auction has provided the required comfort that the new regime is capable of producing the expected benefits it was designed for.

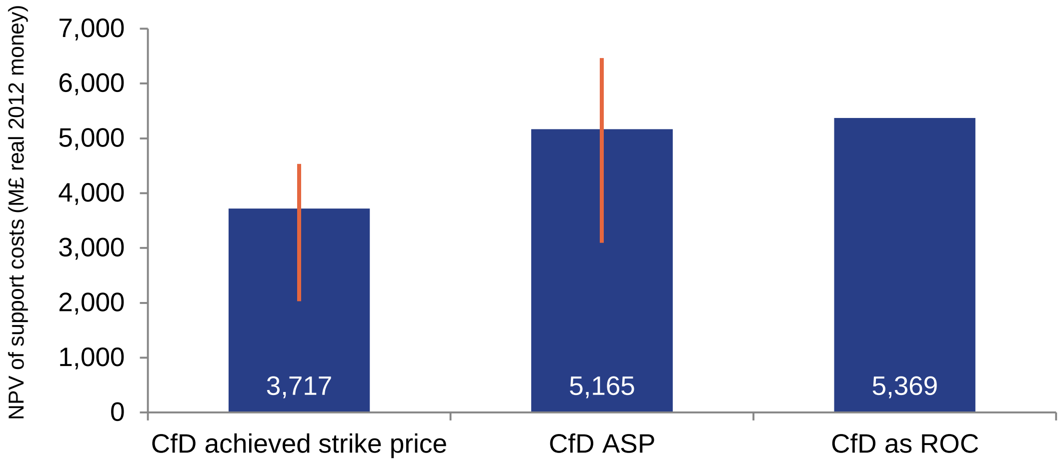
2.28 The round appears to have secured sufficient capacity to keep the UK on track to meet electricity's contribution towards its 2020 targets within the boundaries of the Levy Control Framework according to DECC October 2014 spending projections. However, further CfD rounds for delivery prior to 2020 are recommended given uncertainty over demand, capacity commissioned and load factors, and to ensure a smooth build out to 2030 and beyond in line with the 2050 decarbonisation targets.

2.29 Competition seems to have delivered a relatively lower cost to consumers compared to the previous regime, ie Renewables Obligations. The competitive tension enabled the delivery of around 2.1GW of capacity at clearing strike prices at a considerable discount to the ASP. This has meant that the round secured significantly more capacity than if, hypothetically, the CfD contracts had been awarded the Administrative Strike Price, ASP, on a first come first served basis, or they had been supported under the RO. Figure 5 below makes the comparison.

4 Two solar PV projects – Wick (19.1MW) and Royston (13.78MW) solar parks developed by Hadstone Energy Ltd. and Royston Solar Farm Ltd, respectively – were awarded a contract, but decided to withdraw before signature.

5 Based on anticipated spent as per auction valuation formula.

Figure 5 – Difference in support cost between the CfD and the RO



2.30 Pragmatically, to meet the challenging timetable, timelines had to be condensed and some detail deferred. The transparency and appropriateness of the design process did not score uniformly across work streams, however, industry was generally supportive of the CfD process, believing that the main structures of the CfD should be maintained. Nevertheless, significant scope remains for streamlining processes and amending detailed aspects of the CfD.

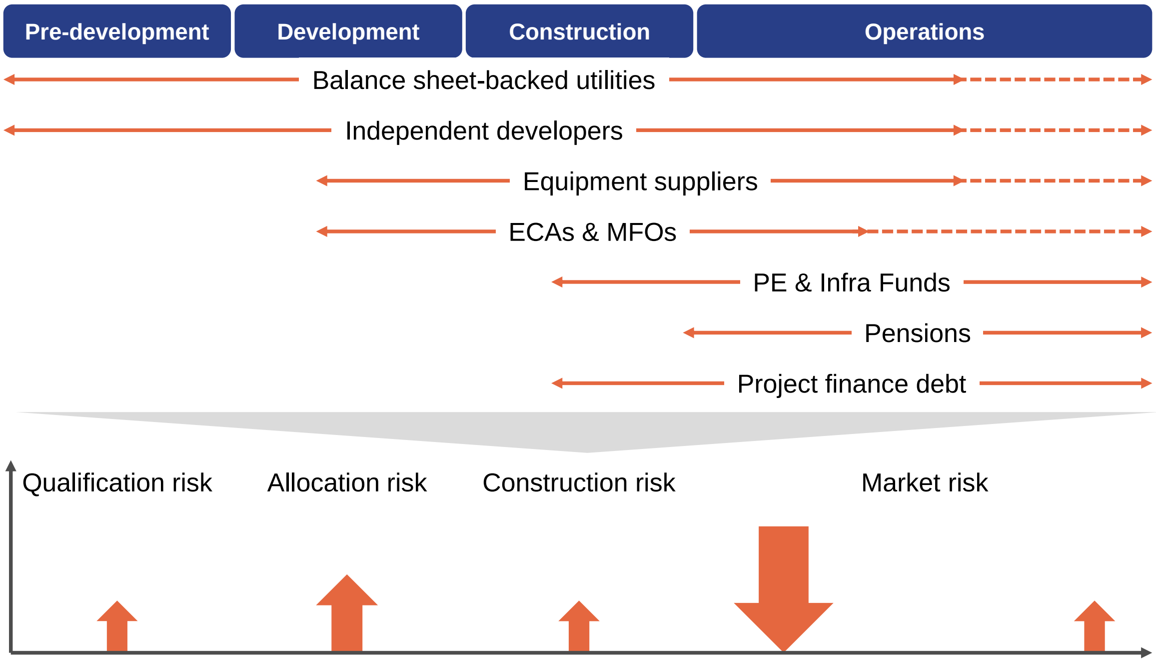
2.31 Restrictions on access to data gathered by National Grid prevented detailed analysis of the auction mechanics and we believe that there may be valuable insights that are being lost. These provisions were put in place to give investors stronger confidence that DECC would not have access to sensitive commercial data. While we agree with this principle, in practice many of the stakeholders we interviewed did not appreciate this distinction. In any case, we think there is scope for relaxing some of the constraints and improve evidence for policy making.

2.32 A full analysis of the CfD's success in encouraging investment will only happen when the RO scheme is not operating in parallel and when the pipeline built up for it has been run down. Many of the current projects have significant sunk costs, and viewed the RO as a fall-back to the CfD for funding. While the first round notionally delivered just above 2GW of capacity, it is possible that this is just the natural progression of a suite of well-developed projects.

2.33 The change in regime produces a considerable shift in risk over the project life-cycle (lower during the operational phase, but higher in earlier phases) compared to an extended Renewables Obligation (RO) under the same Levy Control Framework constraints, as illustrated in Figure 6. This shift results in a different distribution of the total quantum of risk over a project's life, which does not uniformly affect all classes of investors. These will have a different perception of risks depending on their role in the project, its characteristics and competitive positioning, and the timing or priorities leading to the investment.

2.34 In a perfectly functioning CfD market, we expect the total quantum of risk to be lower than under an extended RO, everything else being equal. However, while we would expect successful projects to have a lower risk than equivalent RO-funded projects, the development of a future healthy pipeline relies on the ability of developers to manage the risk in the early stages of the development (as illustrated below).

Figure 6 – Sources of capital and risk during the life-cycle of a CfD renewable project



Note: Export Credit Agencies (ECA) & Multilateral Financial Organisations (MFOs). Please note that entry/exit patterns depend on the project size, and the technology and strategy of individual investors. It is also a function of the market circumstances. This is just an example for an average project.

2.35 There are a number of circumstances, that are not necessarily structural, but that can temporarily alter the balance of risks over the project life-cycle and affect the perception of risks (eg lack of visibility on future budget levels and auction frequency, evolution of competition, etc.). This could in practise prevent the current CfD regime from delivering the full theoretical benefit and create the potential for an investment hiatus.

2.36 The magnitude and timing of financial benefits in terms of cost of capital levels and financing practises are uncertain at this stage. Lower overall cost to consumers may be achieved, not only from a lower cost of capital, but also from other factors, such as removal of infra-marginal rents across the value chain of the industry.

CFD recommendations

2.37 We recommend the following steps in relation to the CfD:

- **Maintain stability of the current structures and processes to ensure investors can adjust to the scheme, while recognising that there is plenty of scope for further evolutions to correct and streamline processes in detail:**
  - Refocus modelling resources to areas that now take on greater prominence (eg from ASP to budget setting, more emphasis on pipeline and less on technology costs);
  - Put in place a more transparent and consistent approach to pot allocation, maxima and minima policy decisions;
  - Streamline the allocation process (eg rolling application process, frequency of allocation rounds, process for review/appeals, etc.) to decrease uncertainty for participants, facilitate participation and mitigate risk of speculative applications;
  - Maintain the auction design, but reduce some of the complexities related to flexible bids; and
  - Encourage stakeholders' engagement, knowledge dissemination via the delivery bodies and circulation of consistent information.

- **Facilitate the CfD to deliver on its expected benefits as well as ensure a healthy pipeline of projects to reach renewables and decarbonisation targets beyond 2020:**
  - Provide long-term structural visibility of Government's commitments – specifically budgets and pot allocation, frequency of future rounds and strike prices – recognising Government's requirements for flexibility, but providing clearer rationale and robust mechanisms for change;
  - Provide for future CfD Rounds for delivery prior to 2020 as currently contracted capacity may not be sufficient to meet electricity's contribution towards its 2020 targets.
  - Increase the level of transparency of the auction results and relax some of the rules restricting Government's access to data gathered from the allocation process;
  - Reinforce some of the measures against speculative6 and disruptive behaviours7 that could reduce the efficiency of the CfD allocation process and/or produce outcomes inconsistent with the policy intent. This should be done in balancing the likelihood of risks with proportionality and assessment of additional costs of measures.
- **Implement significant proactive monitoring of awarded projects[8] and those in the development pipeline to ensure there is time for any corrective actions if problems emerge. This will be particularly to:**
  - Monitor the ability of budget and overall policy to provide a healthy level of competition;
  - Assess the evolution of strike prices over multiple rounds and the actual deliverability of contracted capacity with the objective to verify whether project efficiencies, innovation and cost reductions are facilitated by the regime;
  - Identify if there are any investment hiatus issues with new investments once the RO-led pipeline dries out;
  - Assess whether the CfD Contract proves itself as suitable for various financing structures and project deliverability during the construction phase; and
  - Monitor how conditions for access to financing and route to market agreements evolve with the objective to identify barriers to investments and/or benefits realised by investors that should be transferred to the final consumers.
- **Identify the end goals of the CfD as a process to ensure the outcomes of the enduring regime are in line with Government's longer term goals including the:**
  - desired future electricity mix; and
  - transition of low carbon technologies from support to being sufficiently mature to compete without support.

[6] Speculative projects are those that are not sufficiently mature and have a low chance to deliver against their contractual commitments in the event they were allocated a CfD Contract.

[7] Disruptive behaviours are those adopted by participants that may delay the process, try to game the system to the detriment to other participants or simply consist in submitting bids that are not realistic for their project.

[8] LCCC has already been tasked with monitoring the CfD Contracts. We would recommend DECC to build on this experience for policy development purposes.

Concluding remarks

2.38 The first round delivery of EMR has exceeded expectations in many areas and managed the tensions between cost and delivering capacity. Our view, supported by the vast majority of industry stakeholders, is that the fundamental structures should be kept and industry focus should be on streamlining processes and evolving policy detail.

2.39 While the individual instruments appear to be performing well, we have some concerns regarding some aspects of cohesion across the CM and CfD in the delivery of overall EMR objectives. This stems from the neutrality of each instrument to the wider characteristics of the capacity that they incentivise. This point and its importance is explained below:

- The Capacity Market is neutral to characteristics other than the cost of capacity provision. This potentially increases the burden on the CfD to deliver carbon emission or intensity related targets. If the Capacity Market supports retention of existing capacity or delivery of new capacity with higher emissions, then the CfD may be required to deliver more low carbon generation than would otherwise be the case, with the potential for higher costs.
- The CfD is similarly neutral to the characteristics of the low carbon generation that it supports. Low carbon generation sources differ in terms of their ability to deliver reliable output. For example, wind and solar generation output is dependent upon meteorological conditions. The contribution of reliable capacity from low carbon sources has a bearing on the requirement under the Capacity Market. Greater volumes of reliable low carbon generation will reduce the Capacity Market requirement, while greater volumes of variable low carbon generation will increase the Capacity Market requirement.

2.40 These tensions should be monitored. If the operation of individual mechanisms is considered to be increasing overall system wide costs relative to alternative potential capacity mix permutations, then their interaction should be reviewed.

2.41 In conclusion, when viewed in the round, it is our view that in EMR, DECC does have the necessary policy instruments to deliver its goals, but they are very complex and can interact in intricate and potentially unpredictable ways. In this context, to help ensure that the policy instruments are effectively delivering energy policy objectives across the piece, there is a need for regular monitoring and review of their operation and the outcomes that they promote.

2.42 We are grateful to the DECC team for their cooperation and active involvement in our process: our report reflects the many constructive discussions we had with DECC during the project. The engagement was mirrored by the enthusiastic response from the multitude of industry stakeholders who provided such valuable insight.

3 Introduction

The evaluation

3.1 The evaluation, commissioned by the Department of Energy & Climate Change ('DECC' / the Department / the Client), is for an independent evaluation of the first round of Electricity Market Reform ('EMR') Delivery (first allocation round for Contracts for Difference, and the first Capacity Market auction), and the Final Investment Decision (FID) Enabling for Renewables process (the Evaluation). For the purposes of this document, the first allocation round of Contracts for Difference will be referred to as 'CfD', the first Capacity Market auction as 'CM' and the FID Enabling for Renewables process will be referred to as 'FID Enabling for Renewables'. Collectively, CfD, CM and FID Enabling for Renewables will be referred to as the 'Programme Elements'.

3.2 The evaluation was delivered by a team led by Grant Thornton and Pöyry, and included Professor Steve Martin and Professor Derek Bunn (the Evaluation Team). Field work and analysis was carried out in the period November 2014 to June 2015 and the text in the report is consistent with the programme situation during this period.

Background of the evaluation

3.3 The EMR programme is long-term and designed to meet the UK's long-term energy objectives. The Evaluation Team were asked to report after the first round of the programme. The evaluation is a key source of evidence for the Department and their Delivery Partners in their on-going delivery of the programme and lessons learned will be required to feed into any changes that may be required during future rounds of the programme.

3.4 The overall evaluation comprised a mixture of process assurance, analysis of outputs against Departmental objectives and qualitative work with external participants and stakeholders in the electricity generation and financial investment sectors.

3.5 The outcomes of the evaluation are being split between two reports:

- An EMR report which focusses on the first allocation round for CfD and the first CM auction (this report)
- A FID Enabling for Renewables report

3.6 This report covers the first round of EMR Delivery, the first allocation round for CfD and the first CM auction. Given that FID Enabling was a precursor to CfD there are cross overs and inter-linkages between these two elements which the evaluation captures. It is recommended that anybody with an interest in CfD reads both reports. A key aspect of the evaluation was that the research methods and fieldwork were aligned as closely as possible across the assessment of EMR Delivery and FID Enabling for Renewables. Themes and issues emanating from the FID Enabling for Renewables evaluation and which are pertinent to the ongoing CfD and possibly CM programmes have been incorporated into this report.

Aims and objectives of the evaluation

3.7 The key aims and objectives of the evaluation were to provide:

- assurance and lessons-learned on the first year operation of EMR processes;
- evidence-based advice on EMR policy and processes to inform the second year of operation;
- recommendations that would support the development of updated secondary legislation process and making any changes to the CM and CfD parameters and processes, recognising the tight timescale to make changes;
- scoping and an initial examination of the extent to which EMR and FID Enabling for Renewables are on track to meet objectives;

- identification of any gaps in the supply of data and any other issues that will be required to evaluate the programmes over the longer-term; and
- an evaluation of the process for allocating early Contracts for Difference through the FID Enabling for Renewables process

Evaluation questions

3.8 At the core of the evaluation, were a set of key evaluation questions and sub-questions that DECC had identified against which evaluation evidence was collected and analysed. These sub-questions were split into three groups in order to phase them accordingly:

- **FOCUS**: sub-questions which we expected to answer within his project.
- **SCOPE**: more exploratory sub-questions, for which we scoped the methodology that could best answer the question and the timescale that would be necessary
- **DEFER**: these questions could not be meaningfully covered at this stage or were an expressed focus of a later evaluation. They were not covered at all and were included purely to give a sense of long-term direction.

3.9 As the evaluation has progressed there has been some amendments to the categorising of these questions. A full list of the amended questions and the programme of work to undertake the evaluation is set out in Annex H.

Evaluation framework

3.10 Based on the list of questions proposed by DECC, four major threads with common evaluation frameworks were identified:

- **Design and parameters** – evaluation of the principles and numerical inputs of the programme's design;
- **Process** – how well the processes were designed (prior to implementation) and managed (after implementation);
- **Outcome** – impact/economic evaluation of the short to medium term 'factual' results and consequences of programmes;
- **Policy objectives** – impact/economic evaluation of whether programmes are on track to meet long-term policy objectives. At this early stage, any such view will be indicative.

3.11 These evaluation threads were discussed and validated jointly with DECC officials together with the focus, scope and defer prioritisation of questions. They also formed one part of a structural element for guiding the selection of specific methodologies and for realising synergies. The other part was the emerging themes that arose given that this was a real time evaluation of a live process.

Out of scope activities

3.12 The following aspects of Programme Elements are specifically excluded from this evaluation:

- Evaluation of the Hinkley Point C nuclear Contract for Difference (CfD);
- Carbon Capture & Storage (CCS);
- Levy Control Framework (LCF), and how the renewable CfD interacts with the other spending items capped by the LCF;
- Supplier Obligation;
- Performance of the Low Carbon Contracts Company (LCCC) or Electricity Settlements Company;
- Compliance of the CfD with State Aid guidelines; and
- Electricity Demand Reduction (EDR) which is subject to its own evaluation.

3.13 In addition, there will be insufficient information on several important policy areas to evaluate during this project, although they are in scope for longer-term evaluation work. These are:

- Delivery of CM/CfD projects against milestones; and
- Market effects eg refinancing, offtake contracting practices, etc

Introduction to EMR policy instruments

EMR overview

3.14 The government's objectives for EMR are to:

- **Ensure a secure electricity supply** by incentivising a diverse range of energy sources, including renewables, nuclear, CCS equipped plant, unabated gas and demand side approaches; this will ensure the UK has sufficient reliable capacity to minimise the risk of supply shortages and to reduce the reliance on fossil fuels.
- **Ensure sufficient investment in sustainable low-carbon technologies** to put the UK on a path consistent with our EU 2020 renewables target and the UK's longer term target to reduce carbon emissions by at least 80% of 1990 levels by 2050.
- **Maximise benefits and minimise costs** to the economy as a whole and to taxpayers and consumers. Maintaining affordable electricity bills while delivering the investment needed.

3.15 The key elements of the EMR package are CfD to support investment in low carbon generation and a CM to support security of supply. These are supported by the Carbon Price Floor (CPF), the Emissions Performance Standard (EPS), measures to incentivise Electricity Demand Reduction (EDR), measures to support market liquidity and access to market for independent renewable generators and the transitional arrangements from the Renewables Obligation and the CfD, ie the Final Investment Decision (FID) Enabling for Renewables, which were implemented under a separate process.

3.16 In December 2013, the Energy Bill 2013 gained Royal Assent. This made provisions for CfD and the CM. Following this, secondary legislation was tabled to give effect to more detailed aspects of the arrangements, including CM Rules and CfD Allocation Framework. In June 2014, DECC published its final policy position for implementation of EMR.

Summary of Capacity Market design[9]

Overview

3.17 The 2011 White Paper[10] identified security of supply as an unprecedented challenge for the UK as a result of the closures of existing plants. This paper outlined that over the next decade the UK will lose around a quarter (20GW) of the existing generation capacity and the need to ensure there is sufficient flexible generation. The Government's intention was to offer reliable and investable long-term contracts for capacity. The primary challenges identified by the Government were:

- Diversification of supply,
- Operational security, and
- Resource adequacy.

9 This section is not intended to provide a full description of the Capacity Market design, but rather to provide an overview of important aspects that are referred to in the remainder of the section. Further details are provided in DECC publications such as 'Implementing Electricity Market Reform (EMR)', June 2014.

10 'Planning our electric future: a White Paper for secure, affordable and low-carbon electricity', DECC, July 2011.

3.18 The introduction of a Capacity Market is a key component of EMR. The aim of the Capacity Market is to secure sufficient electricity supplies to meet a defined reliability standard at an affordable cost. It offers capacity providers a capacity payment revenue stream, in addition to energy market and ancillary services revenue streams, in return for which they commit to deliver electricity in periods of system stress or face exposure to penalties if they fail to deliver.

3.19 Capacity Agreements are allocated to providers through auctions intended to secure a capacity requirement needed to meet a reliability standard defined by Government. The auction clearing price forms the basis of the capacity payment to successful auction participants.

Regulatory framework

3.20 The Energy Act 2013 laid the foundations for the Capacity Market and stated that regulations would be made by Statutory Instruments (SI). The SI for the Capacity Mechanism are:

- Electricity Capacity Regulations 2014 – latest version 2015 (no. 875)
- Electricity Capacity (Supplier Payment etc.) Regulations 2014 (no. 3354)

3.21 The Capacity Market Rules work alongside the Regulations. The Rules provide the detail for implementing the operating framework set out in regulations. The Rules focus on the technical and administrative rules and procedures for how the Capacity Market operates and includes matters such as procedures relating to the day-to-day running of the Capacity Market, the process by which capacity providers pre-qualify, and rules for running capacity auctions and issuing capacity agreements to successful bidders.

Scheme design

3.22 Capacity requirements for each delivery year will be secured through a 4 year-ahead auction (T-4), supplemented by a further 1 year-ahead auction (T-1). Each auction will operate on a 'pay-as-clear basis', with all successful bidders receiving the clearing price. A 'descending clock' format applies, under which bidders indicate the quantity of capacity that they are prepared to offer at an announced price, starting at the price cap in the first round[11]. Bidders indicate an 'exit price', which is the minimum price at which they are prepared to offer capacity. When the announced price falls below a bidder's exit price, its capacity is removed. In subsequent rounds, the price is progressively lowered, with the decrement set at £5/kW/year for the December 2014 auction, until supply intersects the administered demand curve and the auction clears. The auction clears when supply is less than or equal to demand at the relevant bidding round price floor. All cleared bids receive the clearing price set by the last accepted bid[12].

3.23 The amount of capacity to be secured is determined with reference to an enduring reliability standard set by the Secretary of State. The reliability standard has been set at 3 hours Loss of Load Expectation (LOLE)[13] per year.

11 This is a non-variable price duration auction. The Rules also allow for variable price-duration auctions (although this option was not adopted for the December 2014 auction). Under the variable price-duration format, participants can vary price and duration in their bids.

12 Where there is not an exact match between supply and demand, a clearing algorithm is used to set clearing volume and price. The algorithm considers the merits of over-procuring versus under-procuring by considering the integral of the Demand Curve at the two points that are above and below the target volume and subtracting the additional costs associated with over-procurement.

13 LOLE represents the number of hours per annum in which, over the long-term, it is statistically expected that supply will not meet demand. This is a probabilistic approach – that is, the actual amount will vary depending on the circumstances in a particular year, for example how cold the winter is; whether or not an unusually large number of power plants fail to work on a given occasion; the power output from wind generation at peak demand; and, all the other factors which affect the balance of

3.24 Based on this reliability standard, National Grid (in its role as Delivery Body) identified a target capacity quantity required to meet the reliability standard for 2018/19. National Grid proposed that 53.3GW de-rated[14] capacity should be procured for 2018/19[15]. Based on this advice, in June 2014 the Secretary of State set a target capacity of 50.8GW for the T-4 auction, with 2.5GW set aside for the T-1 auction[16]. The target capacity parameter was revised in October 2014[17] to 48.6GW to reflect opt-out decisions submitted during prequalification. The final parameters are provided in Table 1 and the resultant demand curve is shown in Figure 7.

Table 1 – Parameters for 4 year-ahead auction demand curve for 2018/19 delivery

	De-rated capacity	Price (2012 prices)
Target capacity	48.6GW Reduction of 2.2GW from 1 August 2014 target taking account of mandatory CMUs opting-out of the Capacity market but stating that they will remain operational	£49/kW/yr Net Cost of New Entry (Net CONE) based on cost of new CCGT minus expected electricity market and ancillary service revenue
Maximum capacity	47.1GW Target capacity minus 1.5GW	£0/kW/yr
Minimum capacity	50.1GW Target capacity plus 1.5GW	£75/kW/yr Price cap

electricity supply and demand. However, it is important to note when interpreting this metric that a certain level of loss of load is not equivalent to the same amount of blackouts; in most cases, loss of load would be managed without significant impacts on consumers.

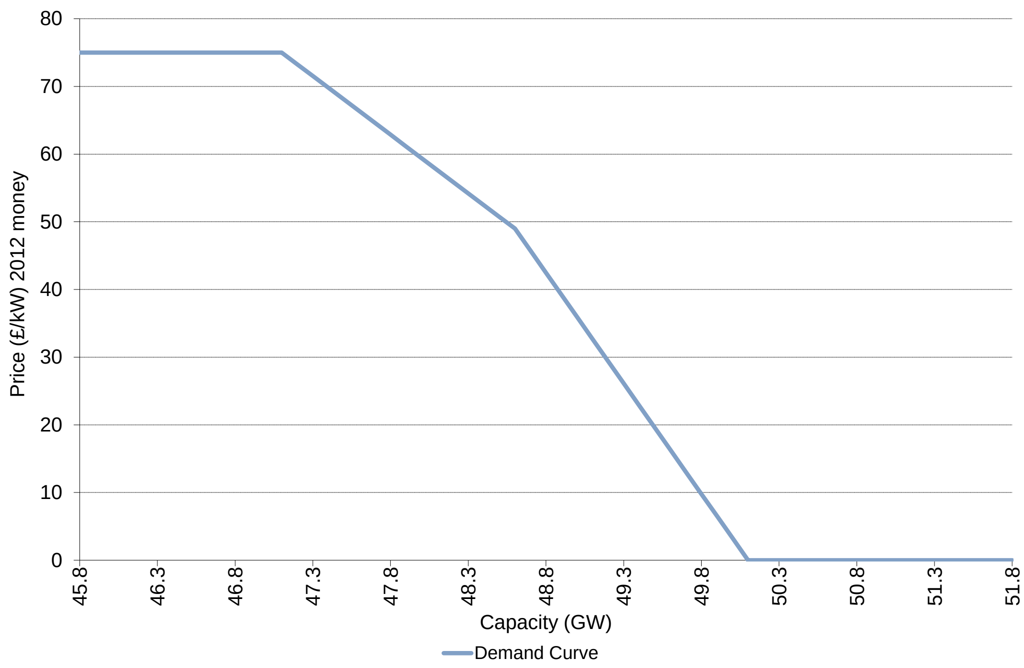
14 The de-rating factors determine the level of Capacity Agreement that can be secured in the Capacity Auction by a given resource. De-rated capacity for a technology is based on historic availability.

15 'National Grid EMR Electricity Capacity Report', June 2014.

16 Confirmation of demand curve parameters for the first capacity auction', Ed Davey letter, 1 August 2014.

17 Confirmation of demand curve parameters for the first capacity auction', Ed Davey letter, 13 October 2014.

Figure 7 – 4 year-ahead auction demand curve for 2018/19 delivery



Eligibility

3.25 The Capacity Market is intended to be technology neutral across generation, storage and demand side providers and to allow new entrants and existing capacity to participate. However, there are some limitations on participation:

- Interconnection and interconnected capacity were not eligible within the first auction, but interconnectors will be eligible in the 2015 auction for delivery in 2019/20.
- Low carbon capacity sources receiving support payments via the Renewables Obligation, Contract for Difference Feed-in Tariffs (CfDs), small scale (<5MW) FITs, NER300 and the UK CCS Commercialisation Programme are also ineligible, at least while they are in receipt of administratively determined payments, to avoid potential double payment.
- Parties holding long-term STOR contracts are also ineligible unless they make an irrevocable declaration to terminate their STOR contracts if awarded a capacity agreement.
- Small scale (<2MW) capacity is not eligible unless combined with other capacity through an aggregation service.

3.26 Participation is voluntary for eligible capacity sources. Parties must for each of their eligible, licensable units either apply to pre-qualify or, for existing generation that they do not wish to bid in the capacity auction, submit an opt-out notification. The opt-out notification must state whether the generator intends to run the unit during the delivery year and, if not, whether it is retiring the plant or closing it temporarily.

3.27 Eligible capacity that has not opted-out can then participate in the auction on the basis of its de-rated capacity.

Auction process

3.28 There are variations in bidding options and the Capacity Agreements on offer depending upon whether the capacity is existing, refurbished or new and also if it is DSR. The dimensions are summarised in Table 2 and discussed below.

Table 2 – Bidding and agreement variations by capacity status

		Price Taker or Price Maker		
		Price Taker	**Price Maker**	**Capex threshold**
Agreement length	**1 year**	Existing plant (default position)	Existing plant (with justification) DSR	n/a
	<3 years		Refurbishing plant	£125/kW
	<15 years		New plant	£250/kW

3.29 The default position is that existing capacity providers (not refurbishing) are Price Takers. Price Takers must submit an exit price at or below a defined Price Taker Threshold (PT Threshold), which was set at £25/kW/yr (2012 prices) for 2018/19. Price Takers cannot exit the auction until the price drops below the PT Threshold. The Price Taker status and the PT Threshold were introduced as measures to mitigate potential for anti-competitive behaviour. Existing capacity can alternatively select Price Maker status and so not be bound by the Price Taker Threshold. This must be backed by submission of a Price Maker Memorandum to the Authority that provides supporting rationale justifying why the relevant capacity should be able to bid above the PT Threshold. New and refurbished plants and DSR are classed as Price Makers, having freedom to select their own bid price within the auction without the need for justification.

3.30 In terms of duration, the default position is that Capacity Agreements have a tenure of one year, although there are exceptions. In the T-4 auction, new build and refurbishing plant have the ability to select longer term Capacity Agreements (up to 15 years for new plant and up to 3 years for refurbished plant) to support an investment case for associated capital expenditure. In line with the default position, non-refurbishing existing capacity and DSR can secure 1 year Capacity Agreements through the auctions, as can interconnectors from the 2015 auction.

3.31 In the T-4 auction, all agreements are adjusted for inflation between the base year at auction and the delivery year, and longer term agreements are adjusted for inflation on an annual basis for the agreement duration.

Funding mechanism

3.32 The Electricity Capacity (Supplier Payment etc.) Regulations 2014 require electricity suppliers to make two types of payments: a capacity market supplier charge to fund capacity payments and a settlement costs levy to fund the settlement body's costs (ESC). The first delivery year for which suppliers will be liable to pay the capacity market supplier charge will be the DSR Transition Delivery Year 2016/17.

3.33 Suppliers will need to submit a forecast of their demand by 1 June 2016 in order for the Settlement Body to calculate each supplier's share of the supplier charge for the 2016/17 delivery year. The liability for paying the Settlement Body's costs begins when the regulations come into force, these will be collected as a single payment at the end of FY 2014/15, after which they will be collected monthly.

Summary of Contract for Difference design

Overview

3.34 DECC designed the Contracts for Difference (CfD) with the primary objective of encouraging investments in low-carbon generation technologies cost-effectively. As defined in the 2011 White Paper[18], the high level principles that have informed the CfD design are:

- Efficiency;
- Cost to society;
- Barriers to entry;
- Coherence; and
- Practicality.

3.35 In order to meet the EMR objectives the CfD regime was designed to:

- be an investable instrument, which is attractive to a wider pool of capital sources;
- mitigate key risks of renewables projects, which allows investment to come forward at a lower cost of capital;
- introduce competition as a conduit for cost reduction and eliciting project efficiencies;
- ensure diversity across technologies and companies; and
- keep spending within the Levy Control Framework (LCF) and enabling support to be approved under the EU State Aid guidelines.

3.36 The policy mechanism to support low carbon generation intended to find an appropriate balance between wider policy goals (eg carbon targets) and market impacts (eg interaction with unanticipated carbon prices, fossil fuel prices or technology costs). The CfD regime was identified as the support mechanism for low-carbon generation, which offered the best balance of results across the assessment criteria: cost-effectiveness, coherence, durability and practicality.

3.37 CfDs seek to provide greater certainty and stability of revenues to electricity generators by reducing their exposure to volatile wholesale prices, whilst protecting consumers from paying for higher support costs when electricity prices are high. CfDs also provide a reliable long term contract protecting generators, such as in the event of unforeseeable changes in law and force majeure events. The initial analysis from the Government on introducing a CfD concluded that CfDs scored well on all three of the Government's key objectives: decarbonisation (2050 commitment, 2020 targets), security of supply and cost-effectiveness. However, the Government did also note at this time that there were a number of design and implementation issues that needed further consideration.

3.38 A CfD is a private law contract between a low carbon electricity generator and the CfD Counterparty (Low Carbon Contracts Company, or LCCC), a government-owned company. The generator is paid the difference between the 'strike price', a price for electricity reflecting the cost of investing in a particular low carbon technology, and the 'reference price', a measure of the market price for wholesale electricity in the market. The CfD Contract duration is primarily for 15 years, however, support for biomass conversions will cease in 2027 and bilaterally negotiated contracts will have a longer term as determined on an individual basis.

3.39 There are two routes to achieve a CfD:

- Generic allocation process, which is the one most eligible technologies would pursue (and our evaluation will focus on); and

18 'Planning our electric future: a White Paper for secure, affordable and low-carbon electricity', DECC, July 2011.

- Bilaterally negotiated, where the Secretary of State can direct the LCCC to offer a contract to an eligible generator (eg early nuclear or tidal barrage).

3.40 In the following sections, we provide a brief summary of the main features of the CfD. Further details can be found in the official documents listed in the following section.

Regulatory framework

3.41 The Energy Act 2013 and the Statutory Instruments (SI) created the legislative framework for EMR. The CfD specific SI are:

- The Electricity Market Reform (General) Regulations 2014 – latest version 2015 (no. 718)
- Contracts for Difference (Definition of Eligible Generator) Regulations 2014 – latest version 2014 (no. 2010)
- Contracts for Difference (Allocation) Regulations 2014 – latest version 2015 (no. 981)
- Contracts for Difference (Electricity Supplier Obligations) Regulations 2014 – latest version 2014 (no. 2014)
- Contracts for Difference (Standard Terms) Regulations 2014 – latest version 2014 (no. 2012)
- Contracts for Difference (Counterparty Designation) Order 2014 – latest version 2014 (no. 1709)

These SI are collectively referred to as the CfD Regulations in this report, unless otherwise specified.

3.42 The Allocation SI sets out that the Secretary of State must ensure that an Allocation Framework applies to each allocation round. The Allocation Framework sets out the allocation process by which the National Grid determines which qualifying applications are successful and the applicable strike price. The Allocation SI also sets out the CfD notices to be made publically available, including the notice that the Secretary of State may establish an allocation round and the content of that notice. The Secretary of State must also by notice specify for the allocation round the overall budget and applicable administrative strike prices, this notice may also specify ‘minima’ and ‘maxima’ and division of the overall budget into ‘pots’.

3.43 The CfD instrument itself is a private law contract structured into two documents, together referred as the CfD Contract in this report[19]:

- CfD Agreement; and
- CFD Standard Terms and Conditions.

Scheme design

3.44 Eligible CfD technologies are able to apply in the announced allocation rounds, the Administrative Strike Prices (ASP) for these technologies for the delivery years 2014/15 – 2018/19 were published in the December 2013 Final Delivery Plan[20]. The table below shows the administrative strike prices for each technology for the 2014/15 allocation

19 Note that there are variations to cover Private Networks and Phasing: CFD (Phase 1) Agreement (Single Metering) with footnotes, CFD (Phase 2) Agreement (Single Metering) with footnotes, CFD (Phase 3) Agreement (Single Metering) with footnotes, CFD (Phase 1) Agreement (Apportioned Metering) with footnotes, CFD (Phase 2) Agreement (Apportioned Metering) with footnotes, CFD (Phase 3) Agreement (Apportioned Metering) with footnotes and Private Network CfD Agreement with footnotes.

20 https://www.gov.uk/government/uploads/system/uploads/attachment_data/file/268221/181213_2013_EMR_Delivery_Plan_FINAL.pdf

round; the stated year is the financial year of a project's target commissioning date. Note the technologies have been grouped by DECC into one of three pots.

Table 3 - Strike prices for renewable technologies (£/MWh, real 2012 money)

Pot 1 (Established technologies)	2014/15	2015/16	2016/17	2017/18	2018/19
Energy from Waste (with CHP)	80	80	80	80	80
Hydro	100	100	100	100	100
Landfill Gas	55	55	55	55	55
Solar PV >5MW	120	120	115	110	100
Onshore Wind	95	95	95	90	90
Sewage Gas	75	75	75	75	75
Pot 2 (Less established technologies)	**2014/15**	**2015/16**	**2016/17**	**2017/18**	**2018/19**
Advanced Conversion Technologies (with or without CHP)	155	155	150	140	140
Anaerobic Digestion (with or without CHP)	150	150	150	140	140
Dedicated Biomass (with CHP)	125	125	125	125	125
Geothermal (with or without CHP)	145	145	145	140	140
Offshore Wind	155	155	150	140	140
Remote Islands Onshore Wind				115	115
Tidal Stream	305	305	305	305	305
Wave	305	305	305	305	305
Pot 3 (Biomass Conversion)	**2014/15**	**2015/16**	**2016/17**	**2017/18**	**2018/19**
Biomass Conversion	105	105	105	105	105

3.45 At inception, the CfD regime was meant to move towards a competitive allocation over three consecutive phases. After an initial First-Come-First-Served stage, where Contracts are signed based on the ASPs, a constrained allocation follows, where ASPs simply act as a cap as competition may drive the achieved strike price below the ASP. It is worth noting that bilaterally negotiated contracts, for example nuclear and CCS, do not have an administrative strike price, but are awarded a project-specific strike price.

3.46 Within the standard CfD Contract there are different applicable terms to reflect the underlying operational characteristics for different low carbon technologies: baseload and intermittent. Under baseload CfD contracts, the market reference price is based on a weighted average of season-ahead forward trades made in the preceding season (potentially moving to year-ahead). However, a day-ahead hourly reference price will be used for intermittent CfDs. Baseload CfDs apply for technologies including biomass, landfill gas, sewage gas, waste with CHP and hydro. Wind, solar, wave and tidal stream power projects are able to access intermittent CfDs.

3.47 The overall amount of support available through CfDs is controlled, due to the Government's need to manage the overall level of support paid by consumers under the Levy Control Framework (LCF). The LCF also covers spend under the Renewables

Obligation (RO), FID Enabling for Renewables, small scale Feed-in Tariff (ssFIT) as well as the cost of running the LCCC and caps the level of support paid for by consumers. CfDs will be allocated to eligible generators via a defined allocation process, with generators having to make applications for CfDs during pre-specified allocation rounds. The first allocation round commenced in October 2014 with the first CfDs awarded in February 2015. Spending under the LCF and its interaction with other support schemes is not covered in this report as it is out of scope.

3.48 The Government will determine the budget for the CfDs to be awarded in each allocation round. This budget will identify the total amount of financial support that is available for allocation and is currently divided into three pots:

- **Pot 1 (established technologies)**: those technologies considered most mature including onshore wind (>5MW), solar PV (>5MW), energy from waste CHP, hydro, landfill gas and sewage gas;
- **Pot 2 (less established technologies)**: technologies considered less mature including offshore wind, tidal stream, wave, anaerobic digestion (>5MW), advanced conversion technologies and dedicated biomass with CHP, geothermal, remote islands onshore wind (for the October 2015 allocation round onwards, subject to State Aid); and
- **Pot 3 (biomass conversion)**: exclusive to biomass conversions.

Eligibility

3.49 The National Grid (in its role of Delivery Body) is responsible for providing analysis to inform ministers' key EMR decisions, primarily on the level of CfD support for low-carbon technologies and administering the CfD. Eligibility to apply for a CfD varies for different projects and all applications are assessed on an individual basis by National Grid. The main eligibility requirements are: applicable planning consents, a grid connection agreement, not in receipt of support from RO, ssFIT or Capacity Market, incorporation details and an approved supply chain if 300MW or more.

Auction process

3.50 At the beginning of each allocation process, developers are invited to submit applications for their projects including capacity and target commissioning date. It will then be determined whether an auction is required, based on whether the funding required for all eligible projects, valued at their ASP, exceeds the budget. If the budget is not exceeded, then an auction is not required and all eligible applicants will be offered a CfD contract at their ASP.

3.51 In the event that an auction is required, eligible generators seeking a CfD are invited to submit sealed-bids, including details on strike price, capacity and target commissioning date. Flexible bids can also be submitted. For each pot projects will be ranked according to their bids, and an assessment carried out on each in turn, starting with the lowest strike price, to see if the allocated budget pot would be exceeded by awarding a contract to that project.

3.52 Auctions for CfDs are 'pay-as-clear' and all bids are stacked in order of price with the cheapest being accepted first up to the most expensive that can be afforded. All projects which are accepted for a contract in a particular delivery year will receive a CfD with the same clearing strike price, being the strike price that was bid by the last accepted project for that delivery year. Bids are capped at the published ASP for each technology, meaning that if the clearing price is higher than the technology's ASP, then that technology will only receive their ASP.

Funding mechanism

3.53 The Electricity Supplier Obligation SI imposes an obligation on electricity suppliers to make payments to the LCCC. The payments are made to enable the LCCC to cover their payments to generators and their costs in administering the CfD scheme. Obligation periods will be quarterly and the first period commenced on 1 April 2015. Payments from suppliers to the LCCC consist of an interim levy, reconciliation, reserve and mutualisation payments, as well as the provision of collateral from suppliers. Suppliers can recoup their costs from their customers.

3.54 Payments to generators will be based on metered output (adjusted for transmission losses) and will be calculated and paid by the LCCC. Generators will receive statements from the LCCC, seven business days after the applicable full day of generation. The statement will detail the LCCC's calculation of the difference amount payment to be made to or by the generator. If the LCCC is required to pay the generator, it will do so no later than twenty-eight calendar days following the day of generation. If the generator is required to pay the LCCC, it must do so no later than the end of the tenth business day following the delivery of the relevant billing statement.

4 Overarching EMR-wide findings

Key messages

4.1 The Capacity Market and CfD chapters highlight detailed findings that are specific to each of the individual policy instruments. A number of themes identified are common to both instruments and are presented here in summary, with more details for the specific policy instrument in the relevant Section:

- General appreciation that DECC and its delivery partners have worked hard to deliver a complex reform in a relatively short timescale[21]. Programmes were delivered and the first auctions run.
- DECC's engagement with its stakeholders on EMR policy was extensive both in terms of scope and breadth of participation. It required a substantial level of interaction between DECC and stakeholders, which was at times difficult to manage for smaller organisations.
- Principles underpinning the Capacity Market and CfD programmes and what they aim to achieve are generally robust. In particular, cost-effective capacity procurement for Capacity Market and competitive allocation for CfD. But it is too early to infer too much in terms of future effectiveness.
- Government now need to convey a strong message about their commitment to regime stability and long-term visibility alongside specification of objectives. DECC also need to show willingness to fine-tune the detailed implementation through engagement with industry.
- Given the early stages of the reform and the level of uncertainty around how regulations will play out, a monitoring programme should be attentively designed (and communicated). Timely reaction to market signals is essential to identify corrective measures.

Challenges across the package

4.2 As a package, EMR is seeking to deliver the low carbon electricity and reliable supplies that the UK needs, while minimising costs to consumers. As outlined in Section 2, the CfD is the primary tool for supporting the delivery of low carbon electricity, while the Capacity Market is the mechanism for delivery of reliable supplies. These two policy instruments are geared towards achieving their own strand of the overall EMR package. While separate instruments, the CfD and Capacity Market will interact, however, there is the potential for the instruments to pull in opposite directions. This could frustrate the delivery of the overall EMR objectives.

4.3 At a high level there are two main areas where cohesion across the package should be considered. These topics are discussed below. At this stage, more evidence is needed to understand the importance of these issues.

Influence on the make-up of the capacity mix

4.4 In seeking to secure reliable capacity at lowest cost, the Capacity Market is neutral in terms of the underlying nature of the capacity being provided (across the eligible capacity sources). Characteristics such as efficiency or emissions linked to a capacity provider are not explicitly accounted for and the Capacity Market does not distinguish between such variations. Some stakeholders express concern that this allows existing assets with lower efficiency and higher emissions (eg coal) to remain on the system and secure Capacity Agreements in place of alternative capacity sources (eg CHP) which offer wider system benefits in relation to emissions and efficiency. In a similar vein, a number of stakeholders

[21] Implementation was largely managed by EMR delivery partners, with LCCC managing the joint CfD plan. Industry readiness for CfD implementation was coordinated by LCCC (as CfD Implementation Coordinator) working closely with National Grid, Elexon and Ofgem.

express concern that a significant proportion of the new entry capacity that secured Capacity Agreements is linked to reciprocating engines. Again, the potential impact of such capacity on emissions and full system costs are not considered within the operation of the Capacity Market.

4.5 The neutrality of the Capacity Market to characteristics other than the cost of capacity provision potentially increases the burden on the CfD to deliver carbon emission or intensity related targets. If the Capacity Market supports retention of existing capacity or delivery of new capacity with higher emissions, then the CfD may be required to deliver more low carbon generation than would otherwise be the case, with the potential for higher costs. In this context, it is worth noting that existing nuclear, existing pumped storage, hydro, energy-from-waste and CHP projects were successful in the first auction, as referenced in paragraph 5.114.

4.6 The CfD is similarly neutral to the characteristics of the low carbon generation that it supports. Low carbon generation sources differ in terms of their ability to deliver reliable output. For example, wind and solar generation output is dependent upon meteorological conditions. The contribution of reliable capacity from low carbon sources has a bearing on the requirement under the Capacity Market. For a given amount of low carbon capacity, the greater proportion of this that comes from intermittent low carbon generation, the greater the target for de-rated capacity in the Capacity Market will need to be. Conversely, the smaller the proportion that comes from intermittent low carbon generation, the lower the target. However, relative reliability of different low carbon capacity sources and the consequential implications for the Capacity Market are not considered in the allocation of CfDs.

4.7 These tensions should be monitored. If the operation of individual mechanisms is considered to be increasing overall system wide costs relative to alternative potential capacity mix permutations, then their interaction should be reviewed.

Interaction between wholesale price and difference payments

4.8 There is some expectation that the Capacity Market will reduce the wholesale electricity price, and DECC's impact assessments have estimated this impact[22]. However, there is still uncertainty as to the scale of impact. If a downward impact is indeed observed and this affects CfD (and Investment Contract) reference price indices, it will increase the scale of difference payments made to generators (reduce difference receipts from generators). While this interaction was considered as part of the policy development and evaluation, the scale of the effect in reality will have an impact on costs of CfD (and FID Enabling for Renewables) difference payments relative to expectations. Evidence in relation to this will only be available when the schemes are in operation and so this may be a topic to revisit in future.

4.9 Overall revenue to the CfD (and FID Enabling for Renewables) generators should not be significantly affected by this re-balancing. But, depending on the scale of the impact, it increases the amount being paid to generators under support arrangements and may have implications for overall funding available under the LCF.

4.10 This interaction should be monitored to assess the impact of the Capacity Market on wholesale prices relative to ex-ante projections and, hence, the consequential impact on CfD (and FID Enabling for Renewables) difference payments.

[22] 'The Electricity Market Reform – Capacity Market, Impact Assessment', DECC, June 2014.

5 Capacity Market detailed findings

Key messages[23]

5.1 Taking the Capacity Market from policy concept to functioning policy instrument in the timeframe from 2011 to 2014 is a major achievement. The auction ran smoothly and secured capacity for 2018/19 within the target range established by the administered demand curve.

Cannot infer too much from the outcome of the first auction alone

5.2 It is clear that the first auction attracted surplus capacity with just under 65GW of capacity prequalified, including over 9GW of potential new capacity, which created 30% headroom relative to the target requirement going into the first auction round. However, we have had only one Capacity Market auction, giving a single data set in terms of results. We remain 3 ½ years from the start of the 2018/19 delivery period and 1 year from the Financial Commitment Milestone for 2018/19, which will be an important staging post for assessing the delivery of new build projects. As such, it is too early to draw conclusions about the effectiveness of the Capacity Market in delivering long-term security of supply.

Participants calling for stability in the arrangements

5.3 While stakeholders have pointed to possible revisions to the arrangements and highlighted design decisions that they would have made differently, there is generally an over-riding desire for some stability to allow the system to bed-in and for a track-record to be established over several years.

5.4 There is scope for fine-tuning of details or enhancements to procedural or administrative aspects of the arrangements, but the overarching framework and design of the Capacity Market should remain stable. At this stage, the system in place is the one that must be worked with and it would be counter-productive to seek major reform.

DECC process was generally consultative, but with some shortcomings

5.5 DECC conducted an extensive consultation and engagement exercise with stakeholders during the development of the Capacity Market. The consultative nature of the process was generally welcomed and valued, although a number of limitations were also flagged. Participants indicated that keeping up to speed with consultations and policy developments was time intensive in terms of both external engagement with DECC and internal assessments, briefings and decision making within individual companies. For some (including smaller parties in particular), the scale of the process relative to available resource limited the opportunity to actively participate. Additionally, several stakeholders considered that the rationale for some of the changes to design during the development phase and for the final decisions was not always clear. Some perceive that the engagement was, in some cases, a formality for the sake of process rather than genuine.

Expedience of the process prevailed over details during final stages, so need to continue industry engagement

5.6 One consequence of the challenging timetable is that expedience of the process (ie working to meet the timeline) and drive to be ready for the December 2014 auction (which was an auction target date generally supported by stakeholders) may have taken precedence over some aspects of design towards the end of the process. This meant that, in the opinion of some stakeholders, aspects of design were rushed or overlooked to some extent in order to meet the timetable. Issues highlighted in this regard include the requirements for co-firing, treatment of private wires and arrangements for CHP.

[23] This section includes the key messages from the evaluation. Further details to support the messages and information concerning the policy context are provided in the main body of this section.

Demand curve pricing parameters lack transparent methodology

5.7 In addition to the target volume, the administered demand curve also hinges on defined pricing parameters, notably the Net Cost of New Entry (Net CONE) and the Price Cap. However, in line with the views of many stakeholders from a range of backgrounds, our view is that the basis for setting these parameters lacks a transparent methodology and supporting justification. This is important because these values set expectations in terms of, for example, maximum willingness to pay for capacity and can be varied at the discretion of the Secretary of State. So, having a clear methodology for the determining these parameters will increase certainty for participants in future.

5.8 Therefore, transparent methodologies for defining these parameters, including explanation of input assumptions and supporting evidence, as well as an indication of potential sensitivities that will be considered when setting values, should be formally set out within the framework of Rules and Regulations for future auctions.

Mixed opinions on appropriateness of differentiated agreement lengths for new generation projects

5.9 Access to 15 year agreements for new capacity helps to secure finance to support project delivery, as it accommodates typical debt finance and re-finance timescales of around seven years each. Some stakeholders consider that the differentiation between agreement durations for different types of participant creates a non-level playing field and express a preference for annual rolling or multi-year agreements for all. However, there is acceptance that rolling annual agreements were unlikely to be feasible for new projects from the outset given the influence of feedback from the finance community in particular. For the time being, in the interests of providing stability and certainty for participants, retaining 15 years as the maximum Capacity Agreement duration appears an appropriate course of action.

Non-availability of longer-term agreements for DSR has attracted criticism, with more evidence needed

5.10 New Demand Side Response (DSR) can secure Capacity Agreements of one year duration (as per the default position), compared to 15 year agreements for new generating capacity with spend in excess of the defined capex threshold. This has attracted criticism and a number of stakeholders consider this to be discriminatory, creating a non-level playing field that disadvantages DSR relative to generation technologies. But there is some evidence to support the adoption of one year agreements for DSR. For example, the Capacity to Customers[24] project suggests that one year arrangements are the optimal length required to secure a contract with DSR providers[25]. Shorter-term arrangements are also consistent with the rationale for the T-1 auction process, which is that DSR cannot necessarily be locked in on a long-term basis given the potential for future uncertainty regarding the make-up and sign-up of the underlying DSR sites.

5.11 There is a clear tension here. To take this forward, the DSR community should continue to be invited by DECC to supply evidence in relation to the implications of 1 year only agreements on DSR deployment and the potential effects of longer-term agreements on this, as well as assessment of delivery risk issues associated with longer-term agreements. This will allow an evidence-based review of this issue.

[24] The Capacity to Customers project run by Electricity North West tested innovative network management technologies in conjunction with new customer commercial arrangements to release capacity on the distribution network as an alternative to traditional reinforcement.

[25] http://www.enwl.co.uk/docs/default-source/c2c-key-documents/customer-segmentation-report.pdf?sfvrsn=4

Refurbishment category increases complexity and there are weaknesses in eligibility criteria

5.12 15.5GW of capacity with refurbishment status confirmed participation in the first round of the auction. The refurbishment category and the optionality that it affords complicates the auction process and provides latitude for plant with this status to modify their behaviour as the auction progresses in a way that other plant are not able to (noting that they are also offering alternative products that other plant are not able to).

5.13 The refurbishment eligibility criteria and/or the ongoing need for the category more generally should be reviewed.

Prequalification process was hampered by several issues

5.14 Failure to deliver the intended prequalification platform due to issues affecting the delivery of the IT system was de-stabilising and a significant issue for participants. The back-up system was cumbersome, but it did work and that it was available as a contingency measure allowed the prequalification process to be completed and the auction to then take place. Having live rule changes throughout prequalification created uncertainty.

5.15 Furthermore, stakeholders have suggested that the information required as part of prequalification could be streamlined to reduce the associated administrative burden. This should be informed by experience from stakeholders from the first auction (and second auction given timing), to strip out any information that is, with hindsight, not needed and address areas where there are overlaps or duplications in information requirements. The prequalification process needs improvement.

Auction systems performed well and preparations supported participants

5.16 Ahead of the auction itself, there was a strong emphasis from National Grid and DECC on providing training sessions and supporting material to participants to allow effective participation. The auction system has been widely praised for functionality and effectiveness by participants generally. This extends to the auction platform and the supporting IT infrastructure alike.

Merchant risk still exists for new projects

5.17 The clearing price from the December 2014 auction was lower than anticipated by many stakeholders and commentators. This means that the revenue stream associated with payments under Capacity Agreements stemming from the December 2014 auction will be below expectations. This is likely to reduce the amount of debt finance that can be secured and increase reliance on alternative, more expensive sources of finance and energy market revenues to recover investment costs. However, there are clearly a number of new build projects that have locked in at the December 2014 clearing price, when they had the option to withdraw from the auction. This suggests that this clearing price and the associated revenue stream are adequate for the project economics of the projects in question. But at this stage there is no firm evidence to suggest that the Capacity Market has had either an upward or downward effect on the overall cost of capital for new build.

Delivery risk ahead of 2018/19 is a prominent concern

5.18 With the completion of the auction process for 2018/19, attention for this period is now on delivery of capacity. With Capacity Agreements in place for 2.6GW of new build capacity, the prime question is whether all of this capacity will be delivered as expected. As yet, there is no evidence that non-delivery of new build projects is a significant risk, but this needs to be monitored. But there is also a delivery risk dimension for existing plant. Aylesford Newsprint is the sole example to date of a project that was successful in the

December 2014 auction confirming that it will not proceed[26]. As the capacity contribution from Aylesford Newsprint is ~3.5MW, the impact on the Capacity Market is small. However, the same would not be the case if there is a sizeable accumulation of capacity that pulls out and/or the withdrawal of a larger scale capacity provider. Also, it is now apparent based on press releases that there is a strong likelihood of closure at Longannet ahead of the delivery year (2018/19)[27], which has implications for the balance between Capacity Agreements secured and the capacity requirement.

5.19 There is a need for regular monitoring and communication of non-delivery risk to allow performance in respect of delivery to be assessed. We recommend that, if this is not already planned, this should be included in the EMR Annual Update and shared with the market as soon as possible respecting commercial sensitivities.

Replicability of Trafford is unclear

5.20 The Trafford plant constitutes the largest new build project to secure a Capacity Agreement. As a new build Combined Cycle Gas Turbine (CCGT), the fact that it secured a Capacity Agreement in the December 2014 auction has been flagged as an indicator of the success of the auction. However, a variety of stakeholders raise questions about the replicability of the Trafford project for other new build CCGTs (eg specifics of the turbine contract) and, hence, its value as an indicator of the prospects for further projects.

Impact of reciprocating engines is uncertain and may be counter to policy aims

5.21 The success of engines in the auction was greater than anticipated, linked to factors including lower capital costs than alternatives and access to embedded benefits, both of which reduce the revenue requirement from the Capacity Market and confer a relative cost advantage. This has prompted concern amongst some stakeholders that the Capacity Market is supporting low efficiency, high emissions diesel capacity, which contradicts wider EMR objectives in pursuit of decarbonisation. It is understood that there is a mixture of diesel and gas-fired assets amongst the reciprocating engines (ie it is not the case that all engines use diesel), with the latter having lower emissions. But the balance between different types of engine and the potential implications that they may have are uncertain.

5.22 There is a need for greater understanding of the underlying characteristics of engine options, implications for running patterns and their potential impact on emissions and costs to consumers in providing security of supply. We recommend that this should be assessed further by DECC and/or National Grid.

Development process

5.23 This section examines how the CM was brought forward by DECC. It reviews the development process undertaken by DECC from the mechanisms conception to implementation and how this could be improved. This section covers the consultation process, the dissemination of information to stakeholders, stakeholder reaction and overall transparency of the process.

[26] Aylesford Newsprint has entered administration since the completion of the December 2014 Capacity Market auction (http://www.bbc.co.uk/news/uk-england-kent-31587533).

[27] http://www.scottishpower.com/news/pages/scottishpower_comment_longannet_power_station_230315.asp

Major achievement to have run first Capacity Market auction in 2014

5.24 The quantity of work undertaken by DECC and industry to deliver the Capacity Market framework and run the first auction in 2014 was significant. Taking the process from policy concept to functioning policy instrument in the timeframe from 2011 to 2014 is a major achievement and was as recognised as such by stakeholders. The scale of this achievement is significant.

DECC process was generally consultative

5.25 DECC conducted an extensive consultation and engagement exercise with stakeholders during the development of the Capacity Market. This included formal consultation documents, stakeholder events and bilateral meetings. The consultative nature of the process was generally welcomed and valued, although a number of limitations were also flagged, as discussed below.

5.26 Stakeholders highlighted that the consultation and engagement processes were resource intensive. Keeping up to speed with consultations and policy developments was time intensive in terms of both external engagement with DECC and internal assessments, briefings and decision making within individual companies. This may be an inevitability given the policy and monetary significance of the Capacity Market. An extensive programme of collaborative workshops was facilitated by DECC, which provided opportunities to engage, but internal constraints on time and resource available limited the opportunity to actively participate in the case of some smaller participants. For some, a passive role was adopted where active engagement was not possible due to resource or time constraints, which compromised their ability to engage and have their voice heard. Such parties have suggested that this meant that they were in a position of having to work within the capacity market rules as defined rather than being able to influence their development.

5.27 A number of stakeholders also suggested that while there was a lot of listening during the consultation process, points raised did not always find their way into the ongoing development and final design of the Capacity Market. Clearly, it is unrealistic to expect one common set of market rules to fully meet the requirements of all parties. There are inevitably tensions in defining market rules as not all views can be accommodated concurrently. Nevertheless, some perceive that the engagement was, in some cases, a formality for the sake of process rather than genuine. This view must be moderated, however, as the specifics of DECC's decisions need to be considered in light of the evidence provided by stakeholders to support views expressed. In cases where evidence was not provided to support views expressed by stakeholders, the ability for DECC to respond and reflect the views in the design is restricted.

Process was generally open, but lacking transparency in some regards

5.28 Building on the above, the consultation process and accompanying engagement helped to deliver transparency in respect of DECC's evolving views throughout the process and final decisions. However, several stakeholders considered that the rationale for some of the changes to the design during the development phase and for the final decisions was not always clear. For example, the rationale for selecting the Net CONE and Price Cap pricing parameters used in the construction of the administered demand curve was not transparent (as discussed in the section beginning with paragraph 5.36).

5.29 A number of stakeholders highlight that the use of an Expert Group during the design process was beneficial, allowing DECC to tap into expertise of industry participants and helping to share evolving thinking. However, for some the Expert Group felt like a 'closed shop' at times, with limited information release to non-Expert Group members early on, in particular. Dissemination improved (drawing on support from Energy UK) through the initiative to publish the Expert Group papers on DECC's website, but there were often timing delays (sometimes several weeks). This created an information asymmetry between different stakeholders due to different timing of access to papers, which did not aid transparency to the market as a whole.

Expedience of the process prevailed over details during final stages

5.30 As alluded to above, the Capacity Market was delivered within a challenging timetable. One consequence of this highlighted by stakeholders is that expedience of the process and drive to be ready for the December 2014 auction (which was an auction target date generally supported by stakeholders) may have taken precedence over some aspects of design towards the end of the process. This meant that some aspects of design were rushed or overlooked to some extent in order to meet the timetable. Issues highlighted in this regard include the requirements for co-firing, treatment of private wires and arrangements for CHP. These issues highlighted that some of the nuances linked to subsets of capacity merited more explicit consideration by DECC and industry alike in the detailed design, given potential implications for participation.

5.31 Perhaps as a consequence of some of these issues, the 'Frequently Asked Questions'[28] (FAQs) responses were used to plug some of the gaps in the detailed design. While practical to resolve issues via this route (and preferable to leaving issues unresolved), for some it created the impression of policy development 'on the hoof'. Some issues could not be addressed through guidance in response to FAQs and instead necessitated changes to the Rules during the prequalification window, which created problems for participants (as discussed in the section beginning with paragraph 5.85).

Design details

5.32 This section reviews the structural aspects of the CM chosen by DECC and the mechanism's overall parameters. It covers the capacity requirement and demand curve pricing methodology, anti-gaming measures, agreement lengths, refurbishment eligibility criteria, new build delivery incentives and the penalty for non-delivery of energy.

Capacity requirement methodology needs to build on experience gained from existing process

5.33 Identifying the capacity requirement needed to meet the identified reliability standard of 3 hours LoLE is a key dimension of the Capacity Market. This is a challenging task, given the range of uncertainties over the 4 year time horizon (eg demand growth, contribution from non-eligible capacity sources) and National Grid are generally regarded as being in the best position to provide a recommendation for the Secretary of State to consider. While we are not assessing whether the target capacity requirement was appropriate, experience of the first process and feedback from stakeholders can usefully feed into future rounds.

5.34 The capacity requirement for the T-4 auction for 2018/19 was, for good reason, adjusted following prequalification to take account of plant that had indicated that it would opt-out but remain operational. This adjustment was based on assessment of the prequalification outcome, including National Grid's report recommending demand curve adjustments based on opt out decisions and updated information regarding quantities of embedded generation[29]. Adjustments made included scaling back the requirement to reflect expectations that Longannet and Grangemouth were not choosing to participate in the Capacity Market, but would remain operational, which created a lower requirement for

[28] https://www.gov.uk/government/publications/electricity-market-reform-capacity-market-frequently-asked-questions

[29] 'Report to Secretary of State. Adjustment to Demand Curve. 2014 Four year ahead Capacity Market Auction', National Grid, October 2014.

capacity to be secured from the Capacity Market. This resulted in a 2100MW reduction in the capacity target requirement (as part of an overall reduction of 2200MW) With the benefit of hindsight, it is now apparent based on a press release dated 23 March 2015 that there is a strong likelihood of closure at Longannet ahead of the delivery year (2018/19)[30]. This creates an issue for the Capacity Market and its participants:

- Had the Longannet announcement been made prior to the auction, presumably ~2GW of additional Capacity Agreements would have been procured. All other things being equal, this would have increased the clearing price by around £5/kW and parties that, in the event, did not secure Capacity Agreements would, instead, have done so.
- As things stand, presumably the shortfall for 2018/19 must instead be fulfilled via the T-1 auction. While this may be manageable, existing capacity that was unsuccessful in the December 2014 auction that may otherwise have secured Capacity Agreements through the T-4 auction may close between now and the T-1 auction.

5.35 Therefore, the Capacity Market and participants face exposure to the impacts of variations in the actual plans regarding 'opt-out, remaining operational' plants. Looking forward, there is a potential question as to the treatment of these plant to manage this non-delivery risk. The balance is between higher cost of over-procurement if a conservative view is taken regarding expected availability of such plant in the delivery period versus the consequences of non-delivery if such plant is assumed to be fully available in the delivery period but this does not actually transpire. There are also implications for the T-1 auction, as capacity requirements may need to be adjusted to reflect such developments[31].

Demand curve pricing parameters lack transparent methodology

5.36 In addition to the target volume, the administered demand curve also hinges on defined pricing parameters, notably the Net Cost of New Entry (Net CONE) and the Price Cap. However, our view is that the basis for setting these parameters lacks a transparent methodology and supporting justification, in line with the views of many stakeholders from a range of backgrounds.

5.37 The Net CONE is intended to reflect the cost of delivering new entry less anticipated revenues from the wholesale market and ancillary services. As such, it forms an estimate of the Capacity Market revenue requirements of a new entrant. Initially, DECC identified a large frame Open Cycle Gas Turbine (OCGT) as the likely new entrant technology of choice, based on the assumption that it would be incentivised to bid into the Capacity Market. On this basis, the draft Delivery Plan[32] included a proposed value of £47/kW as Gross CONE for an OCGT and the subsequent consultation of proposals for implementation[33] highlighted an expectation that an OCGT would secure £18/kW from the electricity market based on an expectation of capturing £6,000/MWh (ie the implied scarcity price at times of lost load stemming from the cashout reform process[34]) in turn based on an assumption of 3 hours of lost load per year (ie the Reliability Standard). This would leave a Net CONE of £29/kW to be recovered through the Capacity Market to support new investment. These steps are summarised in Table 4. While there is scope for different assumptions (eg hurdle rate, capex) to those that led to this Net CONE value, the methodology was clear.

30 http://www.scottishpower.com/news/pages/scottishpower_comment_longannet_power_station_230315.asp

31 This topic is considered in the section beginning paragraph 5.151.

32 'Consultation on the draft Electricity Market Reform Delivery Plan', July 2013, DECC.

33 'EMR: Consultation on Proposals for Implementation,' October 2013, DECC.

34 The cashout reform process involved a holistic review of the cash-out arrangements. At the core of this review was the aim for cashout pricing to provide incentives for sufficient investment in capacity to ensure an efficient level of security of supply. This culminated in Ofgem's approval of P305: Electricity Balancing Significant Code Review Developments.

Table 4 – Derivation of Net CONE for OCGT

Parameter	Value	Comment
Gross CONE	£47/kW	Based on assumptions for large frame OCGT
Energy market margin	£18/kW	Based on assumed capture of prices of £6000/MWh in 3 hours loss of load
Net CONE	£29/kW	Gross CONE less energy market margin

5.38 One of the challenges raised by stakeholders was that a large frame OCGT was unlikely to be the new entrant technology. There were no large frame OCGT projects in the pipeline and large frame turbines of the type used in CCGTs or CHP were highlighted as the cheapest plant per unit capacity by PB Power[35]. In response to consultation feedback, DECC revised its position and installed CCGT as the new entrant technology of choice for purposes of Net CONE and increased the value to Net CONE to £49/kW. The transition from large frame OCGT to CCGT as new entry technology of choice is, in our view, appropriate at present, given technologies included in the project pipeline. The majority of stakeholders (although not all) shared this view and supported the final selection of CCGT as the new build technology.

5.39 However, our view and that of a range of stakeholders, is that the methodology for reaching the revised Net CONE value with a CCGT as the new entrant is not clear and the transparency initially provided with an OCGT as the selected technology was not replicated. This is particularly the case for assumptions regarding energy market margin expectations, which are based on outputs from DECC's Dynamic Dispatch Model (DDM). The assumptions used to reach a Net CONE of £49/kW imply an assumed energy market margin of £51/kW. This seems high relative to margins derived based on forward prices. Perhaps linked to uncertainty regarding its derivation, stakeholders expressed mixed views regarding the appropriateness of £49/kW as the Net CONE value.

5.40 **Importantly, however, the methodology and associated assumptions should be clear**. This is particularly important given that the Net CONE can be revised from year to year[36]. Similarly, the Price Cap of £75/kW was derived as Net CONE times a relatively arbitrary multiplier of 1.5, with little in the way of justification for its appropriateness.

5.41 Although the clearing price was below the Price Cap and the Net CONE (as discussed in paragraph 5.99), suggesting that they played a limited role in the auction itself, they are still important for setting expectations ahead of the auction process, as well as for future auctions. For example, the Price Cap indicates a maximum willingness to pay for capacity and so provides an important signal to participants against which they can benchmark their participation. But the basis for the 1.5 times multiplier is unclear and the Net CONE methodology upon which it hinges lacks transparency. As these parameters can be varied at the discretion of the Secretary of State, having a clear methodology for determining these parameters will increase certainty for participants in future. **Therefore, transparent methodologies for defining these parameters, including explanation of input assumptions and supporting evidence, as well as an indication of potential**

[35] 'Electricity Generation Cost Model – 2013, Update of Non-Renewable Technologies', PB Power, April 2013.

[36] The 'Consultation on Proposals for Implementation' highlighted that Net CONE will be revised if necessary for each auction, for instance based on new engineering cost estimates for new build and on information gained from previous auctions.

sensitivities that will be considered when setting values, should be formally set out within the framework of Rules and Regulations for future auctions.

5.42 Factors to be flagged as explicit considerations in a transparent methodology as sensitivities or sense-checks (but without necessarily influencing the derived values) include:

- **Exchange rate sensitivity impact**: the Net CONE parameter is subject to foreign exchange variations given that turbine costs are typically quoted in dollars or euro rather than pounds sterling. This can affect the applicability of the pounds sterling value if variation in exchange rates results in a divergence between turbine contract prices and the value assumed for new entry purposes. Given this it may be prudent to assess sensitivity to exchange rate fluctuation based on reasonable scenarios and/or historic patterns to check that the cost parameters are robust.
- **Impacts on other technologies**: the Net CONE value is set with reference to CCGT on the basis that it is the new entrant technology of choice. However, new entry can also come from other technologies, with new engines and energy from waste projects evident in the first auction process. While this may not affect the Net CONE value, it is important to understand the implications of a Net CONE set with reference to a CCGT on other technologies to understand what incentives it may create. This can be informed by getting a better handle on potential costs for these alternative new entry technologies as part of the Net CONE setting process.
- **Geographically varying costs**: generation cost assumptions that feed into the Net CONE calculation takes a single, ‘location blind’ view of use of system charges (electricity and (where relevant) gas). However, actual charges vary geographically, with the potential for impact on applicability of pricing parameters used in demand curve derivation for some projects. As for exchange rates, there may be merit in testing the sensitivity of Net CONE, Price Cap and Price Taker Threshold pricing parameters to regionally varying electricity and gas use of system charges. For the avoidance of doubt, we are not suggesting that geographically varying parameters should be defined or adopted – the Capacity Market is a national market and so the demand curve parameters should be common. But the distributional impacts of the selected parameters on capacity providers in different locations should at least be evaluated to ensure that potential implications are understood and noted in the decision process.

Anti-gaming measures are extensive, but create complexity and administrative burden

5.43 The potential for gaming of the Capacity Market was a major concern during the design phase. As a result, the design included measures intended to mitigate the potential for gaming and deliver value for money to consumers. Notable amongst these is default treatment of existing capacity as a Price Taker and the requirement for a Price Maker Memorandum to secure Price Maker status.

5.44 Price Taker status means that capacity is unable to exit the auction until the price drops below the Price Taker Threshold of £25/kW. The rationale behind this is clear. It is intended to put an upper limit on bid prices for existing plant to manage the costs associated with the Capacity Market.

5.45 Existing capacity can, however, submit a Price Maker Memorandum which enables it to set an exit price above £25/kW (although does not require it to do so). This, therefore, provides an avenue for existing capacity to remove itself from the obligation to bid below the Price Taker Threshold. While information concerning the uptake of Price Maker status is not in the public domain, we understand that a reasonable proportion of existing capacity did secure Price Maker status in the December 2014 auction.

5.46 This provides flexibility for parties that believe that they need to bid in excess of £25/kW to reflect the economic situation of their particular units to do so. While this has a sound rationale, it arguably dilutes the need for and impact of the Price Taker Threshold. In effect, parties that have the need to bid above £25/kW can apply for Price Maker status and so bid above £25/kW, while those that are comfortable at a price below £25/kW will accept Price Taker status. The end result should, in competitive circumstances, be the same as if all parties have pricing flexibility. An alternative would be to remove the distinction between Price Takers and Price Makers (and, hence, the Price Taker Threshold) and instead rely on competitive forces and ex-post monitoring of behaviour. The key here, therefore, is whether or not there is functioning competition in the Capacity Market. The headroom of capacity bidding into the first auction relative to the defined target capacity is an indicator of a competitive supply-demand balance going into the first auction round. Headroom may not always be as large as for the December 2014 auction, but in such a case it is unclear whether a solution with a price cap and bidding restrictions that can be circumvented by a Price Maker Memorandum would deliver a different outcome than an alternative with no bidding restrictions and ex-post monitoring.

5.47 With arrangements as they stand, there are a number of issues to flag:

- The Price Taker Threshold value is arbitrarily defined without a robust methodology. It does not reflect the fact that annual fixed costs for different types of plant vary, as does exposure to locational network charges (electricity and gas (where relevant)). So a one-size-fits-all threshold has differing impact and relevance for different units. Again, we are not advocating a geographically varying Price Taker Threshold, but the distributional impacts of a single parameter should be explicitly assessed.
- Information regarding the identity of existing capacity with Price Maker status is confidential to respect commercial sensitivity. But this creates an information asymmetry between participants going into the auction (ie only parties with existing capacity that has Price Maker Status know this fact, while other parties do not). There is a case for making this information public to remove the information asymmetry, noting the potential for this to affect the incentives to seek Price Maker status.
- Stakeholders have highlighted that the content of the Price Maker Memorandum that parties seeking Price Maker status must submit is highly dependent upon a party’s views on the range of possible future scenarios that may outturn, making it subjective. The forward curve does not extend to the end of the four year lead-in to the delivery year and there is uncertainty regarding supply-demand fundamentals. While the details of the Price Maker Memorandum are intended to help ex-post monitoring, uncertainty regarding future fundamentals means that a range of potential scenarios can reasonably be justified ahead of time. Arguably, this reduces the value of the information submitted in a Price Maker Memorandum for the purpose of ex-post monitoring. However, as award of Price Maker status is self-certifying and, to our knowledge, the contents of Price Maker Memoranda have not been reviewed by any party it is difficult to form a firm view[37]. We are unable to comment, therefore, on the value of the information provided in the Price Maker Memoranda for ex-post monitoring purposes.

5.48 Over the longer term, with experience from several auctions it will be possible to assess how genuinely competitive the auction processes were in practice. This review, in the event that it indicates functioning competition, may allow relaxation of some of the anti-gaming measures.

[37] Ofgem’s role as outlined in the rules is solely to receive submissions and issue receipts, although the submissions will be securely stored for future reference.

Mixed opinions on appropriateness of differentiated agreement lengths for new generation projects

5.49 As highlighted in Table 2, new generation projects have the ability to secure agreements of up to 15 years, compared to the default position of one year agreements which applies for non-refurbishing existing capacity, DSR and, from the December 2015 T-4 auction, interconnection. The rationale for this distinction is that new generation projects need longer-term agreements in order to secure finance to support project delivery and to pay for capital expenditure. This view is supported by a range of stakeholders (particularly those with potential new build projects), who state that access to a 15 year agreement is essential for access to finance and compatible with re-financing timescales.

5.50 However, a range of other stakeholders consider that the differentiation between agreement durations for different types of participant creates a non-level playing field, with specific issues in relation to DSR considered separately in the section beginning with paragraph 5.54. Instead of differentiated agreement lengths, these stakeholders expressed a preference for single year agreements renewed on an annual rolling basis or, alternatively, access to multi-year agreements for all with flexibility regarding duration. However, there is acceptance that rolling annual agreements were unlikely to be feasible from the outset given the influence of feedback from the finance community in particular.

5.51 While market context is important here, it is worth noting that new entry has been supported in the other markets where maximum agreement length/pricing arrangements range from 3 to 10 years. Since its inception, the Reliability Pricing Model in PJM[38], which allows new generation resource to lock in capacity prices for 3 years in some cases[39], has attracted 28.4GW[40] of new capacity for delivery periods from 2007/08 to 2014/15, which includes 11.8GW of demand side resources and 4.8GW of new generation[41]. The Reserve Capacity Mechanism in Western Australia, which allows for pricing arrangements of up to 10 years[42] if an auction is needed post-bilateral trade, has supported new entry amongst independent power producers, with the number of providers increasing from 10 in 2005 to around 25 today[43]. Therefore, 15 year Capacity Agreements in GB are of a longer duration than equivalent arrangements in other international markets. However, this decision was informed by evidence provided by the finance community and a range of parties considering new projects, which highlighted the importance of a longer tenure for securing debt finance in particular. This evidence emphasised that debt finance and re-finance periods are typically each 7 years in duration, meaning that a 15 year agreement length can encompass both.

5.52 While nearly all new build projects entered the auction seeking 15 year agreements, a small proportion elected for shorter agreement durations (1 year, 3 year and 14 year agreements were sought, as well as 15 year agreements). This highlights that 15 years is an upper limit and not the de facto agreement length for new build. However, under the current non variable price-duration auction format, there is an incentive for new build

38 Regional Market covering: Delaware, District of Columbia, Maryland, New Jersey, Ohio, Pennsylvania, Virginia, West Virginia, Illinois, Indiana, Tennessee, Michigan, Kentucky and North Carolina.

39 New Entry Price Adjustment arrangements allow Planned Generation Resources to recover the amount of their cost of entry-based offer for up to two additional consecutive years under certain conditions. PJM Capacity Market Manual.

40 This is in the context of a system with generating capacity of around 185GW and peak demand of around 165GW.

41 'Second Performance Assessment of PJM's Reliability Pricing Model, Market Results 2007/08 through 2014/15', The Brattle Group, August 2011.

42 These are termed Long Term Special Price Arrangements. Wholesale Electricity Market Rules (1 May 2015).

43 http://www.imowa.com.au

projects to seek a 15 year agreement in the first bidding round at least, with the option to drop to a 1 year agreement as the price reduces.

5.53 The potential future introduction of variable price-duration auctions may reveal further information concerning required agreement length and its relationship with price, as this format will allow bidders to reduce desired agreement duration as an auction progresses. This approach will definitely not be in place for the December 2015 auction[44], but could be in future subject to development of an appropriate and robust price duration curve methodology. Further review of the merits of the variable price-duration auction format should be undertaken to inform any future decision in this regard, alongside work to develop an appropriate supporting price duration curve methodology. **For the time being, in the interests of providing stability and certainty for participants, retaining 15 years as the maximum Capacity Agreement duration appears an appropriate course of action.**

Non-availability of longer-term agreements for DSR has attracted criticism, with more evidence needed

5.54 New Demand Side Response projects can secure Capacity Agreements of one year duration (as per the default position), compared to 15 year agreements for new generating capacity with spend in excess of the defined capex threshold, as highlighted in Table 2. The decision to opt for one year agreement duration in GB is linked to the expectation that rolling out new DSR projects does not entail the same level of capital expenditure as new generation projects, reducing the need for a longer-term revenue stream to recover capex.

5.55 However, a number of stakeholders consider this to be discriminatory, creating a non-level playing field that disadvantages DSR relative to generation technologies. These stakeholders consider that a commercial proposition spanning several years may be more attractive for a prospective DSR site than a single year agreement[45] and also be more attractive for financing purposes given the relative immaturity of the technology. This may enhance the overall level of DSR that can be provided to the system. On this issue, it is noteworthy that the GB approach differs from that seen in ISO New England, for example, where new generation and demand resources alike can access agreements for up to 7 years.

5.56 The adoption of one year agreements for DSR is, however, supported by evidence from the Capacity to Customers project[46] under the Low Carbon Network Fund. Output from the Capacity to Customers project suggests that one year arrangements are the optimal length required to secure a contract with DSR providers[47]. Shorter-term arrangements are also consistent with the rationale for the T-1 auction process, which is that DSR cannot necessarily be locked in on a long-term basis given the potential for future uncertainty regarding the make-up and sign-up of the underlying DSR sites. This uncertainty could create delivery risks.

44 'Capacity Market supplementary design proposals and Transitional Arrangements and Proposed amendments to the Capacity Market Rules 2014 and explanation of some immediate amendments to the Capacity Market Rules 2014 Consultations, Government Response', DECC, January 2015.

45 The 4-year time horizon may accentuate this (ie the 4-year delay in potential value realisation may make a one year deal less commercially attractive to a demand site than a longer-term arrangement), although this issue may subside as the timeframe to actual delivery reduces and the arrangements gain momentum and rolling annual arrangements become more viable.

46 The Capacity to Customers project run by Electricity North West tested innovative network management technologies in conjunction with new customer commercial arrangements to release capacity on the distribution network as an alternative to traditional reinforcement.

47 http://www.enwl.co.uk/docs/default-source/c2c-key-documents/customer-segmentation-report.pdf?sfvrsn=4

5.57 **There is a clear tension here. To inform this issue for future rounds of the Capacity Market, we recommend that DECC continues to invite the DSR community to provide evidence to help assessment of:**

- **implications of 1 year only agreements on DSR deployment and the potential effects of longer-term agreements on this;**
- **delivery risk issues associated with longer-term agreements; and**
- **whole system cost impacts of longer-term agreements for DSR.**

5.58 **Analysis such as this will allow an evidence-based review of this contentious issue and allow flexibility to reflect upon learning as DSR deployment and associated experience increases.**

Refurbishment increases complexity and there are weaknesses in eligibility criteria

5.59 Capacity prequalified with refurbishment status has multiple options available to it in the auction process. This optionality is available to ensure that existing capacity with potential for refurbishment is not shut out if the single-year price falls below the level needed to support refurbishment and thereby keeps existing capacity in the market. The options are as follows:

- it has the ability to secure a 3 year agreement for capacity post-refurbishment and act as Price Maker with incremental capacity provided through refurbishment;
- if the auction price drops below a refurbishment exit price level (selected by the participant) needed to progress refurbishment, it can either:
  - drop out of the auction;
  - revert to 'existing' plant status and attempt to secure a 1 year agreement as a Price Maker (if Price Maker status was acquired for pre-refurbishment capacity); or
  - revert to 'existing' plant status and attempt to secure a 1 year agreement as a Price Taker.

5.60 The range of permutations available:

- complicates the auction process;
- adds another product to the auction, affecting the auction dynamics; and
- provides latitude for plant with this status to modify their behaviour as the auction progresses in a way that other plant are not able to (noting that they are also offering alternative products that other plant are not able to).

5.61 Stakeholders (including some who sought refurbishment status for their Capacity Market Units and some who did not) expressed mixed views concerning the need for and desirability of the refurbishment category on an ongoing basis. Some consider that it is necessary to provide certainty for refurbishment expenditure. Others, however, feel that refurbishment status gives too much optionality to some plant and its application gives scope for unintended consequences (as discussed in paragraph 5.120).

5.62 There is a question as to whether the refurbishment category could be considered as a transitional measure only to help to manage the effects of the Industrial Emissions Directive (IED)[48] and the cliff-edge that it creates in terms of decisions for coal plant in particular given the effects of IED emission limits on their operation.

[48] Key IED decision points are:
1 January 2016: at this point plant can:
(if not done so already) confirm compliance with Emission Limit Values from 2016
- opt into the Transitional National Plan to allow plants to trade NOx emissions allowances between 1 January 2016 and 30 June 2020

5.63 The Capacity Market and the IED interact around the decisions to be made by 1 January 2016. If any of the coal plant seeking refurbishment agreements that have not already fitted Selective Catalytic Reduction (SCR) secure an agreement in the forthcoming auction, it will be in a position to comply with Emission Limit Values or enter the Transitional National Plan from 2016. If unsuccessful, options include closure or operation under derogation. The outcome of the second auction for delivery in the three years beginning 2019/20 will then influence the decisions to be made by 1 July 2020 for those in the Transitional National Plan, given the overlap in time periods. A refurbishment agreement in this round could then allow plant to comply with Emission Limit Values from 1 July 2020.

5.64 The IED-related drivers for the refurbishment agreement permutation may, therefore, be transitory in nature. Given concerns outlined above relating to the refurbishment agreements, there may be merits in phasing this option out once the IED related cliff edge decisions have passed (ie after the second auction for delivery in 2019/20). This would remove a layer of uncertainty from the arrangements. **This should be informed by a review of the enduring requirement for the refurbishment category.**

Refurbishment capex threshold needs refinement

5.65 A financial metric for assessing eligibility of work that qualifies for refurbishment status was adopted on the basis that it provided a simple and transparent threshold. The value of the refurbishment threshold is principally based on the costs of installing SCR equipment on a coal plant. The identified value of £125/kW was informed by evidence provided by market participants during the consultation process. While this may be representative of the potential costs of SCR installation on coal plant, the £125/kW value has no relevance as a threshold in the context of refurbishment work for other technologies, such as nuclear or CCGT. Nevertheless, it is applied on a technology neutral basis. It was also not clear whether more significant regular maintenance (eg ~5-yearly interval maintenance) could be captured and so treated as refurbishment[49]. As such, the current metric is, in most cases, inappropriate as a basis for qualification as a refurbishing asset. A number of stakeholders have suggested the need for more demonstration of refurbishment to support qualification, rather than relying on reference to the financial metric alone.

5.66 The potential for expenditure to qualify for refurbishment status is increased by the fact that spending from 1 May 2012 that is linked to an improvement programme not yet commissioned is eligible, thereby extending the timeframe of eligibility and hence the pot of potential costs that can be aggregated to meet the refurbishment capex threshold[50]. This increases the pool of capacity that can seek to qualify for longer-term refurbishment

- opt for Limited Lifetime Derogation which means closing plant after 17,500 hours operation
- opt for peaking plant derogation where running is restricted to less than 1500 hours/yr
- close plant

1 July 2020: for plant opting into the Transitional National Plan:

- comply with Emission Limit Values from 1 July 2020
- opt for peaking plant derogation where running is restricted to less than 1500 hours/yr
- close plant

31 December 2023: plant operating under Limited Lifetime Derogation must close.

49 This issue has been resolved going forward based on draft Rule changes published on 27 March 2015 that include requirements that qualifying expenditure for refurbishment should not include substantive routine or statutory maintenance works.

50 The same issue exists for new build projects which are again referenced back to May 2012, although the issue should be more confined for new build as expenditure must relate to a plant which has not yet commissioned, making the May 2012 reference point less relevant over time.

agreements, potentially resulting in over-qualification. This should be revised to avoid unduly allowing spend linked to open-ended improvement programmes to qualify[51].

5.67 Both of these issues are contributory factors behind the unexpectedly high quantity of capacity that prequalified with refurbishment status, with 15.5GW of capacity with refurbishment status confirming participation in the first round of the auction[52]. Nevertheless, the use of a simple financial threshold to justify refurbishment status as applied is crude and the rationale for setting a refurbishment threshold needs to be refined.

5.68 **As a minimum, we recommend that the timestamp from which expenditure qualifies as eligible for inclusion towards refurbishment expenditure should be defined on a rolling basis linked to the relevant auction, rather than being tied to May 2012 (a Rule change on this issue has now been accepted by Ofgem[53]). Additionally, the appropriateness of £125/kW as the threshold as specified in the Regulations and its applicability for all technologies should be reviewed.**

While there are mixed views on effectiveness of new build delivery incentives, they remain untested at present

5.69 New build projects that secure Capacity Agreements are required to post collateral of £5/kW. This is foregone as a termination fee in the event that requirements in terms of minimum expenditure and major contracts are not met at the Financial Commitment Milestone, set at 18 months following the award of the Capacity Agreement. A Termination Fee of £25/kW also applies in the event of failure to reach the Minimum Completion Requirement by the Long Stop Date.

5.70 Stakeholders have provided a range of views in relation to the appropriateness of £5/kW collateral requirement for new build. Some indicate that £5/kW strikes a sensible balance between supporting investment and deterring speculative projects, with higher requirements acting as a disincentive for participation given the financial implications of higher collateral requirements. However, others feel that £5/kW is a weak incentive/penalty that allows speculative projects to participate with the potential for non-delivery risk if new build projects are not forthcoming and so do not deliver the anticipated capacity. The decision to opt for £5/kW was intended to strike a balance between providing incentives for delivery without creating an undue entry deterrent.

5.71 Clearly, at this stage, we are still around 12 months from the first Financial Commitment Milestone. As such there is no evidence at present of non-delivery for new build projects. Therefore, it is not possible to form a view at this stage on the appropriateness of the £5/kW collateral requirement. Nevertheless, many stakeholders express concern regarding non-delivery risk and its potential implications, as discussed further below.

5.72 However, it is worth noting that for some projects the commitments made by new projects extend beyond those made under the Capacity Market Rules. New transmission connected projects also have to post credit under CUSC User Commitment framework[54]. This increases the overall value at risk for such projects and strengthens the incentives for progression of projects. This requirement does not exist for distribution connected projects

[51] This issue has been picked up in proposed Rule changes submitted to Ofgem which suggest that the eligibility for inclusion as capital expenditure for refurbishment should be based on a rolling timestamp with reference to the auction timeframes.

[52] Although scale of refurbishment agreements allocated was limited in the outturn (as discussed in paragraph 5.120).

[53] 'Electricity Market Reform (EMR): Decision (following statutory consultation) on changes to the Capacity Market Rules pursuant to Regulation 79 of the Capacity Market Regulations 2014', Ofgem, 19 June 2015.

[54] http://www2.nationalgrid.com/uk/services/electricity-connections/policies-and-guidance/

that do not need/have to enter into a direct agreement with National Grid, however, creating a distinction between these two broad categories of new build projects. We recommend that this differentiation should be subject to further consideration to assess its importance.

5.73 It is also noteworthy that an equivalent collateral requirement is not imposed on incremental capacity provided by refurbishment projects. This arguably represents an inconsistency given that capacity linked to new projects and refurbishment enhancements is not already in existence and so carries a non-delivery risk.

Penalty for non-delivery of energy in stress event remains material in tandem with cashout reform and a barrier for some projects

5.74 In the delivery window, parties with Capacity Agreements face exposure to penalties if the underlying capacity is not delivering in line with its obligations in a system stress event. Penalty exposure in a particular year is capped at 100% of the overall annual payment, with a monthly cap set at 200% of the relevant monthly payment. The monthly cap means that each party faces exposure to penalties for, on average, four hours of non-delivery in a system stress event per month. However, as monthly payments are scaled based on relative demand between months, exposure could be for more than four hours in months with higher capacity payments, and vice versa. The chance of facing exposure to the full annual 100% penalty in any year is, therefore, limited. But the non-delivery penalties still provide an incentive to fulfil Capacity Agreement obligations[55].

5.75 Capping penalty exposure in this manner is understandable from the perspective of risk management and bankability of an agreement under the Capacity Market. It serves to reduce the risk premium linked to Capacity Agreement obligations, which may have a downward effect on the required Capacity Market clearing price. However, some stakeholders indicated that the finalised penalty regime still presented too great a risk, highlighting this as a specific reason for not participating in the December 2014 auction process. This was a particular issue for energy limited capacity providers, such as storage projects, which have limited discharge duration. The balance of risk and reward for energy limited providers should be reviewed to assess this issue further.

5.76 One consequence of the finalised arrangements is that the Capacity Market penalty does not reflect the short-term economic cost of non-delivery based on the value of lost load. But short-term scarcity value should now be better reflected through the imbalance cashout arrangements given Ofgem's approval of BSC Modification Proposal P305[56] on 2 April 2015. For BSC parties, this bolsters incentives for delivery. Parties with a contracted position in the energy market will also face cashout price exposure for the shortfall between contractual and physical positions, with the expectation of high cashout prices in such circumstances.

Operation

5.77 This section assesses what happened in the first CM auction. It looks at the execution of the CM design details; it examines issues with the prequalification and appeals process but also acknowledges areas which worked well such as the auction systems.

[55] Going forward, how the incentives may interact with the secondary trading arrangements (as they are developed) remains an open question.

[56] P305: Electricity Balancing Significant Code Review Developments. P305 introduces single marginal cashout prices, a reserve scarcity pricing function and pricing of demand control events. These changes should sharpen cashout prices.

Failure to deliver the intended prequalification platform was de-stabilising and a significant issue for participants

5.78 The prequalification process was the first phase of Capacity Market operation. However, it was adversely affected by the non-delivery of the intended prequalification platform by or on behalf of the Delivery Body, which resulted in the adoption of a back-up system and alterations to the timings for the prequalification window with short notice. Stakeholders have highlighted the disruptive effects of this situation on their own processes and internal procedures. This includes practical issues, such as the need to revise holiday timings for key personnel which had been scheduled around the original timetable, and uncertainty created by the need to transition to a back-up system.

Prequalification back-up system was cumbersome, but it did work

5.79 While the need to revert to a back-up system was a major issue, having such an option available as a contingency measure proved valuable to the delivery of the December 2014 auction. Stakeholders indicated that the replacement system was not user friendly (eg CSV files were difficult to use and there were version compatibility issues with the Excel component). However, the back-up system did work and allowed the prequalification process to be completed in time for the auction timetable to be met.

Information requested through prequalification needs to be streamlined

5.80 A number of stakeholders suggested that the information required as part of prequalification could be streamlined to reduce the associated administrative burden. Suggestions were made on the basis of duplication or perceived non-relevance for prequalification. For example:

- duplication between declarations required under Section 3.4 of the Rules and both the Prequalification Certificate and the Certificate of Conduct[57];
- need to confirm holding of Generation Licence by generators;
- information concerning corporate form and legal status of an applicant, which is covered within the legal opinion of Section 3.4 of the Rules; and
- provision of bank account details.

5.81 **Suggestions for streamlining of information requirements have been proposed to Ofgem[58] and a number of changes have been made to reduce the burden. We recommend that information requirements should be subject to regular review to ensure that relevant information only is being required. The burden will be reduced in future to the extent that any information already submitted can be retained as standing data, with fresh submissions only needed for changes or capacity that has not previously participated.**

Disparities between the level and nature of information needed for different types of participant

5.82 Several stakeholders expressed a view that information requirements as part of prequalification are more onerous for existing capacity than for new capacity. They

[57] Ofgem has accepted a number of suggested Rule changes to rationalise these requirements ('Electricity Market Reform (EMR): Statutory consultation on changes to the Capacity Market Rules pursuant to Regulation 79 of the Capacity Market Regulations 2014', Ofgem, 2 April 2015 and 'Electricity Market Reform (EMR): Decision (following statutory consultation) on changes to the Capacity Market Rules pursuant to Regulation 79 of the Capacity Market Regulations 2014', Ofgem, 19 June 2015.).

[58] Ofgem received 91 proposed Rule changes. https://www.ofgem.gov.uk/electricity/wholesale-market/market-efficiency-review-and-reform/electricity-market-reform/change-proposals

highlight that this balance seems counterintuitive given that existing assets have been operational for several years and many have pre-existing contractual arrangements with National Grid.

5.83 **There is scope to consider whether more information should be requested from new projects as part of prequalification (without unnecessarily increasing administrative burden).** This includes tightening of requirement to hold planning consents as part of pre-qualification, rather than later as was permitted for the December 2014 auction only[59]. Possible areas for consideration that have been suggested by stakeholders to encourage genuine new build projects to be put forward and to provide sufficiently detailed descriptions of the projects being offered, including:

- provision of evidence of planning consents;
- provision of evidence of legal rights to use land required for new capacity; and
- agreements / consents / associated gas connection agreements (if new build is gas-fired asset); and
- environmental permits (wherever relevant).

5.84 While some of these changes have been progressed by Ofgem already[60], **we recommend that additional consideration is given to whether additional steps are needed (while striking a balance between encouraging genuine projects and managing administration burden).**

Live rule changes throughout prequalification created uncertainty

5.85 The prequalification process ran during August 2014, with the outcome announced on 3 October 2014. During this time, the Capacity Market Rules 2014, which came into force on 1 August 2014, were the subject of live rule change processes[61], with amendments made in two rounds, first on 21 August 2014 and then on 14 October 2014. Stakeholders highlighted that having live rule changes during the prequalification process created uncertainty. The situation also prompted concerns of unintended or unexpected outcomes given that prequalification information that was submitted based on one set of Rules but appraised relative to another.

5.86 While Rule changes were being progressed with the objective of making technical corrections or clarifications, having ongoing changes during a live operational phase of the Rules application was problematic. Even though the changes were being made for valid reasons, there is the risk that they create the perception that the Rules could be modified again. Future auctions **should lock down the Rules well ahead of the prequalification window to provide a stable basis from which to proceed and also to provide consolidated versions of prevailing Rules and Regulations[62].**

Work ahead of auctions helped to prepare participants

5.87 Ahead of the auction itself, there was a strong emphasis from National Grid and DECC on providing training sessions and supporting material to participants to allow effective participation. This was supplemented by a dummy auction process which allowed valuable testing of auction system functionality in readiness for the live auction.

59 Planning consents were still required ahead of the auction for the December 2014 round.

60 'Electricity Market Reform (EMR): Decision (following statutory consultation) on changes to the Capacity Market Rules pursuant to Regulation 79 of the Capacity Market Regulations 2014', Ofgem, 19 June 2015.

61 These included proposed changes relating to eligibility for 15 year Capacity Agreements. 'Electricity Market Reform: Consultation on proposed amendments to the Capacity Market Rules 2014 and explanation of some immediate amendments to the Capacity Market Rules 2014', DECC, August 2014.

62 A non-legally binding consolidated version of the Capacity Market Rules dated 19 June 2015 is now available on the Ofgem website (https://www.ofgem.gov.uk/electricity/wholesale-market/market-efficiency-review-and-reform/electricity-market-reform/capacity-market-cm-rules).

5.88 Stakeholders welcomed these sessions, highlighting their value and importance to preparations for the auction proper. Given this, **we recommend that there should be a continued commitment to training, support and testing in preparation for subsequent auctions**.

Auction systems performed well

5.89 The auction system has been widely praised for functionality and effectiveness by participants generally. This extends to the auction platform and the supporting IT infrastructure alike.

5.90 One point raised by many participants is that the auction took too long, linked to both the length of and the time between each round. In response, many stakeholders have suggested that the timetable could be shortened (eg to 2 days) to speed up the process. However, this view was not shared universally. Some parties indicated that they fully used the time afforded within the December 2014 auction process to review and update as necessary their bidding decisions. Such parties have called for the timetable to remain unaltered to retain the same opportunity to refine bidding behaviour during the auction process itself.

5.91 A number of parties have suggested that the process of publication of auction results should be formalised to help to support investor relations (as well as employee relations) and compliance with reporting obligations or governance requirements associated with being stock exchange listed. **We recommend formalisation of the timeframe and process for information release as this will support compliance with such arrangements, as well as improving certainty to participants more generally.**

Appeals process was too rigid, resulting in high proportion of CMUs proceeding to appeal

5.92 The prequalification process as designed and implemented led to over 200 units going to a Tier 1 dispute[63]. This is around one-third of the total number of units although only around 5GW (~8%) of prequalified capacity. The reasons for going to appeal were primarily due to administrative errors, lack of clarity on specific prequalification criteria and inconsistencies in the information provided, with only around 20 appeals proceeding to Tier 2.

5.93 As the majority of appeals were minor in nature and easily resolved in practice, there is the potential for such issues to be solved directly with the bidders via a clarification process after submission of prequalification information. This could provide a viable alternative to entering the formal appeal process, which can come at a cost (time and money) and give a signal to the market that many participants have failed prequalification at the first round.

5.94 **Therefore, we recommend that a less rigid and more interactive process for dealing with minor administrative errors could be considered as an option to reduce the burden of and on the appeals process.**

Outcome

5.95 This section evaluates the results of the first CM auction, in terms of both capacity and clearing price. It analyses the dependency of the auction outcome on the capacity requirement and shape of the administered demand curve. It also reviews the level and type of participation in the auction.

[63] Tier 1 disputes involve the Delivery Body reviewing a decision if requested by the appellant. Tier 2 disputes involve referral to Ofgem for determination if the Delivery Body upholds its original position following Tier 1 review.

Auction attracted significant surplus capacity

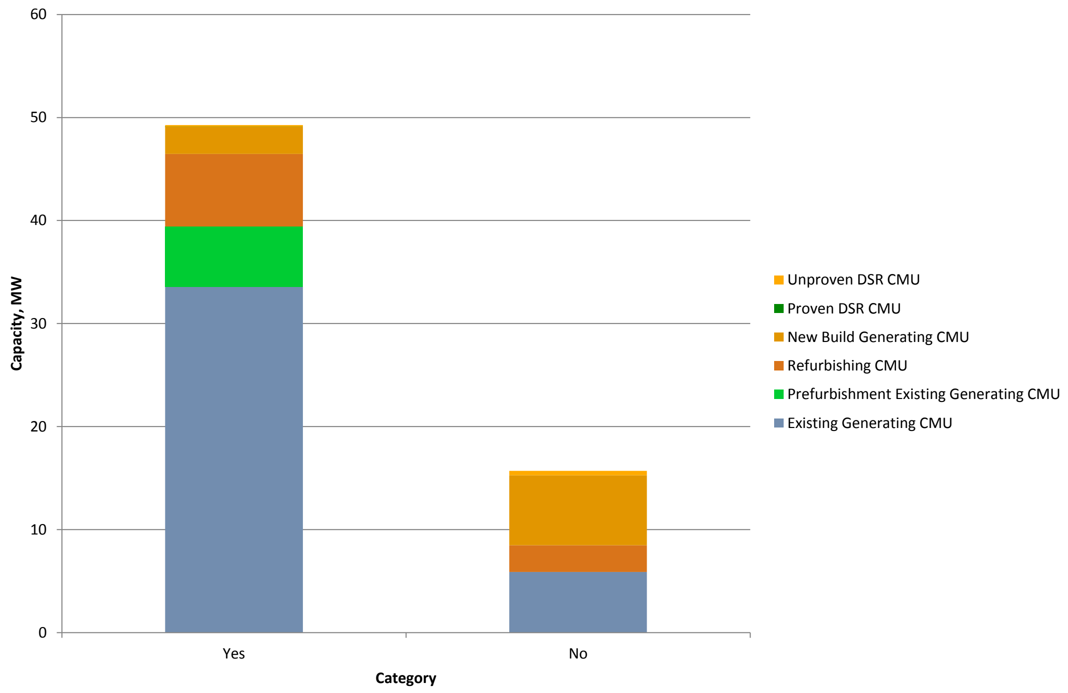
5.96 With just under 65GW of capacity prequalified and a target capacity quantity of 48.6GW, the auction was oversubscribed with around 30% headroom going into the first auction round, supporting a liquid auction. This compares to an average headroom in ISO-NE[64] auctions held to date of ~12%. Existing plant alone provided headroom of 13% relative to the target requirements. This suggests that the Capacity Market framework and the balance of risk and reward on offer were attractive to participants and helped to stimulate competition. The over-supplied nature of the first auction is an important backdrop to the outcome in other regards.

49.3GW of Capacity Agreements awarded, with 15.7GW of prequalified capacity unsuccessful

5.97 At the point of clearing, approximately 49.3GW of capacity was awarded Capacity Agreements.

5.98 The corollary is that 15.7GW of prequalified capacity was not awarded a Capacity Agreement, including a mixture of existing and prospective new build projects. The split between successful and unsuccessful capacity providers is shown in Figure 8.

Figure 8 – Split between successful and unsuccessful capacity in auction



Auction cleared at £19.40/kW

5.99 The auction cleared at £19.40/kW, lower than anticipated by many in advance[65]. This is influenced by the over-supplied nature of the market at the close of prequalification, which increased competitive pressure and applied downward force on the clearing price. The outturn clearing price is influenced by the 30% headroom going into the first auction round (as highlighted in paragraph 5.96).

64 Independent System Operator – New England.

65 DECC's final impact assessment (June 2014) included an estimated clearing price of £39/kW for the first auction, for example.

5.100 Based on the prequalification outcome and ahead of the auction, our analysis suggested two possible variants of the potential supply curve for the 2018/19 auction. To do this, we developed views of potential costs and revenues for the eligible plant in order to assess their 'missing money', which was assumed to form the basis of bids into the capacity auction.

5.101 The first curve shown in Figure 9 factors in coal refurbishment costs at several coal stations. In this case the market clears at around £25/kW with non-refurbishing coal at the margin. The second variant of a potential supply curve shown in Figure 10 assumes that coal refurbishment does not take place, given that it was out of merit in the first stack. In this case the market clears at around £18/kW with a cluster of non-refurbishing coal plus older CCGTs at the margin. The second curve transpired to be the closest to the observed outcome, in terms of clearing price.

Figure 9 – Potential supply curve, with coal refurbishment capex

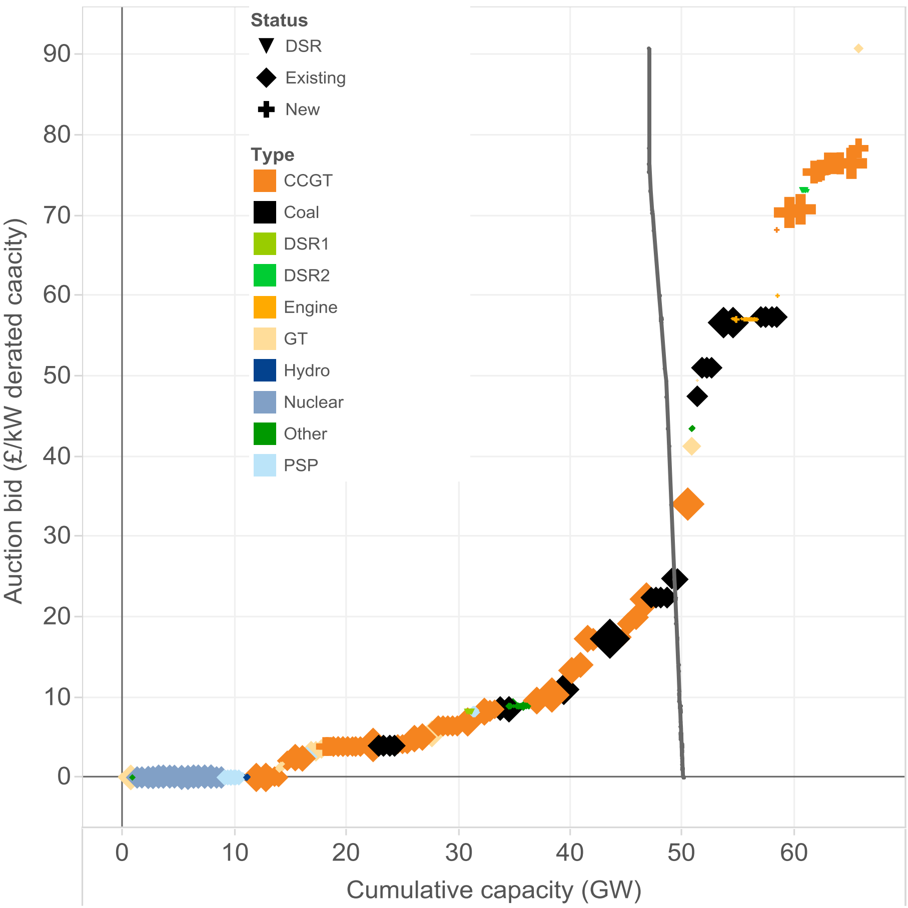
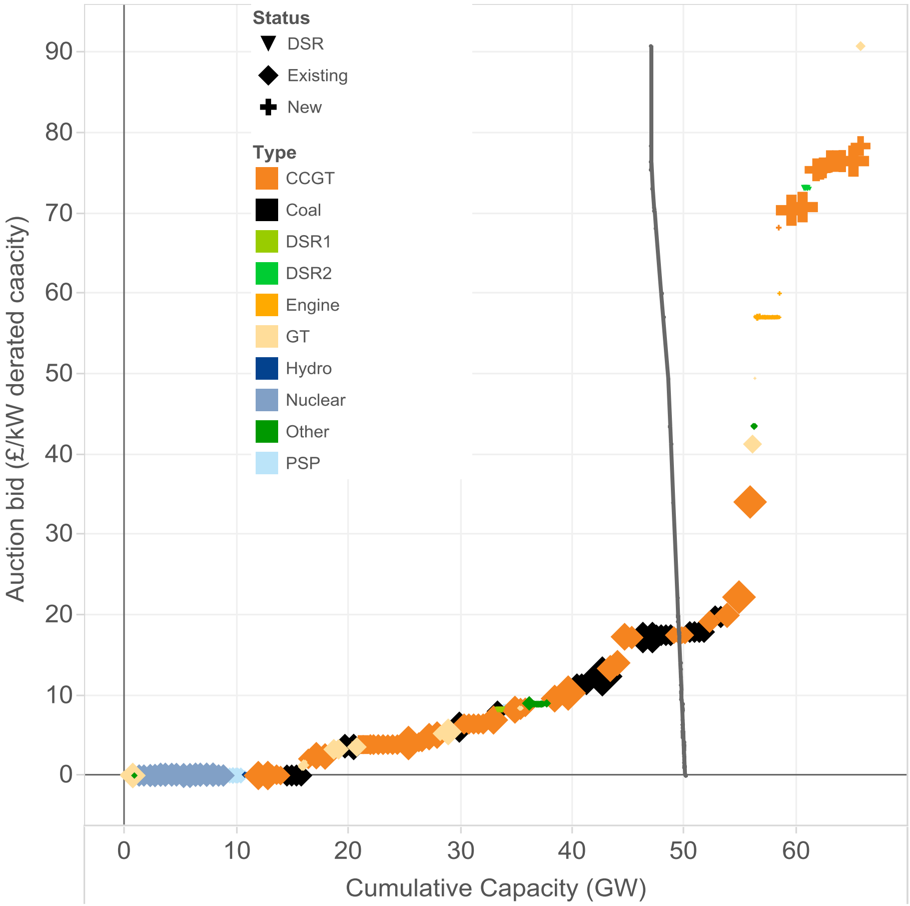


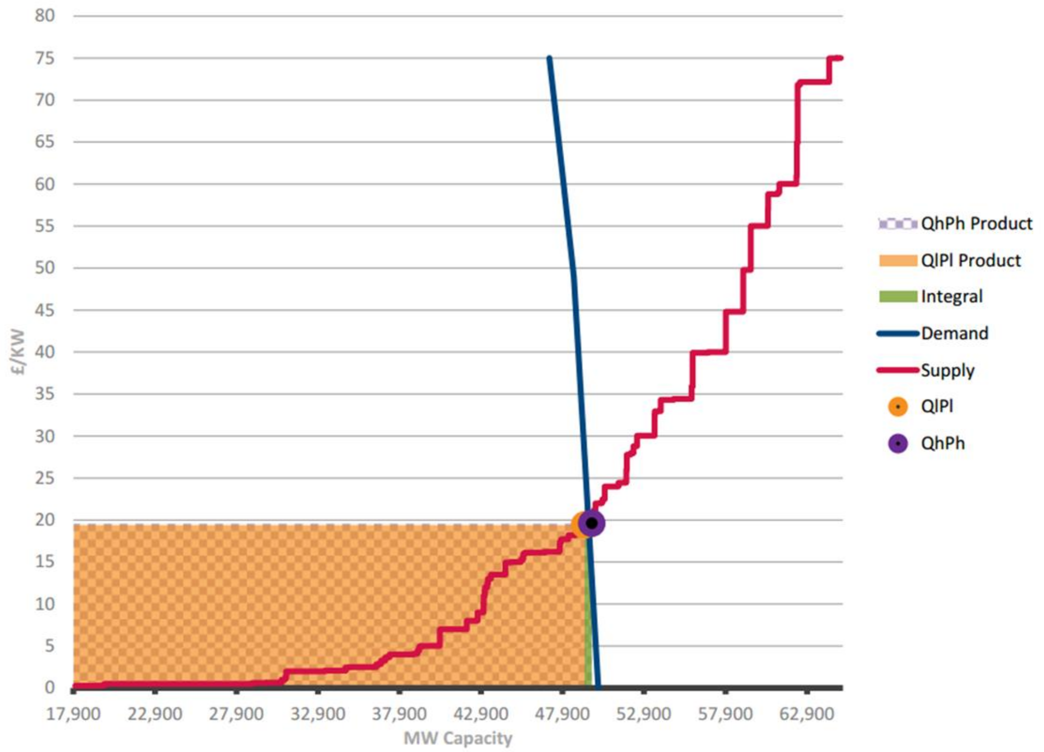
Figure 10 – Potential supply curve, without coal refurbishment capex



Outcome is highly sensitive to decisions on capacity requirement and shape of administered demand curve

5.102 While the auction cleared at £19.40/kW, the outturn supply curve is relatively steep just beyond the clearing point, as shown in Figure 11. This shows the supply curve as it evolved over the auction rounds held against the administered demand curve. A shift of 1GW could have increased the clearing price to £24/kW, other things being equal, highlighting the sensitivity of the outcome to the parameters defined to create the demand curve. It is also notable that ~30GW of capacity bid in at or close to zero, suggesting no ‘missing money’ issue for these plants, with revenues from other sources covering costs.

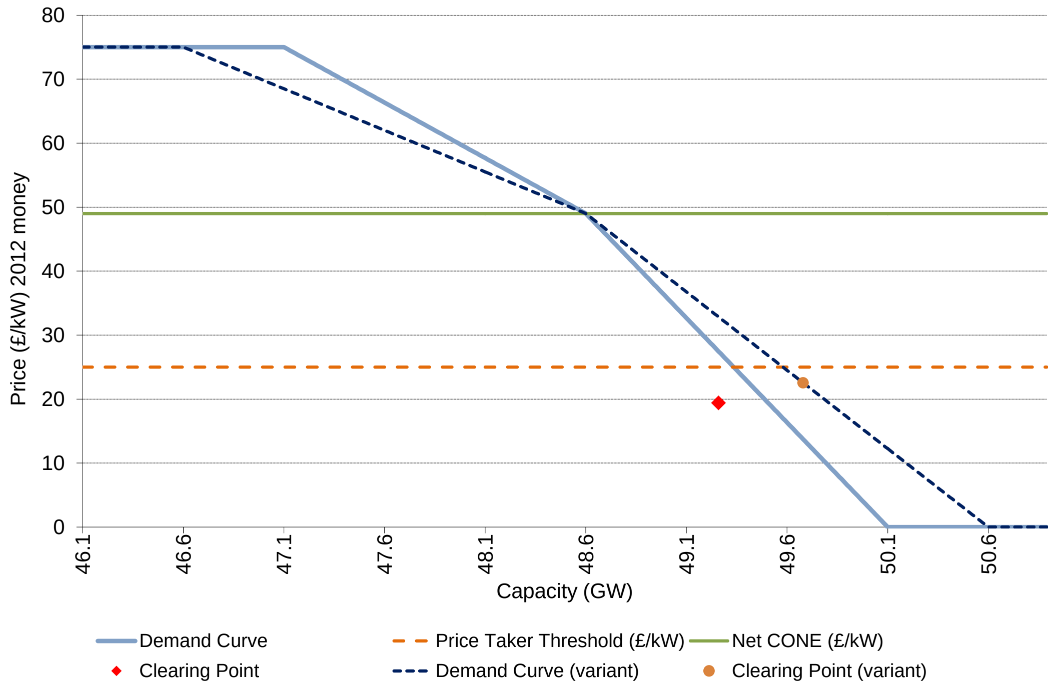
Figure 11 – Outturn supply curve (source: National Grid auction report)



5.103 This highlights the critical nature of the decision, on the level at which the capacity requirement is set for the outcome of the auction and perceptions of its success (noting, though, that consideration of the target level is not in scope for this evaluation). However, if the shape of the demand curve around the target quantity had been different, the outcome may have been different.

5.104 The band around the target quantity was set at +/- 1.5GW. This value was chosen as an anti-gaming measure, as it equates to two CCGTs and so reduces the ability for a single unit to influence the auction outcome. If, however, the band was set at +/-2GW, it is likely (assuming other things being equal) that the auction would have cleared a round earlier, at a price of around £22-23/kW and with agreements awarded for an additional ~0.5GW of capacity (dependent on the workings of the Net Welfare Algorithm). This potential variant outcome is shown alongside the actual outcome in Figure 12.

Figure 12 – Auction outturn alongside an indicative variant demand curve



5.105 The decision regarding the band around the target capacity presents a balance between value for money and ensuring adequate capacity. In the example, the overall cost of Capacity Agreements is higher, with more capacity procured. However, the opposite applies if the auction clears above the Net CONE.

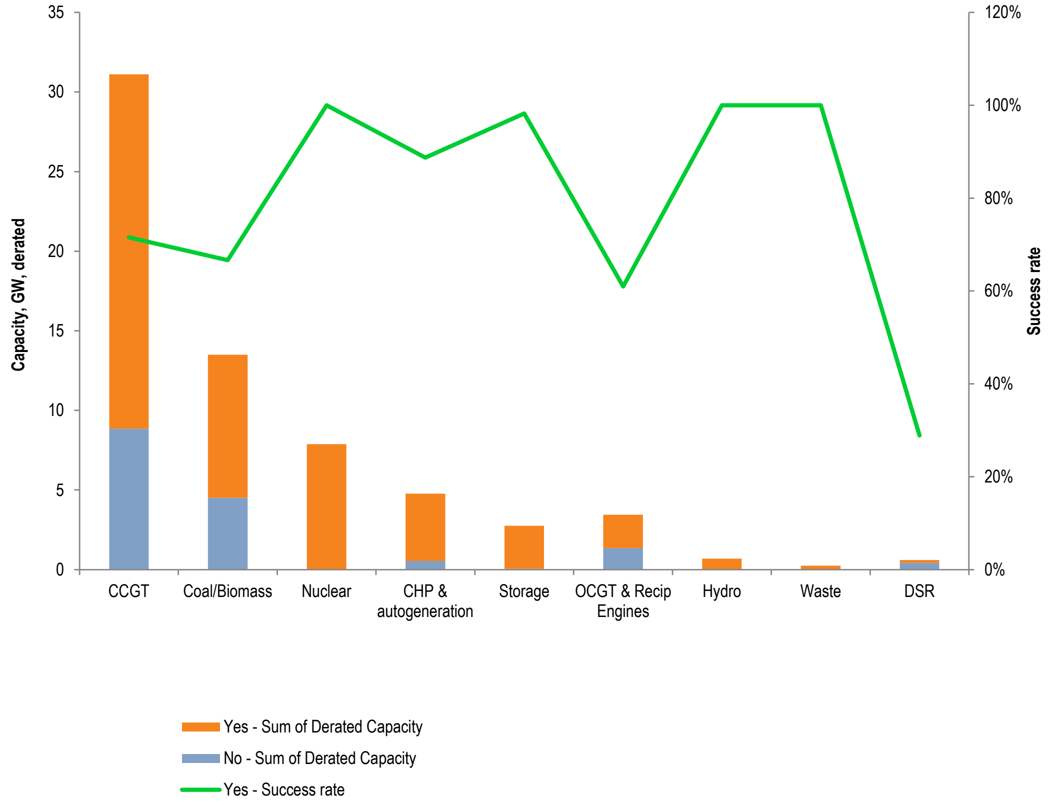
New entry has been supported

5.106 The clearing price of £19.40/kW is nearly £30/kW below the net cost of new entry (Net CONE). Nevertheless, new entry bids were still successful for one CCGT project (~1.6GW de-rated) and several smaller scale OCGT/engine or energy-from-waste projects (as discussed further in paragraphs 5.118 and 5.119).

Participation breakdown by technology

5.107 The split between Capacity Agreements awarded and not awarded is shown by technology type in Figure 13.

Figure 13 – Capacity Agreement success rate by technology



Majority of Capacity Agreements linked to CCGTs

5.108 Just under 50% of prequalified capacity was linked to CCGTs, which is unsurprising given its prevalence in the generation mix and its status as new entrant technology of choice. With ~22GW of Capacity Agreements awarded to CCGTs, this technology accounts for 45% of total capacity securing agreements. Looking across existing and new projects together, CCGT capacity had a success rate of over 70% as shown in Figure 13. The unsuccessful CCGTs are considered further below in the section beginning with paragraph 5.108, as is the outcome for new entrant bidders.

Contribution from OCGTs/engines greater than expected

5.109 Approximately 3.5GW of OCGT/engine capacity prequalified, of which 2.1GW secured Capacity Agreements. The average size of plant securing agreements in this category is 17MW, across around 120 units. The quantity of smaller scale engines in particular is greater than anticipated by most commentators before the process began. This can be taken as an indicator that the design of the capacity market is attractive for engines, potentially linked to underlying economics.

DSR also secured agreements but the results are influenced by the context

5.110 Around 1GW of DSR prequalified for participation in the December 2014 T-4 auction. Of this, around 600MW of DSR confirmed intention to participate in the auction, with 174MW of DSR capacity securing Capacity Agreements. This implies a success rate of just below 30% for DSR that entered the T-4 auction.

5.111 The outturn situation for DSR is, in part, linked to the options available to or restrictions upon it. In addition to the T-4 auction, DSR has the ability to participate in the T-1 auction and also the Transitional Arrangements[66] for delivery in 2016/17 and 2017/18. Exclusivity arrangements are in place, which mean that each DSR CMU can secure a Capacity Agreement through either the Transitional Arrangements (TAs) or the T-4 auctions, but not both. The policy rationale for this is that the TAs are intended to encourage new participants and emerging providers into the sector, and capacity that has already secured a Capacity Agreement through the T-4 auction has demonstrated that it is established, and does not need support offered by the TAs.

5.112 This exclusivity means that DSR CMUs must choose between agreements under the T-4 auction route for 2018/19 and 2019/20 or alternatively under the Transitional Arrangements plus the T-1 auction route for 2018/19 and 2019/20. This choice may have created incentives for DSR capacity to exit the December 2014 auction as the price reduced, in order to allow participation in the Transitional Arrangements and the T-1 auction for 2018/19.

5.113 On the assumption that the T-1 auction is intended as the primary vehicle to incentivise DSR, participation and success of some DSR in the T-4 auction can be regarded as a positive outcome given low expectations concerning participation levels in advance. It is also fair to note that the range of CMU categories available to capacity providers allowed some capacity thought of as DSR on today's system to register as non-CMRS distribution connected generation CMUs[67].

High success rate for 'non-conventional' / non-fossil fuel generation capacity

5.114 While conventional gas-fired and coal-fired capacity makes up the bulk of the plant in receipt of Capacity Agreements, alternative capacity sources generally have high success rates. 100% (or very close to 100%) of prequalified nuclear, existing pumped storage[68], hydro and energy from waste projects secured Capacity Agreements, as did nearly 90% of CHP/auto-generation. All these capacity sources have different economics to conventional coal-fired or gas-fired capacity. For example:

- nuclear and hydro capacity have low short run marginal costs; and
- CHP and energy-from-waste projects have additional revenue sources, linked to heat and waste gate fees respectively.

5.115 The different economic characteristics of these types of capacity influence their revenue requirement from the capacity market, potentially reducing bid requirements. This is likely to be a contributory factor behind their success in the first auction. As this aggregation of capacity providers secured around 15.7GW of Capacity Agreements in total, its role within the capacity market cannot be overlooked when considering design choices.

Participation breakdown by nature of agreement

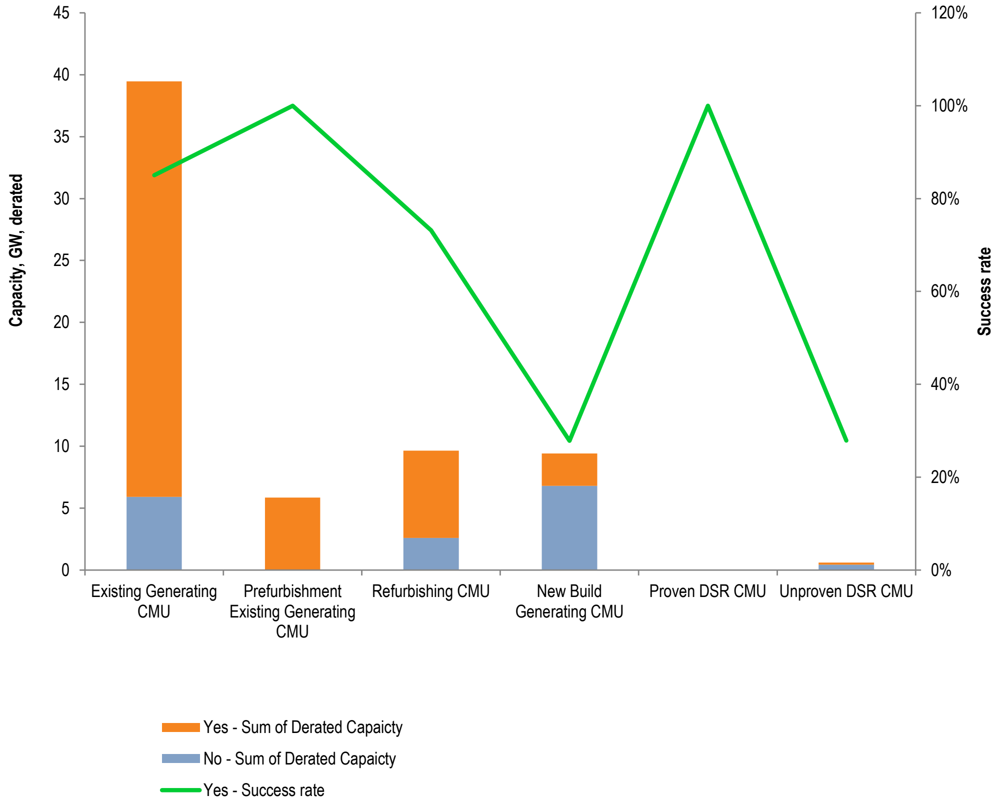
5.116 The split between Capacity Agreements awarded and not awarded is shown by nature of agreement in Figure 14.

66 The Transitional Arrangements have been designed to provide DSR and small-scale generation with a pathway to the Capacity Market. The Transitional Arrangements are intended to limit risk for these providers, encourage enterprise and build confidence for emerging sectors to participate in the one year ahead auction in 2017 and future auctions.

67 This includes the embedded generation that today provides non-Balancing Mechanism STOR and Triad avoidance. This may serve to highlight an issue of consistency in terminology and treatment across different segments of the overall market.

68 Existing pumped storage was successful but new pumped storage was not.

Figure 14 – Capacity Agreement success rate by nature of agreement



Existing capacity accounted for nearly 95% of Capacity Agreements

5.117 46.5GW of Capacity Agreements were secured by existing / refurbishing capacity, emphasising the importance of the existing fleet within the Capacity Market. Not all existing capacity was successful, however, with 5.9GW of plant seeking one year agreements and 2.6GW of capacity seeking refurbishment agreements not successful. The unsuccessful projects are considered more in the section beginning with paragraph 5.137.

2.6GW of new build projects also secured agreements

5.118 While success rate for new build projects was below 30%, plant totalling 2.6GW de-rated capacity was successful in securing Capacity Agreements. The largest single project amongst the new build agreements is the 1.6GW (de-rated) project at Trafford. This is a notable outcome from this first auction and can be viewed as an indicator that new entry has been incentivised via the first auction (this is considered further in the section beginning with paragraph 5.157).

5.119 The remaining 1GW of capacity is linked to OCGT/engines and energy-from-waste projects, which highlights that capacity with 'non-conventional' economics relative to the bulk of the large-scale, thermal fleet have been able to take advantage of the opportunities presented by the Capacity Market.

Uptake and impact of refurbishment agreements is lower than could have been the case

5.120 At the end of prequalification, 17.6GW[69] of capacity had the option to participate as a refurbishing generator seeking an agreement of up to 3 years in duration. Of this capacity, 2.6GW was unsuccessful and 5.8GW switched to participate as an existing generator during the course of the auction. This is likely to be on the basis that the auction round price dropped below what was required to commit to refurbishment capex, but remained high enough to enable participation as an existing participant with refurbishment. The outturn position is that 7GW secured refurbishment agreements. These agreements cover coal units at Cottam, Ratcliffe and West Burton A, as well as Pembroke CCGT and Winnington CHP. Of these, only the units at Cottam and West Burton A actually secured three year agreements, with the remainder opting for one year agreements (which effectively makes them equivalent to agreements with existing capacity providers).

5.121 This means that only 3.1GW of capacity has been locked in for a three year period under the refurbishment agreement option. However, the optionality afforded to capacity that prequalifies with refurbishment status does give greater flexibility to the bidders, which increases the complexity of the auction process for all participants.

5.5GW of multi-year agreements allocated

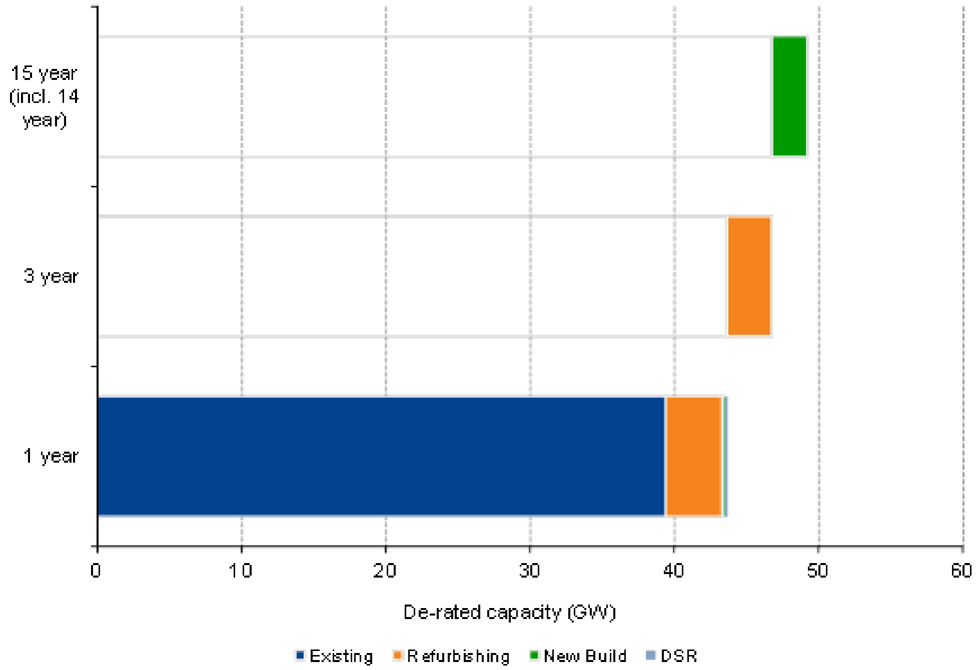
5.122 As illustrated in Figure 15, multi-year agreements have been allocated for 5.5GW of capacity. This consists mainly of 3.1GW of refurbishing capacity (as mentioned in paragraph 5.121) with a three year agreement and 2.4GW of new build agreements with 15 year duration[70]. There is also around 30MW of new build capacity with Capacity Agreements of 14 years in duration, around 20MW of new build capacity with Capacity Agreements of three years in duration and around 180MW of new build capacity with Capacity Agreements of one year in duration.

5.123 The corollary of this is that 5.5GW of Capacity Agreements are foreclosed to other market participants for some future Capacity Market auctions.

69 However, of the 17.6GW quantity, 2.1GW (of which 2GW is nuclear capacity) confirmed ahead of the auction that it would only compete as existing capacity.

70 ~200MW of new build projects secured Capacity Agreements of either 1 year or 3 years in duration.

Figure 15 – Capacity Agreement duration



RSI metric suggests no player has market power

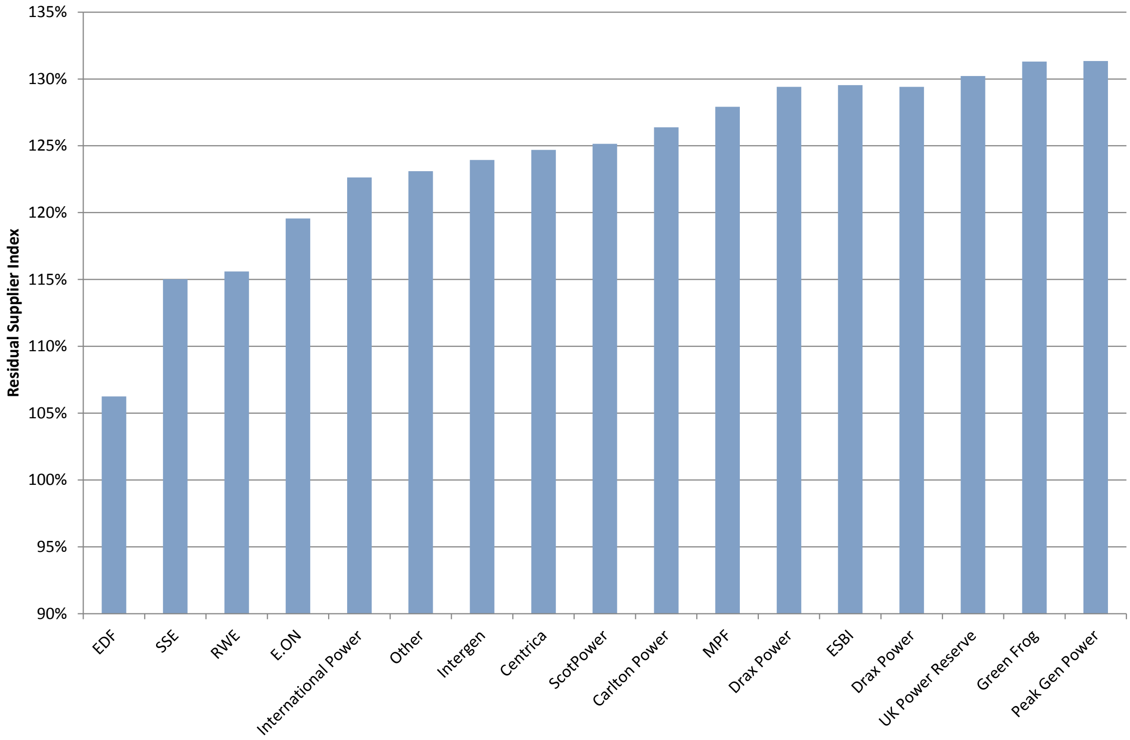
5.124 Applying the Residual Supplier Index (RSI)[71] indicator to the Capacity Market as a whole suggests that no player had market power. RSI is based on a party's share of overall supply into the market divided by total outturn demand. If RSI is below 100% for a party, it suggests that the party has the potential to influence price and could practise market power. Receiving a result bigger than 100% is an indication that a party should have little influence on the price.

5.125 The RSI level for parties with the largest presence in the Capacity Market is shown in Figure 16. EDF has largest share within the market, but its RSI is still above 100%.

5.126 Without access to bid price evolution throughout the auction, further conclusions on market power or gaming cannot be drawn as part of this evaluation.

[71] RSI is a measure of the capacity of all other generation needed to meet demand when the capacity of an individual generator is removed. This was developed by the Californian Independent System Operator (CAISO) as a means of monitoring potential market power in the day-ahead and real time markets as well as in relation to transmission constraints.

Figure 16 – Residual Supplier Index for December 2014 Capacity Market auction



Signals for future

5.127 This section looks forward at the long term implications for the CM based on what has happened to date and discusses the limitations of the current conclusions, which are based on only one auction. It also addresses participant desire for stability in the arrangements, along with the implications of the CM on the wider electricity market.

We cannot infer too much from the outcome of the first auction

5.128 The first Capacity Market auction, gives only a single data set in terms of results. We remain 3 ½ years from the start of the 2018/19 delivery period and 1 year from the Financial Commitment Milestone for 2018/19, which will be an important staging post for assessing the delivery of new build projects. As such, it is too early to draw conclusions about the effectiveness of the Capacity Market in delivering long-term security of supply. The evidence base is not available yet.

5.129 However, it is clear that the first auction attracted surplus capacity with just under 65GW of capacity prequalified, including over 9GW of potential new capacity, which created 30% headroom relative to the target requirement going into the first round.

5.130 The market needs several years of auctions, experience of the ramp up to a delivery period and of actual operation to enable substantive conclusions to be drawn on the effectiveness of the Capacity Market.

Participants calling for stability in the arrangements

5.131 Building on the preceding point, while stakeholders have pointed to possible revisions to the arrangements and highlighted design decisions that they would have made differently, there is generally an over-riding desire for some stability to allow the system to bed-in and for a track-record to be established over several years. **There is scope for fine-tuning of details or enhancements to procedural or administrative aspects of the arrangements (see 'Recommendations' section for suggestions), but the**

overarching framework and design of the Capacity Market should remain stable. The system in place is the one that must be worked with and it would be counter-productive to seek major reform.

5.132 Stability in the arrangements will help to establish within the industry and the finance community understanding of their operation, which should enhance confidence. A track-record over time and the associated evidence base will allow a more robust assessment against objectives, based on which more informed decisions can be taken regarding more substantive potential revisions to the arrangements.

5.133 **In the spirit of wishing to maintain stability within the arrangements and provide certainty, a watch list of potentially more substantive changes (rather than administrative or procedural changes) could be established.**

The process gives a clearer picture of expected capacity over a 4 year horizon

5.134 One of the positive consequences of the Capacity Market is that we now have a clearer picture of anticipated capacity availability over a four year time horizon than may otherwise have been available.

5.135 The prequalification exercise galvanised expectations regarding closures of plant that elected to opt-out and indicated that it would not remain operational in 2018/19. Similarly, expectations regarding existing plant operations in 2018/19 have been informed by success or otherwise in securing a Capacity Agreement, with some closures now announced for plants that did not obtain an agreement (as discussed further in the section beginning with paragraph 5.137). New build plans are also clearer as a result of the auction (notwithstanding delivery risk, as discussed in the section beginning with paragraph 5.145).

5.136 Uncertainty does still remain for 2018/19. Certain plants may change plans and there may be unexpected outages or higher outturn demand, for example. But there is improved certainty looking forward, other things being equal.

Outcome has supported exit decisions

5.137 As highlighted previously, 15.7GW of prequalified capacity was unsuccessful in the first auction, of which around 8.5GW is linked to existing capacity. The existing projects not securing agreements include eight larger scale gas-fired plants and five coal-fired stations.

5.138 Since the auction, there have been developments at a number of the gas-fired stations, which are shown in Table 5. Planned closures have already been announced in relation to Brigg, Killingholme Centrica and Killingholme EON. The TEC Register confirms that EON and Centrica have reduced TEC to zero at their respective Killingholme plants. Centrica has also scaled back its TEC holding for Brigg to 99MW. These changes all take immediate effect. It is arguable that by prompting closure decisions for unprofitable assets, the Capacity Market has supported efficient exit decisions. In addition to these gas-fired stations, the closure of coal-fired Ferrybridge by April 2016 has also been announced[72].

5.139 For a number of the other gas-fired stations that did not secure a Capacity Agreement, contracts with National Grid provide specific revenue streams for part of the period to 2018/19. Corby, Barry, Killingholme Centrica, Deeside and Peterhead have Supplemental Balancing Reserve (SBR) contracts for winter 2015/16 and so will remain on the system

[72] http://sse.com/newsandviews/allarticles/2015/05/sse-announces-closure-of-ferrybridge-power-station/

until the end of this period, at least[73]. Peterhead also has a voltage support contract with National Grid for 385MW that will keep it on the system until at least September 2017[74]. No formal announcements have been made in respect of Peterborough. However, its TEC holdings are being scaled back.

5.140 The net position in terms of TEC holdings across these stations is a reduction of~2GW, of which 1.6GW is linked to closures. This is expected to reduce the quantity of capacity bidding into the December 2015 auction for delivery in 2019/20. TEC holdings at the coal-fired stations that did not secure Capacity Agreements have been maintained, which potentially indicates intention to participate in the upcoming auction process for 2019/20.

Table 5 – Developments at gas-fired stations that did not secure Capacity Agreements

Station	MW de-rated	Developments	TEC register info from 8-May-15
Barry	230	SBR contract for 227MW for winter 2015/16	TEC reduced to 99MW from Apr-16
Brigg	145	Planned closure announced[75]	TEC reduced to 99MW from Apr-15
Corby	360	SBR for 353MW for winter 2015/16	TEC unchanged at 401MW
Deeside	465	SBR for 250MW for winter 2015/16	TEC reduced to 260MW from Apr-15
Killingholme Centrica	600	SBR for 660MW for winter 2015/16 Planned closure announced[76]	TEC reduced to 0MW from Apr-15
Killingholme EON	800	Planned closure announced[77]	TEC reduced to 0MW from Apr-15
Peterborough	220	No public announcements	TEC reduced to 99MW from Apr-16
Peterhead	1040	Voltage support contract for 385MW with National Grid from April 2016 to September 2017[78] SBR for 675MW for winter 2015/16	TEC unchanged at 400MW

Merchant risk still exists for new projects

5.141 As discussed in paragraph 5.99, the clearing price from the December 2014 auction was lower than anticipated by many stakeholders and commentators. This means that the revenue stream associated with payments under Capacity Agreements stemming from the December 2014 auction will be below expectations. A consequence of this is that new build projects will be more reliant on energy market incomes to make project economics

73 'SBR Winter 2015-16 TR2 Market Report', National Grid, June 2015.
74 Peterhead is also a potential site for a CCS demonstration project (http://www.shell.co.uk/energy-and-innovation/the-energy-future/peterhead-ccs-project.html).
75 http://www.centrica.com/files/reports/2014ar/Centrica_AR2014_Annual_Report.pdf
76 http://www.centrica.com/files/reports/2014ar/Centrica_AR2014_Annual_Report.pdf
77 http://pressreleases.eon-uk.com/blogs/eonukpressreleases/archive/2015/03/19/2419.aspx
78 http://sse.com/newsandviews/allarticles/2015/03/sses-peterhead-power-station-awarded-national-grid-contract/

work than may have been expected. This means that market risk will remain to a greater extent than potentially anticipated.

5.142 From a financing (and re-financing) perspective, the lower the capacity payment stream, the lower the level of debt that can be secured against it. This increases requirements on funding from other, generally more expensive sources. Other things being equal, this increases the costs of projects.

5.143 Stakeholders from a range of backgrounds have indicated that the factors above mean that merchant risk for projects is greater than may have been anticipated, suggesting that the Capacity Market has not had any downward effect on the cost of capital (although there is no firm evidence in either direction at this stage). However, there are clearly a number of new build projects that have locked in at the December 2014 clearing price, when they had the option to withdraw from the auction. This suggests that this clearing price and the associated revenue stream are adequate for the project economics of the projects in question.

5.144 But at this stage there is no firm evidence to support conclusions which suggest that the Capacity Market has had either an upward or downward effect on the overall cost of capital for new build. **Evidence (eg financing costs and EPC terms) can be gathered going forward based on assessment of the economics of projects that come forward under the Capacity Market, plus feedback from the finance community and project developers.**

Delivery risk ahead of 2018/19 is a prominent concern

5.145 With the completion of the auction process, attention amongst stakeholders is now more focused on delivery of capacity for 2018/19 (as well as future auctions, of course). With Capacity Agreements in place for 2.6GW of new build capacity, the prime question is whether all of this capacity will be delivered as expected. But there is also a delivery risk dimension for existing plant.

5.146 Taking existing capacity first, while opted-out of the Capacity Market and not in possession of a Capacity Agreement, the situation regarding Longannet can be considered as a type of delivery risk. As outlined in paragraph 5.34, potential closure of Longannet has recently been announced[79]. If this occurs it would leave a gap of ~2GW relative capacity requirements to be addressed through the T-1 auction (discussed further in the section beginning with paragraph 5.151).

5.147 Aylesford Newsprint is the sole example to date of an existing project (unproven DSR) that was successful in the December 2014 auction confirming that it will not proceed. As the capacity contribution from Aylesford Newsprint is ~3.5MW, the impact on the Capacity Market is small. However, the same would not be the case if there is a sizeable accumulation of capacity that pulls out and/or the withdrawal of a larger scale capacity provider.

5.148 In principle, there is the potential for existing capacity with Capacity Agreements to withdraw. While this would create exposure to termination fees, this could be a rational economic decision. If, for example, a transmission connected project relinquishes TEC required to meet its Capacity Market obligations, the termination fee of £25/kW may be less than the avoided TNUoS charge in regions with higher locational charges plus the avoided annual fixed costs. While the broader economics of such a decision would need to be considered, it could happen in principle.

[79] http://www.scottishpower.com/news/pages/scottishpower_comment_longannet_power_station_230315.asp

5.149 Delivery risk concerns are more heavily focused on new build projects, as it does not yet exist and there is potential that some of the 2.6GW of new build capacity does not proceed in practice. As things stand, there is no evidence of non-delivery amongst the new build projects. If projects meet the Financial Commitment Milestone and subsequent delivery requirements, then the issue may not materialise. **However, if there are further indications of potential non-delivery, this needs to be monitored by DECC and communicated to industry at the earliest possible opportunity. We recommend that, if this is not already planned, this should be included in the EMR Annual Update and shared with the market as soon as possible respecting commercial sensitivities.**

5.150 As non-delivery could increase capacity requirements in the T-1 auction, this could be met by DSR and existing capacity that did not secure a Capacity Agreement in the T-4 auction. The potential for existing capacity to fill the gap relies on its still being on the system, given the possibility of closure (as already seen for some plants that did not secure agreements in the December 2014 auction). This heightens the need for regular monitoring and communication of non-delivery risk.

T-1 auction could have important role

5.151 Issues in relation to delivery risk and closure of existing assets bring the T-1 auction into focus. Stakeholders have highlighted the potential for requirements in T-1 to be greater than the 2.5GW set aside and have asked questions concerning the ability for the T-1 auction to deliver. Possible drivers for increased requirements in T-1 include:

- increases in demand relative to expectations that fed into the T-4 capacity requirement assessment;
- withdrawal of opted-out plant whose capacity was netted off the T-4 capacity requirement; and
- non-delivery of new build projects that secured Capacity Agreements in the T-4 auction.

5.152 If a negative outlook is taken, withdrawal of Longannet and a hypothetical delay at Trafford could increase the T-1 capacity requirement by over 3.5GW. The ability of the market to respond to this scale of additional requirement, if it were to materialise, is unclear. There are some potential upsides to factor in as well, however, such as:

- The T-1 requirement may be reduced if updated expectations regarding interconnection contributions are greater than assumed for the T-4 auction. The Float Base case considered in National Grid's Electricity Capacity Report[80] assumed zero net imports/exports in aggregate (0.75GW import from continental Europe and 0.75GW export to Ireland), while the alternative Import Base case considered 2.25GW of net imports (2.25GW import from continental Europe and zero net import/export to Ireland).
- As the T-4 auction allocated 49.3GW of capacity agreements, it surpassed the target requirement of 48.6GW by 0.7GW, which may reduce T-1 requirements.

5.153 Figure 17 shows an illustration of the potential adjustments to the T-1 requirement, taking into account possible upsides and downsides mentioned above. If all the drivers shown in Figure 17 materialise, then the T-1 requirement would increase by 0.9GW. However, there are potential sources of capacity to meet this requirement, as follows, in addition to DSR:

- Carrington (0.8GW de-rated), which did not secure a Capacity Agreement in the T-4 auction, is expected to be available to participate in the T-1 auction.

[80] 'National Grid EMR Electricity Capacity Report', June 2014.

- There is also the potential for some of the existing larger gas-fired assets that did not secure Capacity Agreements through the T-4 auction to participate, if they remain open.

5.154 The scale of capacity associated with these providers is shown in Figure 18. In addition to Carrington, this includes the larger-scale gas-fired stations that did not secure a Capacity Agreement and have not announced closures following the December 2014 auction. This category is broken down into those that currently have SBR or voltage support contracts with National Grid for part of the period running up to 2018/19 and those who have no contracts. For different categories of existing gas-fired stations without a Capacity Agreement, Figure 18 shows both the de-rated capacity and the latest TEC position. This highlights that the TEC position is lower than the de-rated capacity position for the existing gas-fired assets shown. There is also the potential for coal assets that did not secure a Capacity Agreement in the T-4 auction to participate in T-1, if it remains open.

5.155 Whilst Figure 17 and Figure 18 are illustrative, they highlight the potential for the T-1 auction to assume a significant role given potential variations in supply and demand fundamentals. As potential changes in the thermal capacity providers' positions are blocky and large scale in nature, they will have a relatively large impact on T-1 market dynamics given their size versus the overall market size. This could lead to variability in T-1 auction participation and outcomes, given sensitivity to supply and demand variations.

5.156 Clearly, there is no hard evidence in relation to the T-1 auction process at this stage, but the sensitivity of its operation to variations in supply and demand fundamentals merits mention as a flag for the future.

Figure 17 – Possible adjustments to T-1 capacity requirement

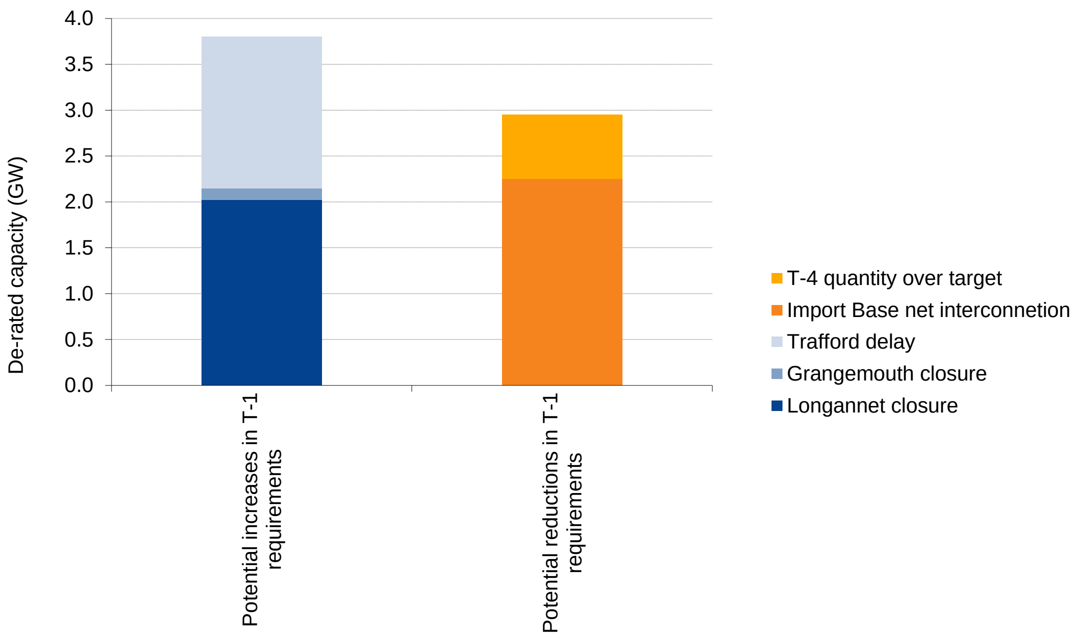
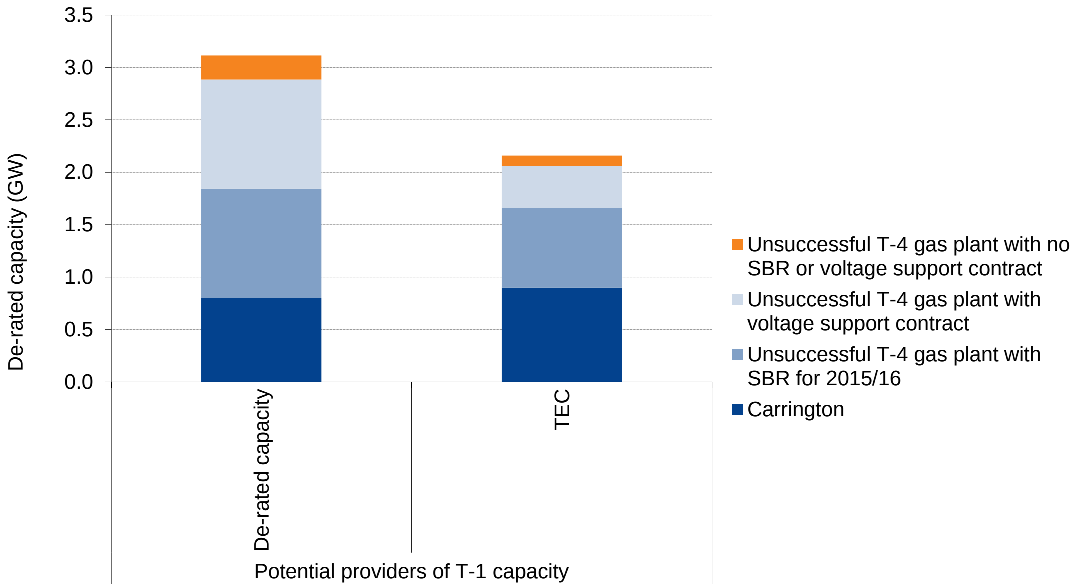


Figure 18 – Possible sources of capacity for T-1 auction (excluding DSR)



Replicability of Trafford is unclear

5.157 The Trafford plant constitutes the largest new build project to secure a Capacity Agreement. As a new build CCGT, the fact that it secured a Capacity Agreement in the December 2014 auction has been flagged as an indicator of the success of the auction. However, a variety of stakeholders raise questions about the replicability of the Trafford project for other new build CCGTs and, hence, its value as an indicator of the prospects for further projects. A general point raised is that the turbine market and turbine prices have been depressed over recent years due to the dampening effect of the financial crisis on turbine demand. This trend may not persist as the market recovers. More specific factors that have been highlighted anecdotally, but are unconfirmed, in the context of Trafford are that:

- the turbine costs are particularly favourable as the manufacturer want a full scale application of its new turbine technology; and
- the collateral requirement has been posted by the turbine manufacturer rather than the developer.

5.158 Clearly, the economics of new build differ from project to project depending upon factors such as the Engineering Procurement Construction, EPC, contracts, the funding arrangements and expectations of future returns. No two projects are directly replicable. But if factors such as those indicated above are indeed applicable to Trafford, then it is not clear that other projects would be able to secure comparable arrangements. While there is no firm view regarding the specifics of Trafford's situation and the extent to which it is comparable, a cautionary note should accompany any conclusions that the success of Trafford indicates that further new build CCGT will occur, certainly at a clearing price such as the December 2014 outturn.

Impact of reciprocating engines is uncertain and may be counter to policy aims

5.159 As highlighted in paragraph 5.109, the outturn contribution of engines to the future capacity requirement was greater than anticipated. The success of engines in the auction can be linked to factors including lower capital costs than alternatives and access to embedded benefits, both of which reduce the revenue requirement from the Capacity Market. It is worth noting that recovery of capacity payments from suppliers based on consumption in peak hours on winter business days increases potential embedded benefits[81].

5.160 This confers a cost advantage to engines in relation to other technologies which can be reflected in Capacity Market bids. This displaces alternative capacity providers, with a downward impact on the clearing price. In this sense, the success of engines is a positive outcome as it offers a low cost source of capacity.

5.161 However, the success of engines has prompted concern amongst some stakeholders that the Capacity Market is supporting low efficiency, high emissions diesel capacity, which contradicts wider EMR objectives in pursuit of decarbonisation. However, the environmental impact will be influenced by factors such as the underlying fuel source and the efficiency for engines.

5.162 It is certainly the case that some of the engines are diesel-fired, although some are gas-fired or have dual-firing capabilities, as indicated in Table 6, which provides details for a selection of engine technologies (the split within the market between different types of engine is not clear creating a requirement for more information in this regard). The impact of engines on emissions will depend upon likely running patterns, which will be linked to efficiency.

5.163 Table 6 also shows for the selected engines efficiencies in the range 42% to 49% (on Lower Heating Value (LHV) basis), which may be higher than some stakeholders expect. This, combined with incentives created by embedded benefits, may increase running time and, as a result, emissions. Conversely, if running hours are low, the emissions effect will be restricted. Therefore, the likely impact of engines in this regard is, at this stage, still uncertain.

81 By selling their output to an electricity supplier serving customers, embedded generators can help suppliers reduce their exposure to charges that recover capacity payments.

Table 6 – Selection of engine technologies[82]

Name	Manufacturer	Size (MW)	Efficiency (LHV, new, gross)	Fuel
34SG	WÄRTSILÄ	9.72	49	Gas (also multifuel version)
34SG GRID STABILITY	WÄRTSILÄ	9.72	48	Gas (also multifuel version)
Gascube	WÄRTSILÄ	7	48	Gas (also multifuel version)
32GD	WÄRTSILÄ	8.9	45	Gas/Oil mix or Oil
J920	GE	9.5	49	Gas
J624	GE	4.1	46	Gas
J616	GE	2.6	45	Gas
J620	GE	3.4	45	Gas
B35:40V12AG2	Rolls Royce Bergen	5.6	48	Gas
B35:40V16AG2	Rolls Royce Bergen	7.5	49	Gas
B35:40V20AG2	Rolls Royce Bergen	9.4	48	Gas
B35:40L9AG*	Rolls Royce Bergen	3.8	47	Gas
B32:40V12A2	Rolls Royce Bergen	5.3	44	Oil
B32:40V16A2	Rolls Royce Bergen	7	45	Oil
G3520E	CAT	2	42	Gas

5.164 Given the relative economics, the contribution of engines is expected to increase. **This creates a need for greater understanding of the underlying characteristics of engine options, implications for running patterns and their potential impact on emissions and costs to consumers in providing security of supply. This will help to inform the importance of the concerns expressed by stakeholders regarding the potential wider impact of engines. We recommend that this should be assessed further by DECC and/or National Grid.**

82 Source: manufacturers' catalogues.

Recommendations

5.165 Building on the sections above, our recommendations for future rounds of the Capacity Market are set out below.

Improve transparency of demand curve pricing parameters

5.166 The basis for setting the Net CONE and the Price Cap lacks a transparent methodology and supporting justification. Having a clear methodology for the determining these parameters will increase certainty for participants in future. The methodologies behind these parameters should, therefore, be formally defined within the Rules / Regulations framework for future auctions.

Assess streamlining the anti-gaming measures

5.167 As a longer term focus, with experience from several auctions it will be possible to assess the competitiveness of the auction processes. This review, in the event that it indicates functioning competition, may allow relaxation of some of the anti-gaming measures.

Continue to invite evidence on agreement duration for DSR

5.168 DECC should continue to invite the DSR community to supply evidence in relation to the implications of 1 year only agreements on DSR deployment and the potential effects of longer-term agreements on this, as well as assessment of delivery risk issues associated with longer-term agreements. This will allow an evidence-based review of this issue.

Tighten refurbishment status criteria and consider ongoing need for it

5.169 The arrangements for qualifying for refurbishment status need revision. Notably, the capital expenditure threshold is imprecise and historical expenditure can qualify as eligible spending. Beyond these enhancements, the ongoing need for the refurbishment category should be reviewed.

Streamline or refine prequalification information requirements

5.170 Based on experience from the first round (and second round given timing), seek to strip out any information that is, with hindsight, not needed and address areas where there are overlaps or duplications in information requirements. Also, allow data or information that is unchanged from one auction to the next to be retained as standing data. In combination, consider whether more information should be requested from new projects as part of prequalification.

Provide consolidated versions of Rules and Regulations

5.171 As Rules and Regulations evolve, consolidated versions of the full texts should be maintained and accessible to stakeholders[83]. This removes an administrative barrier or burden for stakeholders.

Maintain commitment to preparation and training

5.172 As happened for the first auction, there should be a continued commitment to training, support and testing in preparation for subsequent auctions.

Formalise process for auction results release

5.173 To support compliance with governance requirements for stock exchange listed companies as well as investor and employee relations, formalise timeframe and process for auction result information release.

[83] A non-legally binding consolidated version of the Capacity Market Rules dated 19 June 2015 is now available on the Ofgem website (https://www.ofgem.gov.uk/electricity/wholesale-market/market-efficiency-review-and-reform/electricity-market-reform/capacity-market-cm-rules).

Allow more interactive appeals process

5.174 To address minor issues with prequalification information, allow for a more interactive process between participants and the Delivery Body.

Maintain stability of Rules wherever possible

5.175 Given the over-riding desire for some stability to allow the system to bed-in and for a track-record to be established, the overarching framework and design of the Capacity Market should remain stable wherever possible. Enhancements to procedural or administrative elements of the arrangements can be progressed, but the broad fundamentals of the Capacity Market should be retained to allow experience to develop.

Watch list of potential changes

5.176 In the spirit of wishing to maintain stability within the arrangements and provide certainty, a watch list of potentially more substantive changes (rather than administrative or procedural changes) could be established.

Monitoring and reporting on non-delivery risk

5.177 Concerns regarding non-delivery risk create uncertainty for the market and its ability to respond in the event of non-delivery. Also, if non-delivery becomes a significant issue, it could point to the need for modifications to the delivery incentives. There is a need for regular monitoring and communication of non-delivery risk (eg through a publicly available dashboard) to provide transparency to the market. We recommend that, if this is not already planned, this should be included in the EMR Annual Update and shared with the market as soon as possible respecting commercial sensitivities.

Understand characteristics and possible impacts of engines

5.178 Given uncertainty surrounding the characteristics of engine technologies and their implications for emissions in particular, further analysis is needed to enhance understanding of the underlying characteristics of engine options and their potential impact on emissions and costs to consumers in providing security of supply.

6 Contract for Difference detailed findings

Key messages

Primary findings

6.1 The development of the Contracts for Difference (CfD) was a complex process that involved many different commercial, regulatory and legal aspects. **DECC and its delivery partners succeeded in dealing with its complexity and in delivering the programme within a tight timeframe.** For this reason they have been highly commended by stakeholders. The level of consultation was incredibly intense, but greatly appreciated. DECC staff were generally approachable and responsive However, the lack of staff continuity and the multiple points of information at times hindered the dialogue with industry.

6.2 **Most importantly, the first allocation round appears to have been a success. The move to constrained allocation for all technologies in the first round was unexpected and implemented at short notice. However, the results of the auction provided the required comfort that the new regime is capable of producing the expected benefits it was designed for. Specifically:**

- **Competition seems to have delivered a relatively lower cost to consumers compared to the previous regime**. Participation levels in the first CfD Round were not publicly disclosed, however, they appear to have been high, which meant that the auction was oversubscribed. This created a competitive tension that enabled the delivery of around 2.1GW of renewable capacity at strike prices at considerable discount to the Administrative Strike Prices. The Government succeeded in introducing a competitive environment for the renewables sector, and we have found that industry is now widely supportive, despite initial opposition.
- **Sufficient capacity was contracted to keep the UK electricity sector on track to meet its contribution to renewables and decarbonisation targets.** The capacity contracted was dominated by wind and larger projects. It is still to be seen whether contracted projects – both under the FID Enabling for Renewables and CfD October 2014 round – will ultimately commission, so success in contributing to these targets will only be certain once this is known. **Therefore, whilst it is possible this could be achieved without any further CfD rounds for delivery prior to 2020, these are recommended.**

6.3 We believe that **the allocation rules, including auction frequency, budget pots, allied to the use of maxima and minima, give DECC the tools it needs to address cost inefficiencies that could arise under technology neutral auctions due to differences in technology characteristics.** The allocation of budget to these pots, Administrative Strike Prices (ASPs) and other Government policy to address externalities outside the CfD will also support this. Whilst the current use of these tools goes some way to addressing potential cost inefficiencies, we still have some concerns over baseload and intermittent technologies competing in the same Pot, in the absence of a value on reliability for CfD-supported capacity, as well as the difference between project characteristics of offshore wind projects and other Pot 2 technologies. Without a full evaluation of technology characteristics in light of Government's own priorities – for example, the value it puts on community projects – it is not possible to undertake a full assessment of the compatibility of different technologies in the same auction.

6.4 **Overall, the CfD regime has changed the risk profile of renewable projects compared to an extended Renewables Obligation (RO) under the same Levy Control Framework constraints.** It introduces new risks and/or magnified those that typically materialise in the early phases of the project life-cycle – qualification, allocation and construction risks – whereas it reduces the level of risk during later phases – market risk (with the exception that subsidies tail off earlier than under the RO). This shift results in a different distribution of the total quantum of risk over a project's life, which does not uniformly affect all classes of investors. These will have a different perception of risks depending on their role in the project, its characteristics and competitive positioning, and the timing or priorities leading to the investment.

6.5 **In a perfectly functioning CfD market, the total quantum of risk is expected to be lower than under an extended RO.** However, there are a number of circumstances, that are not necessarily structural, but that can temporarily alter the balance of risks over the project life-cycle and affect the perception of risks (eg lack of visibility on future budget levels and auction frequency, evolution of competition, etc.). This could in practise prevent the current CfD regime from delivering the full theoretical benefit. The implication of this shift in risk are multiple and not exclusively related to the cost of capital.

6.6 **Magnitude and timing of financial benefits in terms of cost of capital levels and financing practises are uncertain.** At present, there is no conclusive evidence that the new mechanism has made renewable investment more attractive through lowering the risk of projects for a broader pool of financial investors. Equally, there is no strong evidence whether this alone will drive down the cost of capital materially, as macro-economic conditions will likely play a more fundamental role in driving financing costs of renewable assets. **Lending institutions generally agree that a higher level of revenue certainty is expected to improve financial covenant terms, but some factors could affect their operations and debt terms.** The relevance of these factor remains to be seen. Unfamiliarity with new regime is expected to impact earlier deals, but as soon as more standardised practises will emerge, this should facilitate competition thus lower cost of debt. **From an equity perspective, direction of hurdle rates are less clear given mainly the uncertainties related to Government's medium to long-term policy and future CfD rounds.** Allocation risk is in theory manageable, thus implications on required rate of returns should not offset the other structural benefits of the CfD. However, the current perception of allocation risk is high, therefore cost of equity implications remain unclear.

6.7 It is worth noting that **lower overall cost to consumers may be achieved, not only from a lower cost of capital, but also from other factors, such as removal of infra-marginal rents across the value chain of the industry.**

Secondary findings

6.8 **The quality of the process for the design of the CfD and key parameters set was not uniform across the various work streams. The intensity of the consultation process did not automatically translated into a consistent level of appropriateness and transparency of DECC's decision process.** Specifically:

6.9 **The Administrative Strike Prices setting process was appropriate and transparent:**

- Level of consultation and information disclosure was appropriate;
- RO minus X (RO-X) followed by reducing strike prices with expected falls in technology costs was an appropriate methodology to use in setting strike prices;
- Modelling tools including an electricity market model[84] were appropriate;
- Scenarios and sensitivities were reviewed by and discussed with the Panel of Technical Experts, which helped the robustness of the process;
- Internal quality assurance process required a senior level of sign off[85]; and
- Technology modelling contained the necessary outputs to test the scenarios against Government objectives.

84 DECC's Dynamic Dispatch Model (DDM) was used.
85 An audit of whether all processes were signed off was outside the scope of this project.

6.10 **The budget setting process was generally appropriate[86]:**

- Setting out a clear set of internal objectives provided an important focus to the modelling and decision making process;
- The QA procedure required sufficient senior sign off[85] at several levels;
- The top down and bottom up approach provided the necessary detail and constraints to test Government objectives; and
- Testing the outcomes against different scenarios including wholesale electricity prices and renewables deployment under different schemes to understand the impacts of the main uncertainties on meeting objectives.

But there is still room for improvement, in particular in terms of transparency:

- Information published was relatively limited and this reflected in stakeholders' understanding of the process and rationale. For instance, the last minute addition of £25million to the Pot 2 budget created uncertainty and gave the impression DECC was 'picking the winners'; and
- There is scope to improve some input assumptions eg use of project specific load factor and technology-specific reference prices and alternative strike prices to the ASP.

6.11 Based on our review of the process and stakeholder research, **we found that the faster than expected move to competition reduced the time available for wider discussion on the auction design. Therefore, time pressure meant that consultation was limited and so stakeholders felt less able to fully formulate and submit their views during the process:**

- Organisations felt they had little chance to influence the process, and some lack of clarity around the rationale remains. A higher degree of consultation would have facilitated the buy-in from potential participants at the outset, however, we have not found any strong evidence that this deterred participation.
- Any design may produce sub-optimal results and/or unintended consequences, so the priority is to select the format that could minimise the risks and keep monitoring how it evolves over time. DECC had to balance between economic efficiency, policy and achieving desired outcome. **Given the complexity of objectives, the timeline implementation challenges and other considerations around the common value certainty and robustness against collusive behaviours, the sealed bid pay-as-clear format appears to be broadly appropriate**.
- The framework for flexible bids is relatively complex and may have limitations with respect to economic efficiency, fair competition and its scope. **However we are supportive of the idea of flexible bids as it would deliver against the objective of eliciting project efficiency and preventing potential distortions arising from budget choices or project lumpiness**.

6.12 **In terms of the process of drafting the CfD Contract, DECC had initially underestimated the time and effort required to** transfer policy intent into a private law document, which contains **a robust and broadly consensual set of terms**. However, engagement with the financial community helped to increase the level of collaboration and the final product is in principle accepted by most stakeholders as an investable legal framework. **On the whole, both the developers and the financial community agree that the CfD Contract terms appear to be reasonable and that the allocation of risk between consumers and renewable generators is workable.** The real test will come from the combination of the first financing deals and the first projects stepping through the various contractual and operational milestones.

[86] See paragraph 6.145 to 6.161

6.13 With respect to the CfD Contract terms, we found that:

- The **reduced contract length (15 years vs 20 years under the Renewables Obligation) is considered manageable** by most stakeholders, but it is too soon to identify whether any unintended consequences on projects or any real benefits to consumers will materialise;
- **Milestones requirements may prove to be too stringent for some large or complex projects;** and
- **Among stakeholders, there is uncertainty around how the CfD Contract will work in practice. However, we believe that this is likely to be resolved as contracted projects step through the various contractual phases and** stakeholders will become progressively comfortable in the contract provisions.

6.14 **Despite the concern that the allocation process is too long and cumbersome, the round was delivered without any major setback**. Eligibility assessment generally worked well. Guidance was not sufficient in some instances. This may have caused appeals and delays in running the actual auction. However, only a limited number of applicants appealed and none of the National Grid's decisions were reversed by Ofgem. **The main lesson to be learnt from the appeals process was that there is potential for a scenario to occur where an applicant is over penalised for a minor indiscretion unless further measures are implemented to mitigate this.**

6.15 **It is too early to make a judgement on the effectiveness of the project qualification requirements in achieving the appropriate balance between barriers to entry and preventing speculative projects.** Whilst it is a positive sign that they did not provide a barrier to a competitive first allocation round, the following evidence is necessary to make a full judgement:

- which projects felt able to participate eg unsuccessful participants as well as successful participants;
- which contracted projects successfully commissioned; and
- evidence of a pipeline of projects developed built up after the introduction of competitive allocation.

6.16 There were, however, some concerns raised by stakeholders that could pose issues in the future and warrant further investigation, such as the requirement for a grid connection offer and transparency on scoring and rationale for the supply chain plan.

6.17 We had **limited opportunity to search for evidence of gaming** in the allocation process because of restrictions on data access imposed on National Grid. Public information and evidence gathered from our stakeholder research was not sufficient to perform a robust assessment. The only clear evidence of speculative projects or disruptive behaviours we could find was the award of a CfD Contract to two solar parks (that in the end withdrew) based on our interpretation of their bidding behaviour.

6.18 This raised **questions around the robustness of the current measures against speculative projects and disruptive behaviours, and whether these need to be reviewed.** We found that the **process of designing the measures against speculative projects and behaviours was dictated by the necessity of driving single work streams of the CfD design forward, thus relatively rushed.** However, this has not materially impacted measures.

6.19 The **current measures against projects that have a low chance of delivering against their contractual commitments in the event they were allocated a CfD Contract (speculative projects) are broadly appropriate. Some material weaknesses were found in the measures against disruptive behaviours**, which may delay the process, game the system to the detriment to other participants or simply consist in submitting bids that are not realistic.

6.20 The auction format is on balance appropriate to incentivise straightforward bids. However, the Non-Delivery Disincentives time penalty is not sufficient to discourage strategic bidding. Most importantly, under the available framework DECC lack the ability to assess anti-gaming[87], and therefore there is a risk of perpetuating anti-competitive practices, or leading to uninformed and potentially detrimental changes in rules. **With respect to the contractual phase, the principle of having commitment at certain milestones is valid, however, the advantages of a profiled trajectory, such as staggered milestones and/or time-related financial penalties, were probably underestimated** in the design process as no incentives to free up 'contracted budget' to favour fast recycling of capital into future rounds exist.

6.21 It would appear that **in general roles and responsibilities of the EMR, including the CfD regime, have been well assigned**. This is supported by the vast majority of stakeholders perceiving that roles and responsibilities were generally appropriately assigned.

6.22 **Both National Grid and the Low Carbon Contract Company (LCCC) in their role of delivery bodies were widely commended in their essential role in disseminating knowledge and supporting participants. National Grid also performed well** in running the process to required quality standards and their contribution in terms of expertise in the design process and in the definition of the regime parameters was widely appreciated.

6.23 **DECC's response to the deterioration of the PPA market was justified by the evidence available at the time.** However, the timing of reaction of the Offtaker of Last Resort was too slow to be useful to address the deterioration of the PPA market at the time. **Going forward, its usefulness in tackling route-to-market issues may be relatively limited, as conditions have considerably improved.** Overall, we believe that **this mechanism may support the consolidation of positive trends, such as increased liquidity, newer structures and PPA providers, and may offer benefits to the financing process of future CfD projects**. Industry shares the opinion that the Backstop PPA is in principle a valuable instrument, although it agrees it is too early to draw any conclusion on its effectiveness.

6.24 Ultimately, a **pure 'CfD' market is yet to emerge, so it is too early to unravel temporary effects from long-term implications.** It will take a number of allocation rounds before a 'pure' CfD-driven market can emerge. The transition from the Renewables Obligation to the CfD regime will materialise in the temporary option for existing project to choose between the RO and CfD; and the temporary competition between RO-led and new CfD-led pipeline projects.

Development process

6.25 This section examines how the CfD scheme was brought forward by DECC. It reviews the development processes undertaken by DECC from scheme conception to implementation and how this could be improved. This section covers the CfD consultation process, the dissemination of information to stakeholders, stakeholder reaction and the level of transparency across the different development work streams.

[87] Ofgem and the Competition Market Authority (CMA) have concurrent powers with respect to collusive behaviours during both the CM and CfD auctions, therefore can access bid data.

Given the complexity of the design process, having achieved the first CfD auction in 2015 was a major accomplishment

6.26 **It is our opinion that the development of CfDs from initial policy objectives in 2010 to the agreement of CfD contracts in 2015 is a significant achievement.** It was a complex process and involved many different aspects from commercial to legal expertise. The culmination of this complex development process was the successful competitive allocation of the first CfD contracts in 2015 – a major accomplishment. The scale of this achievement should not be overlooked when considering the scheme's different development areas.

6.27 Stakeholders we spoke to acknowledged the scale of the programme to introduce CfDs and the impressive way in which it was delivered by DECC and its delivery partners. In particular noting the short amount of time in which the scheme was delivered and how DECC attained industry engagement in the development process to support the implementation. However, there was some slippage in the implementation timescales, which reduced the overlap between the existing Renewables Obligation (RO) and commencement of CfDs than originally intended, by around a year. Nonetheless, the first allocation round was completed within the notified timescales.

Level of DECC consultation was incredibly intense, but appreciated

6.28 DECC conducted an extensive consultation and engagement campaign with stakeholders during the development of the CfD regime both in terms of scope and breadth of participation. There were abundant opportunities for stakeholders (industry and finance) to participate in the process through formal consultations, specific working groups, expert groups and information sessions.

6.29 This was widely praised despite participants noting that engaging with so many consultations and policy developments was time intensive, particularly during the final phases of the design process. The level of engagement required limited some stakeholders' ability to actively contribute, for smaller parties in particular. In some cases, very limited time was offered to interested parties to submit their responses, but we acknowledge that this was dictated by the tight timescales and the steps of the legislative process. A similar experience was noted in the development of the Capacity Market programme.

6.30 **Much progress has been made. As discussed in our report, however, DECC may need to refine some of the details before future CfD rounds. To this purpose, we recommend to continue engaging proactively with industry and financial investors.**

DECC was generally approachable, but lack of corporate memory did not facilitate dialogue with industry

6.31 Industry experience of engagement with DECC, during the CfD development process, was mixed. **Numerous respondents to our research acknowledged the engagement effort made by DECC** and felt there had been a good dialogue between industry and DECC both in bilateral meetings and public consultations.

6.32 However, **a number of stakeholders raised occurrences where the quality of DECC responsiveness in the development process could have been improved.** In particular, stakeholders had a mixed experience with public consultations where their questions could not be answered by DECC, or in other instances answers were unhelpful. Other issues raised included meetings which stakeholders felt were not attended by the relevant Government's representatives and that attendees had not been properly briefed on the topic.

6.33 Another particular concern commonly raised by stakeholders was the turnover of DECC staff working on EMR during the development process. They noted that the frequent changeover of staff at DECC regularly caused problems of consistency and made it difficult to find the correct person. Several commented on value of those responsible for a specific policy area having sufficient historical background, and the problems this caused if this wasn't available

6.34 We acknowledge that the EMR team was under a great deal of pressure to deliver the various elements of the CfD programme and did not always have the opportunity to respond appropriately or account for all the key messages from industry. As not all of the stakeholders' proposals are compatible with policy objectives, it is also possible that DECC deliberately decided not to take forward certain proposals leading to individual stakeholders feeling unheard by the Government.

6.35 While the lack of staff continuity does not necessarily lead to sub-optimal policy outcomes per se, it did introduce an element of inefficiency which may hinder development of the process and ability to retain lessons learnt. It also probably did undermine the credibility of DECC officials in their dialogue with stakeholders. **Nevertheless, there is no direct evidence that the issue of staff continuity fundamentally impaired the quality of the regime. We would recommend DECC consider these implications going forward**.

Multiple points of information confused stakeholders

6.36 Stakeholders suggested that DECC did not provide for a consolidated source of information during the CfD development process. The constantly changing CfD policy developments were difficult for potential CfD participants to identify.

6.37 As examples of this lack of clarity and consistency, stakeholders noted that some policy documents covered the whole area, whereas successive versions covered only a number of sub-topics with residual topics addressed in a separate document. Additionally, there was no single list of documentation that was comprehensive. Relevant documents were spread over a number of different web pages on websites from multiple parties: DECC, National Grid, Ofgem and the Low Carbon Contracts Company (LCCC). Version control and accurate labelling of documents at times was also lacking precision and consistency.

6.38 Overall, following policy evolution was difficult; in particular for those who were not able to actively engage due to lack of resources, or for those that did not engage in the process from the outset.

6.39 We acknowledge that the various elements of the regime progressed at different rates and were promoted by the various EMR bodies. This aspect, in addition to the tight deadlines, may have led DECC to prioritise the quality of policy over the clarity of communication. Nevertheless, **we recommend that going forward DECC clarify the narrative of the policy decisions and provide a consolidated source of all the important information for CfD participants to access.** We understand that the delivery partners in collaboration with DECC have already started this process.

National Grid and LCCC should be commended for their essential role in disseminating knowledge and supporting participants

6.40 The feedback gathered through our stakeholder research provided a general view that National Grid and LCCC delivered fair and helpful support to participants, in particular SMEs. Ahead of the first allocation round, National Grid and LCCC provided training sessions and supporting material to participants to allow effective participation. Respondents noted that the workshops arranged by National Grid and LCCC were extremely useful to develop an understanding of the detailed mechanics of the bid submission process, the auction algorithm and the contract management for all types of participants. Support offered on a bilateral basis was also appreciated when organisations were reaching out for further clarifications. Both National Grid and LCCC were considered to be very cooperative and participants commended them for their efforts.

6.41 **Our recommendation is for National Grid and LCCC in collaboration with DECC to maintain the same level of knowledge dissemination and engagement with potential participants for future rounds.** This applies specifically to the next couple of rounds, as the learning curve will remain particularly steep. There are a number of players that did not participate in the first allocation round that will be progressively channelling their efforts towards the CfD programme due to the closure of the RO. Additionally, new organisations, including those from overseas, could enter the renewables market and be unfamiliar with the CfD arrangements.

Move to constrained allocation for all technologies in the first round was largely unexpected and implemented at short notice before the beginning of the round

6.42 **Since early CfD policy documents, the introduction of competition in the allocation process was always presented as a medium to long-term natural development of the new regime.** The move to competition was intentionally structured over a sequence of phases, starting from a First-Come-First-Served stage, then an unconstrained allocation, and finally a constrained allocation with the objective of smoothing the transition. More mature technologies would potentially progress through the three phases faster than the less established ones.

6.43 Until January 2014[88], there was no indication that DECC was even considering accelerating the move to competition. The consultation indicated the Government intended to introduce allocation rounds for mature technologies in the first round (October 2014), but not necessarily that the allocation was ‘constrained’. No mention was made about the same development for less mature technologies. From stakeholders, we also understand, that even in the various information dissemination sessions or other informal discussions, DECC gave no indication of such imminent change.

6.44 It was only with the publication of the Draft Allocation Framework in April 2014 and subsequently the Draft Budget Notice in July 2014 that it became clear the allocation rounds were constrained for both pots: more and less established technologies. **Industry had to adjust to the new process at very short notice and with very limited visibility on some of the details of the regime. Given the major shift in mentality required from industry, DECC might have taken a considerable risk in accelerating the process. However, with the benefit of hindsight, it proved to be advantageous for consumers and achievable by developers.**

Different degrees of transparency across work streams

Transparency is good practice in policy making[89]. As we already discussed in section starting with paragraph 6.28, overall stakeholders had abundant opportunities for participation in the design process of the CfD regime. However, the intensity of consultations did not automatically translate into a consistent level of transparency of DECC’s decision process across all key work streams.

6.45 Table 7 below summarises how each of these key work streams scored while following sections expand our analysis.

88 ‘EMR: Allocation of Contract for Difference, Consultation on competitive allocation”, 16 January 2014, DECC. Government response was published in 13 May 2014.

89 It is one of the five principles of better regulation devised by the Better Regulation Taskforce in 1997 and included in the Better Regulation Framework Manual, BIS, March 2015.

Table 7 – Summary of our assessment of transparency by key work stream

Work stream	Our comment
Administrative strike price (ASP) setting	Generally open, but some confusion over assumptions used
Budget setting	Relatively opaque
Auction design	Rushed and most design detail was done behind closed doors
Measures against speculative projects and disruptive behaviours	Generally rushed and very late into the design, disjointed approach
Drafting of CfD Contract	Initially not consultative, in the end much more collaborative

ASP setting process was transparent

6.46 Stakeholders had a mixed opinion on the transparency of the administrative strike price (ASP) setting process. A number of stakeholders were comfortable with the transparency of the process, understood the approach and were comfortable with the outcome, whereas others were not fully satisfied. The main area of concern among those more critical of the process appeared to be disagreement and/or confusion over the assumptions used.

6.47 The Draft Delivery Plan and Delivery Plan included annexes on the methodology used, the Panel of Technical Experts assessment on the methodologies and analytical techniques used, National Grid's report on the analysis it undertook including modelling outputs and NERA's report on hurdles rates (a key assumption). The final Delivery Plan also included annexes on changes to the modelling assumptions and the Quality Assurance process. Therefore, **our conclusion is that overall the ASP setting process was transparent**.

Process for setting budgets was relatively opaque

6.48 Under competitive allocation budgets are a key operational element of the CfD as they directly impact on the amount of capacity that can be successful in an auction. They become similar in importance to the role strike prices played where support was awarded on an administrative basis. Yet, we believe that the level of transparency in the setting of these two parameters was very different.

6.49 **Information published in relation to the budget setting process was limited.** Budget Notices were published in July 2014 (indicative), October 2014 (final) and January 2015 (further revision) each with a short explanatory note to explain what the figures entail and some intentions for a future allocation round. There was no consultation or other supporting documentation published explaining the levels of the budget set[90].

6.50 We understand DECC held informal industry discussions and consultations with various other Government departments that have an interest in the CfD budgets, in particular:

- Treasury – due to the link to the Levy Control Framework;

90 There were consultations relating to the allocation of technologies to budget pots, see paragraph beginning 6.104.

- Department for Business Innovation and Skills – have an interest in the development of the offshore wind supply chain;
- Department for Environment, Food and Rural Affairs – have an interest in energy from waste technologies and large scale solar (due to the environmental impact); and
- The Devolved Administrations for Northern Ireland, Scotland and Wales.

6.51 The absence of documentation was reflected in stakeholders understanding of the budget setting process. When asked, stakeholders had little understanding of how the budget setting process worked or the assumptions used. This can lead to confusion and misinformation on why budgets were set at a particular level, or subsequently changed (see paragraphs 6.52 and 6.53). This in turn increases perceived risk of future budgets, which can impact on the future investment decisions as discussed in section starting paragraph 6.347).

6.52 The change in budget between the Indicative Budget Notice (July 2014) and Final Budget Notice (October 2014) immediately before the first allocation round[91] demonstrates this issue. The budget for the first allocation round was increased for most years in both pots between the Indicative and Final Budget Notice. The associated press release stated that DECC was providing the industry with additional funding. However, there was confusion among stakeholders over the extent to which more projects would actually be able to receive more funding and how much of the additional budget would simply compensate for lower assumed reference prices.

6.53 More transparency over the reference prices used, would have avoided this confusion. It was not clear in the Budget Notices which reference prices were being used to set the budget. Updated DECC wholesale electricity prices projections were included in DECC's updated Allocation Framework, which was published alongside the Final Budget Notice. These were significantly lower than DECC's previously published wholesale electricity price projections. Lower wholesale electricity prices mean the same budget level cannot support as much capacity, hence stakeholders confusion. In fact, DECC had modelled the previous budget on lower wholesale electricity prices that had not yet been published, and so the increase capacity able to gain support was in line with the increase in budget. This would have been clear if reference prices on which budgets were set at each stage had been published or at least further information provided[92].

6.54 We recognise there can be some sensitivity around the budget setting process where Government is looking to secure a minimum level of capacity or certain degree of competitive tension. Similarly there may be some sensitive assumptions used eg project specific load factors or intelligence on the RO and ssFiT[93] pipeline. Even so, it should still be possible to provide transparency over:

- objectives for setting budgets[94];
- the timeline for setting future budgets;
- the methodology used to set the budget;
- non-sensitive assumptions [95] eg wholesale electricity prices assumptions, technology generic load factors;

91 Had there been no appeals.
92 We acknowledge there may be times when internal projections are not yet finalised and so may not be ready to be published, but still used for internal analysis.
93 Small Scale Feed-In Tariff scheme.
94 To avoid the potential for this having an impact on market participant behaviour these objectives could be given in a general sense eg having an objective to ensure competitive tension, rather than the specifying what range of budget or capacity might achieve this.
95 Provided the assumptions are finalised eg preliminary updated wholesale electricity price projections. In this instance it would still be possible to say that non-published wholesale electricity prices were used.

- deployment ambitions in line with longer term goals; and
- an overview of the modelling outcomes where non-sensitive.

6.55 In paragraph beginning 6.384 we recommend that budgets are set further in advance of allocation rounds and in line with Government ambitions for the future energy mix. With the circumstances under which budgets can be changed set out, similarly to the approach taken for the emergency review of RO bands. This is consistent with a more transparent and consistent approach.

6.56 To avoid misinformation and give stakeholders the opportunity to challenge the process **we recommend that the budget setting process is made more transparent where information is not commercially sensitive or compromises the functioning of the auction process.**

6.57 The transparency over the timing and release of notices is also discussed further in section starting with paragraph 6.145.

The auction design process was rushed and non-consultative

6.58 The details of the auction design were first discussed in the October 2013 consultation on EMR implementation[96], but always in the context of a progressive transition to competition[97], thus with a lesser level of urgency. Decision on the sealed-bid format was then announced in a policy letter dated 12 February 2014 and progressively implemented in the following months through various iterations of the Allocation Framework, discussions with the CfD Expert Group and a number of informative workshops.

6.59 In reviewing the process, we found that **the faster than expected move to competition** – as discussed in paragraph starting with 6.42 above **– reduced the time available for wider discussion with stakeholders and so limited the extent to which consultation was possible**. M**ost of DECC's decisions were made 'behind closed doors', as often commented by stakeholders, and overall, there was little chance to influence the process.**

6.60 The use of the CfD Expert Group was beneficial, but some of the respondents felt that the selection of members was not representative of the wider industry despite the nominees having been put forward via trade associations. When challenged, respondents acknowledged the technical nature of the sessions, which in our view justified the limited the number of organisations invited. We also believe that the degree of frustration amongst those that were not involved were most likely caused by the delay in publishing the content and notes from the session, more than the scope of the group itself.

6.61 Feedback gathered on the Capacity Market process led us to conclude that this was perceived much more open and consultative than that for the CfD auction. Stakeholders felt that the various workshops were merely for disseminating information and defending crystallised positions. DECC was much more engaged with industry in defining the rules of the Capacity Market auction, while DECC was poorly receptive to feedback on the CfD side. If this was a precaution taken by DECC, which feared interference of industry at the expense of a format robust against gaming, we tend to agree with stakeholders that this was probably excessive and counterproductive. Among stakeholders, there is a general lack of understanding as to why DECC have taken different approaches with the two designs. Further discussion on auction rationale is included in section starting with paragraph 6.179.

[96] 'EMR consultation on Proposals for Implementation', October 2013, DECC. Government response was published in June 2014.

[97] 'EMR: CfD – Allocation Methodology for Renewable Generation', 5 August 2013, DECC https://www.gov.uk/government/uploads/system/uploads/attachment_data/file/226976/Allocation_Methodology_-_MASTER_-_6_Aug_v_FINAL.pdf

6.62 In defining the fine print of the auction mechanism, expedience of the process seems to have taken precedence over a more thought through process. Some of the stakeholders are of the opinion that some aspects of design were overlooked to some extent in order to meet the timetable, such as the design of the non-delivery disincentives, or the constraints on flexible bidding.

The process of designing the current measures against speculative projects and behaviours was rushed

6.63 In our dialogue with stakeholders, the key feedback is that measures against speculative projects and behaviours were designed in a relatively rushed manner[98] and as they stand do not provide sufficient comfort to legitimate projects. Stakeholders are concerned that speculative behaviours adopted by some developers could prejudice other participants who may otherwise have made successful applications for viable projects.

6.64 In evaluating the process that led to the current measures, **we found that the approach adopted by DECC was primarily dictated by the necessity of driving single work streams of the CfD design forward** (eg allocation rules, auction design, CfD Contract terms, Non-Delivery Disincentive, etc.). We acknowledge that there are numerous moving parts in the scheme and that expediency in the design process may have prevailed over a final assessment for overall robustness. As further discussion in section starting with paragraph 6.391, **the Government should now take the opportunity to engage with the industry and address some of the weaknesses identified.**

DECC underestimated the complexity of the CfD Contract drafting process and initially adopted a non-collaborative approach

6.65 The process of transferring policy intent into a private law document is extremely complex and requires a cumbersome iterative editing process. **Our view is that DECC had initially underestimated the time and efforts required to develop a robust and consensual set of terms for the CfD Contract**[99].

6.66 Stakeholders felt that at the beginning of the drafting process, DECC did not show a strong desire to engage with developers and adopted a relatively rigid approach. It was only after engaging with the financial community that DECC realised how important it was to collaborate in designing contract terms, to ensure the CfDs could deliver the financing benefits they were intended to offer. **In the end, the process became much more consultative**.

[98] For instance, the non-delivery disincentives were only finalised after the October 2014 round had started.

[99] Contract refers to both the CfD Agreement and the CfD General Terms & Conditions.

Design details

6.67 This section reviews the structural aspects of the CfD scheme chosen by DECC and the scheme's overall parameters. It covers the CfD: contract terms, eligibility criteria, allocation process and round frequency, along with the setting of the administrative strike prices and budget. This section also includes an appraisal of the Offtaker of Last Resort mechanism.

Eligible technologies are consistent with DECCs objectives

6.68 Under the CfD Operational Framework published in November 2012, the approach to CfD technology eligibility was described as:

- The starting point is those technologies listed in Article 2(a) of the Renewables Directive (2009/28/EC);
- It will broadly reflect current practice under the RO; and.
- Other technologies will be added that are expected to have the potential to 'make a significant, desired contribution to decarbonisation and the general mix if offered support'.

6.69 Although not explicit another objective appears to have been to support technologies consistent with other Government policy eg the subsequent bioenergy strategy, see paragraph 6.70.

6.70 The Contracts for Difference (Definition of Eligible Generator) Regulations 2014 define the eligible technologies for a CfD. These reflect the RO eligible technologies with the following exceptions and reasons given in the Final Delivery Plan[100]:

- New dedicated biomass – in line with bioenergy strategy (as more expensive on a £/tonne carbon than offshore wind)
- Standard bioliquids – in line with bioenergy strategy (a preference for sustainable bioliquids to go into transport)
- Geopressure – at an early developmental stage and it's not clear what the costs would be to set a strike price
- Biomass co-firing – a preference for biomass to go into full unit conversions
- Projects below 5MW are not eligible if the technology is eligible for the small-scale FiT
- Overseas projects may be eligible in future but are not currently eligible

6.71 These technologies appear consistent with RO eligibility alongside the bioenergy strategy. In terms of the other exceptions, in practice there are no geopressure projects receiving support under the RO. A view was expressed that projects below 5MW should be eligible for the CfD, particularly if they are an extension to an existing project.

6.72 We note biomass developers generally thought that dedicated biomass should be eligible for CfDs as they offer baseload generation and a different approach is taken with other thermal technologies that do not require CHP eg biomass conversion. The decision to exclude dedicated biomass is consistent with DECC's bioenergy strategy[101] and so is a matter for wider Government policy rather than the operation of the CfD.

100 Electricity Market Reform Delivery Plan, DECC, December 2013.
101 UK Bioenergy Strategy, DfT/DECC/Defra, April 2012.

Qualification requirements are generally workable, but the grid connection and supply chain requirements should be reviewed

6.73 The Contracts for Difference (Allocation) Regulations 2014 define the stage a project has to reach before it can bid for a CfD. The Final Allocation Framework[102] explains the checks to be carried out by National Grid to ensure compliance with the CfD Regulations and supplementary information.

6.74 In summary the qualification requirements are:

- Applicable planning consents;
- A grid connection agreement;
- Not in receipt of support from RO, ssFiT or Capacity Market;
- Incorporation details; and
- An approved supply chain plan if 300MW or more.

The objective of the qualification requirements at the time they were confirmed was to:[103]

"Prevent highly speculative projects but not [be] so onerous investors are deterred from entering the market"

6.75 The use of the term 'highly speculative' gives the impression that DECC is only looking to exclude projects that have very little chance of ever coming to fruition. However, given the qualification requirements, particularly in the case of new projects, DECC's ambitions seem to be closer to excluding speculative projects as well. In the section beginning paragraph 6.391, we explain that we consider speculative behaviour to be driven by the underlying incentives which could reduce the efficiency of the scheme and/or produce consequences inconsistent with the policy intent. In our view excluding speculative projects is a more appropriate aim to maintain credibility and certainty in the scheme.

6.76 We consider the qualification criteria are achievable, as projects were able to qualify for the first qualification round. They also do require some costs[104] and so will provide some barrier to speculative projects. However, **it will not be possible to really judge whether the balance between preventing speculative projects and unnecessarily onerous requirements is appropriate until there is evidence of a pipeline of projects built up after the introduction of competitive allocation.**

6.77 Stakeholder feedback can provide an early indication of whether the balance is appropriate. In general, stakeholders were relatively comfortable that the requirements provide this balance. Grid connection and planning consent were considered sufficient barriers to deter speculative bids. However, qualification requirements are only part of the policy for deterring speculative bids and stakeholders did feel there was scope to strengthen the anti-speculative measures overall, please see section starting with paragraph 6.390.

Stakeholders raised the following concerns on the potential barriers to development:

- Various issues were raised in relation to the grid connection offer requirement (see section starting with paragraphs 6.78).
- The role and assessment of the supply chain needs clarifying (see paragraph 6.79)

102 Contract for Difference: Final Allocation Framework for the October 2014 Allocation Round, 2 October 2014

103 EMR Policy Overview: Annex A Operational Framework, DECC, November 2012.

104 See Electricity Generation Costs, DECC, December 2013.

Elements of the grid connection requirement should be reviewed in light of potential problems raised

6.78 Stakeholders raised the following grid connections related issues that are consistent with our understanding of the operation of grid connection offers:

- **Confusion over what the grid offer requirement entails** – a number of stakeholders across technologies said that they thought the requirements on acceptance of a grid connection offer needed to be clearer eg that the letter needs to be signed. This is backed up by the Tier 2 appeals, two of which experienced confusion over the grid offer requirements.
- **A difference in the approach to deposits to confirm a grid connection offer between Distribution Network Operators (DNOs)** – until recently confirmation of a grid offer required committing to the full cost of connecting. We understand that some DNO's have recently transitioned to a 'fair and reasonable deposit' system to avoid developers having to commit to substantial payment whilst risks of obtaining a CfD remain. This allows a smaller deposit to be made in combination with a timetable of milestones to commissioning. At the time of writing not all DNOs had adopted this methodology. This means projects in different regions could face different upfront cost commitments that do not reflect project or connection costs.
- **The potential for unsuccessful projects to block distribution network capacity** – we understand there is currently no clear mechanism to ensure projects unable to secure a CfD contract return capacity. There is concern among some stakeholders this could lead to new projects in some regions struggling to gain a connection. Based on our understanding of the process for connecting to the distribution network we consider this could be a genuine problem.
- The costs of gaining a grid connection agreement could discourage the development of smaller projects and innovative technologies – smaller project developers raised concerns that upfront grid connection costs (planning permission was also raised to a lesser extent) formed a larger proportion of project costs. This coupled with a lower ability to deal with allocation risk than larger developers could act as a barrier to the development of smaller projects. Whilst this is the response that might be expected from smaller developers, we consider it is worth investigating as the CfD generally appears to favour larger projects see paragraph beginning 6.303 and 6.462 and so more flexibility could help smaller projects compete and the consequence of a small project breaking its CfD contract is also not as great as the consequence of a large project breaking its contract. Less budget was allocated to that project that could otherwise have gone to other projects.

We recommend DECC review the grid connection offer requirement to assess the impact of distortions in the way different projects are treated due to location or size, and then to adjust the policy where appropriate. This includes consideration of whether providing greater flexibility to smaller projects would be appropriate.

Further guidance on the confirmation of grid offer would help to reduce confusion among applicants.

The role and assessment of supply chain plans needs clarifying to ensure it is effective

6.79 The qualification requirements include submission of a supply chain plan certificate. DECC's Supply Chain Guidance[105] explains what is required to obtain a certificate including the assessment methodology considering contributions towards competition, innovation and skills. There is also a requirement for a post build report including reasons

105 Supply Chain Plan Final Guidance. DECC, August 2014.

for deviation from the plan. Where supply chain plans have not been implemented, this will be taken into account in future supply chain submissions involving those organisations. Supply chain plans for projects signing a CfD contract are published.

6.80 There was some confusion among offshore wind stakeholders about how scores for the supply chain plan were arrived at and how the sanction would work in practice. This is partly due to the qualitative nature of the assessment and because this is a relatively new policy. Over time experience of decisions made should provide more clarity on how supply chain plans are judged. Where possible, transparency on these decisions will help. As such **we recommend that scores awarded and associated reasons for successful supply chain plans are also published.**

6.81 Further guidance on how sanctions will be applied may also help as it is not clear the extent to which diversion from the supply chain plan will impact on DECC's future decisions, and if a company plans to exit the market what incentives there will be for it to follow its supply chain plan.

ASP process was generally appropriate

6.82 The ASP setting process is described in the following Annexes to the EMR Delivery Plan:

- Annex B – Strike Price methodology
- Annex D – National Grid modelling
- Annex E – Report from the technical experts
- Annex G – modelling quality assurance
- Annex H – changes to modelling assumptions

6.83 As part of the CfD policy design, ASP play a multi-faceted role:

- they set the strike prices for successful FID Enabling for Renewables projects;
- they establish a price cap of payable subsidies by technology under the CfD allocation process;
- they inform the process of setting the available budgets;
- they are used in the valuation formula to determine if an auction is to be held; and
- they send a message to the market about the Government's aspirations on supply chain cost reduction and provide a transparent measure for project competitiveness.

6.84 At the time ASPs were set it was expected that CfDs would initially be allocated on a first come first served (FCFS) basis, rather than competitive allocation. Under both FCFS and competitive allocation, where ASPs are set too low they can deter project development. Under FCFS if ASPs are set too high they provide poor value for money to consumers. The detailed modelling of deployment and cost outcomes under different scenarios, as National Grid undertook for DECC, was therefore required to understand the trade-offs in ASP decisions[106].

In practice, FID Enabling for Renewables effectively became the first CfD allocation round and administratively-set strike prices set the support level for Investment Contracts awarded under the process. For the October 2014 and future allocation rounds, ASPs still set strike prices for technologies where the pot clearing price is higher than the technology specific ASP.

6.85 **Overall we concluded:**

- RO-X followed by reducing strike prices with expected falls in technology costs was an appropriate methodology to setting strike prices as offering more than the RO would

[106] This still does not resolve the issue of understanding the true costs of new projects and so where possible competitive allocation is preferable to enable this.

counteract the benefit of reduced cost of capital and offering less would incentivise projects into the RO, see paragraph beginning 6.86;
- The technology modelling contained the necessary outputs to test the scenarios against Government objectives, see paragraph beginning 6.101.
- The modelling tools including an electricity market model were appropriate, given the importance and complexity of the task undertaken, see paragraph beginning 6.102;
- The scenarios and sensitivities were reviewed by and discussed with the Panel of Technical Experts (PTE), which helped the robustness of the process, see paragraph beginning C.14; and
- The internal quality assurance process required a senior level of sign off[107], see Annex G of the EMR Delivery Plan.

RO-X followed by reducing strike prices with expected falls in technology costs was an appropriate methodology to use in setting strike prices

6.86 DECC's aim when setting strike prices was stated in Annex B of its 'EMR Delivery Plan' to:

6.87 'Ensure a smooth transition for investors from the RO to the CfD, and to minimise hiatus in investment'

6.88 To achieve this aim DECC set out the following high-level approach in Annex B of its 'EMR Delivery Plan' :

- During the RO/CfD transition period (2014/15 – 2016/17) – ASPs would be set based on "RO minus X" (or RO-X) , where X is the expected difference in hurdle rate required by the CfD and RO; and
- From 2017/18 onwards – ASPs would be set based on the expectation of declining costs due to learning through deployment, and the requirements that deployment remains within the LCF affordability constraint, while providing a level of renewable generation consistent with meeting the 2020 renewable energy target.

6.89 The objective of the technology modelling was to test the strike prices against Government's overarching objectives for the future shape of the electricity market. These are discussed in section starting with paragraph 6.101.

6.90 **The RO-X approach for the RO transition period (to March 2017) appears to be generally consistent with DECC's objectives at the time of setting the administrative strike prices** (when allocation was assumed to be on a first come first served basis). The intention is that the CfD will provide better value for money and so it is assumed there is a preference on the part of the Government for generators to be subsidised under this scheme as opposed to the RO. Any lower strike price than the equivalent benefit (eg assumed lower cost of capital) under the RO would discourage generators from taking part in the CfD, and so would not be consistent with this preference. Equally, any higher strike price than the equivalent subsidy under the RO would diminish the benefit and would send the wrong signal to the market about the long term aim of reducing subsidies over time.

6.91 Whilst in general RO-X appears consistent with Governments objectives. It has the following minor drawbacks:

- it is reliant on the assumption that the RO bands themselves are set at the right level to achieve the Governments desired technology mix; and

107 An audit of whether processes were signed off was outside the scope of this

- generators may prefer to stick with the scheme they know and so the value for money benefits of the CfD regime may not be realised.

6.92 Alternative methodologies such as RO, 'RO minus Y' (where Y is < X) or re-evaluating technology costs also have drawbacks, so it is not clear that any other options provided a better methodology.

6.93 It is important to note that the value for money benefits of the CfD over the RO are contingent on the following two assumptions:

- hurdles rates under the CfD regime are lower than under the RO; and
- Governments projections of wholesale electricity prices at the time of setting ASPs are the same value or lower than outturn wholesale electricity prices.

6.94 **For the enduring regime, reducing ASPs in line with expectations of falling costs appear to fit Government objectives reasonably well.** It appears consistent with the general intention that subsidies for renewables are temporary whilst they establish themselves sufficiently to compete with conventional technologies.

6.95 Stakeholders interviewed across the technologies were generally comfortable with the RO-X and learning rate approach taken to strike prices.

6.96 The role of ASPs in the future and what that means for future ASPs is explored further in section starting with paragraph 6.434.

The strike prices set are consistent with the RO-X and falling costs approach

6.97 DECC's approach to RO minus X (or RO-X) is set out in Paragraphs 9 and 10 of Annex B to the EMR delivery plan. We agree that following this methodology should result in strike prices broadly equivalent to RO-X. We have performed the calculation ourselves[108] with the DECC assumptions[109] and the ASPs set are in the range we would expect.

6.98 For most technologies, strike prices appear to fall broadly in line with learning rates, or offshore wind strike prices, whichever are lower. The ACT and AD technology strike prices appear to be capped by the learning rate of offshore wind, rather than their technology learning rate. Whilst three ACT projects were successful in the first allocation round, if these cost projections are correct, slower cost reductions could cause ACT and AD projects to struggle to be cost effective in future competitive allocation rounds.

6.99 There was no shift in the wholesale electricity market we believe to be significant enough to divert from RO-X at the time that ASPs were set. Since then there has been a significant fall in wholesale electricity prices (£5.8/MWh from 2013 to 2014 in real 2012 money[110]), that make ASPs look relatively attractive.

6.100 The majority of wave and tidal stream developers we spoke to thought that the wave and tidal stream ASP did not reflect the RO-X calculation. Our calculations are consistent with the strike prices set by DECC and so do not support this assertion. This confusion may be due to a difference in circumstances at the point RO-X was calculated and when the wave and tidal stream industry argued for 5ROCs/MWh in 2012. We discuss the potential barriers to the development of wave and tidal stream further in paragraph beginning 6.458.

108 The exception to this is biomass conversion where a different approach was taken.
109 Taken from Annex B of the EMR Delivery Plan and reference prices provided by DECC.
110 Calculated from Reuters day ahead APX wholesale electricity prices.

Technology modelling contained all the necessary high level elements to test Government objectives

6.101 The technology modelling process commissioned used different ASP scenarios to test the following outputs:

- projections of future capacity by technology – testing against the security of supply through technology diversity objective;
- progress towards 2020 targets – testing against the renewables and decarbonisation objective; and
- the cost of support – testing against the value for money for consumers objective[111].

6.102 **We consider that the technology modelling of ASPs contained the necessary high level elements to test Government objectives.** However, given the move to competitive allocation, budget modelling will become the more significant modelling exercise in future. Budget modelling is discussed in the section starting with paragraph 6.145.

We have not conducted a full review of the input assumptions used for setting ASPs as this was the role of the PTE. However, load factors for intermittent technologies, based on a more region and project specific factors are not discussed in the PTE report, but as a key assumption, we consider these worth raising as a potential improvement to the technology modelling. These are discussed in paragraph beginning 6.103.

Use of future project characteristics and wind speed data may help improve load factors assumptions for new projects

6.103 We understand the load factors assumed were based on historic data and technical potential in the case of offshore wind. Given that load factors, particularly for offshore wind are expected to be different for new projects, we have conducted some preliminary analysis of how load factors may change according to new turbine characteristics and project locations[112] as a cross reference against DECC assumptions. A summary of the results of analysis are provided in Table 8. The results for onshore wind are similar to DECC assumptions. For offshore wind, it is possible the load factor for future projects could be notably higher than that assumed. The approach taken in our analysis is discussed further in Annex E.

Table 8 – a comparison of DECC assumed load factors against indicative average load factors based on geographical and turbine characteristics

	Load factors assumed in the October 2014 allocation framework[113]	Indicative average load factors based on project specific characteristics[114]
Offshore wind	38%	41%
Onshore wind	28%	29%

[111] Technology diversity will also help this objective by providing future options for decarbonisation that may become cheaper than alternatives.

[112] Anemos hourly wind speed data were used at 20km grid points at hub height. Wind speed data was converted to wind generation based on wind capacity locations and appropriate aggregated power curves. Turbine capacity, Hub height and rotor diameters used were as published by 4C Offshore.

[113] Annex D to the EMR Final Delivery Plan National Grid EMR analytical report, National Grid, December 2013.

[114] Pöyry calculations using the methodology described in Annex E.

The breadth of low carbon technologies provides a challenge to designing an efficient allocation mechanism

6.104 If all technologies had the same characteristics, economic theory suggests that the most cost-effective way to allocate limited budgets among competing projects, would be to have a single auction encompassing all technologies, with the lowest-cost technologies most likely to succeed. Separating between technologies could therefore lead to economic inefficiencies, as it is not possible for policy makers to perfectly allocate resources eg budget in the case of the CfD between technologies.

6.105 An overview of low-carbon technology characteristics is given in Annex F. Given the range of characteristics across electricity generation technologies, ensuring that all the differences between technologies are accounted for in delivering an optimum future technology mix is complex. We have identified four areas that could cause economic inefficiencies through technology-neutral auctions under the CfD, which we later use to evaluate the allocation of technologies to budget pots and use of maxima and minima (see section starting with paragraph 6.124):

- **Fundamental differences in technology costs –** where the supply curve is shallow, infra-marginal rents will be limited. However, if the supply curve is steep there is potential for high infra-marginal rents. This can be the case in a mixed-technology auction where technologies have fundamentally different costs[115] eg the current typical levelised costs of landfill gas and offshore wind.
- **Differences in typical project characteristics** – technologies differ structurally in various ways such as typical project size, development time and company sponsorship; for example an offshore wind project is typically 100s of MW's, sponsored by a utility, AD plants are typically less than 10MW and sponsored by a small independent developer. These structural distinctions could make it more difficult to for a technology(ies) to compete with another technology(ies) on a level playing field. If larger and smaller projects compete in the same pot, then this could cause potential issues for both larger and smaller projects: for example, the amount of budget available for smaller projects is dependent on the bids of one or two larger projects, or smaller projects could use up just enough budget to prevent a larger project from being successful. This type of uncertainty over the outcome could lead to an increase in perceived allocation risk, potentially disincentivising the development of new projects or continuing solely with existing projects leading to an overall reduction in competition. Allocation risk is discussed in more detail from paragraph beginning 6.347.
- **Under or overvaluing externalities –** where technology characteristics have a value (positive or negative) that would not be valued by private actors in a technology-neutral auction (externality), it could lead to an under or over-allocation of capacity for a particular technology. Positive externalities might include flexibility to generate at times of high electricity demand, potential to develop a British supply chain around a particular industry and providing a waste management solution. Negative externalities might include visual impacts and using biomass from unsustainable sources.
- **Interactions with other markets and policies** – support under the CfD may have implications for other markets or Government policies (or vice vice-versa) where it is necessary to take a co-ordinated approach to ensure that policies are consistent to enable the desired outcome. Examples include ensuring that incentives under the CfD are enabling a smooth transition from the RO to the CfD and the relative attractiveness of tariffs under the small-scale FiT.

115 This will not always be the case, some technologies may have similar costs and some deployment costs are likely to change over time.

6.106 Where technologies differ in any of these four areas, it does not automatically mean they should not compete with one another. There is a balance to be found between these potential barriers to economic efficiency in a technology neutral auction and the inefficiency of separating technologies or groups of technologies. It may not be one single factor that leads to the decision to separate a technology or group of technologies, but a combination of factors. There are also links between the four areas defined; for example, where externalities are valued outside the CfD there may be interactions with other Government policies.

6.107 In the case of externalities and interactions with other markets and policies it may be possible to address these outside of the CfD design, and therefore not require a move away from technology neutral auctions. Such externalities may also be the responsibility of another Government department and not DECC eg waste management policy is Defra's responsibility, and so requires cross-Government co-ordination.

6.108 DECC has put in place the following tools to differentiate between technologies in the allocation of budgets:

- **Budget pots –** groupings of technologies that are intended to compete against each other;
- **Minima –** where the sum of project capacities equal to (or above) the minima will be paid the clearing price for that technology (or the clearing price for that Pot, whichever is higher) or the ASP (if the minima does not exceed the pot/overall budget in any delivery year);
- **Maxima –** only the cumulative capacity of the qualifying applications up to the maximum capacity or budget will be allocated CfD contracts; and
- **Allocation outside the generic auction process–** where a CfD is negotiated directly with DECC for a specific project.

6.109 These tools provide the ability to differentiate between technologies for any of the reasons listed in paragraph 6.152, this could be through segregation of individual technologies or a group of technologies with the same characteristics. Although DECC has agreed with the European Commission, as part of the State Aid approval process, that a minima will not be applied to Pot 1. In addition to this DECC currently caps strike prices at the ASP to limit infra-marginal rents due to fundamental differences in technology costs. Government also already values some externalities outside of the CfD, eg provision of heat through the Renewable Heat Incentive (RHI), a waste management solution through Landfill Tax.

6.110 **The provisions for budget pots, allied to the use of maxima and minima, should give DECC the tools it needs to address cost inefficiencies that could arise under technology neutral auctions due to differences in technology characteristics. The allocation of budget to these pots, ASPs and other Government policy to address externalities outside the CfD will also support this.**

6.111 Support for renewables in the UK currently needs to be approved under the EU State Aid guidelines[116]. DECC was therefore mindful of these guidelines in its initial design of the budget pots, maxima and minima and is likely to consider them in future decision making.

6.112 The State Aid guidelines require a non-discriminatory competitive bidding process from 1 January 2017[117]. There is a presumption that a technology-neutral competitive bidding process is non-discriminatory. The Guidelines also state that a competitive bidding process can be limited to specific technologies, where a process open to all generators

116 Guidelines on State Aid for environmental protection and energy 2014-2020, European Commission, June 2014.

117 Specific exceptions are included such as where strategic or underbidding is expected.

would lead to a suboptimal result, which cannot be addressed in the process design, in particular:

- the longer-term potential of a given new and innovative technology; or
- the need to achieve diversification; or
- network constraints and grid stability; or
- system (integration) costs; or
- the need to avoid distortions on the raw material markets from biomass support.

DECC should set out the rationale for the current pot structure and use of maxima/minima more clearly to ensure consistent decision making

6.113 The total budget available under a CfD allocation round is specified by delivery year and divided into three pots:

- **Pot 1 (established technologies)**: those technologies considered most mature including onshore wind (>5MW), solar PV (>5MW), energy from waste CHP, hydro, landfill gas and sewage gas;
- **Pot 2 (less established technologies)**: technologies considered less mature including offshore wind, tidal stream, wave, anaerobic digestion (>5MW), advanced conversion technologies and dedicated biomass with CHP, geothermal, remote islands onshore wind (for the October 2015 allocation round onwards, subject to State Aid); and
- **Pot 3 (biomass conversion)**: exclusive to biomass conversions.

6.114 In the first allocation round the only minima/maxima set was a 10MW minima for wave and tidal stream. In addition contracts for tidal range, CCS and nuclear are currently negotiated bilaterally.

6.115 The definition of ‘established’ and ‘less established’ technologies were set out in the January 2014 consultation document[118]. Established technologies are considered to have:

- established responsive supply chains;
- already realised the effects of early R&D and learning; and as a result
- they have already secured significant cost reduction.

6.116 The January 2014 consultation states there is still a desire to support less established technologies as they are considered to:

- have the potential to deliver significant low-cost renewable generation in future;
- increase the ability to secure a diverse renewables mix; and
- reduce costs to consumers in the longer term.

6.117 The May 2014 response to the consultation[119] provides a more detailed explanation of the allocation of technologies to Pot 1 and Pot 2 based on technology characteristics. These include current deployment, long term potential, contribution to diversity and benefits to other markets for attributing each technology to the ‘established’ or ‘less established’ pots.

6.118 The rationale for the biomass conversion pot and wave and tidal stream minima were provided in a further consultation published in May 2014[120]:

118 Electricity Market Reform: Allocation of Contracts for Difference, consultation on competitive allocation, DECC, January 2014.

119 Allocation of contracts for difference, a Government response on Competitive Allocation, DECC, May 2014.

120 Allocation of Contracts for Difference a further consultation on the use of technology groupings, minima and maxima, DECC, May 2014.

- Biomass conversion was put in a separate pot to avoid lessening competitive pressure in Pot 1 which predominately have lower strike prices, or distorting competition in Pot 2 due to its size and relative strike prices.
- A 100MW minima[121] was put in place for wave and tidal stream projects across both the RO and CfD to the end of the Delivery Plan period to avoid it being exposed to competition early on. 10MW of this was set as the minima for the October 2014 allocation round. This was to enable innovation and the potential for longer term cost reductions.

6.119 The rationale for not providing maxima/minima to other technologies was also given.

6.120 We agree that biomass conversion could be distortive to competition in Pot 1 or 2 given its size and relative strike price in the two pots, and that wave and tidal stream are too early-stage to be open to competition at this stage (this is clear from the administrative strike price set for wave and tidal stream). However, it is not clear what the broader rationale was that led to these specific decisions, and how it would be applied to all technologies to ensure consistent decisions. In particular:

- What is considered a "distortive" effect on competition and when is it considered a problem – eg why are biomass conversion projects considered distortive but offshore wind projects are not?
- What is it that makes a technology at a sufficiently "early stage" to require a minima – eg what would ACT need to demonstrate to be judged to be at this stage?

6.121 **Economic theory suggests that economic inefficiencies would exist in a purely technology-neutral auction in the UK, and DECC has gone some way to try to resolve these through policy design. However, we believe that it would be helpful to set out a consistent and more transparent approach to pot allocation, maxima and minima policy decisions based on an evaluation of all technologies against a single set of metrics (eg based around the causes of economic inefficiency identified in paragraph 6.105). Alongside this, a clear explanation of a threshold for what constitutes a significant enough issue that it needs addressing by a change to existing policy. We recommend such an approach is used in future.**

6.122 The tables in Annex F provide some examples of the types of metrics that could be used. Once it is clear what project characteristics are compatible, how different externalities are to be valued, and where co-ordination across Government policies[122] is required, this can then feed through into the use of budget pots, minima and maxima.

6.123 In practice it can be very difficult to value some externalities; for example, enabling diversity across technologies, where this is dependent on the amount of each technology that commissions. The alternative is identifying the desired volume of a particular technology. This is more transparent and can be made consistent with renewables and decarbonisation targets. This is in keeping with our recommendation to define DECC's longer term goals for the future electricity mix.

Despite differences in characteristics, technologies can be grouped, but some further separation may provide a more economically efficient auction outcome

6.124 To assess the allocation of technologies to pots we have considered each pot separately against the four potential barriers to cost efficient allocation identified in paragraph beginning 6.105. This assessment is given in paragraphs 6.135 to 6.144. This **is not a full**

[121] To be split between the RO and FiT CfD.

[122] DECC may not be the lead department responsible for the valuation of externalities eg developing a British supply chain or waste management policy. However, DECC will need to work with other departments to gain the desired cross-departmental technology mix.

assessment as the value of externalities and interactions with other Government policies are a matter for Government. We therefore only comment on these insofar as inconsistencies appear to exist between current policies.

6.125 Our assessment of the allocation of technologies to pots suggests that whilst it may be cost effective to group some technologies in the same budget pots, further separation of technologies beyond three budget pots[123] could reduce cost inefficiencies. We have identified two potential causes of cost inefficiencies in under the current budget pots :

- the absence of a value for reliable capacity- whilst in general we have not commented on the value of externalities, we assume that DECC does value reliable capacity over intermittent capacity as this is the purpose of the capacity mechanism for non CfD supported capacity. This is applicable to Pot 1 and Pot 2, see paragraph beginning 6.138, which could undervalue baseload technologies; and
- the size differential between offshore wind and other Pot 2 technologies, see paragraph beginning 6.142, leading to an increase in perceived allocation risk which could reduce competition;

6.126 We also note:

- the interaction of the early closure of the RO to solar PV, at a stage when solar PV may have been unable to compete with onshore wind, which had the potential to cause “boom and bust” for the solar PV industry in the first allocation round, see paragraph 6.139; and
- based on current policy initiatives areas where further consideration of the value of externalities may be warranted to avoid under allocation are for community projects, see paragraph 6.138, and AD, ACT and biomass CHP, see paragraph 6.144.

6.127 Options available to DECC in addressing these potential cost inefficiencies include:

- further separation of budget pots;
- use of maxima or further use of minima;
- making an adjustment to the methodology for selecting successful projects; and/or
- making a policy change outside of the CfD.

6.128 We have considered these four options against the two potential cost inefficiencies identified in paragraph 6.125 and applied these to the CfD pot allocation in the first allocation round. Based on this, policy changes DECC may wish to consider for future CfD allocation rounds are:

- **To recognise the contribution of reliable capacity within Pot 1, DECC could separate Pot 1 between baseload and intermittent capacity, or add a value to reliable capacity within or outside the CfD mechanism.** The use of maxima or minima would have a similar effect to a separate pot but, in both cases, would introduce more complexity as more than one maximum and minimum would be required, providing further segregation between technologies.
- In Pot 2, **separation of offshore wind from baseload Pot 2 technologies would not only enable the value of reliable capacity to be recognised but would also address potential issues arising from the size differential between offshore wind and other Pot 2 technologies, as well as other differences in characteristics between these technologies.** Putting a value on reliable capacity, or use of maxima and minima would not address the difference in size or other characteristics. A downside to a specific offshore wind pot is there may be increased scope for collusion. These issues are discussed in paragraph 6.406. A reduction in perceived allocation

[123] Including a minimum for wave and tidal in Pot 2.

risk as a result of separating offshore wind would also need to be weighed against a potential reduction in competitive tension between technologies.

- **Separating intermittent and baseload technologies in Pot 1 and Pot 2 would offer the option of a single baseload Pot, so that the total number of Pots would only increase by 1 from 3 to 4[124].** However, this could provide the potential for more inframarginal rent for some technologies (eg EfW CHP and Biomass CHP, in the event they achieve their ASP[125]) which may otherwise have been competitive with onshore wind/solar PV and offshore wind respectively.

6.129 **We also note that in the first allocation round a more gradual closure of the RO may have avoided the potential risk of 'boom and bust' for solar PV due to its potential difficulty competing on cost with onshore wind in the first allocation round.**

Competition between technologies should value reliable generation consistently across Government policy

6.130 We consider there is currently an inconsistency between the treatment of intermittent and reliable generating capacity that is and isn't supported by the CfD. Reliable non-CfD generators are expected to gain higher revenues than intermittent generators in two ways:

- higher average wholesale electricity prices – as reliable generators are more likely to be able to generate at times of system tightness, where they can capture higher prices[126]; and
- through support from the Capacity Mechanism – as the derating factors used for reliable generation are considerably higher than for intermittent generators.

6.131 The existence of the Capacity Mechanism demonstrates that DECC places a value on reliable capacity over and above what the wholesale electricity market currently offers. The higher potential revenue from the wholesale electricity market and capacity mechanism incentivises the development of reliable capacity over intermittent capacity. These higher expected revenues from the wholesale electricity market and capacity mechanism incentivise the development of reliable capacity over intermittent capacity, assuming the capacity is not supported by the CfD.

6.132 In contrast, under the CfD, where competitive allocation exists, the same strike price is awarded to renewable capacity irrespective of whether the capacity is reliable or intermittent. This could lead to less reliable renewable capacity being developed than would be the case if its reliability attracted a value equivalent to that received by non CfD supported reliable capacity. If less reliable renewable capacity is developed, then more reliable non-renewable capacity would need to be supported under the capacity mechanism to reach the same total amount of reliable capacity on the system. Attracting this additional capacity under the capacity mechanism is likely to increase the cost of the capacity mechanism, potentially leading to higher overall policy costs[127].

124 It is not clear which pot wave and tidal would be most suited to, though this budget was separated in the first allocation round through a 10MW minima.

125 This may become more likely for biomass CHP if not in a pot with offshore wind which may be more cost competitive than other pot 2 technologies based on DECC projections for electricity generation costs, December 2013.

126 This impact is discussed in 'The challenges of intermittency in North West European power markets', Pöyry, 2011.

127 This is based on the assumption that the price paid for reliable renewable capacity under the CfD is less than that needed to procure the additional reliable capacity under the capacity mechanism that would otherwise be required. This would be expected to be the case if reliable renewable capacity is valued over intermittent renewable capacity at an equivalent value to non CfD supported reliable capacity.

6.133 Under the CfD technologies are categorised as 'baseload' or 'intermittent' for the purpose of allocating a reference price. For baseload technologies to access an additional value for reliability it would be reasonable that they also have some obligation to deliver generation at times of system stress.

6.134 In addition, the existence of the Capacity Mechanism demonstrates that DECC places a value on reliable capacity. Therefore valuing reliable CfD supported capacity should provide a more coherent approach across electricity policy.

Pot 1 – established technologies

6.135 **Differences in the technology costs of Pot 1 technologies are compatible** – the ASP for landfill gas, sewage gas and EfW CHP are lower than the clearing prices in the first allocation round. Of these no landfill gas or sewage gas competed in the first allocation round[128] and 94MW of EfW CHP was awarded a contract at its ASP (representing 4% of the anticipated budget spend). Given the EfW CHP ASP is only £2-3/MWh lower than the clearing strike price, provided the cost assumptions are correct, this provides limited scope for further reductions in infra-marginal rents within Pot 1 in the first allocation round. The potential for landfill gas and sewage gas appears limited in the future, given there was around 75MW of capacity with planning permission but not operational at the time of writing[129]. The combination of the proximity of the EfW CHP ASP to clearing prices in the first allocation round and anticipated future reductions in costs of onshore wind and solar PV could mean that they become competitive with EfW CHP in future rounds, which would mean infra-marginal rents from this technology may continue to be limited.

6.136 In the first CfD round three solar PV projects were successful compared to 15 onshore wind projects. There was a consensus among the solar PV stakeholders interviewed that this was due to higher solar PV costs. The strength and consistency of opinion among stakeholders suggests there was a genuine cost difference. Whilst a difference in underlying costs between technologies is not an issue in itself, the interaction with the early closure of the RO led to a potential 'boom and bust' (see paragraph 6.139).

6.137 **Differences in typical project characteristics are compatible** – 22 projects were awarded contracts in the first allocation round so there was no dominant project. Solar may tend to target earlier delivery years than other technologies, due to its relatively short development timescales. This exposed strategic bidding[130], but did not cause any fundamental problems with solar PV competing against other Pot 1 technologies.

6.138 **If Government values reliable capacity and community projects, as suggested by current policy measures, this may require a change to current policy**– in Pot 1 having no value for reliable capacity is likely to have had no impact on the outcome in Round 1. At the prevailing clearing prices, baseload technologies (eg landfill gas, sewage gas and EfW CHP) would all have been capped by their respective ASPs and so it is unlikely any projects from these technologies participated but were unsuccessful. In future allocation rounds if onshore wind and solar PV become cost competitive with EfW CHP, not valuing dispatchable capacity over intermittent capacity could result in more reliable capacity required under the capacity mechanism. There are also no particular provisions to value community projects (usually onshore wind, solar PV or hydro), which could struggle to compete due to access to information, skills and expertise and resource[131]. However, there are specific provisions made for community projects within the ssFiT for projects up to 10MW where the community and commercial parts of the projects are no

[128] We conclude this on the basis that the ASP for these technologies is lower than the clearing prices for each delivery year for Pot 1, and so had they competed they would have been successful.
[129] Taken from the Renewable Energy Planning Database, June 2015.
[130] These are discussed in paragraph 6.323
[131] Community Energy Strategy, DECC, January 2014.

more than 5MW each. The publication of DECC's Community Energy Strategy in January 2014 suggests Government does place an additional value of this type of project. Provisions for community energy projects could provide additional complexity into the CfD, and so if projects that are not already eligible for the ssFiT are desired, DECC would need to decide whether this is best addressed under the CfD or other policies, eg a further extension of eligibility under the ssFiT.

6.139 **An attractive band under the RO followed by its early closure has risked causing a 'boom and bust' investment cycle for solar PV** – one of DECC's objectives in setting the CfD budget levels was to enable a smooth investment profile, see paragraph 6.146. There is a risk this will not be achieved for solar PV. Around a 1GW of solar PV > 5MW was commissioned in 2013/14, around five times the amount commissioned the year before[132], even more capacity is expected to have commissioned in 2014/15[133]. In the first allocation round no solar PV projects signed contracts for 2015/16[134], some may be eligible for grace periods under the RO, and three signed contracts for 2016/17. To address this in the current CfD pot allocation would have required a minimum for solar PV or reallocation to another Pot. DECC has committed not to apply a minima to any Pot 1 technologies. This means scope for addressing this issue through the CfD was limited, and so instead a more gradual reduction in capacity under the RO would have prevented the potential for this "boom and bust" scenario. Given expectations of cost reductions and that the policy has already been put in place, this is not an issue that we consider needs any future policy intervention.

6.140 It's not clear how support for EfW CHP fits with waste hierarchy[135] if onshore wind and solar PV becomes competitive with it; it would be helpful to continue to monitor this to ensure that incentives under the CfD and waste management policy are aligned.

Pot 2 – less established technologies

6.141 **Differences in technology costs are unlikely to have created large infra-marginal rents but could create a barrier to some technologies competing in future** – no technology cleared at its ASP suggesting no technology specific infra-marginal rents. There were no successful projects for some technologies; without knowing unsuccessful projects, it's not possible to know if this was due to cost or other reasons. In future, DECC electricity generation costs expectations are that offshore wind costs will fall faster than biomass CHP, AD, ACT and geothermal costs in the future. This is not an issue in itself but could lead to a sub-optimal allocation of these technologies if externalities are not properly valued (see paragraph 6.144).

6.142 **The relative size of offshore wind projects to other Pot 2 projects could distort competition in Pot 2** – the two successful offshore wind projects in the first allocation round comprised 95% of the successful capacity. How these projects bid then had implications for other projects. In the first allocation round they appear to have bid below most other projects, leaving a relatively small amount of budget for remaining technologies[136]. In the future, uncertainty over the outcome of the allocation round could

132 Assumed capacity and commissioning dates are based on the date of the first issue of ROCs to a project in Ofgem's Renewables and CHP register.

133 Based on the figures presented in DECC's consultation on changes to financial support for solar PV in May 2014.

134 Two projects were successful in the auction but did not sign contracts due to the low clearing price.

135 As specified in Article 4 of the EU Waste Framework Directive, Directive 2008/98/EC, and referred to in the Guidelines on State Aid for environmental protection and energy 2014-2020, European Commission, June 2014.

136 This will only be an issue in future where offshore wind projects compete for a CfD. If budgets are high enough to enable all offshore wind that wants a contract to be allocated one, this issue would no longer exist, however, there could then be concerns over the potential for infra-marginal rents.

increase allocation risk. In addition there are other differences between offshore wind and other Pot 2 technologies that may add to the complexities of them competing with one another; for example, flexible bids are not generally viable for baseload technologies where they have been designed to a specific capacity and smaller projects may be better suited to more frequent allocation rounds (see paragraph 6.164).

6.143 **If Government values reliable capacity over intermittent capacity, as suggested by the existence of a capacity mechanism, this additional value should be reflected in the CfD** – if any baseload projects competed in the first allocation round and narrowly lost out to offshore wind, or do so in the future this may increase the need for reliable non-renewable capacity increasing the cost of the capacity mechanism.

6.144 **If a minimum level of CHP, AD or ACT is desired for heat or waste management objectives this may need addressing through a separate Pot or minima –** the relative attractiveness of the ssFiT could lead developers to size AD projects to gain support under this mechanism. Competitive allocation could also have implications for the waste hierarchy and provision of renewable heat if AD, ACT and biomass CHP are crowded out due to lower cost competition from offshore wind. It will therefore be important to ensure the value of these externalities through Landfill Tax and the RHI are valued in line with Government objectives, and if there are ambitions for minimum capacities these are fed through to pot separation, maxima and minima decisions or provisions made through non-CfD policies to enable this.

Budget setting process needs some improvements

6.145 In the CfD allocation process, budgets:

- cap support so that spending on renewables remains within the Levy Control Framework (LCF) budget limits which in turn caps the amount of new capacity so that it can be contracted in a CfD allocation round;
- determine the level of competitive tension, alongside the pipeline, within an auction;
- distribute spending between budget pots and any maxima or minima that are set; and
- signal to the market future opportunities for investment.

6.146 In addition to the three EMR objectives, the high level objectives of the budget setting process were[137]:

- manage risks to departmental finances;
- a credible CfD scheme and successful auction;
- managing State Aid risk;
- a steady flow of investments.
- enabling later projects to get funded.

6.147 These objectives appear appropriate for the role of budget setting.

6.148 The process for setting the October 2014 budget combined a top down and bottom up approach using a spreadsheet model. Project level data (bottom up) was used to ensure that the high level objectives were met, whilst taking account of the budget available under the LCF (top down). This is explained further in Annex D.

6.149 **We consider the following elements of the budget setting process appropriate:**

- The QA procedure required sufficient senior sign off[138] at several levels;

[137] This is taken from DECC internal documents and corroborated by internal discussions.
[138] An audit of whether all processes were signed off was outside the scope of this project.

- The top down and bottom up approach described in Annex D to help ensure understanding of implications for deployment objectives, competition, State Aid guideline objectives constrained within the LCF budget; and
- Testing the outcomes against different scenarios, including wholesale electricity prices and renewables deployment, under different schemes to understand the impacts of the main uncertainties on meeting objectives.

6.150 **However, the modelling exercise undertaken should be more comprehensive to understand the implications of budget decisions. In future we recommend modelling budget scenarios across technology pots and over time against the EMR objectives (see section starting with paragraph 6.153).**

6.151 **In addition we recommend changes to the following input assumptions for future modelling:**

- **Strike prices –** modelling the implications of a range of strike prices, including the ASP, but this should not be the central strike price assumption if competition is expected (see section starting with paragraph 6.152);
- **Load factors –** using project specific load factors for larger projects (see section starting with paragraph 6.159); and
- **Wholesale electricity prices –** including technology specific wholesale electricity price projections (see section starting with paragraph 6.161).

Modelling budget scenarios across technology pots and over time against the EMR objectives needs to be done in order to understand the implications of budget decisions

6.152 Under non-competitive allocation, the level of administrative strike prices are DECC's main tool for influencing the balance between the main EMR objectives of:

- Securing sufficient deployment to meet renewables and decarbonisation targets;
- Value for money for consumers; and
- Security of supply through technology diversity.

6.153 Under competitive allocation, budget levels and the allocation of technologies and budgets to pots are the main tool for achieving the desired balance between the EMR objectives. It is therefore appropriate that **the focus of technology modelling becomes different budget scenarios rather than different administrative strike prices scenarios. This would provide DECC with further insight into the impacts of the decisions it is making and the trade-offs that exist in relation to these decisions.**

6.154 We recognise that this was accounted for in part by running different budget scenarios for each pot. In practice, the change would mean running combined pot and current and future allocation round scenarios to understand the impacts of different packages on deployment and costs over time.

6.155 We recognise modelling budgets over time is challenging due to the uncertainties involved, including future wholesale electricity prices, but it is not possible to understand the trade-offs being made without undertaking such modelling.

6.156 This change is also consistent with a move to provide greater visibility of future budgets (see section starting with paragraph 6.384).

Use of ASPs in setting budgets can lead to budget over-allocation

6.157 Where budget decisions are partly based on deployment ambitions, these decisions require a good understanding of the cost of new capacity ie the difference between the strike price awarded and reference price. If the strike price is assumed to be higher than the outturn strike price then there is the potential to set budgets higher than necessary to meet deployment objectives. This could lead to inefficient allocation of budget between pots or over time, as more would be allocated to earlier projects than otherwise would have been.

6.158 The auctions were designed to be competitive with the intention of clearing below the strike price. So ASPs were expected to underestimate the amount of capacity expected to be procured at any particular budget option. It is therefore more appropriate to use an estimate of the anticipated strike price rather than the ASP in determining the amount of deployment anticipated under different budget options. We accept that determining an alternative ASP is challenging. This could be related to DECC electricity cost ranges and desired deployment, and in future will become easier as more auctions are held. However, given the uncertainties, it would also have been prudent to undertake sensitivities based on different strike price outcomes including ASPs.

Project specific load factors should be used for large projects

6.159 DECC already uses project specific load factors for biomass conversions, as these are large and can vary significantly depending on the characteristics of the plant.

6.160 Wind load factors can differ significantly depending on location and the turbines used (see Annex E). Given the size of some offshore wind projects, a historic load factor based on other projects may not always be a good indication of the load factors for that project. It would be appropriate for DECC to use wind speeds and turbine characteristics to estimate load factors of large projects which could be cross checked against historic values. Such a methodology could be applied consistently across projects, and so would be more appropriate than a developer nominated load factor[139]. This is particularly important for projecting spending under the LCF of currently CfD contracted projects. It may also be useful in modelling auction outcomes. Consideration would need to be given to its use in the budget valuation formula. On the one hand it may improve the accuracy of the estimation of budget used by a project. On the other hand they could not be made public without providing information on the projects applying, and determination of the value would be less straightforward and so could be subject to concerns over prejudicing the auction outcome.

Technology specific wholesale electricity price projections should be used for intermittent technologies

6.161 A single annual reference price is utilised for all technologies when setting the budget as well as in the valuation formula for determining whether an auction is to be held, and the budget impact of bids in the auction. This is a baseload reference price.

6.162 Over a 12-month period however, the average reference price captured by technologies, in particular intermittent ones, is likely to differ because of their irregular generation patterns[140]. Everything else being equal, onshore wind, offshore wind, and solar, may have a different impact on the subsidy cost per MWh[141], which is not captured by using the reference baseload price.

6.163 We recommend using a technology-specific assumption for the wholesale electricity prices in the budget setting modelling and valuation formula.

Frequency of rounds should be reviewed

6.164 As part of the wider debate around the future CfD budget, the rationale for pot allocation and how to streamline the allocation process (see sections starting with paragraph 6.384,

139 Although this could be used as a cross reference.
140 This structural difference is reflected in the choice of indexation for the CfD subsidy payments.
141 The actual value will be influenced by several factors including wholesale electricity prices and installed capacity of the technology. According to Pöyry analysis this could be in the region of £1.50 to £2.50/MWh for onshore and offshore wind.

6.104 and 6.253, respectively), we also recommend DECC to reconsider the frequency of allocation rounds.

6.165 Based on the concerns raised by numerous stakeholders, it appears that smaller organisations (typically developing AD, ACT, solar PV, etc.) and projects based on technologies with shorter lead-times (eg solar PV) feel excessively disadvantaged compared to other participants (eg offshore and onshore wind, or medium/large organisations).

6.166 We acknowledge that smaller entities are financially weaker and with less resources than larger organisations. Coping with the uncertainty of the allocation over an excessively long period may be unsustainable, or add extra costs, which would decrease their competitiveness. Therefore, more frequent rounds (eg six-monthly) would suit them better. A higher frequency may also be suitable for technologies with a shorter lead-time, especially solar PV. The typical development cycle for these assets is much faster than all other technologies. Annual rounds (as well as other contractual constraints, see section starting with paragraph 6.234), would change the pace of project development and could result in loss of efficiency.

6.167 Striking the right balance between an efficient management of the budget and suitability of timescales for all types of developers within the framework of overarching constraints, such as the State Aid guidelines, is a difficult exercise. DECC need to balance a number of different elements that are potentially conflicting. For instance, increasing the frequency may facilitate eliciting efficiencies of some technologies and encourage a more diverse participation. However, this could clash with the objective of setting credible budget levels that promote a healthy competition, or logistics considerations, such as overlapping of consecutive rounds. A potential differentiation in frequency depending on technology/pot may also have implications on the auction dynamics, in particular where developers invest in a diverse mix of technologies.

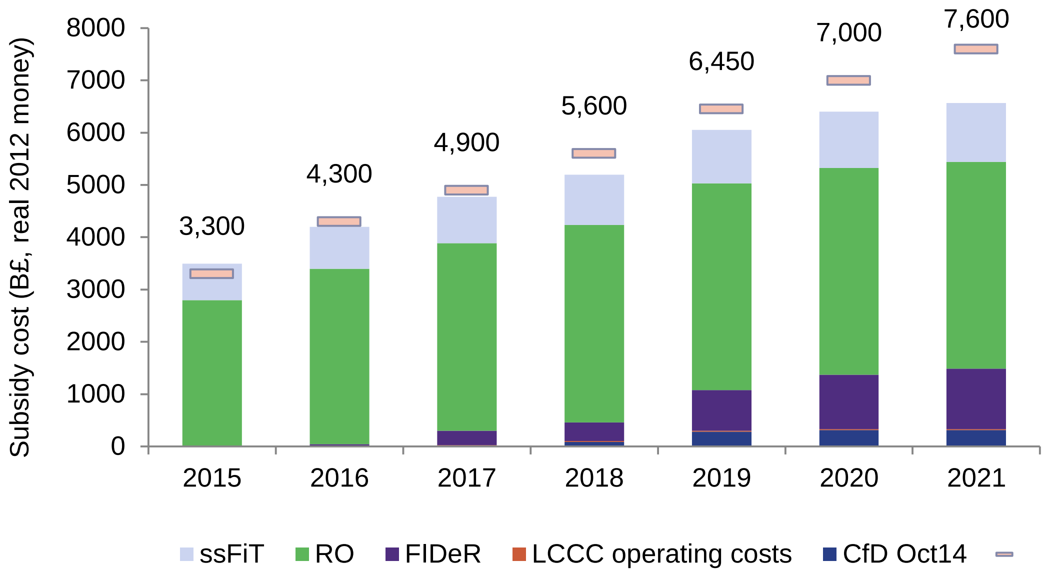
6.168 In any case, the expected remaining budget from the Levy Control Framework in 2020/21 is slightly above £1bn (see Figure 19) based on DECC's November 2014 estimates[142] and the expected cost of CfD Contracts[143]. This residual budget may be reduced by potential additional spending for bilaterally negotiated CfD (eg nuclear, CCS, etc.), hence the available budget for CfDs would be lower than the amount calculated. Independently from the exact amount, this level of budget may be easily allocated through few annual CfD rounds, so any variance in the frequency should be carefully assessed against the residual budget.

6.169 **Overall, we believe that frequency is an element to be reconsidered when assessing future distribution of budget across pots, reallocation of technologies and other elements impacting the ability of projects to compete on a level playing field.**

142 'Annual Energy Statement 2014', DECC, November 2014.

143 These include both the early CfDs awarded under the FID Enabling for Renewables programme and the October 2014 allocation round of the CfD enduring regime. The support cost for CfD projects awarded a contract in October 2015 was calculated following the same methodology stated in the October 2014 "Final Allocation Framework for the October 2014 Allocation Round" and as applied by National Grid. Only CfD projects that signed a contract with the LCCC have been taken into account. Reference prices are from the Allocation Framework and kept flat after 2020 (last published value). The calculation considers partial generation of a unit on the first year of generation and on the last year of generation for full lifetime calculations and days of the year to account for leap years. Assumptions considered from the Allocation Framework are: load factors, transmission loss multipliers, renewable and CHP qualifying multipliers. Target commissioning date, capacity and strike price were considered as published by the LCCC in the CfD Register.

Figure 19 – Budget impact of the different LCF-funded schemes



Note: ssFiT, RO, FID Enabling for Renewables (ie FIDer) and LCCC operating costs are based on DECC's estimates published in the November 2014 Annual Energy Statement, while estimates for the October 2014 CfD contracts (ie CfD Oct14) are based on our calculations based on information from the LCCC's CfD Register and assumptions from the Allocation Framework (see footnote no. 143)

Auction design seems appropriate, but further evidence is required to assess whether some problems may become real

6.170 There is **no clear theoretical view on the most appropriate auction format**. Different auction designs carry different risks, and so the most appropriate will depend on the dynamics of the market considered. **Any design may produce sub-optimal results and/or unintended consequences, so the priority is to select one format that could minimise the risks**.

6.171 In the CfD case, the division in pots arguably introduces an additional element of complexity in that the selected format will need to be robust for all the 'markets' *de facto* created in each pot – and this needs to hold for current and future rounds. As it currently stands, the size and market power of offers – eg how can large and/or multiple projects upset the allocations – or signalling opportunities – eg large players publicly withdrawing from well-known projects ahead of the auction – are greater concerns for Pot 2. Private values and asymmetric information – eg local and project experience – are potential areas of focus for Pot 1 (see paragraph 6.184 below).

6.172 At this stage we believe that **stability in the design is important to maintain investor confidence** and therefore we would support DECC's approach of minimising changes for future rounds. Because of restrictions on access to bid data, we were not able to assess the economic efficiency that alternative formats could have delivered. In principle, we think that the current design – sealed-bid pay-as-clear (PAC) with flexible bids – would yield similar results to a descending clock format on pure economic efficiency grounds.

6.173 **No obvious problem emerged in the first round, therefore the auction design seems to have worked relatively well**. The only undesired result was the award of contracts to two 2015 solar PV projects that in the end decided not to sign. In hindsight, it is possible that a descending clock format could have averted this. However, we believe that this is not sufficient to justify a change in design. Other measures, such as a reinforcement of non-delivery disincentives, could prevent the same situation to occur in future rounds (see section on anti-speculative measures starting with paragraph 6.391).

6.174 In the opinion of various stakeholders, **DECC was too focused on the gaming risk as a driver for the selection of the format**. While we disagree that gaming was the overriding reason for preferring the sealed bids over the descending clock (see paragraph starting with 6.179), we acknowledge that the Government may have relied too much on the high-level design of the auction to deter speculative projects. Reassessment of the anti-speculative measures, including the detection / monitoring of potential anti-competitive behaviours is further discussed in the section starting with paragraph 6.391.

6.175 We believe that **adequate information was available to allow an understanding of the CfD auction process.** Stakeholders reported that it required a substantial investment in terms of internal resources as well as external professional advice, in particular to assess the economic incentives, the likely competition and the formulation of successful bids. We are conscious that this complexity may have favoured larger players at the expense of SMEs, which are less likely to have the same level of market intelligence and modelling capabilities. We have anecdotal evidence that it may have deterred a handful of smaller players from participating in the first round. **There was a general consensus, however, that the complexity is manageable and that the support from National Grid, the LCCC and DECC was valuable, especially to enable smaller players participate** (see section starting with paragraph 6.40). In the future new participants will need to go through the same learning process of participants to the first round, thus the existence of training and information dissemination sessions remains important.

Summary of key design features

6.176 The general auction design features of the CfD auction are:

- Sealed bids (single submission);
- Pay-as-clear (uniform price);
- Multiple sellers (project developers), single buyer (DECC).
- Annual allocation rounds.

6.177 Secondary features include:

- Prioritisation based only on strike price;
- Up to 10 flexible bids (considered only if the project is marginal);
- Stepped budget;
- Budget closure based on the commissioning year of a project, which breaches the budget in any of the years;
- Each delivery year has a separate strike price; and
- Bids capped at the technology-specific Administration Strike Price (ASP).

6.178 These features should be considered in the wider framework set by the annual budgets aligned with the Levy Control Framework (LCF) and the potential existence of multiple auctions in each round to address the 'established' and 'less established' pots and any 'minima' or 'maxima'[144].

Rationale for the selected design was not fully understood by stakeholders

6.179 DECC have explored a range of different auction arrangements, in particular the fundamental features of an auction design, such as the bidding mechanism (descending clock vs sealed bids) and the clearing price rules (pay-as-clear vs pay-as-bid). These are examined in more details in the following sections.

6.180 In assessing the different options, DECC had to balance between economic efficiency, policy and achieving desired outcome (which was not necessarily clear from the very beginning, but became apparent later on). A number of other 'bolt-on' elements were subsequently overlaid – such as budget closure mechanism, flexible bids, non-delivery disincentives, etc. – as driven by other features of the CfD regime and/or address specific circumstances of the UK renewables market.

Choice of sealed bids over descending clock was driven by the complex objectives and the priorities in terms of delivery and gaming risk

6.181 Alternative options considered by DECC's design team were the descending clock and sealed bid formats. The decision was mainly driven by the following considerations:

- Timeline implementation challenges
- Complexities of objectives
- Common vs private value uncertainty & winner's curse
- Collusion and/or predatory behaviour

6.182 **Timeline implementation challenges** – DECC were given a very tight schedule to deliver the CfD auction. As a consequence, considerations around how easily alternative solutions could be designed as well as technically implemented took a prominent role in the decision. Based on their experience with the Capacity Market auction, National Grid advised DECC of the time it would take to implement the full set of rules for a descending clock if the policy and all the rules were developed. Based on this and other considerations on the timing of the internal decision process, DECC reached the

144 'Maxima' can be introduced to limit dominance of a particular technology (none in place for the October 2014 allocation round).

conclusion that a sealed bid format would minimise the risk of delays in the delivery of the first CfD round, or poor implementation, compared to a descending clock scenario.

6.183 **Complexity of objectives** – The selected auction had to deliver a number of complex objectives, such as balancing short versus long-term value for money to consumers, fostering innovation and attractiveness of entry. On balance a sealed bids format seems to offer the best solution to achieve these objectives.

6.184 **Common vs private value uncertainty & winner's curse** – A descending clock format is believed to reduce the uncertainty related to common values as it offers price discovery more effectively than a sealed bids scenario. By allowing an iterative process, bidders can obtain a real-time understanding and can withdraw once they see a significant number of other bidders pull out from the auction. This could enable bidders to be more aggressive – thus improving the value for money all other things being equal – without fear for winning at a price that is too low (ie winner's curse). This risk is generally higher for new assets – where the most part of costs are fairly openly discussed, ie common values – compared to existing assets – where more idiosyncratic valuations exist, ie private values.

6.185 During the design process as well as in the responses to our engagement process, a number of stakeholders have expressed their preference for a descending clock format on the basis of the argument above. In their opinion, sealed bids incentivise a 'race to the bottom' – exposing investors to unreasonable returns and the possibility of successful projects being unbuilt – such as the two 2015 solar PV projects that failed to sign (see section starting with paragraph 6.323). It is worth noting, however, that this did not deter these organisations from taking part in the auction or considering doing so in future rounds.

6.186 In the case of the CfD auctions, we believe that the value of winning is likely to have a valuation that is neither exclusively common nor completely private, thus a sealed bid format is legitimate. Because of the mixed nature of values in the CfD market, the argument that the descending clock format is to be preferred over the sealed bids as it is more efficient in averting the winner's curse is weak. Bids are based on assessments of the project/company's own private parameters – eg costs, resource availability, risk appetite, etc. – as well as common information – eg performance of a specific technology, electricity[145] and additional market revenue streams, cost of offtake contract, etc.

6.187 We would also add that aggressive bidding can be also caused by the interplay of technologies competing for the same pot that are actually structurally different, or by the implications of the RO-CfD transition. For instance, a project concerned to be uncompetitive compared to other technologies in its pot could be tempted to submit an unworkable bid resulting in the winner's curse. The reasons that led the 2015 solar projects to fail[146] in their bidding strategy are attributable to this second group of factors and/or inexperience, not to the auction design itself.

6.188 **Collusion and/or predatory behaviour** – One of the theoretical advantages of a sealed bid format is that it offers a more robust protection against collusion and/or predatory behaviours. Auction design experts suggest that the likelihood of this to happen is higher in a multi-round (descending clock) than a single round auction[147]. As alluded earlier, DECC has dedicated lot of efforts in selecting the auction format that would deter against

145 In particular after the end of the subsidy period as the CfD instrument provides a hedge to movements in power prices.

146 Failing here means failing to achieve the desired outcome ie a higher strike price set by another project.

147 It is worth noting that there are measures that could lead to limiting information disclosure in a descending clock scenario, but probably these will make the format somewhat similar to the sealed bids.

anti-competitive behaviours. DECC have not substantiated their concerns on the potential for collusion in the CfD auctions, and generally referred to the structure of the renewable market, where large dominant players may attempt to manipulate outcomes.

6.189 Constraints dictated by the timeline for implementation combined with the anti-collusion agenda may have strengthened DECC's preference for sealed bids at the expense of the advantages offered by the descending clock in terms of avoiding the winner's curse.

Selection of Pay-as-Clear (PAC) over Pay-as-Bid (PAB) was appropriate

6.190 Once the descending clock was ruled out, DECC considered two options – pay-as-clear (PAC) and pay-as-bid (PAB) – for the sealed bid clearing mechanism. The decision of opting for the PAC was widely supported by stakeholders.

6.191 In terms of the key drivers, time constraints did not play a big role as either option could have been easily implemented. Providing the most appropriate incentives to bid straight-forwardly, reducing opportunities for gaming and encouraging innovation were the leading factors.

6.192 **Encourages projects to bid straight-forwardly**. At first glance, the intuitive attraction of a discriminatory approach (PAB) is that consumers would not pay a higher price to units that actually offered to deliver at a lower price. In reality, PAB is likely to create the opposite outcome. Under a PAB scenario, bidders would be encouraged to bid up to their marginal valuation based on their best guess of the clearing price, ie strategic bidding. Thus, asymmetric information would favour some participants to the detriment of others, which undermines fair competition.

6.193 Under the PAC model, projects are incentivised to submit bids that reflect the minimum amount required to guarantee the delivery of the project, or slightly above that trying to maximise their value in case they were setting the price[148]. On this assumption, it is also hard to argue against uniform auctions, especially as they tend to make it easier for **small companies and new entrants** to simply offer their valuation of required strike price in the expectation that they will be cheaper than the price setting unit.

6.194 PAB may yield lower prices in the short-term than PAC, but these tend to be small and/or static gains, which would not provide **long-term incentives to innovate or realise efficiencies**. This may remain a fairly theoretical advantage. At present, its efficiency is obscured by the circumstances linked to the lack of visibility of Government's commitments or the transition from the RO as the first initial CfD rounds are likely to be anchored to short-term priorities than long-term strategies.

6.195 **A number of other advantages are ascribed to the sealed bid pay-as-clear option.** Over repeated auctions, PAC generally delivers lower average prices than PAB. Additionally, under this scenario it is relatively easier to put in place legal safeguards assuring participants that the use of bids would be restricted to the auction process, not for public disclosure or for any other Government's internal use. This was in response to industry concerns on **confidentiality of sealed bids** and should be read in the context of DECC's objective of discouraging strategic bids in favour of straightforward bidding (see also section starting with paragraph 6.427).

[148] This is connected with the approach of clearing the auction at the last accepted bid, instead of the first rejected one.

Framework for flexible bids is complex. It should be simplified to facilitate participation in future rounds, but without compromising its benefits

6.196 The auction rules allow bidders to submit up to ten bid combinations of capacity, delivery year and strike price subject to certain constraints. The number was judged to be sufficient to elicit flexibility without overstretching the system. Rules are described in more details in DECC's CfD Auction Guidance as well as National Grid's Submission Guide[149]. In offering this option, DECC wanted to achieve three objectives:

- make the outcome less vulnerable to distortions arising from particular budget choices and project lumpiness;
- elicit project development flexibility that could make the outcome more cost efficient; and
- respond to stakeholders' concern around a single-round sealed-bid format.

6.197 Because of restrictions on access to bid data, we were not able to verify the extent to which auction participants made use of flexible bids in the first round, how effective they were in averting distorting effects from project lumpiness or what role flexible bids played in determining the achieved strike prices[150].

6.198 In line of principle, we are fully supportive of the idea of flexible bids as it would deliver against the three objectives above. However, we would flag the following issues:

6.199 **Complexity** – One of the main concerns is that the detailed mechanics for the formulation of bids are unnecessarily complicated, in particular the interplay between delivery year, Target Commissioning Window and Target Commissioning Date, project size and the relationship between the original application and the flexible bids. They may distort a clean formulation bidding strategy and/or become a barrier to participation. From our discussions with stakeholders, this concern emerged quite clearly. Ultimately, the complexity was handled, but relaxing some of the constraints would be beneficial for sake of simplicity, such as capacity constraints or the number of bids per delivery year.

6.200 **Economic efficiency** – The key idea behind allowing participants to bid flexibly in terms of capacity price and delivery year is to incentivise cost reflectiveness. In practise, however, it is possible that bids get formulated with a focus on strike prices and the available budget, and/or profiled for price discovery and learning (but not necessarily gaming)[151]. This could reduce the efficiency of the outcome if any of the sub-optimally sized projects secure a contract.

6.201 **Competition** – Flexibility potential – thus the benefits – varies across technology. For some technologies it may be relatively easier to re-tune the project design to account for different capacities, others may struggle to do so, in particular smaller players, which typically design a project with one strategy in mind, ie a certain capacity by a certain date. For instance, carving out a few turbines from an onshore wind project could be easier than scaling down engine in a biomass CHP plant. This may affect the ability of projects to compete on a playing level field.

6.202 **Limited scope of flexible bids** – Flexible bids are discarded when the project main bid – the cheapest – is accepted; and assessed only if, when rejecting a project, the next bid in the price stack is one of its flexible bids. Both concerns are that this could yield a suboptimal result in terms of budget allocation and overall cost per MWh. Lack of access

149 'CfD Auction Guidance, DECC, 25 September 2014; and 'Contract for Difference, Sealed Bids Submission Guide', 28 January 2015, National Grid.

150 Based on achieved strike prices seem indicating that no flexible bids set the clearing price (all prices were set at no more than two decimal points), but this could not be formally verified.

151 Projects may decide to bid at the strike price and capacity that are likely to succeed in the auction. This combination may not reflect the project design that delivers the lower cost per MWh.

to bid data from the first round prevented the simulation of alternative uses and their impact on auction outcome.

6.203 In combination with the limited scope, it is possible that participants chose not to use flexible bids, which would further limit the usefulness of the measure. **Feedback from stakeholders suggested that in the first round intensity of use was quite wide: some participants admitted only one bid was submitted, while others made use of the full option**. Because of restrictions on data access, National Grid licence conditions alongside the CfD Regulations do not allow it to comment on whether and how participants made use of flexible bids, so a firm conclusion could not be reached on this specific area.

Other detailed aspects of the design need to be monitored

6.204 With auction arrangements as they stand, there are a number of issues that could impact the ability of the auction to provide cleaner incentives to bid at cost:

- **Last accepted bid theoretically suboptimal, but evidence is to be sought** – Theorists would normally expect bidders to have greater incentives to bid at true cost in a marginal losing bid scenario than in a marginal winning one. This is because in the latter bidders would be incentivised to inflate bids in the attempt to influence the price should they be at the margin. Under the losing bid instead, bidders would be fundamentally indifferent submitting a cost reflective bid or a bid, which tries to guess the value at which they expect the first rejected project to clear. In other terms, a PAC with 'marginal losing bid' would avoid strategic bidding, and not 'marginal winning bid'. No challenge was raised by stakeholders to this approach.
- **Systematic bias towards projects delivering in later years and/or with longer lead-time –** Systematic bias could be potentially introduced through the combined effect of three elements of the auction design:
  - lowest to highest-priced bid ranking
  - (basically) flat budget with
  - different strike prices by Delivery Year.

  The valuation process gives absolute priority to projects with the lower strike price bids without making any consideration about other factors, such as the capacity and timing attached to that strike price bid. This decision was made on the sole basis of ensuring that the auction would yield a least-cost solution, hence, everything else equal, the best value for money to consumers. Provided that we believe allocation of funds across pots and level of competition are stronger drivers of value-for-money, it is possible that this approach could introduce a systematic bias towards projects delivering in later delivery years and/or with longer construction periods, especially during the transition from the Renewables Obligation. This should be also read in the context of a relatively flat budget (and separate clearing prices across Delivery Years), which could also reduce the incentives for earlier projects.

CfD contract terms

6.205 For most of the provisions of the CfD Contract, it is too early to identify issues stemming from their implementation. On the whole, the industry – both developers and the financial community – agree that contract terms appear to be reasonable and that the allocation of risk between consumers and renewable generators is workable. The real test will come from the combination of the first financing deals and the first projects reaching the various contractual and operational milestones. DECC – as supported by the LCCC in its independent role of contract manager and through dialogue with the industry – will need to monitor market developments around key events with the objective of capturing valuable lessons for future CfD Contracts.

Reduced contract length is manageable, but it is too soon to identify whether unintended consequences on projects or any real benefit to consumers will materialise

6.206 Since inception of the process, DECC showed the intention of reducing the length of support from 20 years under the Renewables Obligations to 15 years under the CfD. The final position sets the contract term to 15 years[152] with the only exception of biomass conversion, where support is limited to 31 March 2027. It is worth noting that projects may be granted some flexibility when negotiated bilaterally[153].

6.207 The key objective of this decision was to optimise project economic viability and cost of subsidies to final consumers (ie social value of subsidy payments) by considering the impact on strike prices and financeability. The analysis supporting the decision was based on an investment decision tool[154], which modelled project finance cash flows and related constraints (eg interest and dividends, taxation, debt cover ratios, gearing, equity returns, etc.). DECC has widely discussed this change with stakeholders and offered the opportunity to comment on the operational framework[155], however no specific question on the duration of the contract was included in a consultation and only high level analysis supporting the decision was published[156].

Approach and assumptions adopted are simplistic, but broadly satisfactory if the intention was to justify policy decision

6.208 From discussion with DECC officials, we understand that intent of the paper was to justify a policy decision in simple terms – not to provide an accurate estimate of cost savings to consumers or financial implications on projects. With the exceptions of few elements discussed below, we are broadly satisfied with the approach taken. The key assumptions were:

6.209 **Investors have a higher discount rate than electricity consumers** – This means that developers will value receiving the subsidy earlier more than consumers value putting off that payment to later years. The implication of this assumption is the shorter the contract the more cost effective it will be. We think that it is a reasonable assumption that project discount rates are substantially higher than the social discount rate irrespective of the exact figure for project hurdle rates, which is highly variable across projects and time.

6.210 **Government expectations of future electricity prices are higher than developers expectations** – It is assumed Government will have a higher expectation of future wholesale electricity prices than developers, therefore Government will feel more relaxed about the level of payments to be made in later years, and developers more anxious about early exposure to wholesale electricity prices. The implication of this assumption is that a longer contract may suit Government and developers. It is not clear that there is an underlying fundamental reason for electricity price expectations to be different. We therefore don't think this would be sufficient reasoning in itself to determine the optimal contract length. Having said this, this assumption does not appear to be the main influencing factor in driving the decision.

152 Nuclear CfDs are to be negotiated on a bilateral basis with Hinkley Point C receiving payments for a duration of 35 years.

153 The current standard CfD Contract provides for a 15-year duration for these technologies. A different duration could only be negotiated in bilaterally negotiated CfD Contracts, if appropriate.

154 Contract length analysis for the FiT with CfD, summary of onshore and offshore analysis, August 2013. This was an updated version of the analysis presented in the Annex B: CfD draft Operational Framework, published in May 2012.

155 CfD draft Operational Framework published in May 2012 invited industry to submit any comment on the proposals presented in that document. This implicitly included the duration of the CfD contract.

156 'Contract length analysis for Feed-in Tariff with Contracts for Difference. Summary of onshore and offshore wind analysis', DECC, August 2013.

6.211 **Debt providers prefer revenue certainty** – Debt providers are more likely to invest if they know what price will be received for the electricity from the project for the duration of the finance period. This is less of a concern for equity providers who are more willing to accept risk and so the value of a longer contract is less clear after the debt finance period. Revenue certainty therefore allows for higher project gearing rates and so lower weighted average costs of capital (WACC). The implication of this assumption is that contracts need to cover the debt period of a project to benefit from a lower WACC.

6.212 The assumption that projects will use project financing instead of balance sheet and that the CfD will deliver higher gearing, thus a lower cost of capital, is a relatively basic approach. The reality of project developments is much more complex, so in this respect the analysis is too simplistic. Impact on risk and financing practice are explored in more details in section starting with paragraph 6.340 and 6.368, respectively.

6.213 However, we appreciate that assumptions were informed by advice from members of the investment community. We also understand that at the time DECC received feedback from both the financiers and the project sponsors stating that the relevance of tenor risk beyond the 15-year initial financing period has a limited impact on investment decisions; even in the case of project refinancing or equity recycling (eg up to 5 years into operations) the reduced length of support may not have a sufficiently important impact to justify a 20-year CfD. For the purpose of the analysis, we are broadly satisfied that these hold subject to the issues flagged in the next section.

Other considerations

6.214 **Consistency across technologies** – All renewable CfD contracts, regardless of technology, will have the same 15-year contract length (with the exception of those mentioned in paragraph 6.206 above). We acknowledge that the standardisation of the contract length represents a benefit for market players in terms of simplification, harmonisation of project financing and contracting for power.

6.215 **Consistency with the Renewables Obligation** – The length of support under the Renewables Obligation is 20 years. This is what investors are used to and so may be considered the default position. However, we think DECC was right to consider the question of contract length, as the 20 years was less the result of a consideration of optimal support length and more a legacy of how the scheme has evolved since its inception in 2002.

6.216 Some **marginal technologies or groups of developers** may be negatively affected. We would not necessarily recommend to adopt a more flexible approach at the expense of standardisation, however, we would invite DECC to engage with these parties to identify what alternative solutions would be possible to facilitate their investment process. In particular:

- Representatives of **community projects** have reported that a change in duration is not suitable with their current financing strategies. While project finance debt tenors roughly match the 15-year mark, these projects typically raise community share investments over a 20-year period and the capital is typically paid off in the second half of that term.
- More **innovative technologies**, such as wave & tidal stream, have highlighted that a 15-year term is simply too short when compared to the 25-year sea-bed lease and, structurally, project economics may not allow these projects to be viable under a 15-year duration. This would mean that these projects may be forced under bilateral negotiations for CfD instead of participating to the auction (see paragraph 6.206).

6.217 **Compliance with EU State Aid guidelines** – Guidelines suggest that the duration for subsidies should be no longer than the accounting depreciation lifetime of projects. In isolation, we believe that these provisions are not sufficient to justify the decision of reducing the contract term. Based on our experience of typical operational projects, depreciation period currently ranges between 20 and 25 years depending on technology and vintage, only anecdotally 15 years for onshore wind. So a duration of 15 years is towards the lower end of the spectrum we would expect to be in compliance with the guidelines.

6.218 **Exposure to wholesale electricity prices after year 15 and financeability** – A shorter duration introduces a higher market risk at the back end of the project life. This may have an impact on the attractiveness for long-term low-yield investors and/or have value implications on projects, in particular through the achievable cost of capital.

6.219 The value of offering a longer protection against market risk is clearly attractive for infrastructure and pension fund investors. Generally, these investors look at an investment horizon of 25 years and over, so it is possible that the CfD 15-year term may be less appealing than longer schemes. Through our stakeholders research we found, however, that for most of the respondents a 15-year duration was manageable and that it would provide sufficient comfort to deal with the post-CfD market risk.

6.220 In our research, we also engaged with lending institutions to discuss the potential consequences of a shorter tenure. No definite view emerged. Lenders said that they generally look at the project 'tail' – the gap between the final maturity of the loan and the end of the subsidy – to cover a potential extension of the debt repayment period. The change in duration may as a consequence lead to a shorter debt term or to pricing a premium to cover the risk of no tail after the 15-year amortisation profile. Having said this, most parties acknowledged the benefits from the reduction in market risk and commented that it remains to be seen how debt terms will actually evolve.

6.221 It is also possible that in re-financing projects may require a larger equity buffer to cover for operational circumstance impacting the project performance. Over the later phases, the lack of subsidy payments will offer a lower protection against those circumstances – and this will happen sooner than under a 20-year RO. This would impact the cost of financing and the project returns.

6.222 Overall, it is too early to determine the influence on investments and the direction in the cost of capital. We recommend that DECC should monitor evolution of terms as soon as the initial financing deals are closed. More is explored in section starting with paragraph 6.368.

6.223 **Unintended consequences** – Some stakeholders raised the concern that the shorter duration of subsidies may encourage developers to design projects with a shorter technical lifetime, for example by purchasing lower-quality technology or construction and O&M services. This could help cutting costs thus increase their relative competitiveness in the auction. At this stage, it is not clear whether this risk is material.

Intermittent reference price is aligned with current route-to-market practices, while appropriateness of the baseload reference price needs to be proven

6.224 The CfD regime acknowledges the fundamental difference in exposure to merchant value of intermittent vs baseload technologies. Since the early stages of the policy development, different market reference prices for the calculation of the CfD payments have been considered, in particular to avoid bias in exposure to basis risk of these two technology groups. Through debate with the wider industry and expert opinions, day-ahead and forward seasonal (annual) prices were the selected references.

6.225 **Intermittent Market Reference Price** – Intermittent CfDs are settled on hourly volumes and the corresponding GB Day Ahead Hourly Price. The contractual definition currently refers to the APX day-ahead hourly index and the N2EX day-ahead hourly auction results as providers for such pricing. These two exchanges are widely accepted as transparent pricing sources, however, N2EX is substantially more liquid than its competitor APX and it is, based on our experience of long-term power purchase agreements, selected more frequently over the APX equivalent reference price. No apparent bias seems to emerge from this solution and no strong concern emerged from stakeholders. These two sources will be monitored as part of the regular contract management to ensure they remain representative.

6.226 Provisions for addressing circumstances in which these two price references could diverge – despite the Market Coupling mechanism making it unlikely to happen – as well as provisions (Reviews) for amending the price sources to maintain the quality standards set in the principles are included in the Annexes of the CfD Contract under the Review Procedures. We are generally satisfied that these allow sufficient room for manoeuvre, if changes in circumstance require it.

6.227 Current route to market arrangements for intermittent technologies, in particular wind, have established practices of settling based on day-ahead indices. From this point of view, we would not expect the CfD to introduce any new element of uncertainty. It will probably focus the attention on obtaining power purchasing agreements reflecting the CfD payment approach, especially in a project financing context where lenders may require a back-to-back agreement with the CfD[157]. It is possible that some parties used to adopt different trading strategies, thus the CfD indexation will limit their flexibility. Based on our experience, however, this is more an exception to the rule than a consolidated practice.

6.228 **Baseload Market Reference Price –** Baseload CfDs are settled based on half-hourly volumes and the corresponding GB Baseload Price. The contractual definition currently refers to the LEBA Season-ahead index and its NASDAQ equivalent. Despite a number of concerns were raised by stakeholders about the liquidity of these forward products and about how LCCC would implement the periodic reviews, we are satisfied that the CfD Contract provides for the necessary flexibility to ascertain the representativeness of the price sources. In any case, we would expect the debate on the appropriateness of the selected reference price to continue and benefit from additional evidence and information.

6.229 Another aspect to be mentioned is the impact that the indexation may have on different players, in particular smaller vs larger projects. This is in terms of their ability to effectively generate regularly across periods and seasons (ie baseload profile) and of the size of power clips to be traded, which may impact the ability to trade in the market.

6.230 A period of adaptation may also be required for smaller generators. Based on our experience of offtake agreements, these players are not typically offered seasonal forward products in their contracts. Developers, but in particular lenders, may request a back-to-back agreement between the offtake and the CfD contracts in terms of the indexation, therefore new practices may need to emerge. It is still to be seen whether this will penalise smaller generators in favour of larger players.

6.231 We would recommend DECC to follow the evolution of PPAs terms by liaising regularly with offtakers and developers. Further evidence can also be gathered through the LCCC in its role of independent contract manager.

[157] For instance, an agreement with the same duration and indexation for the payment of the electricity volumes.

Milestone requirements may be too stringent, thus some flexibility may be required for larger or complex projects

6.232 The Milestone Delivery Date (MDD) is 12 months from the date of signature of the CfD Contract irrespective of technology. The CfD Counterparty may terminate if the Generator does not prove it has spent at least 10% of Total Project Pre-Commissioning Costs – these are defined amounts included in the contract by technology – or entered into certain commitments – ie General and Technology Specific Project Commitments as detailed in the Annex 6 of the CfD Agreement.

6.233 **Definition of Project Costs** – A number of concerns were raised by stakeholders across various technologies and project sizes with respect to the definition of the project pre-commissioning costs, in particular the cost related to the grid connection, and the degree of flexibility that LCCC can and would exercise in applying these terms. We understand from discussion with DECC officials that this has already been addressed and has been published in the Government's response to the March 2015 consultation.

6.234 **Timing** – DECC have remained firm with a standardised approach despite concerns raised by stakeholders during the design process. From our stakeholder research, we understand that these concerns have not waned, in particular amongst offshore wind investors, some bioenergy developers and the solar PV community.

6.235 With respect to offshore wind, developers expressed the concern that the largest projects may struggle to comply with the Milestones requirements within 12 months from contract signature, in particular because of the financing process. The fact that three offshore wind farms succeeded in negotiating an extended MDD of 19 and 23 months[158] under the FID Enabling for Renewables regime gave the impression these projects received a preferential treatment and that this 'learning experience' was not transferred into the CfD Contract terms. It is worth noting however, that two offshore wind farms awarded an early CfD have successfully met the requirements[159], thus these concerns are not necessarily shared by all participants.

6.236 Similar requests for reconsidering the MDD timing were brought forward by a number of bioenergy developers. Special circumstances related to the technology maturity, the fuel supply infrastructure and other aspects of the project increase the complexity of the due diligence process requiring ad hoc structures. This may translate into longer financing negotiations, thus making the 12-month MDD too stringent.

6.237 **While we do not recommend amending the standard 12-month term as it maintains pressure to deliver, some serious considerations should be given to some form of flexibility, which may be essential to deliver some of the largest or most complex deals.** This was also confirmed by a number of lending institutions, which indicated that structuring a debt facility for more complex offshore wind or bioenergy projects could take longer than a year. **We have also discussed the potential need to amend the requirements to introduce incentives to free up 'contracted budget' to favour fast recycling of capital into future rounds** by means of staggered milestones and/or time-related financial penalties. This is addressed in section starting with paragraph 6.419.

6.238 Under the current terms solar PV units may be forced to spend money or enter into commitments much earlier than they would normally do to meet the MDD requirements. Solar PV would unlikely enter into EPC or supply contracts within such a short timeframe from signature of the CfD if they have to deliver two to three years later. At least in the short to medium term, costs are still expected to fall relatively rapidly. Signing earlier

158 See note to Figure 20 for specific details.

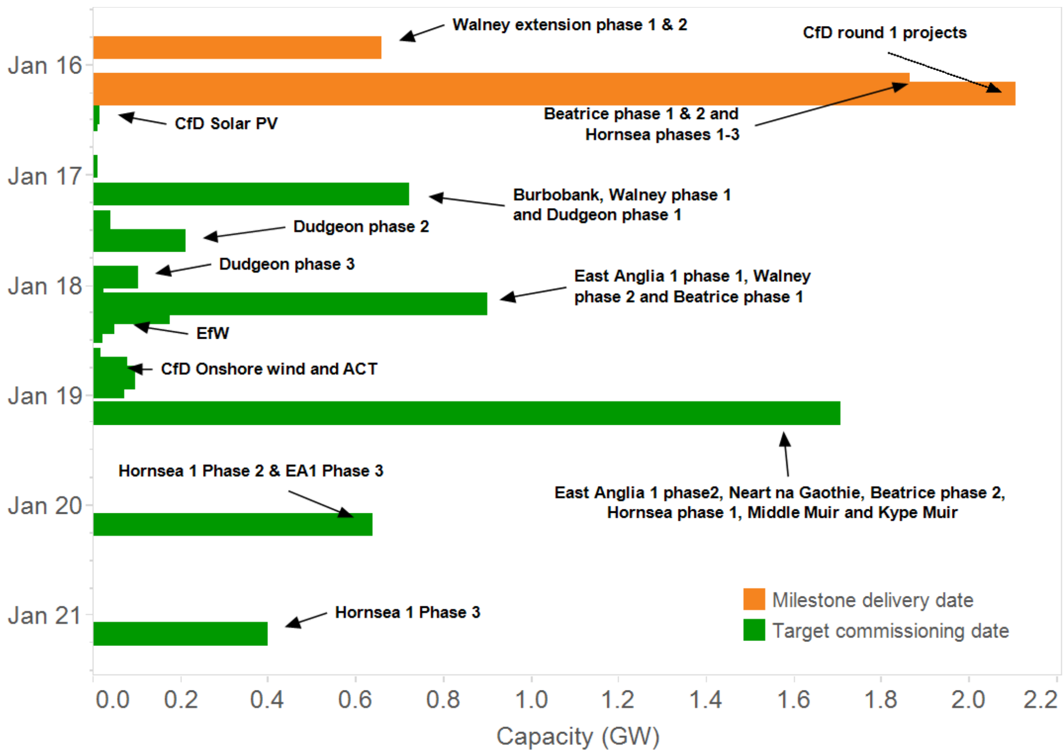
159 Both DONG Burbo Bank Extension offshore wind farm and Statkraft/Statoil's Dudgeon offshore wind farms met the MDD requirements in May 2015.

rather than later would potentially force them to lock in more expensive contracts, thus increasing overall costs. **We acknowledge the value of this observation, however, we would recommend gathering more evidence from real projects before concluding that any action is required for solar units.**

6.239 For projects contracted under the FID Enabling for Renewables and the October 2014 round of the CfD, the earliest evidence that Milestones requirements create wide-spread issues may be seen in the first quarter of 2016, when all CfD first round projects and two FID Enabling for Renewables offshore wind farms will reach their MDD.

6.240 Figure 20 provides an illustration of the anticipated timescales for projects contracted to date. In this chart we have included two key contractual stages differentiated by colour: Milestone Delivery Date (MDD) and the Target Commissioning Date (TCD). While the beginning of 2016 is critical for the MDD requirements, the 2017-19 period is for the Target Commissioning Date. Between March 2018 and March 2020, 68% of the capacity will reach its Longstop Date.

Figure 20 – Capacity at the different strategic dates (monthly resolution)



Assumptions and data sources

1 MDD is set to 12 months from signature for all projects with the exception of Beatrice, Walney Ext. and Hornsea 1, which negotiated an extension to 23, 19 and 23 months, respectively

2 Capacity is assumed equal to their maximum contracted capacity at all stages

3 TCD as per CfD Register

4 LSD as per technology-specific parameters

6.241 Over the next few years DECC will need to take on board LCCC's learnings about how projects move through the various contractual stages and observe whether substantial issues arise. **This experience could then be used by DECC to identify whether any improvements could be made to future CfD contracts to avoid such issues happening in future.** Current contract provisions may also be reviewed in the event project and/or technology circumstances change.

Offtaker of Last Resort may offer benefits to the financing process of future CfD projects

6.242 The Offtake of Last Resort[160] (OLR) was designed to provide eligible renewable CfD generators with a guaranteed 'backstop' route-to-market at a specified discount to the market price. By guaranteeing access to the market at a specified price, the OLR aims (in conjunction with the CfD top-up payments) to give comfort to lenders and investors over route-to-market risks, including the worst-case price that the generator will receive for its power. This would enable generators to access a wider range of counterparties and contracting strategies, including shorter term PPAs or PPAs with less established counterparties. The ultimate objective was for DECC to reduce the barrier to investment and enabling the competitive benefits to reduce the cost of renewable investments.

6.243 The OLR will be implemented by placing an obligation on certain suppliers (and a right on all other licensed suppliers meeting the minimum credit requirements) to bid to enter into a one-year Backstop PPA with an eligible independent renewable generator, when requested. The costs (or profits) incurred by the winning bidder on taking on the generator's power would then be levelised across all licensed suppliers.

6.244 When the Government launched a Call for Evidence in 2012, we had already observed a general deterioration of the market for power purchase agreements (PPA) for a number of years. At the time, appetite of traditional offtakers, in particular large integrated utilities, for participating in tenders was relatively poor. Stricter accounting rules applied by rating agencies had also reduced the ability of some of these organisations to offer floor mechanisms, which in most cases were essential for a contract to be considered bankable by lenders to renewable projects. Additionally, greater uncertainty around the future GB electricity market in light of the EMR reform (ie introduction of the Capacity Market and the phasing out of the Renewables Obligation), the Balancing Significant Code Review and Ofgem's liquidity project had increased the level of risk perceived by offtakers. **Overall, independent renewable generators were still able to put in place a route-to-market agreement, however they could choose from a limited pool of competitive and/or bankable PPAs. This was understandably a major concern for these organisations as they perceived a potential barrier to investment**.

6.245 The Government gathered evidence from the market and set to identify an appropriate policy that could mitigate the risk of under-delivery and non-cost-effectiveness of renewables investments. The Offtaker of Last Resort was the result of this process. Work on OLR started in 2013 and details of eligibility and terms were announced in 2014, in time for the first CFD allocation round. Ofgem published guidance for generators and suppliers in 2015 and will be able to allocate backstop PPAs later that year, in time for first generation under CFDs.

6.246 In our role as professional advisors, we had already seen signs of recovery in early 2013. Both liquidity and pricing structures had improved and a number of new offtakers, in particular aggregators, had entered the market. This trend became stronger during the course of the year, and it became clear that the hiatus in the PPA market was only temporary. **While we believe DECC's policy response was justified in light of the available evidence, the timing of reaction was too slow to be useful to address the deterioration of the PPA market at the time.**

6.247 **Going forward, its usefulness in tackling route-to-market issues may be relatively limited, as conditions have considerably improved.** Shorter term PPAs and a more diverse pool of offtakers, which are not necessarily of the same credit standards as the traditional providers, have emerged independently from the implementation of the OLR.

160 https://www.gov.uk/government/consultations/implementing-the-offtaker-of-last-resort

However, this mechanism may facilitate the consolidation of these trends and offer benefits with respect to the financing process.

6.248 Industry shares the opinion that the Backstop PPA is in principle a valuable instrument, but there is no consensus on its practical value and agrees it is too early to draw any conclusion on its effectiveness. Stakeholders acknowledge that the unattractive commercial terms would discourage generators to use it as a default arrangement, therefore it will be used a last resort mechanism as intended.

6.249 From discussion with lenders, we found that there is some interest in exploring how to use the Backstop PPA to facilitate the financing, and potentially to improve the terms. However, the importance of contracting with a creditworthy party is not diminished and the OLR may not relax the requirements. Additionally, the aggressive discount may potentially make the Backstop PPA less interesting from a debt-sizing perspective to technologies with lower strike prices, given the lower proportion of total revenues that is expected to be recovered from the CfD rather than from the wholesale market.

6.250 In any case, liquidity of the current PPA market is not really a concern to lenders to a CfD project and the existence of a floor mechanism in a PPA is not a prerequisite for bankability. Their main concern in terms of route to market is the project's ability to achieve a back-to-back offtake agreement that reflects the power indexation of the CfD payments and whether the basis risk is a material risk.

6.251 In the next months, **evidence on the evolution of the CfD PPA offering is likely to emerge from real life projects. Terms of these arrangements and general market liquidity should be monitored by the Government. Additionally, we recommend DECC to maintain a dialogue with the financial community in order to attest whether the OLR is practically used as a reference in the financing process.**

Operation

6.252 This section assesses what happened in the first CfD allocation round. It looks at the execution of the CfD design details, including the appeals, eligibility assessment and allocation processes. It discusses areas which worked well such as the role of the National Grid (in its role of Delivery Body) and IT systems. However, it also raises areas to be improved such as communication, treatment of confidential information, late changes to the available budget and handling of speculative auction bids.

Allocation process needs to be streamlined to increase certainty for participants

6.253 The current allocation timeline is structured around five key phases:

- **1. Application –** Applicants apply to National Grid, submitting evidence to demonstrate they meet the eligibility criteria. National Grid assesses whether applicants meet the eligibility criteria and informs applicants of their decision.
- **2. Review –** Applicants deemed not to meet the eligibility criteria by National Grid, have the option to request a review of their application by National Grid (Tier 1 dispute). National Grid can only review the previously submitted evidence.
- **3. Appeals –** Applicants have the option to appeal further to Ofgem (Tier 2 dispute). Ofgem determine the outcome of the qualification appeal as soon as practicable. However, the auction can proceed whilst the outcome of any appeal is pending[161]. Applicants can appeal further to the court[162] (Tier 3 dispute).

[161] Regulation 49, http://www.legislation.gov.uk/uksi/2014/2011/pdfs/uksi_20142011_en.pdf
[162] "The court" means—(a) the High Court; or (b) in Scotland, the Court of Session.

- **4. Auction –** The auction can proceed whilst the appeals process is on-going if necessary. Applicants submit their auction bid and flexible bids if applicable.
- **5. Contract Signature –** Once the auction is completed, the LCCC issue the CfD Contracts to the successful applicants.

6.254 We acknowledge that overall the first allocation round was run without any setbacks and was completed within the timescales defined in the both the allocation round notice and the revised notice. All the different allocation round phases were performed within the maximum time limits, in some cases faster by all the CfD bodies: National Grid, Ofgem, the Independent Auditor and the Secretary of State. The sealed bid submission window was actually opened in advance to the latest date announced under the Tier 2 appeal scenario as Ofgem completed the appeal process sooner than the allocated 30 days[163].

6.255 **Timeline too long and uncertain –** From the stakeholder research a general consensus emerged that the process proved to be too long and uncertain under the current framework. It was not clear when and what dates could change and how much notice would be provided to applicants. For example the allocation round notice published by DECC on 29 August 2014 stated a commencement date for the allocation round as 14 October 2014[164]. However, a variation notice was later published on the 26 September changing the commencement date of the allocation to 16 October 2014[165].

6.256 Furthermore, the indicative timetable for when the auction round would commence was spread over a two and half month period due to the unknown length of the review and appeals process. Therefore it was difficult for applicants to ensure that they were ready and available to submit their auction bids at the correct time. Larger organisations could have more complex sign-off procedures before a submission could be made and smaller organisations could have more limited staff availability to submit the necessary information.

6.257 **Proposal to run allocation pots separately –** The consultation published in March 2015 by DECC on changes to the CFD Contract & CFD Regulations proposed to run each pot as a separate allocation round. This measure is procedural as it would not amend the frequency of allocation rounds, the budget setting process or the overall structure of the allocation process. However, it offers the opportunity to minimise the delay for at least one pot in the event that no appellants are applying in that pot.

6.258 However, there are drawbacks with this proposal which need to be considered. Running the two pots separately could create inefficiencies by doubling up the work to be performed by National Grid, the Independent Auditor and the Secretary of State. Additionally, it is possible that a number of developers will apply for CfD units in more than one pot. This could create practical inefficiencies as well as influence the bidding process for the auction or auctions that is/are delayed. Securing or not securing one CfD in an earlier auction may influence the cost opportunity that gets priced into a later auction bid or bids.

6.259 Overall this proposal does not resolve the real problem, that the number of reviews and appeals are not known from the outset of the allocation round and neither is the length of time that these appeals will take to resolve. The proposal to allow each pot to be run as a

163 23 January 2015 was originally set as target date for completion of Tier 2 disputes. This process was actually completed in advance of the maximum 30 days with the sealed bid submission window opening on 29 January 2015 instead of 3 February 2015.

164 https://www.gov.uk/government/uploads/system/uploads/attachment_data/file/348201/The_Contracts_for_Difference__Allocation__Regulations_2014_-_Allocation_Round_Notice__29_August_2014_.pdf

165 https://www.gov.uk/government/uploads/system/uploads/attachment_data/file/358727/CFD_Allocation_Round_Variation_Notice.pdf

separate allocation round should be considered as a transitional measure only until a long term viable solution is identified.

6.260 **Our recommendation is to separate the appeals process from the auction itself and for a continuously rolling application process to be introduced.** Under the current allocation process applicants can deliberately submit a non-qualifying application, request a review and an appeal which delays the entire allocation round. Instead there should be a rolling application process with a clearly defined date by which applications should be submitted and all reviews and appeals resolved in order to be eligible for the allocation round. If an applicant misses the deadline then their application will move into the next allocation round. This would mitigate the risk of delays to all participants in the allocation round in the event of a review or appeal by just one single applicant[166].

6.261 The different dispute levels of review to National Grid (Tier 1 dispute) and appeals to Ofgem (Tier 2 dispute) should be maintained along with the ability for applicants to request a review or appeal without the risk of incurring a cost or penalty. The ability for applicants to request confidential reviews from National Grid should be maintained as under the current rules the outcome of appeals and appellant details will always be published by Ofgem.

6.262 We discussed this proposal with respondents as part of our evaluation process and we received positive feedback on this proposal. However, this is just a high level proposal at this stage and further feasibility analysis by DECC is needed. Its benefits also need to be considered within the context of the wider need for visibility on CfDs in terms of allocation round frequency, budget etc.

Last-minute changes to the available budget for Pot 2 created uncertainty and gave the impression DECC was 'picking the winners'

6.263 On 28 January 2015, the day preceding the bid submission window, the Secretary of State (SoS) issued a Revised Budget Notice, which increased the funds available to Pot 2. The SoS acted legitimately and in compliance with the CfD Regulations, which give the Government the opportunity to revise the budget upwards after the commencement date of the allocation round.

6.264 The letter was drafted in compliance with the requirements of the CfD Regulations[167] and was not accompanied by any explanatory note providing the rationale as to why the change was required and/or desirable by the SoS. We understand from communication with DECC officials that this decision was prompted by a reassessment of the Pot 2 pipeline since the release of the Final Budget Notice in October 2014, but no communication was given to the market.

6.265 Budget revisions produced when an allocation round is live, and in particular, so close to the bid submission window, may have two major consequences, both of which were consistently mentioned during our discussion with stakeholders:

- They introduce uncertainty as to the exact amount of budget that the Government means to allocate and how the Final Budget can be used as a reference for participation and formulation of bidding strategies.
- They may send out the wrong message that the Government is cherry-picking winners.

166 Obviously, this assumes that DECC is in the position of providing visibility on the frequency of rounds, and the likely level of budget available for future rounds, in aggregate as well as some visibility on near term ones.

167 Regulation 11-13 of the Contract for Difference (Allocation) Regulations 2014 on Budget notices, revisions and revision notices.

6.266 With respect to the first point raised, auction participants may find difficult to incorporate the new information in their bidding strategies at such a short notice before the auction submission window. In our experience, the analysis, which underpins the formulation of a bidding strategy, is undertaken well in advance of the actual submission window. Revising such a fundamental assumption, like the available funds, may lead to different bidding strategies. Last-minute changes – despite they can only be positive, thus welcome by participants – may prevent bidders from being able to examine carefully their strategy and adopt a legitimate strategy. DECC should be particularly attentive to avoid speculative bids[168] led by poor due diligence.

6.267 In terms of the second issue, the fact that the revision affected Pot 2 raised questions around the Government trying to cherry pick specific projects. No information on the identity (or technology) of applicants is released by National Grid, however, the Secretary of State (SoS) has visibility on the large projects that obtained a Supply Chain Certificate, thus are likely to participate in the auction. There is no evidence that the SoS increased the budget in the CfD first round to enable specific assets, but the process would indeed benefit from a higher degree of transparency. Transparency with the budget setting process is also discussed in section starting with paragraph 6.48.

6.268 We acknowledge that the Government may want to retain flexibility as a policy lever for as long as possible in the process. However, **budget revisions should be used as an exceptional measure during the live process.**

A limited number of applicants appealed, none of the National Grid's decisions were reversed by Ofgem

6.269 Three applicants in the first CfD allocation round appealed to Ofgem following National Grid (in its role of Delivery Body) decision that they were not eligible to participate in the first CfD allocation round. Ofgem assessed the appeals against the CfD allocation Regulations[169] and issued their determination on the three appeals on 19 January 2015. Ofgem upheld National Grid's decision in all three cases, a fuller explanation of each case is given on Ofgem's website, below we provide a brief summary:

- OSPRE[170], advanced conversion technology – at the time of submission OSPRE had not signed and returned the acceptance of its grid connection offer and transferred the specified funds necessary to proceed with the connection. National Grid determined that this did not constitute a grid connection agreement. OSPRE appealed arguing that this did constitute a connection agreement within the Regulations, and that the error in question was a mere "foot-fault" which had subsequently been cured.
- Drenl Limited (Drenl)[171], solar PV – failed to provide a countersigned connection agreement in their application. Drenl appealed that they had made a simple mistake in submitting an unsigned copy of their connection offer, and that at the time of their application they did hold a connection agreement.
- Swindon Solar Farms (SSF)[172], solar PV – CfD application was deemed non qualifying on the grounds that the connection agreement and planning consents provided did not meet the qualification requirements. The decision on the connection agreement was not upheld by National Grid. SSF appealed in relation to the planning consents on the grounds they had provided minutes from a meeting which indicated a planning officer's recommendation to the Planning Committee that permission be granted in December 2013. However, the project had later been subject to a Public Inquiry held in

168 Speculative as defined in section starting with paragraph 6.392.
169 http://www.legislation.gov.uk/ukdsi/2014/9780111117316/contents
170 https://www.ofgem.gov.uk/ofgem-publications/93298/determinationospre201501-pdf
171 https://www.ofgem.gov.uk/ofgem-publications/93299/determinationdrenl201501-pdf
172 https://www.ofgem.gov.uk/ofgem-publications/93300/determinationssf201501-pdf

September 2014 as a result of the planning application being called-in by the Secretary of State in April 2014. SSF appealed arguing that it had delivered on every element to generate a timely planning consent and the call-in procedure was not in its control. Additionally, SSF did not provide the required appeal information within the five working day limit. However, this did not impact the outcome of the appeal.

6.270 These are not necessarily the only applications that failed to make it to the bid stage, it is possible there are other applications that were rejected, but did not go to appeal.

Consideration should be given to measures that could avoid the potential to over penalise minor indiscretions

6.271 We have the following observations on the public information about the appeals:

- All the appeals were from smaller companies;
- This is a new scheme so there is no previous experience of applying for CfD to learn from other's mistakes or experience gained within organisations;
- There were individual reasons why the applicants found themselves in a non-qualifying situation beyond simply deciding not to submit required information; and
- Two of the companies who appealed argued that discretion should be exercised. This is also implicit in the third appeal.

6.272 We also note that under the current system the penalty for not meeting the eligibility criteria is not competing in an allocation round. In some circumstances this could be the end of the project.; and

Although companies argued that discretion should be exercised, there is currently no potential for National Grid or Ofgem to exercise discretion to take account of individual circumstances within the current legislation. DECC deliberately did not include discretion in assessing the qualification criteria within the CfD Regulations and this is consistent with its general approach under the CfD that the onus is on the applicant to correctly meet the requirements.

6.273 We recognise the value of an approach that does not allow discretion because it can make implicating the legislation less clear cut and could be open to abuse. **However, given the kind of issues raised by the applicants that appealed, and the penalty that could result in loss of a project, it seems feasible that a situation could occur where a project developer is disproportionately penalised for a minor error made against the qualification criteria**[173].

6.274 If developers feel either they or others have been unfairly treated, it potentially erodes trust in the authorities responsible for the CfD, and effective information flow, to aid future policy development.

6.275 **We recommend that DECC consider whether there is potential for projects to be over penalised; and if so how it can mitigate the potential for projects to be over penalised for minor indiscretions including further education of stakeholders and the potential to introduce a very limited degree of discretion into the eligibility assessment.** The specific circumstances in which discretion could be exercised would need to be made clear so that it was only exercised where minor accidental errors have been made[174].

[173] This view was shared by stakeholders who either had projects that did not reach the bid stage or were familiar with the circumstances of such projects. This information did not cover all projects not reaching bid stage.

[174] An example of where such discretion has been made to work is under the Renewables Obligation in relation to late data, which ordinarily would result in no ROCs being issued to the generating station for that month.

6.276 Introducing a rolling application process, as discussed in paragraph 6.253 below, should help reduce the extent to which such discretion would need to be exercised, as it would allow projects to respond to requests for further information required to qualify before the cut-off date for auction qualification. However, National Grid has no obligation to check applications prior to the cut-off date, and so picking up such information cannot be relied upon.

6.277 The introduction of more frequent allocation rounds discussed in the section starting with paragraph 6.164 would also help by lessening the implications of not qualifying for an allocation round.

Communication protocols with National Grid should be tightened to increase robustness of the application/auction processes

6.278 Some scepticism was raised by participants to the first round about practices adopted by National Grid in communicating with applicants. In particular:

6.279 **Confirmation of receipt** – The IT systems used in the First Round do not provide sufficient assurance that the information submitted for the application and the bid submission phases is duly received and correctly stored on the IT systems for use in the allocation process. It would be beneficial, for instance, if the confirmation email sent to participants not only confirmed receipt, but also provided some form of assurance that the information is readable, storable and reflective of the data submitted by the participant. **In the event an online portal is implemented for the October 2015 round, it should be relatively easier to offer participants the option to verify that the IT systems correctly stored the submission via a secured account at any point during the process**[175].

6.280 **Verbal communication** – It possible that participants may decide to contact National Grid to discuss and/or verify information in relation to their application or bid submission. Anecdotal evidence from discussion with stakeholders suggested that no process was followed to verify whether the person making contact was actually an authorised representative of the specific CfD unit they were inquiring about. We understand from National Grid that a formal procedure is in place to confirm only authorised representatives are engaged in a dialogue regarding a unit and that under no circumstances confidential details are exchanged during a telephonic conversation. Based on the anecdotal evidence, however, it is possible that a more robust level of verification could have been implemented primarily to avoid misperceptions. **As for the confirmation receipt above, the new IT systems may allow to overcome any weakness in the verification protocols thus preventing any residual risk of irregularities and/or anti-competitive behaviours**.

IT systems worked satisfactorily

6.281 The first round allocation had no major technical setback and participants did not find the systems particularly difficult to use with the exception of initial delays in delivering the platform. The Excel-based spreadsheets utilised both for the application and for submitting of the bids assisted bidders with validation and pop-up messages to verify whether the information entered was completed or compliant with the rules of flexible bids.

6.282 A number of parties, however, experienced some issues with the file for bid submission. The spreadsheet was rejecting entries that were technically correct and it took a series of trials before these entries could be validated. Under similar circumstances, it is possible

[175] See implementation of the National Grid's EMR Administrative Portal, which is expected to go live in June 2015.

that participants with less consolidated knowledge of the rules could have been misled by the error messages and given up on those legitimate bids.

6.283 We understand that National Grid is undertaking a restructuring of the platform, which supports the application and bidding process for the CfD, and that this platform will be operational in time for the October 2015 round. So these minor issues are not relevant going forward. It is worth noting that most of the stakeholders expressed a preference for an online system over the Excel-based tool utilised in the first round.

Treatment of confidential information related to the allocation process needs to be clear

6.284 While it was industry that strongly lobbied for strict confidentiality measures on bid information, which resulted in stringent regulations imposed on the dissemination of information by National Grid, we have found numerous parties across the industry did not have a detailed knowledge of these measures. Clarity on what information the Government would be able to access was surprisingly low with the exception of those organisations that had actively engaged with DECC on this particular aspect.

6.285 There was a reasonable expectation that bid information would not to be disclosed to the Government, but despite this numerous parties still assumed that DECC was informed about the identity and nature of participants throughout the process.

Outcome

6.286 This section evaluates the results of the first CfD allocation round. It reviews the auction results in terms of both capacity and strike prices awarded. It also reviews the level and type of participation in the auction. Inferences on the cost-effectiveness of the outcome are then discussed as well as any evidence of gaming.

The first allocation round was a success, awarding contracts to 2.1GW of capacity

6.287 The first CfD allocation round opened in October 2014 and concluded in February 2015 with the award of CfD Contracts to 27 projects equating to 2,138MW of renewable capacity. The total capacity was distributed as follows: five projects for an equivalent capacity of 1,224MW were secured by less established technologies in Pot 2, while 22 projects for an equivalent capacity of 915MW were awarded to established technologies in Pot 1, two of which[176] withdrew leaving 882MW after the signature stage. These 25 projects were added to the eight that were awarded under the FID Enabling for Renewables programme for an additional 4.5GW of capacity (including Biomass Conversion awaiting for State Aid clearance)[177]. All these projects are graphically represented in Figure 21 below.

[176] Two solar PV projects – Wick (19.1MW) and Royston (13.78MW) solar parks developed by Hadstone Energy Ltd. and Royston Solar Farm Ltd, respectively – were awarded a contract, but decided to withdraw before signature.

[177] These eight projects were awarded a CfD Investment Contract: MGT's Teesside (299MW) dedicated biomass with CHP unit, Drax's Drax 3rd Unit (645MW) and RWE's Lynemouth (420MW) biomass conversion units; SSE's Beatrice (664MW), DONG's Burbo Bank (258MW), Walney (660MW) extensions and Hornsea 1 (1,200MW) and Statoil/Statkraft's Dudgeon (402MW) offshore wind farms.

Figure 21 – Geographical distribution of CfD Contracts by technology

Auction was oversubscribed

6.288 The first competitive allocation was successful both in terms of the number of awarded contracts and the number of applicants. While the total number of applications made in the first allocation round was not made public, National Grid disclosed that the total value of all applications received was £1,176.3 million based on the administrative strike prices (ASPs).

6.289 This suggests that only around 36% of the projects[178] were successful in securing a CfD Contract. Although it is not known how this ratio changes at pot level, based on our conversation with stakeholders and our understanding of the pipeline, we are comfortable to conclude that both pots were oversubscribed.

Achieved strike prices were at considerable discount to the ASP

6.290 A possible indication of the competitive tension in the allocation can also be found by comparing the achieved strike prices with the corresponding administrative strike prices. Across all technologies – with the exclusion of the ‘infra-marginal ones[179] – the difference with the ASPs is considerable.

6.291 For example, Neart na Gaoithe offshore wind farm cleared at £114.39/MWh which was around £25/MWh below the administrative strike price of £140/MWh for the delivery year 2018/19. All three solar PV projects[180] for the delivery year 2016/17 obtained a strike price

[178] Based on anticipated spent as per auction valuation formula.

[179] The ASP set the strike price for 4% of the successful capacity: two Energy-from-Waste projects (~100MW).

[180] These are REG’s Netley Landfill (12MW), Lightsource’s Charity Farm (14.67MW) and Cambridgeshire County Council’s Triangle Farm (12MW) solar parks.

equal to £79.23/MWh, which is just above £40/MWh discount to its ASP of £120/MWh, while onshore wind with the same delivery year cleared £20/MWh below its ASP[181].

6.292 While one of the possible interpretations is that the administrative strike prices were set too high, we would conclude that competition for CfD Contracts dictated by the oversupply of applicants was strong. This is based on general knowledge of project costs and our conversations with participants, where they provided some insights on how their bids were formulated (see paragraph 6.313).

6.293 **Independently from any considerations about deliverability of achieved strike prices, competition enabled the first CfD allocation round to secure significantly more capacity within the same budget than would have been possible if DECC had proceeded under a first-come-first-served basis[182].**

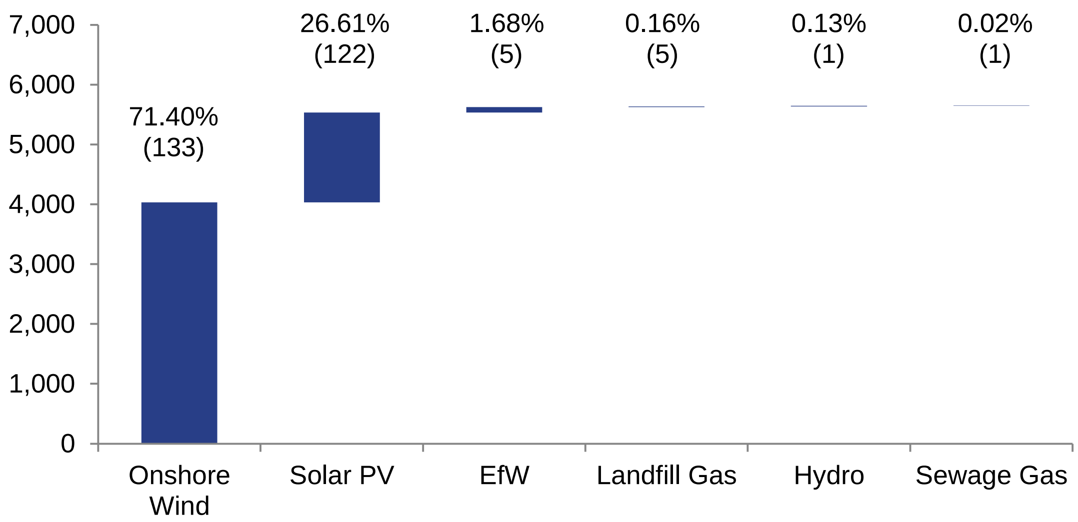
Participation levels are unknown but appear to have been high

6.294 As mentioned above, National Grid released no information regarding the nature and number of participants to the October 2014 allocation round. By analysing public information, we have built a pipeline of possible CfD participating projects for each pot. The information does not allow us to differentiate the possible commissioning dates for these projects making it hard to distinguish between projects that would opt for the Renewables Obligation (RO) or for a CfD auction. Moreover it is not possible to distinguish between projects which could participate in the first or future auctions. All projects contained in the pipeline with the exception of small solar PV projects, have likely been developed under the assumption of an RO-based scheme.

6.295 In Pot 1 a total of 267 projects have been identified in the pipeline at different stages of development, 71% of this capacity is onshore wind followed by 26% from solar PV. This distribution is similar to the successful projects in Pot 1. In Pot 2 a high dominance from offshore wind projects as a total capacity is expected from the pipeline, however this is fed by only 9 different projects which highlights the lumpiness of possible participating projects in Pot 2 (see Figure 22 below).

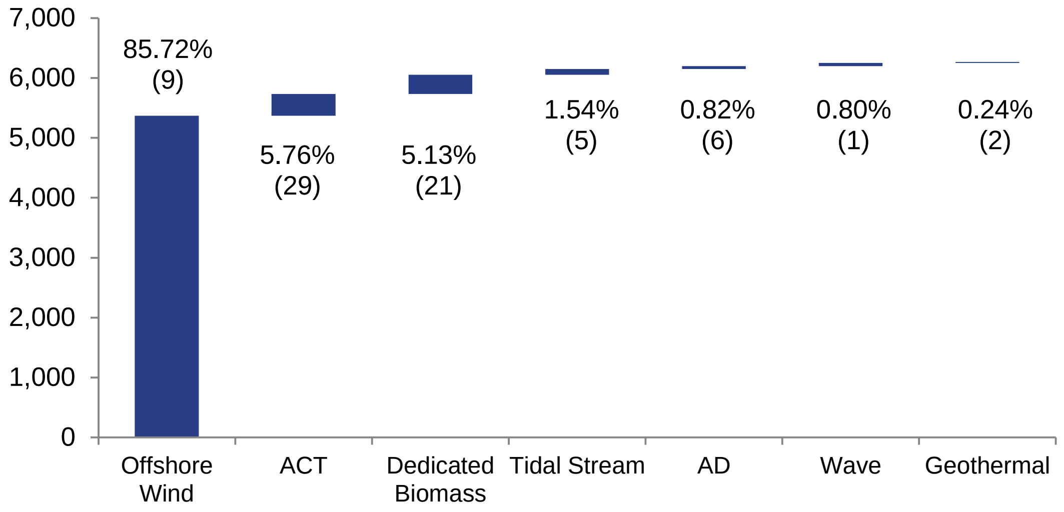
Figure 22 – Distribution and number of projects in the pipeline by technology

Plot 1



181 This is Brenig Wind Farm (45MW).
182 Based on an equivalent budget, but with contracts awarded at administrative strike prices.

Plot 2



6.296 During the parallel running of the CfD and the RO, it is believed that many of the projects identified in the pipeline will either: apply for the RO only, apply to the CfD only, attempt to secure a CfD and if failed secure support under the RO. The proportion of projects under each scenario is not known.

6.297 As mentioned earlier, the total value of all received applications evaluated at ASP by National Grid was £1,176.3 million; this suggests that roughly one in three projects that participated in the first auction were successful. Assuming that proportions of cleared projects between Pot 1 and 2 are reflective of the application levels to the allocation round, we could expect Pot 1 to have had an 375% more applications than budget while Pot 2; 300% more (evaluated at ASP). If this could be verified, it would suggest that both pots had high levels of participation.

Eligibility criteria were sufficiently practical to allow a competitive first allocation round

6.298 **The qualification requirements were workable in so far as they did not prevent a competitive first allocation round.** Successful projects were larger than the average pipeline project and did not reflect the full range of technologies see paragraphs 6.301 to 6.303. This could be due to a number of reasons, of which the eligibility criteria are just one - see paragraph 6.78 on potential barriers to smaller projects, and paragraph starting 6.450 on potential technology specific barriers - most of which do not appear to be a consequence of qualification requirements. **Only once the following are known:**

- **which projects felt able to participate eg unsuccessful participants as well as successful participants;**
- **which contracted projects successfully commissioned; and**
- **evidence of a pipeline of projects built up after the introduction of competitive allocation**

can a proper judgement be made on the effectiveness of the qualification requirements and other anti-speculative measures in achieving the appropriate balance between barriers to entry and preventing speculative projects.

DECCs objectives in setting the budget were generally met

6.299 Below we briefly describe the outcome of the auction against DECC's budget setting objectives:

- Managing risks to departmental finances – DECC projections of Levy Control Framework (LCF) spend, at the time of writing, following the first allocation round are that it will be within the LCF caps. Any comment on the validity of these projections was out of scope of this report.
- A credible CfD scheme and successful auction – Pot 1 and 2 were competitive and 2.1GW of capacity was allocated contracts.
- Managing State Aid risk – Capacity allocation is in line with majority competitive allocation for 2017/18, recognising the capacity of projects granted a grace period under the RO is unknown. No projects signed a contract for delivery in 2015/16 and 84MW is contracted for delivery in 2016/17. This means that the 5% threshold will be met from 2016/17 if current rates of deployment remain the same.
- A steady flow of investments – There is no firm target for this, there appears to be sufficient onshore and offshore wind, however, the small number of successful solar PV projects, and no successful biomass CHP projects could present a 'boom' 'bust' issue for these technology if the number of successful projects does not increase in future rounds.
- Enabling later projects to get funded – Under projections, at the time of writing, there appears to be funding remaining in the pot to enable support to be offered to future projects.

In addition budgets were set at a sufficient level to keep the UK on target towards electricity's contribution towards the 2020 renewable energy target, see Annex B.

There was limited diversity among the successful projects

6.300 CfD contracts were primarily awarded to wind projects, larger developers and larger projects. This is discussed further in the section starting with paragraph 6.301 and 6.303 respectively. The extent to which we expect this to continue in the future is discussed under section starting paragraph 6.384.

Wind was the dominant technology in the first allocation round

6.301 The technology that secured the largest amount of capacity from the first allocation round was offshore wind at 55% (1.2GW) followed by onshore wind at 35% (0.75GW). The contribution of the other technologies were:

- ACT – three projects with a combined capacity of almost 62MW;
- EfW CHP – two projects with a combined capacity of almost 95MW;
- Solar PV – five successful projects, but two of them did not sign their CfD Contract, leaving only 38MW of solar PV.

6.302 The first CfD allocation round offered contracts to five technologies, this compares to 13 technologies being eligible to access the budget[183] and 11 different technologies with planning permission at the time of the first allocation round.

Larger projects were most successful

6.303 There was a wide range of project sizes that were successful in the first allocation round from 6MW to 714MW. To identify whether successful projects represented typical project sizes for their technology we have compared average technology sizes for recent RO

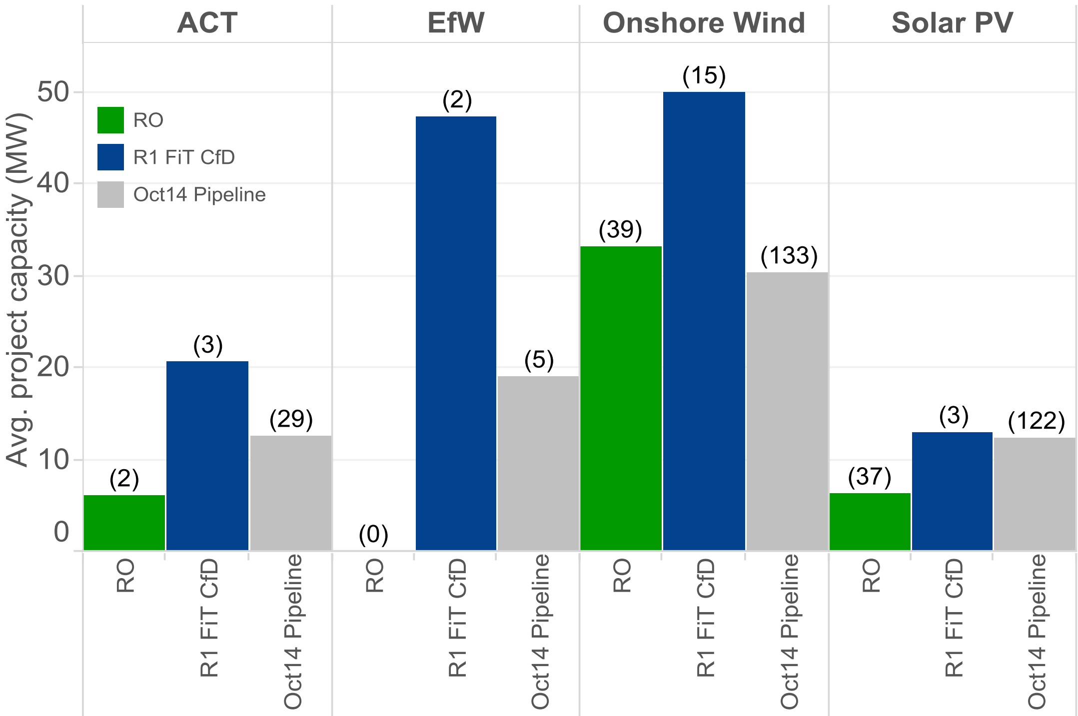
[183] Strike prices are also set for biomass conversion and remote islands wind, these technologies are not included able to access figure as they were not able to access support in the first allocation round.

projects[184], CfD and pipeline. The pipeline taken was all eligible technology projects with planning permission that were not operational or under construction at the time of the first allocation round[185]. We have only compared technologies that were successful in the CfD and have excluded offshore wind as these projects are complicated by phasing.

6.304 The average size of a successful project was higher under the first allocation round than under the pipeline or recently commissioned under the RO, as might be expected due the economies of scale larger projects can achieve. This is best represented by onshore wind as the largest number of successful projects uses this technology. However, the other technologies mirror this result.

6.305 The pipeline is a helpful comparator at this stage as most of the projects are likely to have been developed on the expectation of the RO. The solar PV pipeline figure should be treated with caution as the turnaround time from planning permission to commissioning tends to be shorter than for other technologies, and so projects are more likely to have been developed on the expectation of the CfD (see Figure 23 below).

Figure 23 – Average capacity of projects in the pipeline



Large organisations gained the majority of CfD contracts

6.306 Utilities obtained the largest share of the CfD Contracts accounting for 41% of all CfD projects from the first allocation round. Large independent developers followed with 31% of the capacity to be commissioned. The dominance of larger market players is more prominent in Pot 2 where medium and small developers obtained only 5% of the

184 Recently operational RO projects cover those that became operational between April 2011 and March 2014. Three years were chosen to provide more of a 'typical' trend than a one-off year might offer. It is also broadly similar to the timescales over which contracts for delivery under the first FiT CfD allocation round was offered. Data for 2014/2015 was not available at the time analysis was undertaken, so the previous three years were chosen as the most recent. Projects that could have been eligible under the ssFiT were not included.

185 This was taken from the DECC's Renewable Energy Planning Database.

contracted capacity. Conversely, in the established technologies pot, medium and small developers obtained 57% of the contracted capacity.

Sufficient capacity was contracted to keep the UK electricity sector on track to meet its contribution to renewables and decarbonisation targets

6.307 The CfD appears to have secured sufficient capacity to keep the UK on track to meet electricity's contribution towards its 2020 targets, see Annex B. **Whilst it is possible this could be achieved without any further CfD rounds, further CfD rounds for delivery prior to 2020 are recommended** for the following reasons:

- it is not certain given the potential for demand, capacity commissioned and load factors to differ from those currently assumed;
- exceeding the minimum contribution required from the electricity sector to meet the 2020 targets will allow for some compensation, should heat or transport's contributions prove more challenging; and
- to ensure a smooth build out to 2030 and beyond in line with 2050 decarbonisation targets.

The first CfD allocation round appears to have provided greater value for money than the RO

6.308 The CfD appears to have delivered against its objective of reducing the cost of subsidy to consumers compared to a scenario where the same projects were accredited under the Renewables Obligation (RO).

Competition was the main driver in achieving value for money under the first allocation round relative to the RO

6.309 In Figure 24, we compare the cost of subsidy of the CfD contracts awarded a contract in the first round under three scenarios:

- CfD Competitive Auction – cost of projects is calculated based on the CfD strike prices awarded in the first round;
- CfD ASP auction – cost of projects is calculated based on the administrative strike prices (ASPs) applicable in the first round;
- Renewables Obligation – cost of projects is calculated based on the 'theoretical' RO-band level at which CfD projects could have commissioned under an extended regime.

6.310 Excluding any potential impact from outturn power prices[186] (light-blue and orange error bars), our assessment of the cost of subsidy under an extended RO and under ASP yields relatively similar results. Given the 'RO minus X' approach in setting the ASPs, this is not surprising (see section starting with paragraph 6.86). However, when actual CfD clearing prices are taken into account, the estimated cost of subsidy is considerably lower. This seems to suggest that the competitive nature of the process was the key driver in delivering a better value for money, not the change in structure[187] of the regime.

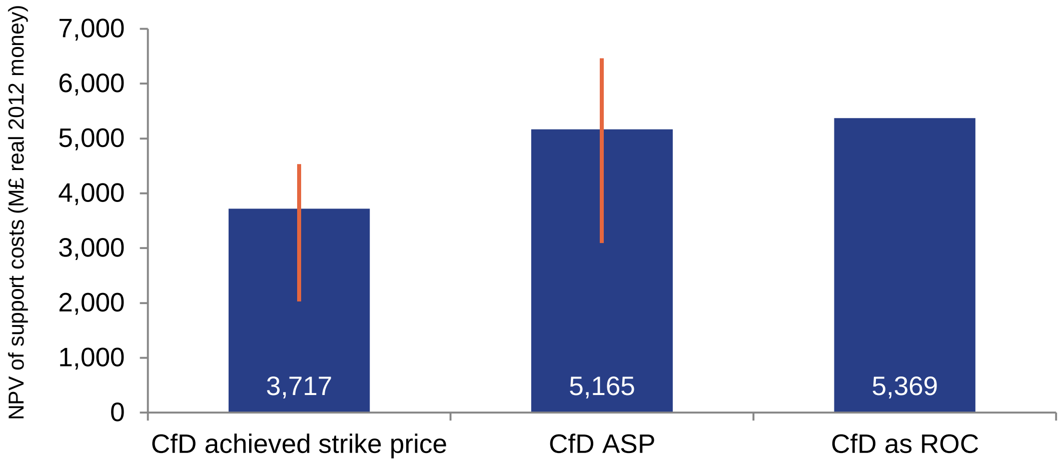
6.311 In the chart, we also indicate the potential impact of fluctuations in power prices on the cost payable by consumers in the form of subsidies. The cost of the RO is not directly linked to the underlying price of electricity, whereas the CfD payments are subject to this uncertainty. After consideration of this aspect, the underlying message does not change. In the event power prices were low, CfD payments would rise towards the top end of the

186 Dark blue bars are based on DECC central scenario from the Updated Energy and Emissions Projections – September 2014, converted to 2012 money.

187 The RO was structured as a 'relatively' fixed top-up payment to the price of electricity, while the CfD is a two-way difference payment around the reference price for electricity.

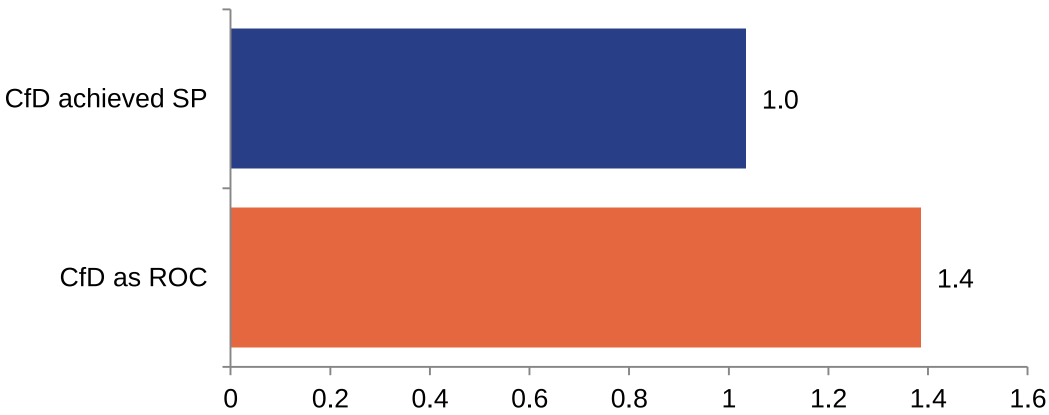
error bar: this level would still be lower than what would be payable under the RO. Under a high prices scenario, the RO cost would remain the same, while the CfD payments would drop providing a sort of compensation mechanism for consumers.

Figure 24 – Difference in support cost between the CfD and the RO



6.312 Figure 25 below compares the subsidy payable to the projects awarded a CfD contract in the first round expressed as a cost per unit of electricity demand under two scenarios consistently with the above assessments (see paragraph 6.309 above): CfD Competitive Auction and Renewables Obligation. The difference in cost per unit of 2020/21 demand[188] that competition seems to have delivered is around £0.4/MWh.

Figure 25 – Cost of subsidy per unit of demand 2020/21



6.313 At this stage, it is difficult to say with a sufficient degree of certainty which were the key drivers of lower strike prices. Based on our stakeholder research, it seems that competition has forced some participants to bid on a sunk development cost basis, others reconsidered achievable margins and/or renegotiate costs throughout the supply chain,

188 Demand assumptions are based on DECC central scenario from the Updated Energy and Emissions Projections – September 2014.

but in general there is a consensus that the constrained allocation has incentivised developers to elicit project efficiencies.

Allocating more of the total budget to Pot 1 would have secured more capacity for the first allocation, but it is not possible to say whether this would have been more cost effective over time

6.314 Greater value for money might have been gained through a smaller budget attributed to the FID Enabling for Renewables scheme. This is discussed further in the FID Enabling for Renewables report.

6.315 Offshore wind is a key technology to achieving Governments longer term decarbonisation targets, and so a steady rate of deployment is required to maintain supply chains and bring down costs. However, relative to Pot 1 technologies, Pot 2 technologies currently expensive[189] – at strike prices achieved in the first allocation round and the reference prices given in the Final Allocation Framework, support is expected to be over double that for Pot 1 technologies.

6.316 To demonstrate the implications for the budget in the first allocation round we use an extreme example, all values given are in real 2012 money. We first assume that the budget allocated to East Anglia 1[190] £155million in 2020/21 was allocated to Pot 1 instead. If this was used to allocate additional contracts to Pot 1 projects equivalent to the generation expected from East Anglia 1[191], and assuming the Pot 1 clearing price rises to the onshore wind ASP[192], it would have saved almost £60million[193] a year from delivery year 2020/21 onwards.

6.317 Had some of this budget been reallocated from Pot 2[194] to Pot 1 it is likely more capacity would have been secured in the first allocation round. However, this would be offset by cost reductions that an additional offshore wind project could bring, and any increase in the strike price for 2018/19. Therefore it is not possible to say whether this would be a more cost effective allocation of budget over time. A clearer view of DECC's ambitions for the future technology mix would enable a better review of whether the allocation of budgets to pots and over time was good value for money whilst meeting DECC's objectives.

6.318 **Re-allocating budget from Pot 1 to Pot 2 would have secured more capacity in the first allocation round, but it is not possible to say whether this would be more cost effective over time.**

Limited opportunity to search for evidence of gaming

6.319 The scope of our evaluation included a review of the auction outcome in search for evidence of gaming and an assessment of anti-gaming measures in light of the evidence.

6.320 As discussed in section starting with paragraph 6.427, access to data related to the allocation process, in particular information related to the bids submitted by participants, was not possible because of the restrictions imposed on National Grid by the CfD Regulations and licence conditions. The only source of evidence that could be used in our

189 We recognise that they are several reasons, see Section beginning paragraph 6.104 to support these technologies and costs reductions are expected in the future.

190 We use this offshore wind farm as it had the higher strike price.

191 Assuming the load factors published in the Final Allocation Framework.

192 The Pot 2 clearing price is assumed to remain as it is, given that no further projects are assumed to have been successful.

193 This figure was calculated based on the NPV.

194 As sufficient budget is required to enable competition and it is important that investors see the success of at least one successful offshore wind project in the first allocation round.

evaluation was information in public domain and any evidence gathered from our stakeholder research, where disclosure would not breach stakeholders' confidentiality.

6.321 With the exception of the two aspects discussed in the following sections – two solar projects awarded a CfD Contract at an unsustainable strike price and Target Commissioning Dates set at the end of a Delivery Period (both based on public information) – **available evidence was not sufficient to perform a robust assessment and to reach any comprehensive conclusion**. For avoidance of doubt, no evidence emerged from our discussions with stakeholders.

6.322 **Regardless of limitations to our evaluation of the first allocation round, we believe that only with experience from several auctions and greater data availability, it will be possible to assess how genuinely competitive the auction processes were in practice.** The governance and institutional arrangements for such a process are discussed in section starting with paragraph 6.417.

Solar PV speculative bids highlighted the need to adjust the valuation formula used in the clearing price algorithm[195]

6.323 As anticipated above, the only clear evidence of gaming we could find – ie a potentially disruptive behaviour that could reduce the efficiency of the allocation and/or produce consequences inconsistent with the policy intent – was the award of CfD Contracts to Wick (19.1MW) and Royston (13.78MW) solar parks developed by Hadstone Energy Ltd. and Royston Solar Farm Ltd., respectively.

6.324 These two units were successful in the first allocation round and were awarded a CfD Contract with a clearing strike price of only £50/MWh for the 2015/16 delivery year. The achieved strike price is below or very close to the reference prices used to value the impact of projects on the available budget, but also to general expectations of future power prices. Effectively the CfD Contract would not provide them with a meaningful top-up payment to the revenues realisable by trading the electricity in the market, and could actually result in payments to the LCCC[196]. Based on these expectations, neither of the two units executed the contract and both are now excluded for 13 months under the non-delivery disincentives.

6.325 It is clear to us that the two solar units submitted strategic bids as the strike prices bid was not sufficient to allow the projects to be delivered. In our view, they might have decided to submit low bids to maximise their chances of obtaining a contract and at the same time assumed that a more expensive bid would set the price for that Delivery Year, thus lifting their achieved strike price above their bid level.

6.326 The consequence of these two strategic bids was the failure to 'deliver' contracted capacity and the exclusion from participating over 13 months. There was also an impact, although small, on the budget available for other units in the allocation round.

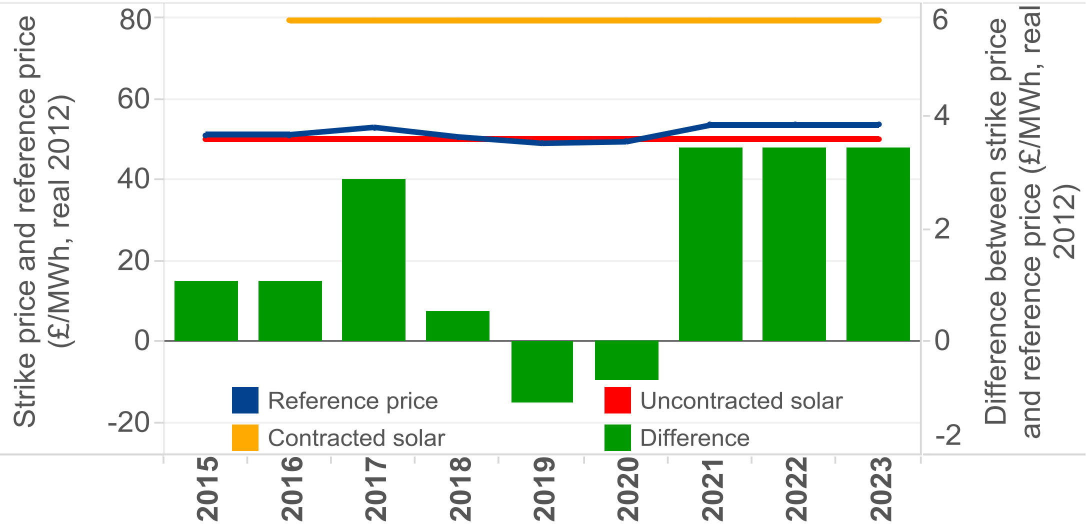
6.327 Because the £50/MWh strike price is below the reference prices in all Delivery Years with the exception of two, this meant that the valuation formula used in the clearing algorithm automatically increased the budget set by DECC by adding the payments that these units were expected to pay back to the LCCC under the CfD Contract. As the algorithm is not built to account for the probability of non-signature of contracts, technically these 'positive contributions' could have led to a different outcome from an alternative scenario where these contributions, or the bids, were discarded.

195 By algorithm we mean all the rules used to determine the winners of an allocation round, such as the valuation formula, the prioritisation of project based on bid price and the annual closure of budget.

196 The CfD Contract is a two-way financial agreement, whereby the generator receives a top-up payment when outturn reference prices are below the strike price, but equally has the obligation to pay back some money to the LCCC when the these prices are above the strike price.

6.328 The following chart plots the strike price (red line) awarded to these two solar PV units ("uncontracted solar") against the power reference prices (blue line) used in the auction clearing price mechanism. We also include the strike price (orange line) awarded to the solar PV projects for the delivery year 2016/17, which signed a CfD Contract at the clearing price of £79.23 ("contracted solar").

Figure 26 – Comparison of strike prices awarded to the "contracted" and "uncontracted" solar PV units with the reference prices



6.329 The spread between the red and the blue line shows the £ per MWh contribution to the overall annual cost of the subsidy. A negative spread – when the strike price (red line) is below the power price (blue line) – means that the algorithm assumes that these two solar PV generators pay money to the LCCC.

6.330 Our calculations indicate that the 'positive budget contribution' of these two solar PV units was around £0.1 million for the year 2020/21, cumulatively £0.2 million across the years 2015/16 to 2020/21. Because of the size and load factors of these projects and the level of the bid, the impact is relatively minimal when compared to the scale of the overall budget in Pot 1 (ie £50 million). Therefore, we believe that there was limited scope for a different allocation, should the positive contributions not be accounted for.

6.331 However, the risk is material. For instance, if those two units had bid above £52.92/MWh, the budget in 2020 would have been breached, potentially leading to a different allocation[197]. Implications could be even worse if units were larger and/or with a higher load factor.

6.332 **Whilst the small budget impact provides some comfort to participants in the first round, appropriate measures should be identified and implemented before future rounds.** DECC should go through a process of assessing the circumstances in which a positive contribution could be made to the budget, whether these are legitimate, and how positive contributions should be accounted for in the valuation formula used in the algorithm to avoid distortions.

6.333 It is worth noting that there could be occurrences when positive budget contributions are a result of genuine applicant bids and DECC needs to be mindful of discounting the value these projects could bring to the overall budget and ultimately cost to consumers. Any corrective action undertaken by DECC needs to account also for these circumstances.

[197] Please note that we were not granted access to bid data, therefore we could not verify the exact impact of the bids submitted or any alternative.

Target Commissioning Date set very close to the end of the Delivery Year may lead to underestimating the budget impact in case projects actually intend to commission earlier

Out of the 25 contracts signed as the result of the first allocation round, we noticed that 11 have set their Target Commissioning Date (TCD) on the last few days of a Delivery Year (see Table 9 below[198]). Because of the data access constraints, we could not verify how wide-spread this behaviour was across all the submitted bids. It is worth noting that also 8 contracts awarded under the FID Enabling for Renewables for a capacity of 2.8GW[199], have set their TCD on the last day of a Delivery Year.

Table 9 – CfD Contracts signed after the first allocation round with a TCD set at the end of a Delivery Year

CfD Contract	Capacity (MW)	Target Commissioning Date	Target Commissioning Window Start Date
Bad a Cheo Wind Farm	29.9	31/03/2019	31/03/2019
Brenig Wind Farm	45	30/03/2017	30/03/2017
Common BarnWind Farm*	**3.15**	**30/03/2019**	**30/09/2018**
EA 1 (Phase 1)	179	31/03/2018	31/03/2018
EA 1 (Phase 2)	285	31/03/2019	31/03/2019
EA 1 (Phase 3)*	250	**31/03/2020**	**30/11/2019**
Enviroparks Hirwaun Generation Site	11	31/03/2018	31/03/2018
Kype Muir Wind Farm*	**104**	**31/03/2019**	**01/03/2019**
Middle Muir Wind Farm*	**60**	**31/03/2019**	**01/09/2018**
Mynydd Y Gwair Wind Farm	40	31/03/2018	31/03/2018
Neart na Gaoithe	448	31/03/2019	31/03/2019
Solwaybank Wind Farm	37.5	29/03/2019	29/03/2019
TOTAL	**12 CfD Contracts (10 projects) for a total 1,495.55MW**		

* Note: these four contracts could receive payments earlier than the Target Commissioning Date as the Start Date of the Target Commissioning Window precedes the TCD.

198 Information is based on the data published on the CfD online register published by the LCCC.

199 These are Beatrice (both phases), Burbo Extension, Hornsea 1 (all three phases), Walney Extension (both phases) based on information released on the LCCC's online CfD Register.

6.334 Some of the bidders may have decided to deliberately set the TCD at that point and then use the flexibility of the Target Commissioning Window (TCW) to accommodate the real project timeline. This would allow them to minimise the budget impact on the relevant Delivery Year, thus minimising the risk of breaching the budget.

6.335 **Setting the TCD so close to the end of the Delivery Year may not necessarily be evidence of gaming as this could be the result of a legitimate project delivery schedule. Additionally, this may not distort results. However, the high incidence of such behaviour among winners (almost one winning project in three) raises some concerns, in particular for future rounds. Evidence available is not sufficient to draw any firm conclusion. However, we would recommend DECC to consider potential implications, in particular from a budget management perspective.**

Signals for future

6.336 This section looks forward at the long term implications for CfD based on what has happened to date and makes recommendations going forward. It discusses the future risk profile, the development of a healthy and diverse future pipeline, along with the measures necessary to ensure CfD projects progress.

It is too early to unravel temporary effects from long-term implications: a pure 'CfD' market is yet to emerge

6.337 It will take a number of allocation rounds before a 'pure' CfD-driven market can emerge because of the transition from the Renewables Obligation (RO) to the CfD regime. This transition materialises in the form of two processes:

- Existing projects can temporarily opt both for the RO and CfD regime; and
- RO-led project pipeline will temporarily compete with new CfD-led projects.

6.338 Broadly, the first is in progress, while the second has yet to start. Over the first couple of CfD rounds, there is an overlap between subsidy schemes: existing projects for a number of technologies have the choice of participating in the CfD allocation process or seeking accreditation under the RO, which will remain open up to 31 March 2017[200]. Over this period, therefore, projects will benefit from the RO as a potentially more valuable subsidy[201] and/or as a back-up plan in case they are unsuccessful in an auction round. The second transition issue is related to the interplay between projects developed under a non-competitive process and those that will be developed under the assumption of constrained allocation.

6.339 Both these aspects of the RO-CfD transition will have impact on participation levels, competitive pressure and bidding behaviours. Market developments will need to be interpreted in light of this transition. Distinguishing temporary versus permanent effects may be a rather complex exercise.

CfDs fundamentally change the risk profile of renewable projects impacting different investors in different ways

6.340 Conceptually, the CfD was engineered to stabilise revenues, thus reducing risk, on the assumption that the business as usual alternative – ie an 'extended' Renewables

200 The Renewable Obligation actually closed sooner for some technologies, ie solar, while for others the overlap is relatively limited (eg offshore wind). Some projects will be able to benefit from grace periods and will commission after the stated deadline. This is also subject to decisions that may be taken by the new Government further to latest statements on the early closure of the RO to onshore wind.

201 Value in this case is not simply the level of subsidy, but also other non-financial benefits, such as the familiarity with the scheme.

Obligation under the same Levy Control Framework constraints – was no longer fit-for-purpose to support investment in low-carbon electricity technologies consistent with Government's ambitions. In DECC's opinion[202], as supported by analysis of NERA Economic Consulting[203], this reduction in revenue risk for projects was the conduit for widening the range of capital sources to guarantee sufficient funding and for incentivising investments to come forward at a lower cost of capital so as to realise savings to consumers.

6.341 From a revenue risk perspective, the CfD regime succeeds in limiting the exposure of projects to market prices and in making subsidy levels clearer much earlier in the development process. However, the rules of the game have considerably changed. **The new regime does not exclusively alter the exposure to revenue risk, but the risk profile of a renewable project as a whole.** Compared to an extended RO, the CfD regime mitigates or magnifies a number of risks, and equally, it introduces new risks (see section below starting with paragraph 6.345).

6.342 Each type of risk is intrinsically linked to a specific stage of the project lifecycle. As a result, the **CfD ends up distributing the total quantum of risk differently over a project's life**. This also means that, because of the entry/exit patterns of different investors, the shift in the shape of risk will not uniformly affect all classes of investors. Additionally, the perception of these risks varies from one investor to another depending on their role in the project, its characteristics, and the timing or priorities leading to the investment (see section below starting with paragraph 6.351).

6.343 **In a perfectly functioning CfD market, we acknowledge that the total quantum of risk is expected to be lower than under an extended RO. However, there are a number of circumstances that are not necessarily structural, but temporarily alter the balance and affect the perception of risks, thus prevent the current CfD regime from delivering the full theoretical benefit.** These are discussed in more detail below (see below section starting with paragraph 6.357).

6.344 Finally, the **implications of this (theoretical or perceived) shift in risk profile are multiple and not exclusively related to the cost of capital.** Developers will need to adapt their business model, re-think how they can bring forward future projects to fruition as well as assess the implications on their required rate of return consistent to the new regime. Similarly, financial investors will make considerations on the attractiveness of CfD projects, their cost for provision of capital and on implications on financing practises. These are further discussed in the following sections starting with paragraph 6.368, 6.384 and 6.390.

Key sources of risk

6.345 Based on our experience, we have classified the primary sources of risk for a renewable project as qualification, allocation, construction and market risk[204]. These are expanded below from a CfD perspective, whereas in the next section, we assess how each risk compares against the theoretical counterfactual, ie an extended Renewables Obligation.

202 'Electricity Market Reform Delivery Plan', DECC, December 2013.

203 'Changes in Hurdle Rates for Low Carbon Generation Technologies due to the shift from the UK Renewables Obligation to a Contracts for Difference Regime', NERA Economic Consulting, December 2013. NERA suggest that the cost of capital for CfD projects would be lower than the cost of capital for projects under the RO based on the assessment of four elements – the wholesale market, the allocation, the construction risks and the novelty premium. In our evaluation we build on this framework by widening the scope in order to capture implications unrelated to cost of capital, but equally important.

204 Our assessment is not intended to be a detailed review of all the categories of risks and their implications. Additionally, it remains qualitative by building on our own expertise and the evidence gathered from stakeholders.

6.346 **Qualification risk –** This risk relates to the ability to obtain a grid connection agreement and planning consents, as well as to compile a supply chain plan to receive the approval certificate (if applicable) in time and in the format required by the CfD eligibility rules.

6.347 **Allocation risk –** This is the risk of not being allocated a CfD contract after having funded development costs. This class of risk actually encompasses two categories of risk, albeit interdependent, which we breakdown as follows:

- **Allocation risk in the strict sense** – This is the risk of not securing a CfD contract through participation in the auction. This is predominantly driven by the uncertainty of the competitive position of a developer's project in relation to other projects contending for the same budget, for instance:
  - Technology vs other technologies within the same pot;
  - Same-technology project economics (eg better siting/load factors, logistics, etc.);
  - Sponsor company financial strength and experience; and
  - Portfolio and other strategic bidding considerations.
- **Budget constraint risk** – This is the risk the Government may decide to:
  - Reduce total funds available to subsidise renewables (or low carbon as a whole, ie 'green commitment' of Government). At present, this essentially takes the form of the Levy Control Framework, which puts a cap on subsidy spending.
  - Change the distribution of available funds across low-carbon technologies. This currently refers to how DECC allocates funds to renewables via the CfD budget and other non-renewables technologies, such as CCS and nuclear, and how renewables technologies are assigned to one of the CfD pots.
  - Take corrective actions to address unexpected fluctuations in power prices, load factors of RO/CfD operational projects, under-delivery on CfD awarded capacities or fall out of projects, etc. All aspects will increase/decrease the budget left under the LCF for future rounds.

6.348 While the allocation risk in the strict sense is to some extent in the hands of developers, the budget constraint risk is outside their control and is predominantly dictated by policy decisions and/or other external factors.

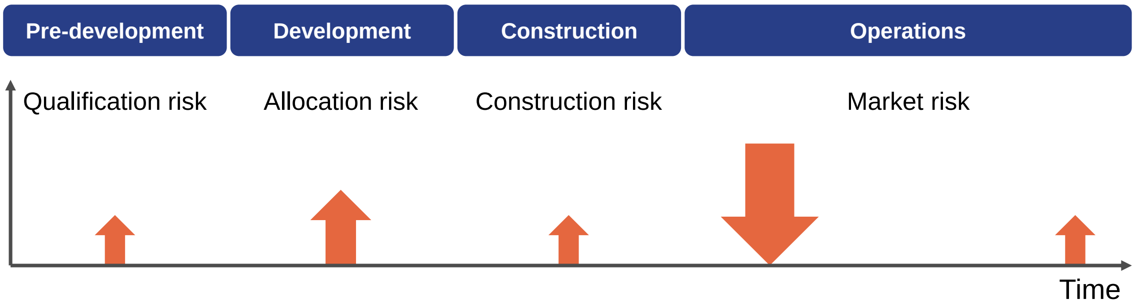
6.349 **Construction risk**. This is the risk arising from delays in the delivery of the detailed design and construction. Under the CfD, this potentially materialises through breach of the Milestone Delivery commitments, the Target Commissioning Window (TCW) and Longstop Date (LSD) requirements, which can lead to exclusion from a subsequent round, reduction in subsidy payments and/or contract termination (eg late commissioning, insufficient capacity delivery, etc.).

6.350 **Market price risk.** This is the risk related to market price fluctuations, which impact the revenue stability of a project. Technically, the ability to capture the reference power price (ie basis risk), exposure to negative prices and imbalance cost should fall under this category, but all references to market risk in following sections will exclude these elements for simplicity of argumentation. Under the CfD, market risk only materialises – in its narrower definition, ie excluding basis risk etc. – after the expiry of the contract.

The shape of risk profile has changed

6.351 Our assessment of the four risks defined above suggests that overall the CfD regime has introduced new risks and/or magnified those that typically materialise in the early phases of the project life-cycle – qualification, allocation and construction risks – whereas it has reduced the level of risk during later phases – market risk (with the exception that subsidies tail off earlier than under the Renewables Obligations). This is graphically represented in Figure 27 below.

Figure 27 – Project life-cycle and risks under the CfD compared to an extended RO



Note: direction of arrows graphically summarises how risk changes compared to the extended RO, while size shows an indicative order of magnitude. Market risk is represented by two arrows showing the different impact depending on the phase pre vs post subsidy period

6.352 **Qualification risk** is slightly higher than under the extended RO. As discussed in more detail in section starting with paragraph 6.253 and 6.271, qualification can only be achieved during a fixed window under the CfD regime, while under the RO this is flexible. Additionally, National Grid is instructed to adopt a mechanistic approach to assess applications with no discretion to account for minor indiscretions. Both of these aspects could lead to a project missing out on an allocation round.

6.353 **Overall allocation risk** is higher. While the **budget constraint risk** remains roughly equivalent under the two regimes[205], the CfD introduces a new and material risk by introducing competition: the **allocation risk in the strict sense.** Under the extended RO, there is the expectation that a project, once developed, will be granted a subsidy. Under the CfD, there is no such expectation as the ability to obtain a subsidy is dependent on the project's competitiveness in relation to others.

6.354 **Construction risk** is in principle relatively greater[206] under the CfD than under the RO, especially between the end of the commissioning window and the Longstop Date[207]. Our view is that CfD delivery obligations and termination risk can lead to more material consequences than a re-banding under the RO – assuming budget constraints are the same for both regimes, hence a re-banding would only be implemented to adjust subsidy levels to lower technology costs.

6.355 **Market risk** is definitely lower under the CfD than an extended RO because the CfD payments are structured to provide a long-term hedge around the variability of power prices. It is worth mentioning that payments will be received over a shorter period of time than under the RO – 15 instead of 20 years – leaving a project exposed to market risk earlier at the back end of its operational phase. This aspect is discussed in more detail in section starting with paragraph 6.218.

6.356 It is the balance between these four key risks that will drive the overall project risk higher or lower under the CfD compared to an extended RO. In principle, a perfectly functioning CfD should lower the total project risk – reduced market risk dominates over the increase in other risks – however, in reality, it is the perception of these risks and their likely impact that matters to investors. Each investor – developer or financial sponsor – may produce a

205 It may actually be slightly higher under the CfD because of the relationship between the LCF and the fluctuation of power prices, which will impact the availability of funds in future rounds. The RO budget risk was mainly linked to the existence of the LCF and the interaction between RO bands, deployment levels and load factors.

206 Compared to the RO, this risk may be relatively lower only in the event of small delays. There are no implications on the level of subsidy as long as the commissioning is achieved within the commissioning window, while under the RO project can suffer from a re-banding up to the point of commissioning.

207 LCCC has the right to terminate the CfD contract in case the unit does not commission by the Longstop Date the Require Installed Capacity.

different assessment of such a balance depending on the project characteristics, the timing or priorities leading to the investment. The fact that there is a fragmentation of ownership across the life of the project also means that early stage providers of risk capital don't necessarily factor in the later stage market benefits, and vice versa.

6.357 In order to contextualise our assessment, we have used our expertise, as well as evidence from the stakeholder research, to identify where the balance of these risks currently are. As alluded earlier, we have identified a number of circumstances that may be temporary, but not necessarily structural, that may prevent a CfD project from being perceived as a lower risk investment, thus realising the full theoretical benefit. These are mainly related to issues reducing the ability of a project developer to manage and price the allocation and budget constraint risks and the uncertainty around the practical implementation of termination clauses and delivery constraints under the CfD Contract:

- **Lack of visibility** on the future budget levels as well as the frequency of future CfD allocation rounds – How much budget is left under the LCF for future rounds? How much of the available budget will be allocated to renewables? When, and how frequently, the Government will issue an allocation round notice over the next few years?
- **Uncertainty around the evolution of competition** – Is 'technology neutrality' the ultimate objective? What does the Government exactly mean by neutrality? How and when would they implement this?
- **Overlap of early CfD rounds with the RO scheme** – How will participants decide to formulate their bidding strategies? How likely is it that strategic and/or aggressive behaviours will impact the auction outcome? Will the RO be closed earlier for some technologies?
- **Lack of transparency on auction participation and outcome** – How much capacity has participated to the auction? What has determined the success or failure in the auction? What is the impact of speculative behaviours? How efficiently are the current rules preventing speculative projects?
- **Limited record on delivery constraints, change in law and termination provisions** – Are Milestones and Longstop requirements feasible? How strictly will the LCCC police them?
- Uncertainty around acceptability of CfD Contract terms to financial investors, in particular lending institutions.

6.358 Some of these circumstances will naturally evolve, arguably disappear, with time eg RO-CfD transition, lack of track records or the uncertainty around the acceptability of the CfD Contract. However, others are dependent on Government's future policy decisions. These specifically relate to **the lack of visibility, transparency and evolution of competition, which increases the perception that developers currently have of allocation risk. If the full low-risk benefit of the CfD is to be unlocked, we recommend that future policy developments should carefully take all of these circumstances into account**.

The impact on investors is not uniform

6.359 As anticipated above, by changing the risk profile of renewable projects, the CfD regime affects different investors – utilities, medium to large independents, SMEs, single-project companies, suppliers, institutional financiers & multilateral agencies, commercial banks offering project financing and refinancing packages, infrastructure, private and pension/insurance funds – in different ways depending on the stage in which each investor decides to participate in the project[208]. We present this graphically in Figure 28.

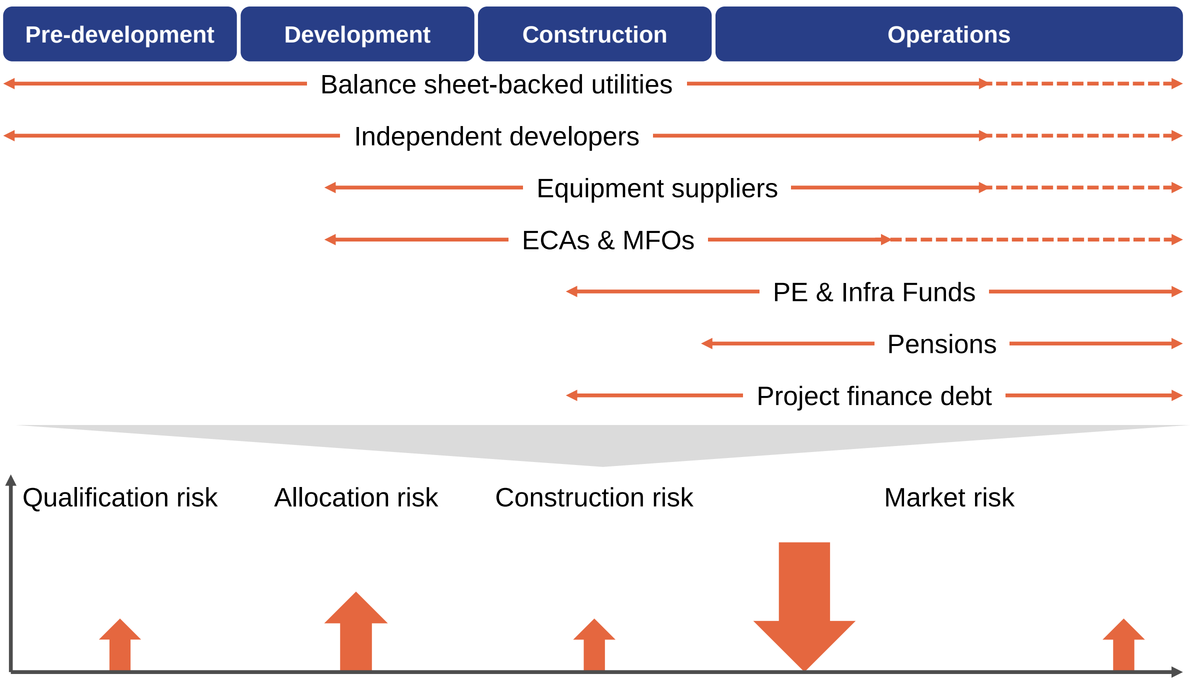
[208] For the purpose of our analysis, we will focus on two key groups of investors: developers and equity/debt financial investors.

6.360 Based on our direct experience of financial transactions, we have observed that **financial (equity and debt) investors** generally enter into a renewable investment during construction with equity providers more typically after a project becomes operational. Assuming the timing is not substantially changed under the CfD, these investors *de facto* benefit from a decrease in market risk, but are not subject to allocation risk or (potentially) construction risk.

6.361 In our stakeholder research, **lenders** confirmed that overall the CfD will generate benefits. They are generally satisfied that the CfD subsidy payment structure de-risks project's revenues and only raises some minor concerns, which are discussed in section starting with paragraph 6.370 below. In terms of the timing of their investment, they affirm that they would not enter into negotiation before the award of a CfD Contract, however seem open to take some construction risk once deliverability of contractual constraints is proved by earlier projects. They also mentioned that despite some of the due diligence practices will need adjusting, they feel confident project financing standardisation will emerge facilitating deals for CfD projects.

6.362 Views gathered from the **institutional investors** are to some extent less consensual. They all welcome a lower exposure to market price risk and comfortable that the CfD is an investable tool that may attract a wider range of capital sources, in particular institutional money. However, some are concerned about the longer merchant period at the tail of the project life-cycle, while others are concerned about the potential implications of higher allocation risk at the beginning of the project life. This could change the value distribution and push them into investing earlier in the project, thus taking more development risk, to ensure returns are sufficiently attractive. Or they could simply choose to invest their risk capital in other sectors and/or markets. Based on the evidence available, we believe that it is too early to draw conclusions on how investment patterns will change, however we would not expect appetite for CfD projects to fail to materialise.

Figure 28 – Sources of capital and risk during the life-cycle of a CfD renewable project



Note: Export Credit Agencies (ECA) & Multilateral Financial Organisations (MFOs). Note that entry/exit patterns depend on the project size, and the technology and strategy of individual investors. It is also a function of the market circumstances (eg familiarity, technology maturity, availability of alternative investments, etc.). This is just an example for an average project.

6.363 **Developers** are the organisations that initiate the investment cycle of projects. An increase in risk in the early phases of a project, in particular allocation risk, will therefore affect their decision process. Assuming developers remain invested in the assets, they will also benefit from the reduction in market risk during the operational phases of the project. The lower market risk may materialise in the form of faster recycling of capital and/or better debt financing terms, as discussed in later sections.

6.364 The overall net impact – increased earlier risks vs decreased risks during the operational phase – will depend on the developer's ability to manage in particular the allocation risk. This will be determined by, not only the size of companies sponsoring projects, their experience and financial strength, but also by the technology characteristics and the relative competitiveness of projects.

6.365 Larger companies are naturally better positioned to diversify risks and/or spread related costs across their portfolios and/or business units, whereas SMEs may struggle to cope with the financial pressure and lack of dedicated resources. Equally, the impact will be more significant for technologies with larger pre-development and development capital outlays and/or a longer lead-time. The uncertainty around the competitive position of a project will also affect the perception of allocation risk that a developer has. Everything else being equal, the higher probability a developer estimates to have of winning the auction, the lower the perceived risk will be.

6.366 For instance, offshore wind projects have greater upfront costs compared to onshore wind. Although utility-type or large companies have traditionally backed these projects, this will not implicitly mean that allocation risk would be easier to manage. For such large investments, it will be relatively more difficult than under the RO to justify cash outlays without certainty of a contract. At the other end of the spectrum, community projects, despite the much smaller upfront commitments, may find competition difficult to 'survive'. Downward pressure on strike prices will potentially squeeze their returns, so that allocation risk will outweigh the benefits from lower market risk. Other technologies may however find it easier to realise the full potential benefit of the CfD, such as EfW CHP, because competition is structurally less, given their cost structure, and reliance on the power market for their revenues is lower.

6.367 As revealed during our stakeholder research, developers are considerably concerned about allocation risk. While they generally agree that risks related to the competitive aspect of the regime can be ultimately handled, it is the uncertainty around the future of the scheme that appears to be unsustainable. Because of some of the temporary issues flagged in paragraph 6.357, their perception of budget constraint risk is high, and this seems to be impacting on their perception of allocation risk in the strict sense as well.

Magnitude and timing of financial benefits deriving from the CfD are uncertain at this stage

6.368 As discussed in the previous section (starting with paragraph 6.340), DECC's primary rationale for moving to the CfD regime was de-risking projects to attract a more diverse pool of finance and decrease the cost of capital[209]. We believe that a perfectly functioning CfD market, in principle, lowers the level of risk and therefore should also lower the cost of capital compared to a business-as-usual scenario (ie Renewables Obligation). **The timing and the extent to which any financing benefits will materialise, however, is unclear based on present evidence**.

6.369 The limited evidence base is mainly dictated by the fact that there are very few projects with their construction finance in place amongst those that have secured a CfD contract via the FID Enabling for Renewables programme, or the first auction round of the enduring

[209] 'Electricity Market Reform Delivery Plan', DECC, December 2013.

regime[210]. Additionally, we understand that all these earlier projects are financed on balance sheet, and project financing negotiations are in a very preliminary phase. Therefore, it is relatively premature to draw any conclusion on whether any of the expected benefits of the CfD have already materialised.

6.370 This uncertainty also emerges from our stakeholder research. **Debt providers generally agree that a higher level of revenue certainty is expected to improve financial covenant terms, therefore lower overall financing costs, everything else being equal[211].** Debt service cover ratios may also enable higher gearing. There are, however, some factors that could affect the way commercial banks operate and the terms at which they provide funds:

- Stricter delivery obligations and termination risk under the CfD regime that did not exist under the RO. These are currently perceived as higher risks than the re-banding under the RO, but concerns may ease once track records from real projects emerge.
- Very low clearing strike prices could squeeze returns[212] to the level at which the debt repayment capability of projects is impaired. As a result, potential for increase in project gearing may be limited[213]. Disclosure of asset economics in the financing negotiations may provide some level of comfort.
- Yield risk, or volume risk, assumes a greater relevance than under the RO, in particular for wind assets. The relationship between low wind and high price periods used to offer a buffer for maintaining debt service cover ratios, which is now not available with the ‘fixed-revenue’ payments under the CfD[214].
- Shorter duration of the subsidy period. This may reduce the debt term or attract a premium and/or require a wider equity buffer in re-financing, as already discussed in the section starting with paragraph 6.218.

6.371 Whether these concerns are real and whether they will materially offset the expected benefits remain unclear until further evidence emerges from initial deals. Potential consequences of the unfamiliarity with the new regime are discussed in section starting with 6.374 below.

6.372 **From an equity perspective, stakeholders are even more uncertain than lenders about the likely direction of hurdle rates.** Developers, as discussed earlier, are concerned about uncertainties related to Government’s medium to long-term policy, future CfD rounds, as well as other practical aspects of the CfD Contract management (see section starting with paragraph 6.357). Allocation risk stemming from the competitive allocation is in theory manageable. It should not impact the required rate of return so substantially to offset the structural benefits deriving from the lower exposure to market price risk. There is also recognition that the CfD will allow anticipation of the financing process and potentially faster capital recycling through financial equity investors, which value revenue stabilisation. However, their current perception of allocation risk is high and

210 Our understanding of project status is that only two projects allocated an Investment Contract (ie early CfD contract) have reached final investment decision and no first round CfD project has reached final investment decision and/or secured project financing at the date of the stakeholder research (ie March 2015).

211 It is worth mentioning that not all industry players may rely on project finance to fund their assets, therefore the cost of capital of these projects would not be impacted by the cost of debt.

212 Some investors seem to suggest that a number of projects awarded under the first round of the CfD may struggle to deliver at the strike price levels they achieved.

213 Gearing achieved in PFI structures seem to be perceived as the cap to those achievable by CfD projects in light of the better protection these structures offer to investors.

214 Everything else being equal, in a low wind year, wind assets tend to capture a higher electricity price per unit of generation (vice versa). This could at least partially compensate for the lower volumes generated, thus reducing the impact on revenues. Given the stabilisation mechanism of the CfD, in low wind year, there is no upside in the electricity price captured, thus the revenues are lower proportionally to the lower volume generated.

the interplay between all these drivers is simply too uncertain to draw conclusions on the cost of equity implications.

6.373 In summary, timing and materiality of financing benefits are uncertain. However, **it would be advisable for the Government to improve the perception of allocation risk by providing sufficient visibility on the evolution of the CfD regime and their green ambitions. This is to ensure that any implication on the cost of development capital is contained to reasonable levels and/or a healthy pipeline is maintained by incentivising providers of capital to invest in the UK.**

Unfamiliarity with new regime is expected to adversely impact earlier financing deals

6.374 From discussions with the financial community, we understand that familiarity with the CfD regime, in particular the contractual requirements, varies considerably across different organisations. Despite some initial discussion between lenders and developers of FID Enabling for Renewables and first round CfD projects, the formers have not shown interest in engaging in detailed negotiations before the conclusion of the selection process or the allocation round, as applicable to the type of project.

6.375 The key message that emerges from these discussions and our general experience of financing transactions, is that the lack of familiarity may have implications on a number of aspects of the financing process, such as:

- Ability to expediently secure debt;
- Level of interest from lending institutions, which are favourable to lend to first-of-a-kind / early CfD projects[215];
- Sophistication of the due diligence process; and
- Requirements for credit committee approval.

6.376 We believe that these will not necessarily take the form of a quantifiable premium to the underlying cost of debt – this is what DECC referred to as the 'novelty premium' based on NERA's report[216]. In most cases, there will be an impact on the time required to complete negotiations of a debt package.

6.377 **After an initial phase, the duration of which remains unclear, lenders are confident that more standardised practises to CfD debt financing will emerge. In our opinion, this should also facilitate competition, thus downward pressure on the cost of debt and the ability of obtaining debt.**

Macro-economic conditions are a fundamental driver of the cost of capital

6.378 As previously discussed, we believe that the CfD regime has the potential to deliver a lower cost of capital during the life-cycle of a project. However, our research and discussions with financial stakeholders indicate that the **credit-cycle, the liquidity in capital markets and the availability of commercial debt will all play a more fundamental role in driving financing costs of renewable assets**.

6.379 It is worth noting that the principal lenders to renewables projects are European and Japanese banks whose debt terms for limited recourse debt vary little according to regulatory risk and incentive mechanisms, which vary considerably across Europe. Where

[215] This will depend, among other factors, on the relationship developers may have established over the years with these institutions, the strategic position of an individual bank in the market and the bank's level of involvement since the CfD design process

[216] 'Changes in Hurdle Rates for Low Carbon Generation Technologies due to the Shift from the UK Renewables Obligation to a Contracts for Difference Regime', NERA Economic Consulting, December 2013.

there is movement in that narrow band of terms offered, it appears to be more a function of the state of the global economy and the availability of capital in general.

6.380 In recent periods, we have also observed through our involvement in transactions that margins and fees for project financing have been dropping across the whole infrastructure/energy spectrum. This was attributed to general market conditions and the increased competition in the lending industry for such a class of investments. This confirms our view, which was also endorsed by members of the financial community, that **the expected order of magnitude in cost of capital, stemming from the change in regime, is likely to be marginal when compared to other macro-economic factors**.

Over time we expect a more diverse range of capital sources to develop

6.381 A reduction in risk, specifically market price risk, will in principle attract a wider range of investor classes, specifically during the operational phases of projects. The private-law nature of the CfD Contract compared to the regulatory instrument such as the RO, is expected to be more attractive to international investors less familiar with the UK market.

6.382 The shorter tenor of the subsidy is potentially one concern of the new policy design, but we believe that this will not be a barrier to investment. As supported by opinions gathered during our stakeholder research, if all other conditions are satisfactory, long-term investors will adapt their strategy around the 15-year subsidy duration with marginal implications on the investment attractiveness.

6.383 There is a general consensus that opening the market to low-cost institutional investors should in principle facilitate a more effective recycling of capital and reduce reliance on commercial debt, which in turn would favour new investments. From the opinions expressed by stakeholders and general market evidence, however, the **CfD seems to be offering the right conditions for a more diverse pool of financial investors, however, its ability to attract a wider pool of investors remains unproven** and, in any case, this pool may take time to materialise.

More visibility on future Government's commitments would help the development of a healthy pipeline

6.384 In order for the UK to achieve its renewables and decarbonisation targets, as outlined in Annex B, there needs to be a pipeline of renewable energy projects. The majority of the current pipeline of renewable projects was developed under the assurance of the Renewables Obligation (RO), but in order for renewable deployment to continue the project pipeline needs to be continuously topped up. Without a strong pipeline, not only the post-2020 targets may become more difficult to achieve, but most importantly, the competitive tension in the forthcoming CfD allocation rounds may not be sufficient to incentivise efficiencies or reductions in technology cost.

6.385 **The impact on the project pipeline due to the introduction of the new CfD arrangements and closure of the RO will take time to materialise. DECC would need to monitor these developments.** As outlined in the stakeholder research, however, a significant gap in the project pipeline may emerge in a few years as an insufficient number of developers may be prepared to take on allocation risk for new sites.

6.386 At present, the allocation risk – linked to the competitive element of the regime as well as to the budget constraints – is perceived to be significantly high amongst developers. As raised in paragraph 6.353, allocation risk is structurally higher under CfDs than under the RO and this affects the early phases of the project life-cycle, when activities are led by developers. In principle, this higher allocation risk is manageable, but there a number of circumstances that may be temporarily reducing the ability of developers to handle and price the risk. Different types of developers may be affected differently, but fundamentally all organisations would face this risk[217].

6.387 As discussed in paragraph 6.357, more visibility on the future budget levels, administrative strike prices (ASPs) as well as the timing and frequency of future CfD allocation rounds would be helpful to enable developers to commit to progressing renewable projects, as well as to invest and bring new developments to the market. Without a clear commitment from Government there will be implications for the amount of new investments and the diversity of these investments in terms of technology, company, size, etc.

6.388 **Our recommendation is for the Government to provide a coherent long-term vision for renewables deployment under the enduring CfD regime and to offer visibility of the individual allocation rounds.** Respondents repeatedly raised the importance of such aspect.

6.389 The exact time necessary needs to be analysed in more detail by DECC to identify the optimum balance between providing the necessary visibility to participants, alongside the ability for DECC to provide accurate and reliable figures to industry[218]. Providing 'visibility' means not exclusively setting an overall budget amount figure, but also clearly outlining the mechanisms that the Government will employ in setting this figure, the allocation rounds, the individual pot splits as well as the process for setting the ASPs and the future technology split.

The developer business model

6.390 The introduction of the CfD regime, particularly with respect to constrained allocation and periodic auctions, has a number of implications on the developer business model, which has established itself since the Renewables Obligation was introduced:

- **Consolidation of developers**. The introduction of allocation risk has made the early phases of project development more a binary proposition and, smaller companies with weaker financial resources are less well placed to cope with the new circumstances. The uncertainty around allocation also delays the first exit point pre-construction (until after CfD allocation), which developers have historically used to cash out and recycle funds for further developments. The industry may therefore become more reliant on larger independents or utilities to bring forward projects and we may see a number of exits or consolidations at the lower end of the company spectrum.
- **Portfolio optimisation**. Constrained allocation has introduced a strong incentive to review project economics in search of synergies or simply ranking projects based on their economic merit to bring forward only the most efficient and competitive assets.
- **Potential decrease in industry collaboration**. Historically collaboration between different stakeholders across the industry has facilitated technology advances and cost reduction. Because of the competitive aspect of the allocation process, developers may lose the incentive to cooperate and slow the process of driving down cost in the industry. At such an early stage, there is no evidence that these concerns are real, however in our stakeholder research developers have commented on the potential change in behaviours. This is to be carefully monitored.

Measures against speculative projects are broadly appropriate, however those against disruptive behaviours should be reinforced

6.391 The award of CfDs to two solar PV projects in the first round – which in our opinion bid strategically at unsustainable levels and in the end withdrew (see paragraph 6.323) – has

217 From the large utilities concerned about their credit rating to small independent developers who cannot afford to lose development and grid investments.

218 Somewhere between 4-8 years of budget visibility is likely to be necessary depending on the technology.

raised questions around the robustness of the current measures against speculative projects and disruptive behaviours, and whether these need to be reviewed.

6.392 In assessing the framework, we have considered all allocation rules, regulations and contractual provisions that are intended to:

- Prevent speculative projects to participate in an allocation round – **Speculative projects** are those that are not sufficiently mature and have a low chance to deliver against their contractual commitments in the event they were allocated a CfD Contract.
- Address potential behaviours which could disrupt the outcome – **Disruptive behaviours** are those adopted by participants that may delay the process, try to game the system to the detriment to other participants or simply consist in submitting bids that are not realistic for their project.

6.393 Both speculative projects and disruptive behaviours might be intentional, because of lack of experience or proper due diligence, or the results of the imperfect incentives created by the allocation rules and contract provisions. Independently from the exact nature of these elements or their rationale, their occurrence could reduce the efficiency of the CfD allocation process and/or produce suboptimal outcomes that are inconsistent with the policy intent.

6.394 For instance, a speculative project may secure a contract in the auction, but in the end fail to progress or commission because of poor financial commitments of the company sponsor, lack of expertise or unresolved technical issues. This may result in a suboptimal allocation of the available budget for that round or bed-blocking for future rounds as other legitimate projects could be allocated a contract instead. Similarly, speculative or disruptive behaviours may distort the process of running the allocation, but also lead to suboptimal outcomes and unintended consequences. For example, this could create an uncertain environment for those investors that are actually committed to bring capacity to fruition. Ultimately, DECC runs the risk of under-delivering against their deployment ambitions or their value for money objectives, therefore the Government needs to ensure that these measures are robust and appropriate to the objective they intend to achieve.

6.395 In reviewing the measures against speculative projects and disruptive behaviours, we have looked at each key stage of an allocation round (including the contract period up to project commissioning) and identified the objective pursued at each stage, the existing measures, and the consequences for speculative projects or disruptive behaviours arising from those measures. These are summarised in Table 10 below together with key findings of our assessment. Each set of measures applicable to a phase will be discussed in turn.

Table 10 – Measures against speculative projects or disruptive behaviours by key stage

Objective	Measures	Consequence
Application stage		
Prevent the participation of projects that are not advanced enough in their development, therefore have low chance to legitimately deliver (speculative projects)	1 Qualification requirements 2 Milestones requirements combined with non-delivery case under the non-delivery disincentives	1 Qualification/non-qualification 2 Exclusion of site in case of non-delivery and potential termination
Avoid submission of incomplete / inaccurate applications that could delay the process (speculative applications)	No explicit measure currently in place	n.a.
Allocation / auction stage		
Reduce the risk of strategic bidding in favour of straightforward bids (gaming)	1 Auction format 2 Non-signature case under the non-delivery disincentives	1 As per provisions of the Competition Act under which Ofgem/CMA have concurrent powers and REMIT[219], where appropriate 2 Exclusion of site in case of non-signature
Minimise the opportunity for collusion (collusion)	1 Auction format 2 National Grid and Ofgem obligation to intervene if collusion is detected	1 n.a. 2 As per provisions of the Competition Act under which Ofgem/CMA have concurrent powers and REMIT[219], where appropriate
Contract delivery stage*		
Incentivise the timely delivery of project (timely progress)	1 Milestones requirements combined with non-delivery case under the non-delivery disincentives 2 Target Commissioning Date and Window 3 Longstop Date	1 Exclusion of site in case of non-delivery and potential termination 2 Reduction in subsidy levels 3 Potential termination

* Note: strictly speaking, measures during the contract delivery stage are not part of framework against speculative projects or behaviours, but are considered here as they are interconnected.

219 Regulation (EU) No 1227/2011 of the European Parliament and of the Council of 25 October 2011 on wholesale energy market integrity and transparency.

6.396 **In summary, our evaluation has concluded that the current measures against speculative projects are broadly appropriate.** The level of costs and the complexity of the process to obtain them incurred to reach, such as stage, are in principle an appropriate barrier to deter speculative projects. By considering the separation of the application process from the allocation round itself, the potential for speculative applications would be substantially mitigated (see section starting with paragraph 6.399).

6.397 **Some material weaknesses were found in the measures against disruptive behaviours during the allocation and auction phases. The auction format is on balance appropriate to incentivise straightforward bids. However, the Non-Delivery Disincentives time penalty is not sufficient to discourage strategic bidding** and an actual financial penalty that attaches a 'cost' to the use of strategic bids may actually be more efficient. **Most importantly, under the available framework DECC lack the ability to assess anti-gaming measures,** and therefore there is a risk of perpetuating anti-competitive practices, or leading to uninformed and potentially detrimental changes in rules (see section starting with paragraph 6.406).

6.398 **With respect to the contractual phase, the principle of having commitment at certain milestones is valid, however, the advantages of a profiled trajectory, such as staggered milestones and/or time-related financial penalties, were probably underestimated in the design process** as no incentives to free up 'contracted budget' to favour fast recycling of capital into future rounds exist. In principle, we are satisfied that both the incentives and penalties related to the TCW and the LSD requirements are appropriate in fostering a timely delivery of projects (see section starting with paragraph 6.419).

Application phase: current measures seem broadly appropriate

6.399 At this stage, the measures should aim at:

- Preventing projects that are not advanced enough in their development therefore have low chance to legitimately deliver to participate in the allocation round (**speculative projects**). Should they pass this phase, these projects may typically result in under-delivery of allocated capacity and/or budget bed-blocking; and
- Avoiding submission of incomplete or inaccurate applications that could delay the process at the expense of other participants (**speculative applications**).

6.400 **The eligibility criteria – specifically the qualification requirements – were purposely designed to avoid speculative projects.** These requirements are already discussed in section starting with paragraph 6.73. In brief, we concluded that planning consent and grid connection are significant hurdles in the development of a project, which should overall guarantee that only sufficiently mature projects take part in the allocation. **The level of costs and the complexity of the process to obtain them incurred to reach, such as stage, are in principle an appropriate barrier to deter speculative projects.** These are more effective in the case of technologies where these costs or complexity are higher, or for developers with relatively lower resources, but we acknowledge the advantages of standardisation and we believe the balance is appropriate. This view was confirmed by stakeholders, who were relatively comfortable that qualification requirements were considered sufficient barriers to deter speculative units.

6.401 The risk of speculative applications mainly stems from the fact that the expediency of the allocation process is dependent on a limited amount of reviews and/or appeals, or none. As the rules currently stand, the auction process cannot proceed as per initial timeline in the event National Grid and Ofgem are called to reassess the eligibility decision. Therefore, it is possible that applicants that may have an interest in delaying the process or have nothing to lose from proceeding in appeal, even if the case is weak. In any case, the whole process would be delayed and other participants would bear the consequences.

6.402 **Currently, there are no measures to address these behaviours. Our recommendation,** as already suggested in section starting with paragraph 6.253, **is considering the separation of the application process from the allocation round itself.** By breaking the procedural chain, the potential for, as well as the incentive to produce a delay, would be mitigated.

6.403 Another measure that does belong to the application stage per se, but acts as a possible deterrent against speculative projects is the Milestones requirements in the CfD Contract. These requirements actually serve a dual objective: preventing speculative projects, but also incentivising contracted projects to deliver on a timely manner. The latter is discussed under the contract delivery stage below.

6.404 The fact that developers need to demonstrate a capital lay-out or an equivalent value in project commitments by the Milestones Delivery Date creates an incentive to apply for CfD when participants have some level of comfort that projects are sufficiently mature, thus they are able and committed to 'spend' funds promptly. The termination risk and the penalty in the form of exclusion from consequent rounds, which participants may face in case of breach of MDD requirements, may indirectly mitigate the risks of speculative projects to apply. Based on the outcome from the first CfD round, it is difficult to assess whether MDD clearly contributed to avoiding such risk. However, stakeholders confirmed that the existence of MDD does have a bearing on their decision to apply.

6.405 A final consideration on the implications of the constrained allocation in the CfD regime is, in principle, that this incentivises developers to abandon relatively uncompetitive early-development projects in their current portfolio as well as to encourage bringing forward new projects that can stand against the competition. Once a CfD-led pipeline emerges, this should also contribute to mitigate the risk of speculative projects.

Allocation / auction stage: measures as well as access to evidence for policy making need to be reinforced

6.406 During the allocation phase, the auction rules and process should aim at:

- Reducing the risk of strategic bidding or other predatory behaviours in favour of straightforward bids (**gaming**). Should they pass this phase, these projects may typically result in under-delivery of allocated capacity and/or budget bed-blocking; and
- Minimising the opportunity for collusion (**collusion**), which again could come at the expense of other participants.

6.407 DECCs' anti-gaming policy relies on the mechanics of the auction design and on the non-signature case under the Non-Delivery Disincentives (NDD). These are intended to create the incentive to formulate bids at a viable level so as to maximise the chances of projects' delivery under the allocated CfD Contract.

6.408 As discussed in starting with paragraph 6.179, one of DECC's key reasons behind the selection of the **sealed bid pay-as-clear (PAC) format is that on balance it provides the economic incentive to formulate bids that reflect the minimum amount required to guarantee the delivery of the project[220] and we concur that this was appropriate in the context of the complex objectives.** The risk of winner's curse remains, as also suggested by a number of stakeholders, however, we believe it is predominantly driven by the context in which the auctions are held – eg lack of visibility, etc. – and not necessarily by the format of the auction.

6.409 The non-signature case covered under the NDD introduces a time penalty for projects that succeed in the auction, but then decide not (or fail) to execute the CfD contract with the

[220] Technically, slightly above that level trying to maximise their value in case they were setting the price. But this is the result of clearing the auction at the last accepted bid, instead of the first rejected one.

LCCC. In such circumstance, projects currently incur a 13-month exclusion from participation to an allocation round running from the date of contract offer/notification of award, unless an exemption is granted[221].

6.410 On the assumption that speculative projects are successfully prevented from participation at the eligibility stage, the exclusion from the consecutive round does impact projects that have serious intentions to invest. However, our opinion is that, **from a pure anti-gaming perspective, the NDD time penalty is not sufficient to deter bidders from adopting strategic bidding behaviours in the first place**. Bidders may take the view that the incentives of the auction design do not favour straightforward bids and that a strategic approach would increase their probability to secure a CfD Contract. This seems to have happened for the two solar parks that were successful, but in the end did not sign. Further evidence from the first round may emerge over time.

6.411 As supported by stakeholder feedback, this indicates that **an actual financial penalty that attaches a 'cost' to the use of strategic bids may actually be more efficient in averting disruptive behaviours.**

6.412 Bid bonds have been frequently mentioned by various stakeholders as possible solutions, but there are concerns around the exact form they may take and the potential for becoming a barrier to entry. It is worth noting that bid bonds are used in the case of the Capacity Market, hence we would recommend reconsidering them as a potential solution in the CfD process[222]. We agree on the importance that measures need to be proportionate to the type of projects, developers and circumstances, therefore DECC would benefit from engagement with the industry to find the right balance.

6.413 An important remark is that the likelihood of disruptive bidding behaviours is also related to the circumstances in which the allocation is run. For instance, the current pipeline was predominantly developed under the Renewables Obligation, which, combined with the lack of long-term structural visibility of future budget, timing of CfD rounds or unsuitable frequency may induce more aggressive biddings than under an enduring 'pure' CfD market.

6.414 Another objective that DECC aimed at achieving through the selection of the auction design is that on balance it offered the most robust regime against collusive behaviours. This in combination with the limitations on the release of information on auction participation and non-successful bidders were designed to minimise the risk of collusion.

6.415 The responsibility of detecting collusive behaviours formally falls under the concurrent powers of Ofgem and the Competition Market Authority (CMA)[223]. Ofgem is also the body responsible for monitoring compliance with, and enforcing against REMIT[224], where appropriate. For these reasons, Ofgem have information gathering powers to assist them with their roles, including access to bid data from the CfD (and the CM) auction. Under the

221 Exemptions to exclusion are mainly related to a qualifying Change in Law or a Construction Event. https://www.gov.uk/government/uploads/system/uploads/attachment_data/file/398825/NDD_Policy_Update_DECC_Update.pdf plus the Consultation Document https://www.gov.uk/government/consultations/emr-contracts-for-difference-allocation-regulations-consultation-on-non-delivery-disincentive-exemptions

222 DECC had consulted on the introduction of bid bonds as part of the commissioning process to incentivise projects to commission – discussed as part of the auction design – however decided against. We couldn't verify the rationale in public documents (ie October 2013 consultation, June 2014 response). https://www.gov.uk/government/uploads/system/uploads/attachment_data/file/324170/Government_Response_to_EMR_implementation_consultation.pdf

223 Enforcing the provisions of the Competition Act 1998.

224 Regulation (EU) No 1227/2011 of the European Parliament and of the Council of 25 October 2011 on wholesale energy market integrity and transparency.

Allocation Framework, National Grid has the obligation to notify Ofgem and the SoS of auction irregularities, which could distort the outcome of the auction.

6.416 **While we do not have concerns about the selected auction format as an anti-collusion mitigation instrument or the concurrent role of Ofgem/CMA in monitoring behaviours, we believe that DECC were too conservative with their approach on National Grid's disclosure licence for information on the outcome of the auction with respect to gaming.**

6.417 With the exception of considerations provided in section starting with paragraph 6.319 on the outcome of the first allocation round, the evidence available for our evaluation on gaming was very limited. The fact that CfD Regulations do not give access to the Government (or a mandated entity) to potential evidence from an allocation round is in itself an area of weakness of the current anti-gaming measures. **Under the current framework, the Government lack the ability to assess whether a policy change would be required to respond and/or prevent future violations. Therefore, there is a risk of perpetuating anti-competitive practices or leading to uninformed and potentially detrimental changes in rules.**

6.418 At this stage, we cannot firmly conclude that an ad-hoc monitoring body would be required. However, this role cannot be fulfilled by DECC without compromising its position[225], therefore a third party should have this responsibility and the appropriate powers to fulfil the function. This may be National Grid (in its role of Delivery Body), the auditor, Ofgem, or a separately instituted body.

Contract delivery stage: generally appropriate, however, a faster recycle of budget could be facilitated through more staggered milestones requirements

6.419 Strictly speaking, measures applicable during the contract delivery stage (up to commissioning) are not primarily designed to prevent speculative projects or behaviours with the exception of the Milestones requirements. However, we believe that these are highly interconnected and are fundamental for the cohesiveness of the evaluation.

6.420 Once a project executes the CfD Contract, there are a number of contractual provisions that incentivise a sponsor company to bring the contracted capacity to fruition in a timely manner (timely progress). These key provisions are the following:

- **Initial Condition Precedents –** The contracted project need to fulfil the Initial Conditions Precedent or it becomes subject to the right to terminate by the LCCC and are excluded for 13-months, unless exempted.
- **Milestones Requirements –** The contracted project needs to fulfil these requirements or can have their contracts terminated by the LCCC and are excluded for 13-months from the date of termination, unless exempted.
- **Target Commissioning Window –** In the event a project fails to commission within the TCW, the subsidy period, thus the total quantum of payments, is automatically reduced[226].
- **Longstop Date requirements** (ie commissioning, Further Condition Precedents) **–** If it fails to commission the minimum capacity by the Longstop Date (ie non-delivery case), LCCC has the right to terminate the contract. No exclusion applies in this case.

225 DECC do not have access to the information gathered from the allocation process, as discussed in section starting with paragraph 6.427.

226 Subsidy period is deemed to run for 15 years from the earlier of the Start Date and the last date of the TCW.

6.421 All commitments stem from the CfD Contract, where termination events and the residual claims and obligations for the two parties after termination are defined. The exclusions (NDD) are part of the CfD Regulations.

6.422 As already discussed in paragraph 6.403, the Milestones Requirements have a dual objective: preventing speculative projects, but also incentivising contracted projects to deliver on a timely manner. With respect to the latter, we believe that the principle of having commitment at certain milestones is valid, however, it is the number and frequency of these milestones and the nature of commitments and penalty that matter.

6.423 In terms of the number or frequency, we also believe that **there are no incentives to free up 'contracted budget' to favour fast recycling of capital into future rounds as rules currently stand, particularly between signature and the TCD. Staggered milestones and/or time-related financial penalties may be useful in this instance, but subject to considerations on proportionality and undesired complexity.**

6.424 Some discussions on the nature of MDD commitments are included in section starting with paragraph 6.232. In this section, we would like to draw the attention on the fact that project progress isn't necessarily evidenced by the quantum of (actual or committed) expenditure. Everything else being equal, an efficient project will seek to back end expenditure to save on carrying costs. If there was an alternative to cash spend or project commitment, such as an independent Technical Advisor certifying that the project was on track to meet the build programme, that might provide some additional flexibility in cases where available options are inappropriate or too stringent. However, these alternatives need to be assessed in terms of their efficiency in signalling actual commitment to deliver.

6.425 One last remark on the MDD measures is that the incentives it introduces may be partially conflicting with those dictated by the competitive allocation, which could encourage projects to spend as little as possible before securing the CfD to minimise the exposure to the risk of not being allocated a contract. This may lead projects to delay some of the activities after the contract award, thus endanger timely compliance with the MDD requirements. This was also highlighted by stakeholder feedback.

6.426 The dynamic created by the Target Commissioning Window (TCW) and the Start Date, which dictates the beginning of the subsidy payments, introduces *de facto* a financial penalty. By commissioning after the TCW, a project would suffer from a reduction in the subsidy period proportional to the delay. This does incentivise an efficient management of the late development and construction activities to avoid incurring in the penalty. Equally, the Longstop Date (LSD) requirements are another incentive for the timely progress of projects, but also a safeguard for the consumers. **In principle, we are satisfied that both the incentives and penalties related to the TCW and the LSD requirements are appropriate to incentivise a timely progress, but this is subject to evidence that may emerge from the implementation of contracts signed to date**.

Rules governing the access to allocation data owned by National Grid should be relaxed

6.427 In designing the CfD framework, DECC has purposely separated its role of policy definition from the responsibility of the allocation process and contract management. National Grid's ownership of information on the allocation stems from this separation of roles. This 'physical' separation materialises also at a legal level through the provisions of Article 54 of the CfD Regulations, which restrict the Government's right of access to specific information gathered from the allocation process, as well as licence conditions. These provisions are mainly the reflection of:

- the Government's intention for the allocation to be seen as a process completely independent from policy intervention; and
- the selected auction format.

6.428 The first aspect relates to the perception that industry stakeholders, in particular CfD applicants, may have of the role of the Government in providing a level playing field for competition and a stable investment environment. Based on our interactions with the market, it emerges that this separation of roles is not that clearly understood by players and there is a general expectation that the Government will actually access some information related to the allocation process (see also section starting with paragraph 6.284, where we discuss lack of clarity on treatment of confidential information).

6.429 The second aspect is in relation to the design of the auction itself. Under a sealed bid uniform price scenario, it is advisable to avoid potential disincentives to straightforward bidding. DECC's access to detailed bid prices could potentially incentivise participants to submit inflated bids fearing true-cost bids would be used by the Government to inform the setting of future administrative strike prices, thus eliminating any potential rent (see also section starting with paragraph 6.179, where auction rationale is discussed).

6.430 Our assessment of the relevant information to evaluate the auction results in terms of efficiency and susceptibility to gaming, has highlighted some of the limitations facing DECC as a consequence of the restrictions imposed through Article 54 of the CfD Regulations[227]. While we agree with the rationale for formally and transparently limiting disclosure to minimise the risk of unintended consequences on future auctions, restrictions may unnecessarily prevent DECC from accessing information that have positive benefits for future auctions by, for example:

- Removing unnecessary complexity;
- Refining the use of flexible bids; and
- Identifying possible cases of market manipulation or gaming.

6.431 In particular, we believe that amendments to the CfD Regulations could be made to allow the release of additional information to DECC. These changes should reflect an appropriate level of aggregation and/or restrictions on information that would prevent DECC from inferring the actual bids made by applicants, but could offer evidence for policy evaluation.

6.432 Stakeholders generally share DECC's concerns around revealing commercially confidential information and restricting the access to the auction participation and outcome. However it is our view that more could be done to provide an aggregated summary of the auction dynamics without revealing project specific detail or other commercially sensitive information.

6.433 As a result of work that led to this report and internal discussions, DECC have already initiated a process of review of rules on data access. In the March 2015 consultation[228], DECC has asked stakeholders' opinion on the potential relaxation of restrictions on non-price bid information and other non-sensitive information, which could be shared with the Secretary of State and used for evaluation purposes. As discussed earlier, we fully support this initiative.

In the future, enabling competition should be the focus in gaining value for money for consumers, rather than via Administrative Strike Prices

6.434 Under competitive allocation, the intention is that it is competitive bids and not Administrative Strike Prices (ASPs) that set strike prices, with the exception of

227 Specifically those included in Art.54 para.3).

228 "Consultation on changes to the CfD Contract & CfD Regulations", DECC, March 2015 https://www.gov.uk/government/uploads/system/uploads/attachment_data/file/410469/Group_3_consultation_MASTER.pdf Consultation closed on 20 April and is in its review phase with response expected in Summer 2015.

inframarginal technologies (eg EfW CHP). This was the case in the first allocation round where ASPs set the strike price for 4% of the anticipated budget spend. ASPs do still play a role in:

- capping strike prices; and
- setting strike prices for inframarginal technologies.

6.435 In this role, the main risks in setting strike prices are:

- setting strike prices too low so that projects are discouraged or unable to compete;
- inframarginal technologies take up a significant proportion of total spend; and
- setting strike prices too high in an environment where there is not effective competition.

6.436 To avoid discouraging competition it may be beneficial to set strike prices at the higher end of required revenue expectations. A continued focus on ensuring effective competition should therefore be the primary focus in gaining value for money for consumers to avoid ASPs setting strike prices.

6.437 Inframarginal technologies should not take up a significant proportion of the total spend. Given the technologies this refers to, sewage gas, landfill gas, EfW CHP, we think this is highly unlikely under the current budget pots. However, were this to ever be the case, then value for money will still be gained over such projects being awarded the competitive strike price.

Given competitive allocation ASPs should be set following a simple methodology in future

6.438 Developers across technologies generally felt that ASPs became largely irrelevant under competitive allocation and favoured a simple system of setting future ASPs. Many suggested they should be left as they are, or subject to a steady digression in line with Government objectives on reducing costs overtime. It will be important not to reduce ASPs so steeply that they discourage competition in an allocation round or the development of new projects. In particular, **we do not recommend using clearing prices to set ASPs for the following reasons:**

- **Clearing prices cannot be relied upon to represent marginal costs**, and therefore the required level of support to attract new investment – companies could rationally bid strategically for various reasons including whether one project is a test case for a pipeline of projects, or simply a ‘nice-to-have’ before exiting the market;
- **Clearing prices will depend where on the supply curve a particular project sits** – in earlier rounds cheaper projects may win, but if they only represent a small number of projects then clearing prices could rise, or just not fall as fast as anticipated cost reductions;
- **Sunk costs may not be included in bid prices and so understate development costs –** this could be a particular issue for earlier projects developed under the expectation of the RO.
- **It has not yet been demonstrated that projects are viable at the clearing price** – only once projects have been commissioned can it be certain that prices bid were viable.

6.439 **As ASPs need to be set at a higher level than anticipated strike prices to encourage competition, competition should be the focus of gaining value for money.**

6.440 Given the change in role of ASPs, we consider setting them in a more straightforward way in future would be more efficient than the current process. Such a methodology would need to be simple, transparent and consulted on with industry.

6.441 Should competition look unlikely for a particular technology or pot taking up a significant proportion of the budget, the need to adopt a more rigorous approach to setting ASPs would need to be reassessed.

The focus of technology modelling in future should be on setting budgets rather than Administrative Strike Prices

Technology modelling should still be undertaken, but the primary focus should be on setting budgets, pot allocation and maxima/minima to ensure the implications of these are in line with Government objectives. As under competitive allocation, it is these policy decisions that will have the greater impact on technology deployment, see paragraph 6.152.

Having a good understanding of the future project pipeline will be critical to ensuring budgets create competitive tension

6.442 The budgets for the October 2014 allocation round were set when a large pipeline of projects existed. These were also mainly developed under the expectation of non-competitive allocation. It is not yet clear how the pipeline will develop under a system of competitive allocation so assumptions cannot be made on the number and the capacity of projects in each that will be available to compete in future allocation rounds. It will therefore be of paramount importance to monitor how the market develops to ensure budgets are set at a level that enables competition for contracts, but provides sufficient budget for projects to feel able to compete.

6.443 Understanding the project pipeline as early as possible should also help to limit the number of changes to the budget parameters and improve certainty for investors.

Technology diversity under competitive allocation requires a long term plan to be developed

6.444 Under the October 2014 allocation round, onshore wind dominated Pot 1 and offshore wind dominated Pot 2.

- Technologies with no successful projects in Pot 1 were: landfill gas, hydro and sewage gas.
- Technologies with a small contribution to Pot 1 were: EfW CHP.
- Technologies with no successful projects in Pot 2 were: Biomass CHP, Anaerobic Digestion, Geothermal, and Wave and Tidal stream.
- Technologies with a small contribution to Pot 2 were: ACT.

6.445 The auction outcome is not surprising. In a mixed technology auction, a particular technology will dominate if:

- there is enough potential to use up the budget;
- there is little other cheaper resource (which could be limited by its ASP); and
- no other technology with sufficient resource at an equivalent cost.

6.446 Onshore and offshore wind currently fit this definition. If the costs of solar PV continue to fall this could also fit this category. As such, without adjustment to the current use of budget pots, and/or minima/maxima, it is possible that the dominance of one technology in each Pot could continue into the future.

6.447 In its EMR Delivery Plan, DECC set out its expected ranges of deployment by technology under the ASPs. The contribution from non-wind technologies has been lower than expected in the first CfD allocation round (see Figure 30). The extent to which these deployment levels are desired by DECC is not clear.

6.448 To deliver more technology diversity through future allocation rounds, **we recommend DECC put in place a long term plan of the desired energy mix in line with its**

renewables and decarbonisation targets. This would then be used to drive more detailed policy decisions on future budgets, pot allocations and the use of maxima/minima, as well as wider policy decisions.

6.449 The issues facing each technology other than onshore and offshore wind are summarised in paragraph starting 6.450.

There are a number of technology specific challenges

6.450 Even if the budget pots were to change, this may not be sufficient to ensure diversity. Whilst wind is likely to continue to form a large proportion of the future successful CfD allocations in the short term due to its deployment potential, there is the potential to gain a greater contribution from other technologies. A summary of technology specific challenges is given below.

Advanced Combustion Technologies

6.451 Whilst three projects were successful in the October 2014 allocation round, anecdotal evidence suggests these may not be typical projects, and so may not be an indication of the future ability for ACT projects to compete with offshore wind. Stakeholders felt that projects below 20MW would not be able to compete with offshore wind, and above that would struggle, but some projects may be able to compete. The average project size for an ACT in the pipeline is 12MW. Under DECC cost projections ACT costs don't fall in line with offshore wind and so it could also become less competitive over time. Also see paragraph starting 6.232 on meeting the milestone delivery date, and paragraph starting 6.164 on frequency of allocation rounds.

Anaerobic Digestion

6.452 The small scale FiT is currently more attractive as it does not require competitive allocation and offers a higher support level. This provides little incentive to develop AD projects larger than the 5MW threshold. Under DECC cost projections, AD costs don't fall in line with offshore wind and so it could also become less competitive over time.

Biomass CHP

6.453 Biomass CHP developers felt that projects below 25MW would struggle to compete with offshore wind. As CHP is dependent on an appropriate location, this limits the number of projects able to compete. At the time of writing there are 3 projects with a combined capacity of over 130MW above 25MW in the pipeline, where the pipeline of all projects is over 320MW across 22 projects. In addition, biomass developers consider the current contract difficult to finance given the requirement for a heat offtaker – biomass CHP currently have a five year grace period if their heat offtaker falls away, after which time their CfD contract is terminated. The provision of heat is very site specific so this could be a particular company going bust or moving away from the area, and there may not be another similar organisation nearby. **We recommend DECC investigate the implications of the heat offtake requirements further and if necessary identify a solution to prevent this causing a barrier to new biomass CHP projects.**

Geothermal

6.454 This is an early stage technology that is yet to be demonstrated at CfD scale in the UK, it could struggle to compete with better established technologies such as offshore wind.

Hydro

6.455 Like AD, hydro is likely to favour the small scale FiT. At the time of writing there is just one unbuilt hydro project above 5MW currently with planning permission in the Renewable Energy Planning Database[229].

Landfill gas and sewage gas

6.456 Landfill gas and sewage gas deployment, particularly in the near term, is likely to be limited by strike prices rather than competition with onshore wind. The potential for new landfill gas and sewage gas capacity may be limited, though given it is relative cost effectiveness it would be worth assessing what additional capacity could be gained from increasing the ASP.

Solar PV

6.457 Five projects were successful in the October 2014 allocation round, three of which signed a contract. PV can be commissioned in relatively short timescales and in modular design. This raises issues with the timescales for auction rounds, delivery dates and milestone delivery, see paragraph 6.164, and the requirement to reach a certain financial commitment to meet the milestone delivery date, see paragraph starting 6.232.

Wave and tidal stream

6.458 There is currently 6MW of wave and tidal stream accredited under the RO, the most recent of which was accredited in January 2013. No wave or tidal stream projects applied for the October 2014 CfD allocation round despite the 10MW minima. Wave and tidal stream stakeholders feel that the current policy environment is not sufficient to drive the commercialisation of wave and tidal stream technologies. This is against a backdrop of a challenging time for the wave and tidal stream sector: in 2014 Pelamis went into administration, Siemens announced plans to divest MCT, and Aquamarine Power announced its intention to downsize.

6.459 Given the reasons explained in paragraph 6.459, we consider it unlikely that wave and tidal stream projects will be deployed to reach commercialisation without further Government intervention[230]. Stakeholders provided many suggestions about how the policy environment could be adapted for wave and tidal stream developers. The key message was that if Government wants to drive commercialisation of wave and tidal stream it needs to make a firm commitment to do so, communicate this, and hold a discussion with industry to formulate a plan to achieve it. We agree this would be an appropriate starting point and is consistent with our recommendation for DECC to developing a clear vision of its desired future technology mix, see paragraph starting 6.444.

6.460 We note that the reasons for desiring commercialisation of wave and tidal stream may come from the anticipated economic benefits of building a new British industry, rather than simply its attraction as a source of renewable energy. So this is as much a matter for the Department for Business, Innovation and Skills (BIS) as it is for DECC, and requires co-ordination between the two departments.

6.461 Areas of concern amongst wave and tidal stream developers are the level of support, eligibility of test centres for CfDs, contract terms eg contract length and MDD and grid upgrade costs.

229 Available on DECC's website.
230 We accept that this may happen with sufficient global deployment, independent from UK Government intervention.

Larger projects are likely to continue to dominate the CfD auctions

6.462 Larger projects of specific technology benefit from economies of scale and so are likely to be more competitive on price. Larger organisations are also more likely to be able to develop projects under competitive allocation, as a portfolio of projects allows risk to be spread.

6.463 This is the inevitable result of competition and so without setting aside budget for smaller projects eg through the use of minima or maxima, or more regulatory restrictions, it is unlikely this will change. An exception to this may be offshore wind, where the size of the budget pot can restrict the size of project able to apply.

Recommendations

6.464 In the previous sections we have described our detailed findings on the Contract for Difference evaluation. Building on these findings, our recommendations for future rounds of the CfD are set out below.

Primary recommendations

6.465 **Maintain stability of the current structures and processes to ensure investors can adjust to the scheme is highly desirable, however there is plenty of scope for further evolutions to correct and streamline processes in detail.**

6.466 **Provide structural visibility on the long-term commitments to renewables and clarity around the future of the CfD allocation rounds.** As discussed in our report, this lack of visibility combined with the uncertainty around how future policy will shape competition are one of the key issues that may prevent the CfD regime to deliver on the expected cost of capital benefits and attractiveness to a wider range of investors. Increased visibility will also allow fostering a healthy, appropriately sized new pipeline of projects, helping developers to price and manage allocation risk and decrease the risk of speculative/opportunistic behaviours in the allocation process.

6.467 **When the LCF is being set beyond 2020/21 we recommend DECC discuss with Treasury the potential to introduce further flexibility to adjust budget caps in response to a sustained change in wholesale electricity prices.** This will to enable DECC to provide longer term visibility of CfD budgets to promote a healthy pipeline of projects and make more informed decisions over the distribution of spending between allocation rounds.

6.468 **Put in place a long term plan of the desired technology mix as auctions are not technology neutral ie different budget pots, to ensure that any technology differentiation is consistent with the outcomes Government desires.** This could be used to drive more detailed policy decisions on future budgets, pots allocations and the use of maxima/minima as well as wider policy decisions. Investors would also benefit from clarity on how competition will be shaped by policy.

6.469 **Put in place a more consistent and more transparent approach to pot allocation, maxima and minima policy decisions** based on an evaluation of all technologies against a single set of metrics (eg based around the causes of economic inefficiency identified in paragraph 5.108). Alongside a clear explanation for what constitutes a significant enough issue it needs addressing. This should also **include consideration of the options for valuing reliable capacity to recognise its contribution towards meeting security of supply objectives and addressing potential compatibility issues between offshore wind and other Pot 2 technologies**. It should also be consistent with DECC's long term desired technology mix. This should be a long- term methodology to increase future visibility over policy decision- making but will need to recognise Government requirements for flexibility whilst providing a clear rationale and robust mechanism for change.

6.470 **Streamline the allocation process to decrease uncertainty for participant, facilitate participation and mitigate the risk of speculative applications.** We would recommend introducing a separation between the application and appeal process from the auction itself. A rolling application process with a clearly defined date by which qualified applications could take part in an auction would mitigate risk of delays in the allocation round to all participants.

6.471 **Review the frequency of allocation rounds as part of DECC's wider assessment** of future distribution of budgets across pots, reallocation of technologies and other elements impacting the ability of projects to compete on a level playing field.

6.472 **Maintain stability in the high-level auction design to support investor confidence, however simplify some of its more detailed features,** specifically by relaxing the constraints on flexible bidding.

6.473 **Reinforce some of the measures against speculative or disruptive behaviours in consultation with stakeholders.** A number of recommendations are proposed:

- Separate the qualification process from the allocation round (as discussed above);
- **Relax the rules governing the access to data managed by National Grid** during the allocation process in favour of transparency and detection of potential speculative behaviours with the aim to assess whether a policy change is required to respond and/or prevent future violations.
- **Consider the introduction of an actual financial penalty that attaches a 'cost' to the use of strategic bids,** but in consultation with stakeholders so as to ensure they are proportionate and do not become a barrier to entry.
- **Introduce staggered milestones and/or time-related financial penalties** with the objective of facilitating the fast recycling of capital into future rounds. This should be subject to considerations on proportionality and undesired complexity.
- **Review the valuation formula used in the clearing price algorithm** to address positive contributions to the available budget from bids that are result from a non-legitimate or opportunistic strategy.
- Monitor whether the choice of setting the Target Commissioning Date very close to the Delivery Year is a strategic behaviour that may lead to sub-optimal budget allocation and management.

6.474 Monitor market developments and evolution of the regime. **This is particularly important to provide the Government with further evidence on whether the CfD regime is on track to deliver its objectives, and whether issues arise from its practical implementation:**

- Monitor the ability of budget and overall policy to provide a healthy level of competition, including the desired technology diversity;
- Assess the evolution of strike prices over multiple rounds and the actual deliverability of contracted capacity with the objective to verify whether project efficiencies, innovation and cost reductions are facilitated by the regime;
- Identify if there are any investment hiatus issues with new investments once the RO-led pipeline dries out;
- Assess whether the CfD Contract proves itself as suitable for various financing structures and project deliverability during the construction phase; and
- Monitor how conditions for access to financing and route to market agreements evolve with the objective to identify barriers to investments and/or benefits realised by investors that should be transferred to the final consumers.

Secondary recommendations

6.475 **Focus on competition to gain value for money rather than Administrative Strike Prices, as these need to be set higher than anticipated clearing prices.** To enable this we recommend:

- **Focus future technology modelling (deployment and associated cost outcomes) on budget rather than Administrative Strike Price decisions.** This modelling should include modelling budget scenarios across technology pots and over time against the EMR objectives (see section starting with paragraph 6.153) to understand trade-offs under a fixed LCF budget. To improve the modelling project specific load factors for large projects and a range of strike prices should be used.
- **Make every effort to gain a good understanding of the future project pipeline**, as this will be critical to ensuring budgets create competitive tension; and
- **Set ASPs in a more straightforward way in future.** Such a methodology would need to be simple, transparent and consulted on with industry (see paragraphs 6.438 to 6.441).
- **DECC discuss with Treasury the potential to introduce further flexibility to adjust budget caps in response to a sustained change in wholesale electricity prices, when setting budgets beyond 2020/21.** To promote a healthy pipeline of projects and make more informed decisions over the distribution of spending between allocation rounds.

6.476 With respect to the **qualification process**, our recommendation to DECC is:

- Review the **grid connection offer** requirement and whether it is causing any distortions in the way different projects are treated eg due to size or region. This includes whether greater flexibility to avoid barriers to participation for smaller generators would be appropriate;
- We recommend that DECC investigate how it can mitigate the potential for projects to be over penalised for minor indiscretions including education and the potential to introduce a very limited degree of discretion into the eligibility assessment.; and
- Publish the scores awarded to the supply chain plans and associated reasons for success.

6.477 **Increase the level of transparency** of a number of processes to avoid misinformation and give stakeholders the opportunity to challenge the process:

- **Set the process of future budget where information is not commercially sensitive or compromises the functioning of the auction.** This also includes our recommendation to avoid changes to the budget while the allocation round is live, unless justified by sudden and substantial changes in market circumstances; and
- Disseminate the policy decision narrative through a consolidated source of all the important information for participants to access.

6.478 **With respect to the circulation of information and communication protocols, we recommend DECC to:**

- Encourage National Grid and the LCCC to maintain a high level of knowledge dissemination and engagement with potential participants to future CfD rounds;
- Tighten the communication protocols between the National Grid and stakeholders during the allocation process, for instance by improving the robustness of the confirmation of receipt mechanism and the verbal communication security measures; and
- Clarify the treatment of confidential information related to the allocation process by National Grid and what is disclosed to the Government and the public.

A Glossary

Term	Description
AD	Anerobic Digestion
ACT	Advanced Combustion Technologies
ASP	Administrative Strike Price
BIS	The Department for Business, Innovation and Skills
BSC	Balancing and Settlement Code
CAISO	the Californian Independent System Operator
CCS	Carbon Capture & Storage
CCC	Committee on Climate Change
CCGT	Combined Cycle Gas Turbine
CfD	Contracts for Difference
CHP	Combined heat and power
CM	Capacity Market
CMA	Competition Market Authority
CMRS	Central Metering Registration Service
CMU	Capacity Market Unit
CONE	Cost of New Entry
CPF	Carbon Price Floor
CUSC	Connection and Use of System Code
DB	Delivery Body
DDM	Dynamic Dispatch Model
DECC	Department of Energy & Climate Change
DNO	Distribution Network Operators
DSR	Demand Side Response
ECA	Export Credit Agencies
EDR	Electricity Demand Reduction
EfW	Energy from Waste
EMR	Electricity Market Reform
EU	European Union
ESC	Electricity Settlements Company

Term	Description
EPC	Engineering Procurement and Construction
EPS	Emissions Performance Standard
FBC	Full Business Case
FCFS	first come first served
FiT	Feed-in Tariff
FID	Final Investment Decision
FIDeR	Final Investment Decision Enabling for Renewables
FTE	Full Time Equivalent
GFCC	Global Financial Credit Crisis
GHG	Greenhouse Gas
GIB	Green Investment Bank
GVA	Gross Value Added Assessment
IC	Investment Contract
IED	Industrial Emissions Directive
ISO-NE	Independent System Operator New England
LCCC	Low Carbon Contracts Company
LCF	Levy Control Framework
LEBA	London Energy Brokers Association
LHV	Lower Heating Value
LoLE	Loss of Load Expectation
LSD	Longstop Date
MDD	Milestone Delivery Date
MFO	Multilateral Financial Organisations
NDD	Non-Delivery Disincentives
NPV	Net Present Value
OBC	Outline Business Case
OCGT	Open Cycle Gas Turbine
OLR	Offtake of Last Resort
ORE	Offshore Renewable Energy
ORED	Office for Renewable Energy Deployment

Term	Description
PAB	Pay-as-Bid
PAC	Pay-as-Clear
PFI	Private Finance Initiative
PJM	Pennsylvania, New Jersy and Maryland
PMO	Project Management Office
PPA	Power Purchase Agreement
PT Threshold	Price Taker Threshold
PTE	Panel of Technical Experts
PV	Photovoltaic
RED	Renewable Energy Directive
RO	Renewable Obligation
RHI	Renewable Heat Incentive
RSI	Residual Supplier Index
SBR	Supplemental Balancing Reserve
SCP	Supply Chain Plan
SCR	Selective Catalytic Reduction
SI	Statutory Instruments
SOC	Strategic Outline Case
SoS	Secretary of State
ssFiT	Small-scale Feed-in Tariff
TA	Transitional Arrangements
TCD	Target Commissioning Date
TCW	Target Commissioning Window
TEC	Transmission Enetry Capacity
TNUoS	Transmission Network Use of System
UEP	Updated Energy Projections
WACC	Weighted Average Cost of Capital

B Meeting Government's decarbonisation and renewables objectives

Meeting renewables and carbon reduction targets

B.1 The UK has signed up to the following renewable energy and carbon reduction targets:

- **2020** – The European Commission's Renewable Energy Directive (RED). This states that the UK must source 15% of its energy consumption from renewable sources by 2020 (the 2020 Renewable Energy Target). This includes consumption from the electricity, heat and transport sectors. The UK Government considers at least 30% of electricity from renewable sources to be in line with this target[231].
- **2030** – The European Commission has an objective to source at least 27% of its energy consumption from renewable sources by 2030. This target is due to be translated into a European Directive in 2015/16. No individual Member State targets have been set, so it is not yet clear what this means for the UK.
- **2050** – The Climate Change Act 2008 which sets a binding target to reduce Greenhouse Gas (GHG) emissions in the UK by at least 80% by 2050, relative to 1990 levels.[232,233]

B.2 Four scenarios were created to assess the UK's progress towards electricity's contribution to the 2020 Renewable Energy Target based on capacity committed to date ie FID Enabling for Renewables and Round 1 CfD contracted capacity alongside, RO and ssFIT supported projects and unsupported renewables. No capacity from future CfD rounds has been assumed. A full explanation of the assumptions made under each scenario is given in paragraph B.12. The scenarios can be summarised as:

- Baseline Build – Assumes all and CfD contracted capacity (including FID Enabling for Renewables contracts)[234] commissions as planned and takes our central assumptions of new build under the ssFiT/RO.
- Central Build – As the baseline scenario but assumes some CfD contracted capacity fails to commission.
- High Build – As the baseline scenario but assumes higher ssFiT/RO new build, and higher load factors for biomass conversion and large biomass with CHP.
- Low Build – Assumes lower ssFiT/RO new build, lower biomass conversion load factors, and lower success rate of contracted CfD capacity than in the baseline and central scenarios.

B.3 We compare our scenarios to the 'NG Scenario 1' which was the base case scenario presented by National Grid as part of DECC's EMR Delivery Plan[235]. This scenario fulfils the criterion of supplying at least 30% of renewable electricity. Thus it provides a useful comparison between expectations at the time of the Delivery Plan and following the award of CfD contracts.

231 EMR delivery plan, DECC, December 2013.

232 The European Commission also has a similar 2050 target for the whole of the EU but the Climate Change Act 2008 is already legally binding, and UK specific, and so in practice is likely to lead UK policy.

233 To guide progress on the 2050 target the Committee on Climate Change (CCC) publishes carbon budgets covering five year periods. The review of the latest carbon budget (Fourth Carbon Budget Review, 2013) recommends the UK government should set a carbon intensity target range from 300gCO2/kWh in 2020 to 50gCO2/kWh in 2030.

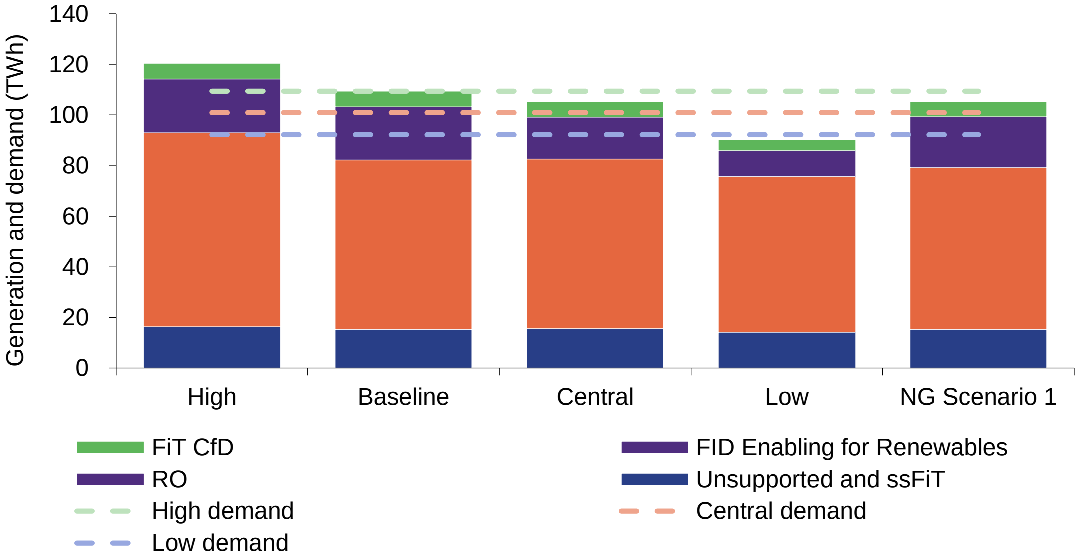
234 This includes that Lynmouth and Drax biomass conversions which have not yet signed a contract but are expected to do so provided they gain State Aid approval.

235 Electricity Market Reform Delivery Plan. DECC, December 2013.

Progress of renewable electricity towards the UK's 2020 Renewable Energy Target

B.4 Figure 29 shows how anticipated generation under our four scenarios compares to DECC's electricity demand assumptions required to meet 30% of electricity consumption.

Figure 29 - 2020 Build scenarios by support scheme (TWh)



B.5 Under DECC's Central 2020 demand assumption, electricity's contribution to the 2020 targets would be met in all but the Low Build scenario even if there were no further CfD allocation rounds[236]. If demand increases to 2020, the target capacity secured in further CfD allocation rounds is likely to be required to ensure the target is met.

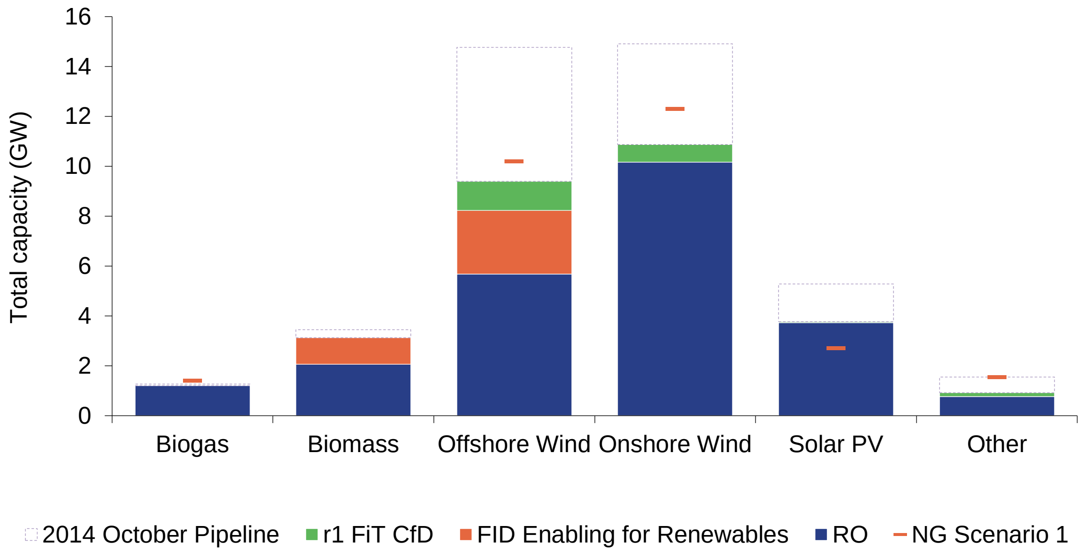
B.6 Under the Central scenario just over a fifth of generation expected to come from the CfD contracted capacity, with almost three quarters of that having been allocated under the FID Enabling for Renewables.

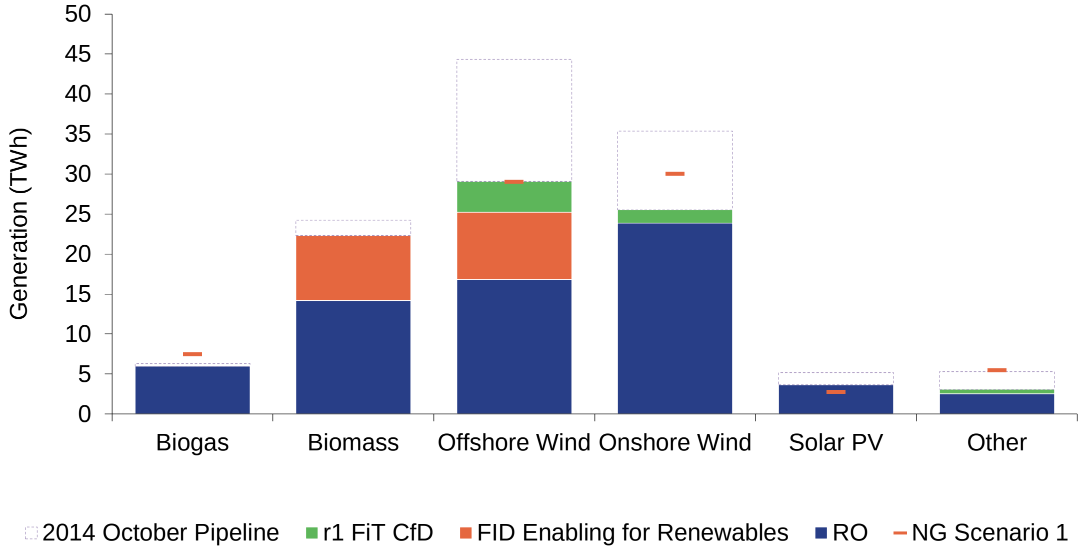
B.7 Figure 30 shows our Central Build scenario by technology and support scheme against National Grid scenario 1. All FID Enabling for Renewables contracts were awarded to offshore wind and biomass projects. The October 2014 successful projects were primarily offshore wind and onshore wind.

B.8 The chart also shows the pipeline for each technology at the time of the October 2014 CfD allocation round. The pipeline is made up of projects that had obtained planning permission in time to compete in the first allocation round, but does not include projects that were successful in the October 2014 allocation round. There is a significant volume of onshore and offshore wind in the pipeline that could be deployed in future allocation rounds if budget was made available. The potential pipeline for solar is much higher than shown in Figure 30; because of the short construction timeframe and small capacity of the typical scheme many projects that could be available for a future allocation round will not yet have planning permission. Similarly there is potential for a much higher contribution from biomass conversions.

236 However, we would advise further allocation rounds, see paragraph beginning

Figure 30 – 2020 Central Build scenario by technology: capacity (GW) and generation (TWh)





What post 2020 targets mean for deployment

B.9 The Committee on Climate Change (CCC) argues that strong progress towards the 2030 target is required for the UK to meet its 2050 target in a cost-effective manner.

B.10 The CCC recommends deployed capacity in 2030 should reach 25GW of onshore wind, 26-40GW of offshore wind, and 13-36GW of biomass and other renewables[237]. For offshore and onshore wind this equates to around 1.5GW of capacity of each technology installed each year throughout the 2020s most little decommissioning of older capacity. For both these technologies it means many additional projects will need to be developed to the stage they can apply for the CfD beyond those already in the pipeline as shown in Figure 30.

237 'Fourth Carbon Budget Review – part 2', Committee on Climate Change, 11 December 2013.

B.11 In addition to renewables the CCC recommends the 2030 capacity mix should consist of 12-19GW of nuclear and 10-15GW of CCS. Should more or less of these technologies be deployed than expected, renewables ambitions could change accordingly.

Key assumptions

B.12 The differences in assumptions between the scenarios are given in more detail in Table 11.

Table 11 – Summary of scenario assumptions to assess the UK's progress toward electricity's contribution to the 2020 target

	Baseline	High	Central	Low
RO capacity	• Operational capacity • Central new build assumptions	• Plus 3 large projects • Plus 20% extra new build capacity for smaller projects	• As Baseline scenario	• less one large project • 20% less new build capacity for smaller projects
Awarded CfD contracts including FID enabling for Renewables	• All contracted capacity	• As Baseline	• Less two large projects • 95% of smaller project capacity commissions	• Less four large projects • Half of smaller project capacity commissions at 75% of proposed capacity
Unsupported and small-scale FiT	• As NG Scenario 1	• 20% more new build capacity	• As Baseline scenario	• 20% less new build capacity
Biomass conversion load factors	• 87%	• 90%	• As Baseline scenario	• 70%

Detailed assumptions

- CfD contracted capacity – LCCC's CfD Register plus the successful biomass conversions
- CfD/FID enabling for Renewables Capacity Load factors – Final Allocation Framework, EMR Delivery Plan for biomass CHP[238]
- RO operational capacity to March 2014 – Ofgem's Renewables and CHP register

238 The EMR Delivery Plan load factor (90%) was used for biomass CHP ie Teesside rather than the Final Allocation Framework load factor (64.5%) as this is what was used to calculate the impact of FID Enabling for Renewables projects on the LCF. The load factor for offshore wind is consistent between the two documents.

- Central RO new build assumptions:
  - new RO offshore wind capacity – one large project;
  - new biomass conversion capacity – no further conversion due to the consultation on changing the grandfathering policy to conversions and co-firing[239];
  - new dedicated biomass capacity – all projects on the 400MW list commission by the end of the grace period; and
  - Other new RO capacity – assume 2013/14 build rates continue except in 2016/17 where deployment falls to 50% of that level, and the RO is closed thereafter. The exceptions to this are for biomass CHP where the rate is not halved in 2016/17 due to grace periods, and also for solar PV where we assume deployment continues at the same rate as <5MW deployment in 2013/14 due to the imposed limit on projects above 5MW)
- RO capacity load factors – 2015/16 Renewables Obligation Calculation[240]
- Unsupported and ssFiT – the NG scenario 1 'Other renewables':
  - minus dedicated biomass without CHP (from Ofgem's Renewables and CHP Register)
  - plus unsupported Hydro (NG scenario 1 'Hydro' minus RO Hydro from Ofgem's Renewables and CHP Register)
- Demand – Central demand figures were issued by DECC which was from the Sep 2014 UEP GB annual demand projections The High and Low demand figures were calculated by applying the High and Low differential from the Central figures presented in the National Grid Delivery Plan report. We take the minimum contribution intended from renewable electricity as 30%.

Strengthening supply chain and industry development

B.13 The 2013 OBC outlined two objectives relating to strengthening the supply chain and aiding industry development as follows:

- To enable a steady pipeline of projects, through preventing an investment hiatus, to enable industry development and drive down costs; and
- To provide new jobs and supply chain opportunities for British companies, resulting from the construction and operation of renewable electricity projects.

Supply chain strengthening

B.14 In addition to the analysis undertaken as part of our evaluation of FID Enabling for Renewables we have undertaken a desktop review of the public messages relating to supply chain that have been broadcast for each of the successful projects under the first CfD allocation round and the successful projects in the CM auction. These messages were also considered alongside the stakeholder research.

B.15 The potential benefits around the supply chain identified include:

- Inward investment into a sub region/ local economy as a result of a CfD/CM projects happening. In the case of Enviropark's Hiwaun project, this anticipated to generate up to £170m in inward investment[241]. Scottish Power have suggested that the Damhead

239 Consultation on changes to grandfathering policy with respect to future biomass co-firing and conversion projects in the Renewables Obligation.
240 Calculating the level of the Renewables Obligation for 2015/16, DECC, October 2014.
241 http://www.enviroparks.co.uk/news/media-releases/minister-launches-enviroparks-hirwaun-to-create-energy-and-jobs-from-waste/

Creek CM power plant project will inject an estimated £27 m into the Medway economy[242].

- The potential to use local businesses for contracts associated with the construction of the projects from construction and maintenance, ground works, quarry and building products, plant hire and haulage, waste solutions, fabrication, aggregates, utilities, professional services, and even hospitality. RWE have stated publicly that the Mynydd Y Gwair Wind Farm offers the potential to generate short and medium term contract opportunities for local civil engineering companies at the construction stage[243]. Building the £52million wind farm would also be good news for the local supply chain, with RWE already looking to work even more closely with local business groups to ensure local businesses benefit from the opportunities that will follow. Ongoing operations and maintenance could account for an additional £1.2 million annually into the Welsh economy and £0.6 million in South and South West Wales.

B.16 In the case of CM, given a large proportion of successful projects in the auction were for existing proven technologies such as CCGT[244], there is little evidence of industry development being presented as a key outcome of the first process.

B.17 However, trade bodies have publicly raised the concern that supply chain strengthening would not materialise if there was on-going uncertainty in the level of available budget for future allocation rounds[245].

B.18 One issue we noted from the evaluation of FID Enabling for Renewables was that the introduction of price competition in the enduring regime may discourage further industry wide cooperation going forward. To address this risk, under the enduring regime, DECC requires projects of a capacity of 300MW and over to submit a Supply Chain Plan (SCP) for assessment. The Department retains the right to publish these plans once a CfD has been awarded in order to share information with the supply chain and support implementation of CfD. Two SCPs have been published so far. These are for East Anglia One and Neart na Gaoithe offshore wind farms[246]. Irrespective of whether they are published we consider that it will be important for DECC to monitor supply chain benefits to assess whether the indicated benefits are realised.

Industry development

B.19 A key objective of EMR is to minimise the cost of electricity to consumers. In order to deliver this, in addition to supply chain strengthening, industry development was expected to be a key contributor to this.

B.20 From our evaluation of the eight successful FID Enabling for Renewables projects, a number of innovative products and approaches across the supply chain to help drive industry development for both biomass and offshore wind technologies were identified (for further details please refer to the FID Enabling for Renewables report). The offshore wind developments should remain valid for the CfD enduring regime. In addition to benefits specifically related to the FID Enabling for Renewables projects, Statkraft have informed DECC that they invested in design studies and geotechnical surveys in advance of receiving a final contract as the scheme had given them confidence that award of a contract was likely. Other benefits include a Dudgeon contract with JDR Cables for inter-

242 http://hoo-peninsula.blogspot.co.uk/2011/01/new-power-station-at-damhead-creek.html
243 http://www.rwe.com/web/cms/en/306332/rwe-innogy/sites/wind-onshore/united-kingdom/in-development/the-proposal/
244 https://www.gov.uk/government/statistics/capacity-market-location-of-provisional-results
245 http://www.renewableenergyfocus.com/view/41523/decc-releases-results-of-uk-s-first-auction-for-contracts-for-difference/
246 https://www.gov.uk/government/publications/contracts-for-difference-supply-chain-plans-for-projects-over-300mw-which-secured-contracts

array cables and cable accessories and Tekmar for cable supply, an extended DONG contract with Atkins for detailed offshore substation designs.

B.21 In respect of successful CfD projects, Iberdrola have publicly said that for the EA1 project, being the first UK offshore project to use a HVDC grid connection, means it will offer more of an opportunity to invest in the UK and build "on the UK's current engineering expertise." Iberdrola have indicated that net additional jobs would represent between £27 M and £52 M GVA per annum at a regional level, between £9M and £35 M for net additional jobs elsewhere in the UK, and in total between £36 M and £87 M. In addition Iberdrola have stated that" "EA1's contracts will also require that suppliers report UK content upon request. This will further drive a broadening of the UK supply chain and materially affect barriers to entry[247]."

B.22 In respect of the Neart na Gaoithe project, the company reports that it ran a "world class tender process" for its turbine and construction work packages to get the highest new level of technology, which involved more than 30 companies worldwide, with 50% of these being new entrants to the offshore sector[248].

B.23 However, the extent to which any of these projects will drive the intended industry development and innovation is unclear at this early stage. There were a number of opportunities cited for projects to share their learning more widely across the industry, for example, through groups such as SuperGen or through allowing engineering companies to retain the intellectual property. However, some of the proposed development is patented and therefore it is unclear the extent to which this will lead to industry-wide development. As with supply chain strengthening we consider that it will be important for DECC to monitor supply chain benefits to assess whether the indicated benefits are realised.

Employment impact

B.24 We understand that during the FID Enabling for Renewables process, the focus became one of developing the industry and strengthening the supply chain, rather than creating jobs. This was, in part, because assessing the economics of job creation is complex and any new jobs created may just be displacement or only have a temporary impact. The focus therefore shifted to improving and expanding workforce skills and capabilities.

B.25 We have however reviewed the job creation or safeguarding estimates publicly proposed by developers with successful projects under the first CfD allocation round.

247 East Anglia ONE Offshore Windfarm Supply Chain Plan, August 2014
248 http://renews.biz/89051/east-anglia-pushes-for-uk-jobs/

Table 12 – Public statements on job creation by projects allocated a CfD in the first round

Project	Public Statement
Enviroparks Hirwaun Generation Site[249]	200 jobs during construction and around the same number of jobs in the long term
K3 CHP Facility[250]	Will help safeguard 800 jobs at the paper mill. And will create hundreds of additional jobs and dozens of operational roles at the plant
EA 1[251]	More than 225 people were employed full time in the country. Peak employment of around 3,000 full time equivalent (FTE) jobs during construction in the entire supply chain
Neart na Gaoithe[252]	Creation of approximately 500 jobs during the execution phase of the project, and several hundred further jobs in the construction industry at fabrication yards, as well as for the required onshore civil works
Kype Muir Wind Farm[253]	226 jobs throughout the lifetime. Following feedback from the communities, they claimed that they've ring-fenced a proportion of the funding generated from the farm for new training and employment initiatives to help local people into a job
Clocaenog Forest Wind Farm[254]	During construction, Clocaenog Forest could sustain up to 236 full time equivalent (FTE) jobs, on average each year. Ongoing operations and maintenance could account for a further 22 FTE jobs, and 15 FTE jobs could be in North Wales
Middle Muir Wind Farm[255]	25 to 50 jobs will be created from construction to decommissioning. The wind farm will create jobs both in its construction and during its lifetime
Mynydd Y Gwair Wind Farm[256]	100 jobs. Ongoing operations and maintenance could account for a further 19 FTE jobs, of which 8 FTE jobs could be in South and South West Wales
Moor House Wind Farm[257]	Up to 30 people will work on site during the construction. The wind farm will bring direct employment to the area

B.26 In the case of CM, the analysis indicates that the majority of jobs created will be in construction (eg SSE have indicated 1,000 jobs on the new build Abernedd power station[258].

B.27 The analysis indicates that the projects have potential to make an impact on local jobs. It is not only limited on creating new jobs but also safeguarding existing jobs by doing work

249 http://www.enviroparks.co.uk/news/media-releases/minister-launches-enviroparks-hirwaun-to-create-energy-and-jobs-from-waste/
250 http://www.theade.co.uk/wheelabrator-uks-k3-chp-facility-secures-a-contract-for-difference_2920.html
251 http://www.norwichadvertiser24.co.uk/news/mixed_results_for_offshore_wind_projects_east_anglia_one_is_successful_in_government_auction_but_race_bank_and_galloper_not_included_1_3971124
252 http://www.fifetoday.co.uk/news/local-headlines/wind-farm-project-can-generate-jobs-1-3707635
253 http://www.banksgroup.co.uk/energy-minister-ed-davey-praises-kype-muir-commitment-to-local-firms/
254 http://www.rwe.com/web/cms/en/2325988/rwe-innogy/sites/wind-onshore/united-kingdom/in-development/economic-investment-and-business-opportunity/
255 http://www.bbc.co.uk/news/uk-scotland-glasgow-west-29377380
256 http://www.rwe.com/web/cms/en/1639590/rwe-innogy/sites/wind-onshore/united-kingdom/in-development/economic-investment-and-business-opportunites/
257 http://www.banksgroup.co.uk/hook-moor/news/work-set-to-start-at-14m-hook-moor-wind-farm-site/
258 http://www.bbc.co.uk/news/uk-wales-south-west-wales-12678852

on existing operations. It is difficult to calculate job changing effects but we consider that it will be important for DECC to monitor employment benefits/ local economy impact to assess whether the indicated benefits are realised.

C Definition of roles and responsibilities

C.1 There are seven main bodies undertaking the key roles and responsibilities for delivery and management of EMR:

- DECC;
- National Grid;
- LCCC (CfD only);
- Electricity Settlements Company (CM only);
- Elexon;
- Ofgem; and
- Independent Panel of Technical Experts (PTE).

C.2 The allocation of these roles and responsibilities discussed below, with particular attention to:

- Appropriateness of allocation;
- Clarity;
- Conflicts of interest; and
- Other emerging themes.

Roles and responsibilities were generally appropriately assigned and structured to keep EMR at arm's length from Government

C.3 Although implementation over time may reveal improvements in the division of roles and responsibilities within EMR, it would appear that in general roles and responsibilities have been well assigned. This is supported by the vast majority of stakeholders perceiving that roles and responsibilities were generally appropriately assigned, or not being opinionated on the matter. Stakeholders tend to hold the view that the structure has been set up such that Government is held at arm’s length from EMR in order to ensure an effective, robust and transparent delivery.

Roles and responsibilities appeared to be mostly clear with the exception of rule changes

C.4 In general, it seems that there is clarity over the assignment of roles and responsibilities. This view was supported by stakeholders. In addition to this, some stakeholders felt that further clarification was needed around the roles of DECC and Ofgem in the management of future changes to the CM rules. They added that better governance was needed in this respect given the high monetary values linked to CM.

Some confusion around roles and responsibilities was caused by the high number of bodies involved

C.5 The large number of bodies led to some confusion around roles and responsibilities for some stakeholders, with one government and regulatory stakeholder suggesting DECC should explore the possibility of simplifying. We note that the distribution of roles and responsibilities over several bodies allows for segregation of duties, which is generally considered to be conducive to a good control environment. However, this is not to say that such distribution of roles and responsibilities could not have been achieved within a single (or fewer) body(ies).

C.6 When it comes to the CfD, the introduction of a subsidy scheme based on a private law contract (ie CfD Contract) and the need for a legal counterparty (ie LCCC) appeared to add some confusion for generators about exactly what roles National Grid and Ofgem would play under the new policy, compared to their roles under the RO. Therefore generators may still need to familiarise themselves with the new structure.

A changing team at DECC caused confusion of individuals' roles

C.7 It has been noted that a constantly changing team at DECC meant that roles of individuals in DECC were sometimes unclear to stakeholders. However, continuity of staff members is difficult to guarantee considering the length of the process. It may be worth noting that one CM applicant questioned whether DECC had the required expertise and therefore suggested that they could have consulted an expert group earlier than they did.

National Grid are a skilled and appropriate choice for Delivery Body

C.8 Due to synergies with its current role and expertise as System Operator, National Grid is seen to be suitable to cover the role of Delivery Body. A number of stakeholders noted that National Grid's experience seemed to help the process and that it was beneficial to have a separate body to operate the process under CfDs. When it comes to CfD, there does not appear to have been any concern around National Grid's role in modelling strike prices.

There is generally little concern for any conflicts of interest with National Grid with minor concerns over institutional bias

C.9 There was generally very little concern about any conflict of interest for National Grid as the Delivery Body. The presence of the independent Panel of Technical Experts (PTE) in addressing conflicts of interest on analysis is considered in paragraph C.14 below, but is broadly positive. It may be worth noting that one stakeholder commented that National Grid observes internal information barriers well and did not allow information to be used to its commercial benefit. However, there were some reservations about a private entity acting in a quasi-governmental role, and it is worth noting some concerns were expressed about National Grid's conservative institutional bias which may lead to over-procurement, although this was only anecdotally raised by stakeholders.

LCCC is a trusted to fulfil its role with minor concerns that some stakeholders do not understand its decision-making powers

C.10 LCCC (in its primary role as CFD Counterparty and also as CFD Implementation Coordinator) has inherited a great deal of DECC experience and the industry trust in this entity (partly due to its government backing) has been good to date. It is noted that the LCCC Framework Document (dated 1st August 2014) gives careful consideration to its role and ensuring good governance, with day to day operational independence from Government.

The Electricity Settlements Company's role and responsibility is not under doubt

C.11 The Electricity Settlements Company retains overall accountability and control of the Capacity Market settlement process. As for LCCC for CfDs, the Electricity Settlements Company maintains independence from Government, which seems appropriate. Stakeholders did not comment in particular regarding the roles and responsibilities of the Electricity Settlements Company, perhaps indicating that the Electricity Settlements Company is not yet on the radar of stakeholders.

Elexon's role and responsibility is not under doubt

C.12 Given Elexon's current role in the market it seems to be an appropriate choice for this entity to perform the settlement function. Stakeholders did not comment in particular regarding the roles and responsibilities of Elexon, which may be due to its largely administrative role.

Ofgem has generally been allocated an appropriate role with minor concerns regarding conflict of interest

C.13 As regulator, it seems to be a natural role for Ofgem to perform conflict resolution. The view that Ofgem was allocated a suitable role was supported by a few stakeholders.

The Independent Panel of Technical Experts' role and responsibility is not under doubt

C.14 It seems important for there to be an impartial body to scrutinise and quality assure analysis carried out by National Grid in its role as Delivery Body. Several stakeholders welcomed the external scrutiny offered by the Panel of Technical Experts in their review of the recommendations for the capacity to procure under the Capacity Market, which helped to test and inform the target volume. The Panel also considered the potential for conflict of interest given the possibility that National Grid may have an interest in over-procurement and concluded that it was not aware of any specific cause for concern. This external review is considered to improve the robustness of the recommendations and supporting analysis.

D Budget setting process

D.1 There were a number of different iterations to the budget for the first CfD allocation round. The draft budget notice for the first CfD allocation was issued by DECC on 24 July 2014:

Table 13 – Cumulative indicative budget for the October 2014 allocation round (£m real average 2011/12 money)

	2015/16	2016/17	2017/18	2018/19	2019/20	2019/20
CFD Budget (2014 release)	50	205	205	205	205	205
Pot 1 (established technologies)	50	50	50	50	50	50
Pot 2 (less established technologies)	0	155	155	155	155	155

D.2 On 2 October 2014 DECC published the final budget notice for the first CfD allocation round, an increase from the 24th July 2014 draft.

Table 14 – Cumulative final budget for the October 2014 allocation round (£m real average 2011/12 money)

	2015/16	2016/17	2017/18	2018/19	2019/20	2019/20
CFD Budget (2014 release)	50	220	300	300	300	300
Pot 1 (established technologies)	50	65	65	65	65	65
Pot 2 (less established technologies)	0	155	235	235	235	235

D.3 On 28 January 2015 DECC issued a revised budget notice. This increased the budget for Pot 2 in the years 2017/18 onwards by £25 million.

Table 15 – Cumulative final budget for the October 2014 allocation round (£m real average 2011/12 money)

	2015/16	2016/17	2017/18	2018/19	2019/20	2019/20
CFD Budget (2014 release)	50	220	325	325	325	325
Pot 1 (established technologies)	50	65	65	65	65	65
Pot 2 (less established technologies	0	155	260	260	260	260

D.4 Each of the following elements of the budgeting process are described below:

- The top down calculation
- The bottom up calculations
- Scenarios and assumptions used
- Consultation with stakeholders
- The Quality Assurance procedures

Top down calculations

D.5 The top down calculation began with a calculation of the maximum LCF budget available in each delivery year deducting committed spend under:

- the RO (operating and new projects);
- ssFiT (operating and new projects);
- FID Enabling for Renewables;
- Running costs of the schemes; and
- CCS.

D.6 Whilst this was the maximum available to be spent, DECC was conscious it did not want to use all of the remaining budget as it:

- had already announced £50million for the next Pot 1 allocation round; and
- intends future allocation rounds to be held for both Pots to enable a smooth investment profile, and to leave open the opportunities to procure some projects at a lower price as the costs of technologies falls.

D.7 Other than £50million minimum indicative figure announced for a future Round 1 auction, there is no clear figure on how much would need to be left. A specific figure to be retained was not determined because it was considered the exercise would not be very precise and many variables could change between now and then.

Bottom up calculations

D.8 The amounts required to meet DECC's objectives for individual pots were considered independently from each other and only combined when comparing the budget requirement to the available budget under the LCF.

D.9 DECC worked out how much deployment would be needed on the basis of:

- sufficient deployment being ensured so that costs could fall over time;
- the minimum and maximum level of capacity under the budget leading to sufficient competition; and
- the amount of capacity that needed to be successful in the auction to ensure that State Aid goals were met.

D.10 To do this DECC analysed potential scenarios of successful projects, commissioning dates and level of expected spend based on pre-defined budgets.

Scenarios run

D.11 To match up the bottom up and top down approach DECC ran a number of potential project scenarios of successful projects, commissioning dates and level of expected spend based on pre-defined budgets:

- high and low fossil fuel prices;
- high and low load factors;
- RO with higher or lower deployment than expected; and
- Capacity at 25% below expectations under the CfD.

Assumptions used

D.12 Key assumptions were:

- Operational capacity – Ofgem RO and ssFiT figures;
- Renewables pipeline – ORED REPD and intelligence;
- Strike prices – Administrative Strike Prices;
- Wholesale electricity prices – those published in the latest version of the allocation framework;
- Load factors – as published in the allocation framework, historic values for RO and ssFiT
- FID Enabling for Renewables projects – all projects assumed to go ahead at declared capacity.

Quality Assurance process

D.13 The QA process followed was:

- Papers initially signed off by a senior member of staff (Grade 5);
- Reviewed by the relevant Senior Responsible Officer;
- Sign off by EMR Executive Board; and
- Sign off by the relevant Minister/Secretary of State.

D.14 The EMR Executive Board was principally set up to focus on the FID enabling for Renewables and EMR. Membership of board comprised of members from each relevant office eg nuclear, CCS, ORED plus finance and legal, all representing their interests but collectively having to make a decision. It is chaired by a Director General.

D.15 There is also an LCF working group to sign off key assumptions to ensure one consistent set is used eg RO deployment.

E Factors influencing future load factors

E.1 Under the CfD, load factors are an important parameter. They are used to:

- Set administrative strike prices – to calculate technology levelised costs, and generation resulting from a given strike prices;
- Calculate progress towards renewables and decarbonisation targets;
- Set budgets - calculating budget available by subtracting budget used by projects currently contracts under the CfD and budget used by projects not supported by the CfD
- Determine if an auction is to be held - as part of the valuation formula; and
- Determine when a delivery year is closed under an auction - through the cost impact of a project.

E.2 Whilst degradation of load factors over time was covered in the PTE review, we do not see reference to the actual load factor assumptions used and so comment upon them here. Our understanding is that DECC generally relied upon historic average load factors with the exception of project specific load factors used for biomass conversion and some consideration of technical potential for offshore wind.

E.3 In this appendix we focus primarily on onshore and offshore wind given it made up almost 90% of the capacity in the first allocation round. We also note that the biomass conversion load factor of 64.5% given in the allocation framework appears low in comparison to the load factor achieved by Drax's operating biomass conversions. These regularly demonstrate monthly load factors around 90%[259], based on Elexon data.

Onshore and offshore wind

E.4 The load factor for a wind farm depends on:

- Location specific wind speeds[260];
- Ratio of swept area to capacity[261];
- Hub height[261]; and
- Proximity of turbines to each other.

E.5 To gain an understanding of how load factors for wind might evolve in the future we have conducted analysis of the future project pipeline based on these elements with the exception of the proximity of turbines[262]. Our assessment of wind availability was based on high-resolution terrain and land use data to determine wind speeds. Load factors for specific sites and/or regions were then calculated based on wind speed data from 2006 to 2013. During these years, the UK experienced still, windy and average years making them a good representation of possible future wind speeds.

E.6 Our analysis indicates an expected load factor for new projects of 40.9% compared to the 37.7% used for strike price modelling due to both a change in turbine characteristics and the geographical distribution of the offshore wind pipeline.

E.7 New onshore wind projects generally appear to have an increase in swept area and average hub height. Our analysis indicates an expected load factor for the UK of 29.2% for new projects compared to the 28% used for setting administrative strike prices. Our

259 This assumes a converted unit capacity of 645MW.

260 Anemos hourly wind speed data was used at 20km grid points at hub height. Wind speed data was converted to wind generation based on wind capacity locations and appropriate aggregated power curves.

261 As published by 4C Offshore.

262 This has been a problem for some early wind projects, but new projects are expected to be sufficiently separated to avoid this issue.

analysis is therefore broadly in line with DECC's assumption, but it is an assumption worth keeping under review given its potential impact on CfD costs and budgets.

E.8 To give an indication of the extent to which characteristics can differ between projects Table 16 compares four example projects and their load factor calculated. Their load factor calculated for 2014 based on publically available Elexon data. Table 16 – Turbine characteristics for four example projects

	Commissioning year	Turbine capacity (MW)	Rotor diameter	Hub height	Load factor in 2014
Robin Rigg	2010	3	90	80	31%
Burbo Bank	2007	3.6	107	84	37%
Walney 2	2012	3.6	120	90	47%
London Array	2013	3.6	120	87	41%

F Technology differences

F.1 Table 17, Table 18 and Table 19 show the differences between technologies which are CfD supported.

Table 17 – Established (Pot 1) technology breakdown

		Onshore Wind	Solar PV	Energy from Waste with CHP	Hydro	Landfill Gas	Sewage Gas
Diversity	CfD Contract Baseload or Intermittent Technology[263]	Intermittent	Intermittent	Baseload	Baseload	Baseload	Baseload
	Fuel Source	Wind	Solar	Waste	Water	Landfill gas	Sewage gas
	Construction Time (years)[264]	2	1	4	2-3	1	1
	Load factor[265]	26.7% (>5MW)	11.10%	42.50%	34.50%	56.70%	51%
	Average Pipeline Project Capacity (MW)[266]	21	7.3	30	6	2	1
Maturity	Current Installed Capacity (GW)[267]	8.3	5.2	0.1	1.7	1	0.2
Potential	Pipeline Capacity (GW)[268]	4	1.5	0.1	0.01 (>5MW and <50MW)	0.01	0
Interaction	Interaction with Other Market Mechanisms	RO, ssFiT	<5MW RO, ssFiT	Landfill tax, RHI, RO	RO, ssFiT	RO	RO

263 A simplistic view of a technologies ability to respond to demand is presented here, some baseload generators will be much more flexible than others.

264 Table 19, for onshore wind and solar PV, https://www.gov.uk/government/uploads/system/uploads/attachment_data/file/223940/DECC_Electricity_Generation_Costs_for_publication_-_24_07_13.pdf
All other values are taken from the Restats database, https://restats.decc.gov.uk/app/reporting/decc/monthlyextract

265 Appendix 3 for all CfD technologies, https://www.gov.uk/government/uploads/system/uploads/attachment_data/file/349370/Final_Allocation_Framework.pdf

266 https://www.gov.uk/government/collections/renewable-energy-planning-data

267 DECC Energy Trends, March 2015, Table 6.1, Q4 2014 for onshore wind, solar PV, hydro and landfill gas, https://www.gov.uk/government/uploads/system/uploads/attachment_data/file/415976/ET_Mar_15.PDF
Regional Statistics 2003-2013 for sewage gas, https://www.gov.uk/government/statistics/regional-renewable-statistics
Energy from waste with CHP, data from December 2013, 0.4 assumed capacity in 2020 (page 41) and 0.3 assumed build between 2013 to 2020 (page 42), therefore assumed current capacity of 0.1, https://www.gov.uk/government/uploads/system/uploads/attachment_data/file/267614/Annex_D_-_National_Grid_EMR_Report.pdf

268 The pipeline capacity presented here has been calculated using the same methodology used in the outcome section of this document. A further explanation can be found in paragraph 6.303.

Table 18 – Less established (Pot 2) technology breakdown

		Offshore Wind	Wave and Tidal stream	ACT	Dedicated Biomass with CHP	AD	Geothermal
Diversity	CfD Contract Baseload or Intermittent Technology[269]	Intermittent	Intermittent[270]	Baseload	Baseload	Baseload	Baseload
	Fuel Source	Wind	Waves and Tides	Waste or solid biomass	Solid biomass	Primarily food waste and farm manures	Geothermal
	Construction Time (years)[271]	3	2	2	2-3	1.5	3
	Load factor[272]	37.70%	31%	64.50%	64.50%	59.40%	91.20%
	Average Pipeline Project Capacity (MW)[273]	400	35	12	15	3	8
Maturity	Current Installed Capacity (GW)[274]	4.5	0.01	0.02	0.2	0.2	0
Potential	Pipeline Capacity (GW)[275]	5.4	Tidal stream - 0.1, Wave - 0.05	0.4	0.3	0.05	0.02
Interaction	Interaction with Other Market Mechanisms	RO	RO, ssFiT	Landfill tax, RO	RHI, RO	RO, ssFiT	Grants, RHI, RO

269 A simplistic view of a technologies ability to respond to demand is presented here, some baseload generators will be much more flexible than others.

270 Tidal stream is predictable.

271 Table 19 for offshore wind, https://www.gov.uk/government/uploads/system/uploads/attachment_data/file/223940/DECC_Electricity_Generation_Costs_for_publication_-_24_07_13.pdf
All other values are taken from the Restats database, https://restats.decc.gov.uk/app/reporting/decc/monthlyextract

272 Appendix 3 for all CfD technologies, https://www.gov.uk/government/uploads/system/uploads/attachment_data/file/349370/Final_Allocation_Framework.pdf

273 https://www.gov.uk/government/collections/renewable-energy-planning-data

274 DECC Energy Trends, March 2015, Table 6.1, Q4 2014 for offshore wind, wave and tidal stream and AD, https://www.gov.uk/government/uploads/system/uploads/attachment_data/file/415976/ET_Mar_15.PDF
Ofgem ROC Register for ACT, dedicated biomass with CHP and geothermal.

275 The pipeline capacity presented here has been calculated using the same methodology used in the outcome section of this document. A further explanation can be found in paragraph 6.303

Table 19 – Biomass conversion (Pot 3) technology breakdown

		Biomass Conversion
Diversity	CfD Contract Baseload or Intermittent Technology[276]	Baseload
	Fuel Source	Solid, liquid, gaseous biomass
	Construction Time (years)[277]	1
	Load factor[278]	64.50%
	Average Installed Project Capacity (MW)[279]	630 (av.RO)
Maturity	Current Installed Capacity (GW)[280]	1.89
Potential	Pipeline Capacity (GW)[281]	0
Interaction	Interaction with Other Market Mechanisms	RO

276 A simplistic view of a technologies ability to respond to demand is presented here, some baseload generators will be much more flexible than others.

277 Table 19, https://www.gov.uk/government/uploads/system/uploads/attachment_data/file/223940/DECC_Electricity_Generation_Costs_for_publication_-_24_07_13.pdf

278 Appendix 3 for all CfD technologies, https://www.gov.uk/government/uploads/system/uploads/attachment_data/file/349370/Final_Allocation_Framework.pdf Project specific load factors for biomass conversion projects is necessary, load factor potentially much higher than this.

279 Average size of existing RO biomass conversion projects.

280 Ofgem ROC Register - for biomass conversion (2 Drax and Ironbridge).

281 The pipeline capacity presented here has been calculated using the same methodology used in the outcome section of this document. A further explanation can be found in paragraph 6.303.

G Stakeholder research methodology

G.1 The purpose of this section is to document the methodology implemented for the stakeholder research element of this evaluation alongside an overview of the level of engagement achieved. This methodology covers the stakeholder research undertaken for Capacity Market, Contracts for Difference and FID Enabling for Renewables. From the outset of the project it has been clear that the stakeholder research was to play a critical evidence generating role and as such it is essential that there is confidence in the robustness of the approach adopted and the results generated.

Key methodological considerations

G.2 Before providing the detail on the methodology it is important to set out the main methodological issues and challenges that were identified at the outset and which have ultimately shaped our approach. It is also worth emphasising that they are common to many other evaluations and the evaluation literature recognises that there is no 'silver bullet' to solve them.

Bias

G.3 Throughout the evaluation we have been cognisant of two main types of bias. The first is in relation to non-responses from certain stakeholder groups, or elements within particular stakeholder groups. The second type relates to the responses to questions given by individual stakeholders. This could be positive in the sense of saying what they think DECC want to hear, or negative as the evaluation process is used to 'lobby' or put forward particular view-points.

G.4 In order to help mitigate impact of this bias we have reflected on the variance in and between stakeholder groups, different technology types and their level of 'success'. Alongside this we have also tested the level of weight that can be place on each finding. This enabled us to identify any vested interests or viewpoints put forward with a particular agenda in mind.

G.5 We believe that our approach has minimised the negative impact of bias. Where we have identified a particular technology view we have ensured that this is presented as such and alongside responses from a wider cross section of stakeholders. Where we believe a view is the result of an application being unsuccessful/successful we have been transparent in identifying this. As such where findings or conclusions are presented without accompanying commentary or caveats it can be assumed that we have deemed that these are unaffected by issues of bias.

Reach and engagement

G.6 Linked to the issue of non-response bias it was important that the evaluation reached a full range of stakeholders and did not just engage with the 'usual suspects'. Reaching those parts of the market that do not normally engage or who have not engaged is a challenge but it is one that we have sought to proactively manage. As such, our approach focused more on the breadth of different stakeholder groups and sub-groups at the expense – in part – of the level of depth that we went into with a particular sub-group.

Stakeholder fatigue/burden

G.7 It was essential that the evaluation was mindful of stakeholder fatigue and over burdening those willing to participate. For many of the stakeholder groups time needed to be given up to the evaluation which is simply not part of the 'day job'. As such it was important that this time was used most effectively. Alongside this for a number of the stakeholders the request to engage in the evaluation formed another in a long list. In order to manage stakeholder fatigue and burden we implemented three measures:

- Ensuring that we were aware of other requests for information/communications from DECC and others.
- Being very clear from the outset how much time we expect the in-depth interview to take and sticking rigidly to this – unless of course the participant was willing to extend it.
- Deploying a range of methods for gathering evidence in order to make the best use of time and resources. We provided the stakeholders some degree of choice about which method we use in order to do as much as we can to facilitate positive engagement. All respondents were also given the opportunity to respond in writing.

G.8 These measures helped management of the risk of stakeholder fatigue and across the work there was a general willingness to engage.

Anonymisation of findings

G.9 It was agreed at the outset that all results would be anonymised and that none of the raw data would be passed on to DECC. This decision was made on the basis of both the desire to enable and encourage respondents to speak openly as well as not wanting to limit potential engagement.

Identifying and mapping the stakeholder universe

G.10 At the outset of the evaluation time we considered both who the key stakeholders groups are and their value to and level of interest/engagement in the evaluation. In total 13 different stakeholder groups were identified. The stakeholder universe was developed using a combination of sources including: analysis of previous DECC consultations, feedback from the DECC teams and our own team's extensive market knowledge and industry contacts.

Table 20 – Overview of stakeholder universe

Stakeholder group	Nature of the stakeholder group	Size of the stakeholder universe
Big 6 Utilities	All big 6 utility companies – looked at from both a generation and supply perspective	6
Power Generators/Utilities	All power generating companies including biomass, energy from waste, renewables, solar and wind developers, developing projects of a scale to be impacted by CfD	100+
Power Suppliers	Covers both domestic and industrial suppliers	10-20
Major Contractors	Major construction / services contractors	10-20
Supply Chain	Tier 1 and 2 technology providers active in the energy space and who are not major contractors plus feedstock suppliers	100+
Banks and Other Debt	Commercial funders providing debt finance to UK energy projects	50-99
Equity Investors	Private equity , equity funds investing in UK equity projects	50-99
Financial Institutions	Financial institutions providing finance to UK energy projects	20-50
Consumer Groups	Consumer groups focussed on domestic and industry energy consumers	10-20
Government and Regulators	Relevant Government and regulatory bodies across the UK	10-20
NGOs	Primarily environmental groups	10-20
Sector Associations	Trade associations specifically linked to different parts of the energy and renewables sector	10-20
Non-Sector Trade Associations	Trade associations linked to sectors / industries that are affected by the energy / renewables market	<10

G.11 These groups formed the foundation of our sampling framework and evaluation methodology.

Sampling framework

G.12 The approach taken to the sampling was relatively simple and was based around two key parameters: ensuring we achieve the breadth of coverage required within individual stakeholder groups; and segmenting across a small number of variables which we believed were likely to result in differences of opinion or view.

G.13 Given the emerging nature of the sector and the relatively small number of organisations involved, a purposive sampling method was adopted on the basis that it is the most practical and effective method. This approach enabled us to effectively engage stakeholders who have diverse and varied levels of engagement with and understanding of EMR. For example it gave us the scope to engage both those who have had significant engagement to date as well as those that have not engaged – a key factor for this evaluation. We believed that while this purposive approach did introduce a degree of selection bias a more structured sampling approach would have removed our ability to: get the most from our market knowledge; engage effectively with the sector; and target resources appropriately.

G.14 Alongside this, given the qualitative nature of the evaluation and the fact that we are not looking to 'gross up' responses to be representative of the whole stakeholder group we expected the impact of any selection bias to be minimal and unlikely to have any bearing on the findings of the evaluation.

Evaluation methodology

G.15 The evaluation method adopted revolved around three main types of engagement:

- In-depth qualitative interviews – these semi structured interviews were based around a detailed topic guide and undertaken by senior and experienced members of the evaluation team, principally the relevant work stream lead. These team members had a good understanding of the policy and its associated issues and worked closely with the relevant teams in DECC.
  Given the exploratory nature of this evaluation coupled with the diverse experiences and engagement of the stakeholders in EMR it was felt that the use of semi-structured interviews provided the required flexibility. The topic guides are structured around seven primary topics: role and relationship to CfD and FID Enabling for Renewables; design and parameters; management of the process; achieving objectives; outcomes; lessons learned; and AOB. Below each of these topics there were a series of questions that focus on a range of relevant issues. The interviewers covered each of the primary topics during the interview but the specific questions asked varied depending on the interviewers' judgment of what the interviewee has most to contribute on. This was based on both the role and involvement in the EMR process of the interviewee and the interviewee's specific interests. This approach enabled the interviewers to extract the most value out of the interview by focusing on the most pertinent and relevant issues.
- Stakeholder round tables – these round tables brought together a number of stakeholders within a particular group and were structured around a series of key topics. The workshops were facilitated by senior and experienced members of the evaluation team, again primarily the work stream leads. The use of workshops was guided by the views of key industry representatives as to their effectiveness as a means of engagement with particular members. For example we worked with various Renewable Trade Associations to effectively engage their members. These workshops covered the same seven primary topics in the interview topic guide.
- Written responses – all stakeholders regardless of whether they are in our sampling frame or not were invited to respond to a short email survey. These written responses contained a mixture of open and closed questions structured around the seven primary

topics. The use of closed questions in the written responses had the added advantage of helping to identify and manage any response bias that may exist.

Level of engagement

G.16 Through the stakeholder research process, 149 stakeholders responded through the three different engagement modes: 62 stakeholders participated in an in-depth qualitative interview; 44 provided written responses (with an additional 29 of those interviewed also providing a written response); and 43 participated in the various round-tables[282].

G.17 These stakeholders were engaged in a short time window with all activity taking place between mid-March and mid-April. For the CfD and FID Enabling for Renewables work streams the engagement took place between 9 March 2015 and 14 April 2015. The reason for this contracted engagement window was that we wanted to avoid contamination by engaging stakeholders who were actively participating in the allocation round.

G.18 Across the three different work streams we interviewed 15 stakeholders in relation to CM and 21 in relation to CfD and FID Enabling for Renewables[283]. In addition to this we also interviewed 16 financial stakeholders covering both equity and debt and 10 overarching stakeholders from a range of government and trade bodies.

282 It should be noted that a small number of the stakeholders that were interviewed also participated in the round-tables. In our analysis we ensured these views were only 'counted' once.

283 For the large majority of the organisations interviewed the same individual(s) was identified as the primary contact for both CfD and FID Enabling for Renewables and as such these interviews were done jointly.

Table 21 - Overview of stakeholder groups engaged in the stakeholder research

Stakeholder Group	Size of the stakeholder universe	Level of response	Notes
Power Generators and/or Developers	100+	56	A range of different sized organisations, ranging from UK (including Big 6 and non-Big 6 including independent generators), based in the UK and worldwide
Power Suppliers	10-20	2	
Major Contractors	10-20	3	
Supply Chain	100+	4	A range of different sized organisations
Banks and Other Debt	50+	6	A range of different sized organisations, based in the UK and worldwide
Equity Investors	50+	10	A range of different sized organisations, based in the UK and worldwide
Financial Institutions	20-50	2	
Consumer Groups	10-20	-	A number of attempts were made to engage different consumer groups in the evaluation but without success. We deem their 'non-response' to have negligible impact on the findings
Government and Regulators	10-20	6	
NGOs	10-20	2	
Sector Associations	10-20	6	
Non-Sector Trade Associations	<10	1	
Consultants/Lawyers	20+	12	A range of different sized organisations, based in the UK and worldwide
Other		12	Including a test centre, utilities analyst, demand-side response

G.19 The data provided by these interviews along with that from the roundtables and written responses has provided a rich vein of evidence to be analysed and synthesised.

Stakeholder coverage – CM

G.20 Across CM we undertook 15 interviews. This included a mixture of participants across technologies and participant types, with differing outcomes from the auction in terms of the extent to which capacity agreements were secured. 18 written responses added additional feedback (of which 10 were from entities that were also interviewed). Of the 23 ‘unique’ responses, 18 were from participants and 5 were from non-participants. Of the 18 participants, five secured capacity agreements for all their prequalified CMUs, four secured no capacity agreements and 9 had a mix of prequalified CMUs obtaining or not obtaining capacity agreements.

Stakeholder coverage – CfD

G.21 Across FID Enabling for Renewables and the enduring CfD regime we undertook over 47 interviews. 21 of these interviews covered organisations developing the following technologies: ACT, Anaerobic Digestion, biomass CHP, biomass conversion, Energy from Waste, solar PV, offshore wind, onshore wind and wave & tidal stream. We also ensured coverage across successful, unsuccessful and non-participants (of both FID Enabling for Renewables and the enduring regime). We engaged with 10 successful participants (some of whom also had unsuccessful projects), at least 4 unsuccessful participants and a number of non-participants. The reminder 36 covered financial (16) and overarching (10) stakeholders.

G.22 We also undertook 5 workshops/roundtables with sub-groups of five sector associations covering the following technologies:

- ACT;
- Biomass CHP;
- Onshore and offshore wind;
- Solar PV; and
- Wave & Tidal stream.

G.23 We received written responses from 46 developers (including 9 entities that we also interviewed). This also included a range of participant (both successful and unsuccessful) across a range of technologies, 7 financiers (including 5 entities that we also interviewed) and 2 overarching stakeholders.

Stakeholder coverage – FID Enabling for Renewables

G.24 Of the CfD interviews undertaken 10 included participants in the FID Enabling for Renewables process. From the written responses 12 respondents had participated in FID Enabling for Renewables, including 4 successful participants, 1 participant with both successful and unsuccessful projects, 5 unsuccessful participants, 1 that withdrew and 1 project that considered participating. Across all forms of interaction undertaken during our stakeholder research we interacted with 36 of the 57 projects that applied for Phase 1 of the FID Enabling for Renewables process.

Analysis and synthesis

G.25 In analysing and synthesising the results and findings from the stakeholder research process four key elements were considered.

Synthesis

G.26 To synthesise the range of different types of evidence emerging from the interviews, round tables and open questions from the online questionnaires a straightforward matrix was developed to identify key findings. Where appropriate some responses were summarised in terms of simple scores. This approach provided a clear overview of the evidence and enabled the identification of recurrent themes and patterns in the data as well as any major variance between groups (see below). It also enabled us to assess a sense of scale around the findings.

Triangulation

G.27 In synthesising the results we continually looked to triangulate the findings both between different stakeholder groups and between different sources of evidence. For example, did the findings from the quantitative questions back up or support the opinions emerging from the stakeholder interviews; are the views about an investment hiatus from the over-arching stakeholders backed up by the views of those at the coal face – the developers and financiers; or are particular findings consistent across all stakeholder groups? The greater the levels of triangulation, the more weight we were able to place on the evidence.

G.28 In addition to triangulating the findings between different stakeholder groups and sources of evidence, we also continually reviewed the findings in the context of other knowledge about EMR and/or the context in which it was delivered.

Variance

G.29 Alongside the process of triangulation, we also reflected on the level of variance within particular stakeholder groups and across the whole sample. While variance is not necessarily a positive or a negative it does need to be acknowledged, either in highlighting strong consensus or caveating findings. It also helped to identify any outliers.

Quality

G.30 Throughout our analysis we also actively considered the 'weight' that can be placed on each finding. This assessment was made on the basis of the following criteria:

- Transparency – was there a vested interest in making a particular point?
- Accuracy – is what we have been told well grounded?
- Corroboration – are other stakeholders saying similar things?
- Relevance – was the point made in relation to this specific line of enquiry?
- Credibility – how well placed is the respondent to comment?

H Mapping to ITT questions

H.1 Table 22 below presents the ITT questions that underpin our evaluation and a reference to where we have addressed these questions within our EMR report. Note that when questions cover both the FID Enabling for Renewables and the CfD work streams, the EMR report provides responses only in relation to the CfD.

Table 22 – Overview of evaluation questions

Priority	Question	Programme	Reference
Question 1 - What evidence is there that CfDs and FID Enabling for Renewables investments contracts have helped to reduce the cost of delivering investment in low-carbon generation and prevent an investment hiatus?			
Scope	1.1 - What evidence is there that the expected financing/cost of capital benefits of Contracts for Difference (and Investment Contracts awarded under FID Enabling for Renewables) for low-carbon technologies relative to the RO are being realised?	FID-er CfD	Section starting with para. 6.340
Scope	1.2 - What evidence is there for the effects of Contracts for Difference (and Investment Contracts awarded under the FID Enabling for Renewables) on consumer bills, relative to existing instruments?	FID-er CfD	Section starting with para. 6.308
Focus	1.3 - Was there a real hiatus risk at the time of the launching FID Enabling for Renewables (March 2013) and has that hiatus risk been proven since?	FID-er	Included in FID-er report
Scope	1.4 - What evidence is there that the provision of an ‘Offtaker of Last Resort’ is tackling route to market issues and allowed independent generators to secure a PPA on commercially viable terms?	FID-er CfD	Section starting with para. 6.244
Defer	1.5 - What evidence is there of the discounts/fees offered and accepted for Power Purchase Agreements (PPAs)?	FID-er CfD	n/a
Question 2 - What evidence is there that the allocation of available monies from the Levy Control Framework within enduring CfD budget and FID Enabling for Renewables funds is meeting the Department’s research, development, deployment and demonstration objectives (as set out in the EMR Delivery Plan)?			
Focus	2.1 - What evidence is there of the impact on outcomes from the balance of support allocated between less and more-established technologies for achieving the respective objectives of EMR and FID Enabling for Renewables (as set out in the respective Full Business Cases and Delivery Plans) and taking into account the information available at the time of decision-making?	FID-er CfD	Section starting with para. 6.104
Focus	2.2 - What impacts did the budget available under FID Enabling for Renewables and CfD enduring regime both individually and collectively and (in the case of the CfD Enduring Regime) the split between more established and less established technologies have on the number and type of projects coming forward?	FID-er CfD	Section starting with para. 6.444

Priority	Question	Programme	Reference
Focus	2.3 - To what extent did constrained allocation secure successful competition?	CfD	Section starting with para. 6.287
Focus	2.4 - Was the modelling, forecasting and analysis behind the setting of strike prices, budget allocation and technology modelling appropriate? How might we improve our evidence base going forward?	FID-er CfD	Sections starting with para. 6.145, 6.438, 0 and 6.442
Scope	2.5 - What evidence is there that Contracts for Difference can contribute to mitigating post-2020 security of supply issues by incentivising a diverse mix of technologies?	FID-er CfD	Annex B
Question 3 - What evidence is there that the Department procured appropriate capacity at the least cost through the Capacity Market to meet its security of supply objectives?			
Defer	3.1 - How robust is the research and process to assess the level of capacity needed?	CM	Section starting with para. 5.43
Focus	3.2 - How robust is the evidence and modelling for the net CONE (predicted cost of new entry)?	CM	Section starting with para. 5.36
Focus	3.3 - What evidence is there for the appropriateness of the price cap set by demand-curve modelling?	CM	Section starting with para. 5.36, para 5.104
Defer	3.4 - What evidence is there that the Capacity Market is likely to deliver sufficient capacity to achieve the Loss of Load Expectation of 3hrs/yr?	CM	n/a
Focus	3.5 - What kind of capacity (incl. non-generation) and participants (eg new entrant) did the CM incentivise to bid and why?	CM	Section starting with para. 5.107
Focus	3.6 - What kind of capacity (incl. non-generation) and participants (eg new entrant) won CM auctions and why?	CM	Section starting with para. 5.107
Scope	3.7 - What evidence is there that the impact of the Capacity Market on consumer bills will be in line with expectations?	CM	Section starting with para. 5.141
Question 4 - Were the design, processes and parameters of the Capacity Market agreements and auction appropriate?			
Focus	4.1 - To what extent was the capacity market process and policy sufficiently transparent and understandable to investors and non-investors?	CM	Section starting with para. 5.25
Focus	4.2 - To what extent did the capacity market design enable all types of capacity provider (eg new entrants, demand-side reduction, differing generation methods) to compete in the auction?	CM	Section starting with para. 5.107
Focus	4.3 - Is there any evidence of gaming and what evidence exists on the extent to which measures to mitigate CM gaming were necessary and successful in practice?	CM	Section starting with para. 5.43 and section starting with para. 5.124

Priority	Question	Programme	Reference
Focus	4.4 - What evidence is there that the parameters of the first capacity market agreements and auction (maximum price, demand curve, penalty regime, eligibility, agreement terms) appropriately balanced attracting investment against value for money?	CM	Section starting with para. 5.33
Focus	4.5 - What can be learnt from the basis of appeals made under the CM process?	CM	Section starting with para. 5.92
Focus	4.6 - Was the clearing price in the first auction as expected? If not, what evidence is there on the underlying reasons?	CM	Section starting with para. 5.99
Scope	4.7 - To what extent are the rules governing the construction and/or operation of plants benefitting from a long term Capacity Agreement appropriate and what evidence is there of a need for more detailed rules governing either construction or long term operation?	CM	Section starting with para. 5.49
Focus	4.8 - What evidence is there for a need to refine the CM Regulations or Rules?	CM	Section starting with para. 5.165
Question 5 - Were the design, processes and parameters of the Contracts for Difference and the FID Enabling for Renewables contract and allocation appropriate?			
Focus	5.1 - To what extent was the process of applying for a CfD transparent?	CfD	Sections starting with para. 6.68 and with para. 6.73
Focus	5.2 - To what extent was the process of applying for an Investment Contract (under the FID Enabling for Renewables) transparent?	FID-er	Included in FID-er report
Focus	5.3 - To what extent did the CfD application process encourage as much participation as possible?	CfD	Sections starting with para. 6.68 and 6.73
Focus	5.4 - To what extent did the FID Enabling for Renewables application process encourage sufficient participation to support the objectives set out in the FID Enabling for Renewables business case?	FID-er	Included in FID-er report
Focus	5.5 - To what extent were the qualification and evaluation criteria used in the CfD and FID Enabling for Renewables process appropriate to delivering the objectives of the process?	CfD FID-er	Section starting with para. 6.73
Focus	5.6 - To what extent was the affordability assessment and 'down selection' process to allocate Investment Contracts appropriate to delivering the objectives of FID Enabling for Renewables?	FID-er	Included in FID-er report
Focus	5.7 - Is there any evidence of gaming in the CfD allocation process and what evidence exists on the extent to which measures to mitigate gaming were successful in practice?	CfD	Sections starting with para. 6.323, 6.319 and 6.391

Priority	Question	Programme	Reference
Focus	5.8 - What improvements if any could be made to improve the future CfD allocation rounds?	CfD	Multiple
Scope	5.9 - Have the underlying assumptions about the comparative benefits of different length contracts been borne out by evidence available?	CfD FID-er	Section starting with para. 6.206
Scope	5.10 - What is the evidence that CfD contract terms could be improved to better support the objectives of EMR?	CfD	Section starting with para. 6.205
Focus	5.11 - What can be learned from the basis of any appeals and challenges made under the CfD process and the FID Enabling for Renewables process?	CfD FID-er	Section starting with para. 6.269
Focus	5.12 - To what extent has the FID Enabling for Renewables process provided an effective transition to the CfD enduring regime (in terms of preparing the market for CfDs and testing the instrument)?	FID-er	Included in FID-er report
Scope	5.13 - What evidence is there that the risk in the contract has been appropriately allocated between developers and Government/consumers?	CfD FID-er	Section starting with para. 6.205
Question 6 - What evidence is there that EMR (including FID Enabling for Renewables projects) will contribute to Government decarbonisation and renewable objectives?			
Focus	6.1 - Has the first allocation/auction round revealed any barriers to commissioning low-carbon projects (eg reasons that finance could not be raised) that the policy design has not addressed?	CfD	Section starting with para. 6.450
Scope	6.2 - To what extent has EMR and the FID Enabling for Renewables process strengthened supply chains in low carbon technologies?	CM CfD FID-er	Annex starting with para. B.14
Scope	6.3 - To what extent has EMR and the FID Enabling for Renewables process contributed to the electricity share of the renewable energy mix and reduction in emissions in line with Government targets?	CM CfD FID-er	Section starting with para. B.19
Scope	6.4 - To what extent has the EMR and FID Enabling for Renewables process contributed to industry development and supported job creation?	CM CfD FID-er	Section starting with para. B.24
Scope	6.5 - What economic, social and environmental impacts have the delivery of projects awarded under the FID Enabling for Renewables process had?	FID-er	Included in FID-er report
Question 7 - How well has the EMR programme been delivered?			
Focus	7.1 - To what extent have the governance and performance management of EMR been fit for purpose?	CM CfD	Annex C
Scope	7.2 - To what extent have roles and responsibilities for delivery and management of EMR been appropriately assigned?	CM CfD	Annex C

Priority	Question	Programme	Reference
Scope	7.3 - Have potential conflicts of interest been successfully mitigated in the System Operator's advice on the Delivery Plan and Capacity Market assessment?	CM CfD	Annex C
Focus	7.4 - How well do participants and stakeholders consider the Department has designed and operated EMR?	CM CfD	Sections starting with para. 5.23 (CM) and 6.25 (CfD)
Defer	7.5 - Have EMR set up and running costs to date been in line with expectations? What is the source of any variance? [DECC asked to de-prioritise this question to Defer]	CM CfD	n/a

Question 8 (and sub-questions) is only relevant to the FID Enabling for Renewables programme, therefore are not addressed in the EMR report.

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