Appendix 5.3: Capacity

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Introduction

Background

1. The Department of Energy and Climate Change's (DECC) key objectives for the Great Britain (GB) electricity system are to deliver security of supply and decarbonisation of electricity generation,[1] while ensuring electricity remains affordable for consumers.[2] Together, these three objectives are often referred to as the energy 'trilemma'.

2. DECC's Electricity Market Reform (EMR) is aimed at meeting these objectives through two main policies. Contracts for Difference (CfDs) are aimed at supporting low carbon generation, while the Capacity Market is aimed at ensuring security of supply.[3] In both cases, the policies are designed to achieve their aims at the lowest possible cost, thereby meeting the third objective – affordability – to the fullest possible extent.

3. Since 2002, the government has supported renewable generation through its Renewables Obligation (RO) scheme.[4] The policies proposed in the EMR will

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[1] The UK is subject to legally binding targets that relate to decarbonisation of the energy system. Under the Renewable Energy Directive 2009, the UK is legally obliged to secure 15% of all its energy consumption from renewable sources by 2020. In addition, the Climate Change Act 2008 (section 1) sets a legally binding target to reduce carbon emissions to 80% below 1990 levels by 2050.
[2] DECC (November 2012), *Electricity Market Reform: policy overview*.
[3] DECC (November 2012), *Electricity Market Reform: policy overview*.
[4] DECC (February 2015), *Increasing the use of low-carbon technologies*.

lead to significant changes in how low carbon generation is remunerated. From 2015, new low carbon generators can opt to receive payments through a CfD, with the RO being phased out to new applicants from 2017.[5,6] DECC's *Annual energy statement 2014* suggests that CfD payments will increase steadily, potentially reaching £2.5 billion per year by 2020/21.[7]

4. Alongside policies aimed at securing investment in low carbon generation, DECC is introducing a Capacity Market to ensure security of supply.[8] This Capacity Market will lead to significant changes in the way in which thermal capacity is remunerated. From 2018, firms that can guarantee availability of capacity during times of system stress can bid to receive payments under the Capacity Market.[9] The first Capacity Market auction (to secure capacity for 2018/19) was held in December 2014, and will result in payments of approximately £956 million for that delivery year (2012 prices),[10] with amounts in future years to be established by future auctions.

5. By 2020/21, these two policies are estimated to account for over £3 billion of expenditure per year.[11]

6. The policies set out above will result in payments to generators and capacity providers of billions of pounds in the coming years, and will be paid for by levies on suppliers, with the expectation that these costs will be passed through to consumer bills. It is therefore important that competition for support drives down these costs to the fullest possible extent.

7. We have engaged with DECC to understand the rationale for some of its design choices, and our provisional findings are set out in Section 5. This appendix gives some additional information on these policies.

Structure of this appendix

8. This appendix is structured as follows:

- Contracts for Difference – paragraphs 9 to 36 give some background on the move from the RO scheme to CfDs as the government's preferred

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[5] DECC (June 2014), *Implementing Electricity Market Reform (EMR): finalised policy positions for implementation of EMR*.
[6] With the exception of onshore wind, for which the ROC scheme is due to close at the end of March 2016.
[7] In 2011/12 prices. The remaining budget to 2020/21 under the Levy Control Framework is set out in DECC (October 2014), *Annual energy statement 2014*, p75.
[8] DECC (November 2012), *Electricity Market Reform: policy overview*.
[9] DECC (June 2014), *Implementing Electricity Market Reform (EMR): finalised policy positions for implementation of EMR*.
[10] National Grid (2014), *Final auction results: T-4 Capacity Market auction 2014*.
[11] DECC (October 2014), *Annual energy statement 2014*, p75 suggests that CfD payments could increase to £2.5 billion per year by 2020/21, while DECC (June 2014) *Electricity Market Reform: Capacity Market – impact assessment*, p28 indicates expected capacity payments of between £0.8 billion and £1.5 billion per year.

method of supporting low carbon generation, and set out the CfD allocation mechanism.

- Capacity Market – paragraphs 37 to 57 give some background on the Capacity Market and how capacity agreements are allocated.
- Annex A – sets out some further observations in relation to previous allocation of CfDs.
- Annex B – assesses the potential for anti-competitive behaviour in the ROC market.
- Annex C – considers the risk that CfD holders may be able to manipulate the CfD reference price.
- Annex D – summarises stakeholders' responses to the capacity working paper and associated sections of the updated issues statement.

Contracts for Difference

What are they?

9. In order to achieve its objective of decarbonising electricity generation, the government has supported renewable electricity generation since 2002 via the RO scheme.[12]

10. Under the current RO system, all eligible renewable generators receive a number of Renewable Obligation Certificates (ROCs) based on their type of generating technology and the amount of renewable electricity they generate. Eligible electricity suppliers are issued an RO, based on a relevant percentage of their supply of electricity to customers in GB, under which they are obliged either to submit a number of ROCs or pay a 'buy-out price' for their remaining RO that they do not meet through submitting ROCs.[13]

11. Suppliers thus have a choice of whether to purchase ROCs from renewable generators or pay the buy-out price. Suppliers therefore have incentives to purchase ROCs from renewable generators, provided they can buy them at a price that compares favourably with paying the buy-out price.

12. Annex B to this appendix sets out our initial assessment of some issues with the current system of ROCs. We note that while ROCs are being phased out

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[12] DECC (February 2015), *Increasing the use of low-carbon technologies*.
[13] DECC (February 2015), *Increasing the use of low-carbon technologies*.

to new generation from 2017,[14] DECC estimates that ROC payments will reach almost £4 billion per year by 2020/21.[15]

13. As part of the EMR, DECC is moving away from using ROCs as its main mechanism for supporting additional low carbon generation. Under the new system, low carbon generators can receive payments by entering into a CfD.[16]

14. A CfD is a private contract between the holder and the CfD counterparty[17] in which the holder receives from (or pays to) the counterparty the difference between a previously agreed strike price and a CfD reference price.[18] The CfD counterparty makes (or receives) a payment per MWh generated, meaning the level of support is based on actual output of low carbon generation (rather than capacity). CfDs typically have a duration of 15 years.[19]

15. DECC's impact assessment highlighted that the rationale for switching from the RO system to CfDs is that it provides a more efficient allocation of risk between investors, consumers and government.[20]

16. Figures 1 and 2 below illustrate the payments under both ROCs and CfDs. Both figures are not based on actual data, and are provided for illustrative purposes only.

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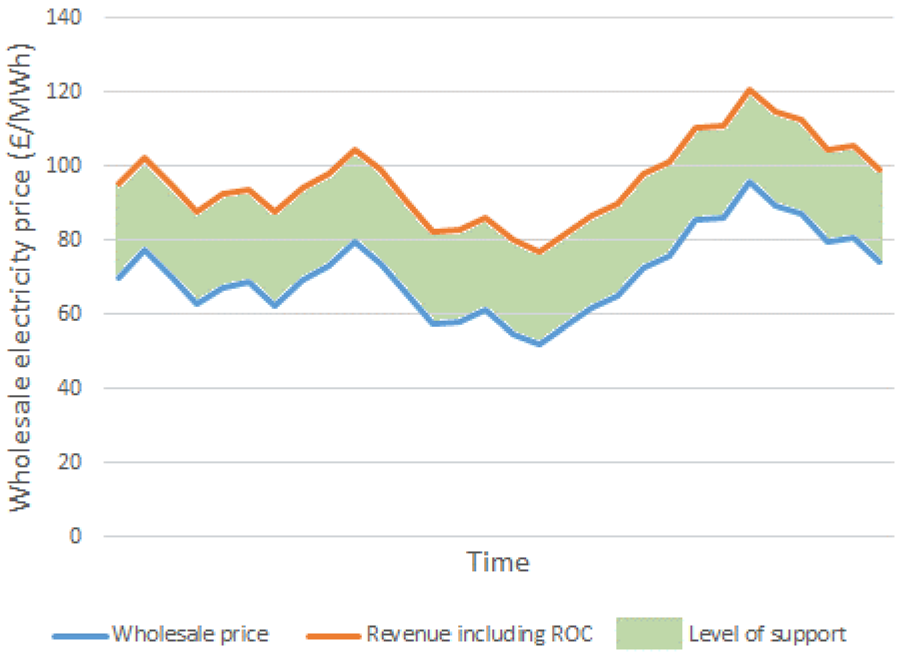
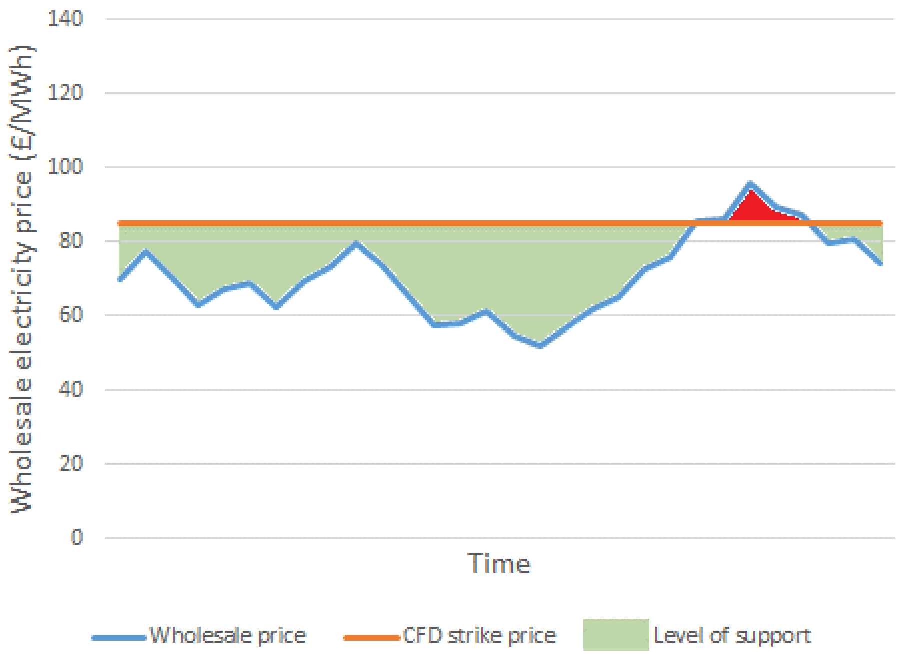
[14] As noted above, the ROC scheme will close at the end of March 2016 for onshore wind.
[15] DECC (October 2014), *Annual energy statement 2014*.
[16] DECC (June 2014), *Implementing Electricity Market Reform (EMR): finalised policy positions for implementation of EMR*.
[17] The CfD counterparty is the Low Carbon Contracts Company (LCCC) – a company wholly owned by the government. Its duties include acting as the counterparty for CfDs issued to low carbon generators. See DECC (August 2014), *Low Carbon Contracts Company Ltd: framework document*.
[18] For baseload generation, the CfD reference price is the volume weighted average of season-ahead baseload prices, based on data from the London Energy Brokers' Association (LEBA) Baseload Index and the Nasdaq Baseload Index. For intermittent generation, the CfD reference price is the volume weighted average of day-ahead electricity prices for the relevant settlement period, based on data from the APX Intermittent Index and the N2Ex Intermittent Index. See FIT Contract for Difference standard terms and conditions for more information.
[19] DECC (August 2013), *Electricity Market Reform: Contract for Difference – allocation methodology for renewable generation*.
[20] DECC (October 2013), *CfD impact assessment*.

Figure 1: Renewables Obligation Certificates



Source: CMA (not actual price data).

Figure 2: Contracts for Difference



Source: CMA (not actual price data).

17. Figure 1 shows that under ROCs the payments that generators receive are independent of the wholesale electricity price, meaning that their overall revenues fluctuate with the wholesale price. In contrast, Figure 2 shows that with CfDs, while the payments that generators receive vary, their overall revenues (strike price) remain constant. CfDs are therefore likely to provide a greater level of certainty for investors compared to ROCs.

18. DECC argues that removing this source of uncertainty from low carbon investment returns creates an environment that is more conducive to investment in these technologies, potentially reducing generators' financing costs, and in turn reducing the support they require and therefore the cost to consumers.[21]

19. Electricity suppliers finance the CfD payments to generators by paying a contribution to the CfD counterparty (the 'Supplier Obligation') based on their share of total metered demand.[22,23]

20. DECC's annual energy statement 2014 suggests that CfD payments will increase steadily, potentially reaching £2.5 billion per year by 2020/21.[24]

21. The European Commission (EC) granted the CfD policy state aid approval in July 2014.[25]

Contract for Difference allocation mechanism

22. This section gives a brief overview of the CfD allocation mechanism.

23. In principle, CfDs can be allocated to renewable generators via two different routes. First, DECC can hold allocation rounds in which it allocates a certain amount of budget to CfDs, and projects compete with each other to secure support (described below as the 'competitive allocation of CfDs'). Second, in exceptional cases, DECC can also direct the CfD counterparty to award a CfD to a generator directly (described below as the 'non-competitive allocation of CfDs'). This section sets out how CfDs are allocated under the competitive allocation.

24. Under the competitive allocation of CfDs, DECC holds an auction to allocate support to renewable generators. Bidders seeking CfDs submit sealed bids setting out the strike price they would require to enter into a contract.

25. DECC allocates a fixed budget for CfD support in each allocation round, divided into three 'pots', each containing different low carbon electricity generation technologies. Pot 1 contains 'established technologies' (see

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[21] DECC (October 2013), *CfD impact assessment*.
[22] The Contracts for Difference (electricity supplier obligations) regulations 2014.
[23] Suppliers pay an amount (fixed per quarter) per MWh of demand, with a process of reconciliation at the end of the quarter to correct any over- or under-recovery. See DECC (June 2014), *Implementing Electricity Market Reform (EMR): finalised policy positions for implementation of EMR*.
[24] In 2011/12 prices. The remaining budget to 2020/21 under the Levy Control Framework is set out in DECC (October 2014), *Annual energy statement* 2014, p75.
[25] EC (July 2014), Letter to the United Kingdom, State aid SA.36196 (2014/N) – Electricity Market Reform – Contract for Difference for renewables.

Table 2 below), Pot 2 contains 'less established technologies' (see Table 2 below) and Pot 3 includes biomass conversion.[26] Projects applying for CfDs compete with other projects in the same pot to secure this limited budget.

26. For the first allocation round, held in January and February 2015, DECC set an annual budget of £65 million to be awarded to Pot 1 projects and £260 million for Pot 2 projects, as shown below in Table 1.

Table 1: Size of budget for the first CfD allocation round – separated into three pots

(£m, 2011/2012 prices)

	2015/16	*2016/17*	*2017/18*	*2018/19*	*2019/20*	*2020/21*
Pot 1 (established technologies)	50	65	65	65	65	65
Pot 2 (less established technologies)	0	155	260	260	260	260
Pot 3 (biomass conversion)	0	0	0	0	0	0

Source: DECC (January 2015), *Budget revision notice for CfD allocation round 1*.

27. DECC set an administrative strike price (ASP) for each technology. This serves as a cap on the strike price that any project can receive. Table 2 below shows the ASP for each technology.

Table 2: Administrative strike price per technology

£/MWh

Technology type	*Pot*	*2015/16*	*2016/17*	*2017/18*	*2018/19*
ACT (with or without CHP)	2	155	150	140	140
AD (with or without CHP; >5MW)	2	150	150	140	140
Biomass conversion	3	105	105	105	105
Dedicated biomass (with CHP)	2	125	125	125	125
Energy from waste (with CHP)	1	80	80	80	80
Geothermal (with or without CHP)	2	145	145	140	140
Hydro (>5MW and <50MW)	1	100	100	100	100
Landfill gas	1	55	55	55	55
Sewage gas	1	75	75	75	75
Offshore wind	2	155	150	140	140
Onshore wind (>5MW)	1	95	95	90	90
Solar PV (>5MW)	1	120	115	110	100
Tidal stream (0–30MW)	2	305	305	305	305
Wave (0–30MW)	2	305	305	305	305

Source: DECC (October 2014) *Budget notice for CfD allocation round 1*.

28. Prospective generators apply to National Grid,[27] which is the 'EMR Delivery Body' (the Delivery Body) for CfDs and the Capacity Market. Within each pot, if there is sufficient budget to issue CfDs to all applicants at the ASP, all applicants receive CfDs at the ASP (known as an 'unconstrained' allocation).[28] In contrast, if there is insufficient budget in a pot, CfDs are

[26] Biomass conversion will be integrated into Pot 1 from 1 January 2017 onwards unless the UK can convincingly demonstrate that a separate bidding process for biomass is necessary. See EC (July 2014), Letter to the United Kingdom, State aid SA.36196 (2014/N) – Electricity Market Reform – Contract for Difference for renewables, paragraph 14.
[27] National Grid (October 2014), *Contracts for Difference round guidance: Contracts for Difference allocation round 1 – 2014*.
[28] DECC (September 2014), *CfD auction guidance*.

auctioned, with a separate auction for each pot as needed (a 'constrained' allocation).[29]

29. The constrained allocation takes the form of a sealed bid auction, where applicants submit bids to the Delivery Body, setting out the strike price they would be prepared to accept in a CfD contract.[30]

30. Each pot has a separate auction with a different clearing price for each delivery year, with the strike price any project receives capped at its ASP.[31] That is, if the auction for Pot 1 in 2016/17 clears at £100/MWh, any successful onshore wind bidders whose projects commission in that year would receive a CfD with a strike price of £95/MWh (the ASP for onshore wind in 2016/17 – see Table 2 above). DECC can also set minima and maxima for each technology in the auction.

31. The Delivery Body considers the applications for a CfD in order of strike price bid (lowest first), and for each project in turn considers whether it could be allocated a CfD without breaching the budget for that pot.[32] If a project can be allocated a CfD without breaching the budget, it is provisionally allocated a CfD.[33]

32. The budget calculation for each project includes an assessment of *(a)* the cost of issuing a CfD to the project at the price bid;[34] and *(b)*, where it would result in a higher clearing price (and therefore higher strike price) for the projects already provisionally awarded CfDs in that year, whether that additional cost can also be accommodated within the budget.[35]

33. When a bid breaches the budget for any year, it is rejected, and the auction is closed to other projects commissioning in the same year (subject to considering flexible bids from that bidder).[36]

34. The auction for each pot continues until all delivery years are closed for that pot, the entire budget for that pot has been used up, or all bids have been

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[29] DECC (September 2014), *CfD auction guidance*.
[30] DECC (September 2014), *CfD auction guidance*.
[31] DECC (September 2014), *CfD auction guidance*.
[32] DECC (October 2014), *Contract for Difference: final allocation framework for the October 2014 allocation round*.
[33] DECC (October 2014), *Contract for Difference: final allocation framework for the October 2014 allocation round*.
[34] Based on DECC's estimates of future wholesale electricity prices and load factors of different technologies, set out in DECC (October 2014), *Contract for Difference: final allocation framework for the October 2014 allocation round*.
[35] DECC (October 2014), *Contract for Difference: final allocation framework for the October 2014 allocation round*.
[36] DECC (October 2014), *Contract for Difference: final allocation framework for the October 2014 allocation round*.

considered. The clearing price in each pot for each delivery year is set by the highest strike price bid by a successful project.[37] However, as noted above, no project can receive a CfD with a strike price above its ASP.

35. Bidders may also submit flexible bids for their projects, setting out alternative combinations of strike price and capacity for which they would be prepared to enter into a CfD contract.[38] When a bid is rejected because it would breach the budget, the Delivery Body considers any flexible bids for that project before closing that year to other bids.[39]

Results of the first Contract for Difference auction

36. Bidding for the first competitive allocation round took place in January and February 2015.[40] In the first auction, CfDs were allocated to 27 renewable generation projects, comprising a total of 2.1 GW of capacity, due to commission between 2015/16 and 2018/19. The total amount of support awarded to these projects through CfDs is projected to be approximately £315 million per year in 2020/21.[41] Table 3 below summarises the results of the auction.

Table 3: Results of the first CfD allocation round

Technology	*Number of projects awarded CfDs*	*Total capacity (MW)*	*Strike price range (£/MWh)*	*Pot*
Onshore wind	15	748.55	79.23–82.5	1
Solar PV	5	71.55	50–79.23	1
Advanced conversion technologies	3	62	114.39–119.89	2
Energy from waste with CHP	2	94.75	80	2
Offshore wind	2	1162	114.39–119.89	2

Source: DECC (February 2015), *Contracts for Difference (CFD) Allocation Round One Outcome*.

Capacity Market

37. The other key policy resulting from the EMR is the introduction of a Capacity Market (CM) to ensure security of supply.[42]

38. The CM is a response to concerns that there may be a 'missing money' problem in the electricity wholesale market, which may prevent investment in sufficient capacity to meet demand at peak times.

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37 DECC (September 2014), *CfD auction guidance*.
38 DECC (September 2014), *CfD auction guidance*.
39 DECC (October 2014), *Contract for Difference: final allocation framework for the October 2014 allocation round*.
40 LCCC (January 2015), *Electricity Market Reform Contracts for Difference: GB implementation plan*.
41 DECC (February 2015), *Contracts for Difference (CFD) Allocation Round One Outcome*
42 DECC (November 2012), *Electricity Market Reform: policy overview*.

39. The CM aims to compensate capacity providers for any missing money in the wholesale market, thereby ensuring sufficient capacity to meet demand at times of system stress. Section 5 assesses the rationale for the CM in more detail.

What is it?

40. Under the CM, the Delivery Body holds a series of auctions to secure agreements from capacity providers to provide capacity when called upon to do so at times of system stress.

41. Winning bidders receive regular capacity payments in exchange for an obligation to provide a previously agreed level of capacity with four hours' notice from the System Operator (SO), National Grid.[43]

42. DECC (with input from National Grid and a panel of independent experts) sets the amount of capacity to procure in the CM for each delivery year, based on its target 'reliability standard'.[44] That is, DECC estimates the amount of capacity needed in any given year to meet its target level of reliability.[45] The Delivery Body then holds auctions to procure this target level of capacity.

43. The CM is paid for by suppliers' contributions based on their share of demand from 4pm to 7pm on working days between November and February.[46]

44. Two auctions are held for each delivery year: one auction takes place four years ahead of delivery (the T-4 auction); the other takes place one year ahead of delivery (the T-1 auction).[47] For example, for the first delivery year (2018/19), there was an initial (T-4) auction in December 2014, and there will be a further (T-1) auction in 2017.

45. The length of agreements for which generators can bid is based on whether they are 'existing', 'refurbishment' or 'new' plants, with capital expenditure thresholds setting out the minimum cost a generator must face in order to qualify as refurbishment or new plant.[48] Existing plants are eligible for a one-

[43] DECC (June 2014), *Implementing Electricity Market Reform (EMR): finalised policy positions for implementation of EMR*.
[44] Expressed as loss of load expectation: the number of hours during each year for which it is expected (statistically) that supply would not meet demand (absent further intervention from the SO).
[45] DECC (June 2014), *Implementing Electricity Market Reform (EMR): finalised policy positions for implementation of EMR*.
[46] DECC (June 2014), *Implementing Electricity Market Reform (EMR): finalised policy positions for implementation of EMR*.
[47] DECC (June 2014), *Implementing Electricity Market Reform (EMR): finalised policy positions for implementation of EMR*.
[48] DECC (August 2014), *Electricity Market Reform – Capacity Market: 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*.

year agreement, while refurbishment and new plants are eligible for three- and 15-year agreements, respectively.[49]

46. As well as generating capacity, demand-side response (DSR) providers can participate in the auction.[50] DSR providers with capacity agreements receive capacity payments in exchange for reducing their demand during times of system stress.[51]

Capacity Marketllocation mechanism

47. This section gives a brief overview of the CM auction mechanism.

48. Capacity agreements are allocated via a multiple-round descending clock auction with a single clearing price.[52] The Delivery Body is charged with either acting as the auctioneer or appointing another person to act as the auctioneer.[53]

49. Ahead of the auction, DECC announces the demand curve the auctioneer will use to determine the amount of capacity to procure.[54] Rather than simply procuring a fixed amount of capacity regardless of price, setting a demand curve allows DECC to trade off the quantity of capacity it procures with the cost of doing so.

50. Figure 3 below illustrates DECC's demand curve for the first auction. It is important to note that the parameters of any future auction may be different.

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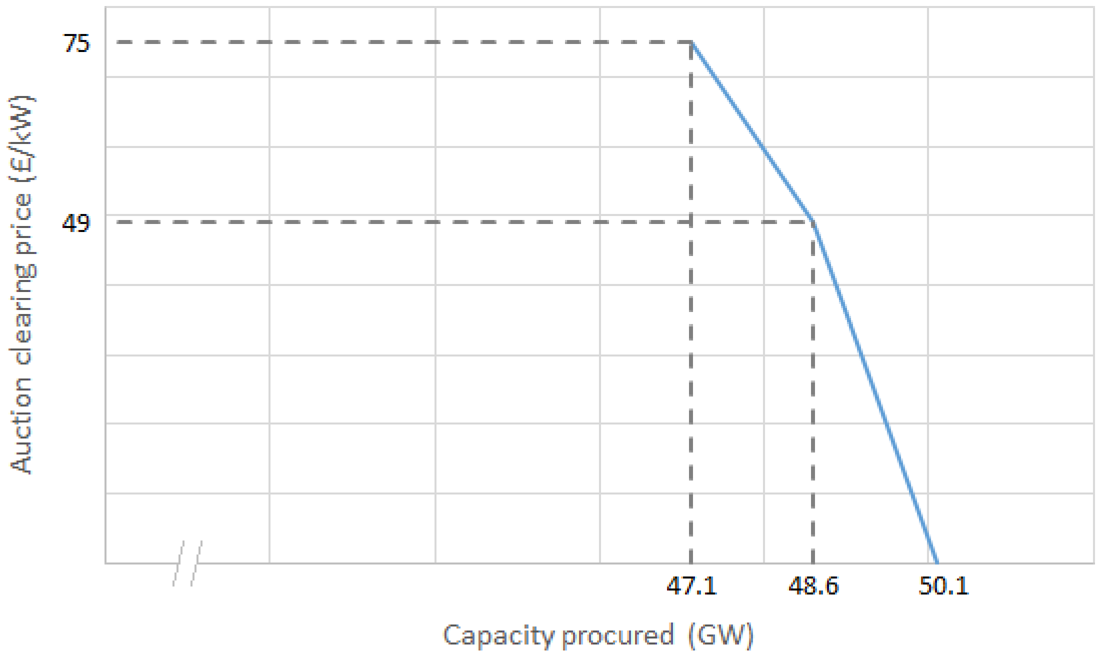
[49] DECC (June 2014), *Implementing Electricity Market Reform (EMR): finalised policy positions for implementation of EMR*.
[50] DSR providers in the Capacity Market can include domestic, commercial and industrial customers that are able to reduce their demand within four hours' notice from the SO. Reducing demand at times of system stress can be considered an alternative to increasing generation.
[51] DSR providers' delivery of their demand reduction is measured against a 'baseline' level of demand that estimates what their demand would have been had they not been called upon to reduce demand. This baseline is calculated based on their average demand over a number of recent comparable periods. See Electricity: the Capacity Market Rules 2014. Basing the baseline on a number of historical periods limits DSR providers' ability to increase the baseline measure of demand in order to make meeting their demand reduction obligations less onerous.
[52] National Grid (July 2014), *Capacity Market user support guide: guidance document for Capacity Market participants*.
[53] The Electricity Capacity Regulations 2014, section 24.
[54] DECC (June 2014), *Implementing Electricity Market Reform (EMR): finalised policy positions for implementation of EMR*.

Figure 3: DECC's demand curve for the 2018/19 T-4 auction



Source: CMA graph of National Grid data.*
*National Grid (December 2014) *Capacity auction user guide: guidance document for Capacity Market participants*.

51. The auction starts at the price cap, with all bidders in the auction. Bidders then drop out as the auction price falls below the price they would require to enter into a capacity agreement.[55]

52. The auction progresses through a series of rounds, with the auctioneer reducing the price by a set decrement in each round.[56] In the first auction, this decrement was £5 per round.[57] During each round, bidders wanting any of their capacity to exit the auction at a price between the start and end price of the round submit exit bids, setting out the price at which they would like to withdraw their capacity from the auction.[58]

53. At the end of each round, the auctioneer announces the amount of excess capacity remaining in the auction (rounded to the nearest 1 GW in the recent 2018/19 T-4 auction).[59] The auction ends when there is insufficient capacity remaining in the auction to meet DECC's demand. The auctioneer then

[55] National Grid (December 2014), *Capacity auction user guide: guidance document for Capacity Market participants*.
[56] National Grid (December 2014), *Capacity auction user guide: guidance document for Capacity Market participants*.
[57] National Grid (December 2014), *Capacity auction user guide: guidance document for Capacity Market participants*.
[58] National Grid (December 2014), *Capacity auction user guide: guidance document for Capacity Market participants*.
[59] National Grid (December 2014), *Capacity auction user guide: guidance document for Capacity Market participants*.

applies the ‘Net Welfare Algorithm’ to determine the clearing bid that best approximates the intersection of DECC’s demand curve and the supply curve (made up of bids).[60] The amount bid by the marginal successful bidder sets the clearing price that all parties receive.

54. DECC included rules to prevent large existing plants from being able to exercise market power. Existing plants are designated as ‘price takers’ by default,[61] and are prevented from submitting exit bids for their capacity above a ‘price taker threshold’[62] (£25/kW in the 2014 auction).[63] The aim of this rule is to prevent generators with substantial existing capacity from withdrawing capacity from the auction at a price above that which they would require to enter into a capacity agreement, with the aim of ensuring a higher clearing price for any of their remaining capacity. New plants, refurbishing plants and DSR are designated as ‘price makers’ by default, and can submit exit bids at any price level.[64]

55. We note that the Capacity Market scheme was approved by the EC under state aid rules in July 2014.[65]

Results of the first Capacity Market auction

56. The first auction (for delivery in 2018/19) was held in December 2014, and procured 49.26 GW of capacity – more than the target amount – at a price of £19.40/kW,[66] considerably below the pre-auction estimates of the clearing price. This will result in total payments for this capacity of £956 million (2012 prices) (with further payments for any additional capacity procured in the T-1 auction).

57. New plants with just over 2.6 GW capacity secured agreements in the first auction, including one new large combined-cycle gas turbine (CCGT) plant of approximately 1.6 GW. In addition, 174 MW of DSR was procured for 2018/19 in the auction.[67]

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[60] National Grid (December 2014), *Capacity auction user guide: guidance document for Capacity Market participants*.
[61] Unless they have submitted a memorandum to Ofgem justifying ‘price maker’ status.
[62] The price maker threshold is set at a level where most existing plants should be willing to receive a capacity agreement. See DECC (June 2013), *Electricity Market Reform: capacity market – detailed design proposals*.
[63] National Grid (December 2014), *Capacity auction user guide: guidance document for Capacity Market participants*.
[64] National Grid (December 2014), *Capacity auction user guide: guidance document for Capacity Market participants*.
[65] EC (July 2014), Letter to the United Kingdom, State aid SA.35980 (2014/N-2) – Electricity Market Reform – Capacity Market.
[66] National Grid (2014), *Final auction results: T-4 Capacity Market auction 2014*.
[67] National Grid (2014), *Final auction results: T-4 Capacity Market auction 2014*.

Annex A: Observations in relation to previous allocation of Contracts for Difference

Analysis of unsuccessful bids in the first Contracts for Difference auction

1. We issued National Grid with an information request under section 174 of the Enterprise Act for the bids from the first CfD auction.

2. [✂] large offshore wind projects were unsuccessful in the first auction, with average strike price bids of approximately £[✂]/MWh, together accounting for almost [✂] of capacity, suggesting that the FIDeR offshore wind projects did displace lower cost offshore wind projects.

3. In addition, the Renewable Energy Planning Database[68] sets out that there is approximately a further 5.4 GW of offshore wind capacity that did not bid in the auction, but has been granted planning permission and is awaiting construction. An additional 5.2 GW of offshore wind capacity is awaiting a planning decision.[69] This compares with the approximately 3.2 GW of offshore wind awarded CfDs under FIDeR.

Observations regarding the costs and benefits of allocating offshore wind to 'less established' Pot 2 technologies

4. Offshore wind has been awarded by far the most support through CfDs of any of the 'less established' Pot 2 technologies to date.

5. The Crown Estate's Offshore Wind Cost Reduction Pathways report[70] set out the potential for a 39% decrease in the levelised cost of energy[71] for offshore wind for projects reaching final investment decision (FID) in 2020 compared with those that reached FID in 2011. Some of the possible future cost reductions highlighted in the study, such as deploying larger turbines as they are developed, may materialise without needing to support deployment in GB. Conversely, some other potential cost reductions, such as those that result from developing the GB supply chain for components may be dependent on levels of GB deployment. Any cost reductions that would materialise irrespective of any support a technology receives in GB should not be considered as benefits to weigh against any costs of subsidising a less developed technology now.

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[68] DECC (May 2015), *Renewable Energy Planning Database*.
[69] DECC (May 2015), *Renewable Energy Planning Database*.
[70] The Crown Estate (2012), *Offshore Wind Cost Reduction: Pathways Study*.
[71] An estimate of the lifetime cost of the project, per unit of electricity generated.

Annex B: Potential for anti-competitive behaviour in Renewables Obligation Certificates

The value of Renewables Obligation Certificates

1. As noted in paragraphs 10 and 11 of the appendix, suppliers subject to the RO must comply with the scheme either by presenting ROCs, or by paying the buy-out price. Suppliers must meet their obligations by 1 September each year for the preceding April–March ‘obligation period’.[72]

2. Before the start of the November following the obligation period, the money from suppliers paying the buy-out price (instead of submitting ROCs) is ‘recycled’ (circulated) to all suppliers that submitted ROCs to meet their RO. Each supplier receives an amount in proportion to the number of ROCs it submitted.[73] Generators can opt to carry over unsold ROCs to the next obligation period.[74]

3. The overall level of support that generators receive will depend on the outcome of negotiations with ROC buyers (most likely suppliers with an RO). The precise nature and outcome of these negotiations is unclear, but it is likely to depend on the value each party places on ROCs, and the outside options they have available to them.

Value to suppliers

4. The maximum value of a ROC to a supplier at the time when it is obliged to settle its RO (at the start of the September following the obligation period) should be equal to the buy-out price plus the amount it would receive through the recycle fund for submitting that ROC.

5. However, the value of a ROC to the supplier earlier during the obligation period may be lower. Buying a ROC before it is obliged to settle its RO could impose financing costs on a supplier, as it would have to pay for it earlier.

6. In addition, buying a ROC before it is obliged to settle its RO can expose a supplier to risks that it would not face if it waited until the deadline. A supplier holding a ROC faces a risk around the amount of buy-out fund that will be recycled to parties submitting ROCs. Likewise, there is a possibility that the price of ROCs could fall before the end of the period (eg if there is an oversupply), and firms that buy early would be unable to take advantage of

[72] Renewables Obligation Order 2009 as amended by the Renewables Obligation (Amendment) Order 2014.
[73] Ofgem (February 2015), *Renewables Obligation annual report 2013–14*.
[74] Renewables Obligation Order 2009 as amended by the Renewables Obligation (Amendment) Order 2014, article 13.

this. By contrast, a supplier opting to wait until the deadline can take advantage of any falls in the price of ROCs in the knowledge that it will have to pay no more than the (fixed) buy-out price.

7. As a result, a rational supplier is likely to value a ROC less during the obligation period than it would in the following September when it is obliged to settle its RO. The precise value of a ROC to a supplier at any point in time is likely to depend on its expectation of the overall balance of supply and demand for ROCs within the obligation period, its financing costs and its appetite towards risk.

8. As noted above, the price suppliers pay for ROCs will depend on negotiations with ROC generators. Suppliers have credible outside options that could affect their bargaining positions in these negotiations. The option of not buying ROCs and paying the buy-out price could give suppliers considerable negotiating strength. We discuss this in more detail below.

Value to generators

9. Generators have to sell their ROCs in order to realise their value. Failure to sell their ROCs would mean that they do not receive any support for their generation. While generators can opt to carry over their ROCs into the next obligation period, there are likely to be costs associated with this: generators would not receive ROC payments for that output until the following year, and there would be a risk that they might not receive a better price for ROCs in the following year.

10. Generators' lack of outside options could potentially affect their negotiating position with suppliers.

Potential for anti-competitive behaviour

11. DECC ensures that suppliers' total RO is 10% above the expected number of ROCs that will be generated over the obligation period.[75] This is intended to ensure that there is a scarcity of ROCs, and it is this scarcity that creates their value. If there is an oversupply of ROCs (and generators could not carry them over to the following year), we might expect the prevailing price of ROCs to fall considerably (perhaps close to zero), as ROC generators compete with

[75] DECC calculates the total RO by taking the larger figure of 'Calculation A', which is based on fixed targets for the level of renewable generation, and 'Calculation B', which aims to ensure that the total obligation is 10% above the expected number of ROCs. In recent years, the RO has been set by Calculation B. See DECC (October 2014), *The Renewables Obligation for 2015/16: calculating the level of the Renewables Obligation for 2015/16*.

each other to ensure that they are not left holding unsold (and valueless) ROCs at the end of the year.

12. The fact that generators can carry ROCs over into the next year could mitigate the impact of an oversupply to some extent. However, as set out previously, doing so could be costly to generators.

13. By choosing to pay the buy-out price instead of buying ROCs, a supplier could effectively reduce the scarcity of ROCs. Any of the Six Large Energy Firms acting unilaterally may have a sufficiently large electricity retail market share (and therefore share of the total RO) to eliminate this 10% headroom if it chooses to pay the buy-out price to meet its RO rather than buy ROCs.

14. By doing so, each of the Six Large Energy Firms may have the option of effectively eliminating the scarcity of ROCs for that year, thereby depressing their value. We set out in the capacity working paper the possibility that this could give each of the Six Large Energy Firms large supplier considerable bargaining power in their negotiations with generators, and could enable them to extract low prices as a result of their ability (unilaterally) to eliminate the scarcity value of ROCs.

15. We received a number of responses on this issue setting out that the threat of such behaviour would not be credible. By meeting its RO through paying the buy-out price rather than securing ROCs, one of Six Large Energy Firms may be able to reduce the market price of ROCs. However, doing so would put it at a disadvantage relative to its rivals; it would have to pay the buyout price to meet its RO, while its rivals could take advantage of the low price of ROCs and meet their RO at lower cost. As a result, we consider that such a strategy for extracting discounts from renewable generators is unlikely.

16. In response to the updated issues statement, Drax submitted some additional analysis regarding the ROC market. It provided a range of estimates of the sale price of ROCs relative to their final value (the buy-out price plus share of recycle fund). Drax suggests that the Six Large Energy Firms are able to extract discounts when buying ROCs from generators, and do not pass these discounts on to consumers because of a lack of competition over customers on standard variable tariffs (SVTs). We do not consider that Drax's analysis provides evidence of anti-competitive behaviour. As set out above, we would expect suppliers to pay less than the full final value of ROCs if buying them earlier during the compliance period. While we have not undertaken extensive analysis in this area, the levels of discount reported by Drax do not seem inconsistent with suppliers' willingness to pay reflecting the financing costs and risk of buying ROCs during the compliance period.

17. In addition, we do not consider that a lack of competition in the retail sector that prevents marginal cost reductions being passed on to consumers would best be tackled by interventions in the ROC market. As a result, we do not consider that there would be significant benefits to consumers from intervening in the ROC market at this point in time.

Annex C: Manipulation of Contracts for Difference reference price

Introduction

1. In the updated issues statement we set out that we consider it unlikely that large CfD holders will be able to benefit from manipulating the CfD reference price. In this annex, we set out why we consider manipulation of the CfD reference price to be unlikely. This analysis is unchanged from that reported in the capacity working paper.

2. We assess whether generators in receipt of CfD payments are likely to have the ability and incentive to manipulate the CfD reference price down in order to benefit from higher CfD payments.

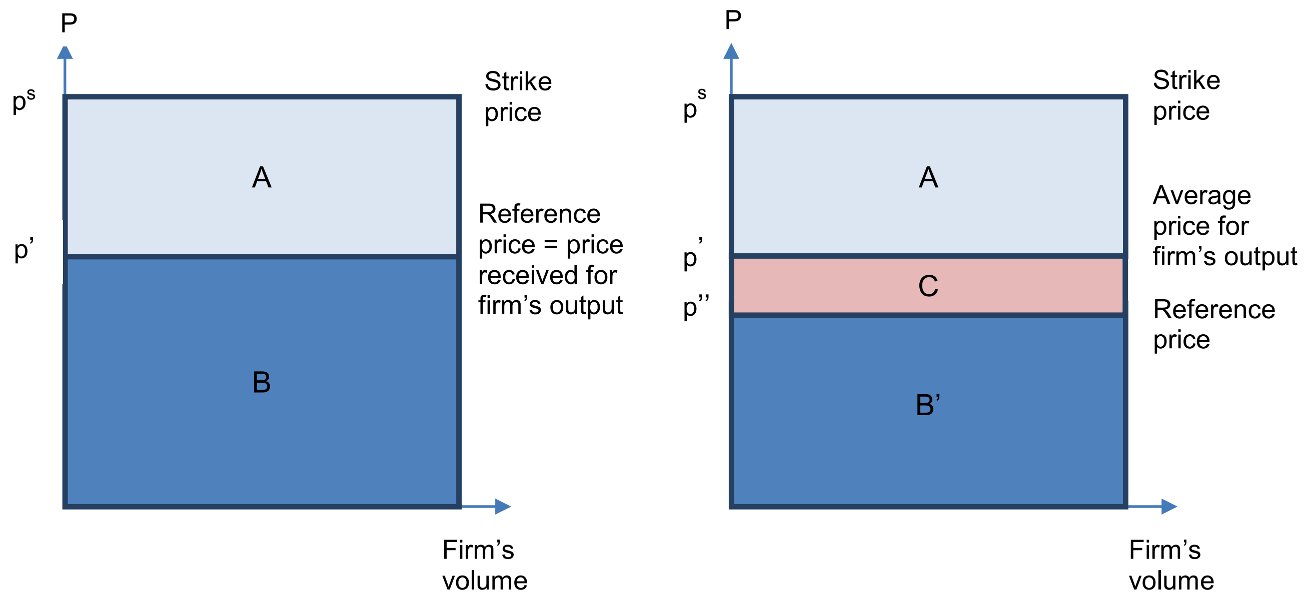
3. This annex focuses in particular on the ability and incentive of large baseload generators to manipulate the reference price. We do not discuss CfDs for intermittent generators (eg wind) in this annex, as the reference price for these CfDs is the day-ahead market, which is generally considered to be liquid and difficult to manipulate.

Mechanics of manipulations

4. The CfD payment is the difference between the strike price and the CfD reference price. The reference price is the average price on the reference market, weighted by volumes traded. Paragraph 13 below sets out in more detail how the reference price is calculated. In general, the reference price should reflect the prevailing market price, especially in liquid markets.

5. If the reference price can be manipulated, there is a theoretical possibility that firms in receipt of a CfD could manipulate the reference price to receive higher overall revenues. This is illustrated in Figure 1 below.

Figure 1: Illustration of the mechanics of manipulation



Source: CMA.

6. The left of Figure 1 shows the revenue that is earned by a generator that does not manipulate the reference price. It is made up of two elements.

7. The first element is the price at which the generator's output is sold (p'), assumed to be the same price as the CfD reference price. The total revenue for this element is equal to the price received multiplied by the output sold at that price. This is shown by area B.

8. The second element is the CfD revenue. This is calculated by multiplying all of the generator's output in receipt of CfDs by the difference between the strike price (p^s) and the reference price (p'). This is shown by area A.

9. The right of Figure 1 shows what might happen if the generator is able to manipulate the reference price down from p' to p''. In this case, the revenue from the CfD will increase by the shaded area C, as the CfD payment is greater with the lower reference price.

10. If all of the output is sold at the new reference price (p''), then total revenue will remain unchanged (ie (A + C) + B' = A + B.) However, if the reference market price decreases to p'', but the average price the generator receives for its output remains unchanged at p', then the generator's overall revenue would increase, as it would receive B' + C for selling its output and A + C from the CfD. In effect, it would be earning revenue from the area C twice.

11. This is a simplified example, as it assumes the generator is able to manipulate the reference price down but still receive an average price for its output above

the new – lower – reference price. Nevertheless, it demonstrates how a generator could benefit from manipulating the reference price down if it is able to sell some of its output at a price higher than the manipulated reference price. The remainder of this paper focuses on whether generators in receipt of CfDs are likely to have the ability and the incentive to engage in this type of behaviour in practice.

Ability

12. In this section we set out how the reference price is calculated before considering whether that reference price is manipulable, drawing out the factors that would make it more manipulable and whether they are likely to occur in practice.

Calculation of market reference price

13. The market reference price is calculated as follows:

Reference price = sum of all trade values[76] ÷ sum of all trade volume

14. It is calculated by summing up the value of all trades over each day of the season ahead (ie around 182 days) and dividing the value of trades over this period by the volume of trades over the same period. The data from which the market reference price is calculated comes from two sources: the LEBA season-ahead Baseload Index and Nasdaq's season-ahead Baseload Index.[77]

15. Our analysis of trading data from a number of large market participants indicates that most season-ahead trades go through brokers, which report through the LEBA index. Therefore, this index should capture the majority of trades. As the index is weighted by trade volume, it is likely to be difficult to manipulate the price unless a generator sells substantial volumes below the reference price, in order to decrease the average price enough to move the reference price downwards.

16. It is worth noting that the CfD counterparty will conduct a baseload reference market price annual review in which it can alter which indices are used to calculate the reference price.[78]

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[76] For each trade, the value is calculated by multiplying the price of the trade and the volume traded. All of these values are then added together.
[77] FIT Contract for Difference standard terms and conditions.
[78] DECC (April 2014), *Implementing Contracts for Difference: policy and drafting update*.

Liquidity of season-ahead baseload market

17. Analysis of trading data indicates that the average capacity of season-ahead baseload sold through brokers is approximately 18.5 GW.[79]

18. If a large generator sold all of its output in the season-ahead baseload market, it could account for a reasonably large proportion of volumes traded in the CfD reference market. For example, a large generator with 2 GW capacity selling into the reference market could control approximately 10% of total traded volumes in that market; potentially enough to manipulate the price. As a result, it is possible that a generator may be able to manipulate the reference price downward.

19. It is unlikely that a generator seeking to manipulate the reference price down would sell all of its output on the reference market, as it would need to withhold some output to sell elsewhere at a higher price in order to maintain an incentive to manipulate. However, the volumes currently traded on the reference market at present do not appear sufficiently large to rule out the possibility that a large generator could have the ability to move the reference price.

Impact of arbitrage in the reference market

20. It is possible that if a generator sells output in the reference market below the prevailing market price, it could create arbitrage opportunities for firms to buy at the low price offered by the generator and sell at a higher price. If a firm buys the generator’s low-priced output and resells it on the same (reference) market, it could increase the overall level of trading in this market relative to the level that would be observed absent the generator’s attempt to manipulate the price.

21. Since the CfD reference price is a weighted average price of all trades in the reference market, if attempts to manipulate the price down result in more trading in the reference market, it would require the generator to sell a greater amount of output in the reference market to achieve a given change in the reference price. This would likely reduce a generator’s ability to manipulate the reference price.

[79] This is based on bought trade volumes through brokers by 14 parties. This is an underestimate of the volumes traded on the season-ahead market as it does not include all parties in the market, including financial players. See Appendix 6.1: Liquidity for more detail on trading data.

Incentive

22. In this section we consider under what conditions a generator might have incentives to manipulate the reference price downwards. Supplement 1 below sets out the incentives to manipulate the reference price in greater detail. In brief, the gains from manipulation can be represented by the following formula:[80]

Gain	=	Revenue from sales in reference market	+	Revenue from sales outside reference market[81]	+	Revenue from CfD contract	–	Revenue without manipulation

23. By simplifying this formula,[82] we can show that in order for manipulating the price downwards to be profitable, the total amount of output in receipt of a CfD that a generator has to sell outside the reference market must be greater than the total volume of energy sold on the reference market by other parties.[83] Further information and calculations are available in Supplement 1.

24. That is, in addition to the output the generator must sell in the reference market to manipulate the price, it must hold back as much output (in receipt of a CfD) as the total amount traded on the reference market.

25. As noted above, the size of the reference market is currently approximately 18.5GW. As a result, at present a generator would need at least 18.5GW of baseload capacity in receipt of a CfD to have incentives to manipulate the reference price.

26. EDF reached commercial agreement with the UK government in October 2013 on the key terms of a CfD for 3.2 GW of baseload nuclear capacity from Hinkley Point C, planned to start generating from 2023. To date, this is the largest CfD that has been agreed for baseload capacity.[84]

27. As a result, absent a significant decrease in trading in the reference market, it is unlikely that any generator would have sufficient output to manipulate the

[80] In Supplement 1, this is formula (2) $\pi = \alpha q p_{\alpha} + (1-\alpha) q p_{-\alpha} + (p^s - p^r)q - p^s q$.
[81] Sale outside of reference market could be either internal sales or sales to other markets (eg month-ahead or year-ahead markets).
[82] We have also assumed that the price the firm receives for its output outside the reference market is the same as that which other market participants receive on the reference market. This is because we assume that, in general, the price reflects the underlying market conditions.
[83] See formula (10) in Supplement 1.
[84] For more information, see EC (October 2014), Commission decision of 08.10.2014 on the aid measure SA.34947 (2013/C) (ex 2013/N) which the United Kingdom is planning to implement for support to the Hinkley Point C nuclear power station.

CfD reference price profitably. Also, as highlighted above, it is possible that attempts to manipulate the reference price down may create arbitrage opportunities that would increase trading in the reference market, thereby making it harder to manipulate.

28. It might be argued that current traded volumes are not a good proxy for future traded volumes. In particular, a number of power stations (including nuclear power stations) may not be operating in the market by 2025 and their traded volumes should not be counted towards trades likely to take place in the future.

29. However, the key drivers of trading are likely to be market liquidity and underlying demand rather than electricity supply as such.[85] Given that the reference price in other baseload generators' CfDs is also likely to be the season-ahead baseload market, there will likely remain considerable demand for hedging the season-ahead market in order for suppliers to lock in stable returns from their capacity in receipt of CfDs. Therefore, trading may increase rather than decrease on the season-ahead market.

Key observations

30. We do not consider it likely that any generator in receipt of CfD payments could profitably manipulate reference market price downwards. Therefore, we did not carry out an assessment of the possible effects of such behaviour. We considered both the ability and incentives of this strategy.

31. In terms of ability, we were unable to rule out the possibility that a large generator in receipt of a CfD could sell sufficient output on the reference market to manipulate the price. However, we noted that selling output in the reference market below the prevailing market price might create arbitrage opportunities that could increase the volume of trading in that market, thereby making it harder to manipulate the price.

32. In terms of incentive, our analysis indicates that for manipulating the reference price downwards to be profitable for a generator, it would have to sell at least as much output outside the reference market as the total volume traded by other parties in the reference market. The capacity traded in the reference market is currently approximately 18.5 GW, and the generator that has been awarded the most baseload CfDs to date will have 3.2 GW of capacity in receipt of CfDs when it comes online. As a result, absent significant changes

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[85] A retraction of certain plants from the wholesale market will lead to others being in merit earlier and trading as baseload generators. These generators are likely to want to hedge the price they receive and are likely to engage in the season-ahead market in place of plants that were previously baseload generators.

in the amount of trading in the reference market, our provisional conclusion is that it is unlikely that a generator would face incentives to manipulate the CfD reference price.

33. DECC will need to monitor these reference markets to ensure volumes traded do not fall sufficiently to make manipulating the reference price profitable. In addition, DECC may need to ensure that no single firm receives CfDs for sufficient capacity to face incentives to manipulate the reference price.

Supplement 1: Further technical analysis of incentives for manipulating Contracts for Difference

1. In this supplement we set out the formulae for calculating whether there is an incentive to manipulate reference markets to benefit from greater CfD payments. We start with some annotation and definitions. We then make a simplifying assumption before providing the calculations showing the incentive condition for CfD manipulations.

Annotation

2. We begin with some annotation. Let:

- Q = output sold by all other power plants;
- β = proportion sold on the reference market by other power plants;
- q = total output to be sold by generator manipulating price;
- α = proportion of output of generator manipulating price sold on reference market;
- p' = price achieved by other power plants on reference market (can also be interpreted as the underlying power price);
- p^s = strike price;
- p^r = reference price;
- p_α = price achieved by generator manipulating price on reference market; and
- $p_{-\alpha}$ = price achieved by generator manipulating price outside of reference market.

Definitions

3. The reference price is calculated as follows (given it is quantity weighted):

$$(1)\ p^r = \frac{\beta Q p' + \alpha q p_\alpha}{\beta Q + \alpha q}$$

4. Profits from manipulation are as follows:

$$(2) \quad \pi = \alpha q p_\alpha + (1-\alpha) q p_{-\alpha} + (p^s - p^r) q - p^s q$$

5. This profit function states that the additional profit from manipulation is equal to the revenue from sales into the reference market, the revenue from sales to other markets, the revenue from the CfD (which is equal to the difference between the strike price and the reference price multiplied by output), less the opportunity cost of no manipulation (which is equal to the strike price multiplied by the quantity).

Assumptions

6. For the purposes of evaluating the profit function, we will make the following assumption:

$$(3)\ p_{-\alpha} = p'$$

7. This assumption is that the price of output sold elsewhere is equal to the underlying price of electricity. If we concluded that downstream market power could be combined with vertical integration to offer vertically integrated generators an opportunity to sell their own power at higher prices, this assumption would have to be relaxed. There may be retail unilateral market power, but we do not believe that its exercise would depend on own-generation. Similarly, if there were wholesale market unilateral market power, this would affect the CfD payments.

Calculations

8. If we take this assumption and apply it to (2), we would have the following:

$$(4)\ \pi = \alpha q p_\alpha + (1-\alpha)qp' + (p^s - p^r)q - p^s q$$

9. We can simplify the profit function as $p^s q$ cancels out:

$$(5)\ \pi = \alpha q p_\alpha + (1-\alpha)qp' - p^r q$$

10. We can substitute (1) into (5) so that:

$$(6)\ \pi = \alpha q p_\alpha + (1-\alpha)qp' - \frac{\beta Q p' + \alpha q p_\alpha}{\beta Q + \alpha q} q$$

11. With some further simplification we can get the following:

$$(7)\ \pi = \alpha q(p_\alpha - p')[1 - \frac{q}{\beta Q + \alpha q}]$$

12. This profit function says that overall profits from manipulation are a function of the proportion of output sold on the reference price market, the difference between the price that the generator attempting to manipulate price sells on the reference market and the price other participants sell on the reference

market, and 1 minus the total output of the generator attempting to manipulate price as a proportion of all output sold on the reference market.

13. If the owners of the generator attempting to manipulate price are seeking to manipulate the reference price downwards, then $(p_\alpha - p') < 0$. Therefore, we need to have $\left[1 - \frac{q}{\beta Q + \alpha q}\right] < 0$ for this profit function to be positive. Since we require that:

(8) $\frac{q}{\beta Q + \alpha q} - 1 > 0$

14. Therefore, we need:

(9) $\gg\ q > \beta Q + \alpha q$

15. As α > 0 when there is some attempt to manipulate, we require:

(10) $\gg\ q(1 - \alpha) > \beta Q$

16. This says that the amount of output that the generator attempting to manipulate price sells outside the reference market must be greater than others' sales into the reference market for it to have an incentive to manipulate the reference price.

Annex D: Summary of responses to the capacity working paper and relevant sections of the updated issues statement

1. This annex sets out a summary of the responses we received to the capacity working paper and the associated sections of the updated issues statement. We have taken these responses into account in forming our provisional findings. We have summarised the responses by topic, in the order they appeared in the capacity working paper.

Contracts for Differences

Non-competitive allocation of CfDs

2. **DECC** set out that awarding FIDeR contracts played a crucial role in enabling the transition to competition on faster timeline than originally expected. It set out that there may be circumstances under which further CfDs may have to be allocated outside the competitive process, such as where there are large or unique projects. It noted that the Secretary of State will seek to ensure that, where appropriate, there are competitive pressures on projects seeking CfDs outside the allocation mechanism to prevent overcompensation. It also noted that the Secretary of State has committed to engage with the sector to set out its rationale for using the powers to award contracts outside auction.

3. **EDF Energy** set out that it supports the competitive allocation of CfDs where possible. It set out the process through which it agreed commercial terms for a CfD for Hinkley Point C, and set out that it believes that the Secretary of State will need to allocate CfDs outside competitive process for future, large projects.

4. **E.ON** set out its concerns with the amount of budget allocated through the FIDeR process, as it leaves less budget for future projects that could have provided capacity at lower cost. It noted that the strike prices in the first auction were almost 20% lower than the ASP. It set out its concerns about the Secretary of State's power to award further CfDs outside the auction, especially where projects could take up large proportion of budget. It suggested that projects such as Swansea Bay Tidal Lagoon should be supported with government grants, rather than CfD budget.

5. **RWE** set out that it supports the award of early FIDeR contracts in principle, but has some concerns. It noted that the application conditions for FIDeR applicants were different to those faced by firms applying under the enduring regime (as FIDeR projects did not need planning permission or a transmission agreement at the time of applying). It also noted that the terms of these contracts means that the FIDeR projects can make their FIDs later than those

awarded CfDs in the first allocation round. It is concerned about the Secretary of State's ability to award further CfDs outside the competitive processes, especially given the lack of policy or legislative clarity as to the allocation of the Levy Control Framework subsidy beyond the rules which are in place for renewables only.

6. **Scottish Power** noted that the Secretary of State may need to award CfDs directly in cases such as nuclear and early stage technologies, but noted that these powers should not be used for technologies that have already competed in the auction.

7. **SSE** set out its view that the FIDeR process was competitive.

8. **DONG Energy** set out that it supports FIDeR, as it brought forward developments in the UK supply chain.

9. **Carbon Capture and Storage Association** set out that it supports competition in the allocation of CfDs, but notes that competition on strike price alone may not capture the full value of a technology. It suggests that carbon capture and storage (CCS) should not be allocated through competitive auctions at present given the relative immaturity of the technology compared to some other low carbon technologies, but should be tendered (with competition between potential providers). It notes that we should not consider only the near term costs of technologies, but the longer term costs of decarbonisation. Its submission cited analysis showing considerable value of CCS, and set out that it is crucial to commercialise the technology over the 2020s to realise this value. It noted the considerable benefits to other sectors of the economy from developing CCS electricity generation, such as the benefits of a CO2 network for other industries. It supports the Secretary of State's power to allocate CfDs outside the auction, as it believes that competition through the auction is not currently appropriate for CCS. It also sets out that different CCS projects could have different costs and benefits, and that allocating CfDs based on cost alone (through the auction) would not take this into account.

10. **Drax** set out that it supports FIDeR, and noted that there were strict criteria for approval, such as demonstrating a risk of delay or cancellation. It set out its view that the Secretary of State's powers to award CfDs outside the competitive process are necessary, but should be used only under limited circumstances.

Dividing budget into separate pots could result in inefficient allocation of support and distort competition between different technologies

11. **Ofgem** suggested that in assessing DECC's policy design, it is important to consider the long-term dynamics of the development of low-carbon technologies. There could be long-term benefits for consumers in allowing less established technologies to get higher levels of support.

12. **Centrica** set out that there is a risk if less developed technologies are exposed to competition too early, but also highlighted the risk of protecting them for too long (if they prove unable to reduce costs sufficiently to compete with more developed technologies).

13. **EDF Energy** set out that it supports separate pots to protect developing technologies and prevent less-established technologies from setting the clearing price for low cost technologies.

14. **E.ON** set out its view that there should be separate pots in the short term to support technologies that may be able to lower their costs over coming years. However, it noted that DECC should move to technologically neutral auctions over time, and that the government should set out a clear pathway towards this.

15. **RWE** set out that it supports the use of a different pot for less established technologies (eg offshore wind) on the basis that meeting long-term decarbonisation targets at least cost to the consumer will require the deployment of such technologies in significant volume. It cited a study showing costs of offshore wind have fallen by almost 11% over the past three years.

16. **Scottish Power** set out that it considers it necessary to support less-developed technologies in order to deliver cost reductions and ensure they can compete in the future. It also noted that separating technologies into pots ensures competitive pressure on developed technologies.

17. **SSE** set out its view that supporting less-developed technologies is important to ensure broad mix of renewable technologies.

18. **DONG Energy** set out its view that separating technologies into pots is necessary to ensure innovation and to achieve the benefits of a diversified energy system. It noted that the pots can be merged when technologies are more established. It also stressed that cost reductions in offshore wind will come from a stable and transparent framework that helps developers and suppliers make long term investment decisions. It set out that it does not

believe that technologically neutral auctions would enable offshore wind to deliver all of its potential benefits.

19. **Carbon Capture and Storage Association** set out that over time CCS should be able to compete with other technologies (ie in a technology neutral auction). It set out that it recognises the lack of transparency around the allocation of budget to pots, and stressed the need to be on the least cost decarbonisation pathway.

20. **Drax** set out that the division of technologies into separate pots is in line with EC guidelines, and believes that a separate pot for biomass conversions is the best solution. It also pointed out that biomass conversion CfDs will end in 2027, regardless of commissioning date, making it increasingly hard to compete with other technologies.

21. **Good Energy** stressed the need for different renewable generating technologies, and that a technology neutral auction would threaten the viability of a low carbon energy system. It set out that we need technologies that complement each other. It also set out that it supports the division of technologies into pots as a way of delivering more efficient outcome.

22. **Which?** noted that dividing technologies into pots could distort competition, and noted the lack of explanation for how the budget was divided between pots. It submitted a document it had published in 2013, setting out that the government should do more to encourage competition in CfDs. It pointed out that competition for Pot 1 means some low cost projects are excluded, which it stated is not good for consumers. It questioned whether offshore wind should be in the less developed category, and questioned whether it will face price competition in Pot 2. It suggested a two-stage auction, with some budget being allocated to specific technologies, and the remainder being allocated to a generic auction with all technologies. It states that over time, the budget allocated to the generic auction would increase and the budget set aside for specific technologies would decrease. It set out that the developed technologies (eg tidal) would be allocated CfDs on a first come first served basis, but with clear targets for cost reduction.

23. **Professor Grubb of UCL** submitted an analysis setting out the need to support developing technologies in the short term, to ensure sufficient investment and innovation, and noted that there may be longer term benefits from doing so.

Overlap of ROCs and CfDs could reduce competition in early CfD auctions

24. **DECC** noted that the overlap of CfDs and ROCs could affect competition between Pot 1 technologies (that are quick to build), but that there are projects seeking to build later in the period that will not be eligible for ROCs that are likely to provide competition in the auction.

25. **EDF Energy** set out that it does not think that the overlap of CfDs and ROCs will put a floor on CfD bids. It notes that it would have been difficult to remove ROCs earlier, given the pipeline of projects working on the assumption that ROCs will be available. It also noted that given the short timescale before ROCs are closed to new generators, few projects would actually have a choice between the two schemes (decreasing further in future years as the ROC deadline approaches). It also noted that the different risks faced by holders of CfDs and ROCs could drive choice as much as price.

26. **E.ON** set out that it supports the transitional arrangements to CfDs, as some projects had started development before EMR proposals were in place (so their investment cases were based on ROCs being available). It also noted that the first auction appears to have been reasonably competitive, and that the issue of overlap will apply less in future auctions as the ROC deadline approaches.

27. **RWE** set out that it supports the overlap between CfDs and ROCs to prevent hiatus. It warned that DECC should not remove the ROC regime early, as investors have made plans based on it being in place, and removing it would impair investor confidence. It also did not think that the overlap overly affected auction outcomes.

28. **Scottish Power** set out that it considers that the transitional arrangements to CfDs were useful in ensuring a steady stream of onshore wind projects, and does not think the overlap will put a floor on the strike price in CfD auctions, as the deadline for ROC support approaches.

29. **SSE** set out that it does not see the overlap of CfDs and ROCs as an issue.

30. **Drax** set out that it considers that the risk of reduced CfD competition from the overlap with ROCs is unlikely to be significant, and will diminish substantially in future auctions as the ROC deadline approaches.

Risk of manipulating the CfD reference price

31. **EDF Energy** noted that the risk of selling outside the reference market would dwarf the benefits of manipulating price. It also noted that there is a minor

error in our summary of how CfD reference prices are calculated, but that it does not affect our conclusions.

32. **E.ON** set out that it considers there is limited scope for manipulating the CfD reference price. It argued that both intermittent and baseload generators should have the day ahead price as the reference price, but noted our analysis that manipulation is unlikely even in season ahead market.

33. **RWE** set out that it considers manipulation of the CfD reference price unlikely.

34. **MPF** set out that the reference price must be sufficiently reliable and liquid.

35. **Drax** set out that there are low risks of manipulating reference prices, and notes that this was looked at by DG Comp in its assessment of state aid for Hinkley Point C.

36. **Which?** set out that it had concerns about the quality of price data used to calculate the CfD reference prices.

Supplier obligation

37. While there was not a specific section relating to the CfD Supplier Obligation, we set out our intention to consider this is more detail.[1]

38. **EDF Energy** set out that it supported a proposal for the Supplier Obligation to be based on actual daily costs (as opposed to the current proposals. It notes that other suppliers argued for a fixed annual levy. It set out that it considers the current arrangements to be an acceptable compromise.

39. **E.ON** noted that suppliers face certain risks with CfDs, as they bear the risk of capacity mix and plant output, and suggested that these risks should be centralised within government.

40. **First Utility** set out that the move to CfDs represents a significant transfer of risk from generators to suppliers, with impacts on the prices suppliers will charge to consumers. It noted that our focus on the impact on generators ignores the implications of the design of the Supplier Obligation. It set out that the level of Supplier Obligation payments will depend on the level of renewable generation, and the level of wholesale prices. It set out that it will become increasingly hard to manage this risk in setting tariffs as the CfD scheme grows. It set out that a volatile cost that changes each quarter in an unpredictable way conflicts with market that offers up to three-year fixed tariffs. It recommended taking steps to reduce volatility to suppliers. It also

[1] See footnote 41 of the capacity working paper.

noted that the Supplier Obligation will result in a risk premium being added to customers' bills. It suggested that the Six Large Energy Firms are shielded from these risks because of their large number of customers on SVTs and because they may also be recipients of CfD payments through their generation businesses. It set out its view that the Supplier Obligation constitutes an adverse effect on competition (AEC). Its submission also stresses the importance of being able to forecast charges. It recommended a fully fixed Supplier Obligation with no end of year reconciliation, whereby over or under-recovery would be taken into account in setting the following year's charges. It noted that we have not taken account of the impact of supplier risk on customers' bills.

Other issues relating to CfDs

41. **DECC** set out that it considers there are strong efficiency arguments for switching from ROCs to CfDs, and that competition for support enables consumers to benefit from cost reductions. It also noted that the first allocation round showed competition driving down costs.

42. **EDF Energy** set out that it supports EMR as the most appropriate measure to meet the energy trilemma, and that it supports replacing the RO scheme with CfDs as it reduces fossil fuel price risk, and caps the amount that consumers pay.

43. **E.ON** set out that it supports the move to CfDs, as it should reduce risks compared to the ROCs scheme. It also suggested that a descending clock auction should be used for CfDs, as it states that this is more compatible with a transition towards technologically neutral auctions.

44. **RWE** noted its support for moving to competitively allocated CfDs as a way to drive down costs. It also highlighted the risk being taken by industry in developing projects beyond the current Levy Control Framework timelines. It suggested clarity around future levels of support to prevent undermining supply chain investment.

45. **Scottish Power** set out its broad support for DECC's policy decisions (while noting our concerns).

46. **SSE** set out its views that no aspect of the CfD design gives rise to AEC.

47. **DONG Energy** set out its view that the introduction of CfDs facilitates competition better than ROCs.

48. **Carbon Capture and Storage Association** set out its support for CfDs subsidising a wide range of technologies, and considers that CfDs are a

significant improvement over ROCs. It also suggested that DECC should be able to adjust the strike price in CfDs as the costs of projects become known and that this could be particularly important to ensuring CCS and other technologies with long project development/construction phases deliver best value for consumers.

49. **MPF** noted that the GB electricity system will still require flexible plants in addition to renewable generation in order to maintain system stability.

50. **Drax** set out that it agrees there are benefits from transitioning from ROCs to CfDs, and that the CfD regime strikes the right balance. It does not consider that the issues we raised are likely to give rise to competition concerns. It pointed out that the CfD allocation mechanism does not take account of the costs that each technology puts on the system (eg balancing costs), meaning that technologically neutral auctions may not deliver the lowest (overall) cost to consumers. It also noted that all biomass conversion projects over 250 MW will automatically require state aid approval, even if awarded via a technology specific competitive process. It also suggested that posting security ahead of auctions could prevent speculative bidding, and gave the example of solar in the first auction.

51. **Which?** set out its desire for a more concrete mechanism to ensure that if wholesale electricity prices rise above the strike price, payments from generators to suppliers are passed on to consumers. It also proposed that the government publishes an in-depth assessment of the outcomes of the first auction.

Capacity Market

Length of agreements

52. **DECC** noted that it seeks to use longer agreements only where absolutely necessary, and that it has received little robust evidence on the need for longer term agreements for DSR. It also noted that it has commissioned work on the cost structure of different DSR technologies.

53. **Centrica** welcomed the ability of DSR to participate in the CM.

54. **EDF Energy** recognised the importance of DSR in the CM. It also noted the importance of the transitional arrangements for DSR. It set out that where DSR requires significant investment, there may be an argument for longer term agreements, but questions whether 15 year agreements would be appropriate.

55. **E.ON** set out its concerns about offering different contract lengths under the CM. It noted that doing so could result in inefficient outcomes, and could distort the auction outcomes. It also provided a report by DotEcon assessing the CM auction mechanism.

56. **RWE** questioned the extent to which DSR capacity can be considered 'firm' generation capacity in the context of the CM. It set out its view that some aspects of the design are skewed in favour of DSR (eg DSR transitional arrangements), and notes that DSR suppliers can benefit from other sources of revenue (eg triad avoidance). RWE set out that it supports the equitable treatment of all providers of firm capacity, and considers that all providers should be eligible for the same tenor of agreement. It noted that the current arrangements risked inefficiently building new plant in cases where it would have been cheaper to maintain existing plant to provide capacity over the same tenor. It also questioned the efficiency implications of having the same price for agreements regardless of length, given that the value of capacity could fall in future. It noted that long-term agreements in general risk locking in inefficient costs that would have to be recovered from consumers.

57. **SSE** questioned the ability of DSR providers to commit to providing capacity via the CM over the length of a long term contract.

58. **GDF** set out that it supports one year contracts for DSR, as it stated that the level of investment is lower than for new build generation.

59. **DONG Energy** set out its concerns that the current arrangements do not support DSR, and that longer term agreements should be offered to DSR to ensure level playing field.

60. **MPF** set out that it disagrees with awarding long term contracts to new but not existing generators, as it could distort competition in favour of new generation. It set out that this could result in the closure of efficient existing gas plants, over-procurement of new plants, and notes the risk that new generating plant that secures capacity agreements may not get built, all potentially leading to increased costs to consumers. It notes that discount rate for generators receiving one year agreements would likely be higher than for those 15-year agreements, and that this could mean that the auction could fail to procure the lowest cost capacity. It also suggested that this could lead to existing plant closing before the CM comes into play, potentially increasing the reliance on SBR.

Recovery of Capacity Market costs

61. **EDF Energy** set out that the mechanism for recovering CM costs was designed to ensure that it reflects consumer demand during times of system stress, while ensuring that suppliers' costs are predictable. It noted that triads may not be a good proxy for times of system stress, as stress events may occur during periods of high demand with little wind generation rather than necessarily periods of peak demand. It also pointed out that basing the recovery of CM costs on triads could make the Supplier Obligation less predictable for suppliers. It set out its view that the current regime strikes a reasonable balance, but that it could be an area to consider in future.

62. **E.ON** set out its view that CM costs should be recovered based on parties' demand for capacity, which it asserts is determined by the capacity of customers' meters.

63. **RWE** noted that Notices of Inadequate System Margins occur throughout the year, and provided a graph of their distribution. It states that the role of the CM is therefore to provide capacity across the year, and that costs should be recovered in a manner that reflects this.

64. **GDF** set out that it supports the currently proposed cost recovery mechanism, as it creates a wider incentive to reduce load at peak times.

65. **Green Frog Power** set out that the periods for which the CM is trying to ensure capacity align well with the periods in which the CM costs are recovered, and cautions against a less sharp signal.

Penalty mechanism

66. **Ofgem** set out that the electricity market provides strong incentives for capacity providers to deliver. It suggests that for a plant not generating, the opportunity cost of foregone revenues, ie the revenue lost by not selling electricity at times of system stress (plus the cash-out price on any electricity sold but not delivered), should already be equal to the administrative value of lost load (VoLL), and therefore the CM penalty is not designed to provide further delivery incentives. Instead, the CM penalty is designed to return capacity payments to consumers when plant has not delivered.

67. **Centrica** noted that given poor financial performance of CCGTs, the penalties regime should be sufficient to incentivise generators to meet their obligations under the CM. It also suggests that higher penalties could deter participation in the CM (both from existing parties and new build).

68. **EDF Energy** noted that there are three sources of risk from for an unreliable generator failing to deliver during system stress. Firstly providers face penalties for failing to deliver at times of system stress. Secondly, testing ensures that there is limited incentive to gamble on there not being any stress events. Thirdly, generators failing to meet their obligations forego (high) energy market revenues. It suggested that increased penalties could decrease participation in the CM, and potentially increase the clearing price.

69. **E.ON** noted that the penalty for failing to provide capacity is approximately £800/MWh based on 2018/19 T-4 auction (£20/kW x (1/24)). It set out its concerns the penalty regime may not be sufficiently punitive. It notes the trade-off between ensuring delivery and keeping the clearing price low, but is concerned that DECC may not have got the right balance.

70. **RWE** noted that until near the end of the design process, DECC's proposal was for penalties to be based on VoLL. It also notes that the current arrangements link penalties to the clearing price of the auction in which a CMU was successful, capped at the annual income arising from the Capacity Agreement. RWE noted that this means that the penalties could be different for different generators, based on the year in which they secured their agreement, and that this could potentially undermine the development of a liquid market for trading capacity obligations and thus the efficiency of generators' dispatch decisions.

71. **SSE** sets out its view that limiting penalties to total CM revenues sends a sensible market signal.

72. **GDF** set out its view that the penalties involved are sufficient for those plants with capacity contracts – to have imposed higher penalties would threaten their future financial viability.

73. **Green Frog Power** set out that it supports the current CM penalty mechanism. It believes that it results in the right balance of risk and reward, and that are more penal penalty mechanism would directly harm competition. It stresses the importance of minimising risks to potential future income for investors, and questions whether it would be possible to finance projects at any price if the penalty regime was too risky for investors.

74. **Drax** set out that it does not have concerns around the penalty mechanism. It noted that firms that fail to deliver during periods of system stress will face high cash-out costs (and notes these may be higher than currently, should cash-out reforms go through). It also set out the risk that excessive penalties could prevent existing generators from recovering their fixed costs, and could put off investors in new capacity.

75. **Which?** set out its concerns that capping the level of penalty at total CM revenues is insufficient.

Other issues relating to the Capacity Market

76. **Ofgem** stressed that the CM and CfDs should not be considered in isolation. The costs of the CM are offset (at least to some extent) by lower electricity prices in the wholesale market.

77. **Centrica** set out its view that there are strong arguments for the CM, and that it appears to be broadly competitive.

78. **EDF Energy** set out that it supports the introduction of the CM to ensure security of supply.

79. **E.ON** set out that it agrees with the introduction of the CM to ensure security of supply.

80. **SSE** set out that it supports the introduction of the CM, and does not think that any aspects give rise to an AEC.

81. **RWE** set out its concerns about the way in which interconnectors participate in the CM, setting out that it is relative market prices, not the actions of interconnector owners, that determine the direction of flow over interconnectors.

Renewables Obligation Certificates

82. **Ofgem** set out that the ROC recycle fund means that more firms paying the buyout price would increase the value of ROCs in that year. It also suggested that because the Six Large Energy Firms own a lot of generation, they may not have incentives to reduce the ROC price. It also noted that lots of ROCs are transferred as part of PPAs over many years, which would require renegotiation if the supplier no longer wanted to take ROCs.

83. **Centrica** set out that it always tries to meet its RO at least cost. It set out that the price it pays for ROCs purchased in advance tend to include a small discount to the buyout price, reflecting financing costs. It noted that a large supplier threatening to pay the buyout price (driving down the ROC price) in order to extract low prices from generators would have two effects: driving down price to competitors, and increasing the value of the recycling fund (again, benefiting competitors that buy ROCs).

84. **EDF Energy** set out that there is strong competition between suppliers to secure ROCs. It also suggested that the prices paid reflect fair value, taking

account of risks and costs of buying ROCs. It also provided a more detailed analysis of the ROC market.

85. **RWE** set out that in the last compliance period it met 98.75% of its RO by submitting ROCs. It set out that in most years, 40 to 60% of its ROCs are externally sourced, at a discount of [✂] for transaction costs.

86. **Drax** set out that inaccurate headroom calculations result in a risk of significant ROC discounting. It also noted that suppliers have buyer power resulting from their option to pay the buyout price, and that this will be made worse as the Six Large Energy Firms source an increasing amount of ROCs internally. It set out an analysis of the level of discount typically observed with ROCs. It asserted that smaller suppliers are put off sourcing ROCs because of low liquidity, and tend to pay the buyout price instead. It stated that suppliers demand a discount for buying ROCs before the submission deadline, despite receiving payment from their customers before the ROC submission deadline. It states that this is a design flaw in the ROC design, and it is not clear that this financing benefit to suppliers is passed through to consumers. Its submission questioned more generally whether discounts extracted by suppliers are passed through to retail consumers, given its perception that there is a lack of competition for SVT customers. It set out its estimate of how much detriment this could cause to consumers, and suggested we look at the ROC price paid by the Six Large Energy Firms, and the amount of this cost that is passed through to SVT consumers. It suggested that if there is a problem, DECC should reconsider moving to a fixed price ROC from 2018 (instead of 2027). It also suggested that we consider remedies to increase competition for SVT consumers.