Energy market investigation

Capacity

3 March 2015

This is one of a series of consultative working papers which will be published during the course of the investigation. This paper should be read alongside the updated issues statement and the other working papers which accompany it. These papers do not form the inquiry group's provisional findings. The group is carrying forward its information-gathering and analysis work and will proceed to prepare its provisional findings, which are currently scheduled for publication in May 2015, taking into consideration responses to the consultation on the updated issues statement and the working papers. Parties wishing to comment on this paper should send their comments to energymarket@cma.gsi.gov.uk by 18 March 2015.

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Executive summary

Background

1. The Department of Energy and Climate Change's (DECC's) key objectives for the GB electricity system are to deliver security of supply and decarbonisation of electricity generation, while ensuring electricity remains affordable to consumers. 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. 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.

Aim of this working paper

3. The EMR policies 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.

4. This working paper sets out the CMA's preliminary analysis of the effects of these policies on competition, and the extent to which the government has ensured that this support is allocated in a competitive manner.

Contracts for Difference

5. From 2015, investors in new low carbon generation can opt to receive support via a CfD – a contract under which the holder receives from (or pays to) the counterparty the difference between a previously agreed strike price and a market reference price (CfD reference price).

6. DECC's rationale for moving from the Renewables Obligation Certificates (ROC) scheme (the current method of supporting low carbon generation) to CfDs is that this should reduce the uncertainty of generators' returns. This, in turn, should reduce their risk, and therefore the support they require, resulting in lower costs for consumers.

7. DECC suggests that CfD payments will increase steadily, potentially reaching £2.5 billion per year by 2020/21 (in 2011/12 prices). The outcome of the first

CfD allocation round was announced in February 2015, and we will consider this in our subsequent analysis.

8. DECC allocates the CfD budget into three separate ‘pots’, each of which contains different low carbon electricity generation technologies. Pot 1 contains ‘established technologies’, Pot 2 contains ‘less established technologies’ and Pot 3 includes biomass conversion. Projects applying for CfDs compete with other projects in the same pot to secure this limited budget.

Potential issues

9. Overall, the move from ROCs (not allocated competitively) to CfDs (which introduces competition to the allocation mechanism) may be seen as positive with regards to ensuring competition drives down the level of support. However, we would like to understand better DECC’s rationale for certain aspects of the allocation process.

Non-competitive allocation

10. CfDs with a total value of £16.6 billion over their lifetime were awarded early, without price competition. We would like to understand further DECC’s rationale for allocating these contracts outside the auction process. We also note that the Secretary of State for Energy and Climate Change has the power to direct the CfD counterparty to award additional CfDs in a non-competitive manner. It is important that additional CfDs are allocated using a competitive process to ensure the lowest possible cost for consumers.

Dividing budget into pots

11. Separating the budget into different pots could result in a failure to award CfDs to the lowest-cost projects. There is also a risk that this could distort competition between different technologies by intensifying competition for some technologies, while weakening it for others.

12. DECC’s rationale for dividing the budget into separate pots is to protect less established technologies from competition with more established technologies while they develop. We would like to understand better how DECC weighed the potential costs of this approach against the benefits of protecting less developed technologies from competition.

Overlap of Renewables Obligation Certificates and Contracts for Difference

13. Low carbon generation projects that are due to commission before the end of March 2017 have the choice of applying for CfDs or ROCs. We would like to explore further whether the ability of CfD bidders to opt for ROCs could effectively put a floor on the strike price they are prepared to bid in CfD auctions, limiting the degree of competition in the early CfD allocation rounds.

Manipulating Contract for Difference reference markets

14. We considered whether a generator in receipt of CfD payments would have the ability and incentive to manipulate the CfD reference price. Our analysis indicates that this is unlikely to be a profitable strategy.

Other issues

15. In addition to the issues set out above, we would like to clarify DECC's rationale for some of the rules in the CfD auction. We will continue to engage with DECC on these issues.

Capacity Market

16. Under the Capacity Market, the Delivery Body holds a series of auctions to secure agreements from capacity providers to provide capacity when called upon at times of system stress. 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.

17. DECC (with input from National Grid and a panel of independent experts) sets the amount of capacity to procure in the Capacity Market for each delivery year. This target level of capacity is procured via a multiple-round descending clock auction with a single clearing price.

18. The first auction (for delivery in 2018/19) was held in December 2014, and procured 49.26GW of capacity at a price of £19.40/kW – considerably below the pre-auction estimates of the clearing price. This will result in total payments for this capacity of £956 million in 2018/19 (2012 prices).

Potential issues

19. As with CfDs, competition between bidders for capacity agreements can drive down the level of support required. While the auction is likely to ensure competition for support, we have identified some issues we would like to consider further.

Demand side response

20. We received a submission from Tempus Energy[1] setting out some issues relating to the treatment of demand side response (DSR) in the Capacity Market. Specifically, it highlighted that while generators can be eligible for up to 15-year capacity agreements, DSR providers are eligible for only one-year agreements. The submission also set out that the way in which the costs of the Capacity Market are recovered from suppliers could harm the ability of DSR providers to compete. We intend to investigate further whether these issues are likely to distort competition.

Penalty mechanisms

21. Capacity providers with capacity agreements face penalties if they fail to deliver their obligations. However, the total penalties a capacity provider faces over the course of a year cannot rise above the revenue it receives from Capacity Market payments. We would like to consider further whether the penalty mechanism could result in generators that are unable to meet their obligations reliably bidding into the Capacity Market.

Initial views

22. As set out above, there are a number of areas where we would like to explore DECC's mechanisms for allocating support to generators in further detail. We will continue to engage with DECC to understand better the issues outlined above.

Introduction

Background

23. DECC's key objectives for the GB electricity system are to deliver security of supply and decarbonisation of electricity generation,[2] while ensuring electricity remains affordable for consumers.[3] Together, these three objectives are often referred to as the energy 'trilemma'.

[1] Tempus Energy (December 2014) Submission to CMA energy market inquiry.
[2] 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.
[3] DECC (November 2012) *Electricity Market Reform: policy overview*.

24. 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.[4] 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.

25. Since 2002, the government has supported renewable generation through its Renewables Obligation (RO) scheme.[5] The policies proposed in the EMR will 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.[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]

26. 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.

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

Aim of the paper

28. 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

[4] DECC (November 2012) *Electricity Market Reform: policy overview*.
[5] DECC (February 2015) *Increasing the use of low-carbon technologies*.
[6] DECC (June 2014) *Implementing Electricity Market Reform (EMR): finalised policy positions for implementation of EMR*.
[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.

through to consumer bills. It is therefore important that competition for support drives down these costs to the fullest possible extent.

29. We have engaged with DECC to understand the rationale for some of its design choices.[12] This working paper sets out the CMA's preliminary analysis of the effect of these policies on competition, and the extent to which the government has ensured that support is allocated in a competitive manner.[13]

Structure of the paper

- Contracts for Difference: Paragraphs 30 to 54 give some background on the move from the RO scheme to CfDs as the government's preferred method of supporting low carbon generation, and set out the CfD allocation mechanism. Paragraphs 55 to 75 then discuss some issues we would like to explore further in relation to CfDs.

- Capacity Market: Paragraphs 76 to 96 give some background on the Capacity Market and how capacity agreements are allocated. Paragraphs 97 to 103 then discuss some issues relating to the Capacity Market that we would like to explore in further detail.

- Initial views: Paragraphs 104 to 109 set out our initial views on the issues identified in this paper.

Contracts for Difference

What are they?

30. In order to achieve its objective of decarbonising electricity generation, the government has supported renewable electricity generation since 2002 via the RO and ROCs.[14]

31. Under the current RO system, all eligible renewable generators receive a number of 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

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[12] DECC submission to CMA energy market investigation, January 2015.
[13] In addition to the EMR, National Grid is implementing policies to ensure security of supply during the period before the Capacity Market comes into force. The Supplemental Balancing Reserve (SBR) pays generators to be available to generate when they would otherwise not be, while the Demand Side Balancing Reserve (DSBR) pays non-domestic consumers to reduce their demand when called upon to do so. We have not identified specific issues relating to these policies that we consider warrant further analysis at this point in time, so do not consider them further in this paper.
[14] DECC (February 2015) *Increasing the use of low-carbon technologies*.

customers in Great Britain, 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.[15]

32. 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.

33. Appendix A sets out our initial assessment of some issues with the current system of ROCs. We note that while ROCs are being phased out to new generators, DECC estimates that ROC payments will reach almost £4 billion per year by 2020/21.[16]

34. 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.[17]

35. A CfD is a private contract between the holder and the CfD counterparty[18] in which the holder receives from (or pays to) the counterparty the difference between a previously agreed strike price and a CfD reference price.[19] 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.[20]

36. 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.[21]

37. 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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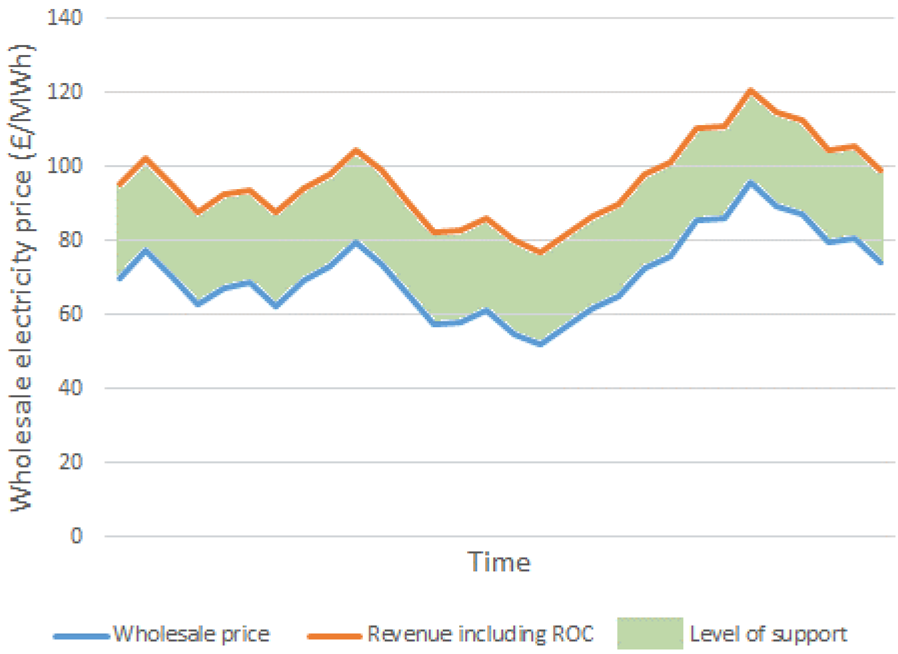
[15] DECC (February 2015) *Increasing the use of low-carbon technologies*.
[16] DECC (October 2014) *Annual energy statement 2014*.
[17] DECC (June 2014) *Implementing Electricity Market Reform (EMR): finalised policy positions for implementation of EMR*.
[18] The CfD counterparty is the Low Carbon Contracts 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*.
[19] 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.
[20] DECC (August 2013) *Electricity Market Reform: Contract for Difference – allocation methodology for renewable generation*.
[21] DECC (October 2013) *CfD impact assessment*.

FIGURE 1

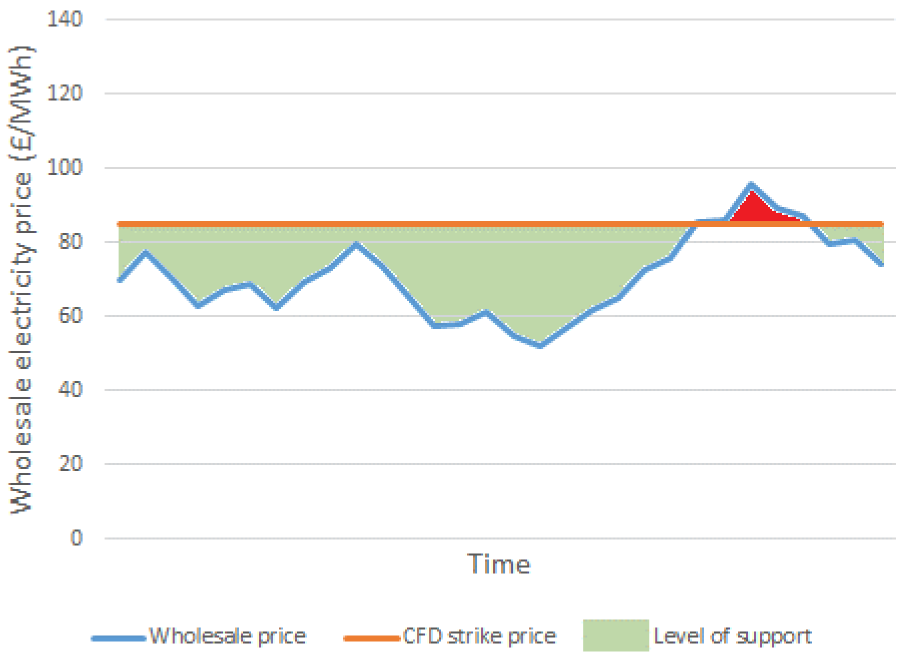
Renewables Obligation Certificates



Source: CMA (not actual price data).

FIGURE 2

Contracts for Difference



Source: CMA (not actual price data).

38. 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.

39. 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, in turn reducing the support they require and therefore the cost to consumers.[22]

40. Electricity suppliers finance the CfD payments to generators by paying a contribution to the CfD counterparty based on their share of total metered demand.[23]

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

42. The first allocation round that was scheduled to take place in 2014 was delayed as Ofgem considered appeals from applicants whose applications had been rejected by the Delivery Body. Bidding for the first allocation round took place in January and February 2015. [25] The outcome was announced on 26 February 2015, and we will consider this in our subsequent analysis.

43. The European Commission granted the CfD policy state aid approval in July 2014.[26]

Contract for Difference allocation mechanism

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

45. 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 Table 2, below), Pot 2 contains 'less established technologies' (see Table 2, below) and Pot 3 includes biomass conversion.[27] Projects applying for CfDs compete

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[22] DECC (October 2013) *CfD impact assessment*.
[23] The Contracts for Difference (electricity supplier obligations) regulations 2014.
[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] Low Carbon Contracts Company (January 2015) *Electricity Market Reform Contracts for Difference: GB implementation plan*.
[26] European Commission (July 2014) Letter to the United Kingdom, State aid SA.36196 (2014/N) – Electricity Market Reform – Contract for Difference for renewables.
[27] 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 European Commission (July 2014)

with other projects in the same pot to secure this limited budget. Table 1, below, sets out the level of support allocated to each pot for the first allocation round.

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*.

46. DECC sets 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*.

47. Prospective generators apply to National Grid,[28] 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).[29] In contrast, if there is insufficient budget in a pot, CfDs are auctioned, with a separate auction for each pot as needed (a 'constrained' allocation).[30]

Letter to the United Kingdom, State aid SA.36196 (2014/N) – Electricity Market Reform – Contract for Difference for renewables, paragraph 14.
[28] National Grid (October 2014) *Contracts for Difference round guidance: Contracts for Difference allocation round 1 – 2014*.
[29] DECC (September 2014) *CfD auction guidance*.
[30] DECC (September 2014) *CfD auction guidance*.

48. 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.[31]

49. 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.[32] 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.

50. 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.[33] If a project can be allocated a CfD without breaching the budget, it is provisionally allocated a CfD.[34]

51. The budget calculation for each project includes an assessment of *(a)* the cost of issuing a CfD to the project at the price bid,[35] 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.[36]

52. 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).[37]

53. 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 considered. The clearing price in each pot for each delivery year is set by the highest strike price bid by a successful project.[38] However, as noted above, no project can receive a CfD with a strike price above its ASP.

54. 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

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[31] DECC (September 2014) *CfD auction guidance*.
[32] DECC (September 2014) *CfD auction guidance*.
[33] DECC (October 2014) *Contract for Difference: final allocation framework for the October 2014 allocation round*.
[34] DECC (October 2014) *Contract for Difference: final allocation framework for the October 2014 allocation round*.
[35] 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*.
[36] DECC (October 2014) *Contract for Difference: final allocation framework for the October 2014 allocation round*.
[37] DECC (October 2014) *Contract for Difference: final allocation framework for the October 2014 allocation round*.
[38] DECC (September 2014) *CfD auction guidance*.

enter into a CfD contract.[39] When a bid is rejected because it would breach the budget, the Delivery Body considers any flexible bids from that bidder before closing that year to other bids.[40]

Potential issues

55. Overall, the move from ROCs (not allocated competitively) to CfDs (which introduce competition to the allocation mechanism) may be seen as positive with regards to ensuring competition drives down the level of support. DECC's mechanism for allocating support is likely to encourage competition between prospective generators, and therefore drive down the level of payments (and therefore cost to consumers).

56. More generally, as noted above, CfDs are likely to offer benefits over ROCs, as the risk profile of CfDs is likely to be more conducive to investment than that of ROCs.[41]

57. Since the level of payment under CfDs is a function of both the strike price and the CfD reference price, if the CfD mechanism fails to ensure that both the strike price and CfD reference prices are set competitively, there is scope for CfD holders to receive higher payments than necessary.

Strike price

58. The CfD allocation mechanism aims to ensure that competition drives down the level of strike price in the CfD contract, and therefore the level of payments to low carbon generators.

59. Generators are likely to have better information than the government about the true level of strike price they require, and may be able to take advantage of this information asymmetry to extract higher payments than they require.

60. Competition between prospective generators for a finite amount of support might mitigate this problem of information asymmetry, and drive the support down to a level that better reflects that required to deliver the desired capacity.

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[39] DECC (September 2014) *CfD auction guidance*.
[40] DECC (October 2014) *Contract for Difference: final allocation framework for the October 2014 allocation round*.
[41] First Utility's submission to the CMA's energy market investigation, August 2014, raised the issue that exposure to a variable supplier obligation for CfDs could increase risks faced by suppliers. We are in the process of considering this argument.

Non-competitive allocation of Contracts for Difference

61. CfDs with a total value of £16.6 billion over their lifetime were awarded early, without price competition, under the Final Investment Decision enabling for Renewables (FIDeR) scheme. This included CfDs awarded to eight different projects: five offshore wind, two biomass conversion and one biomass combined heat and power.[42,43]

62. The National Audit Office (NAO) report on these early CfDs estimated that these contracts constitute 58% of the total amount of budget available to CfDs until 2020/21.[44] The report concluded that awarding such a large proportion of the CfD budget in a non-competitive manner 'limited [DECC's] opportunity to secure better value for money through competition under the full regime'.[45]

63. We would like to understand further DECC's rationale for allocating these contracts outside the auction process. We also note that the Secretary of State for Energy and Climate Change has the power to direct the CfD counterparty to award additional CfDs in a non-competitive manner.[46] It is important that further CfDs are allocated using a competitive process to ensure the lowest possible cost for consumers.

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

64. We would like to understand better whether dividing the CfD budget into three separate pots runs the risk of allocating CfDs in an inefficient manner, and potentially distorts competition between different technologies.

- *Inefficient allocation of CfDs*

65. If any of the projects that fail to secure CfDs in the Pot 1 auction bid a lower strike price than any of the projects that are allocated a CfD in Pot 2, the allocation mechanism will fail to allocate CfDs to the lowest-cost projects. For example, if there is a prospective onshore wind generator that bids £90/MWh in Pot 1 and is not allocated a CfD, but an offshore wind generator (of the

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[42] NAO (June 2014) *Early contracts for renewable electricity*.
[43] We note that the European Commission approved individually under state aid rules the five offshore wind projects (European Commission (July 2014) Letter to the United Kingdom, State aid SA.38758 (2014/N), SA.38759 (2014/N), SA.38761 (2014/N), SA.38763 (2014/N) & SA.38812 (2014/N) – United Kingdom support for five offshore wind farms: Walney, Dudgeon, Hornsea, Burbo Bank and Beatrice) and the biomass combined heat and power (European Commission (January 2015) IP/15/3601 (press release) – decision not yet available). The two biomass projects are currently under review.
[44] NAO (June 2014) *Early contracts for renewable electricity*.
[45] NAO (June 2014) *Early contracts for renewable electricity*, paragraph 17.
[46] See Energy Act 2013 and Electricity: the Contracts for difference (allocation) regulations 2014.

same size) is allocated a CfD in Pot 2 at £130/MWh, the CfD would have been allocated to the higher-cost project.

66. However, it is also important to note that the impact on overall costs and value for money of separating the budget into pots is not clear. While separating the budget into pots could increase the strike price paid to higher-cost generators, it could also reduce the strike price paid to lower-cost generators. The overall impact on cost will depend on the nature of the bids and the allocation of the budget between pots.

- *Distortion of competition between different technologies*

67. In addition, there is a risk that separating the CfD budget into different pots could distort competition between different technologies. For example, under the current division of technologies into pots, solar photovoltaic generation has to compete with onshore wind for support (as both are in Pot 1), whereas offshore wind does not (as it is in Pot 2).[47] This risks intensifying competition for some technologies, while weakening it for others.

68. Any distortion of competition is likely to be felt by technologies allocated to Pot 1 that fail to receive CfDs. As noted above, projects failing to receive CfDs under this approach may have been able to deliver capacity at lower cost than projects that are successful in Pot 2. This could potentially harm technologies that have lower costs than some projects receiving CfDs but fail to secure CfDs under DECC's multiple-pot approach.

69. DECC's rationale for dividing the budget into separate pots is to protect less established technologies from competition with more established technologies, in order to help them to develop to the point where they can compete with the more established technologies.[48] DECC considers there are dynamic efficiency benefits from protecting less established technologies, as it could enable them to become more efficient over time, to the point where they can compete with established technologies.[49]

70. Given that Pot 2 contains £260 million of budget per year from 2017/18, with projects eligible for 15-year CfDs, almost £4 billion could be allocated to projects in Pot 2 in the first allocation round, with any future allocation rounds

[47] See Table 2, above.
[48] DECC (January 2014) *Electricity Market Reform: allocation of Contracts for Difference, consultation on competitive allocation*.
[49] DECC (January 2014) *Electricity Market Reform: allocation of Contracts for Difference, consultation on competitive allocation*.

increasing this figure. Failure to allocate CfDs to the lowest-cost projects could therefore result in a considerable cost to consumers.

71. As a result, we are minded to explore further the rationale for separating the budget for established and less established technologies. We would like to understand better how DECC weighed the potential costs of this approach against the benefits of protecting nascent technologies from competition.[50]

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

72. Low carbon generation projects that are due to commission before the end of March 2017 have the choice of whether to apply for CfDs or ROCs.[51] We would like to explore further whether the ability of CfD bidders to opt for ROCs could effectively put a floor on the strike price they are prepared to bid in CfD auctions, and whether this could limit the degree of competition in the early CfD allocation rounds.

Contracts for Difference reference price

Risk of manipulating the Contracts for Difference reference price

73. As set out above, CfD holders receive (or make) payments equal to the difference between the strike price and the CfD reference price. In the issues statement we set out that we would consider whether large CfD holders may be able to manipulate the CfD reference price down in order to receive higher CfD payments.[52]

74. We consider it unlikely that any generator in receipt of CfD payments would have the ability and incentive to manipulate the CfD reference price. Our analysis indicates that the volumes sold by the CfD holder in the reference market to make this profitable would need to constitute a larger proportion of trades in that market than we consider plausible. Appendix B sets out our thinking on this issue in more detail.

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[50] We note that the CfD scheme was approved by the European Commission under state aid rules (European Commission (July 2014) Letter to the United Kingdom, State aid SA.36196 (2014/N) – electricity market reform – contract for difference for renewables). In particular, the European Commission explicitly accepted the arguments of the UK in favour of organising separate tenders for less established technologies due to their longer-term potential and considering the need to achieve diversification (paragraph 72). It further agreed that, with respect to the technologies in Pot 2, the selection process would be competitive enough to presume that the aid is proportionate and would not distort competition to an extent contrary to the EU internal market, in accordance with point 126 of the Environmental and Energy State Aid Guidelines (paragraph 75).
[51] DECC (June 2014) *Implementing Electricity Market Reform (EMR): finalised policy positions for implementation of EMR*.
[52] CMA (July 2014) *Energy market investigation: statement of issues*.

Auction rules

75. In addition to the issues set out above, we would like to clarify DECC's rationale for some of the CfD auction rules. We will continue to engage with DECC on these issues.

Capacity Market

76. The other key policy resulting from the EMR is the introduction of a Capacity Market to ensure security of supply.[53]

77. The Capacity Market 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.

78. The Capacity Market 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. The wholesale electricity market rules working paper assesses the rationale for the Capacity Market in more detail.[54]

What is it?

79. Under the Capacity Market, 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.[55]

80. Winning bidders receive regular capacity payments in exchange for an obligation to provide a previously agreed level of capacity with 4 hours' notice from the System Operator (SO), National Grid.[56]

81. DECC (with input from National Grid and a panel of independent experts) sets the amount of capacity to procure in the Capacity Market for each delivery year, based on its target 'reliability standard'.[57] That is, DECC estimates the amount of capacity needed in any given year to meet its target level of

[53] DECC (November 2012) *Electricity Market Reform: policy overview*.
[54] See wholesale electricity market rules working paper
[55] DECC (June 2014) *Implementing Electricity Market Reform (EMR): finalised policy positions for implementation of EMR*.
[56] DECC (June 2014) *Implementing Electricity Market Reform (EMR): finalised policy positions for implementation of EMR*.
[57] Expressed as loss of load expectation (LOLE): the number of hours during each year for which it is expected (statistically) that supply would not meet demand (absent further intervention from the System Operator)

reliability.[58] The Delivery Body then holds auctions to procure this target level of capacity.

82. The Capacity Market is paid for by suppliers' contributions based on their share of 4pm to 7pm winter weekday demand.[59]

83. 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).[60] 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.

84. 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.[61] Existing plants are eligible for a one-year agreement, while refurbishment and new plants are eligible for three- and 15-year agreements, respectively.[62]

85. As well as generating capacity, demand side response (DSR) providers can participate in the auction.[63] DSR providers with capacity agreements receive capacity payments in exchange for reducing their demand during times of system stress.[64]

86. The first auction (for delivery in 2018/19) was held in December 2014, and procured 49.26GW of capacity – more than the target amount – at a price of £19.40/kW,[65] considerably below the pre-auction estimates of the clearing price. This will result in total payments for this capacity of £956 million (2012

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[58] DECC (June 2014) *Implementing Electricity Market Reform (EMR): finalised policy positions for implementation of EMR*.
[59] DECC (June 2014) *Implementing Electricity Market Reform (EMR): finalised policy positions for implementation of EMR*.
[60] DECC (June 2014) *Implementing Electricity Market Reform (EMR): finalised policy positions for implementation of EMR*.
[61] 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*.
[62] DECC (June 2014) *Implementing Electricity Market Reform (EMR): finalised policy positions for implementation of EMR*.
[63] 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.
[64] 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.
[65] National Grid (2014) *Final auction results: T-4 Capacity Market auction 2014.*

prices) (with further payments for any additional capacity procured in the T-1 auction).

87. New plants with just over 2.6GW capacity secured agreements in the first auction, including one new large combined-cycle gas turbine (CCGT) plant of approximately 1.6GW. In addition, 174MW of DSR was procured for 2018/19 in the auction.[66]

Allocation mechanism

88. This section gives a brief overview of the Capacity Market auction mechanism.

89. Capacity agreements are allocated via a multiple-round descending clock auction with a single clearing price.[67] The Delivery Body is charged with either acting as the auctioneer or appointing another person to act as the auctioneer.[68]

90. Ahead of the auction, DECC announces the demand curve the auctioneer will use to determine the amount of capacity to procure.[69] 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.

91. 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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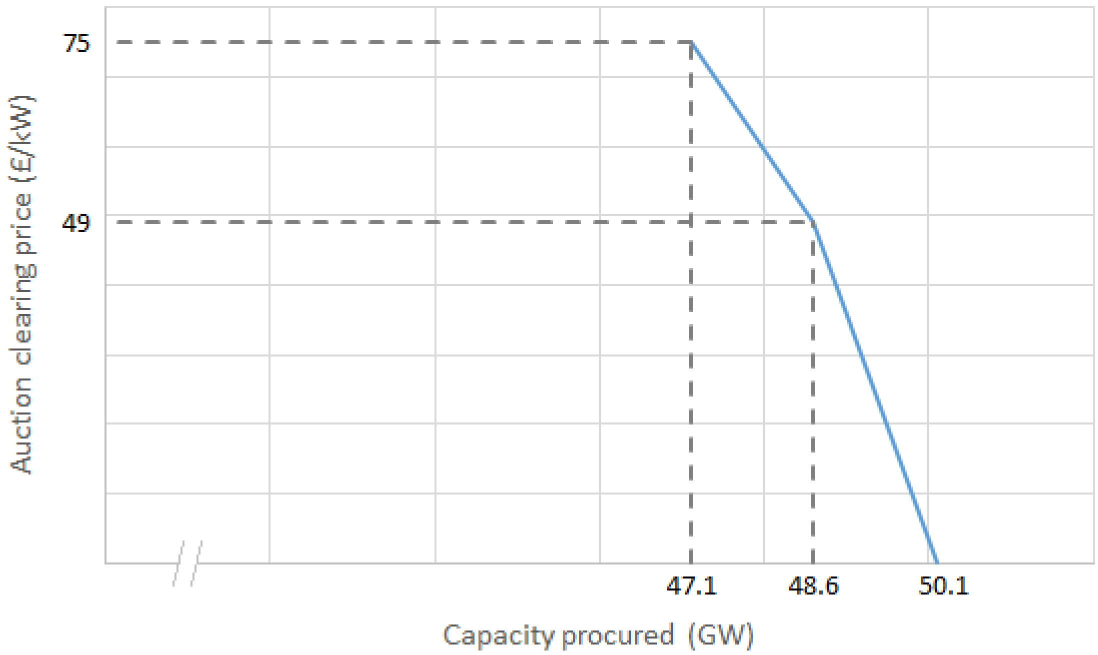
[66] National Grid (2014) *Final auction results: T-4 Capacity Market auction 2014*.
[67] National Grid (July 2014) *Capacity Market user support guide: guidance document for Capacity Market participants*.
[68] The Electricity Capacity Regulations 2014, section 24.
[69] DECC (June 2014) *Implementing Electricity Market Reform (EMR): finalised policy positions for implementation of EMR*.

FIGURE 3

The Department of Energy and Climate Change'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*.

92. 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.[70]

93. The auction progresses through a series of rounds, with the auctioneer reducing the price by a set decrement in each round.[71] In the first auction, this decrement was £5 per round.[72] 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.[73]

94. At the end of each round, the auctioneer announces the amount of excess capacity remaining in the auction (rounded to the nearest 1GW in the recent

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[70] National Grid (December 2014) *Capacity auction user guide: guidance document for Capacity Market participants*.
[71] National Grid (December 2014) *Capacity auction user guide: guidance document for Capacity Market participants*.
[72] National Grid (December 2014) *Capacity auction user guide: guidance document for Capacity Market participants*.
[73] National Grid (December 2014) *Capacity auction user guide: guidance document for Capacity Market participants*.

2018/19 T-4 auction).[74] The auction ends when there is insufficient capacity remaining in the auction to meet DECC's demand. The auctioneer then 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).[75] The amount bid by the marginal successful bidder sets the clearing price that all parties receive.

95. DECC included rules to prevent large existing plants from being able to exercise market power. Existing plants are designated as 'price takers' by default,[76] and are prevented from submitting exit bids for their capacity above a 'price taker threshold'[77] (£25/kW in the 2014 auction).[78] 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 and DSR are designated as 'price makers' by default, and can submit exit bids at any price level.[79] Refurbishing plants can also be designated as 'price makers', but this is subject to detailed rules, including the submission of a memorandum justifying their requirement for price maker status in most cases.

96. We note that the Capacity Market scheme was approved by the European Commission under state aid rules in July 2014.[80]

Potential issues

97. As with CfDs, competition between bidders for capacity agreements should drive down the level of support required. Since the costs of the Capacity Market are expected to be passed through to consumers, it is important to ensure the auction procures the required capacity at the lowest possible cost.

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[74] National Grid (December 2014) *Capacity auction user guide: guidance document for Capacity Market participants*.
[75] National Grid (December 2014) *Capacity auction user guide: guidance document for Capacity Market participants*.
[76] Unless they have submitted a memorandum to Ofgem justifying 'price maker' status.
[77] 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*.
[78] National Grid (December 2014) *Capacity auction user guide: guidance document for Capacity Market participants*.
[79] National Grid (December 2014) *Capacity auction user guide: guidance document for Capacity Market participants*.
[80] European Commission (July 2014) Letter to the United Kingdom, State aid SA.35980 (2014/N-2) – Electricity Market Reform – Capacity Market.

Demand side response

98. In December 2014, Tempus Energy brought an action before the European General Court seeking the annulment of the European Commission decision to approve the Capacity Market.[81] Also in December 2014, the CMA received a submission from Tempus Energy regarding the role of DSR in the Capacity Market.[82]

99. In its submission, Tempus Energy set out that the Capacity Market does not enable DSR providers to compete with generators on an equal basis. Specifically, it highlighted that while generators facing high capital costs are eligible for up to 15-year capacity agreements, DSR providers are eligible for only one-year agreements (even where they face high capital costs).

100. The submission also claimed that the way in which the costs of the Capacity Market are recovered from suppliers could harm the ability of DSR providers to compete. The submission set out that smoothing the costs of the Capacity Market across all winter weekday evenings could reduce incentives for DSR providers to decrease demand at times of system stress, compared to the other options DECC considered.

101. We intend to investigate further whether the rules relating to length of capacity agreement available to DSR providers and the way in which Capacity Market costs are recovered run the risk of distorting competition.

Penalty mechanisms

102. Capacity providers with capacity agreements face penalties if they fail to deliver their obligations.[83] However, these penalties are capped at 100% of the capacity provider's annual capacity market payments.[84] That is, the total penalties a capacity provider faces over the course of a year cannot rise above the revenue it receives from Capacity Market payments in that year.

103. We would like to consider further whether the upside of the capacity payment, coupled with no apparent downside of entering into a capacity agreement, could result in existing generators that are unable to meet their obligations reliably bidding into the Capacity Market.[85]

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[81] Case T-793/14, *Tempus Energy and Tempus Energy Technology v Commission*, lodged 4 December 2014.
[82] Tempus Energy (December 2014) Submission to CMA energy market inquiry.
[83] DECC (June 2014) *Implementing Electricity Market Reform (EMR): finalised policy positions for implementation of EMR*.
[84] The Electricity Capacity Regulations 2014, schedule 1.
[85] We note that new plants face significant penalties for failing to build the capacity for which they have been awarded capacity agreements (see DECC (June 2014) *Implementing Electricity Market Reform (EMR): finalised policy positions for implementation of EMR*).This is not the focus of this working paper.

Initial views

104. As set out above, there are a number of areas where we would like to explore DECC's mechanisms for allocating support to generators and capacity providers in further detail.

Contracts for Difference

105. Overall, the move away from ROCs (non-competitive allocation) to CfDs (which introduces competition to the allocation mechanism) can be seen as positive with regards to competition. However, we would like to understand better the rationale behind some of DECC's choices regarding the CfD allocation mechanism.

106. More specifically, we would like to understand:

(a) DECC's rationale for allocating a large proportion of the budget available for low carbon generation without price competition;

(b) whether dividing the CfD budget into separate pots could result in an inefficient allocation of CfDs, and could potentially result in a distortion of competition between different technologies;

(c) whether the period of overlap between ROCs and CfDs could serve to limit competition in the early CfD auctions; and

(d) DECC's rationale for some of the rules in the CfD auction.

107. On CfDs, we considered the extent to which generators with large CfDs would have the ability and incentive to manipulate prices in the reference market. Our initial view is that this is unlikely.

Capacity Market

108. On the Capacity Market, we are interested in exploring further:

(a) whether the way in which the Capacity Market treats DSR could result in a distortion of competition; and

(b) whether the penalty mechanism may run the risk that existing generators that would be unable to meet capacity obligations reliably may face incentives to seek capacity agreements.

109. We will continue to engage with DECC to understand better the issues outlined above.

Appendix A: Potential for anticompetitive behaviour in Renewables Obligation Certificates

The value of Renewables Obligation Certificates

1. As noted in paragraphs 30 to 33 of the main document, suppliers subject to the Renewables Obligation (RO) must comply with the scheme either by presenting Renewables Obligation Certificates (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'.[1]

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.[2] Generators can opt to carry over unsold ROCs to the next obligation period.[3]

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

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

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 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 asymmetry in negotiations

11. DECC ensures that suppliers' total RO is 10% above the expected number of ROCs that will be generated over the obligation period.[4] 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

[4] 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*.

fall considerably (perhaps close to zero), as ROC generators compete with 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. They may be able to do this at reasonably low cost (by paying the buy-out price rather than buying ROCs at their prevailing value). In addition, the repeated nature of the interaction between suppliers and generators in the ROC market could increase incentives for a supplier to depress the price of ROCs, if it gave it stronger bargaining power in future negotiations.

15. If the above effect is sufficiently strong, it could give each of the Six Large Energy Firms large supplier considerable bargaining power in its negotiations with generators, and could enable it to extract low prices as a result of its ability (unilaterally) to eliminate the scarcity value of ROCs.[5]

16. However, we note that the more suppliers engage in this type of behaviour, the greater the incentives other suppliers might face to buy ROCs (as a result of the increased buy-out recycle fund).

17. The Drax response to our issues statement noted a number of issues with the system of ROCs relating to the potential buyer power of the Six Large Energy Firms. Its submission set out a number of options for reducing their buyer power, including moving to a fixed payment for ROCs.[6]

Initial views

18. We recognise that the incentives faced by suppliers and generators in negotiating ROC prices are complicated. At this stage, we have not formed a view of the market outcomes that are likely to emerge. We will consider

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[5] In practice, firms would need to consider the impact of depressing the value of any ROCs they generate when considering this sort of behaviour.
[6] Drax (August 2014) Submission to CMA.

further the extent to which the Six Large Energy Firms large electricity suppliers might have buyer power in purchasing ROCs, and would welcome feedback and evidence from interested parties on the following:

- evidence on how the price of ROCs has changed over time;
- the impact of this regime on investment, given the forthcoming replacement of ROCs with CfDs; and
- the impact of this regime on the prices that retail customers pay.

Appendix B: Manipulation of Contracts for Difference reference price

Introduction

1. In the issues statement we set out that we would consider whether large CfD holders may be able to benefit from manipulating the CfD reference price.[1] In this appendix, 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.

2. This appendix 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 appendix, 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

3. 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 12, 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.

4. 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.

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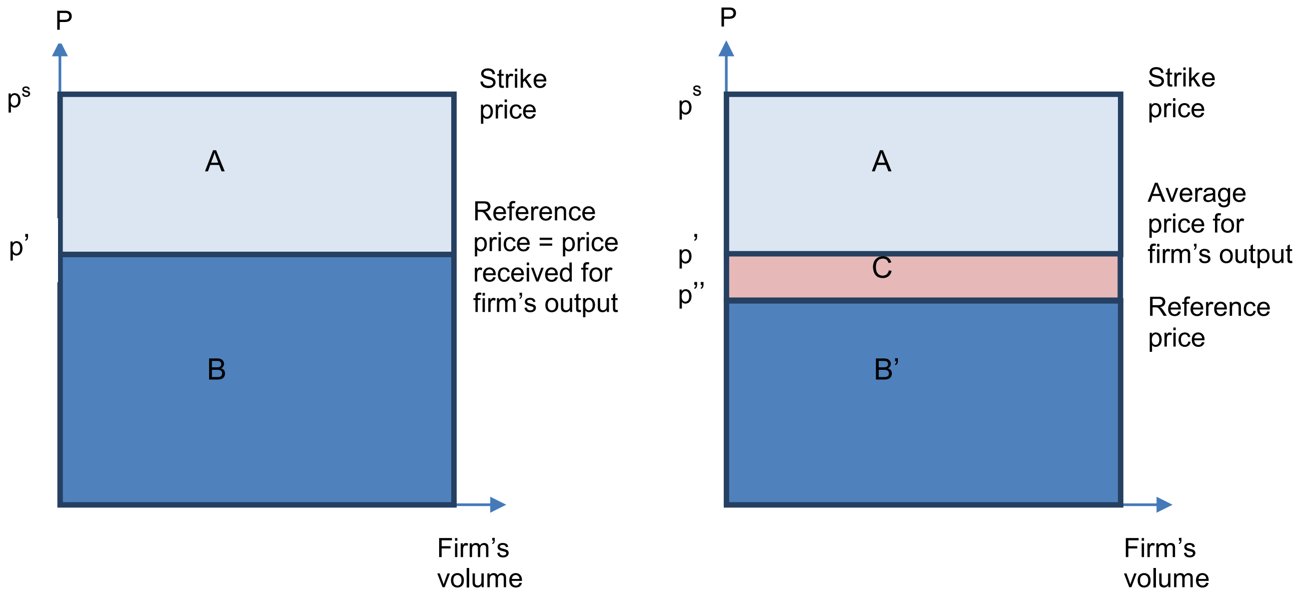
[1] CMA (July 2014) *Energy market investigation: statement of issues*.

FIGURE 1

Illustration of the mechanics of manipulation



Source: CMA.

5. 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.

6. 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.

7. 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.

8. 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.

9. 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.

10. 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

11. 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

12. The market reference price is calculated as follows:

Reference price = sum of all trade values[2] ÷ sum of all trade volume

13. 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.[3]

14. 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.

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[2] 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

[3] FiT C*ontract for* Difference standard terms and conditions.

15. 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.[4]

Liquidity of season-ahead baseload market

16. Analysis of trading data indicates that the average capacity of season-ahead baseload sold through brokers is approximately 18.5GW.[5]

17. 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 2GW 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.

18. 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

19. 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.

20. 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

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[4] DECC (April 2014) *Implementing Contracts for Difference: policy and drafting update*.
[5] 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 liquidity working paper for more detail on trading data.

reference price. This would likely reduce a generator's ability to manipulate the reference price.

Incentive

21. In this section we consider under what conditions a generator might have incentives to manipulate the reference price downwards. The Annex, 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:[6]

Gain	=	Revenue from sales in reference market	+	Revenue from sales outside reference market[7]	+	Revenue from CfD contract	–	Revenue without manipulation

22. By simplifying this formula,[8] 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.[9] (Further information and calculations are available in the Annex.)

23. 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.

24. 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.

25. EDF reached commercial agreement with the UK government in October 2013 on the key terms of a CfD for 3.2GW of baseload nuclear capacity from

[6] In the Annex, this is formula (2) $\pi = \alpha q p_{\alpha} + (1-\alpha) q p_{-\alpha} + (p^{s} - p^{r})q - p^{s} q$.
[7] Sale outside of reference market could be either internal sales or sales to other markets (eg month-ahead or year-ahead markets).
[8] 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.
[9] See formula (10) in the Annex.

Hinkley Point C, planned to start generating from 2023. To date, this is the largest CfD that has been agreed for baseload capacity.[10]

26. 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 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.

27. 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.

28. However, the key drivers of trading are likely to be market liquidity and underlying demand rather than electricity supply per se.[11] 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.

Initial views

29. 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.

30. 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.

[10] For more information, see European Commission (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.

[11] 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.

31. 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 18.5GW, and the generator that has been awarded the most baseload CfDs to date will have 3.2GW of capacity in receipt of CfDs when it comes online. As a result, absent significant changes in the amount of trading in the reference market, we consider it unlikely that a generator would face incentives to manipulate the reference price.

32. 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.

Annex: Incentives for manipulating Contracts for Difference

1. In this annex 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:

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

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

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

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

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

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:

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

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.