Appendix 18.1: Regulatory governance and financial transparency: analysis and consultation responses

Contents

Introduction

1. In this appendix we set out analysis that supports our finding of a Governance AEC, the first of two AECs regarding the governance of the regulatory framework we set out in Section 18. When considering the Governance AEC we look at whether certain aspects of the broader regulatory framework, and its governance, risk affecting competition either through distorting incentives, increasing barriers to entry, stifling innovation or encouraging ill-advised policy interventions. Analysis supporting the other AEC we find in this area, the Codes AEC, is set out in Appendix 18.2.

2. We set the scene to this appendix by providing a background explanation of the current regulation.

3. As explained in Section 18, we have organised the four features that lead to the Governance AEC under two headings:

   (a) Allocation of powers, roles and responsibilities between DECC, Ofgem and the industry.

   (b) Lack of clear and trusted analysis underpinning decision making and implementation.

4. This appendix provides further analysis on two of the four features leading to the Governance AEC. Firstly we discuss DECC's and Ofgem's respective roles and powers (heading *(a)*) before moving on to explore whether, in certain instances, a lack of coordination between Ofgem and DECC might have led to inefficient or delayed implementation of policy decisions, for instance through code modifications. Secondly, we analyse and discuss financial transparency, the absence of which has contributed to a lack of clear and trusted analysis (ie heading *(b)*).

Background: regulation in the GB energy markets

Overview of GB system of energy regulation

5. In general, in the GB energy sector primary and secondary legislation is used to set the high-level objectives and the structure of the regulatory framework, while more detailed rules are set out in licence conditions and industry codes.[1]

6. The current regulatory system of licensing was established in the act of privatising the energy markets through the GA86 and the EA89. Unless an exemption applies, a licence is required to carry out:

   - generation of electricity;
   - shipping of gas;
   - transmission;
   - distribution;
   - supply;
   - the operation of an interconnector; and
   - the operation of a smart meter communication service.[2]

7. In addition, licensees are subject to a series of industry codes which set out technical and commercial rules. We discuss these codes, and their governance, in more detail in this appendix.

Shared competence of UK and EU institutions[3] to regulate GB energy markets

8. The GB regulatory framework for energy has been shaped by various EU interventions. The Treaty on European Union (TEU),[4] as amended in 2009, formally established the shared competency of EU institutions and the individual Member States to legislate on the subject matter of energy.[5] However, a number of policies affecting the energy market were previously adopted by EU institutions (see Appendix 2.1: Legal and Regulatory

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[1] See DECC 2011 Ofgem Review.
[2] See Appendix 2.1: Legal and Regulatory Framework.
[3] In this appendix, reference to the 'EU institutions' should be interpreted to include reference to the European Parliament, the European Council and the European Commission.
[4] Article 4(2) of the TEU.
[5] See Appendix 2.1: Legal and regulatory framework.

Framework for a description of the key EU policies), and in particular with a view to promoting liberalisation and decarbonisation across the EU.

9. Pursuant to enacted Regulations,[6] the EU institutions established energy regulators (the European Network of Transmission System Operators for Electricity[7] (ENTSO-E), the European Network of Transmission System Operators for Gas[8] (ENTSO-G) and the Agency for the Cooperation of Economic Regulators[9] (ACER)) for the purpose of supporting, developing and enforcing legislation concerning energy. This secondary legislation also required the creation of binding European network codes for the purpose of facilitating a fully liberalised internal energy market. The European network codes, which are at different stages of development, will have to be transposed into national law in the coming years, with the result that any conflicting provisions within the current GB industry codes, licence conditions and legislation will have to be amended.[10]

10. A number of parties, including Ofgem, stated that the implementation of these European network codes will have a significant impact on the GB regulatory framework. European network codes contain complex technical provisions that cut across various pieces of legislation, licence conditions and GB industry codes. A significant amount of resources, as well as close coordination between DECC, Ofgem and the industry, will therefore be necessary in order to identify the areas where change is needed and to ensure a consistent and efficient implementation. This circumstance might exacerbate some of the issues identified in Section 16.

DECC's and Ofgem's respective roles and powers

11. As noted above, appropriate levels of coordination between DECC and Ofgem are necessary to avoid duplication of (or even conflicts between) regulatory interventions and ensure a swift and consistent implementation of

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[6] Regulations (EC) 713/2009 and 714/2009.
[7] ENTSO-E is governed by a general assembly representing the 41 electricity TSOs operating within the EU and by a management board consisting of 12 elected members. NGET is the sole GB TSO to appoint a representative to the general assembly of ENTSO-E. We note that the current president of the management board of ENTSO-E is an employee of NGET.
[8] ENTSO-G is governed by a general assembly representing the 44 gas TSOs operating within the EU and by a management board consisting of 12 elected members. NGG is the sole GB TSO to appoint a representative to the general assembly of ENTSO-G.
[9] ACER is composed of permanent staff seconded by certain of the national regulatory authorities for energy. Its governing body is the Board of Regulators, which is composed of senior representatives from the national regulatory authorities of each of the 28 Member States.
[10] We note that an employee of Ofgem is the current chairman of the electricity working group at ACER, which is the body within ACER that is mainly concerned with the development of the electricity European network codes.

policy decisions. We discuss below DECC's and Ofgem's respective roles and powers.

Description of DECC's and Ofgem's respective roles and powers

12. DECC, as a department of government, has the power to enact secondary legislation and the ability to initiate and drive the process of enacting primary legislation. Pursuant to that ability and power, DECC may cause legislation to be enacted that overrules any conflicting licence conditions, industry codes or Ofgem policies. DECC's powers in this regard are subject to EU legislation. Since 2010, government has used primary legislation[11] to greatly broaden DECC's powers to enact secondary legislation in order to implement policies concerning the electricity markets (in particular, those related to the EMR).

13. Pursuant to requirements established under the Third Package, Ofgem is the designated GB National Regulatory Authority and as a result, pursuant to EU law,[12] it must be 'legally distinct and functionally independent from any other public or private entity'.

14. However, we note that DECC has a number of direct and indirect powers that it can exercise to influence Ofgem's function and operation. In particular, it has the power:

    (a) to appoint the chairman of GEMA as well as other members of GEMA (after consulting with the chairman);[13]

    (b) pursuant to its ability to drive primary legislation, to cause Ofgem's statutory duties and objectives to be altered;

    (c) pursuant to its ability to drive primary legislation and enact secondary legislation on certain subjects, to exert institutional pressure on Ofgem by threatening to act to address a certain issue in the event that Ofgem does not itself act to address the issue in question;[14]

    (d) pursuant to the powers granted to it in primary legislation, to modify directly licence conditions and to veto an Ofgem decision to modify

[11] Namely, the Energy Act 2010, Energy Act 2011 and Energy Act 2013.
[12] Each of article 35(4) of Directive 2009/72/EC and article 39(4) of Directive 2009/73/EC require that the Member States individually designate a National Regulatory Authority to regulate the electricity and gas markets, respectively (which may be the same entity, such as is the case in GB). See Appendix 2.1: Legal and regulatory framework.
[13] Schedule 1 of the Utilities Act 2000.
[14] Section 34(3)(b) of GA86 and section 47(2)(b) of EA89.

licence conditions (including a decision by Ofgem to approve or reject a MP);[15] and

(e) to issue a general direction to Ofgem that it should regard certain considerations when prioritising the order in which it is to review the energy markets.[16]

15. When using their powers under GA86 and EA89, both DECC and Ofgem must pursue the same principal objective. This objective leaves a wide margin of appreciation to DECC and Ofgem, which therefore could decide to take different approaches in seeking to achieve this objective.

16. Recognising the complexity of Ofgem's statutory duties and objectives under GA86 and EA89, in 2013 DECC was granted by law the power to designate[17] a statutory Strategic Policy Statement (SPS)[18] in order to provide Ofgem with a clear steer concerning the government's long-term strategic vision.[19] The objective of the SPS is to provide more clarity about the respective roles of Ofgem and government, the strategic context for Ofgem's independent regulatory role, and greater confidence that policy and regulation will be consistent and coherent. This reform followed the 2011 Ofgem Review,[20] which found that the regulatory framework of the gas and electricity markets has struggled to keep pace with wider policy developments, in spite of governments attempts to address this issue by revising Ofgem's duties. DECC published a draft SPS in August 2014, but has not yet exercised its power to designate that document. While GA86 and EA89 establish parameters for Ofgem's regulatory action, it is important to note that primary legislation leaves Ofgem discretion to decide what constitutes the appropriate level of intervention in each regulatory context.[21]

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[15] Section 23(5) of GA86 and section 11A(5) of EA89.
[16] Section 34(3)(a) of GA86 and section 47(2)(a) of EA89.
[17] Ofgem must have regard to the strategic priorities set out in a designated SPS when carrying out its regulatory functions. Section 132 of Energy Act 2013.
[18] Section 131 of Energy Act 2013.
[19] Specifically, DECC must designate an SPS for the purpose of setting out: (i) the strategic priorities of government for energy policy; (ii) the outcomes to be achieved as a result of those policies; and (iii) the roles and responsibilities of the persons (whether the Secretary of State, Ofgem or other persons) involved in the implementation of those policies. Sections 131 to 138 inclusive of Energy Act 2013. The SPS designated pursuant to this power must be reviewed by the Secretary of State every five years. Section 134 of Energy Act 2013.The power to designate an SPS replaced the Secretary of State's previous power, established under the Utilities Act 2000, to issue non-binding social and environmental guidance to Ofgem.
[20] DECC (July 2011), Ofgem Review: Final Report.
[21] In certain contexts, this has resulted in a situation in which the powers of DECC and Ofgem overlap. For example, Ofgem's general power under section 23 of GA86 and section 11A of EA89 to modify SLCs overlaps with the power granted to DECC under section 84 of the Energy Act 2008 to modify SLCs for the purpose of facilitating access or the efficient use of a transmission system.

17. Ofgem has general duties[22] to keep the gas and electricity markets under review and to collect information necessary for the effective performance of its functions.

18. Licences are the primary means by which Ofgem regulates, and enforces obligations placed on, the relevant operators in the gas and electricity markets. For these purposes it has the general power to:

    (a) grant licences;[23]

    (b) modify any of the SLCs as it considers necessary;[24] and

    (c) modify the conditions of any licence, or the licences of all licensees of a certain category.[25]

19. Ofgem has the power to sanction a licensee for the breach of any relevant licence condition or requirement by imposing a penalty of up to 10% of the annual turnover of the licensee. Ofgem also has powers to impose enforcement orders and, since 2014, consumer redress orders.

20. DECC has the power to alter the scope of licensable activities, thus permitting it to broaden or curtail the scope of the regulated energy sector.[26] Similarly, in specific instances, DECC may grant an exemption from the obligation to hold a licence under either GA86 or EA89.[27] Also, in limited circumstances set out by law, it may modify licence conditions for the purpose of implementing a particular policy objective (for instance policy objectives linked to liberalisation of the energy market, which it has used in the past to implement the NETA and BETTA reforms).[28]

Observations relating to Ofgem's and DECC's respective powers and responsibilities

21. Policy objectives may be implemented by a combination of measures taken by DECC (mainly through legislation), Ofgem (mainly through licence conditions) and the industry (through constrained self-regulation of codes). In principle, DECC is responsible for setting policy objectives and developing

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[22] Section 34 of GA86 and section 47 of EA89, respectively.
[23] Section 7 of GA86 and section 6 of EA89.
[24] Section 8 of GA86 and section 8A of EA89.
[25] Section 23 of GA86 and section 11A of EA89.
[26] Sections 43 and 88 of Utilities Act 2000 added new section 41C to GA86 and new section 56A to the EA89, respectively.
[27] Section 5 EA89 and section 6A GA86.
[28] For instance, the legal basis for the development of the CUSC, the BSC and MRA is section 68 of the Utilities Act 2000 which granted DECC the power to modify any category of electricity SLC for the purpose of implementing NETA.

policies. However, in view of its powers, duties and objectives, Ofgem inevitably takes decisions that develop certain areas of policy, and go beyond mere implementation. In practice, the delineation between the powers and roles of DECC, Ofgem and the industry are naturally blurred. However, this lack of clarity may be inevitable and independent regulation is going to be a hard model to sustain in an environment where policy goals are changing dramatically. It is not clear that this problem is avoidable.

22. Regulation must be implemented in a coherent manner and at a sufficient pace to react to market developments and wider policy changes, which suggests that it would be beneficial to centralise the powers to regulate in the hand of one authority. However, this should not be achieved by undermining the independence of Ofgem, which is essential to guarantee a fair playing field. Also, the complexity of the industry, and the technical constraints that characterise it, mean that certain changes cannot be implemented by DECC or Ofgem without involving the industry in the design of these changes.

23. As set out in paragraph 14 above, DECC has a number of tools that it can use to influence Ofgem's action. However, short of regulating a particular area by way of statutory instruments, there are no formal powers for DECC to direct Ofgem to implement a specific change, nor clear formal processes for Ofgem and DECC to discuss transparently a strategy for the implementation of DECC's policies. There might also be instances where measures covering different areas of regulation adopted by DECC and Ofgem independently might overlap and possibly be inconsistent with each other.

24. In the following paragraphs we discuss three case studies illustrating situations in which implementation of policy goals was delayed (or sub-optimal) due to a lack of coordination between DECC, Ofgem and the industry.

Delayed implementation: 17-day switching and P272

25. These two case studies (Annex A of Appendix 18.2) relate to DECC's smart meter agenda. 17-day switching and half-hour settlement were seen as two measures necessary to deliver certain important benefits of smart meters. However, DECC decided not to implement these supporting measures itself by way of secondary legislation, instead leaving this task to Ofgem and the industry. In both cases, DECC amended SLCs to support its smart agenda. However, in the case of P272 it did not mandate the use of data from smart meters to settle Profile 5-8 customers. A long and costly industry modification process had to be initiated to allow for the use of data from smart meters to settle these customers. For 17-day switching, DECC's changes to SLCs could

not be enforced. To rectify this issue, Ofgem had to amend SLCs to make three-week switching a licence obligation on suppliers rather than customers.

26. Both cases show that DECC used its power to only partially implement policy changes and that later intervention by Ofgem or industry was needed to fully implement these policy changes. If DECC had entirely delegated implementation to Ofgem, the latter could have arguably implemented more efficiently the necessary changes to allow faster switching and half-hourly settlement for Profile 5-8 customers.

Poorly coordinated regulatory interventions: capacity market and EBSCR

27. A good illustration of the interplay between DECC's and Ofgem's measures relates to the EBSCR reform carried out shortly after DECC's capacity market (see also Appendix 5.1: Wholesale electricity market rules). In this case, Ofgem intervention to reform cash-out rules, although covering a different aspect of the market, had a clear interaction with the capacity market. More specifically, both measures originally sought to remedy the 'missing money' problem. We note that the coexistence of these two mechanisms reflects two different approaches. On the one hand, DECC's capacity market seeks to resolve the problem by creating a competition for the market for capacity, while Ofgem, through the cash-out reform, sought to solve this problem through competition in the market for energy.

28. We understand that DECC and Ofgem have collaborated in order to ensure that these two measures would not lead to overcompensation of capacity providers. They reached the view that capacity providers would take into consideration future expected revenues under the reformed cash-out mechanism when bidding for capacity market contracts, in order to be more competitive in the auction. This point was not challenged by the European Commission within the context of its assessment of the capacity market under State aid rules.

29. In Section 5, we have however identified concerns arising from the interaction of the two measures which might lead to conservative bidding in the capacity market auctions (due to the uncertainty of future revenues under the reformed cash-out rules) and ultimately the overcompensation of certain capacity providers. We believe that a more coordinated solution to solve the 'missing money problem', with more transparency (and appropriate consultation phases), could have led to the development of solutions that are less complex and less likely to introduce unintended consequences.

Financial Transparency

Introduction

30. Many firms including the Six Large Energy Firms operate in several different markets, often across a vertical or horizontal value chain. The Six Large Energy Firms themselves are in the best position to determine the basis for financial reporting that best enables them to run their respective businesses.

31. From the perspective of the public policy debate and wider regulation, it can be important to obtain market orientated financial information that reflects the financial performance of generation and retail supply as stand-alone businesses, in particular for considering profitability.[29] This is particularly the case where firms operate internationally.

32. Both UK and European statutory financial reporting rules[30] require firms[31] to report the financial performance for their activities as a whole.[32] These rules also require firms to report a limited set of financial information for the key operational divisions (segmental information) through which senior management run the business as a whole. In addition, since 2009, Ofgem has required the Six Large Energy Firms to report to its specification a set of profit and loss information for generation and retail supply activities.

33. It is important that the regulatory framework for financial reporting makes available to regulators and policy-makers financial information (including balance sheet information) on market lines consistently delineated across firms and giving a sufficient degree of transparency over revenues, costs and profitability. In this regard, the financial information needs to be relevant and reliable as well as having a clear and accessible basis of preparation.

34. In this section of this appendix we set out the status quo regarding the financial information available to help Ofgem in its regulatory and public-policy decision making roles. We also summarise stakeholders' responses to our provisional finding that the lack of a regulatory requirement for clear and relevant financial reporting concerning generation and retail profitability (hereafter 'the lack of financial transparency') as set out in our provisional report. This section of this appendix is structured as follows:

[29] See Section 18, paragraphs 18.74 to 18.77 for some examples.
[30] These rules are a mix of company law reporting requirements and financial reporting rules as embodied in either UK or International accounting standards.
[31] Here, incorporated firms such as the Six Large Energy Firms.
[32] These rules focus on the information needs of investors.

(a) Ofgem's initiatives to obtain further financial information (paragraphs 36 to 52);

(b) our diagnosis of the Six Large Energy Firms' accounting information (paragraphs 53 to 75); and

(c) parties' comments on the lack of financial transparency contributing to our provisional Governance AEC (paragraphs 76 to 95).

35. In addition, there is one annex (Annex A) to this section of the appendix, which sets out our review of the reporting of wholesale energy costs by the Six Large Energy Firms and our conclusions thereon.

Ofgem's initiatives to obtain further financial information

36. Ofgem has taken a number of initiatives in this area over the last past few years, as set out below. These range from obtaining further ex post 'accounting' information from the Six Large Energy Firms to developing its own financial information. The justification given for each initiative has varied.

Use of Ofgem's powers to require segmental accounting information

37. In the following paragraphs we set out the recent history leading up to Ofgem's current position for the provision of segmental accounting information by the Six Large Energy Firms. This is relevant as it explains the starting point for the financial information provided to us in this market investigation.

Post-liberalisation

38. As discussed in paragraph 2.40, caps on retail prices for domestic consumers were imposed in the initial period after liberalisation. These were removed in 2002, along with the requirement on energy firms hitherto subject to price caps to provide financial information for their retail businesses beyond that required to be published for statutory reporting purposes. There was no requirement for generation businesses to provide financial information to the regulator pre liberalisation because all generation plant had been in public ownership and subsequent to that were considered to be a competitive part of the value chain.

Energy Supply Probe

39. The Energy Supply Probe in 2008/09 (the 'Probe') highlighted the need for more transparency with regard to the relationship between the generation and retail supply activities of the Six Large Energy Firms. Ofgem explained that,

as not all of the Six Large Energy Firms produced separate segmental accounts at the time for gas supply, electricity supply and electricity generation, it was difficult for existing and potential market participants to assess the profitability of these different activities. In addition, Ofgem observed that there was little transparency regarding the transfer price used by the supply and generation businesses of the SLEFs to exchange wholesale energy, which gave rise to concerns about cross subsidisation.[33]

40. Ofgem argued that segmental reporting and increased transparency on transfer pricing would provide better visibility to existing market participants and potential new entrants regarding margins in different parts of the value chain.[34]

41. Ofgem put forward four options for consultation and ultimately decided to require the Six Large Energy Firms to publish separate profit and loss accounts for the supply of electricity and the generation and supply of gas and to reconcile such accounts to Great Britain (GB) group earnings before interest tax, depreciation and amortisation (EBITDA). All accounting policies would need to be consistent with and reconcilable to the policies that such firms had adopted in their statutory accounts.[35,36]

42. After the publication of Ofgem's analysis of the first set of profit and loss information for 2009 in March 2011, Ofgem issued guidance in May 2011 that the 2010 information, amongst other things, should explain how the transfer pricing methodology related to open market prices and/or a cost plus methodology.[37] These sets of profit and loss statements are described as the Consolidated Segmental Statements (CSS).

Retail market review

43. As part of the subsequent 2011 retail market review (RMR), Ofgem appointed the accountancy firm BDO to review the way the Six Large Energy Firms provided information about the profits of different parts of their vertically integrated (VI) businesses. BDO had found that the Six Large Energy Firms had allocated key functions to different parts of their business, but the transfer pricing methodologies each had employed had accounted for these

[33] Ofgem (7 August 2009), Energy Supply Probe – Proposed Retail Market Remedies, paragraph 6.1 (p33).
[34] Ofgem (7 August 2009), Energy Supply Probe – Proposed Retail Market Remedies, paragraph 6.2 (p33).
[35] Ofgem (7 August 2009), Energy Supply Probe – Proposed Retail Market Remedies, paragraphs 6.2 and 6.11 (pp33 & 35).
[36] See Electricity generation SLC 16B and Electricity supply SLC 19A.
[37] Ofgem (23 May 2011), Financial Information Reporting: Amended Guidance, paragraph 1.9 (p4).

differences.[38] BDO concluded that such firms transfer pricing policies were broadly 'fit for purpose and transparent'[39] and would likely meet the measure of best practice described in the OECD's transfer pricing guidelines.

More recent developments

44. In the summer of 2014, Ofgem commissioned BDO to review the Six Large Energy Firms' latest transfer pricing methodologies as reflected in their 2013 profit and loss accounts for generation and retail supply of gas and electricity. BDO's key finding was that such firms' current transfer pricing rules reflected the arm's length standard. As a result, Ofgem concluded that it was even more confident that the profits the Six Large Energy Firms declared were the ones they actually made from their activities in generation and supply.[40]

Ofgem's development of the supply market indicator

45. Following the Probe, Ofgem committed in 2008 to continually monitor price changes to help stakeholders better understand the relationship between domestic retail prices and wholesale costs. This was in part in response to the concern that falls in wholesale energy costs had not been translating into lower retail prices as quickly as increases had been leading to higher retail prices. This initiative eventually became the supply market indicator (SMI).[41] This information was updated and published regularly[42] from 2009 to April 2015.

46. In its most recent form, the SMI, as calculated by Ofgem, inferred a measure of the expected retail margin for the Six Large Energy Firms as a whole by comparing annual energy charges for an average[43] customer based on such firms' published tariffs at a particular point in time with the costs of supply determined on the following approaches:

    (a) Wholesale energy costs – based on the average of forward prices for the forthcoming year that had prevailed over a period[44] in the immediately preceding past.

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[38] Improving the Reporting Transparency of the Large Energy Suppliers, 1 May 2012, Footnote 4 to paragraph 3.20 (p13).
[39] Ofgem (31 October 2013) Rebuilding Consumer Confidence: Improving the transparency of energy company profits, paragraph 3.16. The footnote cross refers to p56, Ofgem Segmental Statements Review, BDO LLP Final Report, 16 January 2012.
[40] The revenues, costs and profits of the large energy companies in 2013, paragraph 5.6 (p42).
[41] Supply Market Indicator Methodology, Ofgem, dated 30 October 2014, paragraphs 1.3 & 1.4.
[42] The frequency of publication has varied: quarterly, weekly and monthly.
[43] 'A dual fuel direct debit 'medium' typical consumption customer as per the definition prevailing at the time of publication.
[44] This period over which the average forward wholesale price for the forthcoming year was determined varied between 190 to 365 trading days preceding the particular point in time.

(b) Network costs – a bottom-up estimate using the prevailing wholesale transmission and distribution charging tariffs inflated by forecast RPI.

(c) Indirect costs of supply – actual costs (ie historically incurred) of supply taken from the Six Large Energy Firms' CSS profit and loss statements inflated by forecast RPI.

(d) Environmental and social obligations – future cost estimates taken from DECC's published impact assessments.

47. This approach to comparing costs with charges therefore utilises the following perspectives to measure costs and charges over the forthcoming year:

(a) Wholesale energy costs – a *forecast* of these costs for the forthcoming year using an average of already known *historical* forward prices covering the same year.

(b) Network costs – a *forecast* of costs to be incurred in the forthcoming year.

(c) Other indirect costs of supply – a forecast of costs to be incurred in the forthcoming year directly based on *reported actual* costs in the most recently available sets of CSS inflated by forecast RPI.

(d) Environmental and social obligations – a *forecast* of costs made by DECC.

(e) Energy charges – a *forecast* of charges based on the assumption that tariffs would remain unchanged over the forthcoming year.

48. We note that the approach to measuring wholesale energy costs adopted in the SMI, ie one based on the prevailing market price for products traded on the open wholesale market is conceptually the same approach we recommend that Ofgem should require the Six Large Energy Firms to adopt when disaggregating wholesale energy costs.

49. On 22 May 2015, Ofgem announced that it had suspended the SMI as part of its review of the information it collected and published. The purpose of that review was to enable Ofgem to provide greater transparency about the market to inform the energy debate in the future.[45]

[45] Ofgem (22 May 2015), Ofgem announces review of markets data.

Profitability analysis undertaken

50. Both the CSS and SMI initiatives focused on obtaining a better understanding of profits and profit margins. In 2011, as part of its RMR work to promote trust and engagement in the energy markets, Ofgem tried to assess the retail profitability, rather than retail profits, of the Six Large Energy Firms. Ofgem sought, with the help of a firm of consultants specialising in the energy sector, Redpoint, to analyse these firms' retail supply profitability both as a VI firm and as a standalone retail supplier. In the absence of actual balance sheet information, Ofgem estimated on a bottom-up basis the operating capital employed by the Six Large Energy Firms including collateral requirements both as a VI firm and as a standalone retail supplier.

51. To calculate profitability, Ofgem multiplied its estimate of capital employed by its estimate of the cost of capital and deducted this from operating profits, which in principle the same approach that we have used to present the results of our retail profitability analysis.[46]

52. Ofgem did not publish this piece of analysis. We understand that this was in part because it was not confident that it had got to the bottom of the capital employed/collateral issue. Ofgem, however, did use it to inform its public assessment as to what operating margins should be. This analysis suggested that an operating margin of 3 to 4.5% of revenue for VI firms and up to 10.5% of revenue for a standalone supplier would allow firms to earn a reasonable return on capital employed.[47,48]

Our diagnosis of the Six Large Energy Firms' accounting information

53. We now explain why, in our view, the accounting information that the Six Large Energy Firms initially supplied to us within the context of this market investigation did not provide a sufficiently robust basis for our analysis of profitability. In the course of our investigation we sought to address those issues surrounding this financial information that were material to our conclusions. We did this by requiring parties to provide us with information that more closely reflected the financial performance of generation and retail supply as stand-alone businesses, and/or by making our own adjustments to the information initially supplied.[49] We illustrate below why the accounting information initially supplied to us differed from that which we considered to be

[46] See Appendix 9.10, paragraph 21.
[47] Ofgem (1 March 2011), RMR Profitability Analysis, paragraph 5.1.
[48] See RMR – Findings and initial proposals - Supplementary Appendices (pp41–44) for how the output of this profitability analysis was used publicly. Ofgem (21 March 2011).
[49] We set out the detail of how we did this across Appendices 9.10, 9.11, 9.13 and 4.2.

appropriate to conduct the profitability analyses for our market investigation. The inability of most of the Six Large Energy Firms to readily provide such market-orientated financial information[50] may explain why some stakeholders consider the status quo regarding financial transparency in relation to Ofgem's regulatory and public-policy decision making role as inadequate.[51]

54. We would like to emphasise that the following analysis is not a criticism of how the Six Large Energy Firms have chosen to organise their business or the set-up of their financial reporting systems. Firms design their financial reporting systems primarily to support the running of their business and enable them to fulfil their statutory reporting obligations, which are focused on the needs of investors. Inevitably, the information that the firms initially supplied to us was based on the financial information they were already routinely producing.

55. Our analysis within the context of this market investigation was focused on establishing the profitability of the Six Large Energy Firms for generation and retail supply. There were two distinct but interrelated themes as to why the accounting information initially supplied to us by the Six Large Energy Firms differed from what we considered we needed for our analysis.

Misalignment of the scope of the activities of the Six Large Energy Firms to the needs of our analysis

56. The first theme related to the scope of the activities undertaken, and therefore reported, within each of the Six Large Energy Firms' operating divisions. Their groupings of activities within divisions did not necessarily align with the way we wished to group their activities for our analysis.

57. In addition, each of the Six Large Energy Firms organised their activities across their generation, trading and retail supply divisions differently, so simply basing our analysis on which activities they included in each of their divisions would have seriously hindered cross-comparability.

- *Generation defined as a tolling business*

58. In order to assess the profitability of the Six Large Energy Firms' generation activities we considered it relevant to include all the activities that a 'full-function' generator would undertake. See Appendix 4.2, paragraph 18. We

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[50] This is because, the existing divisional reporting lines of certain firms differs from the segmentation of the energy value chain on market lines. As a result these firms need to re-cut their financial information. Unless the firms' reporting systems have this flexibility already built in to their reporting systems, the information segmented on an alternative basis across the value chain cannot be easily and robustly produced in a timely fashion.
[51] See Section 18, paragraphs 18.74 to 18.77 for examples.

considered this to be the concept of generation that fully aligned the risks and rewards for owning and operating generation plant. It was also the business model that had been adopted for newly acquired generation assets in GB over the period of review.

59. The main issue we found here was that some of the Six Large Energy Firms had allocated their generation activities between their generation and trading divisions. These firms had limited the scope of the activities of their generation division to selling to the trading division the right to use the plant to generate electricity.[52] Unadjusted,[53] this would also have meant a lack of comparability across the Six Large Energy Firms in terms of what activities were included within generation.

- *Wholesale energy costs not necessarily reflecting the actual costs incurred by the firm*

60. The main issue we found here was that some of the Six Large Energy Firms had included within their results for retail supply transfer charges for wholesale energy that did not wholly reflect the costs the firm had actually incurred. These practices indicate that these firms do not define the boundary between retail supply activities and trading/generation activities consistently. This results in a lack of comparability across the Six Large Energy Firms for this highly material cost item.

61. The approach to transfer charging that is relevant for our analysis is different from that set out in the OECD transfer pricing guidelines.[54] These guidelines focus on the pricing of transfers between different legal entities, whereas we are concerned with the pricing of transfers between markets. In the case of analysing the profitability of retail supply, we wanted input costs to reflect transfers between the wholesale energy market and retail supply, and for these transfers to be based on prices achieved in external markets.

62. For example, we found that [✄]'s retail supply division recorded that it had ordered certain shaped products before such products were available on the open wholesale markets for that delivery date,[55] and that [✄] had purchased products so far ahead of the point of delivery that it was unlikely that these quantities would have been available on the open market.[56] Other of the Six

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[52] Where some of the Six Large Energy Firms sold the right to use generation plant it was to their trading division, not to an independent third party.
[53] Five of the Six Large Energy Firms were able to provide us information either in line (EDF, Centrica and Scottish Power,) or approximately in line (RWE and E.ON) with the basis specified. The firm that could not was SSE (see Table 1 in Appendix 4.2).
[54] See paragraph 43 where the OECD transfer pricing guidelines were used as the relevant benchmark.
[55] See Annex A, 'review of wholesale energy costs, paragraphs 32–35.
[56] See Annex A, 'review of wholesale energy costs', paragraphs 64–66.

Large Energy Firms reported purchases of energy on a bespoke basis. This is in particular an issue where these purchases are the result of internal trading (ie in [✂]'s case) where it is doubtful that an equivalent standalone retail supplier would have been able to purchase energy on the same terms. As a result, the prices 'negotiated' would not reflect what could have been achieved on external markets.

63. There will inevitably be a difference between the value of energy priced on the basis of products traded on the open wholesale markets and the value of energy priced on some other (bespoke) basis. We found that this difference appeared to be inconsistently handled across the Six Large Energy Firms. For example, for [✂], retail supply reflected the purchase of some [✂] electricity sourced on a bespoke longer term basis, whereas for [✂], retail supply reflected the purchase of all energy, including presumably some internally supplied energy, wholly on the basis of traded products. This implies that, for [✂], any difference in the values between bespoke and traded products for this [✂] electricity was reflected in retail supply, but elsewhere for [✂].

64. Another example of this difference is the treatment of intermittent energy such as wind. Only [✂] and [✂] showed such purchases in retail supply, despite the fact that all of the Six Large Energy Firms own GB wind generation plants. On account of its intermittency, no wind output is sold in the form of traded products which guarantee provision of a certain volume over a specified period of time; rather it is sold with reference to, but not at the same level as, the prices prevailing at the time of production/delivery.

The perspective of a standalone firm in each relevant segment of the value chain

65. The second theme was that, even if the Six Large Firms had consistently grouped their activities across generation, trading and retail supply on the lines we considered relevant for our analysis, they did not always account for these activities to reflect the costs and revenues that would have been incurred by a standalone firm. As explained in paragraph 32 in Appendix 9.9, in our profitability analysis, we used as the relevant benchmark the costs and revenues that would have been faced by a new entrant entering into a competitive market.

- *Absence of transfer charges for implicit guarantee*

66. The Six Large Energy Firms told us that their retail supply businesses benefited from being part of a financially strong wider corporate group. This enabled them to maintain investment grade credit ratings, which allowed

them, among other things, to enjoy preferential trading terms on commodity markets.

67. However the Six Large Energy Firms did not explicitly account for the cost of obtaining these benefits in their results for retail supply.[57] Our analysis set out in Appendix 9.10 shows that a standalone supplier would have to pay a third party to obtain these benefits. We therefore made an adjustment (a transfer charge) to account for the cost of obtaining this guarantee based on the level of the fee that a couple of independent retail suppliers paid over the period of review to obtain similar benefits from an intermediary.

- *Absence of grossing up*

68. There are some benefits that arise within an integrated group. For example, such firms may be able to net off transactions made and balances held by different parts of the group with external parties.[58] However, in order to reflect the costs that a standalone firm would face, it would be necessary for these transactions and balances to be grossed up. We found that some balance sheet items reflected the net position across generation and retail supply, and therefore were not consistent with the perspective of what a standalone generator or retail supplier would have posted.[59]

Other transparency issues

69. There were some other issues that did not stem directly from either the firms' divisional structures or the need to reflect the costs that would be faced by a standalone firm. We outline some of the most important of these issues below.

- *The need for balance sheets aligned with scope of our analysis*

70. To assess profitability it is necessary to take into account the operating capital employed in the business.[60] However, some of the Six Large Energy Firms had difficulties providing us with a full balance sheet in line with the

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[57] In principle, generation would also benefit from being part of a financially strong wider group too. The extent of this benefit is not as significant as it is for retail supply as only the generation gross margin, rather than the whole of wholesale energy costs, would need to be hedged in order to avoid the risk of the firm suffering from unexpected movements in commodity prices.
[58] For example, the retail division of a firm might need to post collateral of 100 with an external counterparty whereas this same counterparty might at the same time need to post collateral with the firm's generation division of 70. If, as is normal commercial practice, the firm and the external counterparty net off these balances between themselves, then the firm will only need to post collateral of 30 with the external counterparty.
[59] See paragraph 65 where we discuss the standalone firm principle.
[60] See paragraphs 25 & 29 of Appendix 9.9.

divisionally-based profit and loss accounts they had supplied us for retail supply and generation.[61]

- *Granularity of reporting within generation and retail supply*

71. Sometimes it can be important to analyse profitability at a more granular level than the business or market as a whole. For example, we attempted to analyse generation by technology and retail supply by the customer types set out in our terms of reference. However, as a result of the way some of the Six Large Energy Firms accounted for the sales by their generation business – once the energy had been initially sold it went into a general pot – they were not able to provide revenues by generation technology, and therefore not able to report generation profitability by technology. We therefore were unable to report generation profitability by technology across all the Six Large Energy Firms. See Appendix 4.2, paragraph 95.

72. In contrast, all of the Six Large Energy Firms were able to provide information which disaggregated retail supply between domestic and non-domestic customers to a certain degree. However, while the Six Large Energy Firms were generally also able to disaggregate non-domestic customers between SME and Industrial & Commercial (I&C), they were not able to provide granular information for microbusinesses. This may have been because these customers had been defined in such a way in our terms of reference that did not lend them to being systematically identified as microbusinesses.

- *Selective use of other accounting bases other than historical cost*

73. To assess profitability on a comparable basis, it is necessary for the financial information to have been prepared adopting a consistent and relevant accounting convention. For the most part the Six Large Energy Firms adopted the historical cost accounting convention in the financial information they supplied. However, there were two instances where we came across the use of other accounting bases. While these other bases may more closely align with a measure of current costs, and therefore economic costs, the selective use of other accounting conventions can lead to a lack of comparability both within and across the Six Large Energy Firms.

[61] Ofgem required the Six Large Energy Firms to supply profit and loss accounts and not balance sheets, which may explain the difficulties some of the Six Large Energy Firms experienced in supplying us with that information.

74. For example, [✄] had revalued some of its gas contracts when it [✄]. This meant that the cost of gas procured under these contracts did not reflect the historical cost, rather the historical cost plus an amortisation charge.[62]

75. A further example was [✄] which, for its I&C customers alone, transfer charged wholesale energy costs on the basis of the average market price on the day that a supply contract was agreed,[63] rather than its hedged (ie historical) costs. [✄].

Parties' comments on the lack of financial transparency contributing to our provisional Governance AEC

76. In paragraphs 11.14 to 11.35 of the provisional findings, supported by the analysis set out in Appendix 11.1 of the provisional findings we set out why we considered that the lack of a regulatory requirement for clear and relevant financial reporting concerning generation and retail profitability contributed to our Governance AEC. Most of the comments we received on our analysis of the state of financial reporting related to our possible financial reporting remedy (see Appendix 19.1). However, a few parties did question whether there was any material lack of financial transparency and one whether current levels of transparency had led to an AEC. Some parties repeated these concerns in their response to the provisional decision on remedies. Below we give a brief overview of these comments before setting out comments on a party-by-party basis. We respond to these comments in Section 18.

Overview

77. There was only one response (SSE) which directly commented on the linkage, or otherwise, between robust financial information and good quality decision making on the part of the regulator (and more broadly on the part of the various branches of government such as DECC).

78. The Six Large Energy Firms didn't see financial transparency as a feature contributing to an AEC for the following reasons. The existing reporting regime already provided adequate transparency (SSE, E.ON) or we had found vertical integration not to be an issue (Centrica, RWE) and therefore financial transparency was not needed. Alternatively/additionally some of the Six Large Energy Firms framed the issue in terms of the desirability of further evolutionary improvements to the existing regime (RWE, EDF, Scottish Power).

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[62] See Annex A, 'review of wholesale energy costs', paragraph 71.
[63] See Annex A, 'review of wholesale energy costs', paragraph 55.

79. Ofgem also saw existing financial transparency as sufficient for its purposes.

Parties' comments on financial transparency/provisional AEC finding

Ofgem

80. Ofgem told us it thought that the existing reporting regime (CSS) already delivered clear and relevant financial reporting concerning generation and retail profitability. Ofgem explained that the CSS was one of the key tools it used to improve transparency of energy firm profitability. In its view the statements produced by the Six Large Energy Firms helped to fulfil the objective it had set for the CSS ie to provide robust, useful and accessible information on the revenues, costs and profits of the electricity generation and supply businesses of the large vertically integrated firms. Nevertheless it was open to further improvements to the current regime.[64]

SSE

81. SSE told us that it believed that the overall transparency of generators' and suppliers' revenues, costs and profits was currently fit for purpose and advanced against other comparable markets.[65] The CMA's provisional finding that 'clear and relevant financial reporting concerning generation and retail profitability' had contributed to an AEC in relation to regulatory decision-making[66] was thus surprising to SSE and unfounded in its view.[67]

82. SSE explained that, to the extent that policy and regulatory activity had negatively impacted the market, it was clear that a lack of certain firm-specific financial information had not been the root cause of this problem. Indeed, to the extent that any AEC could exist in relation to a 'lack of transparency and robustness in regulatory decision-making', the evidence clearly indicated that this should be more properly attributed to other features of the market.[68]

83. SSE instead pointed to well-intended, but flawed, regulatory initiatives introduced since 2009 that had had a negative impact on competition and consumer outcomes.[69] The evidence showed, SSE continued, that regulators and policy-makers had not lacked sufficient market-related financial information to fulfil their policy and regulatory remits. Instead, other features of

[64] Ofgem response to the Remedies Notice, Remedy 14, paragraphs 1.2–1.4.
[65] SSE response to Remedies Notice, paragraph 3.20.1
[66] SSE referred to the provisional findings summary, paragraph 205(a).
[67] SSE response to Remedies Notice, paragraph 3.20.2.
[68] SSE response to provisional findings, Section 11, paragraph 11.1.1.
[69] These regulatory initiatives included the Probes and RMR.

the regulatory process had contributed to the policy and regulatory decision-making concerns the provisional findings identified.[70] Furthermore, the CMA had not been able to provide any direct evidence for this AEC which was predicated on there being a causal link between the lack of market-orientated reporting and specific difficulties experienced by Ofgem. As a result this remedy was, in SSE's view, not justified, proportionate or well-targeted.[71]

84. SSE observed that the proposed remedy as set out in the provisional decision on remedies was intended to 'provide Ofgem with information that will allow it to provide a clear and trusted assessment of the GB energy markets.' However, Ofgem had consistently indicated that the segmental statements were accurate and fit-for-purpose. No further evidence on this point had been provided in the provisional decision on remedies. This proposed remedy was therefore not justified, proportionate, or well-targeted.[72]

Centrica

85. Centrica told us that it did not agree that there were financial transparency issues that arose in part due to the Six Large Energy Firms' vertically integrated structure that in turn gave rise to an AEC.[73] To support its view Centrica pointed to the fact that it provided a transparent and audited view of its generation and retail supply profit and loss as part of the annual consolidated segmental statement process. Centrica explained that these profit and loss accounts gave stakeholders assurance that the stated profits earned upstream and downstream were accurate.[74]

RWE

86. RWE told us there was no compelling need for significant changes to the current reporting framework, not least because we had found no fundamental issues with the operation and presence of vertical integration across value chains in the industry. RWE pointed to the considerable transparency, in its view, provided by the financial statements for generation and retail supply produced under the current reporting regime (CSS).[75]

87. RWE would, however, support and assist with discussions to enhance the information currently available. It agreed with us that financial reporting within

[70] SSE response to provisional findings, Section 12, paragraph 12.1.1.
[71] SSE response to provisional findings, Section 11, paragraphs 11.3.1 to 11.3.3.
[72] SSE response to the provisional decision on remedies, paragraph 7.2.3.
[73] Centrica referred to paragraph 6.123 of provisional findings.
[74] Centrica response to provisional findings, vertical integration, paragraph 225.
[75] RWE response to provisional findings, paragraph 101.

the industry should be transparent, robust and aim to build rather than detract from consumer confidence.[76]

E.ON

88. E.ON told us that, whilst there was scope for improvement, the existing financial reporting frameworks already gave a high degree of transparency and assurance around the profitability of the Six Large Energy Firms. E.ON had in the past supported Ofgem in its work to continuously improve and develop the efficacy of financial reporting in the form of the electricity generation and electricity and gas supply licences (CSS) and would continue to do so in the future.[77]

89. E.ON noted that in the provisional decision on remedies we had not made a final decision regarding the existence and form of any AEC. For there to be an AEC that would, in turn, require a link between potential deficiencies in the current reporting regime and AECs.[78]

Scottish Power

90. Scottish Power told us that it continued to support transparent and robust financial reporting of the industry. Scottish Power noted that it, unlike some of the Six Large Energy Firms, had reported across the value chain by reporting trading as well as generation and retail supply. It advocated that there would be benefits in terms of increased transparency if this approach were to be applied across the industry.[79]

EDF Energy

91. EDF Energy told us that it supported improvements to the existing reporting regime, the output of which is the consolidated segmental statements (CSS). EDF Energy stated that these financial statements could be the primary means of improving stakeholder understanding of energy generation and supply profitability.[80]

[76] RWE response to provisional findings, paragraph 100.
[77] E.ON response to Remedies Notice, paragraph 360.
[78] E.ON response to provisional decision on remedies, paragraph 278.
[79] Scottish Power response to Remedies Notice, paragraph, 14.1.
[80] EDF Energy's response to Remedies Notice, paragraph, 14.1.

Telecom Plus[81]

92. Telecom Plus pointed out the initial rationale for the introduction of transparency of generators' and suppliers' revenues, costs and capital employed was to look at the perceived theory that vertical integration was harming the retail market and negatively impacting the price that consumers pay. However, as the CMA had now concluded that there was no effect on competition by vertical integration, it argued that most of the reasons for these licence conditions had now disappeared.[82]

Citizens Advice

93. Citizens Advice told us that the debate about profitability and energy prices was closely linked to questions about the extent to which the large firms were able to use incumbency and vertical integration to their advantage.[83]

Professor George Yarrow

94. The response from Professor George Yarrow[84] did not comment on financial reporting but noted that good governance was capable of creating a higher trust, lower transactions cost environment in which market participants can go about their buying and selling with reasonable confidence, for example by establishing and enforcing market rules that are stable, not in the sense of being set in aspic – because changing circumstances will dictate adjustments – but that are contingently predictable, ie for any given change in background circumstances, market participants can form reasonable expectations of how the market rules will likely evolve in response.[85]

95. He argued that such predictability had been seriously degraded over the recent past and in his view was the single most important explanatory factor for the observations set out and examined in the CMA documents – a sectoral regulator whose actions in relation to retail energy markets had become detached from the principled pursuit of stable objectives, and hence whose behaviour lacked contingent predictability, including to itself. As a result the principal benefit that could potentially come from the CMA's investigation

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[81] Telecom Plus trades under the name of The Utility Warehouse and retails a variety of utilities including energy to retail consumers. It has an arrangement with RWE (who used to own the Telecom Plus group) whereby RWE procures its wholesale energy on behalf of Telecom Plus.
[82] The Utility Warehouse response to provisional findings, p15.
[83] Citizens Advice joint response from both Citizens Advice Scotland and Citizens Advice England & Wales to Remedies Notice, p64.
[84] Professor George Yarrow is Chairman of the Regulatory Policy Institute, an independent, charitable organisation dedicated to the study of regulation and deregulation. His response to provisional findings was in his own name.
[85] Professor George Yarrow response to provisional findings, p14.

would be to increase regulatory certainty, implying that this should be a principal criterion to be used when assessing remedies.[86]

[86] Professor George Yarrow response to provisional findings, p14.

Annex A: Review of wholesale energy costs

Introduction

1. As part of our financial data request, the CMA asked the Six Large Energy Firms to provide details of wholesale energy purchase costs reflected in their retail divisional cost base over the period 2009 to 2013. In this annex we assess whether these costs accorded with the costs (measured on a historical cost accounting (HCA) basis) that each firm had actually incurred in the retail supply market.

2. We sought to do this because almost the entirety of the wholesale energy costs (as reported to us) comprised of transfer charges from energy firms' trading divisions into their retail supply divisions. We wanted to assess the extent to which such firms' transfer charging practices resulted in a cost base that would have been incurred by a stand-alone retail supplier that had made same (external) purchases – the 'equivalent stand-alone retail supplier test'.

3. For the purposes of this analysis, we also wanted to consider the extent to which purchases related to the purchase of wholesale energy products that were traded on the open wholesale market. The purchase of any other energy products by retail supply would include the results of what we would consider a bundled activity.[87]

4. We also note that products bought and sold on traded markets replicate the sourcing options open to a stand-alone retail supplier where:

   (a) the pricing of transactions unambiguously reflects the outcome of a competitive market process; and

   (b) transaction prices are subsequently made publicly available and are therefore capable of being independently verified after the event as market prices.

5. The rest of this annex is structured as follows:

   (a) approach taken to assessing wholesale energy costs (paragraphs 6 to 12);

   (b) description of wholesale energy costs by firm (paragraphs 13 to 75); and

[87] See Section 19, paragraph 19.203.

(c) assessment of basis of wholesale energy cost by firm (paragraphs 76 to 97).

Approach taken to assessing wholesale energy costs

6. We used the responses we had received from the Six Large Energy Firms, to a number of requests for information, to help us assess the wholesale energy costs across the period of our review (2009 to 2013 inclusive) against the benchmark set out in paragraph 1 of this annex including:

   (a) the analysis of wholesale electricity and gas costs for their retail supply business by channel and component part;

   (b) the analysis of wholesale energy costs by broad customer segment (domestic, SME and industrial and commercial); and

   (c) the narrative responses to a number of questions on transfer pricing and trading practices.

7. We also held discussions with the Six Large Energy Firms on this subject.

8. We were not only interested in the transfer charges for the underlying wholesale energy products but also any other elements reflected in the total costs given for wholesale energy. For example, recharges to recover the operating costs of the trading division (eg the cost of employing traders to purchase or sell energy and working capital to support that activity). However it was important to us that these sorts of costs were separately identified as some firms might report these costs within wholesale energy and others elsewhere within other direct costs or indirect costs, or in another division. We wanted to establish the scale of any recharges of this nature within wholesale energy costs.

The benchmark implied by an 'equivalent stand-alone retail supplier'[88]

9. We are seeking to assess whether the wholesale energy costs for each of the Six Large Energy Firms reflected the costs that a stand-alone retail supplier of the same size and pursuing the same wholesale energy purchasing strategy as these firms, in terms of hedging timescales and products purchased, would have incurred transacting on external markets. This is what we mean by these firms reporting their actually incurred costs. This had important implications for our assessment of the profitability of retail supply.

[88] See paragraphs 35 and 37 of Appendix 9.9: Approach to profitability and financial analysis.

10. First, where some purchases were made using bespoke products not available on traded markets, the costs of these products would reflect the results of individual negotiations, often between two divisions of the same firm.[89] Therefore these costs would not necessarily reflect verifiable open market prices.

11. Second, we understand that the Six Large Energy Firms start purchasing their energy requirements for their retail customers up to three years ahead of delivery.[90] We also understand that liquidity in wholesale traded markets, both for electricity and gas, was restricted three years out to basic seasonal products, and that such products were subject to wider bid/offer spreads than the same products traded closer to delivery. Only when it became much closer to delivery was it possible to trade in more granular products. Therefore the implication was that any charges for shaped products ahead of these becoming available in external market were by definition not based on market products.

12. This caused us to scrutinise energy purchases that were sourced on a bespoke basis either because their pricing would not necessarily be objectively verifiable/reflect a bundled proposition or because the products in question were not at the time available to be purchased.

Description of wholesale energy costs by firm

13. In this section we describe for the Six Large Energy Firms the approach each had used to determine its wholesale energy costs, most notably the basis of the transfer charging from its trading division into retail supply. We start with the firms whose approach is the more straightforward to describe and then move on to the firms whose approach is more complicated.

14. The following text refers to ‘purchases’. In this context ‘purchases’ is intended to refer to net purchases and so may include sales of energy surplus to requirements.

[89] Some of the Six Large Energy Firms purchased wholesale energy from third parties on a bespoke basis. In these circumstances whilst transfer charging might well reflect the outcome of individual commercial negotiations, the effective pricing of an individual transaction could not be observed and therefore could not be readily verified. Such pricing might have also have reflected market conditions at the time of negotiation which might have been many years earlier, and before the period of our review.
[90] See Appendix 7.1: Liquidity.

[Firm A]'s approach

Purchases of wholesale energy

15. [Firm A] told us that its transfer charges into retail supply for wholesale energy (both electricity and gas), throughout the period of our review, comprised entirely of the purchase of standard products traded on wholesale markets. These products were always priced at the prevailing market price for that product at the time the trading division was instructed. The vast majority of retail supply's orders led to an external purchase by the trading division in the wholesale market, although in some cases the external purchase would not be immediate.

16. [Firm A] also explained that retail supply didn't necessarily accept the 'offer' prices prevailing in the wholesale market at the time. Its retail supply division was able (via its trading division) to 'bid' (lower) prices at which it would like to buy energy in the market to find out if a counterparty would be forthcoming to sell at that price. If such a counterparty came forward, it would transact at that lower price.

17. [Firm A] told us that [✂] upstream exploration and production division for gas and this [✂] the source of some of its wholesale gas requirements. Nevertheless the basis on which retail supply had procured its wholesale gas requirements over the period of review had been on the basis of wholesale traded products at the prevailing market prices.

Internal supply

18. [Firm A] told us that it didn't tag the trades that its trading division transacted on behalf of its other operating divisions including retail supply. However it had estimated that about 10 to 15% of the total annual volumes of its wholesale electricity requirements had been sourced from its own Great Britain generation, the rest coming from external wholesale traded markets.

Financial hedges

19. [Firm A] told us that it had entered into weather hedges for both power and gas to manage the financial impact of unexpected variations in weather. What it had done over the years had varied, however in each case the trading division had recharged to retail supply the cost of the hedge on a back-to-back basis. These transactions were included within wholesale energy costs.

Imbalance charges ('cash out')

20. Like all retail suppliers, [Firm A] incurred these costs whereby National Grid supplied and charged for any gap between what it had contracted to buy on behalf of its retail customers over each and every half hour period and what these customers had actually used in each half hour period. [Firm A] told us that it had included these (relatively minor amounts) in 'other costs of sales'. National Grid also charged firms for any shortfall in the volumes of wholesale gas purchased, and these costs were likewise included in 'other cost of sales'.

Recharges to recover the costs of operating a trading division

21. [Firm A] told us that its trading division charged its retail supply division under an umbrella service level agreement (SLA) to recover these sort of costs. There were a variety of charging mechanisms, some based on the gross volumes traded, others on the net volume traded and there was a separate fee for the provision of short-term position management that was required close to the point of delivery.

22. [Firm A] told us that these costs had been included within indirect costs under the subheading of 'other costs'. The total cost for these recharges had ranged from £[✀] million to £[✀] million per year.

[Firm B]'s approach

Purchases of wholesale energy

23. For the purposes of this review [Firm B] had two trading divisions, one whose role was to focus on managing [Firm B]'s overall portfolio of GB interests (its GB trading division[91]), the other, a transnational operating unit, with the role of managing the global [Firm B] position (its global trading division) and executing the vast majority of any trading required on wholesale energy markets. What we describe below are the transfer charges into retail supply that [Firm B]'s GB trading division levies. (There are separate transfer charges between its GB trading division and its global trading division.)

24. As with [Firm A], [Firm B] told us that its transfer charges into retail supply for underlying wholesale energy (both electricity and gas), throughout the period of our review, were based entirely on products traded on wholesale markets. These products were always priced at the prevailing market price for that product at the time the order was placed with trading.

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[91] [Firm B] refers to this division as its [✀] Division.

25. In practice [Firm B]'s GB trading division saved up (typically until the end of the trading day but the period could be longer) all the orders to buy and sell received from each of its GB operating units, including retail supply, before placing the net purchase or sell order with its global trading division. However the transfer price for the product purchased would be determined when the order was placed by retail supply, rather than when [Firm B]' global trading division transacted the net order, which was potentially a few days later.

26. Regarding wholesale gas, [Firm B] told us that [✂] long-term gas supply contracts. [✂] bought the use of wholesale gas storage [✂], or the equivalent financial trades, which enabled cheaper summer gas to be stored for supply in the subsequent winter.

Internal supply

27. [Firm B] told us that it routinely tagged all trades that its GB trading division handled on behalf of the other GB operating divisions including retail supply. This tagging enabled the identification of the netting of purchases and sales (ie internal supply) undertaken by the GB trading division across each pair of GB operating divisions. However this tagging couldn't be used to reliably identify the extent of *overall* internal trading between, for example, generation and retail supply. Internal transfers were transacted at mid-market prices.[92]

Financial hedges

28. [Firm B] told us that it had had a small amount of financial hedges for weather (mainly gas) and it had recorded the costs of these within 'other direct costs'.

Imbalance charges ('cash out')

29. [Firm B] had included these (relatively minor amounts for both electricity and gas) within its analysis of wholesale energy costs.

Recharges to recover the costs of operating a trading division

30. [Firm B] told us that it had included the recharge of brokerage costs within the transfer charges for traded product purchases. [Firm B] estimated these to amount to less than £[✂] million a year for retail supply.

[92] Trades at mid-market prices result in there being no bid-offer spread (ie same transaction price for generation and retail supply).

31. [Firm B] told us that it also recharged a relevant portion of the costs of running its GB but not its global trading division within ‘other indirect costs staff’.

[Firm C]’s approach

Purchases of wholesale energy

32. [Firm C] told us that its transfer charges into retail supply for underlying wholesale energy (both electricity and gas) throughout the period of our review comprised entirely of the purchase of products based on, but not always exactly the same as, those traded on wholesale markets. When [Firm C] had set up the basis of its trading division’s interaction with its retail supply businesses in the UK, [✂] and [✂] it had decided that these businesses would buy shaped products, rather than the standard ‘flat’ products available in the wholesale market throughout the hedging window (up to 3 years out until the start of the delivery period[93]).

33. [Firm C] told us that, while there had been no market prices for these shaped products, it had been able to price them using the market prices for the (unshaped) products that had been available at the time of transfer as a starting point.

34. [Firm C] explained that it could have implemented a policy to base transfer prices on unshaped products and then add shape later, but had instead put in place a transfer charging mechanism which incorporated shape right from the beginning. Such a mechanism meant that its trading division, rather than retail supply, took on the responsibility for managing any risks arising from selling a shaped profile (to retail supply) but only being able to buy unshaped products on the open market until shortly before delivery.

35. When it came to pricing its shaped product, [Firm C] had sought to reflect full bid /offer pricing within the transfer charges since June 2011. In other words, retail supply would pay the higher (ie ‘offer’) price if it was buying and receive the lower (‘bid’) price if it was selling back energy surplus to its needs. Previously the basis for transfer pricing of purchases had been at the offer price less a 20% discount on the bid-offer spread[94]. [Firm C] explained that the change in policy had been prompted by a desire to more closely align transfer charges between its divisions to the open market prices for traded products.

[93] The end of the delivery window for a product can be up to 41 months out.
[94] For any sell-back transactions the price would be the (unadjusted) bid price.

Internal supply

36. [Firm C] told us that its trading division, subject to the overall constraints imposed on it by [Firm C] management, had the flexibility to either back out a purchase request into the wholesale market, net it against an opposite request from another division, or hold an open position. This flexibility meant that [Firm C] was in practice unable to quantify the extent of internal supply between, for example, GB generation and retail supply that might have been able to be inferred had each individual purchase or sale transaction been tagged.

Financial hedges

37. [Firm C] told us that its trading division entered into weather derivatives on behalf of its retail supply business and it included these costs within its wholesale energy costs.

Imbalance charges ('cash out')

38. [Firm C] had identified these costs (relatively minor amounts for both electricity and gas) as the only item additional to its transfer charges for its shaped products within its analysis of wholesale energy costs.

Recharges to recover the costs of operating a trading division

39. [Firm C] told us that, since June 2011 when its trading division had moved to full bid/offer pricing, its trading division no longer levied transfer charges to recover such costs. Previously the trading division had also levied a service charge based on volumes delivered to recover the trading division's operating costs. These costs had been reflected in the transfer charges for the shaped product but they were small.

[Firm D]'s approach

Purchases of wholesale energy

Electricity

40. [Firm D] told us that its transfer charges into retail supply throughout the period of our review reflected a wider mix of purchases than simply the purchase of products traded on wholesale markets. In relation to the latter it told us that these products were always priced at the prevailing market price for that product at the time the purchase was agreed.

41. [Firm D] also reflected in its transfer charges bespoke purchases of electricity, most notably:

(a) purchase of [✂] from [Firm [✂]] under a [✂]. The pricing under this long term agreement was [✂]. See paragraph 46 for an explanation of this formulation;

(b) purchase of a certain quantity of the output from a [✂] fired plant owned by [✂]. The purchase price of this output reflected a unit 'fixed clean [✂] spread' fee, the cost of the [✂] and carbon allowances, and any associated foreign exchange costs;

(c) purchase of the output of wind farms, primarily those owned by third parties but also some from its own or plant in which it had a minority stake. The purchase price of this output was generally specified at a discount to the prevailing day or month ahead market price to reflect wind's intermittency.[95]

42. These bespoke purchases in total comprised [✂]. [Firm D]'s total purchases in any one period.

Internal supply

43. [Firm D] provided us with a split of its transfer charges for traded products between internal and external purchases. It explained that internal supply only arose in those situations where date of trade, product, volume and duration matched between one division and another. [Firm D] told us its calculation for 2013 showed 14%[96] of total supply volumes (including bespoke purchases) had been sourced internally.

Gas

44. [Firm D] provided us with an analysis showing that over the period of review [✂] of its transfer charges related to the purchase of physical gas from third parties on long-term supply contracts. [✂] of its transfer charges into retail supply comprised purchase of products traded on wholesale markets. [Firm D] told us these latter products were always priced at the prevailing market price for that product at the time the purchase was agreed.

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[95] The discount reflected in the pricing of such wind reflects an implicit fee for trading the intermittent output of the wind farm (ie route to market) *and* forecasting/managing the wind farm's exposure to the balancing market as part of the purchaser's own overall balancing market position.

[96] Part matches reflected in this calculation eg a 50 MW power generation sale could be part-matched with a 100 MW order.

45. [Firm D] provided us with an analysis of the transfer charges for each of these long-term gas supply contracts, which it told us fully reflected the terms of each contract, the principal details for which (including identity of counterparty and pricing formula) it provided alongside.

46. Most of these long-term gas supply contracts specified the pricing in terms of the following structure:

(a) a 'pricing-in period', defined as the length of the time over which a contract priced in;

(b) a 'lag period', defined as the time offset between the pricing-in period and the delivery period; and

(c) a 'delivery period', defined as the length of time during which the price is effective.

47. For example, where the contract price was specified as '6, 0, 6', this meant that the price for gas supplied under the contract over a particular season of 6 months (the 'c') would be priced at the average of the daily market prices prevailing over the 6 month period (the 'a') preceding a 0 month lag (the 'b') between the end of the pricing-in period and the actual period of physical supply.

48. Such pricing formulae mimic the phasing-in of price that the Six Large Energy Firms have sought to implement when executing their purchasing strategy.

Financial hedges

49. [Firm D] told us it had entered into weather swaps for gas and electricity (although small when compared to gas) over the period of review and these costs had been included in its wholesale energy transfer charges for retail supply.

Imbalance charges ('cash out')

50. [Firm D] had identified this item (relatively minor amounts for both electricity and gas) as one of the items comprising its wholesale energy costs.

Recharges to recover costs of operating a trading division

51. [Firm D] had a policy of recharging the costs of running its trading division to each of its operating divisions which benefitted from its services. In its analysis of its wholesale energy costs, [Firm D] separately identified its apportionment to retail supply of the general running costs of the trading

division from the incremental costs of transacting trades (such as brokerage fees) in the external wholesale market. For both electricity and gas, both items were a very small element of total wholesale energy costs (around [✄] out of nearly [✄] per year).

[Firm E]'s approach

Purchases of wholesale energy

Electricity (both externally sourced and internal supply)

52. [Firm E] had distinct approaches to the basis of transfer charging for the supply of electricity to, on the one hand, its domestic and SME customers and, on the other, its larger industrial and commercial customers. The distinction between the two groups arose because the latter's consumption of electricity was measured on a half-hourly basis.

- *Domestic and SME customers*

53. Like [Firm D], [Firm E] told us that its transfer charges into retail supply for wholesale electricity, throughout the period of our review, reflected a wider mix of purchases than simply the purchase of products traded on wholesale markets. In relation to the latter it told us that these products were always priced at the prevailing market price for that product at the time the purchase was agreed.

54. However, in contrast to [Firm D], [Firm E]'s bespoke purchases of electricity mostly comprised of self-supply, rather than being sourced from third parties. The most notable elements of the bespoke mix were:

    (a) purchases of output of coal- and gas-fired generation plants. The purchase price of this output reflected fees for the right to use the plants (capacity fees), the HCA cost of the fuel and carbon allowances plus any associated foreign exchange and financial hedging costs. Almost all of these plants were either owned by [Firm E] or, in the case of the [✄] gas-fired plant, deemed for statutory reporting purposes to be owned by [Firm E];[97]

    (b) purchases of the output of wind farms, primarily those owned by [Firm E] but some from plants owned by third parties;

[97] [Firm E] has an offtake agreement similar to [✄] for the [✄] gas-fired plant. This latter plant is not deemed for statutory reporting purposes to be owned by [Firm E].

(c) purchases of conventional (‘run-of-river’) and pumped storage electricity from its own hydroelectric plant.

- *Larger industrial and commercial customers*

55. The approach to transfer charging for these customers significantly differed to that for domestic and SMEs. [Firm E] used the average market price on the day that a supply contract was agreed adjusted for shape of demand on the day to determine the level of transfer charges.

Gas (both externally sourced and internal supply)

56. [Firm E] had a single approach to transfer charging for the supply of gas to its retail gas customers and its gas-fired generation business as described below.

57. [Firm E] provided us with an analysis that showed over the period of review that most, if not all, of its transfer charges into retail supply reflected the purchase of products traded on wholesale markets. It told us that these products were always priced at the prevailing market price for that product at the time the purchase was agreed.

58. [Firm E]’s analysis also showed some transfer charges related to the purchase of physical gas on long-term supply contracts both from third parties and its upstream exploration and production division. The pricing for these long-term contracts varied from referencing to day-ahead pricing to long-term indexation to oil or other commodity indices. This same analysis also showed transfer charges for the use of its [✄] gas storage facilities.

Financial hedges

59. [Firm E]’s analysis showed that for both electricity and gas it had, to a limited extent, entered into option contracts over the period of review. For example to hedge its generation fuel costs and these costs had been included in its wholesale energy transfer charges for retail supply.

Levies on wholesale energy purchases

60. [Firm E] levied a charge of [✄] in relation to all purchases and financial hedges for retail supply (but not for supply to its generation business) to reflect that its trading division had assumed responsibility from it for the following:

(a) marked-to-market volume risk;

(b) volatility;[98]

(c) shape risk; and

(d) imbalance charges.

[Firm E] told us out that whilst imbalance charges were a clearly measurable cost, the other three items related to other, difficult-to-measure, real costs borne by its trading division.

Imbalance charges ('cash out')

61. Because these charges were in principle recovered through the levy on wholesale energy purchases, [Firm E] had not included imbalance charges in its analysis of wholesale energy costs for retail supply. The costs had instead been included in the costs of its trading division.

Recharges to recover costs of operating a trading division

62. [Firm E] had not included any other recharges within its wholesale energy costs to recover these costs.

[Firm F]'s approach

Purchases of wholesale energy

Electricity

63. [Firm F] told us that since April 2011, after it introduced a new transfer pricing methodology, its transfer charges into retail supply had, in form, comprised entirely of the purchase of products traded on wholesale markets. These products were always priced at the prevailing market price for that product at the time the purchase was agreed.

64. [Firm F] further explained that the only difference between the products on which its transfer charges were based and the products available on the open market were their clip sizes (ie quantity of power supplied at each moment during the period of supply).

65. [Firm F] told us that prior to April 2011 it had based its transfer pricing on buying forward the entirety of the expected energy requirement for an

[98] [Firm E] did not provide us with a detailed explanation of what it meant by risks a) and b). However [Firm F] has, for what appears to be broadly the same risks – see paragraph 73.

individual customer at the point in time [Firm F] judged that the customer had committed to buy it. [Firm F] would then buy or sell incremental volumes to reflect changes in its expectation of these requirements on a daily basis using a forward price which was recalculated every month using the average of daily forward market prices for the prior month.

66. This approach had meant that between 2008 and 2011 a significant proportion of purchases had had a relatively flat profile (ie close to 100% of forecast demand had been purchased at the outset from its generation division) rather than the more typical phased purchase profile. [Firm F] told us that, although the internal transfer price had been based on the then published market prices, it was doubtful whether there would have been sufficient depth of liquidity for a stand-alone retail supplier to have purchased this volume of power in the market. [Firm F] also told us that, although this ‘long’ strategy had been initially successful, wholesale prices fell sharply in the aftermath of the 2009 financial crisis, and thereafter it would have been cheaper for its retail supply division not to have acquired power on that basis.

67. [Firm F]’s wholesale energy costs also reflected a range of bespoke purchases, in particular from generators embedded in its retail distribution network and from wind farms, both those owned by [Firm F] and by third parties. Prior to April 2011, these purchases formed part of retail supply’s wholesale energy costs, but from April 2011, these purchases had then been sold on to its generation division at cost, so [Firm F] made no profit or less on these purchases.

68. [Firm F]’s analysis of its purchases (both pre- and post-April 2011) also showed that a small proportion of its trades had been negotiated directly between it and the counterparty using the product structure and pricing available on the over-the-counter (OTC) market.

Internal supply

69. [Firm F] told us that its approach to netting generation requests to sell forward against retail supply requests to buy forward (see paragraph 64) resulted in a very significant proportion of its electricity for retail supply being supplied internally. This ranged from 30% (in 2011) to 63% (in 2013) of total purchases by volume.[99]

[99] 25% and 62% by value in 2011 and 2013 respectively.

Gas

70. The same picture also broadly applied to gas. In other words, post-April 2011 transfer charges into retail supply had largely comprised of the purchase of products traded on wholesale markets. These products were always priced at the prevailing market price for that product at the time the purchase was agreed. Pre-April 2011 the transfer charges in relation to traded products had been determined as described in paragraph 65.

71. In addition to the transfer charges based on products traded on the open market, there was also a [✂] proportion throughout the period (for example, [✂] of total retail supply volumes for 2013) which reflected purchases of gas acquired by [Firm F] on the basis of long-term contracts from third parties. These transfer charges were based on the contract price plus a premium, which had been retained by its trading division. This premium reflected the amortisation of the upward revaluation of these contracts [✂] market value in [✂].

Financial hedges

72. [Firm F] told us that it had not carried any financial hedges over the period of review.

Levies on wholesale energy purchases

73. Prior to June 2011 [Firm F] levied a varying charge of between £[✂] million and £[✂] million in relation to all purchases to reflect that its trading division had assumed responsibility from it for the following:

   (a) *Volume variability*: unexpected changes in weather, for example, could change the forecast of total retail demand in the final month before delivery. [Firm F]'s then approach to determining the transfer price for changes in volume would however not have taken account of any changes in market prices in the final month before delivery.

   (b) *Market movement*: the daily forward market price had been based on an external view of the closing prices of the previous day. A factor had been used to reflect that market prices would have changed between the previous day's closing price and when an actual trade had been carried out; and

   (c) *Shape (electricity only)*: a levy had been added to reflect that electricity was traded for each half hour to reflect the shape of customer demand. As the transfer price had been based on 'unshaped' market prices for

each prior month, there had been a need to add ‘shape’ to take account of the half hourly demand shape.

Imbalance charges (‘cash out’)

74. [Firm F] had identified this item (relatively minor amounts for both electricity and gas) as one of the items comprising wholesale energy costs.

Recharges to recover costs of operating a trading division

75. [Firm F] told us that it had not recharged any of the costs of running its trading division over the period of review [✂].

Assessment of the basis of wholesale energy costs by firm

76. In this section we evaluate how well each of the Six Large Energy Firms’ approach to determining its wholesale energy costs accorded with the basis set out in paragraph 1 – the ‘equivalent stand-alone retail supplier’ test. We do this first by answering the question of whether wholesale purchases reflected products traded on open market at the time of purchase for each of the Six Large Energy Firms in turn. If not, we ascertain whether these comprised third party bespoke purchases, the pricing for which would be expected to directly reflect the outcome of commercial negotiations. We then separately consider the question of whether prices for these traded purchases reflected market prices. We then finally consider the other costs that some of the Six Large Energy Firms included in their analysis of wholesale energy costs.

77. We then conclude on the implications this has for our assessment of whether the Six Large Energy Firms' reported wholesale energy reflected the costs the firms had actually incurred in the market for retail supply.

78. As explained in paragraph 6 and 7, this assessment is based on what firms have told us as summarised in paragraphs 15 to 75 above, the numerical analyses provided and our subsequent investigation.

Underlying wholesale energy costs

79. These comprise the transfer charges for traded and bespoke products, any associated financial hedges plus imbalance charges. They would (in theory) exclude any recoveries for the cost of running a trading division or dealing in external markets.

80. In Table 1 below we set out the answers to two questions which aided our assessment of whether the Six Large Energy Firms’ wholesale energy

transfer charges accorded with those that would have been reported by an equivalent stand-alone retail supplier of the same size and pursuing the same wholesale energy purchasing strategy in terms of hedging timescales and products purchased.

Table 1: Answers to questions which aided our assessment of the Six Large Energy Firms' transfer charging practices

Energy firm	***CMA questions***	
	*Do wholesale electricity purchases reflect **in form** products traded on open market at time of purchase?* *(If not, do the products reflect purchases from third parties?)*	*Do wholesale gas purchases reflect **in form** products traded on open markets at time of purchase?* *(If not, do the products reflect purchases from third parties?)*
[Firm A]	Yes	Yes
[Firm B]	Yes	Yes
[Firm C]	No, not all of the time: all of its purchases are for shaped products, which are only available from third parties in prompt timescales	No, not all of the time (as per electricity)
[Firm D]	Not entirely. (In addition to its purchase of traded products, it purchased power on a bespoke basis mainly from third parties, primarily [Firm [✄]],[✄] and renewable firms)	Not entirely (It has [✄] bespoke gas contracts but these reflect purchases from third parties)
[Firm E]	No (Much of the cost base comprises bespoke purchases of power, primarily from internal sources)	Mostly, but not entirely. (There are some bespoke purchases which are a mix of internal and external purchases)
[Firm F]	A qualified 'yes' post-April 2011 (ie for FY12 onwards)* No, pre-April 2011 (ie for FY11 and before)	Not entirely (There is a [✄] proportion of bespoke contracts, (which were revalued post-[✄]) but these reflect purchases from third parties)

Source: CMA analysis.
* Throughout the period of review [Firm F] had a much higher proportion of internal trades (30 to 60%) with its generation division than was the case for the other Six Large Energy Firms that were able to provide this information – [Firm A] (10 to 15%) and [Firm D](14% in 2013).

81. The next question we considered was whether purchases based on traded products had been priced at open market prices. The Six Large Energy Firms had told us that this had invariably been the case.

82. There were some subtleties as to how the actual open market prices had been determined. Please see the explanations in paragraphs 15 and 16 ([Firm A]), 25 ([Firm B]) and 36 and 39 ([Firm C]). These demonstrate that, at the margin, there might have some differences between the Six Large Energy Firms around how the bid/offer spread had been treated.

Levies on wholesale energy purchases

83. As explained in paragraphs 60 ([Firm F]) and 73 ([Firm E]), both the [✂] firms had imposed a levy on underlying wholesale energy transfer charges. We considered their explanations for what these levies related to.

84. [Firm E] explained that the levy in part was due to the fact that its retail supply division did not bear the cost of imbalance charges. Based on our review of the analyses provided by the other Six Large Energy Firms which all had included these imbalance costs within wholesale energy costs, we concluded that these costs would have been small compared with size of [Firm E]'s levies.

85. Regarding the other eventualities these levies were designed to cover, we considered that these were likely to be small in extent, and therefore that these levies were unlikely to be cost-justified. [✂]

86. We therefore concluded that we would exclude these costs from our assessment of their wholesale energy costs on the basis that they did not appear to relate to costs that an equivalent standalone supplier would have incurred.

Recharges to recover costs of a trading division

87. There was a variety of practice across the Six Large Energy Firms as to whether these costs were recovered through wholesale energy transfer charges or not. Based on our review of the amounts analysed by the firms that had been able to isolate these costs,[100] we concluded that the amounts were so small compared with underlying wholesale energy costs that, for the purposes of our analysis, these differences were unlikely to matter.

Other observations

88. [Firm F]'s forward purchase of almost the entirety of its electricity requirement over the period 2008 to 2011 when [Firm F] judged them to have been committed (see paragraph 66) was, in particular, unlikely to have resulted in

[100] See paragraph 30 regarding [Firm B] and paragraph 51 regarding [Firm D].

the costs that an equivalent stand-alone retailer supplier would have incurred. Such a firm would not have bought ahead to such extent because there would not have been sufficient liquidity in the market, and, to the extent there would have been liquidity, on account of the unattractive bid-offer spreads.

89. The extent of [Firm F]'s internal supply of traded electricity products post-April 2011, compared with the other Six Large Energy Firms who also had based their transfer charges on purchasing traded products, was very marked.[101] This suggested there was some dialogue between its generation and retail divisions regarding internal transactions and / or the detail of [Firm F]'s approach to netting transactions across operating divisions was different from either that of, for example, [Firm A] or [Firm D].

90. [Firm E] purchased wholesale electricity for its larger industrial and commercial customers (see description at paragraph 55) in the form of standard traded products at the point of the contract was signed, whereas it largely took a different approach for its other retail customers.

91. The fact that not all the Six Large Energy Firms' transfer charges comprised in form exclusively of purchases of traded products has implications for the recognition of profits or losses across the energy value chain. For example, whilst [Firm D] sourced some of its electricity from [Firm [✂]] on a bespoke [✂] basis ([✂]) [102], [Firm [✂]] sourced all of its electricity for retail supply using traded products. The implication of this is that any difference in costs between these two firms would have been reflected in retail supply in the case of [Firm D] and elsewhere in the case of [Firm [✂]].

92. The Six Large Energy Firms' retail supply divisions in general did not purchase intermittent energy.[103] Although in layman's terms there is an obligation for them to purchase electricity from renewable resources, strictly speaking they are only obliged to buy renewable obligation certificates (ROCs) from renewable energy providers.[104] As intermittent energy cannot be used to implement a forward purchasing strategy, the Six Large Energy Firms tend instead to channel purchases of renewable elsewhere, typically either to their generation or trading divisions. For example, [Firm F] pre-April 2011 initially included the purchase of wind (and embedded power) within its wholesale energy costs, but post-April 2011these were then sold on at a no profit/no loss basis to its generation division. Due to its intermittency,[105] there

[101] See paragraph 69.
[102] See paragraph 41(a).
[103] All the Six Large Energy Firms own wind generation assets and/or have agreements to purchase the output of independently-owned wind farms.
[104] Or pay the buy-out price for ROCs.
[105] See also paragraph 41(c) including its footnote 95.

is the scope for a wider diversity of accounting treatment across the energy value chain than for other sources of energy. This in turn makes it more likely that the Six Large Energy Firms will have taken a variety of approaches to accounting for this source of energy, including into their retail supply businesses.

Conclusion

93. Based on our review of how each of the Six Large Energy Firms had approached determining their wholesale energy costs, we concluded that [Firm D]'s energy transfer charges would accord with those that would have been reported by an equivalent stand-alone retail supplier had it pursued the same wholesale energy strategy (assuming, for the bespoke purchases, that firm would have been able to replicate for itself the deals [Firm D] had negotiated with third parties).[106]

94. Whilst [Firm A] and [Firm B]'s approach to transfer charging for both electricity and gas relied exclusively on open market prices for traded products, the transfers might not always necessarily reflect what the wider firm had purchased in external markets, leaving the potential for some discrepancy between the reporting of the equivalent stand-alone retail supplier and [Firms A and B].

95. The equivalent stand-alone supplier would not have been able to replicate the purchasing of shaped products reflected in [Firm C]'s transfer charging, rather it would have reported the purchases [Firm C]'s trading division had bought on its retail supply division's behalf. As a consequence [Firm C]'s transfer charges into its retail supply division did not reflect the actual costs incurred by it at the level of the firm.

96. For both [Firm F] and [Firm E], it is doubtful whether an equivalent stand-alone retail supplier would have been able to purchase the bespoke wholesale 'products' that [Firm F] and [Firm E] had used, at least for some of the period of review, as the basis of their transfer charging into retail supply, particularly the internal PPAs ([Firm F]) and the multi-year internal forward purchase of power ([Firm E]). In this respect these firms' transfer charges into retail supply would not have reflected the actual costs incurred by it at the level of the firm.

[106] Costs, however, would have differed between the two if the equivalent standalone firm had in fact bought a different mix of products and/or purchased these products at different points in time.

97. We also concluded to exclude both [Firm E] and [Firm F]'s levies on underlying wholesale energy transfer charges from our assessment of wholesale energy costs incurred by their retail supply businesses.