Competition & Markets Authority

Energy market investigation

Provisional findings report

Notified: 7 July 2015

The Competition and Markets Authority has excluded from this published version of the provisional findings report information which the inquiry group considers should be excluded having regard to the three considerations set out in section 244 of the Enterprise Act 2002 (specified information: considerations relevant to disclosure). The omissions are indicated by [✂].

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Appendices

Summary

1. On 26 June 2014 the Gas and Electricity Markets Authority made a reference to the Competition and Markets Authority (CMA) for an investigation into the energy market in Great Britain.[1] The terms of reference for this investigation allow us to look at any competition issue connected with the supply or acquisition of gas and electricity in Great Britain, including both retail and wholesale markets, except that, in the case of retail markets, only the retail supply of households and microbusinesses are included within the reference. This document sets out our provisional findings from this investigation.

2. We are required to decide whether 'any feature, or combination of features, of each relevant market prevents, restricts or distorts competition in connection with the supply or acquisition of any goods or services in the United Kingdom or a part of the United Kingdom'.[2] If that proves to be the case, this constitutes an adverse effect on competition (AEC).

3. Alongside this document we have prepared:

   (a) a Notice of provisional findings,[3] in which we identify the features that we provisionally find give rise to AECs in the in the energy markets; and

   (b) a Notice of possible remedies,[4] in which we set out possible actions that we may take to remedy, mitigate or prevent the AECs we have provisionally identified or any resulting detrimental effect on consumers.

Overview of GB energy markets and key outcomes

4. The period since the privatisation of electricity and gas in Great Britain has been one of continued regulatory change, as policymakers have attempted both to secure greater degrees of liberalisation and, particularly in recent years, to achieve the overarching policy goals of reducing emissions, ensuring security of supply and improving the affordability of prices.

5. In several respects, the energy sector has performed well against these objectives. There have been no significant security of supply incidents in recent years, emissions from electricity and gas have reduced and renewable deployment has increased. However, concerns have arisen in relation to the affordability of energy – domestic price increases have far outstripped inflation over the past ten years and there have been concerns about levels of

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[1] Energy market investigation terms of reference.
[2] Section 134(2) of the Enterprise Act 2002 ('the 2002 Act').
[3] See the energy market investigation case page.
[4] See the energy market investigation case page.

profitability – and standards of service appear to have deteriorated. Pressure on prices is likely to grow in the future, due in part to the increasing costs imposed by climate and energy policies.

Market structure and participants

6. At a high level, there are some strong similarities between the physical supply chains for gas and electricity:

   (a) In the electricity sector, different types of generation technology (for example, coal, gas, nuclear or renewable) generate electricity, which is transported to consumers via high voltage transmission lines and low voltage distribution lines.

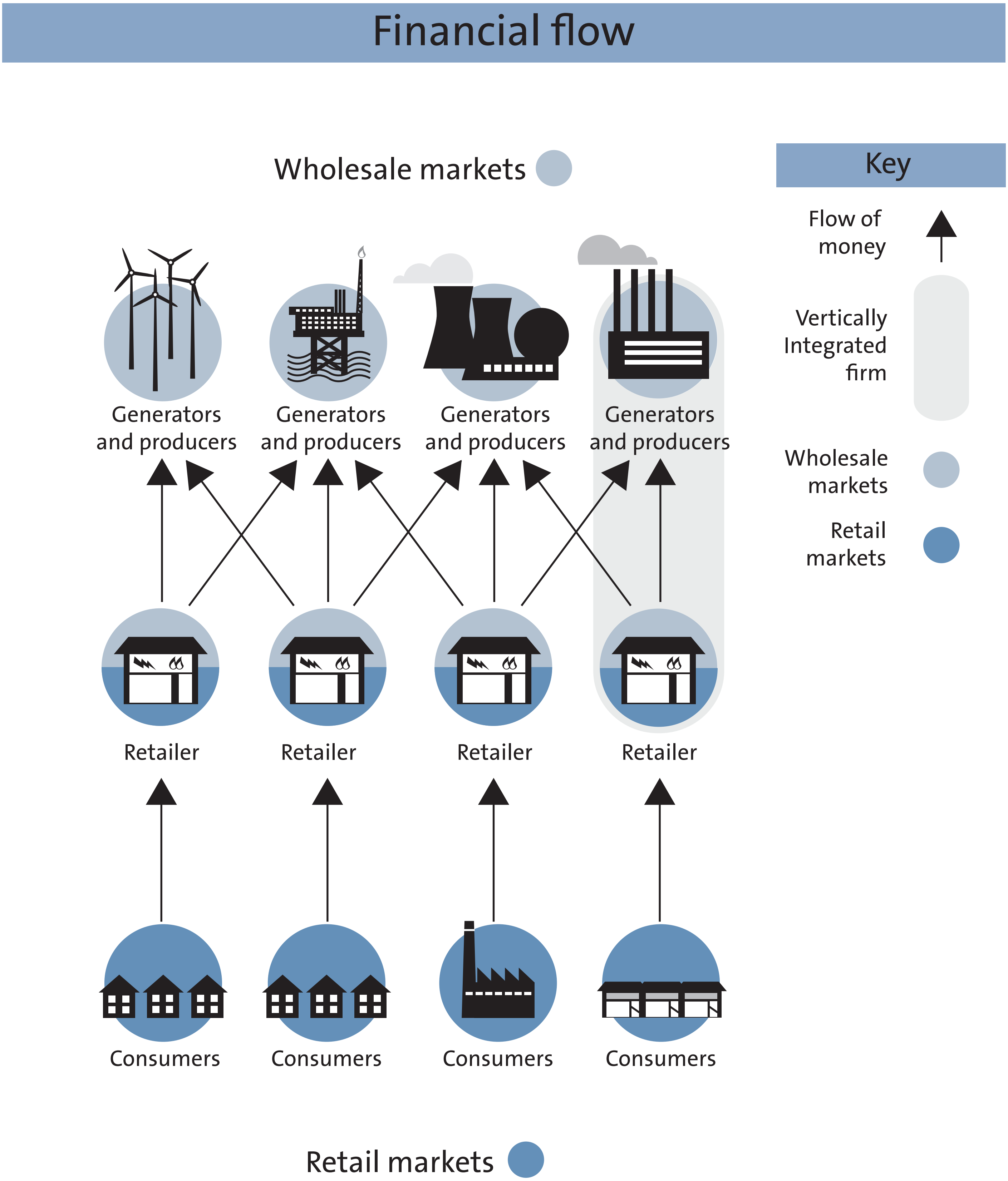
   (b) In the gas sector, different sources of gas (eg from offshore fields in the North Sea, imports via interconnectors to other countries or imports in the form of liquefied natural gas (LNG)) are transported to consumers via high pressure transmission pipes and low pressure distribution pipes.

7. The chart below provides a high level overview of the financial flows and market arrangements in the gas and electricity sectors.

8. Gas and electricity wholesale markets share several common features: trading can take place bilaterally or on exchanges, and contracts can be struck over multiple timescales ranging from several years ahead to on-the-day trading markets.

9. Retail markets provide the strongest point of commonality between gas and electricity, since the products are often sold together by retailers through a bundled tariff called a ‘dual fuel’ tariff. Moreover, the regulatory regime applying to retail functions generally applies equally to gas and electricity. As of 31 January 2015, there were 27 million domestic electricity customers and 23 million domestic gas customers. There were 19 million dual fuel customers, 8 million single fuel electricity customers and 4 million single fuel gas customers.

Figure 1: Financial flows and market arrangements



10. The Six Large Energy Firms are Centrica plc (Centrica), EDF Energy plc (EDF Energy), E.ON UK plc (E.ON), RWE npower plc (RWE), Scottish and Southern Energy plc (SSE) and Scottish Power. These firms are the former monopoly suppliers of gas (Centrica) and electricity (EDF Energy, E.ON, RWE, SSE and Scottish Power) to GB customers.

11. Together, the Six Large Energy Firms currently supply energy to around 90% of the domestic customers in Great Britain and generate over 70% of total electricity generation in Great Britain. They are all partially vertically integrated in respect of electricity (ie they are all active in both generation and retail) and Centrica is vertically integrated in respect of gas (ie it is active in both generation and upstream production). Both SSE and Scottish Power also have interests in electricity transmission and gas and electricity distribution.

12. In relation to retail, there are currently 25 suppliers selling both electricity and gas to households and a similar number of suppliers selling both electricity and gas to non-domestic customers. The largest suppliers to domestic customers outside of the Six Large Energy Firms are: Utility Warehouse, Co-operative Energy, First Utility and Ovo Energy (which we collectively call the 'mid-tier suppliers').

13. The single biggest cost item for both electricity and gas is the cost of wholesale energy (about 45 to 55% of the costs of supplying electricity and gas to domestic customers), followed by network costs (20 to 25%). The costs associated with retailing (including a profit margin) are between 15 and 20% of the costs of supplying electricity and gas to domestic customers. The costs of the social and environmental policies that energy suppliers are required to deliver on behalf of government ('obligation costs') are higher for electricity (almost 15%) than gas (around 5%).

Regulatory and policy framework

14. The regulatory and policy framework governing the energy sector in Great Britain profoundly affects the shape and nature of energy market competition. It is set out in:

(a) EU and UK legislation;

(b) licences, which Ofgem grants to operators for the purposes of engaging in specified activities relating to gas and electricity supply; and

(c) industry codes, which are detailed multilateral agreements that define the terms under which industry participants can access the electricity and gas networks, and the rules for operating in the relevant markets.

15. The past 30 years have seen a sustained liberalisation of both the gas and electricity sectors, driven by both UK and EU legislation. It has also been a period of rapid and regular regulatory change, particularly in the electricity sector. Policies developed over this period have increasingly had to balance the competing goals of ensuring security of supply, improving affordability and reducing emissions.

Physical flows

16. The period since privatisation has seen a significant change in the composition of electricity generation, with the introduction of combined cycle gas turbine (CCGT) plants and, more recently, a significant increase in generation from renewable plant. Residential consumption of electricity has fallen since 2005. The capacity margin – the excess of generation capacity over peak demand – has been relatively high in recent years, although margins are expected to tighten in 2015/16, reflecting in part the intermittency of renewable generation.

17. The UK moved from being a net exporter of gas to a net importer in 2004. Residential consumption of gas has fallen since 2004, and in 2013 was roughly at the level it was 20 years previously. The UK is relatively resilient to potential gas infrastructure disruptions and there has never been a network gas supply emergency in Great Britain.

18. Greenhouse gas emissions from the power sector were almost 30% lower in 2013 compared to 1990. This partly reflects the impact of policies to put a price on carbon and support low carbon generation. Residential emissions (largely combustion of gas) were only marginally lower than in 1990.

Prices, costs and profits

19. The rapid increase in domestic energy prices in recent years and the perception that profits and overall prices are too high have been a major source of public concern and were key drivers for the market investigation reference.

20. After a sustained period of real terms reductions in the years following privatisation, domestic gas and electricity prices have increased significantly over the last ten years. Average domestic electricity prices rose by around 75% in real terms between 2004 and 2014, and average domestic gas prices rose by around 125% in real terms over the same period.

21. We have reviewed financial data submitted by the Six Large Energy Firms, for the period 2009 to 2013. This suggests that, for electricity, the main drivers of

domestic price increases from 2009 to 2013 were the costs of social and environmental obligations and network costs. Reported wholesale costs remained flat while profit (EBIT[5]) margins fluctuated over the period. For gas, there has been a broadly even percentage increase in wholesale costs, network costs, obligation costs and indirect costs, with EBIT increasing significantly after 2009. Average EBIT margins earned on sales to domestic customers were 3.3% over the period. Average EBIT margins on sales of gas (4.4%) were higher than those on sales of electricity (2.1%).

22. We have noted that there is a wide variation in the prices that different domestic customers pay for energy, which is particularly striking since electricity and gas are entirely homogenous products. We calculate that, over the period Quarter 1 2012 to Quarter 2 2014, most customers of the Six Large Energy Firms could have made considerable savings from switching a combination of suppliers, tariffs and payment methods. For all the dual customers of the Six Large Energy Firms, average potential gains from switching externally to any tariff offered were equivalent to 14% of the average bill (equivalent to about £160 a year) over the period. As discussed further below, the gains available to specific customers depend considerably on the tariff and payment method that customers are currently on and the supplier they are currently with: for some categories of customer, the average gains from switching were equivalent to more than 20% of the bill over the period.

23. We have also noted that, over the period 2011 to 2014, average revenue per kWh earned by the Six Large Energy Firms from customers on the standard variable tariff (SVT) – which about 70% of the customers of the Six Large Energy Firms pay – was around 10% higher for electricity and 13% higher for gas than average revenue earned from customers on other tariffs.

24. We have also found considerable variation in the prices paid by small and medium-sized enterprises (SMEs) including microbusinesses. In particular, we compared rollover tariffs (tariffs that customers would pay if they took no action at the end of an existing fixed-term contract), retention tariffs (tariffs that customers actively renegotiate with their existing supplier at the end of an existing contract), and deemed tariffs (a tariff paid until a customer, typically in new premises, contacts its supplier to enter into its first contract).

25. Our comparison of average unit revenues (earned by the Six Large Energy Firms and a number of independent suppliers, from 2012 to 2014) showed that rollover tariffs were 29 to 36% higher than retention tariffs for electricity (depending on the size of customer), and 25 to 28% higher for gas. Deemed

[5] Earnings before interest and tax, or gross profit less indirect costs.

tariffs were 66 to 82% higher than retention tariffs for electricity, and 70 to 116% higher for gas. EBIT margins from retail sales in the SME segment were on average 8% over the period – significantly higher than those on sales to domestic customers or industrial and commercial (I&C) customers. Margins on sales of gas to SMEs (10%) were higher than those on sales of electricity (8%).

Quality of service

26. There have been considerable concerns about the quality of service offered by the Six Large Energy Firms. We asked them to provide information on the number of complaints they had received, broken down by type of complaint. The results indicated that the number of recorded complaints increased fivefold between 2008 and 2013. Problems related to billing, customer services and payments accounted for the majority of complaints.

Market definition

27. Defining the market provides a framework for the assessment of the effects on competition of features of a market. Our provisional view is to consider the relevant markets for this investigation to be the following:

(a) the wholesale electricity market in Great Britain (including trading);

(b) the wholesale gas market in Great Britain (including trading);

(c) the retail supply of electricity to domestic customers in Great Britain;

(d) the retail supply of gas to domestic customers in Great Britain;

(e) the retail supply of electricity to SMEs in Great Britain, comprising, at least, a microbusinesses segment; and

(f) the retail supply of gas to SMEs in Great Britain, comprising, at least, a microbusinesses segment.

28. Market definition is a useful tool, but not an end in itself, and we note that the boundaries of the market do not determine the outcome of our competitive assessment of a market in any mechanistic way. Notably, in some cases, where we consider that competitive pressures differ between different types of customer, we identify discrete customer segments within markets.

Nature of wholesale market competition

29. There are broad similarities between the nature of competition in wholesale gas and electricity markets. At a high level, both involve: upstream production and importation, for sale into wholesale trading markets; and bilateral and exchange trading between producers, generators, suppliers, traders and consumers in wholesale trading markets.

30. In gas and electricity, there are important interactions between market design and the need to physically balance the system. One of the most important differences between the two is that, because of the ability to store gas within a day, it is financially settled and balanced on a daily basis. Electricity, in contrast, is priced and financially settled on a half-hourly basis.

Competition in wholesale gas markets

31. A large but declining proportion of gas consumed in Great Britain is from the UK Continental Shelf (UKCS) in the North Sea (currently around 50%). An increasing proportion comes directly from Norway and also from the European gas grid, which is supplied mainly by Norway, Russia and North Africa. Finally, a small but increasing amount is shipped in on LNG ships, much of it originally extracted in Qatar.

32. We have provisionally not found any features in wholesale gas markets that lead to an AEC. Concentration in gas production is low, suggesting limited scope for exercising unilateral market power. Almost all gas producers are price takers most of the time: given a level of demand, price can be expected to be set by the opportunity cost of the last producer required to meet that demand.

33. There is a degree of vertical integration (VI) in the gas market. For example, Centrica, and to some extent Statoil and Total, have significant interests in several parts of the value chain. We do not believe that the harm that can sometimes arise from VI – typically involving using influence in one market to disadvantage rivals in another market – is a significant risk in the wholesale gas market.

34. There have been criticisms of the level of transparency in the wholesale gas market and some allegations of the manipulation of reported gas price indices. On the point of transparency, we have found that prices of almost all trades are available to market participants through the data made available by the trading platforms. Lack of price transparency therefore is not likely to constitute a barrier to entry in the gas market. On the question of index manipulation, we found that Ofgem and the Financial Conduct Authority (FCA)

have actively investigated allegations and have demonstrated a willingness to use the powers that they have to deal with problems they have identified.

Competition in wholesale electricity markets

35. The wholesale price of electricity represents just under half the total cost of supplying electricity to customers, and it is therefore important to consider whether competition operates well in the wholesale market.

36. The costs of producing electricity can vary substantially depending on which types of generating plant are required to meet demand at any one point in time. Nuclear and many renewables have near-zero short-run marginal costs, while oil-fired plants have high short-run marginal costs, for example. Coal- and gas-fired plant costs lie between these two extremes, with their relative positions depending on the prices of the input fuels, which are themselves variable. In addition, wind generators only generate when the wind is blowing. The eight largest owners of generating capacity have very different portfolios of technologies. EDF Energy is currently the largest generator with a 26% share of generation output.

37. We have considered to what extent any generating company can exercise market power to raise wholesale spot prices and have developed a model to test this. We found that, reviewing the period 2012 and 2013, no single generator had the incentive to increase the wholesale price by a significant amount in a significant number of half-hour periods.

38. Furthermore, our analysis of the profitability of the generation operations of the Six Large Energy Firms between 2009 and 2013 indicates returns that were generally in line with or below the cost of capital. Our provisional view is that the profitability analysis does not provide evidence that overall, the Six Large Energy Firms earned excessive profits from their generation business over the period or that wholesale market prices were above competitive levels. This evidence is consistent with our provisional conclusion that generators do not have unilateral market power.

Wholesale electricity market rules and regulations

39. We have also considered the impact on competition of five key elements of the design principles and market rules and regulations that shape competition in GB wholesale electricity markets. Two of these are established characteristics of the electricity wholesale market regulatory framework:

(a) the principle of self-dispatch introduced about 15 years ago; and

(b) the absence of locational pricing for transmission losses and constraints, an issue that has been debated at length since privatisation 25 years ago.

40. We also consider three recent reforms that are likely to have a significant impact on the nature of wholesale market competition in the future:

(a) the reforms to the system of imbalance prices that Ofgem has recently approved;

(b) the Capacity Market that the Department of Energy & Climate Change (DECC) introduced in 2014 as a means of improving incentives to invest in and maintain thermal generating capacity and encouraging DSR; and

(c) the introduction of Contracts for Difference (CfDs) as the principal means of incentivising investment in low carbon generation.

Self-dispatch

41. Economic dispatch is the process by which the optimal output of generators is determined at any point in time, to meet overall demand, at the lowest possible cost, subject to transmission and other operational constraints. The current dispatch mechanism in force in Great Britain, introduced by the New Electricity Trading Arrangements (NETA) / British Electricity Trading and Transmission Arrangements (BETTA) reforms, was designed as a self-dispatch wholesale electricity market, based on bilateral trading between generators and suppliers. This contrasts with the system that it replaced, the England and Wales ‘Pool’, which was centrally dispatched.

42. We have reviewed the principle of self-dispatch that underpins current wholesale electricity market arrangements and considered whether there may be benefits to competition from a move to a more centralised system of dispatch. Our provisional view is that this does not appear to be the case. We do not believe that the self-dispatch system in Great Britain, when compared with alternative dispatch systems, reduces price transparency or increases transaction costs. Nor have we found evidence of systematic technical inefficiency arising from self-dispatch.

Absence of locational prices for transmission losses and constraints

43. Energy is lost when electricity is transported from one part of the country to another. In addition, it is sometimes not possible to generate electricity from the cheapest source because of limits to the transmission network (constraints). The costs of both losses and constraints vary considerably by geographical location. For example, in an area with relatively low levels of

demand and high levels of generation, consuming electricity will be associated with low losses and is unlikely to be subject to constraints, while generating electricity will be associated with relatively high losses and high likelihood of constraints. Despite this locational variation in the costs of losses and constraints, under the current regulatory regime, these costs are allocated to generators and consumers in a way that takes no account of their geographical location.

44. We have found that the current system of uniform charging for transmission losses creates a system of cross-subsidisation that distorts competition between generators and is likely to have both short- and long-run effects on generation and demand:

(a) In the short run, costs will be higher than would otherwise be the case, because cross-subsidisation will lead to some plants generating when it would be less costly overall for them not to generate, and other plants – which it would be more efficient to use – not generating. Similarly, cross-subsidies will result in consumer prices failing to reflect fully the costs of providing the electricity.

(b) In the long run, the lack of locational pricing may lead to inefficient investment in generation, including inefficient decisions over the extension or closure of plant. There could also be inefficiency in the location of demand, particularly high-consumption industrial demand.

45. **The absence of locational pricing for losses is a feature of the wholesale market rules that we provisionally conclude constitutes an AEC**.

46. Modelling conducted to inform consideration of a recent proposal to introduce locational charges for losses suggests that such a reform could lead to an efficiency benefit over ten years of somewhere between £160 million and £275 million. Introducing locational pricing for losses would also have a distributional effect, leading to transfers:

(a) from customers in areas of low generation relative to demand to customers in areas of high generation relative to demand (for example, the above modelling suggested that the reform would result in a transfer of just under £40 million a year from consumers in the South of England to those in Scotland and the North of England); and

(b) from generators in areas of high generation relative to demand to generators in areas of low generation relative to demand.

47. We have also considered whether the absence of accurate prices to reflect transmission constraints is a feature of the market that constitutes an AEC.

From our initial analysis, this question is finely balanced, with reasons to see both costs and benefits. EU legislation requires this issue to be considered at regular intervals in the future. For these reasons, we have decided not to investigate it further.

Imbalance price reforms

48. Imbalance prices play a key role in wholesale electricity trading in Great Britain, providing incentives to generators and suppliers continually to match supply and demand. Under current market rules generators and suppliers are charged an imbalance price if, in any given half-hour period, they have produced less than (or consumed more than) the volumes of electricity covered by their contracts. Conversely, they are paid an imbalance price if they have produced more than (or consumed less than) the volumes of electricity covered by their contracts.

49. Ofgem has recently approved fundamental reforms to the system of imbalance prices under the Electricity Balancing Significant Code Review (EBSCR). While no appeal was made against Ofgem's decision, several parties have written to us, expressing their concerns about the reforms.

50. These reforms are:

(a) A move to a single imbalance price.

(b) A move to making the imbalance price in all periods equal to the cost of the 1MWh most costly action in the balancing mechanism (known as 'price average reference volume of 1MWh', or PAR1), which is a narrowing of the base for the calculation from the previous 500MWh.

(c) A move to reprice Short Term Operating Reserve (STOR) actions (typically periods of tight short-run margins due either to high demand or to supply disruptions) to the probability of lost load multiplied by £6,000/MWh (the 'value of lost load' (VoLL), if this is greater than their utilisation price. This is known as 'reserve scarcity pricing', or RSP.

(d) A move to price disconnection or voltage reduction actions equal to the VoLL.

51. We consider the move to a single price for imbalances to be positive for competition, as it will eliminate the inefficient penalty that has previously been imposed on companies that find themselves in 'helpful' imbalance at any given time.

52. The reformed move to PAR 1 is being phased in, with an opportunity to learn from the experience at PAR50. Should this demonstrate that there are real problems with further tightening, the modification can be revisited. We suggest that Ofgem should use the opportunity of the move from PAR500 to PAR50 to do a careful empirical analysis of the likely effects of a further move to PAR1.

53. We think RSP (including the move to price disconnection or voltage reduction actions equal to the VoLL) will provide stronger incentives for contracting and forecasting ex ante, and some additional incentives for flexible generation and demand, but there is likely to be an irreducible element of risk that parties cannot directly control. While smaller parties are generally more exposed to imbalance volumes than larger parties, under single pricing they are as likely to benefit from an unexpected event as lose out. Further, the prevalent use by smaller suppliers of intermediaries should help any such risks be managed. Overall, while we have not seen strong evidence in favour of a move to RSP, we believe that there are insufficient grounds to consider that it is likely to lead to an AEC.

Capacity Market

54. The Capacity Market was introduced by DECC to help ensure sufficient investment to meet future demand. In an energy-only market, potential investors in generation might be sceptical about their ability to recover the costs of their investment, since this would require prices to be allowed to spike to very high levels on the (rare) occasions of system stress. Under the Capacity Market, National Grid holds auctions to secure agreements from capacity providers (generation and DSR) to provide capacity when called upon to do so at times of system stress.

55. Our provisional view is that there are cogent arguments for introducing a capacity mechanism, to help ensure that an appropriate level of security of supply is maintained. In particular, because it is based on a competitive process, this should help to improve incentives to invest in and maintain thermal generating capacity at a time of considerable policy change and provide greater incentives for DSR. We have found that since 2009 the Six Large Energy Firms have suffered significant impairment losses in relation to their conventional CCGT and coal generation fleet. Impairment losses are a clear indication that investors do not expect to fully recover the cost of past investments in these technologies.

56. A number of concerns were raised with us relating to specific aspects of the operation and design of the Capacity Market. Having considered these, our provisional view is that the design of the Capacity Market appears broadly

competitive. As regards the recovery of Capacity Market costs and the Capacity Market penalty mechanism, our provisional view is that these are unlikely to give rise to an AEC. As regards the length of the capacity agreements, and the different treatment of DSR providers, in view of DECC's work in this area and the case pending before the General Court, we do not intend to carry out further work in this area.

Contracts for Difference

57. A further area we have considered are the policy mechanisms in place to drive future investment in low carbon generation. The decisions being taken now in this area will have a major impact on future prices.

58. The Renewables Obligation (RO) has been successful in driving investment in renewable generation, which accounted for just under 20% of all GB generation in 2014. However, it has imposed an increasing burden on bills – DECC estimates that Renewables Obligation Certificate (ROC) payments will reach almost £4 billion per year by 2020/21, comprising around 8% of the domestic electricity bill in 2020.

59. CfDs have been introduced to replace the RO as the main mechanism for incentivising investment in low carbon generation. Unlike the RO, which takes the form of a payment on top of the revenue generators receive from the wholesale electricity market, under CfDs, generators are paid the difference between a strike price (which is fixed in real terms) and a market reference price.

60. CfD payments are due to increase steadily, reaching about £2.5 billion a year by 2020/21. DECC has expressed the view that, by insulating low carbon generators from a fluctuating wholesale price, CfDs will allow them to manage risks more effectively, resulting in a lower cost of capital and, in the long run, lower costs to consumers. We have found that there is some evidence to support DECC's view that the more attractive risk properties of CfDs will encourage investors to accept a lower level of support per MWh of generation.

61. In our view, a central benefit of the move from ROCs to CfDs is that, while under the RO levels of support are set administratively, under CfDs competition can be used to set the strike price and hence the level of support provided to low carbon generators. By enabling a competitive process, CfDs should provide a more efficient means of providing support.

62. We therefore think that DECC's move to a competitive allocation process was a positive step towards ensuring an efficient allocation of support. The first

competitive auction was held in 2015, resulting in prices considerably below the reserve price ('Administrative Strike Price'). We estimate that the amount of support to projects awarded CfDs in the first auction was approximately 25% lower than it would have been had CfDs been awarded to projects at their Administrative Strike Prices, saving consumers around £110 million a year.

63. The scale of the decisions being made and their impact on future bills mean that it is essential that support to low carbon generation is provided at least cost to consumers. The benefits of using a competitive allocation process are, in our view, clearly demonstrated by looking at the Final Investment Decision enabling for Renewables (FIDeR) scheme, under which contracts were awarded through a non-competitive process. In March 2013, DECC launched this scheme to award an early form of CfDs to renewable generation projects with the intention of avoiding investment delays during the transition to the enduring CfD regime.

64. We have compared the subsidy awarded to the offshore wind projects under the FIDeR scheme to the levels of subsidy awarded under the competitive auction. Our analysis suggests that the support cost per MWh to consumers of the offshore wind projects awarded under the FIDeR scheme was between 30 to 60% higher than the support cost of similar offshore wind projects awarded through competitive allocation a few months later. We estimate that DECC's decision to award a large proportion of the available CfD budget outside the competitive process under the FIDeR scheme is likely to have resulted in consumers paying substantially higher costs (approximately £250–£310 million per year for 15 years, equivalent to a 1% increase in retail prices). This provides a stark illustration of the additional costs that can be expected if the competitive process is circumvented. While DECC has highlighted the general benefits of providing greater certainty to investors, we have not seen any analysis of the specific benefits arising from supporting these projects early through FIDeR.

65. We are therefore concerned that some elements of the CfD allocation process currently in place potentially restrict the use of competition in setting the strike price in the future. Notably, the Energy Act 2013 gives DECC powers to award CfDs directly to parties through a non-competitive process in the future. While there will be some situations where competition may not be the most appropriate means by which contracts should be allocated (for example, where there is a very limited number of potential competitors), the experience of FIDeR shows that any proposal not to use a competitive process in the future needs to be considered carefully, transparently and in full recognition of the likely costs. Without this, there is a risk that future contracts may be awarded that do not deliver value for money for customers.

66. We have also reviewed two important aspects of the approach DECC has taken to the competitive allocation of CfDs. Specifically, we have considered the division of the technologies into separate ‘pots’, whereby DECC separates different technologies for the purposes of the competitive process; and we have also considered the way that budgets are allocated into each of these pots. Decisions on both of these parameters influence the intensity of competition and the level of support provided through the scheme.

67. While there could be reasons, based on economic efficiency, for different technologies to be separated out, these decisions need to be carefully made, given the potential impact on competition and future prices. Regarding the division of technologies into pots, we have not received evidence from DECC demonstrating how its preferred option would result in the best outcome for consumers. Nor have we been made aware of significant analysis undertaken by DECC on the rationale for its decision on how to allocate the budget between the pots. Going forward, we believe it is important that DECC regularly monitor the division of technologies into pots and provide for each auction a clear justification for the allocation of budgets between pots to ensure that an appropriate amount of support is allocated to technologies at different stages of development.

68. Overall, while DECC’s introduction of CfDs represents a positive step towards an efficient competition-based process, **in light of these concerns and the potential impact on future bills we have reached a provisional finding that the mechanisms for allocating CfDs are a feature giving rise to an AEC**.

Vertical integration

69. A range of parties have expressed concerns about VI in the electricity sector, both in the context of this investigation and in the wider debate about competition in the energy sector. For example, in its decision to make a market investigation reference, Ofgem said that vertical integration ‘can provide efficiency benefits but can also harm competition. A full investigation of the balance between costs and benefits is needed, to establish whether vertical integration is best for competition.’

70. The Six Large Energy Firms are all vertically integrated to some extent, in that they have electricity generation and electricity retailing activities under common ownership. Some other energy firms are also vertically integrated, including Drax, which owns the non-domestic supplier Haven Power, and Ecotricity. The degree of operational integration varies considerably between firms.

71. We have examined three main ways in which VI might harm competition in wholesale and retail electricity markets.

72. First, it could mean that independent (non-VI) generators are not able to compete effectively because of the prevalence of VI suppliers. The concern here is that independent generators would be harmed because VI suppliers refuse to buy from them, or will buy on worse terms. However, we have found no evidence of this, and continued investment in independent generation suggests that this is not a concern.

73. Secondly, if VI generators refuse to supply independent (non-VI) suppliers, or supply them on worse terms, it could mean that independent suppliers have to pay higher costs for wholesale energy than VI suppliers. As a result they may be unable to compete effectively, resulting in harm to consumers. The lack of unilateral market power makes it implausible that VI generators would be able to discriminate in this way, and the recent growth of independent retailers suggests that they have not been foreclosed from the market in this way.

74. Lastly, VI could raise barriers to entry and growth by new suppliers if they were unable to secure sufficient wholesale energy. However, our analysis of wholesale market liquidity suggests that VI firms carry out extensive external trading, and liquidity in the products that VI firms use to hedge their exposure to wholesale market risk is sufficient for independent firms to hedge in a similar way.

75. One concern that has been expressed in relation to VI is the lack of financial transparency. We consider the broader issue of financial transparency and the need for robust market-orientated financial information below.

76. We have also considered whether there are potential cost savings associated with VI. There may be a potential benefit to VI firms resulting from the 'natural hedge', whereby certain outcomes that may be detrimental to the VI firm's supply arm may be beneficial to its generation arm (and vice versa). This would reduce the volatility of a VI firm's returns. However, these benefits are likely to materialise only under fairly specific circumstances, and as a result are likely to be limited in scale.

77. Some other potential benefits from VI are not directly related to the natural hedge. VI is a form of diversification which may improve VI firms' credit ratings (thereby potentially reducing VI firms' financing costs), but we note that other forms of diversification could potentially give the same benefit. There may also be economies of scope resulting from VI between supply and generation (such as shared trading or management personnel). While it is not clear to what extent these benefits are likely to be passed through to consumers,

overall consumers are likely to be better off than they would be if these efficiencies were not present.

78. We have not sought to quantify precisely the scale of the benefits identified above, but our provisional view is that they are likely to be modest. The fact that some of the Six Large Energy Firms are moving away from a VI structure gives further weight to our provisional conclusion that any benefits from VI are likely to be limited (although they may have been greater in the past when integration took place).

79. Overall, we have not identified any areas in which VI is likely to have a detrimental impact on competition for independent suppliers and generators. In addition, we consider that there may be some efficiencies resulting from VI, which may be passed through to consumers. As a result, our provisional conclusion is that firms' VI structure does not give rise to an AEC.

Nature of retail market competition

Demand and supply characteristics and the parameters of retail competition

80. Reliable and continuous access to energy is a fundamental requirement of households, necessary for heating, lighting and the use of appliances. If demand for electricity and gas is not satisfied instantaneously, customers incur severe costs.

81. Gas and electricity can be characterised as 'necessity goods', which are goods that are considered indispensable for maintaining a certain standard of living. Such goods have a low income- and price-elasticity of demand. We note that the poorest 10% of the population spend almost 10% of total household expenditure on electricity and gas, while the richest 10% spend about 3% of total household expenditure on electricity and gas.

82. Gas and electricity are extreme examples of homogenous products in that the energy that customers consume is entirely unaffected by the choice of retailer. We would expect, therefore, that price would be the most important product characteristic to a customer in choosing a supplier and/or tariff. A further implication of homogeneity is that customers may be less interested in engaging in the market for electricity and gas supply than in other markets, where there is quality differentiation of products.

83. Traditional gas and electricity meters used in households do not record when energy is used and are only read infrequently. This means that households have no reason to adjust their use of gas or electricity in response to short-term wholesale price changes. Further, as a result of the infrequency of meter

reads, customer bills are typically based on estimates rather than actual consumption, which can create barriers to understanding and engagement in the market.

84. Retail energy suppliers do not own or operate any of the physical assets required for the delivery of gas or electricity to their customers' homes. They are engaged, rather, in financial and commercial activities relating to the sale of energy to customers. These activities are: energy procurement; securing network access; sales and marketing; metering; billing and customer service; the delivery, on behalf of DECC, of obligations relating to environmental and social policy objectives; and, optionally, the provision of a range of bundled products and services.

85. We would expect competition in a well-functioning retail market to be largely on price, with competitive pressures bearing down on elements of the overall costs of energy supply, in particular suppliers' gross margin (ie the combination of indirect costs and net profit). This is currently around 17% of the retail cost of electricity and 19% of the cost of gas across the Six Large Energy Firms. We would also expect a (more limited) degree of competitive pressure on wholesale costs and obligation costs, which together comprise around 60% of the costs of electricity and gas. After the smart meter roll-out we would expect suppliers to have a greater degree of influence over wholesale costs and some limited influence over network costs.

86. We would expect competitive pressures to be such that customer service meets certain minimum required standards, notably accurate billing. We would expect some degree of innovation, around tariff design, convenience and services such as advice on improving energy efficiency. We consider that the scope for such innovation could expand significantly with the full roll-out of smart meters and greater potential for demand response.

Influence of regulation in shaping retail competition

87. The nature of price competition between the Six Large Energy Firms has evolved several times since liberalisation, due in large part to changes in the regulatory regime. We have found that, post-liberalisation, competition was initially focused on the SVT. Over the last six years, three major interventions by Ofgem have changed the nature of retail competition significantly:

(a) The prohibition on regional price discrimination introduced in 2009.

(b) The introduction of new licence requirements, standards of conduct and enforcement action resulting in the withdrawal of the Six Large Energy Firms from doorstep selling in 2011 and 2012.

(c) The introduction of Retail Market Review (RMR) reforms in 2014 introduced a number of obligations on suppliers, including several provisions relating to tariffs, notably restricting the number of core tariffs.

Customer activity and engagement

88. Domestic customer activity can be measured along several dimensions:

(a) Choice of tariff – notably whether the customer is on the SVT or a non-standard tariff.

(b) Choice of payment method – standard credit, direct debit or prepayment.

(c) Choice of supplier, for one or both of electricity and gas.

89. We commissioned a survey of 7,000 domestic retail energy customers. The survey provides material evidence of domestic customers' lack of understanding of, and engagement in, retail energy markets. For example:

- 36% of respondents either did not think it was possible or did not know if it was possible to change one (or more) of the following: tariff, payment method and supplier;
- 34% of respondents said they had never considered switching supplier;
- 56% of respondents said they had never switched supplier, did not know it was possible or did not know if they had done so; and
- 72% said they had never switched tariff with an existing supplier, did not know it was possible, or did not know if they had done so.

Choice of tariff

90. The SVT is the default tariff – ie the tariff energy customers will pay if they have not made an active decision to change tariff. Unlike other tariffs, the SVT has no end date – customers will be on the SVT indefinitely unless they make an active decision to change.

91. We have observed that, for the Six Large Energy Firms, gas and electricity revenues per kWh from the SVT are consistently higher than average revenue from non-standard (generally fixed-price) tariffs. Over the period 2011 to 2014, average revenue per kWh from the SVT was around 10 and 13% higher than average revenue from non-standard tariffs for electricity and gas respectively across the Six Large Energy Firms. Despite this, around 70% of the customers of the Six Large Energy Firms are currently on the SVT. We

also note that a customer on the SVT is more likely to be with the historical incumbent supplier.

Choice of payment method

92. In the mid-1990s the majority of customers paid by standard credit but since then there has been a significant shift towards payment by direct debit, with 57% of customers choosing to pay by this method in 2014 and only 28% of customers paying by standard credit. The proportion of customers on prepayment meters doubled over the period, from 7% in 1996 to 15% in 2014.

93. Most customers have a choice as to whether to pay by standard credit or direct debit. The Six Large Energy Firms have offered a variety of discounts to customers to pay by direct debit over the years. Standard Licence Condition (SLC) 27.2A, introduced by Ofgem in 2009, requires any such discounts to be cost-reflective. We understand that dual fuel SVT customers paying by standard credit currently pay about £75–£80 per year more than if they paid by direct debit, although we have not yet examined whether this is cost-reflective.

94. Prepayment, in contrast, is not generally a choice on the part of the customer: all customers on prepayment meters must pay by prepayment. Prepayment meters are generally installed where a customer has a poor payment history or in certain types of accommodation such as student accommodation. We understand that the premiums paid by dual fuel SVT prepayment customers are currently about the same as those for standard credit – about £75–£80 per year (compared with paying by direct debit). Nearly all prepayment customers are on the SVT, reflecting the limited choice of non-standard tariffs they face.

Choice of supplier

95. We have observed a steady upwards trend in switching until 2008 followed by a decline, to levels below those in 2003. There are a number of potential reasons for this, including the prohibition of regional price discrimination through SLC 25A in 2009 and the decision by suppliers (in particular, the Six Large Energy Firms) to stop doorstep selling in 2011 and 2012. There was also a very noticeable spike in switching towards the end of 2013, which may have been due to the high level of political debate surrounding energy prices at that time.

96. Between about 20 and 30% of the domestic electricity customers of the Six Large Energy Firms have been with their current supplier for more than ten years. For gas, the range is wider – between about 10 and 40% depending on

the supplier. The evidence suggest that incumbents have a higher proportion of such customers: regarding electricity supply, around 35 to 45% of the domestic customers of incumbent suppliers within each region have been with their supplier for ten years or more.

Market shares

97. Currently British Gas has the largest share of both gas and electricity customers, followed by SSE and E.ON. There has been a rapid expansion in the market shares of suppliers outside of the Six Large Energy Firms, to around 10% in gas and electricity in the first quarter of 2015. The largest of the mid-tier suppliers are First Utility, Ovo Energy and Utility Warehouse.

Nature and extent of price competition

98. The price of the SVT can in principle be changed by the supplier at any time, with the condition that, if the price is to be increased, it must give 30 calendar days' notice to customers of its intention to do so. The Six Large Energy Firms typically make public statements, in advance of implementation, of intentions to change the price of the SVT. SVT prices have generally changed once or twice a year.

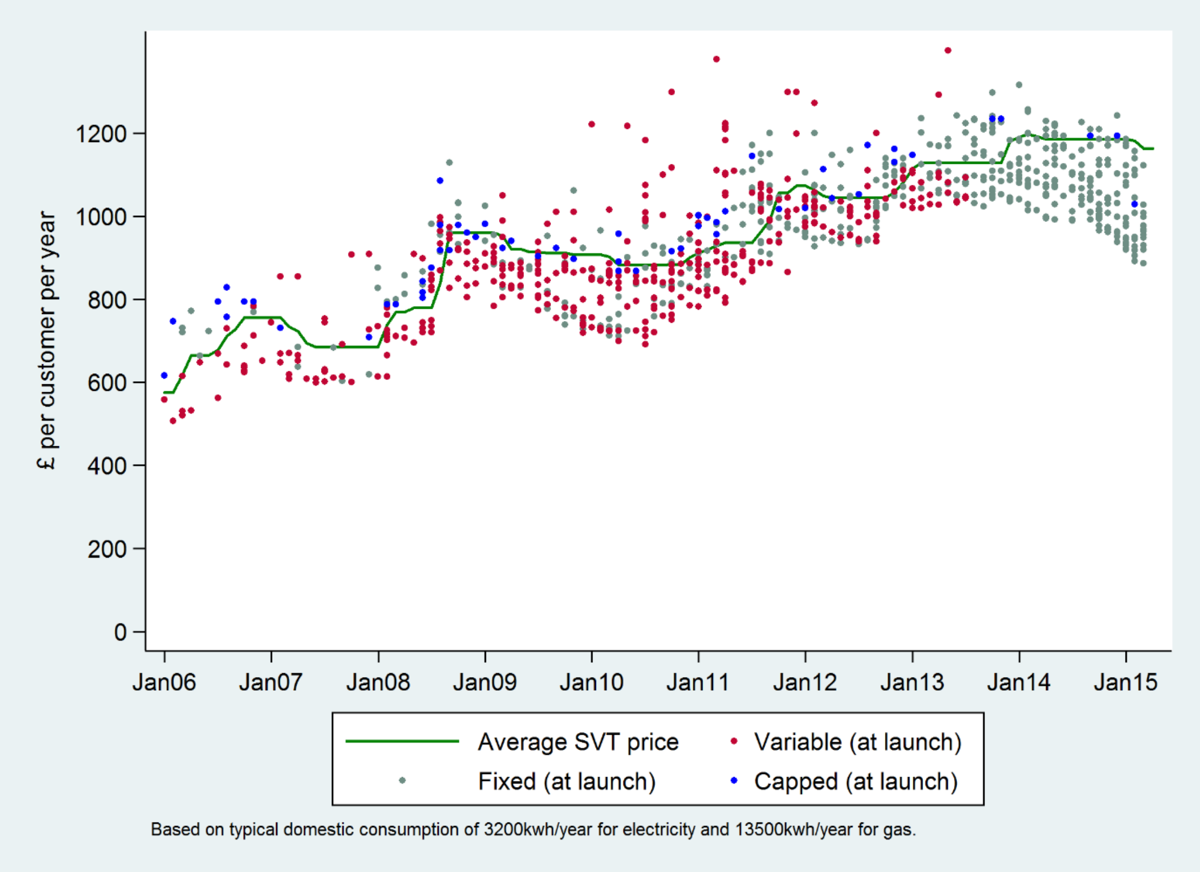
99. The SVT is an acquisition tariff for prepayment customers, who have a very restricted choice of non-standard tariffs. For non-prepayment customers, the SVT is generally no longer an active acquisition tariff.

Comparison of the SVT and non-standard tariffs

100. Non-standard tariffs come in a variety of forms, including fixed-rate and capped tariffs. One-year fixed-rate products are currently the most popular form of non-standard tariff. In contrast to the SVT, non-standard tariffs are acquisition tariffs. The majority are priced at significant discounts to the SVT, with a strategy of ensuring that they achieve a good position on price comparison websites (PCWs). There are, however, some non-standard tariffs such as longer-term price fixes, which are more expensive than the SVT.

101. The chart below compares the non-standard tariffs launched by the Six Large Energy Firms and the mid-tier suppliers with the flat average SVT across each of the Six Large Energy Firms.

Figure 2: SVT and non-standard tariffs offered by the Six Large Energy firms and the mid-tier suppliers (based on an annual bill for a dual fuel, direct debit, typical consumption customer)



Source: CMA analysis of data collected from the Six Large Energy Firms, the mid-tier suppliers and Ofgem.

102. For the majority of this period, up to the end of 2012, there were many non-standard variable tariffs, which offered some of the cheapest rates. Fixed-rate and capped products were often sold at a premium – as might be expected, given the fact that they reduce the risk to which the customer is exposed. With the introduction of RMR, discounts on the SVT were banned and fixed products have taken their place as the cheap acquisition product. Over the last year, the disparity between the SVT and the cheapest non-standard products has increased substantially.

103. We have also observed that the SVT has risen over the last three years, despite that fact that forward-looking measures of direct costs have on average fallen over the period, particularly over the last 12 months. In contrast, the cheapest non-standard tariffs have tracked changes in expected direct costs more closely.

104. Several of the Six Large Energy Firms have told us that there is an inter-relationship between their pricing of the SVT and of non-standard products. For example, in setting the price of a cheap non-standard product, they told us that they assume that a certain proportion of customers will revert to the

SVT (for which there is a bigger margin) at the end of the product's fixed term. They have argued that it is only because this happens that they can offer the cheapest of their non-standard products.

Competition in the devolved nations and regional competition

105. Our survey suggests that there are some differences in levels of activity and engagement between customers in Scotland, Wales and England. In general, we found that customers in Scotland and Wales were somewhat less likely to have been active in the market than those in England. We also found that in Scotland and Wales, customers were somewhat more likely to express satisfaction with their current supplier and to trust it.

106. A relatively high proportion of customers in both Scotland and Wales (29%) had been with their supplier for more than ten years (compared with 21% in England). Further, in Scotland and Wales, 65% and 61%, respectively, of respondents were with an incumbent supplier (for at least one fuel) compared with 53% in England.

107. Market concentration is higher in Scotland and Wales compared with the GB average, and lower in England. We also note that the two regions in Great Britain where the electricity incumbent has a market share of over 50% are North Scotland and South Wales.

108. These results are consistent with higher degrees of incumbent brand loyalty in Scotland and Wales. Overall, our provisional view is that retail consumers in Scotland, Wales and England are likely to face a broadly similar range of issues, albeit with somewhat lower levels of market engagement in Scotland and Wales.

109. We are aware, however, of two specific constraints relating to metering that are likely to affect customers in Scotland and Wales to a greater extent than customers in the rest of Great Britain. We were told when we visited Scotland of the challenges imposed by Dynamic Teleswitched (DTS) meters, which are used to provide electric heating by homes off the mains gas grid. They are located almost entirely in three regions: North Scotland, South Scotland and East Midlands. Ofgem research suggests that the level of market engagement among DTS customers is particularly low and that DTS face particular barriers to switching. Further, incumbent suppliers have a particularly high market share of DTS customers in Scotland. We have also observed from our survey that there is a higher proportion of customers on prepayment meters in Wales (in which 18% of respondents prepaid) compared with England (where 11% of respondents prepaid).

Domestic retail: weak customer response, supplier behaviour and regulations

110. We have identified three areas in which domestic retail markets may not be working well for customers:

(a) weak customer response and lack of engagement with domestic retail energy markets;

(b) supplier behaviour; and

(c) the regulatory framework governing domestic retail market competition.

Weak customer response and lack of engagement

111. Our customer survey suggests that there are substantial numbers of customers who are disengaged from retail energy markets. We have considered further sources of evidence that shed light on the nature and extent of disengagement, including our analysis of: the gains from switching available to customers; the characteristics of customers who are disengaged; and our analysis of the barriers to engagement that customers face in domestic retail energy markets.

Gains from switching

112. We estimate that there were significant gains from switching that went un-exploited by domestic energy customers over the period Q1 2012 to Q2 2014. We calculated the savings available from the key dimensions of choice – choice of tariff; choice of payment method; and choice of supplier, for one or both of electricity and gas – considering a number of scenarios, which differ according to the extent to which they restrict the choices available to customers.

113. Bringing the above results together, the table below shows how the gains from switching differ for all the customers of the Six Large Energy Firms according to their different tariff and payment type, under the most liberal scenario for switching (in which they are allowed to change supplier, tariff and payment method).

Table 1: Average savings from switching tariff, payment type and/or supplier for customers on different tariff and payment types Q1 20212 to Q2 2014

Dual/ single fuel	*Tariff type*	*Payment type*	*% of total gas customers*	*% of total electricity customers*	*Average savings, £*	*Average savings, % of bill*
Dual	Non-standard	All	31	26	137	12
Dual	SVT	Direct debit	26	22	183	15
Dual	SVT	Standard credit	13	11	232	22
Dual	SVT	Prepay	11	10	69	8
Single gas	All	All	18	0	107	18
Single electricity	All	All	0	31	86	15

Source: CMA analysis.

114. The table shows that – considering the most liberal scenario for switching– the savings relative to the bill are highest for standard credit SVT customers and single fuel (particularly single fuel gas) customers. The gains from switching for prepayment customers are low, which reflects the restricted availability of tariffs for such customers. We also note that there appears to be a rising trend in available savings and that the most recent 12 months, which appear to be characterised by a wider disparity in tariffs, are not included in the current analysis. We will include this period in updates to our analysis before publication of the final report.

115. Overall we have not seen evidence that we have significantly overstated the gains from switching in our analysis. In particular:

(a) we have not identified characteristics of an SVT to which customers might attach substantial value; and

(b) on choice of supplier, we have seen no evidence to suggest that suppliers offering the cheapest tariffs have worse quality of service than those offering more expensive tariffs.

116. In relation to the choice of payment method, the evidence suggests that a proportion of customers who pay by standard credit are likely to be doing so by default rather than through active choice. However, there are likely to be some who do have an active preference for paying by standard credit, and are likely to assign some value to this payment method. We have therefore also calculated the gains to available to customers from switching suppliers and tariffs alone, keeping the payment method fixed. The main difference is that savings for dual fuel customers on the SVT who pay by standard credit are lower – equivalent to 14% of the bill (as opposed to 22% for those prepared to switch to direct debit).

117. Our finding of material potential savings that are persistent over time, available to a significant number of domestic customers and that go unexploited provides evidence of weak customer engagement in the domestic

retail markets for electricity and gas in Great Britain. While gains from switching are likely to be present in most markets, we attach particular significance to the fact that they are available at such levels to customers for domestic gas and electricity (which are homogenous goods and constitute a significant proportion of household expenditure).

Characteristics of disengaged customers

118. The survey results suggest that there is a material percentage of customers who are disengaged in domestic retail energy markets. The survey results also suggest that those who are have low incomes, have low qualifications, are living in rented accommodation or who are above 65 are less likely to be engaged in the domestic retail energy markets against a variety of indicators of engagement. For example, 35% of those whose household incomes were above £36,000 had switched supplier in the last three years, compared with 20% of those whose household incomes were below £18,000, and 32% of those with degree level qualifications had switched in the last three years compared with 18% of those with no qualifications.

119. We have also assessed to what extent the gains from switching are associated with demographic characteristics. Overall, we find that, excluding prepayment customers, those households who are: in rented accommodation; have incomes below £18,000; or in receipt of a Warm Home Discount rebate have higher gains from switching. By implication, such customers are on average paying a somewhat higher price for their energy than those customers who do not fall into these categories.

120. We note that the disengaged are not limited to these demographic groups: there are many households who are disengaged who do not fall into these categories. However, we consider these results to be important, as they help to shed some light on the possible reasons for inactivity and lack of engagement in the markets. Had we found that it was generally higher-income households who did not engage, we might have concluded that saving money through switching was of relatively low importance to them.

121. The fact that this is not the case – indeed, there appears to be a higher proportion of households on lower incomes who are disengaged and inactive – makes the above hypothesis more difficult to sustain, particularly given the fact that expenditure on energy constitutes a high proportion of the total expenditure for the poorest households.

Barriers to engagement

122. We have identified a number of barriers to engagement that customers face in domestic retail energy markets.

123. We consider that two fundamental characteristics of energy consumption are likely to impede customers' understanding of and engagement in energy retail markets. First, the fact that there is no quality differentiation of gas and electricity may fundamentally reduce consumers' enthusiasm for, and interest in, engaging in the domestic retail energy markets, leading to customer inertia. Second, conventional meters are not very visible or immediately informative to the customer, as a result of which customers are generally not aware of how much gas and electricity they consume, when they consume it and which uses require the most energy. Further, conventional meters are generally read infrequently by the customer or the supplier, which adds considerably to the complexity and opacity of gas and electricity bills.

124. We have also identified barriers (both actual and perceived) to accessing and assessing information, which influence the extent to which customers engage in the process of shopping around for the best deal. Our survey suggests that, while the majority of respondents who shopped around in the last three years found the process of shopping around to be very or fairly easy, others experience difficulties. For some, lack of access to the internet (or a lack of confidence in using the internet) appears to be a barrier to engagement.

125. Third party intermediaries (TPIs) such as PCWs can significantly reduce search and switching costs for domestic customers by providing an easy means to gain personalised quotes, on a comparable basis, from a range of different suppliers. However, we have found that customers on low income and with low levels of education are less likely to use PCWs. Of those who are not confident using a PCW, 43% said they did not trust or believe PCWs.

126. We have observed that there is some evidence indicating that the process of searching for an alternative supplier and successfully switching has been problematic for some consumers. Significantly, the perception of the complexity and burden of the process appears to be worse than the reality, which may further dissuade domestic customers from shopping around and/or switching.

127. We have also found that prepayment meters place technical constraints on customers from engaging fully with the markets, which contributes to such customers facing higher costs and a more limited choice of tariffs. Prepayment meters therefore reduce customers' ability and incentive to

engage in the markets and search for better deals. We expect these problems to be partly addressed with the full roll-out of smart meters.

Provisional finding on weak customer response

128. Our provisional finding is that **we have identified a combination of features of the markets for the domestic retail supply of gas and electricity in Great Britain that give rise to an AEC through an overarching feature of weak customer response**, which, in turn, gives suppliers a position of unilateral market power concerning their inactive customer base (as discussed below).

Supplier behaviour

129. We have also considered to what extent supplier behaviour may be leading to an AEC. We have considered two hypotheses:

(a) That some suppliers have a position of unilateral market power, arising from the extent of customer lack of engagement in the market, and that these suppliers have the ability to exploit such a position, for example, through price discrimination by pricing their SVTs materially above a level that can be justified by cost differences from their non-standard tariffs and/or pricing above a level that is justified by the costs incurred with operating an efficient domestic retail supply business.

(b) That suppliers are tacitly coordinating in the retail market through public price announcements.

Unilateral market power

130. We have observed that there are significant disparities in the tariffs charged by the Six Large Energy Firms that cannot be fully explained by differences in cost.

131. Specifically in relation to discounts on the SVTs, we have found that, over the period July 2013 to March 2015 just over 40% of non-standard tariffs were priced at a discount of more than 10% on the SVTs. The extent of discounting differs between firms. All of the Six Large Energy Firms said that the price of fixed-term tariffs is not determined by reference to the relative cost of supplying customers subscribing to standard and non-standard tariffs.

132. With regard to direct costs, we conclude that transmission and distribution charges and costs of meeting social and environmental obligations do not differ between customers subscribing to standard variable and non-standard

tariffs. In relation to energy costs, our provisional view is that there is no evidence that energy costs are systematically and materially higher for SVTs as compared with fixed-term, fixed-rate tariffs.

133. Overall, our provisional view is that the Six Large Energy Firms enjoy a position of unilateral market power over their inactive customer base and have the ability to exploit such a position through pricing their SVTs materially above a level that can be justified by cost differences from their non-standard tariffs.

134. We note that the extent of discounting differs between firms and over time and that some suppliers have argued that they can only afford to discount some non-standard tariffs in expectation that a proportion of customers will revert to the SVT at the end of that tariff's term. However, we also note that other evidence (including evidence on profitability, cost inefficiency and the prices offered by the mid-tier suppliers) suggests that the average prices offered by the Six Large Energy firms have been above those that we would expect to prevail in a well-functioning competitive market).

135. Overall, our provisional view is that **the overarching feature of weak customer response gives suppliers a position of unilateral market power concerning their inactive customer base and that suppliers have the ability to exploit such a position through their pricing policies**: through price discrimination by pricing their SVTs materially above a level that can be justified by cost differences from their non-standard tariffs; and/or by pricing above a level that is justified by the costs incurred in operating an efficient domestic retail supply business.

Tacit coordination

136. Our provisional finding is that the evidence does not suggest that there is tacit coordination between the domestic retail energy suppliers in relation to price announcements. In particular, we do not have evidence of suppliers using price announcements as a mechanism to signal their intentions in relation to the pricing of their SVT to rival suppliers. There are some characteristics of the supply of gas and electricity to domestic customers that may be conducive to tacit coordination. However, we have also identified factors that may make it more difficult for firms to reach and sustain coordination.

Regulations

137. The supply of electricity and gas is heavily regulated, and the form that regulation takes has a profound effect on the shape of competition in retail

energy markets. We have considered several elements of the regulatory regime that may have an impact on competition between suppliers.

Retail Market Review reforms

138. Ofgem launched the RMR in late 2010 due to concerns that retail energy markets were not working effectively for consumers. The stated purpose of RMR was to promote customer engagement in energy markets in order to improve the competitive constraint provided by customer switching.

139. We have analysed the impact on competition of the ‘simpler choices’ component of the RMR rules, which includes the following measures: *(a)* the ban on complex tariffs; *(b)* a maximum limit on the number of tariffs that suppliers are able to offer at any point in time; and *(c)* the simplification of cash discounts.

140. The stated purpose of RMR was to promote customer engagement in the retail energy markets in order to improve the competitive constraint provided by customer switching. However, some of the RMR measures restrict the behaviour of suppliers and constrain the choices of consumers in a way that may have distorted competition and reduced consumer welfare.

141. The RMR rules have not been in place long enough for us be able to assess with full confidence their overall impact on consumer engagement and competition. That said, the evidence in hand at this stage is not particularly encouraging. There are few, if any, signs that consumer engagement is improving materially, either in terms of direct consumer activity (eg switching, shopping around) or their experience and perception (eg views on tariff complexity). Those who were disengaged before the RMR appear to remain so. Further we have doubts that the four-tariff rule will have a benefit on engagement in the long term, since given the number of suppliers, any customer who wishes to find the cheapest tariff on the market will in practice need to use a TPI, with or without the four-tariff rule.

142. The introduction of the four-tariff rule has led to a number of the Six Large Energy Firms withdrawing a number of tariffs and discounts and changing tariff structures, which may have made some customers worse off. In particular, some innovative tariffs were withdrawn; various discounts were removed by the Six Large Energy Firms as a result of RMR rules; and RMR curtailed the ability of the Six Large Energy Firms to offer attractive tariffs for low volume users.

143. We consider that the restrictions imposed by the RMR four-tariff rule limits the ability of suppliers to innovate and provide products which may be beneficial

to customers and competition. This is of particular concern over the longer term as RMR rules could potentially stifle innovation around smart meters.

144. A further area where the impact of the RMR appears to be harmful to price competition is in relation to PCWs. PCWs can no longer compete with each other to attract customers by reducing commission – either directly by way of passing on cashbacks, or indirectly by securing exclusive tariffs from suppliers – because of the four-tariff rule.

145. The impact of the RMR rules on the intensity of price competition between suppliers is less clear. While the suppliers no longer offer discounted variable-rate tariffs, price competition now takes place in the fixed-term fixed-rate space where many tariffs are priced at a sizeable discount to SVTs.

146. Overall, **our provisional finding is that the 'simpler choices' component of the RMR rules, (including the ban on complex tariffs, the maximum limit on the number of tariffs that suppliers are able to offer at any point in time, and the simplification of cash discounts) is a feature giving rise to an AEC in the retail supply of electricity and gas to domestic customers**, through reducing retail suppliers' ability to innovate in designing tariff structures to meet customer demand, in particular, over the long term, and by softening competition between PCWs.

Prohibition on regional price discrimination

147. In 2009, Ofgem implemented SLC 25A, in an attempt to address concerns that certain groups of customers were not benefiting from competition. The prohibition lapsed in 2012. However, suppliers told us that, following a communication from Ofgem warning against 'pricing practices which are unjustified […] returning to the market', they continued to adhere to the principles of SLC 25A in their pricing of SVTs. In December 2014, Ofgem wrote to suppliers to confirm that SLC25A had lapsed and that suppliers were not bound by it in any way.

148. The decision to introduce the prohibition in 2009 has been heavily criticised by two former regulators, Stephen Littlechild and George Yarrow, both of whom argued to us in hearings that the licence change had the effect of restricting competition to the detriment of customers.

149. We note that our analysis of the relationship between the SVT and measures of direct costs is suggestive of an apparent softening of competition in SVTs from 2009 onwards (in that the gap between the average SVT and total costs appears to widen since 2009) and that this broadly coincides with the introduction of the prohibition. We also note that other important changes

have taken place over this period – notably the withdrawal of the Six Large Energy Firms from doorstep selling – which may also have contributed to the pattern observed. We also note that the gap between the average SVT and measures of direct costs was low before 2009.

150. Overall, we think it is likely, on the basis of the evidence that we have seen, that SLC 25A contributed to a softening of competition on the SVT, although other factors may also have had an impact. However, since Ofgem has confirmed that this licence condition is no longer in place, we do not consider that it currently leads to an AEC.

PCW Confidence Code

151. We have considered the likely impact on customer engagement and competition of the Confidence Code that Ofgem has developed to govern independent PCWs offering an energy comparison and switching service. The purpose of the Confidence Code is to give assurance to customers using PCWs accredited under the Code that the service they receive will meet the principles of independence, transparency, accuracy and reliability.

152. Ofgem recently amended the Confidence Code such that from the end of March 2015 Code-accredited PCWs would no longer be able to present as a default only those tariffs for which they are paid commission. Instead PCWs must present all available tariffs as a default unless a customer makes an active and informed choice to see filtered results. The wording of this choice given to site users must be clear and simple. The aim of this amendment was to promote customer trust and confidence in accredited PCWs.

153. In response to the Ofgem consultation on the Confidence Code the Six Large Energy Firms were generally in favour of PCWs being required to display as a default the whole of the market, but there was less consensus among the smaller suppliers. PCWs are concerned about the new requirement, including that it will change the relationship between PCWs and energy suppliers to favour suppliers and benefit suppliers by providing them with free advertising of tariffs, on which PCWs are not paid a commission.

154. We consider that it is too early to assess the impact of the change to the Confidence Code. It is unclear whether the requirement to display the whole of the market will result in more consumers using PCWs as trust in PCWs increases, or whether it will lead to an increasing number of suppliers not entering into commercial relationships with PCWs at all, resulting in a withdrawal of PCWs from the market. We therefore do not consider that the amended Confidence Code currently leads to an AEC. We may, however,

need to consider the appropriateness of the Confidence Code in light of other possible remedies we may consider.

Gas and electricity settlement and metering

155. Settlement is the system by which disparities between the volumes of energy covered by suppliers' contracts and the volumes their customers actually use are identified, reconciled and paid for. Accurate and timely settlement is fundamental to well-functioning retail energy markets. However, we have concerns that elements of the settlement systems of both gas and electricity lead to inaccuracies and delays that distort competition between energy suppliers.

Gas settlement

156. Domestic gas customers do not have their meter read on a daily basis so their consumption for the purposes of settlement is based on an Annual Quantity (AQ), which is the expected annual consumption of the meter based on the historical metered volumes and seasonal normal weather conditions. The AQ value can only be adjusted – at the discretion of the supplier – during a specified AQ review period and only if meter reads demonstrate that actual consumption is at least 5% higher or lower than the AQ value. Further, there is no reconciliation between estimated and actual consumption once the meter is read.

157. We consider that the inaccuracy of AQs and the lack of reconciliation do not provide the correct incentives to suppliers. In particular, they disadvantage certain types of supplier – notably those that have been particularly effective in helping their customers reduce their gas consumption – and lead to gaming opportunities (whereby a supplier may delay adjusting an AQ value if it would be to their disadvantage).

158. We note that a significant upgrade of the gas settlement system is planned, in an attempt to address some of these issues, called Project Nexus. However, Project Nexus has taken many years to develop and the most recent deadline for Nexus reforms becoming operational (October 2015) is not likely to be met. Further, we note that the incentives that shippers face to place a higher priority on adjusting AQs down and delaying adjusting AQs up will still be present after Project Nexus is implemented.

159. Overall, **our provisional finding is that the current system of gas settlement is a feature that gives rise to an AEC in the domestic retail gas market** through the inefficient allocation of costs to parties and the scope

it creates for gaming, which reduces the efficiency of domestic retail gas supply.

Electricity settlement

160. Electricity settlement takes place every half hour but the vast majority of electricity customers do not have meters capable of recording half-hourly consumption. Therefore, their consumption must be estimated on an ex ante basis. This is done by assigning customers to one of eight profile classes, which are used to estimate a profile of consumption over time and allocate energy used to each half-hour period.

161. Our main concern in relation to electricity settlement is that the current profiling system of settlement distorts supplier incentives (compared with a system of settlement based on customers' actual half-hourly consumption). The use of profiling to estimate each supplier's demand fails to charge suppliers for the true cost of their customers' consumption – costs that can differ considerably at different times of the day. This means that suppliers are not incentivised to encourage their customers to change their consumption patterns, as the supplier will be charged in accordance with the customer's profile. This in turn may distort suppliers' incentives to introduce new products such as time-of-use tariffs.

162. We have reviewed the evidence on the potential value of load shifting through time-of-use tariffs. DECC, drawing on the results from several trials, estimated that domestic peak load shifting could be expected to generate present value savings of the order of £900 million through reducing the need for investment in generation (the majority of savings) and the distribution network.

163. In principle, smart meters should remove the need for profiling in electricity, since they provide accurate half-hourly meter reads which could be used for settlement. However, there are currently no concrete proposals for using half-hourly consumption data in the settlement of domestic electricity customers, even after the full roll-out of smart meters.

164. Given the time that code modifications have taken in the past, we are concerned at the lack of concrete plans for a move to half-hourly settlement, and the fact that no code modification process on this has begun.

165. Therefore, **our provisional finding is that the absence of a plan for moving to half-hourly settlement for domestic customers is a feature that gives rise to an AEC in the domestic retail electricity market** through the distortion of suppliers' incentives to encourage their customers to change

their consumption profile, which overall reduces the efficiency and, therefore, the competitiveness of domestic retail electricity supply.

Small supplier exemptions

166. Some government policies to deliver social and environmental objectives are delivered through energy suppliers. These policies put obligations on suppliers to carry out a range of activities such as: installing energy efficiency measures in customers' homes (Energy Company Obligation); and providing support, primarily direct energy bill reductions, to vulnerable customers (Warm Home Discount). The costs of such obligations are recovered from their customers through energy bills. The Energy Company Obligation represents the largest cost. The Six Large Energy Firms as well as three of the mid-tier suppliers currently fully comply with these initiatives but exemptions exist for smaller energy suppliers.

167. We have considered whether the exemptions regime distorts competition by: giving smaller suppliers a distortionary subsidy (as the Six Large Energy Firms have argued); and/or creating a barrier to expansion (through dulling incentives to acquire customers as the smaller suppliers near the obligation exemption thresholds).

168. Overall, our provisional view is that there is a legitimate rationale for providing some degree of exemption. Without these exemptions, the cost of delivering any scheme would fall disproportionately on small suppliers due to the fixed costs of compliance and therefore make entry into the market more difficult. We also note the benefits that entry has brought to the sector in terms of increased competition. Given the relative strength of firms above the exemptions thresholds compared with new entrants, due for instance to the existence of an established customer base and experience in dealing with regulatory requirements, we do not believe that the impact of the current exemptions is likely to be market distorting. Our provisional conclusion is, therefore, that we do not believe that the small supplier exemption causes an AEC.

Microbusinesses

169. The terms of reference for this market investigation cover the supply of energy to microbusinesses, applying Ofgem's definition of a microbusiness (based on employees, turnover and energy consumption). Some microbusinesses are much larger than domestic customers – the upper threshold of Ofgem's microbusiness volume definition for electricity is around 30 times typical domestic consumption – while others spend similar amounts to domestic customers.

170. In relation to customer engagement, we note that some microbusinesses do engage in choosing their energy contracts. We also note positive signs of a recent increase in switching between suppliers. However, we are concerned that many microbusinesses appear to show limited engagement and that they have limited interest in their ability to switch energy supplier. For example, in 2013 45% of microbusinesses were on default electricity tariffs (ie had been placed on tariff that the customer had not actively negotiated).

171. In relation to transparency, our provisional view is that there is a general lack of price transparency concerning the tariffs that are available to microbusinesses, which results from many microbusiness tariffs not being published, and a substantial proportion of microbusiness tariffs being individually negotiated between customer and supplier. In particular, the limited availability and low usage of PCWs makes it more difficult for SMEs to get a view of prices across each market. Suppliers have recently made it easier for SME customers to get quotes, although we do not know if customers are widely aware of this development.

172. TPIs have the potential to help microbusiness customers engage with retail energy markets and reach good outcomes. However, we note that a number of complaints have been made to various official bodies concerning alleged TPI malpractice, which may have reduced the level of trust in all TPIs and discouraged engagement more generally. We also note that some TPIs may not have the right incentives to give non-domestic customers the best possible deal. We are concerned that customers are not aware of this and therefore do not take steps to mitigate it (for example, by consulting more than one TPI or seeking other benchmark prices).

173. We have also found that a substantial number of microbusinesses appear to be achieving poor outcomes in their energy supply. EBIT margins were generally higher in the SME markets than other markets (8% rather than 3% in domestic markets and 2% in I&C markets) and beyond what appears to be justified by risk. We observed that average revenues are substantially higher on the default tariff types that less engaged microbusiness customers end up on, compared with acquisition or retention tariffs, which require an active choice by customers. These differences in revenues between tariffs go beyond what is justified by costs.

174. We therefore have concerns that the less engaged customers on these tariffs are not exerting sufficient competitive constraints on energy suppliers. Our concerns are particularly about the various types of default tariffs that customers can be automatically moved on to if they have not actively engaged with their energy supply (auto-rollovers and replacement contracts),

or if they are receiving energy supply in circumstances where they have not agreed a contract (deemed and out of contract tariffs).

175. Overall, our provisional finding is that **we have identified a combination of features of the markets for the retail supply of gas and electricity to SMEs in Great Britain that give rise to an AEC through an overarching feature of weak customer response from microbusinesses**, which, in turn, give suppliers a position of unilateral market power concerning their inactive microbusiness customer base which they are able to exploit through their pricing policies. These features act in combination to deter microbusiness customers from engaging in the SME retail gas and electricity markets, to impede their ability to do so effectively and successfully, and to discourage them from considering and/or selecting a new supplier that offers a lower price for effectively the same product.

Analysis of profitability and competitive price benchmarks

176. We have considered whether there is evidence that the overall average prices paid by customers of the Six Large Energy Firms have been higher over the past few years than they would have been under a well-functioning competitive market in which costs and profits are competed down to efficient levels.

Analysis of profitability and efficiency

177. We have assessed the profitability of the supply businesses of the Six Large Energy Firms by comparing the return on capital they earned on sales across all customer segments with their cost of capital. In a well-functioning competitive market we would generally expect to see returns broadly in line with the cost of capital over the long term.

178. The results of our analysis are that on a combined basis the supply businesses of the Six Large Energy Firms earned a return on capital of 28% on average across the five-year period from 2009 to 2013. We estimated that the cost of capital was around 10%. Therefore, the return on capital employed was substantially above the cost of capital over the period 2009 to 2013. Profits in excess of the cost of capital amounted to about £900 million per year, equivalent to about 2% of revenues from the sales of the Six Large Energy Firms to the domestic, SME and I&C segments over the period.

179. There was considerable variability in the returns earned by the Six Large Energy Firms:

(a) Four of the Six Large Energy Firms earned returns of 44% on average across the five-year period – substantially in excess of the cost of capital. We note that these profits are unevenly distributed between the firms.

(b) One of the Six Large Energy Firms earned average returns below the cost of capital, and one of them made losses in each of the five years.

180. There were several factors behind the observed differences in profitability between the Six Large Energy Firms, such as differences in average price levels and differences in costs (including wholesale energy costs and indirect costs). In particular, we have observed differences in unit costs between the Six Large Energy Firms – including wholesale energy costs per MWh, and indirect costs per customer – which suggest that some firms may not have operated efficiently

181. We have attempted to control for these differences in cost to estimate a competitive benchmark price level that would have allowed firms to recover efficient levels of costs and earn a fair rate of return on capital employed. The initial results of this analysis suggest that average prices offered by the Six Large Energy Firms over the period 2009 to 2013 were around 5% above the competitive level in the domestic segment, and around 14% in the SME segment. This equates to domestic customers paying around £1.2 billion and SME customers paying around £0.5 billion more on an annual basis than would have been the case had competition functioned more effectively.

182. This suggests that the results of our profitability analysis, set out above, may be an underestimate of the extent to which prices have been above competitive levels.

Analysis of average prices offered by suppliers to domestic customers

183. We have noted that there is a substantial variation in the prices paid by domestic customers, which provides evidence of significant degrees of disengagement. We also note that some of the Six Large Energy Firms have said that they can only afford to offer the cheapest non-standard tariffs if a proportion of customers revert to the more expensive SVT at the end of the tariff's term. An important further question for this investigation is therefore whether the **average** domestic prices offered by the Six Large Energy Firms are above those that would prevail in a well-functioning competitive market. In addition to the analysis set out above, we have compared the average domestic prices offered by different suppliers, notably those offered by the Six Large Energy Firms and the mid-tier suppliers. We have reviewed the evidence on average revenues earned by suppliers on their sales to domestic customers, comparing in particular revenues earned by the Six Large Energy

Firms and the mid-tier suppliers. We have noted that the average price offered by one of the mid-tier suppliers has been below that offered by the Six Large Energy Firms over the last few years. In 2014, its domestic average electricity and gas prices were 11% and 12% respectively below the average of the Six Large Energy Firms.

184. For another of the mid-tier suppliers, average gas prices have been consistently cheaper than those of the Six Large Energy Firms and in 2014, the average price for gas was 20% below the average for the Six Large Energy Firms. The same supplier's average electricity prices were above those of the Six Large Energy Firms in 2012, but below the average for the Six Large Energy Firms in 2014.

185. We note that these results may in part reflect regional differences and differences in customer mix (including the proportion of customers on direct debit as opposed to standard credit and prepayment). Using tariff data and controlling for factors such as customer payment methods and regions, we have calculated that the average prices offered by the cheapest of the Six Large Energy Firms were on average around £95 cheaper (about 8%) than the average prices of the most expensive of the Six Large Energy Firms over the period 2012 to Q2 2014.

186. While we do not yet have the data to include the mid-tier suppliers within this analysis, we note that:

(a) the cheapest tariff offered by the mid-tier suppliers was around £30–£40 cheaper than the cheapest tariff offered by the Six Large Energy Firms over the period 2012 to Q2 2014; and

(b) the evidence from our survey suggests that in Q2 2014, the customers of two of the mid-tier suppliers were paying around 8% less than the customers of the cheapest of the Six Large Energy Firms, and around 4% less controlling for both payment method and tariff type.

187. Overall, the evidence suggests that:

(a) the average domestic prices offered by the Six Large Energy Firms are above the competitive benchmark level as estimated using cost and profit benchmarks; and that

(b) there are significant disparities in the average domestic prices offered by the Six Large Energy Firms, and some evidence that two of the mid-tier suppliers offer cheaper prices than those of the Six Large Energy Firms.

188. We will look to develop this analysis further in the next phase of our investigation.

Provisional views on profitability and competitive price benchmarks

189. Overall, our provisional view is that there is a range of evidence that suggests that average prices paid by domestic customers have been above the levels we would expect to see in a well-functioning competitive market. For SMEs, the evidence suggests that average prices have been substantially above the levels we would expect to see in a well-functioning competitive market.

190. We note the challenges involved in conducting this type of analysis but gain assurance that different sources of evidence on profitability and prices give broadly consistent results. We consider that the preponderance of evidence discussed above is suggestive of weak competitive conditions in the retail energy market. It is consistent with our provisional finding that suppliers have the incentives and ability to raise prices above costs to a significant segment of their customer bases who are disengaged or only periodically engaged in retail energy markets.

Governance of the regulatory framework

191. We have considered whether aspects of the structure and governance of the regulatory framework – including the roles and responsibilities of institutions, the design of decision-making processes and the availability of appropriate information – are likely to increase the risk of policies being developed in the future that are not in consumers' interests or to inhibit the development of policies that are in their interests. We have also considered whether elements of this framework have contributed to the lack of trust in the sector that many parties have highlighted in the course of our investigation.

Framework for financial reporting

192. We have observed that there is a lack of shared understanding of the factors that have led to price increases, in particular the relative contribution of wholesale costs, network costs, policy costs and profit.

193. Trusted and transparent information on the costs incurred, and the profits earned, by energy companies may help to inform the public debate and reduce the risk of errors in policymaking, by providing clearer information about whether and where intervention is required. It may also help to improve confidence in the regulatory system on the part of policymakers and the general public, which itself may improve the stability of the regulatory regime.

194. The absence of such trusted and transparent information is a potentially material problem, undermining regulatory stability. Parliamentary committees, consumer groups, policy think tanks, Ofgem and political parties, among others, have all expressed their dissatisfaction with the status quo concerning the transparency of financial reporting. This is a particular concern given the importance of these bodies in contributing to the general perception of the industry and policy relating to it.

195. Based on our experience, we consider that the Six Large Energy Firms' current reporting systems are unable readily to provide all the market-orientated financial information that regulators and policymakers require. Our provisional view is that improvements could be made to the regulatory framework for financial reporting that would improve the robustness of information available to Ofgem, and hence overall transparency of costs, profits and profitability.

Effective communication on the impact of policies and policy trade-offs

196. Climate and energy policies have to balance the competing objectives of: reducing emissions; ensuring security of energy supply; and ensuring energy prices are affordable. We have considered whether a lack of independent scrutiny of such policies – and the policy trade-offs within them – might be one of the factors that increases the risks of inefficient policy design in the future.

197. There are several institutions already providing independent analyses of energy sector impacts. We note, however, that these analyses could be communicated more effectively to a wider audience, in particular interactions between policies and policy trade-offs within policies. Clearer communication around these issues may increase the transparency of the information already available and improve the quality of the public debate and policy decision-making.

Ofgem's duties and objectives and independence

198. We have noted that Ofgem has taken some decisions that we consider have not had the effect of promoting effective competition, including: the decision not to approve introduction of locational charging of transmission losses; the decision to prohibit regional price discrimination; and the decision to introduce the simpler choices component of the RMR reforms.

199. In relation to its duties, Ofgem stated that the competition duty had been progressively downrated relative to other duties over the last ten years. It expressed concern that, if we suggested it should change its policies towards

improving competition, our conclusions and remedies might be difficult to reconcile with the current structure of its duties.

200. We regard it as a significant cause for concern that Ofgem considers that these duties impose a constraint in practice on its ability to pursue competition-based policies (for example, through placing a priority on approaches that do not promote competition).

201. We have also considered whether: Ofgem's role overlaps excessively with DECC's role, leading to suboptimal decision-making; and whether the coincidence of DECC's and Ofgem's roles risks undermining Ofgem's independence.

202. We note that Ofgem's decisions to implement both SLC 25A and RMR were taken against a backdrop of DECC taking powers to implement changes in primary legislation (or stating its readiness to do so) in the event that Ofgem did not act. We do not know how material this context was in influencing Ofgem, but it is possible that institutional pressure from DECC was one of the factors behind one or both of these decisions. Further, the coincidence of DECC and Ofgem's actions risks creating the perception of a lack of independence on the part of Ofgem.

203. 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.

204. It would not be realistic for DECC to refrain from exercising its discretion over elements of policy and we note that it is always possible that DECC and Ofgem will disagree on a particular area of policy. However, where this is the case, we think that the absence of a mechanism through which such disagreements can be surfaced transparently, so that stakeholders can understand why a particular decision is being made, leads to a lack of transparency in regulatory decision-making. We believe that the introduction of such mechanisms – in particular allowing Ofgem to set out its views on particular DECC policy proposals and seek formal direction from DECC to pursue certain regulatory activities – may facilitate rational debate and promote regulatory stability.

205. **We have provisionally found that a combination of features of the wholesale and retail energy markets in Great Britain give rise to an AEC through an overarching feature of a lack of robustness and transparency in regulatory decision-making** which, in turn, increases the

risk of policy decisions that have an adverse impact on competition. More particularly, these features are as follows:

(a) the lack of a regulatory requirement for clear and relevant financial reporting concerning generation and retail profitability;

(b) the lack of effective communication on the forecast and actual impacts of policies over energy prices and bills;

(c) Ofgem's statutory objectives and duties which, in certain circumstances, may constrain its ability to promote effective competition; and

(d) the absence of a formal mechanism through which disagreements between DECC and Ofgem over policy decision-making and implementation can be addressed transparently.

Industry codes

206. Regulation of a number of technical and commercial aspects of the energy markets is governed by industry codes, which are managed by industry participants. We have considered whether the current system of code governance delivers timely change that is needed to support competition, innovation and wider policy objectives.

207. We have seen evidence that the existing governance and modification arrangements can lead to inconsistent or delayed outcomes, and create material burdens on parties, in particular smaller ones, which could undermine their incentives to promote changes. We believe that Ofgem has taken important steps to prevent or mitigate these risks through its Code Governance Review and other measures. However, despite Ofgem's reforms, there are still circumstances where the current model does not allow code modifications to be developed and/or implemented efficiently. This is the case in particular where a proposed change has significant and unevenly distributed impacts on market participants. We have identified a number of examples of this in our case studies.

208. Our central concern is that the limited ability of Ofgem to influence development and implementation processes might cause certain changes that are in consumers' interest not to be delivered in a timely and efficient way. Consumer detriment is likely to be particularly acute where a change is needed to achieve policy objectives or to support competition and innovation (eg Project Nexus, which facilitates the development of tariffs that rely on smart meters).

209. We have provisionally found **a combination of features of the wholesale and retail gas and electricity markets in Great Britain that are related to industry code governance and which give rise to an AEC** through limiting innovation and causing the energy markets to fail to keep pace with regulatory developments and other policy objectives. These features are as follows:

(a) parties' conflicting interests and/or limited incentives to promote and deliver policy changes; and

(b) Ofgem's insufficient ability to influence the development and implementation phases of a code modification process.

Provisional findings

210. Our provisional findings for this investigation are set out in Section 12 of this document and reproduced in our Notice of provisional findings.

Provisional findings

1. Introduction

1.1 On 26 June 2014 the Gas and Electricity Markets Authority made a reference to the CMA for an investigation into the energy market in Great Britain.[6] The terms of reference for our investigation are provided in Appendix 1.1. We are required to publish our final report by 25 December 2015.

1.2 On 24 July 2014 we published an issues statement, setting out the areas of concern on which the investigation would focus based on the terms of reference and the initial information and evidence we had received. On 18 February 2015 we published an updated issues statement and accompanying working papers, in which we summarised our thinking and highlighted those issues that would represent the focus of our investigation in the period up to our provisional findings.

1.3 This document sets out our provisional findings from our investigation.

Our statutory task

1.4 Section 134(1) of the 2002 Act requires us to decide whether 'any feature, or combination of features, of each relevant market prevents, restricts or distorts competition in connection with the supply or acquisition of any goods or services in the United Kingdom or a part of the United Kingdom'. If the CMA decides that there is such a feature or combination of features, then there is an AEC.[7]

1.5 Under section 131(2) of the 2002 Act, a 'feature' of the market refers to:

- the structure of the market concerned or any aspect of that structure;
- any conduct (whether or not in the market concerned) of one or more than one person who supplies or acquires goods or services in the market concerned; or
- any conduct relating to the market concerned of customers of any person who supplies or acquires goods or services.

1.6 If the CMA finds that there is an AEC, it is required under section 134(4) of the 2002 Act to decide whether action should be taken by it, or whether it

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[6] Energy market investigation terms of reference.
[7] Section 134(2) of the 2002 Act.

should recommend the taking of action by others, for the purpose of remedying, mitigating or preventing the AEC, or any detrimental effect on customers[8] so far as it has resulted from, or may be expected to result from, the AEC; and, if so, what action should be taken and what is to be remedied, mitigated or prevented. The 2002 Act requires the CMA 'to achieve as comprehensive a solution as is reasonable and practicable to the AEC and any detrimental effects on customers so far resulting from the AEC'. In considering remedies, the CMA may take into account any relevant consumer benefits, as defined in the 2002 Act, arising from the feature or features of the market.

1.7 In the remainder of this section, we set out *(a)* the background to the reference; *(b)* our conduct of the investigation to date; and *(c)* the structure of these provisional findings.

Background to the reference

1.8 On 26 June 2014 Ofgem referred the market for the supply and acquisition of electricity and gas to the CMA for further investigation. The reference covered supply to domestic and small business customers. Ofgem's decision was based on:

- the findings of the State of the Market report, carried out with the Office of Fair Trading and the CMA and published in March 2014;
- the persistence of problems with the market, despite a series of Ofgem investigations and reforms to the market; and
- Ofgem's consultation document and stakeholders' views on its proposed decision to refer, which were generally supportive of the reference.

1.9 The State of the Market report identified the principal market features that may have a harmful effect on competition:

- Weak customer response. Evidence that customer activity was low, and trust was low, which was preventing the process of competition from working effectively.
- Incumbency advantages. Suppliers that gained a large customer base when competition was introduced continue to charge higher prices to

[8] A detrimental effect on customers is defined in section 134(5) of the 2002 Act as one taking the form of: *(a)* higher prices, lower quality or less choice of goods or services in any market in the UK (whether or not the market to which the feature or features concerned relate); or *(b)* less innovation in relation to such goods or services.

their less active customers. This suggested that competition was not working effectively for all customers.

- Possible tacit coordination. Ofgem found no evidence of direct coordination, but suggested that there was evidence of possible tacit coordination, which can weaken competitive rivalry between companies.

- Vertical integration was prevalent. Ofgem considered that a full investigation of the balance between costs and benefits was needed, to establish whether vertical integration is best for competition.

- Barriers to entry and expansion. Barriers identified in Ofgem's report included credit and collateral requirements, low wholesale market liquidity, extensive industry regulation, and policy uncertainty.

1.10 Ofgem stated that the above key features of the market contribute to poor outcomes for consumers, including increasing retail profitability and low levels of consumer trust.

Conduct of the investigation

1.11 Over the course of the investigation to date we have received over 100 submissions from energy suppliers, generators, government bodies, consumer groups, academics and other interested parties. These submissions have been in response to the issues statement, the updated issues statement, produced as an initial submission to the investigation or produced in relation to other market issues. Non-confidential versions of these submissions have been published on our website

1.12 We have visited the premises of the Six Large Energy Firms in Scotland, England and Wales, a smaller supplier, a generator and National Grid. We have held formal hearings with the Six Large Energy Firms, DECC, Ofgem, National Grid, consumer bodies, a small energy supplier, bodies responsible for settlement in gas and electricity, PCWs, a collective switching website and several academics. Non-confidential versions of the summaries of the hearings we have held are on our website.

1.13 A significant focus of our investigation has been on gathering, cleaning and analysing data and other forms of evidence. We have collected a range of written evidence and data from the ten largest energy suppliers and a large number of other parties including DECC, Ofgem, National Grid, generators, power exchanges, brokers and traders, consumer bodies and PCWs. We also commissioned GfK NOP to conduct a survey of domestic customers of energy suppliers in Great Britain.

1.14 Throughout the investigation we have consulted with key parties on our approach to certain pieces of analysis. These include our proposed approaches to assessing profitability and the gains from switching. We also invited comments on the outline design of the customer survey and on the questionnaire to be used in the survey.

1.15 We have also allowed a limited number of approved external legal and economic advisers of the relevant parties to access confidential data and information through a disclosure room and a confidentiality ring operated in March 2015. In particular, the confidential data disclosed included the data underlying the customer survey and the data underlying our analyses included in the gains from switching and cost pass-through working papers published in February 2015.

Structure of provisional findings

1.16 This document, together with its appendices, constitutes our provisional findings. It refers, where appropriate, to material published separately on the CMA website. The report, however, is self-contained and is designed to provide all material necessary for an understanding of our provisional findings. The accompanying Notice of Possible Remedies sets out, as a basis for discussion, the possible remedies which seem appropriate for further consideration to address those features which in our provisional view give rise to an AEC.

1.17 Following consideration of responses to these provisional findings and our Notice of Possible Remedies, as well as any further evidence received, we shall publish our final report.

1.18 The remainder of these provisional findings is set out as follows:

- Section 2 provides **an overview of energy markets in Great Britain and key outcomes** experienced by consumers in the years since the privatisation and liberalisation of the gas and electricity sectors.
- Section 3 sets out our approach to **market definition**.
- Section 4 explores the **nature of competition in wholesale gas and electricity markets**.
- Section 5 provides our assessment of the impact on competition of several important aspects of **wholesale electricity market rules and regulations**.

- Section 6 assesses the costs and benefits of **vertical integration** in the electricity sector.
- Section 7 sets out our assessment of the **nature of competition in retail energy markets**.
- Section 8 provides our assessment of the **impact on retail market competition of weak customer engagement, supplier behaviour and regulatory interventions**.
- Section 9 sets out our analysis and assessment of **competition in the retail supply of energy to microbusinesses**.
- Section 10 describes our assessment of **competitive benchmark prices and profitability in the retail supply of energy** to domestic customers and microbusinesses.
- Section 11 considers the impact of the **broader regulatory framework**, **including the current system of code governance**, on energy market competition and consumers.
- Section 12 presents our **provisional findings** in relation to the statutory questions that we are required to answer.

2. Overview of GB energy markets and outcomes

2.1 This section provides an overview of energy markets in Great Britain and key outcomes experienced by consumers in the years since the privatisation and liberalisation of the gas and electricity sectors. The focus throughout this section is on sector-wide outcomes. Analysis by individual firm and by region is provided in subsequent sections.

2.2 The purpose of the section is to provide context for the assessment of competition in GB energy markets in subsequent sections, both by providing background information that is necessary to understand the analysis that follows and by setting out some of the key outcomes and concerns that will frame our analysis of competition problems.

2.3 The section is structured as follows:

- We provide a **high level overview of gas and electricity market structures and participants**.
- We summarise **the regulatory and policy framework** that governs energy market competition.
- We provide a summary of **physical flows** within the energy sector, identifying some of the key changes that have taken place in the supply and demand of electricity and gas.
- We analyse the recent evolution of **costs, prices and profits**, which provide important background for our consideration of potential competition problems.
- We summarise available data on the **quality of service** offered by energy retailers.
- We identify potential **future changes** in policy and outcomes that will be relevant for our analysis.
- Finally, we **conclude** and set out implications of this section for the broader investigation.

Market structure and participants

2.4 This section provides a basic introduction to gas and electricity market structures. It considers first the physical supply chain that delivers energy to customers and then the financial flows and market arrangements that support competition in energy markets. Finally, a summary is provided of the key operators and market participants and the role of DECC and Ofgem.

Physical supply chain in gas and electricity

2.5 At a high level, there are some strong similarities between the supply chains for gas and electricity:

- In the electricity sector, different types of generation technology (for example, coal, gas, nuclear or renewable) generate electricity, which is transported to consumers via high-voltage transmission lines and low-voltage distribution lines.

- In the gas sector, different sources of gas (eg from offshore fields in the North Sea, imports via interconnectors to other countries or imports in the form of Liquefied Natural Gas (LNG)) are transported to consumers via high pressure transmission pipes and low pressure distribution pipes.

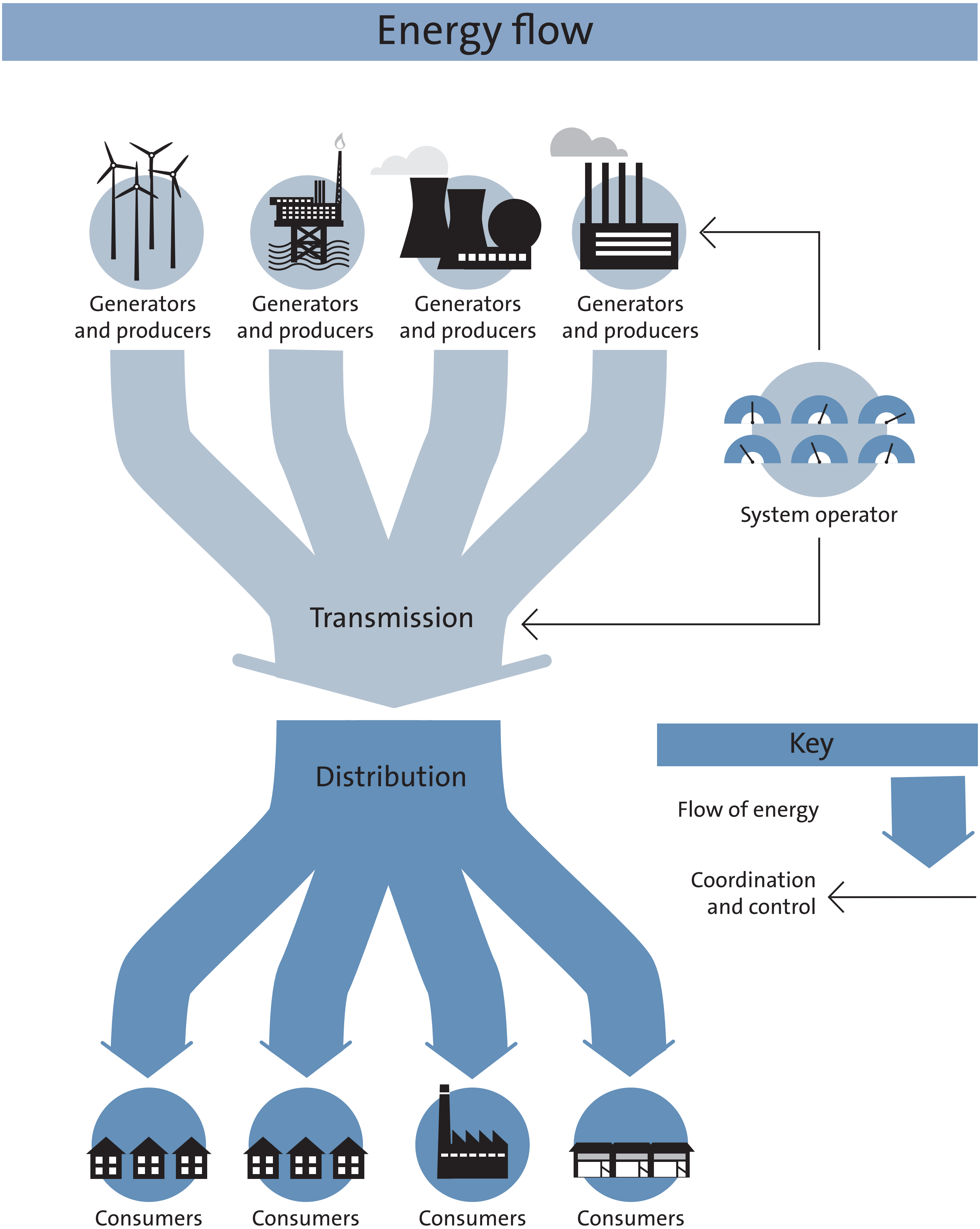
2.6 This is shown in Figure 2.1 below, which shows, at a high level, the basic flow of energy to consumers in both the gas and electricity sectors.

2.7 In electricity, different types of **generating plant** have very different cost and operating characteristics. Nuclear and many renewables have near-zero short-run marginal costs, while oil-fired plants have high short-run marginal costs, for example. Coal- and gas-fired plant costs lie between these two extremes, with their relative positions depending on the prices of the input fuels, which are themselves variable. In addition, wind generators only generate when the wind is blowing. These differences lead to wide variations in the short-run marginal cost of electricity over the day.

2.8 In relation to **gas production**, in recent years the highest-cost gas has typically come via the interconnectors with mainland Europe and from LNG. Baseload gas typically comes from the North Sea and Norway. Section 3 provides more detail on the differing cost characteristics of generation and gas production.

2.9 In both gas and electricity, **transmission and distribution** are natural monopolies: it is cheaper to have producers and customers connected via a single network rather than multiple networks.

Figure 2.1: Physical supply chain in gas and electricity



2.10 In both sectors, there is an important role for the **system operator (SO)**, whose fundamental function is to ensure that demand for energy can be satisfied at any point in time. This is a particularly important and difficult task in electricity, on account of a fundamental characteristic that distinguishes it from gas: electricity is very costly to store. The SO therefore has to ensure that electricity generation has to match demand second by second. If there is insufficient generation to meet demand at any point in time, this may result in voltage reductions or even blackouts, which impose considerable costs on consumers. Gas, in contrast, can be stored. Gas is injected into storage during periods of low demand and withdrawn from storage during periods of peak demand. The role of the SO in gas is to make sure that gas supply matches gas demand on a daily basis.

2.11 **Energy consumption** can vary significantly by season. Gas consumption is much higher in winter than in summer, driven primarily by domestic heating needs. The pattern is similar for electricity, but not as pronounced (partly because a smaller proportion of electricity is used for heating). Both electricity and gas consumption can vary considerably within a single day.

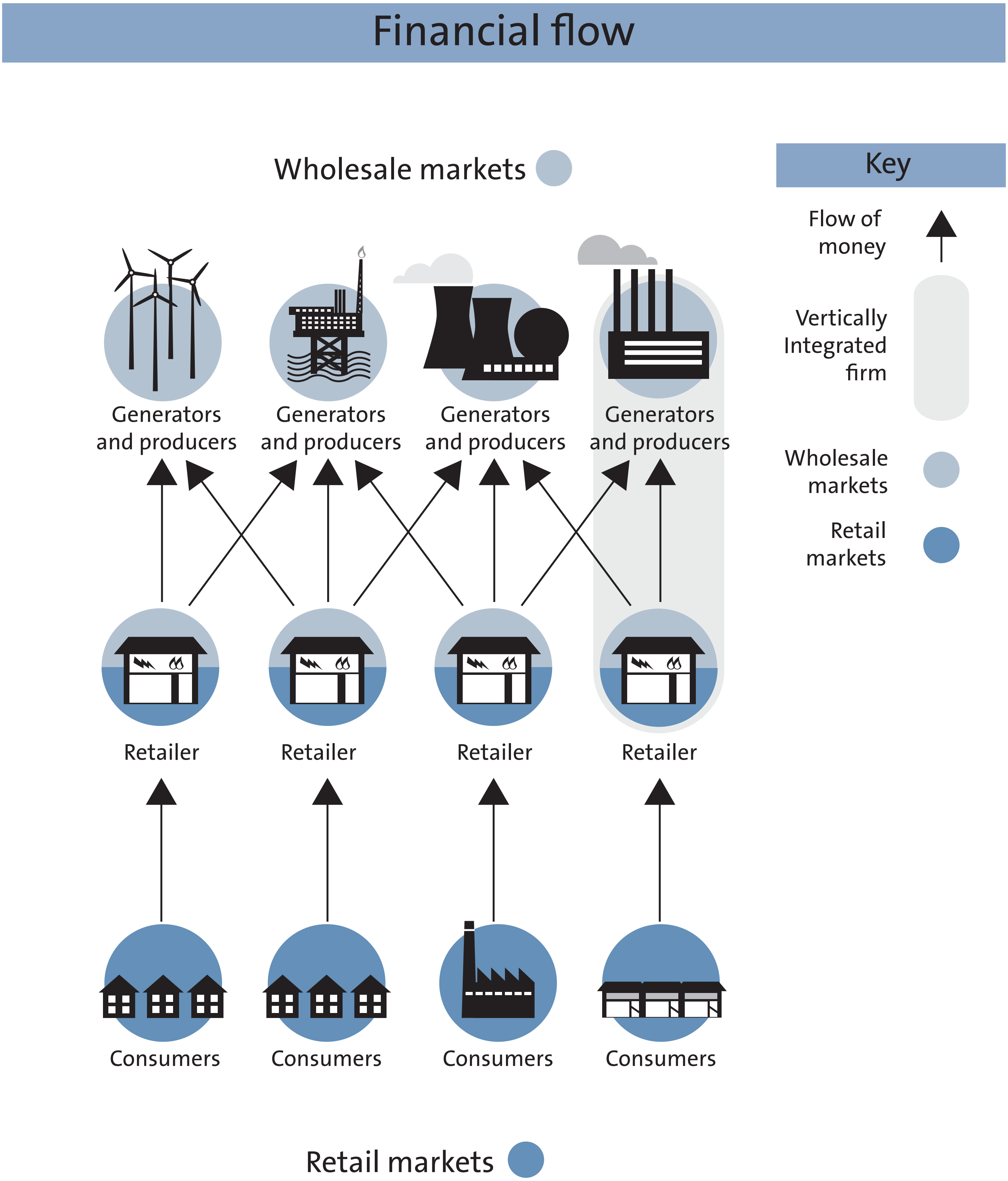
2.12 It is worth noting that retailers do not appear in the above diagram, as they have no role in the physical delivery of gas and electricity to final consumers. Their role is focused exclusively on commercial and financial transactions, as set out in the next section.

Financial flows and market arrangements

2.13 The financial flows and market arrangements that underpin competition in gas and electricity are shown in the chart below. In the electricity sector, generators compete to sell to retailers in wholesale markets, and retailers compete to sell to final customers in retail markets. Similarly, in the gas sector, gas producers and importers compete to sell to retailers in wholesale markets and retailers compete to sell to final customers in retail markets.[9]

[9] As explained later in this section, the gas licensing regime specifies two separate activities that we describe here as 'retail': shipping, which involves buying gas from the producers and selling it to gas suppliers; and supply, which means selling to final customers. In practice, both 'shipping' and 'supply' functions are often carried out within the same company.

Figure 2.2: Financial flows and market arrangements



2.14 Gas and electricity **wholesale markets** share several common features: trading can take place bilaterally or on exchanges, and contracts can be struck over multiple timescales ranging from several years ahead to on-the-day trading markets. Further, in both gas and electricity, there are important interactions between market design and the need to physically balance the system. One of the most important differences between the two is that, because of the ability to store gas, it is financially settled and balanced on a daily basis. Electricity, in contrast, is financially settled on a half-hourly basis.

2.15 The nature of competition in wholesale markets – and the market rules and regulatory framework that underpin them – is analysed in Section 4 of this report.

2.16 As the chart shows, some companies are **vertically integrated**, in the sense of owning both generation and retail businesses in the case of electricity (or both production and retail businesses in the case of gas). One implication of this is that, in addition to engaging with wholesale markets, such firms may engage in internal trading. Vertical integration, and its potential implications for competition, is discussed in Section 5 of this report.

2.17 **Retail markets** provide the strongest point of commonality between gas and electricity, since the products are often sold together by retailers through a bundled tariff called a 'dual fuel' tariff. Moreover, the regulatory regime applying to retail functions generally applies equally to gas and electricity.

2.18 As noted above, retailers have no involvement in the physical delivery of gas and electricity to consumers. Their role is a purely financial and commercial one – they are responsible for procuring energy in wholesale markets, selling it to customers through a variety of tariffs and carrying out metering and billing functions.

2.19 Traditional gas and electricity meters used in households do not record when energy is used and are only read infrequently. This has had an important influence on the form retail competition takes for gas and electricity. First, there has therefore been no practical way to give households and other small-scale users any reason to adjust their use of gas or electricity in response to short-term price changes. The result is that, unlike the vast majority of markets, spikes in wholesale prices cannot provoke a demand response in residential and other small-scale demand. This can be costly both to suppliers and customers – in extreme cases, where demand exceeds available supply, the SO may have to cut whole areas of customers off from the network.

2.20 Second, as a result of the infrequency of meter reads, customer bills are typically based on estimates rather than actual consumption, which leads to difficulties in understanding the bill, as discussed in Section 8. Further, a complicated system of 'settlement' has had to be created for gas and electricity, in which disparities between the volumes of energy covered by suppliers' contracts and the volumes they actually use are identified and paid for – in many cases a long time after the energy has been consumed.[10]

2.21 The nature of retail competition is discussed in more detail in Sections 7 and 8 of this report.

Current market participants

2.22 This section identifies some of the key participants in GB gas and energy markets.[11]

Firms operating in wholesale and retail markets

2.23 The **Six Large Energy Firms** are Centrica, EDF Energy, E.ON, RWE, SSE and Scottish Power. These firms are the former monopoly providers of gas (Centrica) and electricity (EDF Energy, E.ON, RWE, SSE and Scottish Power) to GB customers.[12]

2.24 Together, the Six Large Energy Firms currently supply energy to around 90% of the domestic customers in Great Britain and generate over 70% of total electricity generation in Great Britain. They are all vertically integrated in respect of electricity (ie they are all active in both generation and retail) and Centrica is vertically integrated in respect of gas (ie it is active in both generation and upstream production). Both SSE and Scottish Power also have interests in electricity transmission and gas and electricity distribution.

2.25 In relation to upstream gas production, of the Six Large Energy Firms, only Centrica is a major player, with around 10% of GB production in 2012/13. Statoil, the Norwegian state-owned producer is larger with 17% of production. Other gas producers on which the GB market depends include

[10] We note that with the introduction of smart meters, some of these characteristics might change, as discussed in Sections 7 and 8.
[11] A more detailed description of the companies operating in the GB gas and electricity sectors is provided in Appendix 2.2: Industry Background.
[12] In the gas market, British Gas (now part of Centrica) was privatised as a vertically integrated company with a monopoly on supply to gas customers before domestic competition was introduced. When electricity was privatised, 14 regional electricity companies were created, each with monopoly supply in their regions. Over time, the number of these original monopoly suppliers fell to six through horizontal mergers.

ExxonMobil, Total, Shell, BP, GDF and Gazprom with market shares ranging from 9 to 3%.

2.26 The **mid-tier electricity generators** in Great Britain are the largest electricity generators outside of the Six Large Energy Firms. They are: Drax; GDF Suez; Intergen; and ESB International. Drax is also active in business retail through its interest in Haven Power, while GDF Suez is also active in oil and gas exploration and production; LNG; gas storage; and business retail.

2.27 In relation to retail, as of 31 July 2014 there were 19 suppliers selling both electricity and gas to households.[13] The largest suppliers outside of the Six Large Energy Firms are: Utility Warehouse, Co-operative Energy, First Utility, Ovo Energy (which we collectively call the '**mid-tier suppliers**' elsewhere in this report).

2.28 There is a larger number of active suppliers in the non-domestic retail energy markets than in the domestic retail energy markets. In the microbusinesses segment of the small and medium-sized enterprise (SME) retail energy markets specifically, the largest electricity suppliers outside of the Six Large Energy Firms are Haven Power and Opus Energy. In gas, the other largest suppliers are Corona, Gazprom, Opus Energy and Total Gas and Power.

Providers of natural monopoly services

2.29 **National Grid** performs the functions of system operation for both gas and electricity. In addition, it owns and maintains the onshore gas transmission network in Great Britain, and the high-voltage electricity transmission network in England and Wales. Scottish Power is the transmission owner for the South of Scotland, while SSE is the transmission owner for the North of Scotland.

2.30 In relation to electricity distribution, there are 14 licensed distribution network operators in Britain, which are owned by six different groups: Electricity North West Limited; Northern Powergrid; SSE; ScottishPower Energy Networks; UK Power Networks; and Western Power Distribution. There are eight gas distribution networks, owned by four companies: National Grid Gas; Northern Gas Networks Limited; Wales & West Utilities Limited; and Scotia Gas Networks Limited.

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[13] Source: Cornwall Energy (October 2014), *Competition in British household energy supply markets: An independent assessment*.

Institutions with policy and regulatory functions

2.31 The **Department for Energy and Climate Change** (DECC) is responsible for supporting the Secretary of State in developing policy and legislative proposals in relation to the energy sector in Great Britain, while the European Commission performs an analogous function at the EU level.

2.32 **Ofgem** is the economic regulator for the gas and electricity sectors in Great Britain, which broadly involves price regulation of those segments of gas and electricity that are natural monopolies – namely, transmission and distribution – and developing rules and regulations that shape the nature of competition in wholesale and retail markets.

2.33 The roles of DECC and Ofgem are explained in greater detail in the discussion of the regulatory and policy framework which follows.

Regulatory and policy framework

2.34 The regulatory and policy framework governing the energy sector in Great Britain profoundly affects the shape and nature of energy market competition. It is set out in:

- EU and UK legislation;
- licences, which Ofgem grants to suitably qualified operators for the purposes of engaging in specified activities relating to gas and electricity supply; and
- industry codes, which are detailed multilateral agreements that define the terms under which industry participants can access the electricity and gas networks, and the rules for operating in the relevant markets.

2.35 In the following paragraphs, we set out some of the key features of this framework.[14] We focus first on those elements of the regulatory framework that determine the basic parameters of competition in GB energy markets, including the legislation that has led to the progressive liberalisation of the sector, the role and objectives of Ofgem and the coverage of licences and industry codes.

[14] This section draws on Appendix 2.1: Regulatory and legal framework, which provides a more detailed description of the regulatory provisions governing competition in electricity and gas and provides specific references to sections of the relevant legislation referred to.

2.36 We then summarise key policies and regulations that have been introduced to meet three overarching policy objectives for the energy sector:

- reducing emissions from the energy sector;
- ensuring security of energy supply; and
- ensuring energy prices are affordable.

2.37 These three policy objectives are sometimes characterised as the 'energy trilemma', since policies put in place to meet one of the objectives can have the effect of undermining achievement against the other objectives. For example, policies to support low carbon generation often have the effect of increasing costs and hence energy prices. Policy and regulatory design, whether at an EU or UK level, has therefore often involved a trade-off between these objectives.

Liberalisation and the current regulatory framework

2.38 This section provides a brief history of energy market liberalisation, before summarising the key elements of the current regulatory framework governing gas and electricity markets operation (for more details see Appendix 2.1: Legal and regulatory framework).

A brief history of liberalisation

2.39 Great Britain has been at the forefront of many of the developments aimed at liberalisation that have subsequently been introduced at EU level. It first privatised *(a)* the gas markets, through the Gas Act 1986 (GA86), and *(b)* the electricity markets, through the Electricity Act 1989 (EA89).[15]

2.40 Over subsequent years, the sector was liberalised and evolved such that the natural monopoly networks (transmission and distribution) were separated from the competitive or contestable markets at wholesale/generation and retail levels, and initial price caps were ultimately removed as competition developed. The GA86 and EA89 remain the principal domestic legislative instruments governing both the activities of companies engaged in the supply or acquisition of gas and electricity in Great Britain today and the oversight of the sector by Ofgem and DECC.

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[15] Between 1996 and 1998 the first energy liberalisation package was introduced by the EU, consisting of Directive 96/92/EC (the Electricity Directive) and Directive 98/30/EC (the Gas Directive) setting out common rules for the internal market in electricity and natural gas, in particular, as regards (a) member states' decision-making on building new electricity generation capacity; (b) access to, and initial unbundling steps regarding, transmission and distribution systems for electricity and gas; and (c) the supply and storage of natural gas.

- *Liberalisation of the gas markets*

2.41 Liberalisation of the energy sector in Great Britain began in 1986 with the privatisation of British Gas through powers contained in the GA86, which also laid the foundations for the economic regulation of the markets and established a licensing regime for gas transportation, shipping and supply activities.

2.42 After privatisation British Gas was responsible for the operation of the gas transmission system and had a monopoly on the retail supply of gas. British Gas fully demerged in 1997, creating entirely separate businesses which included a business handling transmission (Transco) on the one hand and a business handling trading and supply (Centrica) on the other. Transco later became National Grid Gas plc (NGG), a subsidiary of National Grid plc (National Grid).

2.43 Competition in gas supply to customers was introduced in stages over a period of 14 years, starting with supply to large industrial customers. Competition was extended in 1992 to a wider proportion of the industrial and business sector, and ultimately to all domestic consumers in November 2000.

- *Liberalisation of the electricity markets*

2.44 The EA89 paved the way for the privatisation and subsequent liberalisation of the electricity markets, by establishing a licensing regime for electricity generation, transmission, interconnection, and distribution and supply activities.

2.45 The separate licensing of generation and transmission activities heralded the end of the integrated Central Electricity Generating Board which had previously conducted all generation and transmission business across England and Wales. National Grid Company plc (now National Grid Electricity Transmission plc (NGET), a subsidiary of National Grid)[16] was awarded a single national transmission licence for England and Wales, and was also responsible for running the 'Pool', a mechanism for setting a single wholesale price for electricity, and for balancing generated capacity and electricity demand.[17] Three generation licences were initially awarded to

[16] Jointly owned by the regional electricity companies that existed following the introduction of the EA89. The regional electricity companies sold their stakes in National Grid in the mid-90s, shortly after it was listed on the London Stock Exchange.
[17] The Pool operated as a day-ahead market. Generators would bid to supply National Grid for each settlement period a day in advance, with the last unit needed to meet demand fixing the market-clearing price. It was compulsory for licensed generators to sell the majority of their generated electricity output into the Pool and for licensed suppliers to purchase all their electricity from the Pool to meet the demand of their customers. Licensed

National Power (now RWE), PowerGen (now E.ON) and Nuclear Electric (now EDF Energy).

2.46 In Scotland, by contrast, a dual region, fully vertically integrated model was retained (consisting of the North of Scotland Hydro-Electric Board (now SSE) and the South of Scotland Electricity Board (now Scottish Power)), with Scottish Nuclear (principally, now EDF Energy) providing additional generation capacity.

2.47 In relation to supply and distribution, the existing regional monopolies of the 14 area boards were initially maintained by virtue of public electricity supply licences being granted to regional electricity companies, with provision for gradual introduction of supply competition, initially for large customers (with peak demand in excess of 1 MW). Licences were granted to independent suppliers and also to the regional incumbents for supply outside of their incumbent area. Competition to supply electricity was further opened up in 1994 (when supply was generally permitted to customers with peak demand in excess of 100 kW) and again in 1998/99 when the remainder of the market was opened up to competition.

2.48 In both gas and electricity, price caps were imposed to protect consumers in the initial period after liberalisation. The move to full competition in domestic retail supply (for both gas and electricity) occurred with the removal of price caps by Ofgem in 2002.

- *Further liberalisation and reform post 2000*

2.49 Further changes were made to the regulatory regimes for both electricity and gas by the Utilities Act 2000. For example, the Utilities Act 2000 mandated separate licences for electricity distribution and supply activities. The regulation of operators in the electricity markets was also brought into line with the regulation of operators in the gas markets, for example making the regulator responsible for issuing electricity licences (rather than the Secretary of State).

2.50 The Utilities Act 2000 also abolished the Pool and replaced it (in 2001) with the New Electricity Trading Arrangements (NETA) in England and Wales, a set of market arrangements based around bilateral contracting and a mandatory imbalance settlement process. NETA was extended to Scotland in 2005 under the British Electricity Trading and Transmission Arrangements (BETTA), which introduced a single wholesale electricity market for Great

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generators and suppliers were obliged to become party to the Pooling and Settlement Agreement under their respective licences, alongside National Grid.

Britain under a single licensed transmission system operator, NGET. Sections 4 and 5 provide a detailed analysis of the current wholesale electricity market rules, which are still based on the basic principles established under NETA.

2.51 In addition, the Utilities Act 2000 combined the formerly separate regulatory bodies, Ofgas and Offer, to create Ofgem, whose objectives and duties are described in the following section.

2.52 The decade also saw major liberalisation initiatives implemented by the EU. In 2003, the second energy liberalisation package introduced a range of measures including: *(a)* greater consumer protection; *(b)* a requirement that transmission system operators (TSOs) be separate from operators of other energy activities; *(c)* mandated access to transmission and distribution systems based on published, cost-reflective, objective and non-discriminatory tariffs; and *(d)* designated national regulators responsible for ensuring non-discrimination and effective competition.

2.53 The Directives of the third energy liberalisation package in 2009 included: *(a)* a three-week limit on switching supplier; *(b)* increased autonomy and decision-making powers for national regulatory authorities, including a greater number of duties; *(c)* full unbundling of TSOs; and *(d)* an increased emphasis on emissions reduction and security of supply.

Ofgem and the current regulatory framework

2.54 Ofgem is responsible for the economic regulation of the gas and electricity sectors. In broad terms, this involves price regulation of those segments of gas and electricity that are natural monopolies – namely, transmission and distribution – and developing rules and regulations that shape the nature of competition in wholesale and retail markets.

2.55 Ofgem has concurrent powers with the CMA under the Competition Act 1998. These enable Ofgem to deal with anti-competitive behaviour such as agreements that prevent, restrict or distort competition, and the abuse of dominant position. Ofgem also has powers under the 2002 Act to conduct market studies or to make a market investigation reference to the CMA. In relation to consumer protection, Ofgem may apply to the court for an order to stop breaches of certain consumer legislation.[18]

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[18] Including the Unfair Terms in Consumer Contracts Regulations 1999 and the Business Protection from Misleading Marketing Regulations 2008.

2.56 Ofgem exercises its functions through granting licences and determining the content of Standard Licence Conditions (SLCs), which themselves require compliance with detailed industry codes, which set out the rules for operating in the relevant markets.

- *Ofgem's objectives*

2.57 Ofgem's principal objective, as set out in the GA86 and EA89, is to protect the interests of existing and future consumers in relation to gas and electricity supply. The interests of consumers are taken as a whole, including their interests in the reduction of greenhouse gasses and in the security of supply.[19]

2.58 Ofgem must carry out its functions in the manner which is best calculated to further this principal objective, wherever appropriate, by promoting effective competition. In doing so, it must consider to what extent the interests of existing and future consumers would be protected by competition and whether there is any other manner (whether or not it would promote competition) in which Ofgem could better protect those interests.[20]

2.59 When carrying out its functions, Ofgem must also have regard to a number of considerations, including the need to:

- secure that, so far as it is economical to meet them, all reasonable demands in Great Britain for gas conveyed through pipes and for electricity are met;
- secure that licence holders are able to finance the activities which are the subject of obligations on them;
- contribute to the achievement of sustainable development;
- promote efficiency and economy by licensees and efficient use of the gas and electricity distribution and transmission systems;
- protect the public; and
- secure a viable and diverse long-term energy supply.

[19] Ofgem must also ensure the fulfilment of the objectives set out in the EU Directives concerning gas and electricity when carrying out its functions as the designated regulatory authority for Great Britain.
[20] In Section 11, we consider whether Ofgem's duties and objectives impose a constraint on its ability in practice to promote competition.

- *Licences*

2.60 Under the GA86 and EA89, certain activities concerning gas and electricity can only be carried out with a licence, which are the primary means by which Ofgem regulates, and enforces obligations placed on, the relevant operators in the gas and electricity sectors.

2.61 In relation to electricity, separate licences are required to engage in: Generation; Transmission; the operation of an Interconnector (ie a transmission line between member states); Distribution; and Supply (which allows the licensee to sell electricity, either to domestic and non-domestic premises, or to non-domestic premises only).

2.62 In relation to gas, separate licences are required to engage in: Transporting (covering the operation of both high and low pressure networks); the operation of an Interconnector; Shipping (for procuring gas and paying for transportation); and Supply (which allows the licensee to sell gas to final customers).

2.63 All licensees for a particular activity are governed by SLCs for that activity, as determined by Ofgem and/or the Secretary of State. In Sections 7 and 8, we consider two recent changes to SLCs that have had a significant effect on the nature of retail competition. The first concerns a range of prohibitions on price discrimination, introduced following the Energy Supply Probe in 2008/09. The second relates to SLCs introduced in 2013 following the Retail Market Review (RMR), which, among others things, limited the number of tariffs that suppliers can offer domestic customers and introduced other changes that aimed to improve engagement in the domestic and SME retail energy markets.

2.64 Under the GA86 and EA89, 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 turnover of the licensee. Ofgem also has powers to impose enforcement orders and, since 2014, consumer redress orders.

- *Codes*

2.65 Industry codes define the terms under which the industry participants can access the electricity and gas networks, and the rules for operating in the relevant markets. Licensees are required to comply with specified industry codes in accordance with the terms and conditions of their licences.

2.66 The main industry codes in electricity include: the Balancing and Settlement Code (BSC), which contains the rules and governance arrangements for the balancing mechanism (BM) and settlement; the Connection and Use of System Code (CUSC), which sets out the rights and obligations (including charging methodologies) concerning access to the transmission network; and the Distribution and Connection Use of System Agreement (DCUSA), which performs a similar function in relation to access to the distribution network.

2.67 In relation to gas, the principal industry code is the Uniform Network Code (UNC), which forms the basis of the commercial and operational arrangements between transporters, shippers and all other network users, including storage operators.

2.68 Codes are an important form of industry self-governance within the energy sector and are analysed in some detail in Section 11, which assesses in particular whether they have the potential to inhibit pro-competitive innovation and change.

Reducing greenhouse gas emissions

2.69 Increasing awareness of the need to tackle global climate change over the past 20 years has led to major policy changes in the energy sector, which accounts for a significant proportion of UK greenhouse gas emissions.[21] This section summarises the key climate change targets set out in UK and EU legislation and the main policies that have been put in place to meet them.[22] As will be seen, these policies relate almost exclusively to emissions from electricity rather than gas.

Objectives and targets

2.70 The Climate Change Act 2008 (CCA08) has committed the UK to reducing emissions by at least 80% in 2050 from 1990 levels. The Act also requires the UK government to set legally binding ‘carbon budgets’, to ensure that the UK remains on track to meet this long term objective.

2.71 A carbon budget is a cap on the amount of greenhouse gases emitted in the UK over a five-year period (starting with the period from 2008 to 2012). The first four carbon budgets have been put into legislation and run up to 2027. Under the current (second) carbon budget, which runs from 2013 to 2017,

[21] In 2013, emissions from electricity generators and residential emissions (largely, consumption of gas) combined constituted roughly 40% of total UK emissions. Source: DECC, 2013 Greenhouse Gas Emissions, Final Figures.
[22] These targets and policies are described in more detail in Appendix 2.1: Legal and regulatory framework.

emissions must not exceed a level that equates to a 29% reduction on 1990 levels.

2.72 The UK is also subject to targets set at an EU level. The European Council agreed in 2007 on a series of climate and energy targets for 2020, which have been implemented through various EU directives collectively known as the ‘2020 Climate and Energy Package’. These targets were to:

(a) reduce by 20% greenhouse gas emissions from 1990 levels (for the UK, a reduction of approximately 35% on 1990 levels);

(b) increase to 20% the share of renewable energy consumed in the EU (for the UK a 15% share); and

(c) make a 20% improvement in energy efficiency.[23]

2.73 In October 2014, the European Council endorsed the following binding targets to be achieved by 2030: reduce EU greenhouse gas emissions by at least 40% from 1990 levels; and increase to at least 27% the share of renewable energy consumed in the EU.

2.74 The UK targets for emissions reductions set by EU and UK legislation in the period up to 2020 are largely consistent with each other. Cost estimates conducted at the time suggest that the renewables target for 2020 is more constraining for the UK than the emissions reductions targets.[24]

Policies that put a price on greenhouse gas emissions

2.75 Several policies have been put in place in order to put a price on greenhouse gas emissions, including both trading schemes and taxes. In principle, by exposing producers and consumers to the social and environmental costs of climate change, such approaches provide an efficient means of reducing emissions, by ensuring that they are reduced where it is cheapest to do so.

2.76 This section reviews the key policies that currently put a price on emissions, foremost among them the EU Emissions Trading System (EU ETS). Again, we note that these policies are focused almost exclusively on electricity rather than gas.

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[23] This target was not included in the 2020 Climate and Energy Package but in Directive 2012/27/EU of 25 October 2012 on energy efficiency.
[24] See, for example, DECC 2009 Low Carbon Transition Plan Analytical Annex.

- *EU Emissions Trading System*

2.77 The EU ETS is a cap-and-trade scheme for direct emissions from energy-intensive facilities, introduced in 2005. The scheme sets a cap on total emissions of certain greenhouse gases from participating organisations. European Union Allowances (EUAs) are created, one for each tonne of CO2 (or its equivalent, CO2e, for other greenhouse gases) and are allocated to participants via auctions or (for certain types of installation) for free. Participants must surrender one allowance for each tonne of CO2e they emit. The scheme allows companies to trade emission allowances and thereby determine how and where emissions are reduced.

2.78 The EU ETS covers emissions from power stations, industrial plants, aviation and other energy-intensive sectors. In the UK, the EU ETS covered about 40% of total UK emissions in 2012. In the current phase of the scheme, the cap will be reduced across the EU by 1.74% each year from 2013 to 2020, resulting in an overall reduction of 21% on 2005 levels by 2020.

2.79 The EU ETS has been successful in delivering projected emissions reductions, and will account for over 50% of the emissions reductions needed to meet UK targets between 2013 and 2020.[25] However, due to a number of factors including the impact of the recession, the cap has not been as stringent as originally anticipated, resulting in a dramatic fall in the EUA price from around €35 in July 2008 to around €7.50 at the start of 2014.[26]

2.80 The low EUA price in recent years – and the failure to secure agreement for a more stringent cap – is one of the reasons the UK government has developed alternative policies that seek to provide incentives to invest in low carbon generation, as outlined in the following sections. We observe, however, that, while the ETS cap is still in place and binding, such policies will not reduce aggregate EU or global emissions, but serve to depress the EUA price.

2.81 We also note that the original design of the EU ETS, which allocated the majority of allowances to the power sector for free, is likely to have resulted

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[25] Source: Policy paper: *2010 to 2015 government policy: greenhouse gas emissions*, Appendix 2: EU Emissions Trading System (EU ETS).
[26] See, for example, Causes of the EU ETS price drop: Recession, CDM, renewable policies or a bit of everything?—New evidence, Energy Policy 73 (2014), 676–685.

in substantial windfall transfers to the UK generators.[27] As of 2013 the sector is required to purchase all its allowances.

- *Climate change levy and the carbon price floor*

2.82 The climate change levy (CCL) is a tax, introduced in 2001, levied on the supply of electricity, gas, liquefied petroleum gas (LPG) and solid fuels supplied to businesses. Rates vary across energy types but do not reflect differences in fuel carbon content.[28]

2.83 In order to address concerns that the EUA price was too unstable to support investment in low carbon generation, the carbon price floor (CPF) mechanism was introduced in 2013. This involves setting a tax (the Carbon Price Support Rate, CPSR) on fuels used for electricity generation, at a rate such that the expected combined carbon price of the CPS and EUA is no lower than a trajectory announced in 2011 (£16/tCO_2 in 2013 rising to £30 in 2020). The CPSR is set two years in advance.

2.84 In the Finance Act 2014 the CPSR was capped at £18/t CO_2 due to concerns that the size of the CPSR (given the prevailing low EUA price) would have unduly increased electricity prices in the UK relative to the rest of the EU.

Policies that provide support to low carbon generation and heat

2.85 To comply with its targets for emissions reductions and renewables deployment, the UK government has progressively increased support for renewable and low carbon generation.

2.86 A major recent development has been the introduction of Contracts for Difference (CfDs) in 2014 as a mechanism for supporting low carbon generation. Under the CfD regime, generators of low carbon electricity agree long-term contracts to supply energy at a 'strike price'. If the wholesale market price is below this, the generator receives the difference from the contract counterparty. If the market price is higher the generator pays the difference to the counterparty.

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[27] See, for example, research reported in *Assessing the effectiveness of the EU Emissions Trading System* (Centre for Climate Change Economics and Policy and Grantham Research Institute on Climate Change and the Environment, January 2013).

[28] Climate Change Agreements (CCAs) provide a discount on the rates of CCL (currently 90% for electricity and 65% for other fuels) to certain energy-intensive industries in exchange for agreements to undertake actions to reduce carbon emissions.

2.87 CfDs will become an increasingly important driver of both investment decisions and costs faced by consumers. Given their importance, the design of CfDs, including the method used for allocating them, is analysed in some detail in Sections 4 and 5, and they are not discussed further in this section, which focuses on the policy they replace – the Renewables Obligation (RO) – and schemes for supporting small-scale electricity and heat generation.

- *Renewables Obligation*

2.88 Launched in 2002, the RO requires energy suppliers to source an increasing proportion of electricity from renewable sources by purchasing Renewable Obligation Certificates (ROCs) from accredited renewable generators. Suppliers who hold insufficient ROCs must buy out their remaining requirement. The costs of ROCs are passed through to electricity consumers. With the introduction of CfDs, the RO will close for new generators in 2017 (although support will still be paid under the scheme until 2037).

- *Small-scale Feed-in Tariffs*

2.89 Feed-in Tariffs (FITs) are payments made to households and businesses that install small-scale renewable generation technologies (up to 5 MWh). First introduced in 2010, the payments vary by technology and date of installation. Additional payments may be made for energy exported to the grid. The costs of FITs are passed through to consumers.

- *Renewable Heat Incentive*

2.90 The Renewable Heat Incentive (RHI) provides payments to businesses and households that have installed renewable heat technologies such as heat pumps. Unlike the policies to support low carbon and renewable electricity, the RHI is funded by general taxation and hence does not add to the price of energy.

Policies that aim to improve energy efficiency

2.91 Policies to improve energy efficiency are unusual in that they can simultaneously help to meet emissions reductions targets, address security of supply concerns and reduce customer bills. Further, they are one of the few climate policies that directly affect gas. In this section, we focus on the Energy Company Obligation (ECO) and smart meters, although we note there are many other policies that have a bearing on energy efficiency, including policies relating the efficiency of energy-using products and buildings regulations.

- *Energy Company Obligation*

2.92 The ECO is an energy efficiency programme delivered through energy suppliers. It was introduced in 2013, replacing two previous schemes, The Carbon Emissions Reduction Target and the Community Energy Saving Programme.

2.93 ECO requires large energy companies to support domestic energy efficiency through measures such as improved insulation. There is an exemption for suppliers that serve fewer than 250,000 domestic customers and in Section 8 we consider the potential competition implications of this exemption.[29]

- *Smart meters*

2.94 Suppliers are required to roll out smart meters to all domestic customers by 2020. Smart meters record information on energy use which is transmitted directly to energy suppliers without the need for visits to read meters. Real-time information on energy usage is provided to consumers through in-home display units.

2.95 The expectation is that smart meters will help energy users to reduce wasteful consumption and hence bills. They will also have benefits in terms of leading to more accurate billing and reducing certain elements of supplier costs. Further benefits, such as load shifting leading to a reduction in peak demand, are likely to be dependent on changes in the regulatory regime, which we consider in Section 8.

Security of supply

2.96 Ensuring adequate security of supply has long been a fundamental policy objective for the gas and electricity sectors, reflecting the considerable costs consumers face if their demand for energy cannot be met. Since liberalisation, market rules in both gas and electricity have been designed to achieve security of supply, through a mix of prices and direct interventions by the system operator.

2.97 The key provisions in the industry codes that relate to gas and electricity security of supply are summarised in Appendix 2.1 and are not repeated here. Rather, we focus, briefly, on the introduction of the Capacity Market, which marks a fundamental shift in the model for incentivising investment and ensuring security of supply in electricity.

[29] The exemption also applies to the delivery of FITs and Warm Home Discount, which is described below.

Capacity Market

2.98 The Capacity Market was introduced to address the concern that potential investors in generation and other forms of capacity might not be confident about their ability to recover the costs of their investment in an energy-only market (ie a market without a specific mechanism for remunerating capacity). This is in part because of greater intermittency brought about by increased deployment of renewables and in part because cost recovery would require prices to be allowed to spike to very high levels on the (rare) occasions of system stress.

2.99 Under the Capacity Market, National Grid holds auctions to secure agreements from capacity providers to provide capacity when called upon to do so at times of system stress. The first auction (for delivery in 2018/19) was held in December 2014, and procured just under 50 GW of capacity at a price of just under £20/kW. This will result in capacity payments of just under £1 billion in the delivery year. Costs are passed through to electricity consumers.

2.100 In Sections 4 and 5 we explore the Capacity Market in more detail, considering the design of the auction and penalty regime and potential issues arising from the simultaneous introduction of fundamental reforms to imbalance prices under the EBSCR, which also has the objective of improving incentives to invest.

Affordable prices

2.101 As with security of supply, the third principal policy goal – ensuring prices are affordable – has long been a key objective of the sector. Indeed one of the main rationales for liberalisation was to use competitive pressures to reduce cost and hence prices.

2.102 A range of additional policies have been employed to improve the affordability of energy, relating to taxes, subsidies and levies. Some of these measures reduce prices overall, while others are targeted on segments of the population (particularly those considered to be in fuel poverty).[30] More recently, a further range of interventions, specifically aimed at addressing concerns about the impact on energy prices of climate change policies, have been introduced.

[30] According to the current definition, a household is considered to be in fuel poverty if: they have required fuel costs that are above the national median level; and, were they to spend that amount they would be left with a residual income below the official poverty line. See DECC, *Annual Fuel Poverty Statistics Report, 2014*.

Reduced rate of VAT

2.103 Residential customers pay a VAT rate of 5% on domestic energy use (including electricity, gas and non-metered fuels such as coal) compared with the standard VAT rate of 20%. Energy used by non-domestic customers is taxed at the standard rate of 20%.

2.104 The reduced rate of VAT for domestic energy is the single biggest subsidy affecting energy prices. Its cost has been estimated at around £5 billion per year.[31] Among EU countries, the UK charges the lowest VAT rate on domestic energy. Most other member states tax domestic energy at the full rate of VAT, though a few others have reduced rates.[32]

Winter Fuel Payments

2.105 Winter Fuel Payments are a cash transfer, initially introduced in 1997, to households containing someone over the female state pension age. In 2013/14 the payment is £200, rising to £300 if someone is aged 80 or over. In 2012/13, 12.7 million payments were made at a cost of £2.15 billion.

Cold Weather Payments

2.106 Cold Weather Payments are another form of cash transfer, introduced in 1986, to vulnerable households to meet the cost of higher energy bills in periods of cold local weather. The payment is currently £25 following every 7-day period in which temperatures are forecast to fall below 0˚C. Eligible households include those in receipt of a range of means-tested benefits with older people, young children or disabled people. In 2012/13, 5.8 million payments were made at a cost of £146.1 million.

Warm Home Discount

2.107 The Warm Home Discount came into force in 2011 and is scheduled to operate until 2016. It puts an obligation on large energy suppliers to provide bill rebates, worth £140 in 2014/15, to low-income and vulnerable households. Those on the Guarantee Credit element of Pension Credit receive automatic rebates. Energy companies can set their own rules about which other vulnerable groups can apply for a rebate, typically those on means-tested benefits with young children or a disabled member.

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[31] IFS, Energy use policies and carbon pricing in the UK.
[32] See European Commission, *VAT rates applied in the Member States of the European Union: Situation at 1st January 2015*.

Levy control framework

2.108 In recognition of the growing importance of energy-related levies, in 2010 HM Treasury and DECC agreed a 'control framework' which sets a cap on the overall value of policies that support DECC objectives on climate change and fuel poverty, are paid for by energy companies, and where the costs are recouped through consumer energy bills. The schemes which are covered by the Levy Control Framework include the RO, FITs and CfDs. The annual cap began at £3.3 billion for the period 2014/15 and will rise to £7.6 billion for the period 2020/21.[33]

Government Electricity Rebate

2.109 The Government Electricity Rebate, implemented through a licence modification, is a partial refund on the cost of the UK government's environmental policies to domestic electricity customers. From 3 October 2014, it obligates suppliers to rebate annually £12 on electricity bills for the next two years, worth a total of £620 million. The UK government will reimburse suppliers for the rebates they deliver to their eligible customers.

Concluding observations

2.110 The past 30 years have seen a sustained liberalisation of both the gas and electricity sectors, driven by both UK and EU legislation. It has also been a period of rapid and regular regulatory change, particularly in the electricity sector. Policies developed over this period have increasingly had to balance the competing goals of ensuring security of supply, improving affordability and reducing emissions.

2.111 While some policies – such as those to improve energy efficiency – are able in principle to support all three objectives, we observe that tensions have emerged in other areas – notably between policies designed to put a price on carbon and those intended to improve affordability. For example, the lower rate of VAT for domestic energy consumption means that, despite the substantial policy costs that have been imposed on the electricity sector, the net carbon price facing domestic consumers of electricity is currently relatively low. And, in relation to the domestic consumption of gas, there is a significant negative carbon price.[34] We consider the policy trade-offs within the current system of energy taxation in more detail in Section 11.

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[33] National Audit Office (27 November 2013), *The Levy Control Framework*.
[34] Source: IFS, *Energy use policies and carbon pricing in the UK*.

2.112 In the next section – on physical flows – we consider in more detail how the gas and electricity sectors have performed in practice against the objectives of security of supply and reducing emissions, while in the following section we consider the evidence on prices and costs.

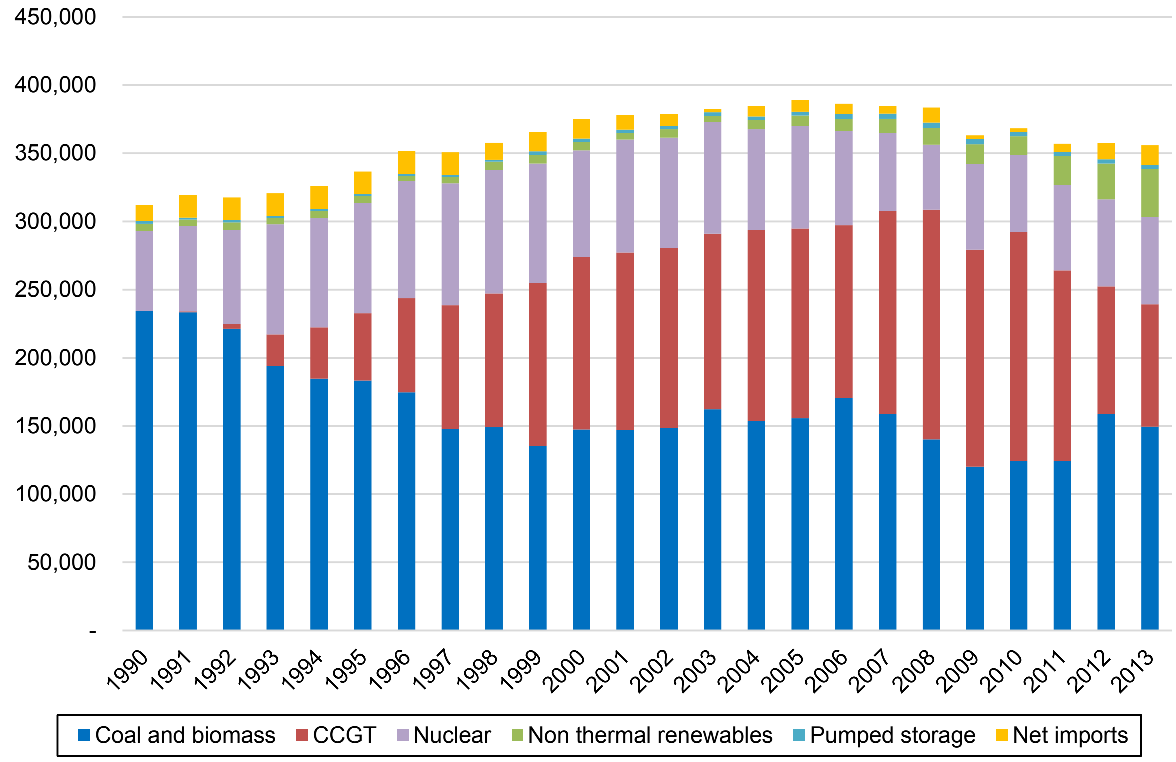
Physical flows

2.113 In this section we review some of the key changes that have taken place in the supply and demand of electricity and gas over the period since privatisation, with a particular focus on the decarbonisation and security of supply objectives discussed earlier.

Electricity supply and demand

2.114 Figure 2.3 below shows how the sources of electricity generation have changed over time.

Figure 2.3: Annual electricity generation by technology type (GWh)



Source: Digest of UK energy statistics (DUKES) 2014, Table 5.1.3.

2.115 The figure shows a number of key trends in the composition of electricity generation since 1990, and notably:

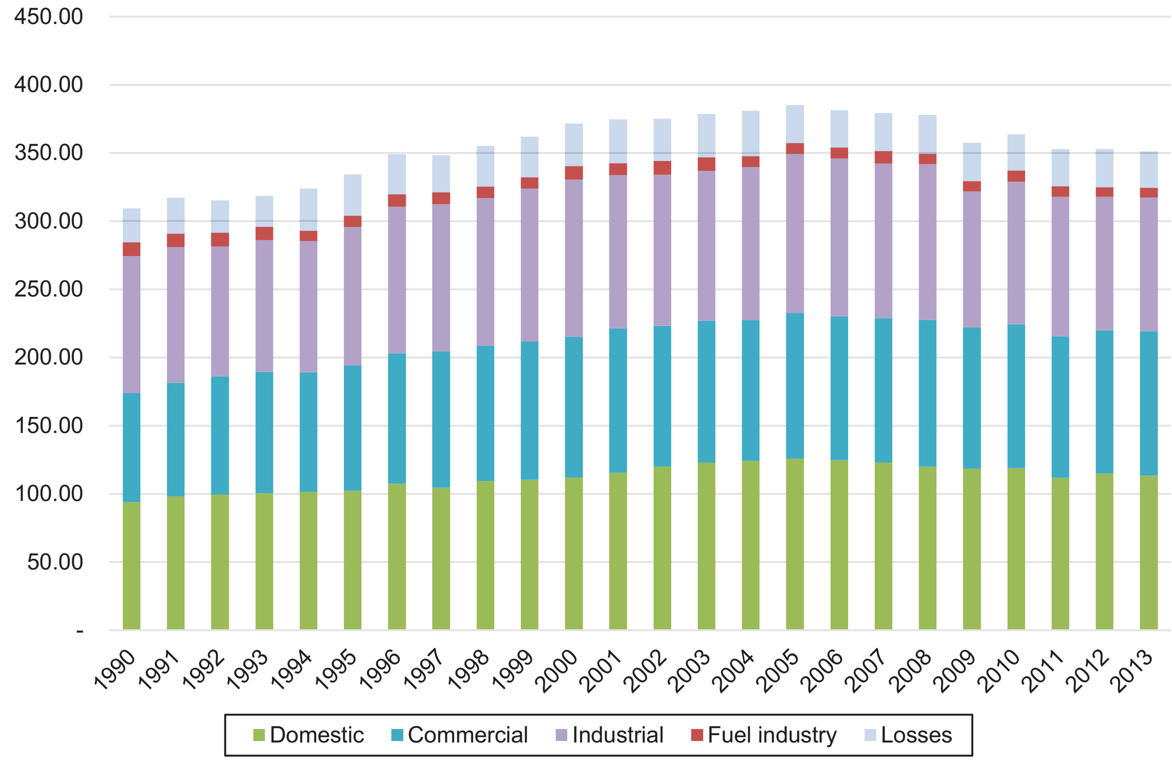
- the rapid expansion in the use of combined-cycle gas turbine (CCGT) plants in the 1990s, from no generation in 1990 to almost 50% of generation in 2010. In 2012 and 2013, there was a significant contraction in the use of CCGTs, caused both by the fall in coal prices relative to gas prices and the collapse of EUA prices;

- the significant increase over the final five years of the period in the use of renewable generation, in response to policies to put a price on carbon and support renewable generation, in particular the RO. Provisional figures for 2014 suggest that renewable generation was over 19% of total generation over the year;[35]
- generation from nuclear plant grew to 1998, then halved over the following ten years, before picking up from 2009 onwards; and
- while the level of net imports has fluctuated year on year, there have been consistently positive net imports in each year since 1990.

2.116 In relation to electricity consumption, shown in Figure 2.4 below, residential consumption grew steadily until 2005 and since then has fallen back to 2000 levels. Commercial consumption[36] has been relatively stable since around 2000. Industrial consumption has been the main driver of overall changes in demand, growing steadily until the mid-2000s and then falling rapidly as a result of the recession. Total system losses have been relatively stable over the period, at about 7%.

[35] DECC, *Energy Trends: March 2015*, Section 6.
[36] Microbusiness represents a subset of the 'commercial' sector shown here.

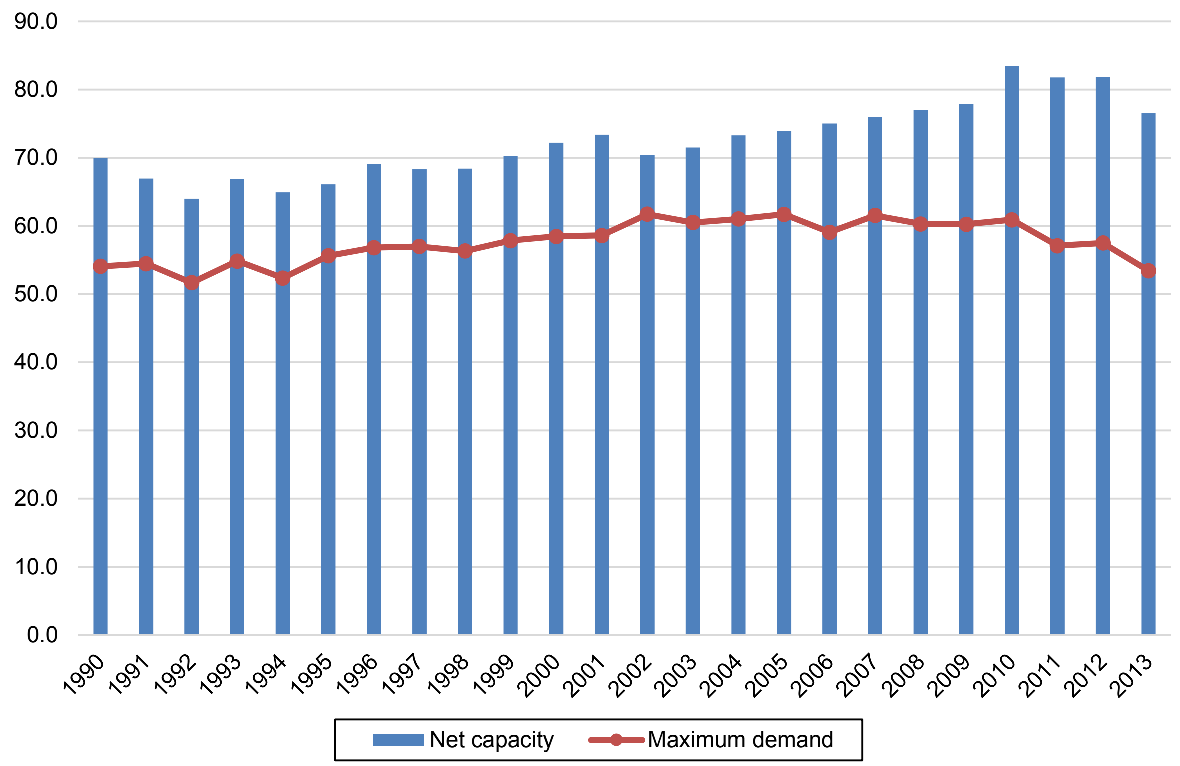
Figure 2.4: Annual electricity consumption by sector (TWh)



Source: DECC, Historical electricity data, 1920 to 2013.

2.117 One of the key metrics for assessing the security of supply of electricity is the 'capacity margin' – namely the excess of generating capacity over maximum demand. As is shown in the figure below, the electricity margin has increased significantly in recent years.

Figure 2.5: Annual electricity net capacity and maximum demand (GW)



Source: DECC, Historical electricity data, 1920 to 2013.

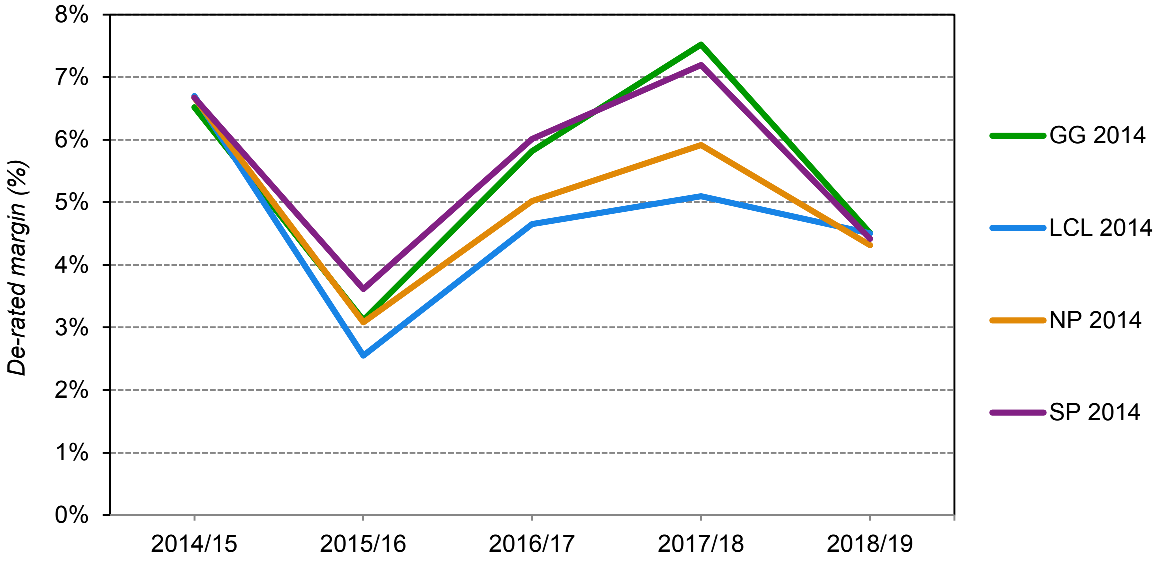
2.118 There has been only one loss of load event in the last three years.[37] This occurred on 11 February 2012, where voltage control was required to balance the system for a couple of hours. This was the result of several plants (totalling around 3.5 GW of capacity) failing to provide their expected output in cold weather conditions.[38]

2.119 Not all generating capacity is equally reliable. An increasing proportion of capacity is from renewable generation, much of it, such as wind, intermittent and hence less reliable than conventional thermal plant. To account for this, derated capacity margins can be calculated, which take account of the likely availability of plant specific to each type of generation technology.

2.120 Figures 2.6 and 2.7 show that National Grid anticipates that the derated capacity margins in 2015/16 will be particularly tight under a range of scenarios, with higher associated loss of load expectations.

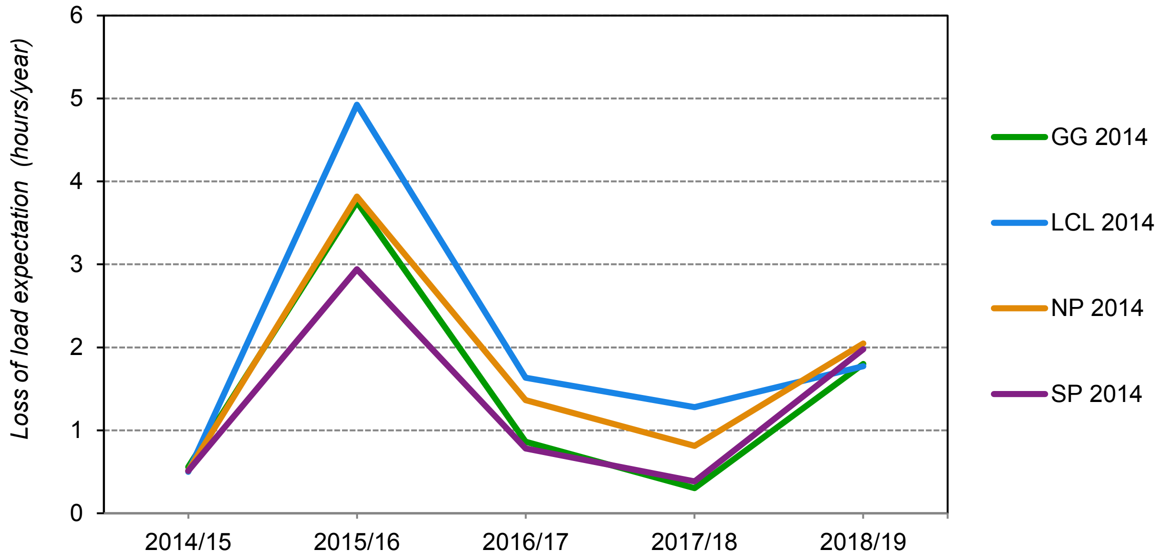
[37] A 'loss of load event' does not necessarily mean blackouts. This term applies to a range of outcomes, from voltage reduction (brownouts), requiring generators to operate outside of normal operating parameters (maximum generation), securing emergency services from interconnectors and controlled disconnections (blackouts).
[38] National Grid (2012) Saturday 11th February 2012, presentation to Electricity Operational Forum. This event illustrates that security of supply events do not necessarily occur at peak demand – this event occurred on a Saturday morning, rather than at the weekday peak.

Figure 2.6: Estimated derated capacity margins (2014/15 to 2018/19)



Source: Ofgem, Electricity Capacity Assessment Report 2014, Figure 4.

Figure 2.7: Loss of load expectations (2014/15 to 2018/19)



Source: Ofgem, Electricity Capacity Assessment Report 2014, Figure 5.

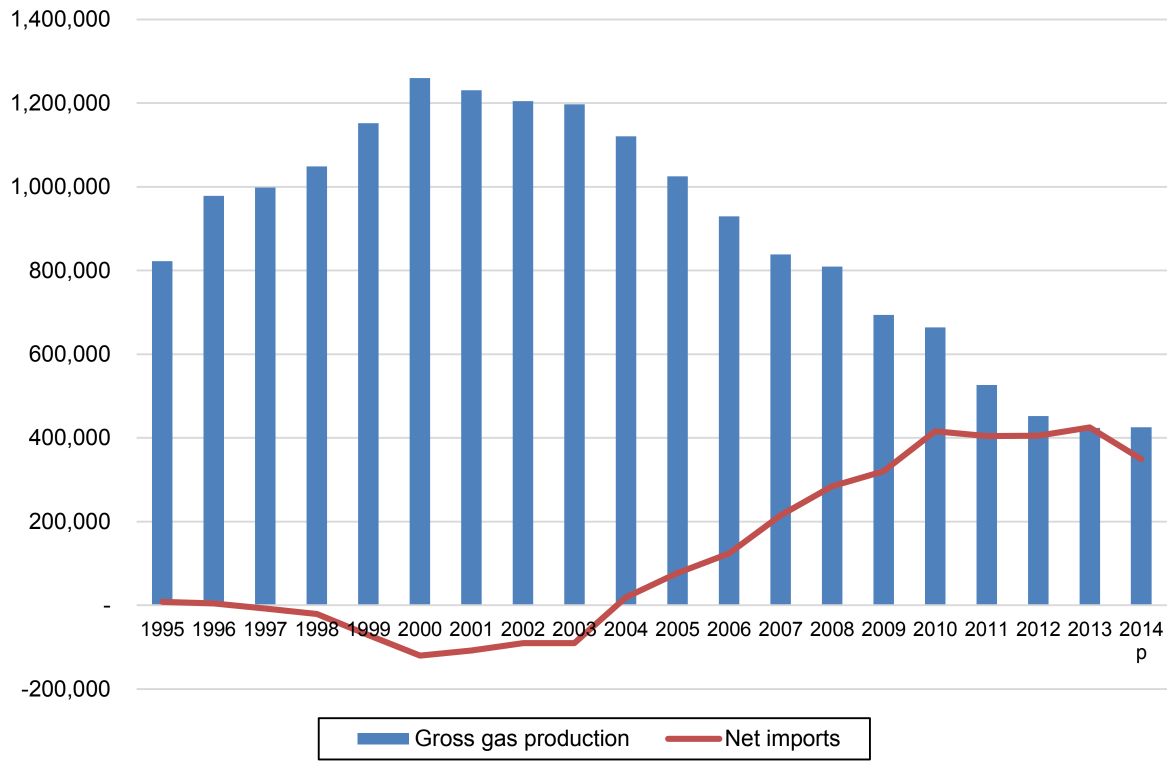
2.121 In response National Grid (with support from DECC and Ofgem) developed two new balancing services to allow it to procure additional reserve from both demand-side participants and power stations.[39] (The figures above present the estimated margins before the introduction of these new balancing services.)

[39] Supplemental Balancing Reserve and Demand Side Balancing Reserve.

Gas supply and demand

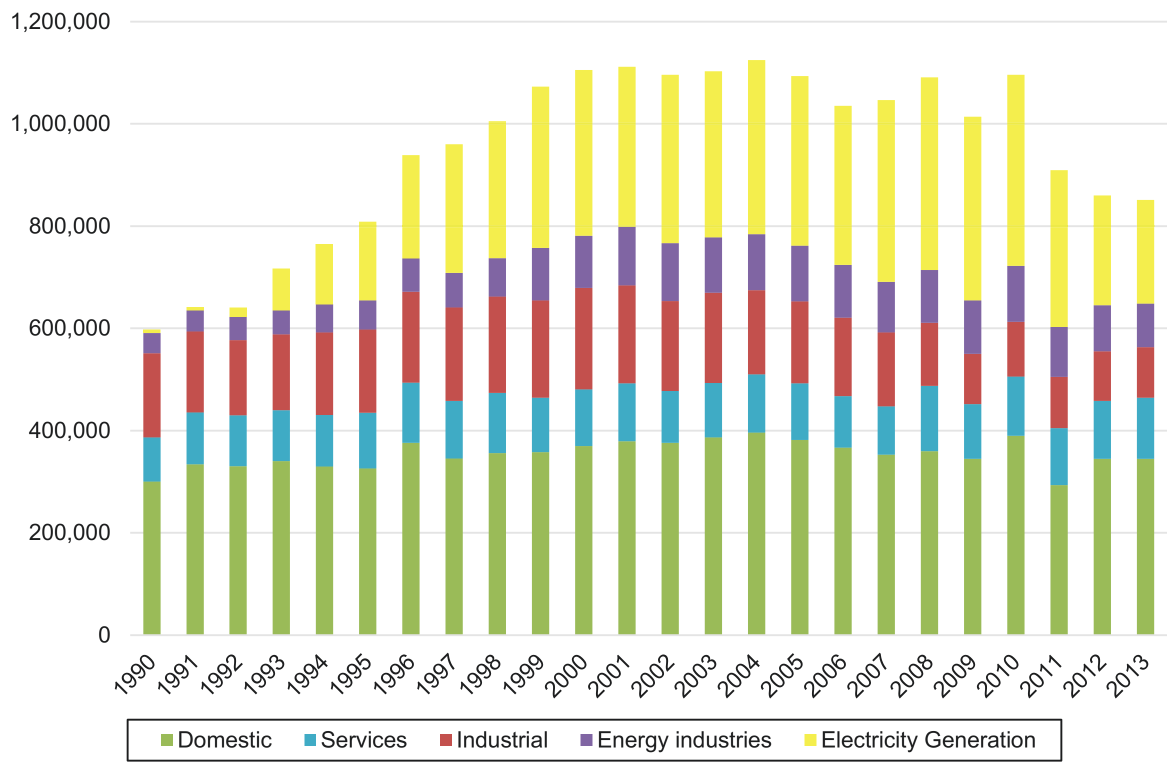
2.122 The figure below shows that gas production peaked in 2000 and that since 2004 the UK has been a net importer of gas. Import capacity has risen considerably over the past 15 years. The current main sources of gas imports into Great Britain are the gas interconnectors (linking to Belgium and the Netherlands), pipelines (linking to Norway) that connect the National transmission system (NTS) to Continental Europe and LNG, which arrives into Great Britain through four terminals.

Figure 2.8: Gross gas production and net imports (GWh)



Source: DECC (April 2015), Energy Trends Section 4: Gas.

Figure 2.9: Annual gas consumption by sector (GWh)



Source: DECC, DUKES 2014, Table 4.2.

2.123 Domestic gas consumption grew steadily to 2004 and then declined gradually, the exception being a dramatic increase in 2010 (due to exceptionally cold weather) followed by an equally dramatic fall in 2011 (due to milder average temperatures in that year). By 2013, domestic consumption was roughly at the level it had been 20 years earlier. Given the level of economic growth and population increase (both of which would tend to increase gas consumption), this result suggests that energy efficiency is likely to have improved over the period.[40]

2.124 Industrial consumption of gas has declined significantly since 2000, while gas used for electricity generation shows the pattern described earlier – a rapid increase followed by a contraction over the past three years.

2.125 In relation to security of supply, the GB gas system has diverse sources of supply sources, with gas being supplied onto the national balancing point (NBP) from:

[40] The available evidence suggests that considerable energy savings have been made by installing energy efficiency measures, such as loft and cavity wall insulation. See DECC (June 2014), Summary of analysis using the National Energy Efficiency Data-Framework.

- fields on the UK continental shelf (UKCS) and the Norwegian continental shelf (NCS), via pipelines;

- global gas fields, for example in the Middle East, via import terminals for LNG;[41] and

- the mainland European gas pipeline network via interconnector pipelines that connect Bacton in the UK with Zeebrugge in Belgium and Balgzand in the Netherlands.[42]

2.126 Gas storage also plays a critical role in managing variation in gas demand, in particular the seasonal swing between winter and summer, which is much more pronounced for gas than it is for electricity. By far the largest facility in Great Britain is the Rough storage facility which is owned and operated by Centrica Storage, under regulatory undertakings imposed by the Competition Commission (CC).

2.127 According to DECC analysis, the UK was relatively resilient to potential gas infrastructure disruptions in 2013: 197% and 175% of peak demand could have been met with the loss of the largest and two largest gas supply routes respectively. On this metric the UK was the ninth most resilient EU member state to gas supply infrastructure disruptions.[43]

2.128 There has never been a network gas supply emergency in Great Britain.[44]

Greenhouse gas emissions relating to electricity and gas

2.129 Overall UK emissions in 2012 were roughly 25% below 1990 levels, such that the first carbon budget (from 2008 to 2012) was met.[45] In relation specifically to emissions from electricity and gas, the figure below shows the change in power sector emissions and residential ‘combustion’ (largely gas heating and cooking) since 1990.

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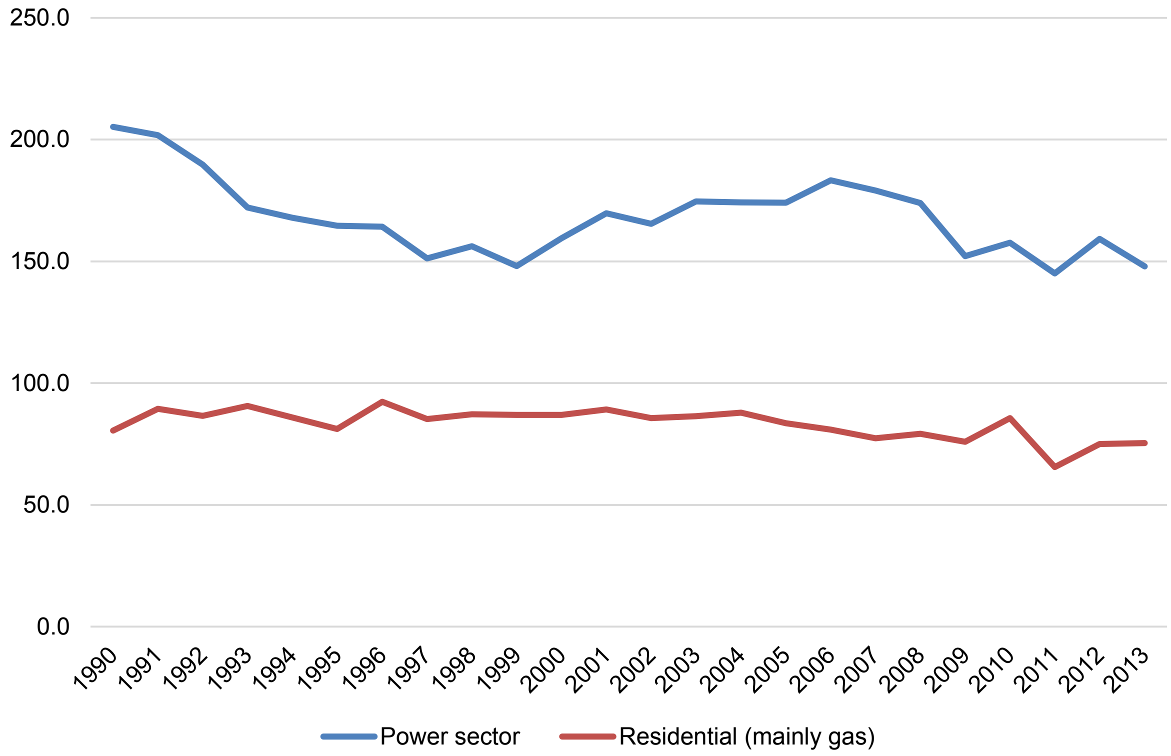
[41] LNG is transported in specialised container ships and then re-gasified prior to being input into the network.
[42] The IUK pipeline is bidirectional (ie it can flow either way depending on contractual positions and/or price differentials between the UK and Europe) while the BBL pipeline flows one way from the Netherlands to the UK.
[43] DECC (2014), Physical gas flows across the EU-28 and diversity of gas supply in 2013.
[44] National Grid, Network Gas Supply Emergencies.
[45] This takes into account the effect of the EU ETS cap. Physical emissions were lower than this figure, meaning that the UK was a net exporter of EUAs in the year. Source: DECC, 2013 Greenhouse Gas Emissions, Final Figures.

Figure 2.10: Greenhouse gas emissions from electricity generation and residential combustion (Mt CO2e)



Source: DECC, 2013 Greenhouse Gas Emissions, Final Figures.

2.130 Residential emissions initially rose but have fallen since 2004, while power sector emissions show a more complicated trend. Emissions fell rapidly during the 1990s, due to the increasing use of CCGT plants displacing generation from coal (which has a higher carbon intensity than gas) but increased from 2000 to 2006, as coal generation recovered at the expense of nuclear. From 2006, emissions fell again, reflecting the increasing deployment of renewables, the exception being the increase in 2012, driven by the increase in coal generation in that year. Overall, power sector emissions in 2013 were roughly 28% lower than in 1990, and residential emissions 6% lower.[46]

Conclusion

2.131 In relation to electricity, the period since privatisation has seen a significant change in the composition of generation, with the introduction of CCGT plants and, more recently, a significant increase in generation from

[46] As noted, emissions from the power sector are capped under the ETS, so the contribution of the power sector to the UK's emissions reduction targets will differ somewhat from the position presented here, and will need to take into account purchases and sales of EUAs. UK installations that are covered by the scheme have in aggregate been net sellers of EUAs since 2009, implying that the marginal cost of abatement in the UK traded sector has been higher than that in the rest of the EU over this period.

renewable plant. Residential consumption of electricity has fallen since 2005. The capacity margin has been relatively high in recent years, although the derated capacity margin, reflecting the intermittency of renewables, is projected to tighten in 2015/16, with higher associated loss of load expectations.

2.132 In relation to gas, the UK has moved from being a net exporter to a net importer over the period. Residential consumption has fallen since 2004, and in 2013 was roughly at the level it was 20 years previously. The UK is relatively resilient to potential gas infrastructure disruptions and there has never been a network gas supply emergency in Great Britain.

2.133 Emissions from the power sector were roughly 28% lower in 2013 compared with 1990. This partly reflects the impact of policies to put a price on carbon and support low carbon generation. There was, however, considerable variation in emissions over the period due to shifts in the merit order of plant, reflecting changes in underlying fossil fuel prices.

2.134 Residential emissions were only marginally lower than in 1990. While this is likely to reflect some improvement in energy efficiency relating to domestic gas consumption, the lack of a more significant reduction may also reflect the absence of a strong carbon price facing residential consumers of gas.

Prices, costs and profits

2.135 Whereas the previous section considered physical flows within the energy system, this section assesses financial flows and the evolution of prices, costs and profits.

2.136 Total revenues from the sale of gas and electricity by the Six Large Energy Firms exceeded £45 billion in 2013, of which revenues from sales to the domestic customers were around £29 billion (64%), those to SMEs around £4 billion (9%) and sales to the Industrial and Commercial customers around £12 billion (27%).

2.137 The analysis that follows focuses on the two categories of customers within our terms of reference: first, retail supply to domestic customers and then microbusinesses (although, where relevant, we provide analysis that relates to the SME retail market). Finally we set out our approach to addressing one of the key questions for this investigation, namely, whether average prices paid by domestic customers and/or microbusinesses have been above the levels that we would expect in a competitive market.

2.138 An analysis of prices and profitability in the wholesale energy markets is set out in Section 4.

Domestic prices, costs and profits

2.139 The rapid increase in domestic energy prices in recent years and the perception that profits and overall prices are too high have been a major source of public concern and represent one of the key reasons for the market investigation reference.

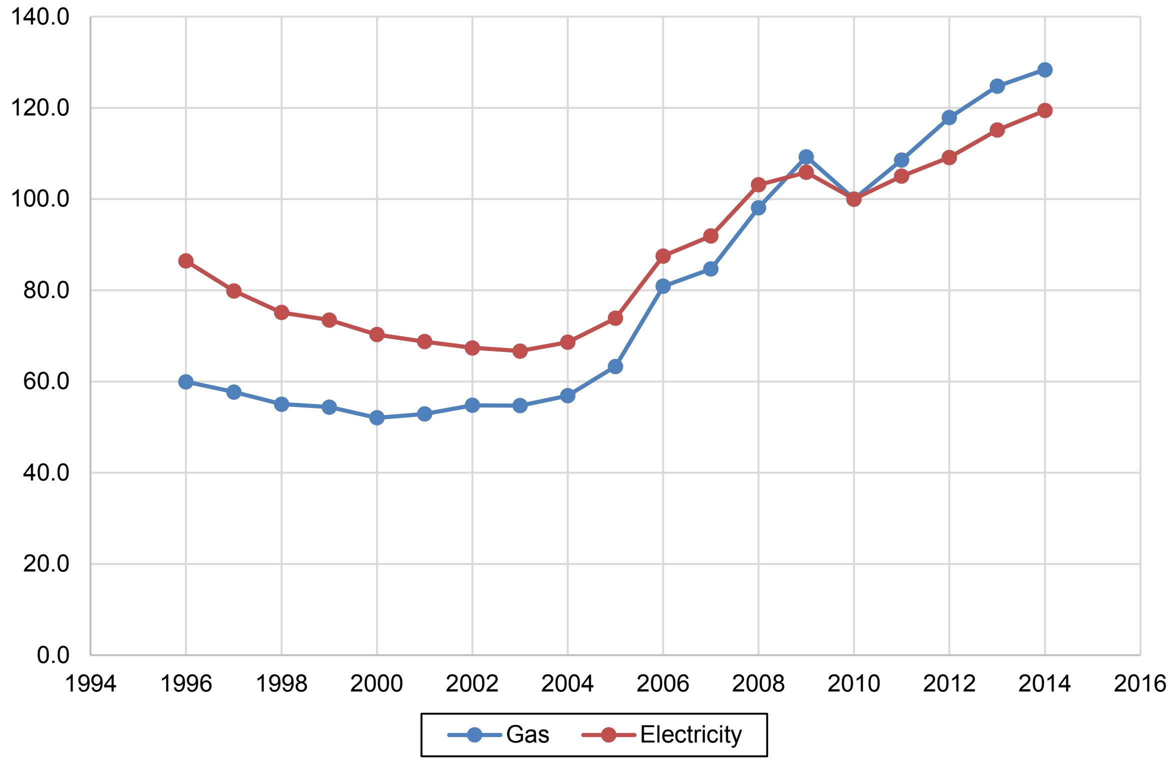
2.140 In this section we explore some of these concerns and consider:

- as background, long-run changes in domestic prices over time and how current average price levels paid by domestic customers compare to those in other EU countries;
- the extent to which changes in average prices paid by the domestic customers of the Six Large Energy Firms over the past five years have been associated with changes in costs and/or profit margins; and
- the extent of variability in prices paid by individual customers and the implications for our analysis of competition.

Background: price changes and price comparisons

2.141 After a sustained period of real terms reductions, domestic gas and electricity prices have increased significantly over the last ten years.

Figure 2.11: Electricity and gas real terms price indices, 1996–2014



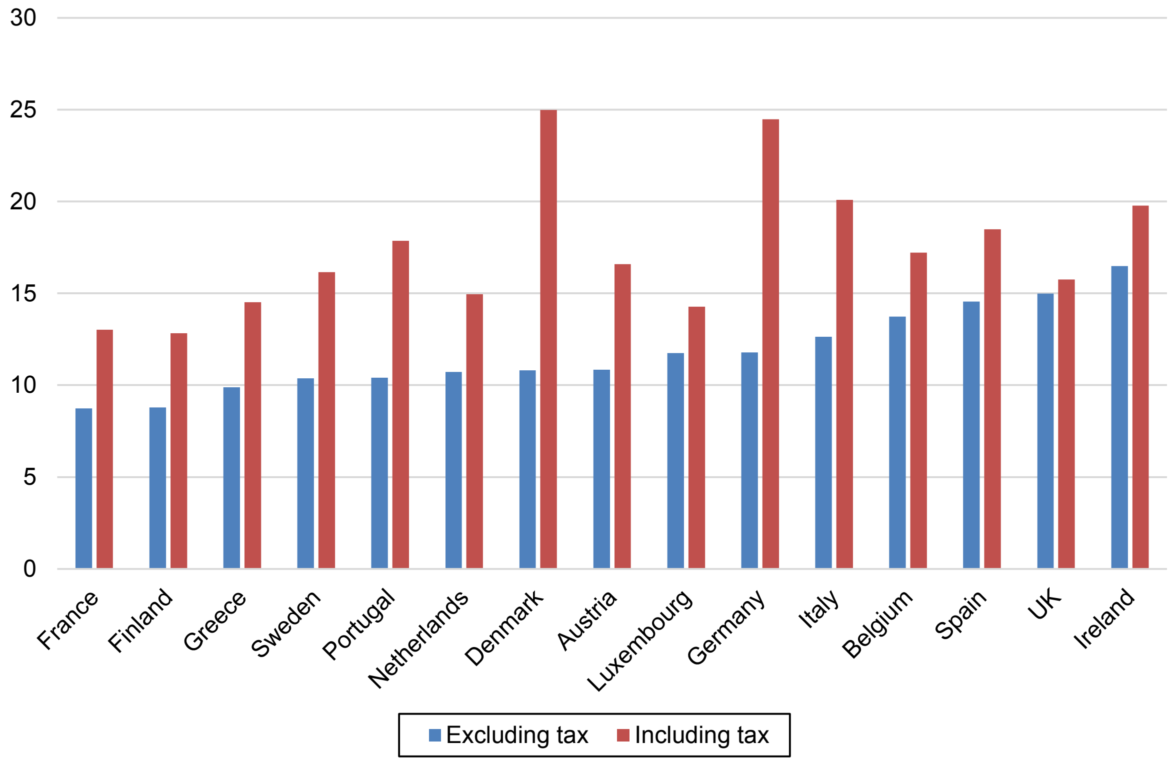
Source: ONS, Consumer prices index. Adjusted for inflation using the GDP (market prices) deflator.

2.142 The figure shows that average annual domestic electricity prices rose by around 75% in real terms between 2004 and 2014, and that average annual domestic gas prices rose by around 125% in real terms over the same period.

2.143 DECC publishes international price comparison on a regular basis. The most recent comparisons, covering prices paid by medium domestic customers during the period June to January 2014, are presented below. It is not possible to use such comparisons to draw strong conclusions about the appropriateness of UK prices, as significant factors affecting costs differ between countries – notably geographical endowments.

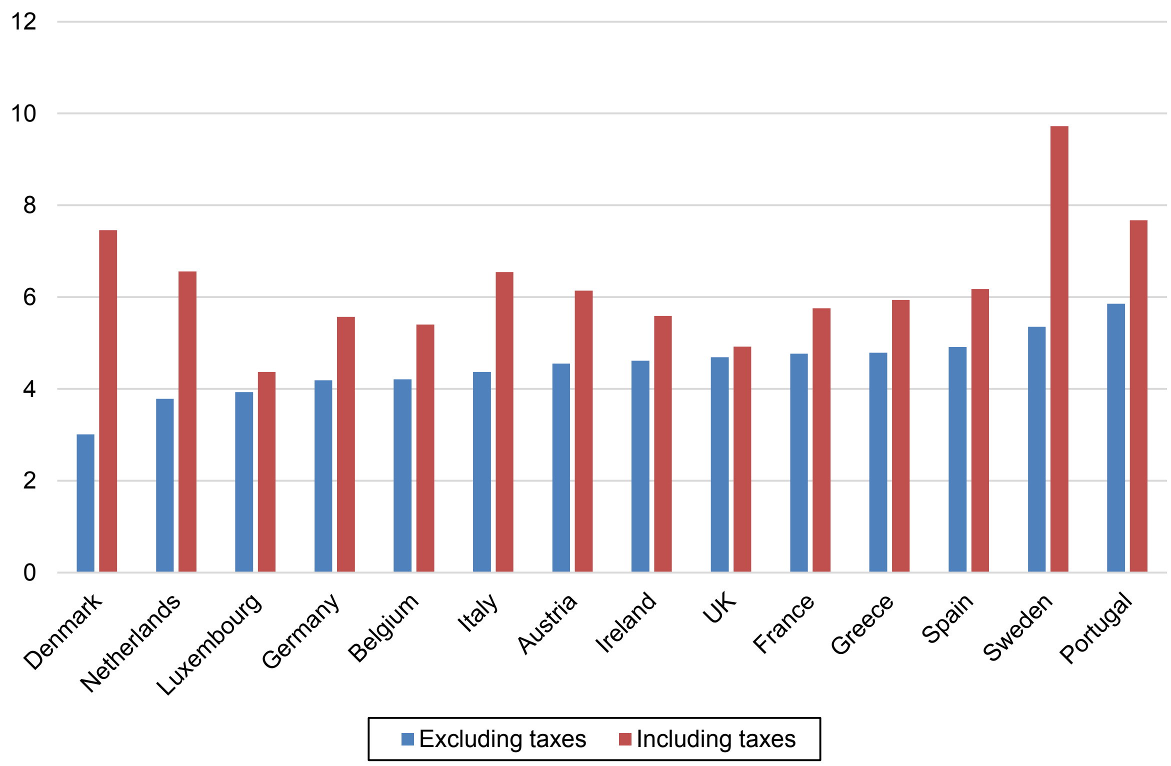
2.144 However, the comparisons do illustrate the impact of VAT on overall prices. Due to the low rate of VAT on UK energy consumption, UK prices look more favourable including tax than excluding tax. For example, the average domestic electricity price **including** taxes in the UK for medium domestic consumers for the period July to December 2014 was the EU 15 median price. The UK price **excluding** taxes was the second highest in the EU15 (and was 43% above the median price). For gas, the UK was second cheapest including tax and ninth cheapest excluding tax.

Figure 2.12: Electricity prices in the EU 15 for medium domestic customers from June to January 2014, including and excluding tax (p/kWh)



Source: DECC Domestic electricity prices in the EU, March 2015.

Figure 2.13: Gas prices for medium domestic customers in the EU 15 from June to January 2014, including and excluding tax (p/kWh)*

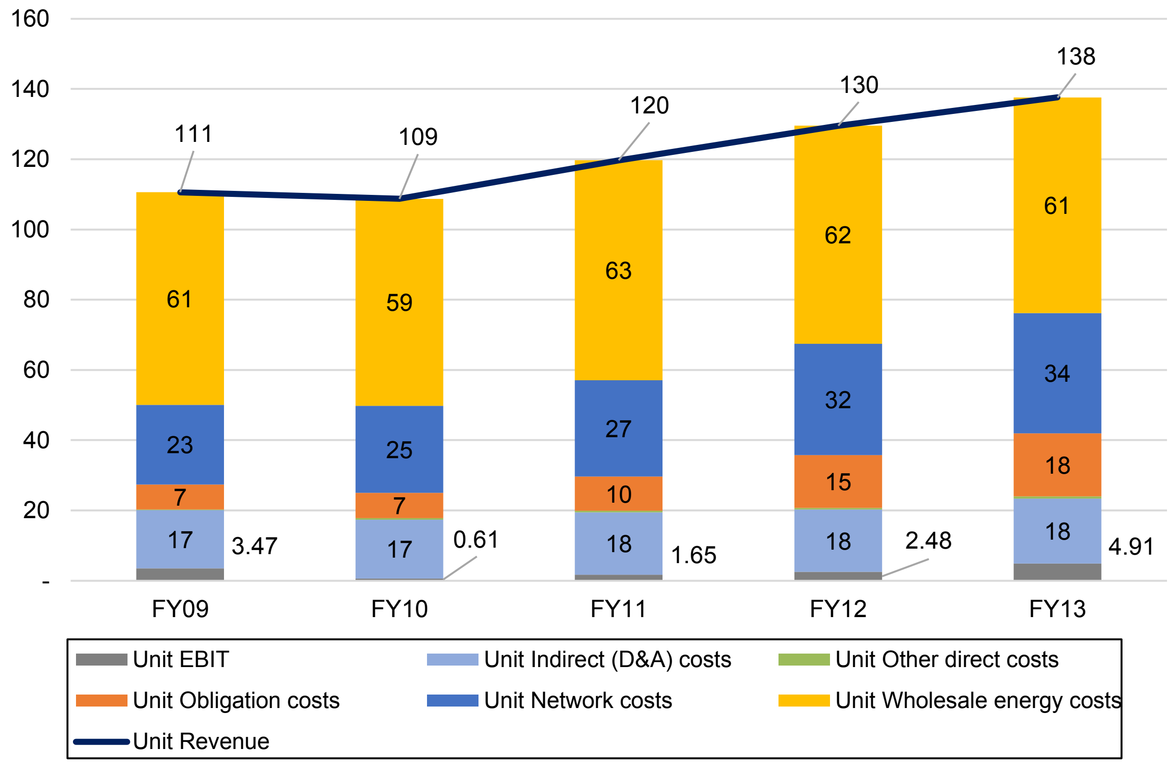


Source: DECC Domestic gas prices in the EU, March 2015.
*Data for Finland not available.

Changes in average domestic prices and costs

2.145 Figures 2.14 and 2.15 below show data on average electricity and gas prices[47] and costs as reported by the Six Large Energy Firms over the period 2009 – 2013.[48] As can be seen in the charts, from 2009 to 2013 average energy prices[49] rose significantly over the period for domestic customers. Average domestic electricity prices grew by 24% (in nominal terms) over the period, and average domestic gas prices grew by 27%.

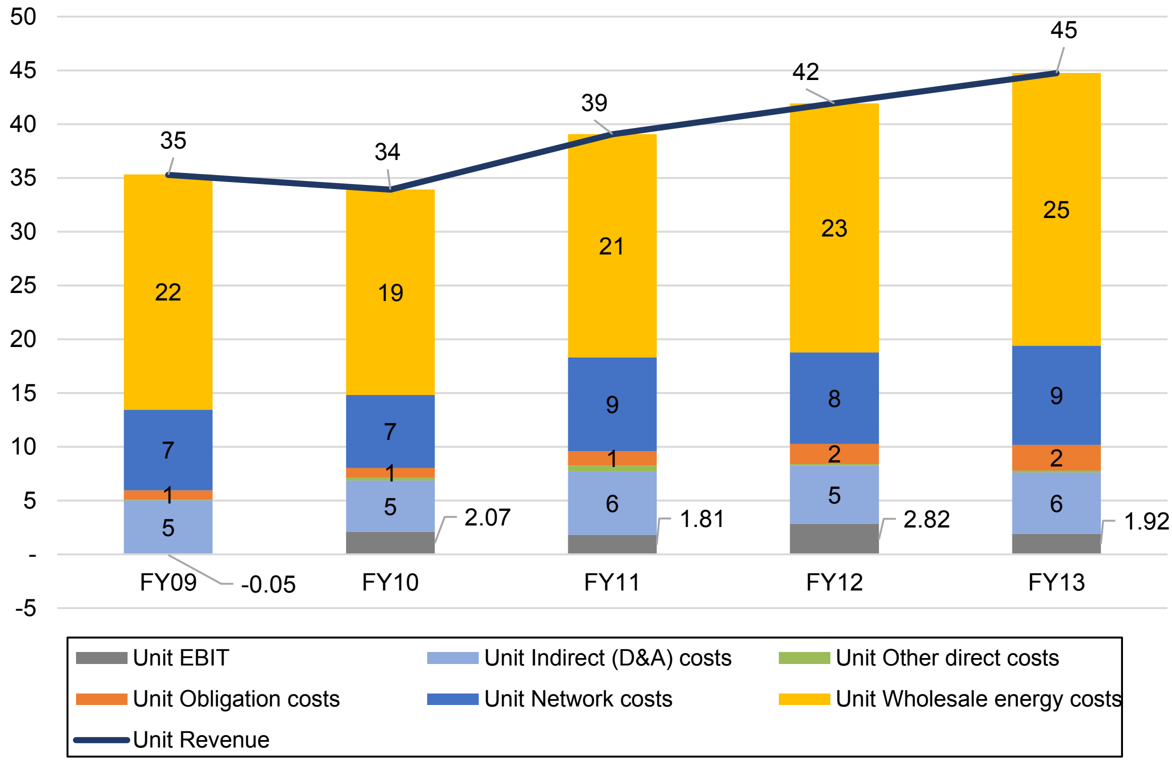
Figure 2.14: Domestic electricity supply unit revenue breakdown, 2009 to 2013 (£/MWh)



Source: CMA analysis of P&L information submitted by the Six Large Energy Firms.

[47] Calculated as revenues/kWh.
[48] The data is broadly reconcilable with the Consolidated Segmental Statements that Ofgem requires the Six Large Energy Firms to produce.
[49] As measured by revenue/kWh.

Figure 2.15: Domestic gas supply unit revenue breakdown, 2009 to 2013 (£/MWh)



Source: CMA analysis of P&L information submitted by the Six Large Energy Firms.

2.146 The data suggests that average profit (EBIT)[50] margins earned on sales to domestic customers were 3.3% over the period. Average EBIT margins on sales of gas (4.4%) were higher than those on sales of electricity (2.1%).

2.147 For electricity, the main drivers of price increases have been the costs of social and environmental obligations[51] and network costs. Reported wholesale costs have remained flat while EBIT has fluctuated over the period. For gas, there has been a more even increase in each cost component, with EBIT increasing significantly after 2009.

2.148 A significant component of this investigation is to explore some of these cost elements in more detail. In Section 7 we analyse further the relationship between prices and a variety of measures of wholesale cost – both historical and forward looking – and assess implications for the nature of retail competition. In Section 10 and Appendix 10.5, as part of our assessment of competitive benchmark prices, we review both indirect costs and wholesale costs and examine the efficient level of such costs, by considering how they

[50] Earnings before interest and tax, or gross profit less indirect costs.
[51] We note that this category is a subset of overall policy costs and does not include either the impact of either ETS or the carbon price floor, both of which have the effect of increasing the wholesale price.

compare between firms, over time and how they relate to exogenous cost indices where available.

2.149 In relation to obligation costs, the data provided by the Six Large Energy Firms suggested that these represented around 13% of the domestic electricity price and around 4% of the domestic gas price in 2013.[52] Our focus, in Section 5, is on the future level of such costs, in particular CfDs, where the method of setting the overall level of support is likely to have a major impact on prices and bills.

2.150 One significant area we do not explore further is network costs. As explained above, transmission and distribution are natural monopolies and these costs are subject to price regulation by Ofgem, whose decisions are appealable to the CMA.[53]

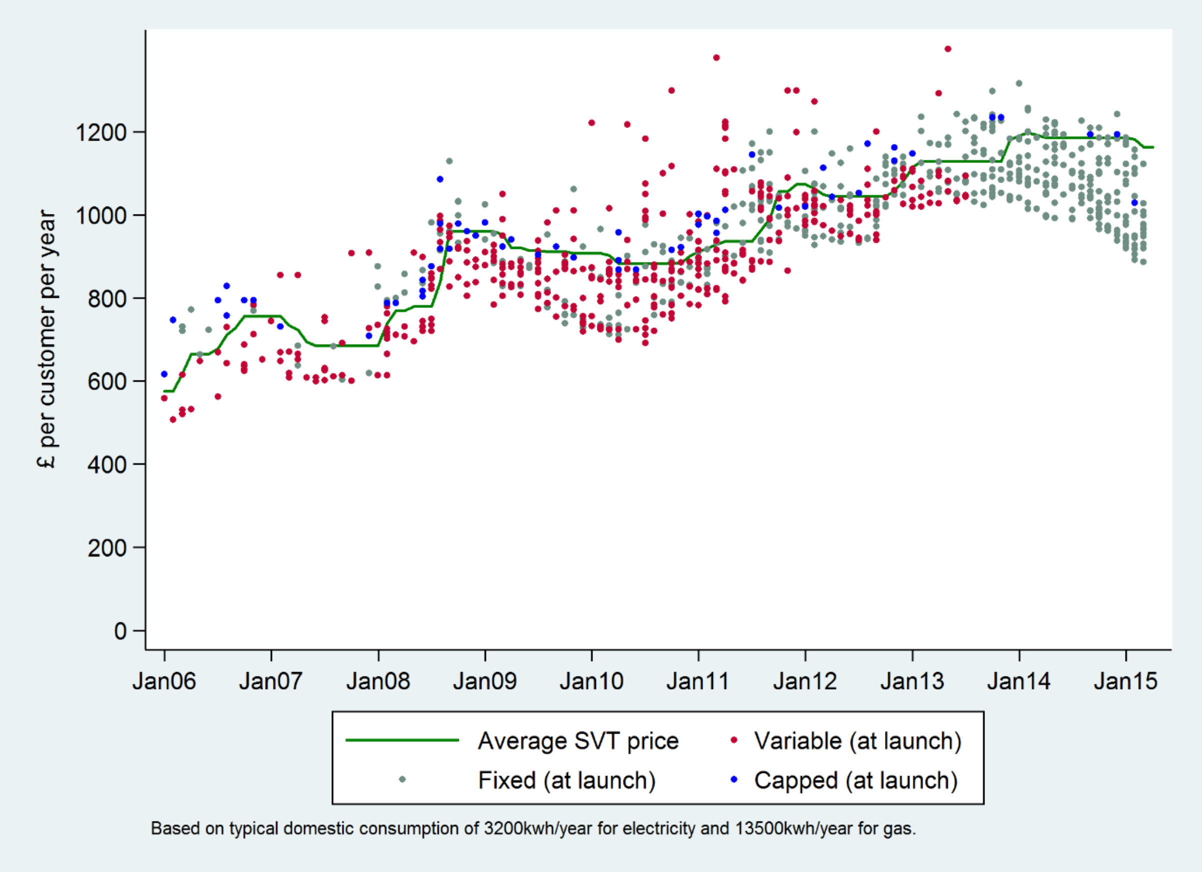
Variability in the prices paid by domestic customers

2.151 The overall figures reported above mask considerable variation in the profits and average prices associated with different types of tariff offered to domestic customers. Over the period 2011 to 2014, average revenue per kWh from the SVT was around 10% and 13% higher than average revenue from non-standard tariffs for electricity and gas respectively across the Six Large Energy Firms.

2.152 The chart below shows all the tariffs that have been launched over the last nine years by the Six Large Energy Firms and the mid-tier suppliers, with the corresponding annual bill based on typical domestic consumption. Besides the SVT offered by the Six Large Energy Firms[54] are a range of non-standard tariffs – fixed, variable and capped. We observe that there is a wide range of tariffs and a striking variation in price level, particularly for a homogenous product. Further, the range appears to have widened over the past 12 months.

[52] These figures are broadly consistent with DECC's most recent estimates of the impact of these obligations on prices and bills. See DECC (November 2014), Estimated impact of energy and climate change policies on energy prices and bills.
[53] The CMA is currently considering two appeals against Ofgem's RIIO-ED1 price control decision for electricity distribution companies.
[54] The green line on the chart is a flat average of the SVTs offered by the Six Large Energy Firms.

Figure 2.16: Tariffs offered by the Six Large Energy Firms and mid-tier suppliers, 2006 to 2015



Source: CMA analysis based on information provided by the Six Large Energy Firms and the mid-tier suppliers.

2.153 Comparing available domestic tariffs – but excluding certain niche tariffs and those offered by very small suppliers – we calculate that, over the period Quarter 1 2012 to Quarter 2 2014, most customers could have made considerable savings from switching a combination of suppliers, tariffs and payment methods.

2.154 For all the dual customers of the Six Large Energy Firms, average potential gains from switching externally to any tariff offered were equivalent to 14% of the average bill (equivalent to about £160 a year) over the period. As discussed in Sections 7 and 8, the gains available to specific customers depend considerably on the tariff and payment method that customers are currently on and the supplier they are currently with. For example, the SVT customers of the Six Large Energy Firms who pay by standard credit could have saved an average of 22% of their bill by switching tariff and/or supplier and payment method, and 14% of their bill by switching tariff and supplier while keeping their current payment method. The SVT customers of the Six Large Energy Firms who pay by direct debit could have saved an average of 15% of their bill by switching tariff and/or supplier. We will update this analysis to include data from the past 12 months in the next phase of our investigation.

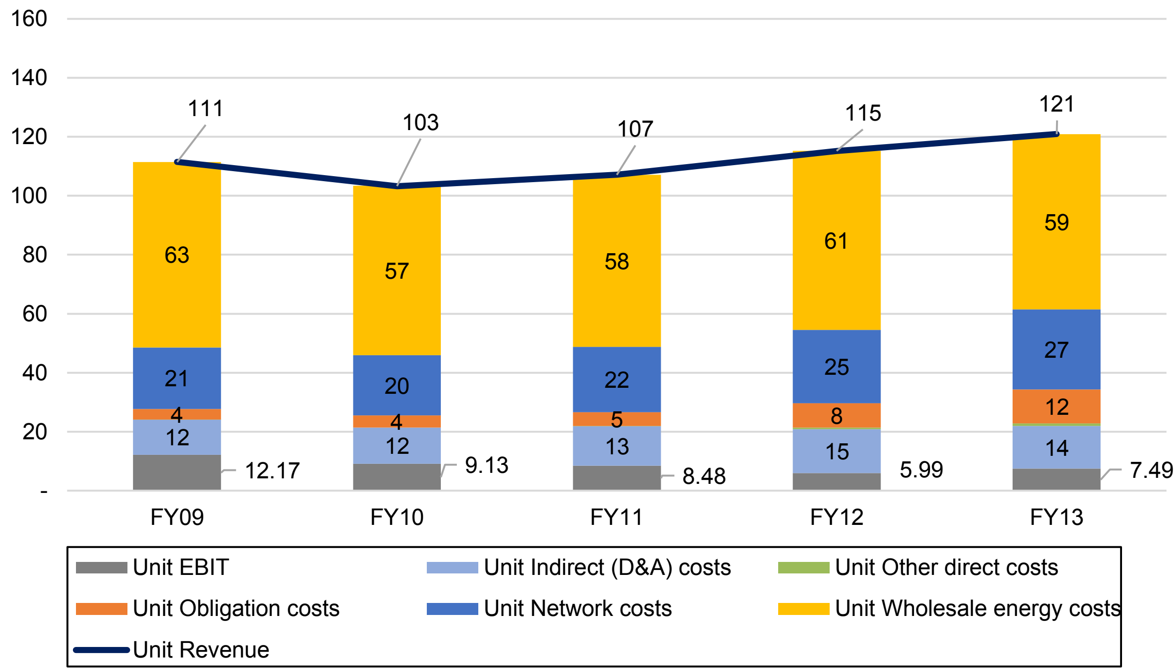
2.155 A key question that we consider in Sections 7 and 8 is whether the wide divergence in tariff levels – and the significant gains that many customers could make from switching – is indicative of a lack of customer engagement in the energy market.

SME and microbusiness prices costs and profits

2.156 The financial information provided to us does not provide specific results for microbusinesses, but for SMEs as a whole, price increases over the period were lower than those observed for domestic customers. Average electricity prices grew by 8% and average gas prices grew by 11%, ie broadly in line with inflation. For electricity, obligation costs and network costs were again the most significant driver of price increases. Reported wholesale costs fell slightly.

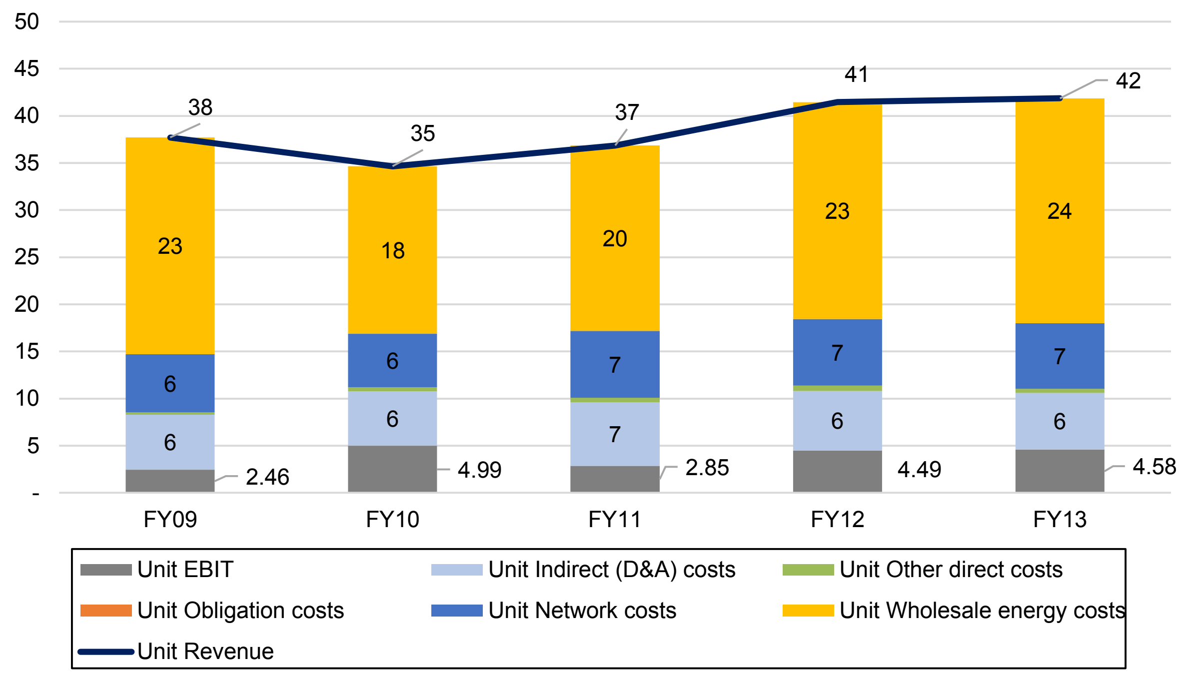
2.157 EBIT margins in the SME retail energy markets were on average 8.4% over the period – significantly higher than those on sales to domestic customers. Margins on sales of gas to SMEs (10.1%) were higher than those on sales of electricity (7.9%).

Figure 2.17: SME electricity supply unit revenue breakdown (£/MWh)



Source: CMA analysis of P&L information submitted by the Six Large Energy Firms.
Note: Line and bar height both equal annual unit revenues. Indirect costs include D&A costs.

Figure 2.18: SME gas supply unit revenue breakdown (£/MWh)



Source: CMA analysis of P&L information submitted by the Six Large Energy Firms.
Note: Line represents unit revenues. Indirect costs include D&A costs.

Variability in the prices paid by microbusinesses

2.158 We have also found considerable variation in the prices paid by SMEs including microbusinesses. In particular, we compared rollover tariffs (tariffs which customers would pay if they took no action at the end of an existing fixed term contract), retention tariffs (tariffs which customer actively renegotiate with their existing supplier at the end of an existing contract), and deemed tariffs (a tariff paid until a customer, typically in new premises, contacts its supplier to enter into its first contract).

2.159 Our comparison of average unit revenues (from our data including the Six Large Energy Firms and a number of independent suppliers, from 2012-2014) showed that rollover tariffs were 29 to 36% higher than retention tariffs for electricity (depending on the size of customer), and 25 to 28% higher for gas. Deemed tariffs were 66 to 82% higher than retention tariffs for electricity, and 70 to 116% higher for gas.

2.160 In Section 9, we explore to what extent such price disparities provide evidence of a lack of engagement on the part of microbusinesses.

Have prices been above competitive levels?

2.161 A key question we consider in this investigation is whether the average prices paid by domestic customers and microbusinesses have been above the levels that we would expect to see in a well-functioning competitive market. In Section 10 we set out our analysis on this issue, considering two related questions:

- Have levels of profitability been excessive?
- What price levels would we expect to have seen in a competitive market?

2.162 In relation to the first question, we review the margins earned on electricity and gas with those earned in other sectors and other countries. We also calculate the return on capital employed (ROCE) for retail suppliers and compare this with the weighted average cost of capital (WACC) for the Six Large Energy Firms.

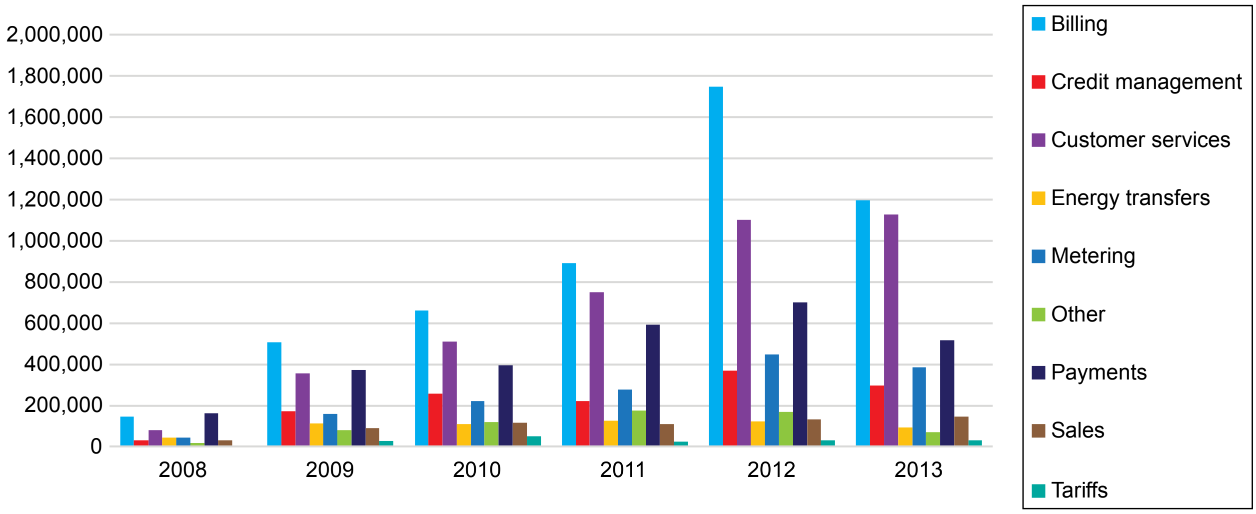
2.163 We also adopt two approaches to addressing the second question. First, we adopt a bottom-up approach to assessing a competitive price level, by assessing the efficient level of indirect costs, wholesale costs and capital base. Second, we consider the average price levels offered by some of the mid-tier suppliers and consider whether these provide an indication of a competitive price level.

Quality of service

2.164 There have been considerable concerns about the quality of service offered by the Six Large Energy Firms. We asked them to provide information on the number of complaints they had received, broken down by type of complaint. The results indicated that:

- the number of recorded complaints has increased fivefold from 2008 to 2013; and
- problems related to billing, customer services and payments accounted for the majority of complaints, as shown in the chart below.

Figure 19: Evolution in complaints for five of the Six Large Energy Firms



Source: CMA analysis of data provided by four of the Six Large Energy Firms.

2.165 Complaints received by the Energy Ombudsman more than doubled between 2013 and 2014, driven primarily by increases in complaints about two suppliers and concerning billing, although problems relating to transfers have also been a factor.[55] The Energy Ombudsman told us that complaints about billing largely concerned: disputed charges; inaccurate invoices/ absence of bill; quality of customer services; and back billing.

2.166 We note that increasing numbers of complaints may reflect: declining quality of service; price rises; changes in reporting standards; increasing media scrutiny of the sector; or a combination of these factors.

2.167 We have reviewed other pieces of evidence that would suggest that the customer service provided by the Six Large Energy Firms may be relatively poor. For example, in recent years Ofgem has taken enforcement action for breaches of the complaints-handling regulations against several of the Six Large Energy Firms. We also note that, according to a survey conducted in 2014 by Which? into standards of customer service across different sectors, all of the Six Large Energy Firms were in the bottom fifth of the table for customer service and two of them came last and second to last out of the 100 brands included in the survey.[56]

2.168 We have also seen some evidence that would suggest that the negative publicity surrounding the sector may have had an effect on attitudes towards energy firms. For example, evidence from the CMA's customer survey suggests that domestic energy customers have a much higher level of trust

[55] Energy Ombudsman 2013/14 Annual Report.
[56] A summary of results is available on the Which? website.

that their own supplier will treat people in a fair and honest way than that other energy suppliers will treat people in a fair and honest way. Further, the results suggest that trust in other energy suppliers is considerably below that in other service companies, such as retail banks, car insurers and mobile phone network providers.

Future changes

2.169 We are mindful of the fact that this is a time of rapid change in the energy sector, with elements of the regulatory framework and supply and demand characteristics subject to fundamental change over the next few years. Accordingly, in assessing whether particular features of energy markets give rise to an AEC – and, if so, in considering the appropriateness of remedies – we need to take account of the likely impact of such changes.

2.170 In this section, we set out some of the key changes that are likely to have a bearing on competition in energy markets.

Increasing role of government in the energy markets/increasing impact of policy costs on energy bills

2.171 The next few years will see the government take a more important role in energy markets, particularly in the wholesale electricity markets, where investment decisions will increasingly be driven by CfDs and the Capacity Market. The nature of competition will increasingly shift to one of ‘competition for the market’, in which operators compete for long-term contracts through a centralised allocation process.

2.172 The growing role of government policies and interventions in the energy markets will also have an impact on the prices and bills paid by customers. Most of the policies will add to costs and increase prices while some will have the effect of reducing bills, through improving energy efficiency.

2.173 On the basis of current announced plans, DECC estimates that the net effect of policies such as smart meters and the ECO will be to reduce average bills in 2020, while other policies will impose an increasing cost on households. For example, the cost of support for large-scale low carbon generation (the RO and CfDs) is expected to more than double from £38 on a household electricity bill in 2014 (about 6.5% of the electricity bill) to £82 in 2020 (about 13.5% of the projected household electricity bill).[57]

[57] 2014 prices. Source: DECC (November 2014), Estimated impact of energy and climate change policies on energy prices and bills, Table D1.

2.174 This underscores the need to ensure that such policies are developed in a way that maximises the use of competition to bear down on costs faced by consumers, an issue we consider in Section 5, in relation to CfDs.

Increasing importance of renewable generation

2.175 There will be a fundamental change in the types of plants expected to be generating electricity over the next few years, as fossil fuel plants are increasingly replaced by renewable generation, with different cost and operating characteristics, and in particular a growing share of capacity and output of wind generation, which is dependent on weather conditions.

2.176 In 2014 the share of renewables in generation output was 19% and it will have to increase substantially again to meet the 2020 renewables target. The resultant increase in intermittency will put an additional premium on flexible generation and demand-side response.

Full roll-out of smart meters

2.177 Smart meters will be rolled out to all households and businesses by 2020. These meters will allow consumption to be recorded on a half-hourly basis, potentially addressing some of the major sources of customer dissatisfaction relating to billing and making energy use and the cost of energy more visible and easy to understand. We consider these potential impacts in Section 7, on the nature of retail competition.

2.178 In addition, smart meters could allow for time-of-use pricing, and provide for two-way communication, which could enable more price-responsive demand or better-targeted direct load control. In Section 8 we consider changes to the regulatory framework that may be required to achieve these outcomes.

Final observations

2.179 The period since the privatisation of electricity and gas in Great Britain has been one of continued regulatory change, as policymakers have attempted both to secure greater degrees of liberalisation and, particularly in recent years, to achieve the overarching policy goals of reducing emissions, ensuring security of supply and improving the affordability of prices.

2.180 In several respects, the energy sector has performed well against these objectives. There have been no significant security of supply incidents in recent years, emissions from electricity and gas have reduced and renewable deployment has increased. However, concerns have arisen in relation to the affordability of energy – domestic price increases have far outstripped inflation over the past ten years and there have been concerns about levels of profitability – and standards of service appear to have deteriorated. Pressure on prices is likely to grow in the future, due in part to the increasing costs imposed by climate and energy policies.

2.181 These concerns provide important context for our analysis of competition in the rest of this document.

3. Market definition

Introduction

3.1 In this section we set out our approach to market definition.[58] Our guidelines state that defining the market helps to focus on the sources of any market power and provides a framework for the assessment of the effects on competition of features of a market. However, market definition and the assessment of competition are not distinct chronological stages of an investigation but rather are overlapping and continuous pieces of work, which often feed into each other.[59]

3.2 A market is a collection of products provided in particular geographic areas connected by a process of competition. The process is one in which firms seek to win customers' business over time by improving their portfolios of products and the terms on which these are offered, so as to increase demand for them. The willingness of customers to switch to other products is a driving force of competition. In forming our views on market definition, we therefore consider the degree of demand substitutability. In some markets, supply-side constraints will also be important.[60] Market definition in a market investigation flows from the statutory questions the investigation is required to address. Markets defined in the context of answering other statutory questions, or under other regimes, may not therefore be comparable.[61]

3.3 Our guidelines also state that market definition is a useful tool, but not an end in itself, and that identifying the relevant market involves an element of judgement. The boundaries of the market do not determine the outcome of our competitive assessment of a market in any mechanistic way. The competitive assessment takes into account any relevant constraints from outside the market, segmentation within it, or other ways in which some constraints are more important than others.[62]

3.4 There are normally two dimensions to the definition of a market: a product dimension and a geographic dimension. We consider each of these aspects

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[58] The 'relevant market' is defined in the 2002 Act to mean the market for the goods or services described in the terms of reference given to the CMA for investigation. However, the market definition(s) used by the CMA need not correspond with the 'relevant market(s)' (see *Guidelines for market investigations: their role, procedures, assessment and remedies, CC3*, April 2013, paragraph 26).
[59] *CC3*, paragraphs 94 & 132.
[60] *CC3*, paragraph 130.
[61] *CC3*, footnote 74 (paragraph 132).
[62] *CC3*, paragraph 133.

below. In line with previous decisions taken by Ofgem and competition authorities, we have assessed wholesale and retail markets separately.

3.5 Our starting point for assessing market definition is the terms of reference for this investigation, which concern the activities connected with wholesale and retail supply[63] and wholesale purchasing or trading of energy for purposes which may ultimately include retail supply in Great Britain.

Wholesale energy market(s)

Product definition

3.6 Wholesale market activities in the energy sector in Great Britain broadly encompass the following:

(a) upstream production and importation of gas, and generation and importation of electricity,[64] for sale into the wholesale trading market; and

(b) bilateral and exchange trading between producers, generators, suppliers, traders and consumers in the wholesale trading market.[65]

3.7 We discuss below whether the wholesale market(s) may be distinguished by output fuel type and/or further segmented by types of products within output fuel type.

Product market defined by output fuel type

3.8 From the point of view of demand-side substitution, gas and electricity are distinct products from each other and from other sources of energy. Although there is likely to be, in the long term, some demand-side substitutability by end-users of gas and electricity (eg for heating and cooking), there are very few substitutes for end-users for gas and electricity in the short term. Moreover, gas producers and electricity generators, and those operating at the level of the wholesale trading market (including retail suppliers of gas and electricity), typically have very limited, if any, ability to influence the purchasing choices of end-users in response to short-run price

[63] In summary, 'retail supply' is defined in the terms of reference as supply to premises at which gas or electricity is or is to be consumed by a person who is a domestic customer or who falls within Ofgem's definition of a microbusiness. For further details, see the energy market investigation terms of reference.
[64] We include in these activities ancillary services associated with the wholesale supply of electricity and gas.
[65] When using the term 'wholesale markets' in this report, we refer to both activities unless otherwise noted. This is consistent with previous decisions. See in particular COMP/M.5224, EDF/British Energy, 22 December 2008.

signals (in particular, domestic customers and microbusinesses).[66] We also note that, from a supply-side perspective, there is limited commonality between the companies that are engaged in gas production and the companies that are engaged in electricity generation. Our provisional view is therefore that the upstream production and importation of gas and upstream generation and importation of electricity should be considered as distinct wholesale product markets.[67]

Further segmentation by types of products

- *Wholesale electricity*

3.9 We have considered whether the electricity that is sold into the wholesale trading market by generators and importers of electricity should be segmented by time period over which such electricity is sold (eg three years ahead; day ahead; other time period), and/or whether the electricity that is sold is baseload or peakload.

3.10 End-users of electricity, and their retail suppliers, have limited ability to store electricity, meaning that the electricity that is purchased from the wholesale trading market must match demand, and trading typically occurs up until gate closure in order for a retail supplier to match demand to its customer base.[68] Electricity retail suppliers in Great Britain purchase products on the wholesale trading market ranging from up to three years ahead (where they may purchase an initial amount of baseload and/or peakload electricity), with further trading occurring up until the day ahead of delivery, in order to ‘shape’ their electricity purchasing to match forecast demand. Given the different purposes to which electricity purchased over different time periods is put, there appears to be limited, if any, demand-side response from retail suppliers concerning electricity products purchased over different time periods. From a supply-side perspective, generators will typically either produce baseload or peakload electricity from each generation asset, which typically limits the time periods over which such electricity can be sold in the wholesale trading market. In addition, the electricity that is sold in the wholesale trading market comes from different sources (eg nuclear, gas, coal, biomass) and follows various trading routes (differentiated mainly by their time horizon and size/volume of trade, including over-the-counter

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[66] See further Section 4, the nature of wholesale competition and Section 7, the nature of retail competition.
[67] We note that, from the point of view of production and generation, gas and electricity are linked through the presence of CCGT and open-cycle gas turbine (OCGT) technology that allows an electricity generator to convert gas into electricity. In such instances, therefore, it might be useful to think of the gas and electricity markets as one market, and we have not reached definitive conclusions in these provisional findings.
[68] See further Section 4, the nature of wholesale competition and Section 7, the nature of retail competition.

(OTC) brokered and non-brokered trades, trades on the GB Power Exchange and trades operated through the BM).

3.11 However, within the context of our analysis to date, it has not been necessary to distinguish between products by any of these characteristics (eg time, baseload/peakload, or source). Accordingly our provisional view is therefore to consider the wholesale electricity market to be one market comprised of different segments including generation (both the production of electricity at power stations and imports through interconnectors) and trading.

- *Wholesale gas*

3.12 Similarly to electricity, gas products come from different sources, are traded in different ways (eg OTC, on the ICE Futures Exchange, On The Day Commodity Market (OCM)), and may relate to different type and time periods (eg peak or off-peak, each for durations ranging from within-day to six years ahead).

3.13 We note that in previous decisions, the European Commission found that gas storage, or gas flexibility, could constitute separate product markets.[69] However, within the context of our analysis to date, it has not been necessary to adopt a similar approach. Accordingly our provisional view is therefore to consider the wholesale gas market to be one market comprised of different segments including production (including imports through interconnectors) and trading.

Geographic definition

3.14 Our Guidelines state that geographic markets may be based on the location of suppliers and defined as an area covering a set of firms or outlets which compete closely because enough customers consider them to be substitutes.

3.15 The form of geographic competition in the wholesale markets is determined by the market rules. These are described in Appendix 5.2. By and large, wholesale suppliers of each fuel compete in separate GB markets regulated by Ofgem.

3.16 There can be times, especially as regards electricity generation and importation, when transmission constraints render competition on a GB-wide

[69] See, for instance, COMP/M.1383-Exxon/Mobil, 29 September 1999; COMP/M.3410-Total/GdF, 8 October 2014; COMP/M.3868-DONG/Elsam/Energi E2, 14 March 2006.

basis impossible and some generators and/or interconnectors may find themselves in isolated markets. Thus, there are certain times when markets may be more localised or regionalised from the point of view of substitutability.

3.17 We note that the geographic definition may be more complex in relation to gas, and that in previous decisions the wholesale market for gas has been considered to be either a UK-wide market[70] or, more frequently, a GB market.[71] For the purposes of our investigation, however, it has not been necessary for us to take a definitive view on this to date.

3.18 Accordingly, our provisional view is therefore to consider that the geographic wholesale markets for both gas and electricity are best defined as Great Britain.

Retail energy market(s)

Product definition

3.19 We discuss below whether the retail energy market(s) may be distinguished by types of fuel, by categories of customers or by tariff types.

Types of fuel

3.20 As noted above, from a demand-side point of view, there are very few substitutes for gas and electricity in the short term for end-users, although there is likely to be some substitutability between the two (eg for heating and cooking) in the long term. Moreover, a retail energy supplier has very limited, if any, ability to influence the purchasing choices of end-users in response to short-run price signals (in particular, domestic customers and microbusinesses).[72] Our provisional view is therefore to consider the retail supply of gas and electricity to be distinct product markets.[73] We discuss below whether it may be appropriate to segment the retail energy markets more narrowly by category of customer and/or by tariff types.

[70] CC (August 2003), *Centrica plc and Dynegy Storage Ltd and Dynegy Onshore Processing UK Ltd: A report on the merger situation*; COMP/M.5585 – Centrica/Venture Production, 12 August 2008.
[71] Storengy UK Ltd's application for a minor facilities exemption for Stublach phase 2.
[72] See further Section 7, the nature of retail competition.
[73] We include in this definition of the product markets the services associated with the retail supply of gas and electricity including billing and metering.

Categories of customers

3.21 Retail suppliers may provide gas and electricity to customers connected to the distribution grid. These include households, SMEs (including microbusinesses) and I&C[74] (some I&C customers may however be connected directly to the transmission grid). Our terms of reference concern the supply and acquisition of gas and electricity to domestic customers and microbusinesses only. In this section, we have first examined whether it is appropriate to distinguish separate markets between domestic customers and SMEs, and then within each of these two categories of customers.

- *Domestic customers vs SMEs*

3.22 There are a number of broadly similar characteristics of the retail supply of gas and electricity to SME customers (including microbusinesses) and domestic customers, such as (i) the same major suppliers, and (ii) the same fundamental characteristics concerning energy supply (eg homogeneity and traditional meters and bills). However, in relation to both fuels, there are material demand-side and supply-side differences, as follows:

(a) SME customers have different characteristics from domestic customers, with different requirements, such as fewer use gas and take dual fuel.

(b) SME customers purchase retail energy supplies by different sales channels (more rely on third party intermediaries (TPIs) such as brokers, as compared with domestic customers who rely more heavily on PCWs).

(c) There are more retail suppliers of energy to SME customers than there are to domestic customers.

(d) There are different tariff structures available (as compared with those available for domestic customers).

(e) There are different costs associated with supplying to SME customers as compared with domestic customers (including significant differences in the levels of environmental obligations and bad debt).

(f) There are different regulatory rules governing energy supply to SMEs and domestic customers.[75]

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[74] As set out in previous decisions, there is a clear distinction between I&C customers, on the one hand, and smaller businesses and domestic customers on the other hand. See for instance COMP/M.3868-DONG/Elsam/Energi E2, 14 March 2006.
[75] See Section 8.

3.23 In light of the material demand-side and supply-side differences, our provisional view is to consider domestic customers as being in different markets from SME customers in relation to both gas and electricity. We have also considered whether retail supply to microbusinesses should be distinguished from larger SME customers.

- *Microbusinesses vs larger SMEs*

3.24 SMEs are highly diverse in size, complexity, and their electricity and gas needs. We also find, as set out in Section 9, considerable variation in engagement between SME customers. However, in general, SMEs are taken as a group by suppliers, and SMEs of different sizes have access to the same tariff structures. In contrast, SMEs do not have access to the same tariff structures that are available to domestic customers or I&C customers.

3.25 We note that there are regulations specific to microbusinesses, and have considered whether, on that basis, retail supply to microbusinesses might be considered as separate markets from the SME markets. However, we note that, in practice, retail suppliers generally apply the same protections to all of the customers that they classify as SMEs, and therefore we do not consider that these microbusiness-specific regulations constitute a meaningful justification to define a separate market for retail supply to microbusinesses as from retail supply to SMEs.

3.26 Accordingly, our provisional view is to consider that microbusinesses are a distinct segment of the markets for the supply of electricity and gas to SMEs in Great Britain, respectively.

Length of contracts (domestic customers)

3.27 We have also considered whether the domestic retail markets could be defined more narrowly based on the duration of supply contracts.

3.28 We note in Sections 7 and 8 that there appears to be considerable variation in engagement between domestic customers. For example, some domestic customers switch regularly to get the best deals, while others have been on an SVT for many years; others may not have exercised choice at all since liberalisation. We also note that different domestic customers pay widely varying prices for their energy, with those who have not engaged generally paying more than those who have.

3.29 As set out in our Guidelines, we reflect this sort of situation in our approach to market definition:

One set of customers may be more affected than others by any particular feature. Where such diversity exists, and where suppliers can charge different prices to different groups (ie price discriminate), the CMA will recognize these differences. In terms of market definition, depending on the market and the evidence presented, the CMA may choose either to treat these different groups as separate markets, or as segments within one market, noting the scope for price discrimination between different groups within the market.[76]

3.30 We have examined whether domestic customers subscribing to SVTs fall into a different product market from those subscribing to non-standard tariffs. On the supply side, we note that all suppliers have consistently priced their SVTs at a premium to fixed-term tariffs. In Sections 7 and 8, we provisionally find that suppliers are able to price discriminate between domestic customers on an SVT and those on a non-standard tariff.

3.31 However, as we consider in Sections 7 and 8, customers do not fall into discrete camps of 'engaged' and 'disengaged'. There is a variety of degrees of engagement, and some domestic customers are relatively active before defaulting to an SVT. We therefore do not think that customers subscribing to SVT and non-standard tariffs are sufficiently distinct to warrant defining separate markets for them.

3.32 Accordingly, our provisional view is to consider customers subscribing to an SVT and those subscribing to non-standard tariffs to fall into different market segments of the domestic retail markets, in the light of the different intensity of competition to which they are subject.

Types of meter (domestic customers)

3.33 There are broadly three main types of meter to measure domestic customers' consumption of gas and electricity:

(a) traditional meters;

(b) smart meters; and

(c) prepayment meters.

[76] *CC3*, paragraph 150.

3.34 Customers whose consumption in measured by a traditional or smart meter have a choice as to whether to pay by standard credit or direct debit. In contrast, all customers on prepayment meters must pay by prepayment.

3.35 We note in Section 8 that there appears to be some demand-side and supply-side differences between customers on prepayment meters and customer on non-prepayment meters. As noted above in paragraph 3.29, we do reflect this sort of situation in our approach to market definition.

3.36 Domestic customers on prepayment meters have different characteristics from other domestic customers, with different requirements, such as fewer use gas and take dual fuel. Prepayment meters are generally installed where a customer has a poor payment history or in specific types of accommodation such as holiday homes and student accommodation.

3.37 We also note that nearly all prepayment customers have been on an SVT, due to technical constraints imposed by certain types of prepayment meter. As a result, domestic customers on prepayment meters have a very restricted choice of non-standard tariffs compared with other domestic customers. SVTs are an acquisition tariff for customers on prepayment meters, but are generally not an active acquisition tariff for other domestic customers.

3.38 However, we do not think that these differences are sufficient to warrant defining separate markets for customers on prepayment meters. We note however that, due to the limited availability of non-standard tariffs to customers on prepayment meters, and some demographic characteristics of these customers, they might face additional actual or perceived barriers to engaging in the market.

3.39 Accordingly, our provisional view is to consider domestic customers on prepayment meters and customers on non-prepayment meters to fall into different market segments of the domestic retail markets, in the light of the different intensity of competition to which they are subject.

Geographic definition

3.40 Historically, Great Britain was divided into 14 electricity distribution network areas and 13 gas distribution areas defined by the physical layout of the distribution and transmission network. This geographic segmentation of the supply of gas and electricity to domestic customers and SMEs continues to a certain extent today with:

(a) costs varying between regions given different network costs; and

(b) tariffs determined at a regional level broadly reflecting cost differences and, in the case of fixed period tariffs, differences in competitive dynamics.

3.41 We note that:

(a) the regulatory regime, which determines to a large extent the basic parameters of retail competition, applies equally across Great Britain;

(b) all of the Six Large Energy Firms have a presence in all regions (and the mid-tier suppliers have a presence in most regions); and

(c) the range of tariffs offered by suppliers is similar across regions (although the prices may differ, principally due to higher transmission and distribution costs).

3.42 These considerations apply to both domestic and SMEs customers.

3.43 Accordingly, our provisional view is to consider the geographic retail markets for both fuels (electricity and gas), and for both categories of customers (domestic and microbusiness), as GB-wide, although we are mindful, as noted above, of the particular constraints that might be disproportionately faced by customers in certain nations and regions.

Summary of relevant energy markets

3.44 The supply and demand of wholesale and retail gas and electricity involves a large number of interdependent products and services supplied to and demanded by different types of customers. The regulatory framework applicable to such products and services to different categories of customers may vary significantly. We have not reached definitive views as to the boundaries of these markets. We have not needed to do so under any of our theories of harm to date. When we refer to a specific market or markets, we therefore do not mean to imply that we have formally defined it as a market for the purposes of any particular question.

3.45 However, based on our analysis to date, our provisional view is to consider the following relevant markets:

(a) the wholesale electricity market in Great Britain (including trading);

(b) the wholesale gas market in Great Britain (including trading);

(c) the retail supply of electricity to domestic customers in Great Britain;

(d) the retail supply of gas to domestic customers in Great Britain;

(e) the retail supply of electricity to SMEs in Great Britain, comprising, at least, a microbusinesses segment; and

(f) the retail supply of gas to SMEs in Great Britain, comprising, at least, a microbusinesses segment.

3.46 In our provisional findings, we have sometimes aggregated for convenience, and given similar demand and supply conditions, the markets for the retail supply of gas and electricity to domestic customers. This is because, in particular, the major suppliers supply both gas and electricity; the majority of customers buy both fuels from the same supplier; and much of the regulatory framework concerning how suppliers engage with their customers applies to both fuels.

3.47 Likewise, broadly similar demand and supply conditions apply to both fuels in relation to SMEs. The major SME suppliers supply both gas and electricity, and much of the regulatory framework concerning how suppliers engage with their customers applies to both fuels (although compared with the domestic retail markets, fewer SME customers take both fuels, and fewer take both from the same supplier). Therefore, in our provisional findings, for convenience, as with domestic retail markets, we have sometimes aggregated the markets for the retail supply of gas and electricity to SMEs.

4. Nature of competition in wholesale energy markets

4.1 This section assesses the nature of competition in GB wholesale gas and electricity markets. Its purpose is to analyse the competitive pressures that are brought to bear on gas producers and electricity generators in producing energy and selling it to retailers and to identify specific areas of competition concern that we consider warrant more detailed investigation. These areas of concern are analysed in more detail in Section 5.

Introduction

4.2 The nature of competition in the wholesale gas and electricity markets can be characterised, at a high level, in three parts:

(a) Investment in gas fields and power stations that determine over the long term the productive capital mix in these industries.

(b) Spot markets that determine how existing capacity is used moment to moment.

(c) Financial markets that spread and share the risks involved in these two activities.

4.3 Investment decisions in gas production and electricity generation are capital-intensive and long-lived. The risks attached to each project – both technical and financial – are often very significant. The nature of competition is that a number of expert firms – usually global players – compete to bring together the expertise in the many different markets that are brought into play in a decision to make a capital commitment of this type.

4.4 Most of the activities involved in the investment decisions are negotiated business-to-business and often business-to-government; for example, the acquisition of sites; the selection of technologies and plant; and the management of construction and maintenance. As discussed in Section 2, there has recently been a set of significant reforms in the electricity sector that will see increasing use of formal government-led auctions and competitions **for** the market, substituting for competition within the market.

4.5 A small but, increasing, element of the investment decisions that are made in the wholesale energy markets relates to demand-side responses: capital equipment can reduce energy demand or increase the flexibility of its time of use. Examples would be heating systems that anticipate cold weather and store up hot water in order to avoid high gas prices. In conceptual terms, investments on the demand side are much like investments on the supply side – they both aim to provide ‘energy services’ – but they are often carried out by very different actors.

4.6 In the short term, owners of existing capacity compete to produce energy from their assets and sell it to retailers and large consumers. Operational decisions at this stage are informed by the following question: given the short-run variable costs of inputs and the expected unit price of outputs, is it worth selling product from a particular capital source? Gas and electricity are both homogenous goods, for which short-term efficiency can be maximised by intense price competition between competing sources.

4.7 To a small extent, consumers are also involved in making short-run decisions about whether to consume energy given a likely price. It is hoped that smart meters and intelligent control systems will increase the amount of demand responsiveness in the system. Large I&C consumers are metered half-hourly and a small number have flexibility to ‘load shift’ from periods of high price to periods of low price. Smart meters are being rolled out (see Appendix 8.6) to all consumers by 2020 and some increase in demand responsiveness is an important part of the anticipated benefits.

4.8 There are unavoidable risks in the long-run and short-run decisions of the participants and there are active financial and forward markets that spread, swap and share those risks. Investment risks can be shared through long-term purchase agreements; cash flows can be smoothed to some extent (up to three years out, but more usually less than two years out) by locking in prices for expected output and demand volumes; fuel input price volatility can be reduced through purchases of fuel derivative contracts.

4.9 While at this level, the nature of competition in wholesale markets is much the same as for other commodity markets, the details are particularly complex in energy markets because of a unique combination of factors:

(a) Technical/engineering factors, like the non-storability of electricity; the joint production of many gas resources; and the unique transport infrastructures required to connect supply and demand.

(b) Historical factors, like the financial settlement systems that the industry inherited from the days of nationalised VI and has upgraded in a piecemeal fashion as liberalisation of the markets has progressed.

(c) Policy factors, like the social importance of security of supply and the large and complex environmental externalities involved in most forms of energy consumption.

(d) Potential complications due to the strategic interactions of firms.

4.10 This section provides an overview and basic description of these complicating factors and points to their possible impact on the nature of competition. It attempts to link the expected nature of competition to the upstream theories of harm that we have examined. It is structured as follows:

(a) We analyse the nature of competition in the **wholesale gas market**, considering investment in capacity, short-term operation and the performance of financial markets.[77]

(b) We analyse the nature of competition in the **wholesale electricity market**, along the same dimensions.[78]

Wholesale gas market

Investment decisions

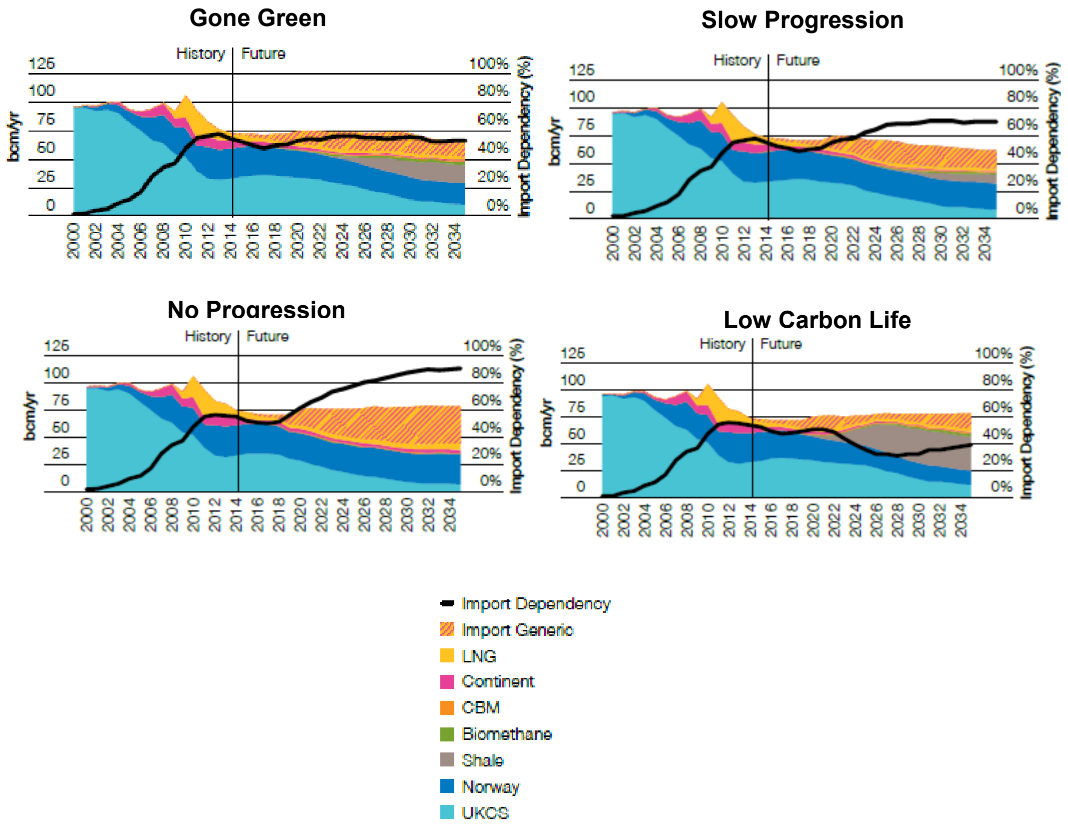
4.11 The natural gas consumed through the gas grid comes ultimately from reservoirs – either gas-only fields or joint gas and petroleum product fields.

4.12 A large but declining proportion of gas consumed in Great Britain is from the UKCS in the North Sea (currently around 50%). An increasing proportion comes directly from Norway and also from the European gas grid, which is itself supplied mainly by Norway, Russia and North Africa. Finally, a small but increasing amount is shipped in on LNG ships, much of it originally extracted in Qatar.

4.13 Figure 4.1 shows the historical and anticipated supply of gas by source to the GB market according to National Grid's Future Energy Scenarios.[79] The figure shows the decline of the UKCS as a source; rising supply from Norway, Europe and LNG; and some role by the middle of the next decade for domestically fracked gas.

[77] This section draws on Appendix 8.6: Gas and electricity settlement and metering and our working paper on the Gas Wholesale Market, which set out our analysis in more detail.
[78] This section draws on Appendices 5.1: Wholesale electricity market rules; 4.2: Generation return on capital employed; Appendix 4.1: Market power in generation; 5.3: Capacity; 6.1: Liquidity; 5.2: Locational pricing in the electricity market in Great Britain; and 8.6: Gas and electricity settlement and metering, which set out our analysis in more detail.
[79] For details, see our working paper on the Gas Wholesale Market, and specifically the section – 'Barriers to entry'.

Figure 4.1: Supply mix and import dependency to 2035, National Grid Future Energy Scenarios



Source: National Grid. The names 'Gone Green', 'Slow Progression', 'No Progression' and 'Low Carbon Life' are the names for National Grid's central scenarios relating mainly to differences in climate change policy.

4.14 Decisions to invest in gas production projects are case-specific and depend on a number of factors relating both to physical geography and the tax regime in the country where the gas is located.

4.15 New investment in UK gas supplies is likely to come from LNG (requiring landing facilities), new interconnectors to Europe, or, at a longer horizon, from incremental investment on the UKCS, and from fracking in the UK. Over the next five years, we do not expect a substantial requirement for new investment: National Grid forecasts peak demand to be flat and current import capacity is sufficient to accommodate the need for additional imports. We have come to no conclusion as to whether the sources on which we might come to be reliant in the future – for example, European supplies – would themselves provide us with a healthy level of competition for supplies.

4.16 An important factor in fossil fuel investment decisions worldwide is the expectation and uncertainty relating to environmental policy particularly that aimed at discouraging carbon emissions. As explained in Section 2, gas-fired electricity generation has a lower carbon intensity than coal-fired plant, and policies such as the EU ETS and the CPS, which put an explicit price on carbon emissions, have led to a degree of coal to gas switching.

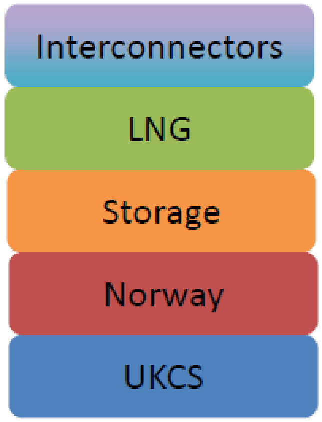
Short-run production decisions and the price-setting process

4.17 A complicated competitive process determines gas prices and production on any given day. Demand for gas is highly temperature dependent both because of its predominant use in heating applications and also because of its use as an input to electricity production. The level of gas demand on a severe peak day is almost twice the average level of demand.

Gas merit order

4.18 There is, at least notionally, a 'stack' of supply options that have different costs to supply the GB market, as shown in Figure 4.2.

Figure 4.2: Relative cost of wholesale gas sources



Source: Ofgem.

4.19 The cost of supplying gas to the GB market on any particular day is mostly made up of the opportunity cost of that gas: selling today involves the sacrifice of selling that gas at another time or another place. In the case of UKCS gas, that cost tends to be low: North Sea fields do not have cheap transport options to other markets; much of the gas produced is from joint gas/oil fields, so that shutting in gas for use at a future time implies also shutting in oil, thus reducing the opportunity cost of current production; finally, shutting in gas for later production tends to mean not producing it for many years hence, making a delay in sales unattractive. This gas therefore tends to be Great Britain's cheapest source. Norwegian gas is next; this has a higher opportunity cost because of large direct pipeline capacity into the European market.

4.20 The next three elements of the 'production stack' are approximate and their positions can change on any given day. The GB system has some capacity for gas storage whose opportunity cost is determined by the ability to sell at times when gas is scarce. Some LNG is a globally traded commodity with a quoted spot price; ships need to be assured of a better price in the GB market than elsewhere in order to divert their course. European supplies can be imported through two interconnectors, one to Holland and the other to Belgium when European prices are lower than GB prices.

Concentration and market power in gas production

4.21 There is competition between providers of gas within and between sources. Ofgem provided us with analysis of market shares and HHIs[80] for the gas wholesale market, looking both at overall gas supply and at flexible gas only. There are a large number of gas producers supplying into the GB market. Their market shares are shown in Figure 4.3. Concentration is low with an HHI of concentration of 720. We found that regardless of which market definition is used, the gas wholesale market appears to be relatively unconcentrated based on market shares and HHIs, suggesting limited scope for exercising unilateral market power.

Figure 4.3: Market shares of upstream GB gas supply, 2012/13

[✄]

Source: Ofgem based on shipper/industry data (confidential and commercially sensitive).
Note: HHI = 720.

4.22 Another metric used by Ofgem to assess the scope for unilateral market power is pivotality analysis. This looks at the supply capacity held by a given player in the wholesale market, and assesses whether demand could be met in all relevant periods (eg each day, week, month, quarter and season) if that supply capacity were not available. Different sensitivities are modelled on both the supply side (looking at the impact of infrastructure outages, specifically the loss of the IUK interconnector and the Milford Haven landing terminal) and the demand side (varying the weather profile used in the analysis using four different weather profiles ranging from mild, based on the 2011/12 winter profile, to 'extreme cold', which is a one-in-50 winter).[81]

4.23 [✄]

4.24 [✄]

[80] Herfindahl-Hirschman Index.
[81] Specifically, the four profiles used by Ofgem are: mild – 2011/12 weather profile; cold – 2012/13 weather profile; very cold – 2010/11 weather profile; extreme cold – 2011/12 weather profile uprated to a one-in-50 winter. More detail on the methodology used in Ofgem's pivotality modelling can be found in Appendix 4 of Ofgem's recent assessment of Storengy UK Ltd's application for a minor facilities exemption for Stublach phase 2.

4.25 Caution must be exercised in interpreting the sort of pivotality evidence that Ofgem adduces to conclude that there are low risks of upstream unilateral market power for two reasons:[82]

(a) Gas, like electricity, is a market that is characterised by peak demand pricing patterns. These are markets in which prices will sometimes rise to very high levels, and that must sometimes rise above the short-run marginal cost of the marginal producer in order to create the necessary incentives for marginal producers to invest in capacity. In periods when demand must be curtailed to meet available supply (when the capacity constraint is binding), by definition every producer is pivotal. There is therefore no surprise in the finding that in some very severe winters, the largest producer is pivotal – there will always be some severity of winter that leads to concerns that prices will exceed short-run marginal costs under a pivotality criterion.

(b) Analysis of market power in spot markets needs to take account of the fact that most participants forward-contract. This is discussed in the Appendix 4.1 in relation to market power in the wholesale electricity market but applies here also: if a large producer has forward-sold output, its incentive to exercise unilateral market power is decreased because the pre-sold units do not benefit from higher spot prices. Unilateral market power opportunities that only arise in very extreme demand situations are likely to be theoretical only, since prudent producers, not being able to anticipate extreme future demand, will have forward-sold much of their output based on forecasts of average demand.

4.26 Taken together, this means that almost all gas producers almost all of the time are price takers: given a level of demand, price can be expected to be set by the opportunity cost of the last producer required to meet that demand.

4.27 Once the decision to actually supply gas at a prevailing price has been taken, a producer confronts some important complications in the market due to the nature of the transportation network required to connect supply and demand.

Transmission, system operation and settlement

4.28 A gas supplier – a firm with a retail customer who has the ultimate demand for gas – must show that it has a contract with a producer for a sufficient

[82] See our working paper on the Gas Wholesale Market, and specifically the section – 'Potential for unilateral market power'.

quantity of gas to meet its customers' demand. However, there are three aspects of the wholesale gas market which make this quite difficult to achieve.

4.29 The first is simply the question of recovery of transmission costs. There are both fixed costs associated with building and maintaining the network and variable costs associated with creating the pressure differences that allow gas to move around it. The network is a natural monopoly and its permitted revenue is recovered from participants under a number of mechanisms. We have not examined the competitive impact of this (intensely regulated) aspect of the market in detail because we have no reason to believe that the natural monopoly regulation is at the heart of concerns over outcomes in the industry. We touch on some of the issues surrounding the distribution of network costs when we consider code governance in Section 11.

4.30 The second complicating factor is that the gas that is bought and delivered by the producer is not physically the gas that is consumed by the end-customer. The transportation and distribution networks are maintained within their required pressure limits by the balancing of what it has put in and taken out of the system, but the gas purchased is in no physical way the gas consumed. There therefore needs to be a central balancing organisation – the SO, in our case National Grid – whose task is to ensure balance at minimum cost. This is a natural monopoly function: balance is a system-wide feature and ultimately needs central control by a single party. From 3:45pm on every day, the SO becomes the sole counterparty for trades on that day.[83] Trades are conducted through the OCM where producers and consumers can offer balancing bids: the price at which they are prepared to increase or reduce supply or demand.

4.31 The third feature of the gas transportation system that complicates transactions is that most consumers are very approximately metered in their actual consumption of gas.[84] Balancing is required day by day; however, suppliers do not know, for most of their customers, what actual consumption is day by day. At the very best, with most domestic customers, suppliers have monthly meter readings. They are usually more infrequent than that. The entry and exit points from the high pressure transportation system are continually metered. However, the allocation of consumption on a day to specific suppliers is carried out through a series of slow and successive approximations. There is currently never an actual reconciliation with most meter readings for domestic consumers.

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[83] See our working paper on the Gas Wholesale Market paragraph 2.
[84] For details, see Appendix 8.6: Gas and electricity settlement and metering.

4.32 This system of settlement is the result of history: the fully vertically integrated operation that was British Gas never needed disaggregated metering and settlement was entirely an internal matter between divisions; when retail competition was layered on to the old physical infrastructure, working approximations were deemed preferable to precision. The widespread introduction of smart meters and the promise of increased demand responsiveness in the energy system, however, has, for the past eight years or so, shone a light on the deficiencies of the settlement system. We consider in Section 11 whether the governance of changes to the inescapably common rules that bind together these processes in the industry has been up to the task, and we specifically highlight the time and difficulty the industry has had in overhauling gas settlement systems.

Vertical integration

4.33 There is a small degree of VI in the gas market.[85] For example, Centrica, and to some extent Statoil and Total have significant interests in several parts of the value chain. Centrica both owns gas fields and is a large consumer of gas as an electricity generator and as a supplier to retail customers. Unlike the old British Gas, Centrica has no involvement in the transportation and distribution part of the vertical chain.

4.34 Figure 4.4 shows the degree to which, in 2012/13, the major companies were involved in both upstream and retail activities.

Figure 4.4: Estimated physical positions (consumption, output and net gas position) by party (2012/13)*

[✂]

Source: Ofgem.
*Units used are billion cubic metres. UKCS: UK continental shelf production, Norway: Norway production, LNG: LNG imports, IUK (imp): Imports from Belgium interconnector, BBL: Imports from Netherlands interconnector, Storage (With): Withdrawals from storage, IUK (exp): Exports from Belgium interconnector, Storage (inj): Injection to storage. RWE sold RWE Dea AG in March 2015 and no longer has any upstream gas assets.

4.35 We do not believe that the harm that can sometimes arise from VI – typically involving using influence in one market to disadvantage rivals (for example by raising their costs) in another market – is a risk in the wholesale gas market. The ability to harm rivals requires market power in a market to which the rivals require access. The only plausible candidate for this harm would be Centrica with its upstream ownership of gas and downstream retail business. However (as shown in Figure 4.4), Centrica, despite its ownership

[85] See our working paper on the Gas Wholesale Market and specifically the section – 'Vertical integration'.

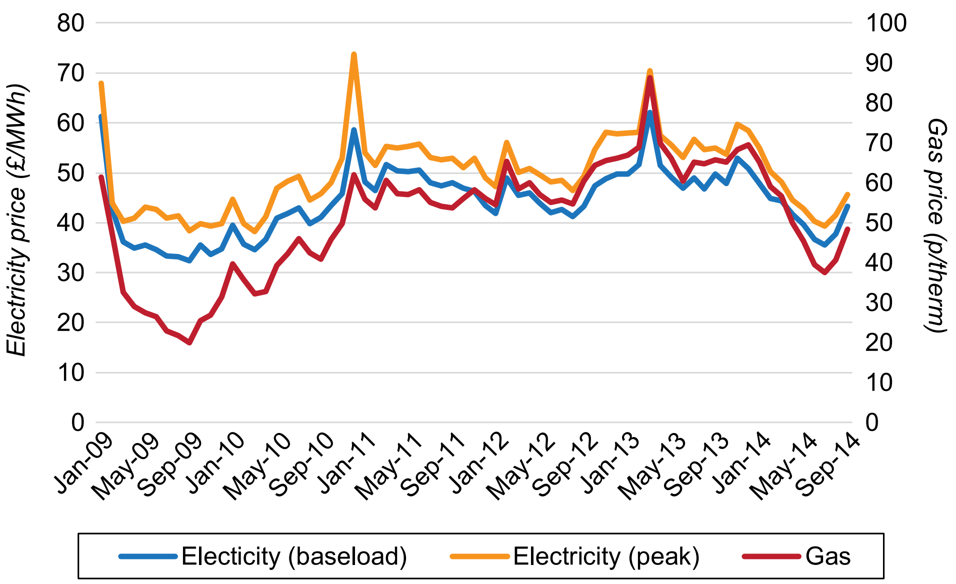
of gas fields, remains a net buyer of gas in the wholesale market. Higher wholesale prices would thus damage Centrica.

4.36 The wholesale gas market has close interdependencies with the wholesale electricity market because gas is an important input to electricity production in many periods during the year. High gas prices therefore cause high electricity prices. Moreover, times of high demand for gas and electricity tend to be correlated: peak gas demand occurs on cold winter days, while peak electricity demand tends to occur during cold, dark early evenings. During such periods, a large proportion of energy services supplied to the GB economy are ultimately being supplied by burning gas, be it in home boilers or power stations, and prices are high in both markets. The correlation in prices between the two markets is very clearly visible in Figure 4.5.

Financial markets

4.37 Gas prices vary a great deal both because of the weather dependency of demand but also because of interactions with other fuel prices and the general economy. Many European gas contracts remain indexed to the oil price. Figure 4.5 shows monthly average GB day-ahead prices for gas and electricity from 2009 to 2014.

Figure 4.5: Monthly average of day ahead gas and electricity prices



Source: Bloomberg, ELUBDHAD, ELUPDHAD, NBPGDAHD.

4.38 Suppliers seek to smooth purchasing costs through forward purchases. Producers have some interest in smoothing their cash flows and selling forward. The GB wholesale gas market has developed deep and liquid forward markets based mainly around a standard contract. On all measures of liquidity, the GB wholesale gas market is healthy.[86] Figure 4.6 shows the churn (the volume traded divided by the physical volume consumed, or the number of parties through which gas ownership passes between production and consumption) which has been consistently high since at least 2008.[87]

Figure 4.6: Traded volume and churn on GB gas markets

[✄]

Source: Ofgem (response on 22 October 2014).
Note: The National Grid data only includes trades that resulted in a change in physical nominations. The second churn series is therefore likely to be more representative, as it includes all trades, but is only available since 2012. We therefore include both series on this chart for reference.

4.39 There have been criticisms of the level of transparency in the wholesale gas market and some allegations of the manipulation of reported gas price indices. We have not judged[88] that these issues ought to be priorities for this investigation for two reasons:

(a) On the point of transparency, we found that prices of almost all trades are available to market participants through the data made available by the trading platforms. Lack of price transparency therefore is not likely to constitute a barrier to entry in the gas market.

(b) On the question of index manipulation, we found that Ofgem and the Financial Conduct Authority (FCA) have actively investigated allegations and have demonstrated a willingness to use the powers that they have to deal with any problem

Provisional conclusion

4.40 Based on the analysis set out above, we have provisionally not found any features within the wholesale gas market that lead to AECs.

Wholesale electricity market

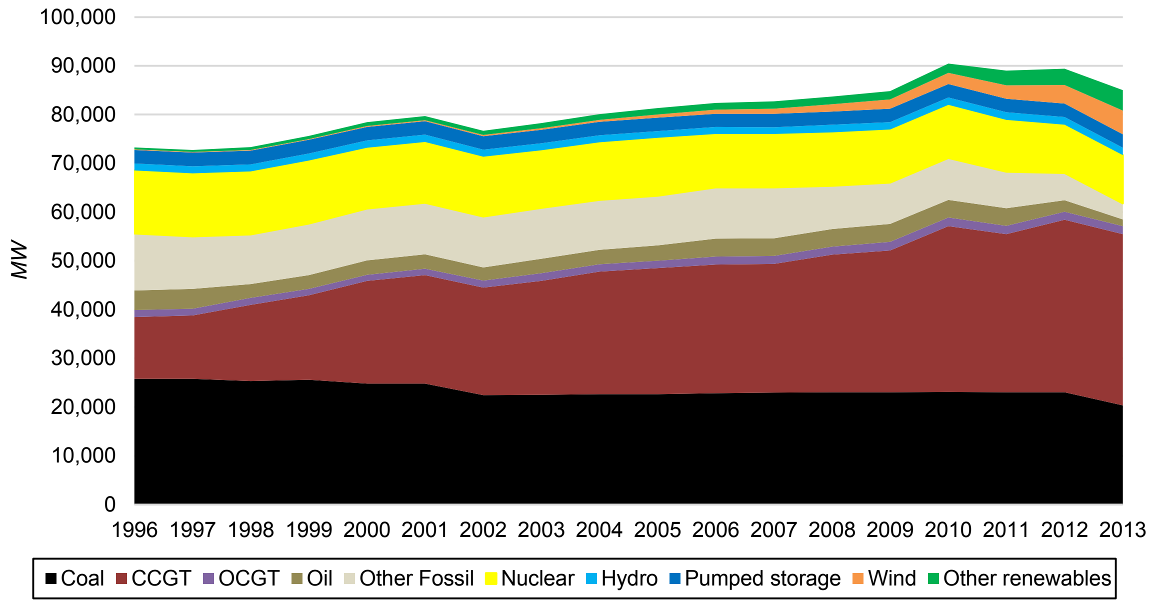
Investment decisions and capacity

4.41 The assets from which electricity demand can be satisfied at any time are made up of a mix of long-lived assets of different technologies. Figure 4.7 shows the evolution of the mix since 1996. Investment decisions over the

[86] See our working paper on the Gas Wholesale Market, and specifically the section – 'Liquidity'.
[87] ibid, paragraphs 41–45.
[88] See Wholesale gas working paper, paragraphs 49–63.

period have tended to favour CCGT plant as well as wind and other renewables. There has been a slow decline in coal capacity as well as some closure of nuclear capacity.

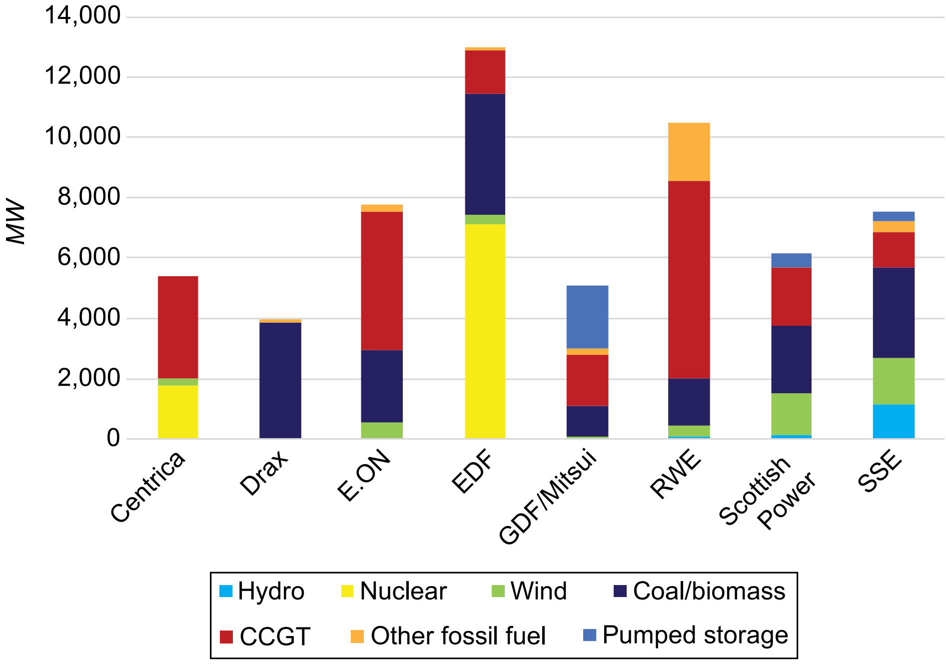
Figure 4.7: Generation capacity by technology (1996 to 2013)



Source: DECC (2014), DUKES, *Electricity: Section 5*, Table 5.6.

4.42 The eight largest owners of generating capacity have very different portfolios of technologies, as shown for 2014 in Figure 4.8. Drax owns a single plant, part coal, part biomass. Centrica has mostly chosen to own gas and nuclear plant; Drax is a single-plant owner exposed to coal and to a small degree to biomass; E.ON is mostly a coal and gas owner, with a small wind portfolio; EDF Energy owns nuclear, coal and gas assets with a small wind portfolio; RWE is mostly a coal and gas owner, with some oil and some wind; Scottish Power is a coal and gas owner with some wind and hydro; SSE owns coal and gas, with some hydro, pumped storage and wind.

Figure 4.8: Generation capacity by party and technology (2014)



Source: DUKES 2014, Table 5.10.

4.43 Interconnection capacity also contributes to the GB wholesale electricity market's ability to meet demand, although, when prices are higher at the non-GB end of a link, the capacity will add to demand rather than to supply. Figure 4.9 shows the current interconnector assets and capacity. There are currently four interconnectors in Great Britain. Their total capacity accounts for around 5% of Great Britain's generating capacity. While the two interconnectors with mainland Europe usually import electricity (in 2013 average net imports from BritNed and Interconnector France-Angleterre (IFA) were 60% of potential operating capacity[89]), the two interconnectors to Northern Ireland and the Republic of Ireland generally export. Total net imports contributed 3.9% of electricity supply in 2013.[90]

89 DUKES, Table 5B.
90 DUKES, paragraph 5.6.

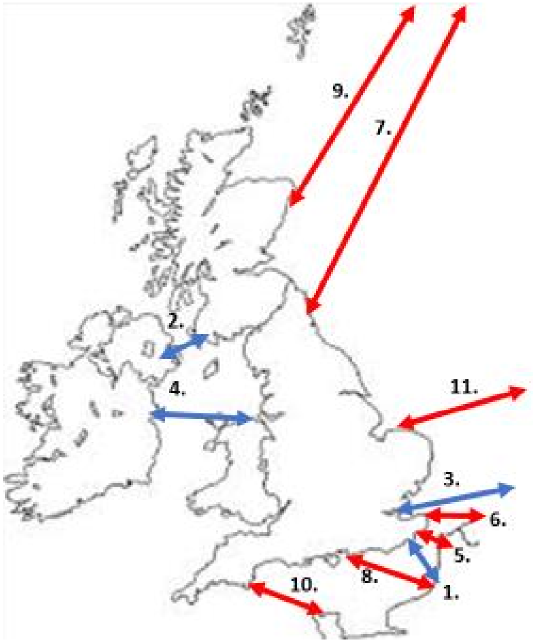
Figure 4.9: GB interconnectors

Number on map	Interconnector	Connects to	Capacity (MW)
Operational interconnectors			
1.	IFA	France	2,000
2.	Moyle	Northern Ireland	450
3.	BritNed	The Netherlands	1,200
4.	EWIC	The Republic of Ireland	500
		Total	**4,150**

Source*:* CMA analysis, National Grid Interconnector Register and 10-year plan.

4.44 There is active interest in investment in greater interconnection capacity, as shown in Figure 4.10. Great Britain has among the lowest levels of inter-connector capacity in Europe, compared with its total generation capacity. This is partly due to Great Britain being an island. If all projects were to go ahead, this could add a further 7,850 MW capacity which would account for around 15% of GB generation capacity; it could also add that amount to peak demand.

Figure 4.10: Operational and proposed interconnectors*



Number on map	Interconnector	Connects to	Capacity (MW)	Date of completion (estimate)
Operational interconnectors				
1.	IFA	France	2,000	
2.	Moyle	Northern Ireland	450	
3.	BritNed	The Netherlands	1,200	
4.	EWIC	The Republic of Ireland	500	
Proposed interconnectors				
5.	Eleclink	France	1,050	Oct 16
6.	Nemo	Belgium	1,000	Oct 18
7.	NSN	Norway	1,400	Oct 19
8.	IFA 2	France	1,000	Oct 19
9.	North-connect	Norway	1,400	Oct 21
10.	FAB	France	1,400	Dec 20
11.	Energinet	Denmark	1,000	Oct 20
		Total	**12,000**	

Source: CMA analysis, National Grid Interconnector Register and 10-year plan.
*Proposed interconnectors are only those that feature on the interconnector register. We are aware that there are other interconnectors that are being considered.

Drivers of investment in generation

4.45 Between the introduction of NETA in 2001 and DECC's introduction of a Capacity Market in 2014, sunk and fixed capital costs were recovered entirely from earnings derived from energy sales in the wholesale electricity market. The decision to invest in a power project is high risk. A large capital commitment (around £0.5 billion for a mid-sized project) is required in exchange for an uncertain flow of revenues that will recoup sunk costs over decades.

4.46 In this sense, entering the traditional generation markets at scale has been equivalent to placing a large bet on complex outcomes over a 20- to 50-year horizon. A decision to invest requires consideration of a wide range of factors including:

(a) a forecast of likely electricity prices (and risks) over a long period (15, 30 or 50 years, depending on the technology being considered). Electricity prices at peak times, and their frequency, are particularly important in assessing investment decisions, because it is at peak times that capital costs can fully be recovered in a situation in which price competition for a homogenous good tends to push prices to incremental avoidable cost in times of excess capacity;

(b) a forecast of fuel input costs;

(c) an assessment of the impact of the current and likely future policy regime, notably the impact of taxes and subsidies (including, for example revenue accruing policies designed to encourage low carbon generation such as the RO regime;[91])

(d) an assessment of the likely regulatory and political environment, for example with respect to rules that affect the determination of spot prices; this is particularly important for prices at peak times, when the risk is greatest that governments will intervene to keep prices low;[92]

(e) a forecast of the likely short-run competitive position of any given technology over that period; this depends on an assessment of the likely operating costs of each competing plant over the period, and therefore requires a view of:

(i) all other investment decisions that are likely to be made over the period, and, in combination with knowledge of existing plant, an assessment of the likely plant mix;

(ii) input costs, especially fuel costs; and

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[91] See Section 2, Section 5 and Appendix 5.3: Capacity.
[92] This is the configuration that leads to the 'missing money' problem analysed further in Section 5 and in Appendix 5.1.

(iii) environmental costs, like the likely level of any carbon tax or the prices of carbon permits;

(f) an assessment of operational and project-specific risks; and

(g) an understanding of the sunk capital and investment costs of each competing technology.

4.47 The risks relating to investments are considerable and are likely to have increased in the recent past, when emissions-reductions objectives and policies have led to a rapid and substantial transformation of the capital used to generate electricity. It is a UK and EU policy goal that the electricity system in 40 years will have been transformed to power very low carbon economies. The exact ways in which this is going to be delivered and incentivised are not yet absolutely clear, so adding to the risk of investment.

The impact of the policy framework on investment incentives

4.48 Despite the risks inherent in generation capacity investment, the GB system has delivered substantial new investment since privatisation. But the transformations required by decarbonisation – and the greater price volatility they lead to through increased deployment of intermittent renewable generation – have led to the introduction by DECC and Ofgem of three new mechanisms designed to encourage the right investment decisions:

(a) DECC introduced Contracts for Differences (CfDs) in 2014 to fund renewable, nuclear and other low carbon generation capacity,[93] with the first round of competitive allocations this year.

(b) DECC introduced the Capacity Mechanism in 2014, due to start paying for capacity in 2018, to reduce the risk involved in owning carbon-based thermal generation and in installing equipment for demand-side response (DSR) solutions[94]

(a) Ofgem approved in April 2015 a set of reforms to very short run pricing under the Electricity Balancing Significant Code Review (EBSCR) aimed, among other things, at incentivising investment in flexible capacity.[95]

4.49 We consider the competition impact of each of these policy changes in Section 5.

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93 Considered in detail in Section 5 and Appendix 5.3: Capacity.
94 Considered in detail in Section 5 and Appendices 5.3: Capacity; and 5.1: Wholesale electricity market rules.
95 Considered in detail in Section 5 and Appendix 5.1: Wholesale electricity market rules.

4.50 The introduction of CfDs effectively takes market price risk out of the investment decision for low carbon technologies. It is a fixed-price long-term contract for output. It will gradually come to replace the RO mechanism which required suppliers to either buy a given amount of output from qualifying technologies or pay a regulated top-up 'buy-out' price.

4.51 In terms of the nature of competition, the CfD allocation can be thought of as being competition for the market for low carbon generation capacity through a public tender, whereas the RO mechanism attempted to create conditions of competition in the market between renewable sources. Each mechanism raises many detailed competition questions, which we consider in Section 5.

4.52 The Capacity Mechanism (analysed in Section 5, and the Appendix 5.1) reduces but does not eliminate reliance on spot market sales in a thermal generators' revenue stream. Capacity owners and investors tender to supply the target level of capacity. A single clearing price for capacity is established in a multi-unit uniform price auction. This replaces some energy market revenues with a guaranteed capacity payment recovered directly from consumers. It seeks to substitute to some degree competition **in** the market for competition **for** the market. Generators are no longer so reliant on peak prices to recover their sunk costs. In its broad principles, it changes the nature of competition but is nevertheless in principle a competitive mechanism.

4.53 Investment decisions will still require a view of future spot market prices. Regulatory choices that influence spot prices will therefore continue to have an impact on investment choices. We specifically examine the investment incentives created by Ofgem's EBSCR in detail in Section 5 and Appendix 5.1.

4.54 The impact of DECC policies and mechanisms on the market inevitably interact with Ofgem decisions. We consider, in Sections 5 and 11 the impact on competition of the particular ways in which Ofgem and DECC have exercised concurrent powers to incentivise investment adequacy.

4.55 An important aspect of generating capacity investment decisions is their location. Where a plant is situated can have many direct and knock-on effects. The output of renewables like wind, solar, wave and tidal is directly tied to location. Electricity is transported over the grid, and the location of generation plant influences transport costs in four ways:

(a) There are direct connection costs of a plant to the transmission network.

(b) There are knock-on costs related to capacity elsewhere on the system that may mean that generation investment requires transmission investment.

(c) The entire pattern of production at any time determines the capacity of each part of the network, so that congestion costs will be influenced by investment choices.

(d) Electricity is consumed in transport, and some elements of the losses are dependent on location.

4.56 The impact of location on cost and the mechanisms by which those costs are recovered lead to some degree of competition for investment between locations. We do not consider in detail the aspects of that competition arising from the first two costs noted above: these are natural monopoly regulation problems and high-level policy choices. However, we do examine the impact of charging schemes for congestion and losses in Section 5, as well as examining in detail the governance process as it applied to various attempts to introduce different schemes for charging for losses in Section 11 and Appendix 11.2.

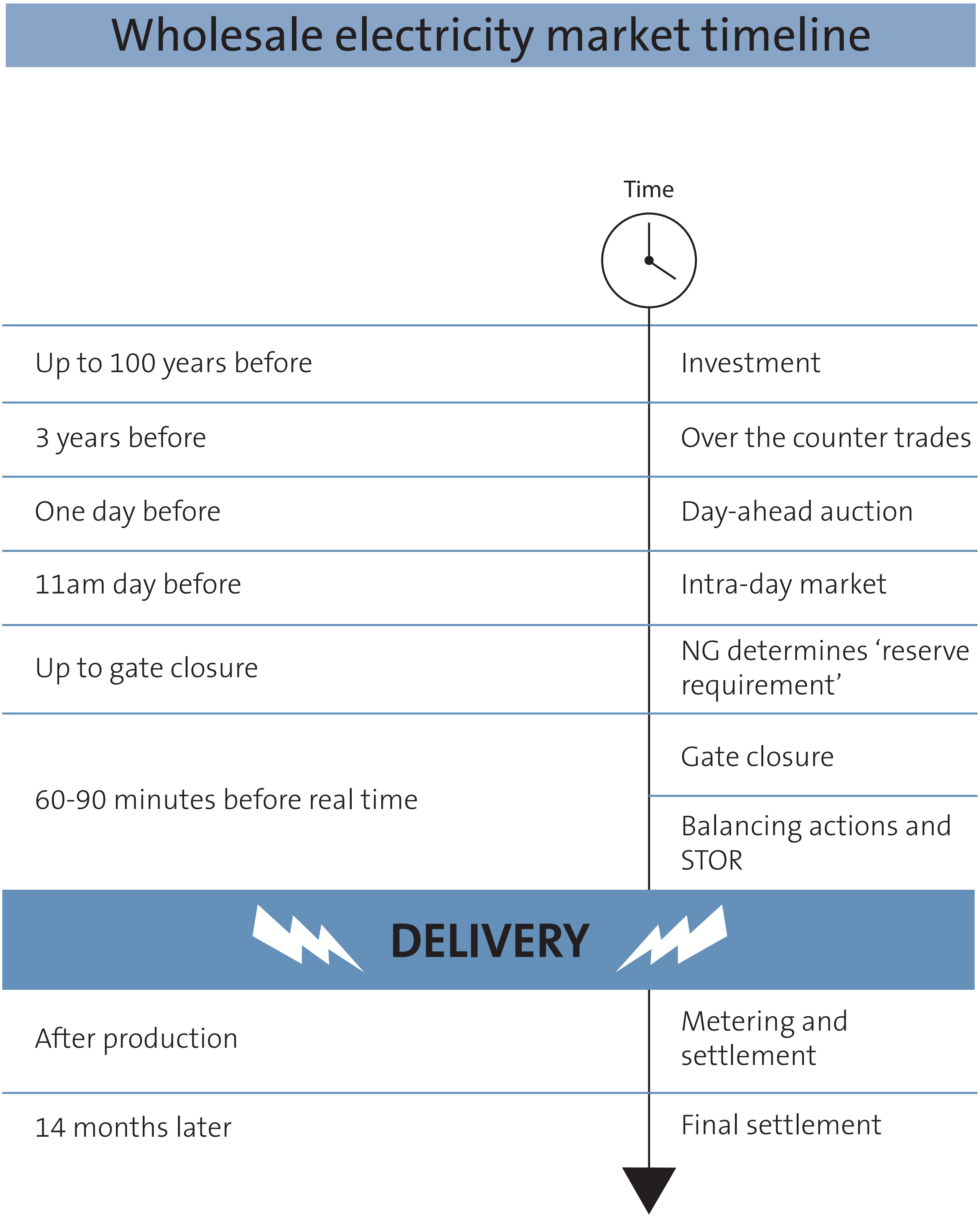
4.57 An important aspect of the nature of competition in capacity investment revolves around the way in which the risks inherent in the activity are distributed. Risk in generation projects can be distributed between companies with various types of long-term contracts. Electricity can be forward sold on moderately liquid markets up to two years out; specific 'tolling agreements'[96] can be negotiated between investors in generation and suppliers or intermediaries or even large end-consumers that can reallocate project risk. We consider the nature of competition in these markets for risk further below at paragraph 4.94 to 4.104, as well as in Section 6.

Short-run production decisions and the nature of spot market competition

4.58 The decisions that enable electricity demand to be satisfied at any instant occur on a range of time-scales and in a number of markets. Figure 4.11 shows a timeline from investment (up to 50 years before production for long-lived nuclear assets, for example) to the instant of production and through to the final financial settlement for that instant up to 14 months later.

[96] See Appendix 4.2: Generation return on capital employed, and specifically Annex A – Business models.

Figure 4.11: Wholesale electricity market timeline



4.59 The electricity spot market comprises the set of actions that determine, at any time, the operating output, demand level and prices for a given level and mix of capacity investment. The mix and level of investment is determined, in part, by expectations of prices and operating outputs; it is through the spot market that these variables are realised.

4.60 In this section, we assess the nature of competition in markets close to real time. It is structured as follows:

(a) We describe the process of buying and selling electricity close to real time.

(b) We assess the factors that owners of generation take into account in deciding whether to generate or not, including the role of spreads.

(c) We summarise the shares of generation output between different generators.

(d) We present an analysis of generation merit order.

(e) We summarise our analysis of unilateral market power in generation.

(f) We discuss issues relating to VI.

Buying and selling close to real time

4.61 In this section, we briefly describe the various ways in which buying and selling electricity occurs close to real time. The 'spot market' is not in fact a precisely defined term and tends to encompass a host of activities that can take place from one day before production or consumption right up to the instant in which they take place.

4.62 On the day before production, two voluntary auctions are held (organised by different platform operators, N2EX and APX) which trade volumes equal to about 40% of the electricity produced. Anyone with electricity to sell can submit, for each hour in the day ahead, the prices at which they are willing to offer different quantities of electricity; anyone with electricity to buy can submit bids for the price and quantity they are willing to pay.

4.63 A seller need not be a physical producer. Someone – a supplier, a bank or a trading house – might have bought electricity for delivery tomorrow on a future contract and might be seeking to find a physical buyer for that electricity. They are 'long' in electricity and are seeking someone 'short'. Similarly, a generator might find itself being a buyer in the auction. It might have contracted the output of its plant a long time previously and subsequently suffered technical problems with it; it now needs to procure electricity to make good on its contract.

4.64 Bids and offers are aggregated into supply and demand and a clearing price is found. Each bid and offer is a contract with the platform rather than between bilateral parties. The platform assumes the risk of non-fulfilment and requires each side to post collateral to cover that risk.

4.65 These day-ahead auctions produce hourly day-ahead prices for the GB market. They are also ‘coupled’ with similar auctions across Europe which allows interconnector flow to be planned. In hours when day-ahead prices are lower in France than in Great Britain, it is assumed that electricity will be flowing towards the higher price and bid accordingly into the auction; an iterative process adjusting bids and prices in day-ahead EU markets determines the planned pattern of cross-market interaction.

4.66 Most of the 60% of volume that does not get cleared through one of the auctions is covered by forward contracts that are traded through bilateral contracts before the auctions, sometimes as much as two years before.[97] The decision to participate in the day-ahead auctions will involve the following considerations:

(a) Is there an imbalance between the electricity that a company thinks it has to sell on the day and the electricity that it thinks it will need?

(b) Could there be cheaper ways of acquiring the electricity needed than producing it themselves?

(c) What are the trading and transactions costs on the platform? (For example, collateral costs are needed to cover the risk that a party will not fulfil its contract; and the platform charges transaction fees to cover costs and profit.)

4.67 If there were no transactions costs for participation in the auction, there would be no good reason for a company – whether vertically integrated or not – to refrain from participating in it. There are a number of frictions which mean that participation is not 100%:

(a) There are platform fees; all participants in the market will already be paying platform fees for access to the OTC market[98] which will have been used for longer-term hedging; at very small scales of operation, the

[97] We describe the process in detail in Appendix 6.1.
[98] The OTC market refers to a trading system in which bilateral trades are facilitated by a ‘match-making’ intermediary.

OTC platforms may be thought to be a good enough substitute for the day-ahead auction not to require both sets of fixed costs being incurred.

(b) There are transactional frictions in the market; for example, bids to the auction close at 11am and the market is not cleared, usually, until 45 minutes later; therefore, if a bid to the auction depended on being able to source gas for the next day at a given price, there is a risk that the gas price may no longer be available. In times of volatility, a company in this position might prefer the certainty of being able to execute back-to-back gas and electricity trades through bilateral platforms than face the risk of locking-in a loss.

4.68 Conditions change for both suppliers and producers between the day-ahead auction and the instant of physical production and consumption, so there are additional markets after the day-ahead auction in which decisions can be altered and refined. These are also part of the spot market.

4.69 Up until one hour before the start of a half-hour settlement period, the point called 'gate closure', parties adjust their positions mostly using the APX platform. This is a continuously cleared matching market in which APX is the central counterparty. Some intra-day trading occurs on bilateral markets in which a broker brings parties together through an electronic platform. A very small proportion of which (under 3%[99]) are not visible to all parties in the market.

4.70 At gate closure, the electricity system becomes centrally operated. Competitive mechanisms nevertheless continue to be used in order to minimise costs. These include the BM, where rapidly available incremental output from plant on the system can be purchased by the System and various other options, like short-term operating reserve (STOR) that the SO can call on to balance supply and demand. The BM is organised as a formal pay-as-bid auction and STOR purchases are made by competitive tender.

4.71 The SO has considerable latitude in the way in which it purchases or sells energy to balance the system, including direct interventions in the pre-gate-closure markets. The technical and allocative efficiency of the last stages of the spot market rely to an extent on the regulator's skill in good regulation of the natural monopoly balancing function. The nature and degree of competition in these centrally designed elements of the spot market are described in detail in Appendix 5.1.

[99] See Appendix 5.1: Wholesale electricity market rules, paragraph 27.

4.72 An important element of the final stage of the spot market is the cash-out mechanism which determines the price paid for electricity bought or sold without a contract. A supplier might find that demand was unexpectedly high, in which case it would find itself to have been an unplanned buyer of electricity; or it might be unexpectedly low, in which case it is an unplanned seller. A generator might suffer an unexpected drop in output, making it an unexpected buyer of electricity; or, for a wind or solar plant, it might find its output to be unexpectedly high and it will have unplanned sales of electricity. The 'price-of-last-resort' is determined in the cash-out process which has been subject to a substantial reform that is discussed further in Section 5.

4.73 The goal of the cash-out price-setting process is both to help with the natural monopoly regulation of the SO in terms of making sure that not too much balancing work is left to the SO, by making parties contract for their anticipated needs ('balancing efficiency') as well as to provide incentives for parties to invest in the plant, forecasting capacity and reliability options that allow them to avoid the price-of-last-resort for most of their needs most of the time.

4.74 Figure 4.12 shows how the costs of imbalance fall on different companies. The cost per customer is lower for the Six Large Energy Firms than for most other companies. It is high for Good Energy and for SmartestEnergy, both of which have a focus on supplying renewable energy, whose output is hardest to predict. We consider whether imbalance charging creates a significant barrier to entry or expansion in Section 5.

Figure 4.12: Size of imbalance costs and customer cost per year by energy supplier (April 2013 to March 2014)

[✂]

Source: [✂].

4.75 The electricity transportation and distribution system suffers from similar metering and settlement problems as were discussed with respect to gas in paragraphs 3.31 and 3.32. Almost all producers' injections on to the system are metered in real time;[100] most consumers' loads are not – at least not yet, pending smart meter roll-out.[101] The process of determining whether contracts were fulfilled is therefore relatively simple and quick for most generators. But for many customers – and almost all domestic and SME customers – it requires a lengthy process of successive approximations and reconciliations. It can take up to 14 months[102] for a supplier to know the final

[100] This is not true of 'embedded' renewable generation.
[101] See Appendix 8.6: Gas and electricity settlement and metering.
[102] See Appendix 5.1: Wholesale electricity market rules, paragraph 43.

quantity that it is deemed to have consumed in a particular half-hour and therefore to know the full financial consequences of any exposure to cash-out. We consider potential competitive issues arising from the settlement process in Section 8 and from the governance of settlement in Section 11.

Factors influencing the decision to generate

4.76 If a price-taking generator with a good forecast of what the price will be in a given period[103] has incremental unit cost of operation smaller than the price for which it can sell its output, it will want to be producing and therefore to have sold its output. The incremental unit cost of operation will vary by technology and by period, driven by a large number of factors including:

(a) **Variable fuel input costs:** for gas plant, these are gas spot market prices; for coal plant with stocks of coal, these can be thought of as being the opportunity cost of using that coal at a different time, which will be determined by expectations of coal spot prices; oil plant will similarly typically carry stocks and will therefore face an opportunity cost related to expected spot prices; incremental nuclear fuel costs are almost zero; wind and solar incremental fuel costs are zero.

(b) **The price of carbon permits and the level of carbon taxes:** a coal or gas plant, in order to comply with EU and domestic legislation aimed at tackling climate change, must buy carbon credits to cover its emissions and must top up that purchase by an amount equal to the carbon price floor. The price of credits and the level of the carbon price floor are input costs to electricity generation by coal and gas. They are described further in Section 2.

(c) **Plant operating efficiency and dynamic considerations:** each plant converts its fuel input to electricity at its own efficiency level; moreover, that efficiency can depend on whether it is operating at full capacity or not; the precise operational conditions of the plant thus in part determines the rate at which it can convert a fuel cost to an electricity revenue.

(d) **Maintenance costs and non-sunk fixed costs:** operating a plant will add to its wear and tear, and whether or not it operates, even planning to operate it requires certain fixed costs (like staff) to be incurred; maintenance costs as well as the economic life of a plant can depend on how

[103] For spot-market purposes, the 'period' might be thought to be a half-hour – the administratively determined settlement period in the GB system (see paragraph 3.69 above); alternatively, it might be thought to be an hour, which is the period traded in the day-ahead auctions (see paragraph 3.65 above).

frequently a plant is turned on and off, complicating the simple assessment of points (a) to (c) above.

(e) **The cost of the risk of failing to be available:** there is always a chance that a plant will not be able to produce because of unforeseen technical problems; if this occurs, the company that has contracted to produce must face a cash-out price (see Section 5 and the Appendix 5.1); the difference between the contracted price and the cash-out price times the probability of technical problems is part of the cost of promising to produce.

(f) **BSUoS costs and RCRC revenues:** in any settlement period in which a plant produces, it is liable for its share of any balancing and settlement use of system (BSUoS) costs – for example the costs that National Grid incurs to maintain a stable voltage. BSUoS charge contains the costs relating to transmission congestion (see the Locational pricing in the electricity market in Great Britain Appendix); a plant also receives a share of any net revenues that National Grid has collected in selling electricity to those who need to make-up for uncontracted positions (this quantity is the residual cashflow reallocation cashflow (RCRC)).

4.77 In relation to the first three factors, market participants frequently encapsulate the determinants of the operating decision through a margin measure called a 'spread', which aims to measure the difference between an electricity price and the fuel cost needed to produce it. For a given fuel and technology, the spread measures the £ per MWh that would be earned or lost if: the fuel input were purchased at the spot price; the electricity were sold at the spot price; and the conversion efficiency from one to the other were at a standardised level. When applied to gas and CCGT plant, this is called the 'spark spread'; applied to coal it is called the 'dark spread'. Each of these spreads come in 'clean' and 'dirty' versions, where the clean spread includes the cost of carbon permits and taxes required to burn the fuel.

Figure 4.13: Spark and Dark Spreads

[✂]

Source: [✂].

4.78 The clean spread can be interpreted in this way: if it is positive, then with the relevant equipment, from an economic perspective an asset owner ought to want to use it as a means of transforming the input fuel into electricity (unless unaccounted for variable costs are too large). The higher it is, the greater the incentive. If it is negative, the owner would be disincentivised from producing electricity.

4.79 The fact that the spreads are such central metrics to decision-making in the industry (it is even possible to trade a standardised ‘spark spread’ contract, which effectively buys gas and sells electricity forward in the proportions of a ‘standardised’ CCGT plant) underlines an important large-scale aspect of the nature of competition: wholesale electricity is a homogenous, non-storable good with low transport costs. This implies, generally, that intense price competition can be expected to whittle prices down to avoidable costs.

Generation merit order

4.80 The calculation of the short-run break-even electricity price at which it is profitable to operate a plant can be represented for the whole system as a per-period supply curve, (also called a ‘merit order’ or a ‘stack’).[104] The industry uses these sorts of ‘fundamental’ models extensively in forecasting prices, explaining out-turn prices and in developing scenarios. These approximations to actual decisions are made with varying degrees of sophistication depending on the use to which they need to be put: day-to-day actual operating decisions need more detail, while long-term project appraisal and investment needs less.

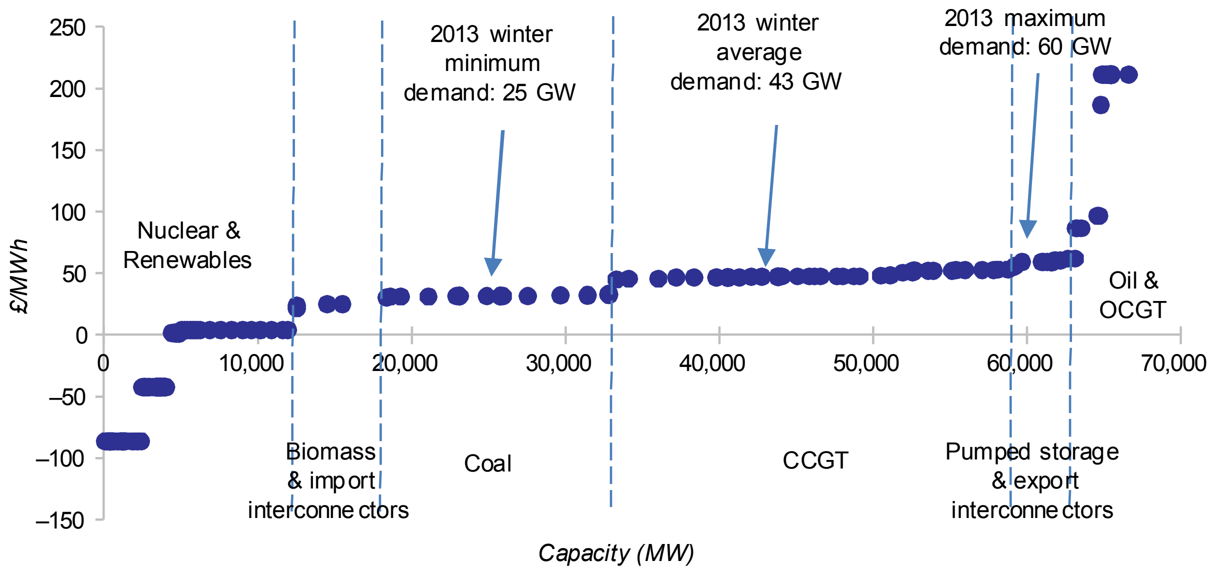
4.81 Figure 4.14 below shows a stack model supply curve for 31 October 2013. The figure shows nuclear and renewables running at baseload – essentially zero operating cost (and, in the case of renewables earning ROCs, negative operating costs arising from the fact that **not** producing entails the loss of the ROC subsidy). Next in the merit order come biomass and interconnectors. Biomass avoids having to purchase EUAs or to pay for the carbon price floor, which is one of the factors making it more competitive than the coal,[105] which is next in the merit order.

4.82 Great Britain has 3200 MW of interconnection capacity to/from continental Europe and 950 MW to/from Ireland. As a rule of thumb, in a well-functioning market, power flows to higher-priced zones. The interconnectors are therefore either a source of demand or a source of supply, depending on local market conditions. Gas comes next in the merit order on that day – whether coal is above gas or vice versa is very dependent on spot market conditions on the day as well as the level of carbon taxes and permits. At very high levels of demand, the system will call on pumped storage (hydro storage technology that allows electricity to be stored at times of low price

[104] See Appendix 4.2: Generation return on capital employed, and specifically the section – ‘Basics of demand and supply of electricity’.
[105] Some biomass on the system, like a part of the Drax power station, is converted from coal.

and used at times of high price). And at times of extreme system stress, high operating cost oil plant and OCGTs are available.

Figure 4.14: Merit order of GB generators (31 October 2013)*

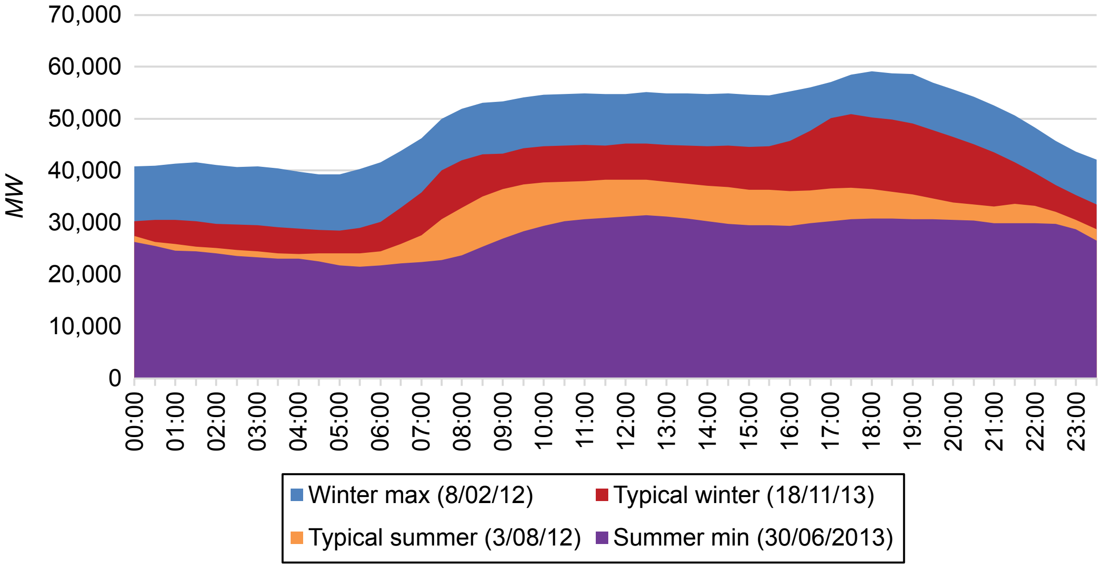


Source: CMA unilateral market power model.
*This model has placed pumped storage at the end of the CCGT stack. Approaches to modelling pumped storage vary. For reference, minimum summer demand in 2013 was 21GW. The merit order varies season by season, day by day and hour by hour. The date chosen here has no particular significance.

4.83 The spot price can be thought of as being determined by the interaction of stacks of this sort with system demand. Figure 4.15 shows typical demand levels by time of day and time of year. The minimum demand occurs in the early hours of a summer morning, around 20,000 MW. (The marginal plant at these times will depend on the level of output from wind and whether all the nuclear plant are available; there is some possibility that electricity prices could be close to zero or even negative in such periods.) Figure 4.15 shows a peak demand around 50,000 MW for February 2012 around 6pm. If the supply curve had looked similar to that on 31 October 2013 shown in Figure 4.14, the system would still have had a comfortable margin of capacity.

4.84 The merit order on this day demonstrates its typical shape. Since demand varies throughout the day while the supply curve varies less, prices will be variable throughout the day. The curve also demonstrates the importance of prices at peak times for the recovery of fixed costs. A coal or CCGT asset owner will only earn substantial margins when price is set by oil or OCGT plant.

Figure 4.15: Intra-day electricity consumption



Source: Elexon.

Assessment of unilateral market power in generation

4.85 We developed a simple stack model to test the degree to which any generator has the unilateral ability and incentive to raise wholesale spot prices, which is described in detail in Appendix 4.1. In order to do this, we compare the 'competitive' market price to an 'optimal' price for each firm for each half-hourly period in 2012 and 2013. The competitive market price is the marginal cost of the marginal plant when all plants are stacked up in order of their marginal cost. The optimal price is the price that maximises profits for the firm in question. If the price increases from the competitive strategy, this optimal price is achieved by a firm by withholding capacity.[106] We take the firm's optimal withholding strategy as the profit-maximising response to other firms' competitive offerings, ie assuming that rival firms offer their output as if the market were competitive and do not withhold capacity. The best response of other firms to withholding by one firm is likely, in the specific circumstances of the wholesale electricity market, to be to maintain competitive levels of output. The reason for this is that market power, when it is exercised, involves making another technology the price-setting technology – for example, shifting this from coal to gas. Once this has been done, there is no further opportunity to raise prices by small additional capacity reductions. Therefore, we believe that the strategies we have identified as optimal for each firm would also be stable for the market as a whole.

[106] If the withholding strategy is inferior to the competitive strategy, the optimal strategy is the competitive strategy for that period.

4.86 We analyse the ability and incentive for each of the Six Large Energy Firms and Drax to exploit unilateral market power. We refine the methodology outlined above to take account of non-modelled constraints on plant operation – especially the fact that for most plant, it is not economic to turn them on and off frequently or rapidly. In the course of that work, we also reviewed a number of similar but more sophisticated modelling exercises by generators.

4.87 We find that for 2012 and 2013, what opportunities there might have been to increase prices occurred largely because of the 'coal to gas step': CCGT was slightly above coal in those years in the merit order; there were some periods when a small reduction in the amount of coal made available could increase prices to the CCGT avoidable cost level; this could occasionally be profitable, especially for firms with a lot of non-CCGT baseload capacity. However, the number of such periods was very small. Moreover, it is likely that generators will have forward-sold output in those periods, making it hard to exploit the profitable spot opportunity. The work concludes that no single generator has the incentive to increase the wholesale price by a significant amount in a significant number of half-hour periods.

4.88 Our analysis of generation profitability adds strength to the conclusion by suggesting that unilateral upstream market power has not been exercised in the recent past. Our analysis of the profitability of the generation operations of the Six Large Energy Firms between 2009 and 2013 indicates returns that are generally in line with or below the cost of capital once adjustments are made to reflect the deprival value of the assets. During 2007 and 2008, ROCE (based on carrying values) appears to have been higher for some of the operators, although we expect that these figures would be reduced by revaluing assets to their deprival value.[107]

4.89 In certain years (and for some of the firms), the returns on coal were above the WACC. However, when the period is considered as a whole, these relatively high returns are reduced by negative returns in other years which are the result of significant impairments to asset values. We observe that the operating profits (EBITDA) earned on these assets have generally fallen over time, with coal generation likely to decline further in the future as a proportion of total GB generating capacity due to the age of the existing fleet

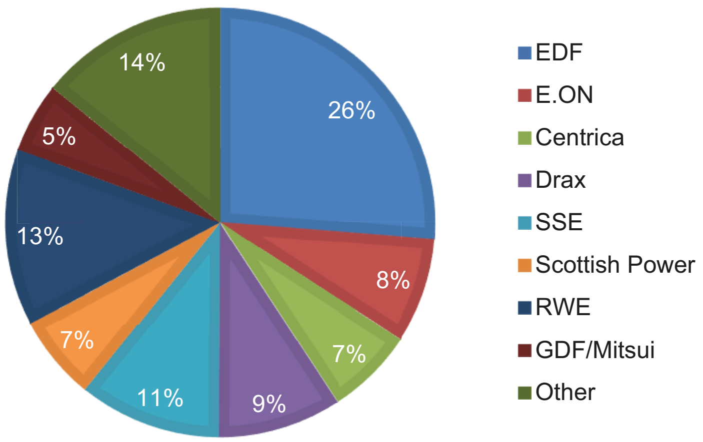
[107] During this period (2007–2008), we understand that there were not significant impairments of assets. As a result, profits would not be affected by large one-off impairment expenses and capital employed would be estimated on the basis of depreciated replacement cost which tends to be higher than the carrying values actually used. This is particularly the case for coal-fired power stations.

and various environmental regulations that make new-build coal uneconomic at the current time.

Shares of generation output

4.90 The period-by-period operation of the spot market determines the production pattern for companies. Figure 4.16 shows how output in 2013 was divided between the top eight producers. EDF Energy, with its baseload nuclear fleet producing almost all the time, is the largest producer with a 26% share. Centrica, which owns the energy produced by a part of the nuclear fleet via a contract with EDF Energy as well as a CCGT portfolio, is currently the next largest at 14%.

Figure 4.16: Shares of generation output (2013)



Source: Ofgem, National Report 2014.
Note: Some generation is treated as negative demand in these statistics, and hence the share of remaining generators may be slightly overstated. Nuclear output allocated 80% to EDF Energy and 20% to Centrica.

Vertical integration

4.91 Vertical integration can introduce specific risks for competition. A company can use power in one market to harm rivals in another market and thus benefit from reduced competition there. This sort of harm requires markets to be linked and firms to operate in the linked markets. This particular condition is met in the electricity market, as shown in Figure 4.17, where the Six Large Energy Firms are to varying degrees vertically integrated over production and retail. Only SSE and Scottish Power are vertically integrated in the sense of owning transmission and distribution networks as well. We have not considered any potential competitive harm arising from ownership of transmission and distribution because of the strict regulatory enforcement by Ofgem of third party access to the networks (see Section 5).

Figure 4.17: Consumption, output and net electricity position by party (2012/13)

[✄]

Source: [✄].

4.92 Figure 4.17 shows a great deal of diversity in the nature and extent of VI among the Six Large Energy Firms, with EDF Energy being the only one to generate more than it requires for its retail business. The landscape of VI among the Six Large Energy Firms is in flux. E.ON has announced a substantial demerger, which implies some degree of vertical separation, and Centrica has announced substantial moves towards de-integration by closing some of its gas-powered plants.[108]

4.93 Vertical integration is often associated with efficient market operation. However, it can sometimes lead to competition problems. The conditions under which harm can arise from VI are stringent, and we examine whether they hold between the wholesale and retail electricity markets in Section 5. We also consider in Section 5 the impact of VI on transparency in the market.

Financial markets in electricity

4.94 Electricity purchases and sales include a very large volume of forward contracts of different terms before the day-ahead market and for different types of products. It is plausible that forward-trading is part of an efficient use of capital: it allows for smoother costs and revenues and therefore for higher debt and more efficient capital structures.

4.95 The simplest forward contract is a 'baseload' contract, which is a promise to deliver/purchase a given quantity of electricity at a constant rate throughout the day. A 'peak' contract, by contrast, is a promise to deliver/purchase at a given rate between the hours of 7am and 7pm. The parties to these contracts are not necessarily companies with any physical presence in the GB electricity market (commodity traders and hedge funds may be in the market with purely trading interests).

4.96 The nature of competition in the forward markets is diverse, including, for example, the following:

(a) Long-term power purchase agreements, which are one-off, long-term, bilaterally negotiated, non-transparent agreements.

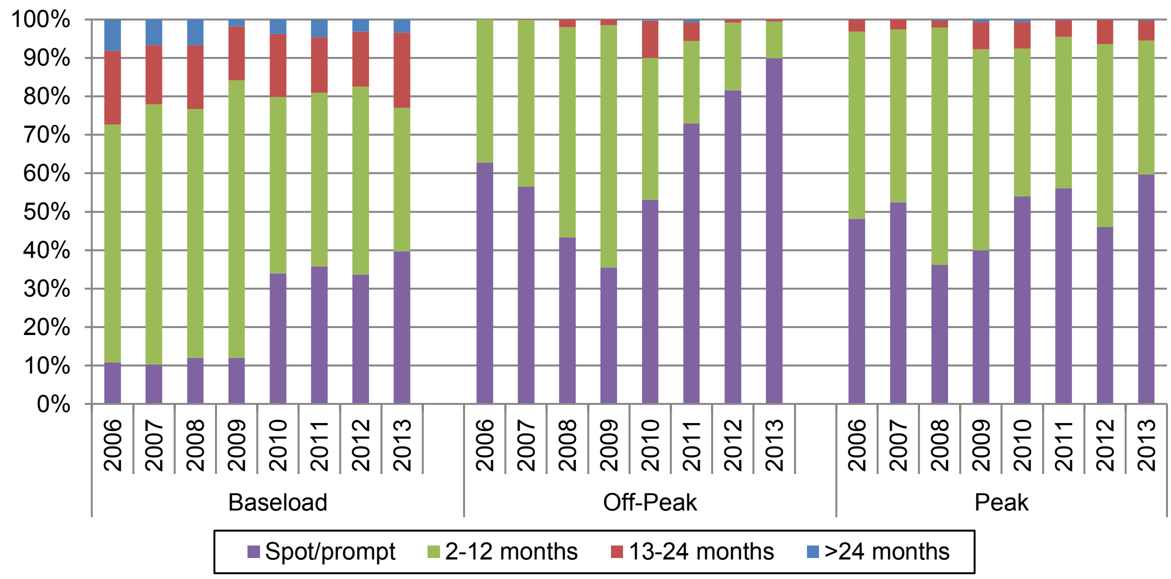
[108] Centrica subsequently made the decision to retain CCGT assets following a sales process, as bids received were significantly below its internal valuation.

(b) Tolling agreements, which are effectively an agreement to 'rent' out a power station in return for a fee. In practice they often take the form of a firm's generation division granting an option on the use of the power plant by the trading division, which then decides when to run the plant and to whom and when to sell the resulting power. These are typically bilaterally negotiated, long-term, and non-transparent.

(c) Forward contracts, with terms typically ranging from three years to just pre-day-ahead. These are almost all bilateral OTC trades in which price and quantity are visible to market participants (see Appendix 6.1: Liquidity). The standard forward contracts divide into different 'products' – baseload, off-peak and peak.

4.97 Figure 4.18 shows how the total amount of forward trading divides between the various term markets and products. (In this figure, 'spot/prompt' is defined as any trade one month before delivery.) In 2013, 60% of baseload contracts were traded more than one month before delivery. The number for peak contracts is 40% and off-peak contracts 10%. These figures are one indication of the importance of risk management in the industry.

Figure 4.18: Trading ahead of delivery in selected electricity products



Source: Ofgem (liquidity final proposals – Figure 13, p45).

4.98 Liquidity is a measure of the availability of products that market participants wish to trade; we consider that a product can be considered to be liquid if it is possible to buy or sell it without causing a significant change in its price. Poor liquidity could distort competition, particularly if it benefits vertically integrated firms at the expense of other firms.

4.99 Several independent suppliers believed that liquidity in wholesale electricity was sufficiently low, at least in particular products, as to impose additional risk and/or costs on them. One also told us that it believed it placed vertically integrated suppliers at a competitive advantage because they could trade internally even when products were not available in externally traded markets. Not all independent suppliers identified liquidity as a concern, however, and one told us that sufficient liquidity was available.

4.100 Independent generators told us that there were limits to liquidity, which affected their businesses. One of them suggested that it was suppliers' unwillingness to trade until their demand becomes more predictable closer to delivery that explained the lack of availability of certain products at longer terms.

4.101 We have assessed the extent of liquidity in the wholesale electricity market by gathering data from suppliers, generators and brokers.

4.102 Our analysis of broker data suggested that availability (at any spread) of baseload season products (delivery for six months, Oct–Mar and Apr–Sep) was very good for more than two years ahead of delivery. Peak season products were not always available, but had reasonable availability (70% or more) three seasons ahead. Baseload months were almost always available two months ahead, and peak month availability was best one month ahead. Quarters were available less than months. Products other than these six had relatively little availability.[109]

4.103 We generally found that spreads were tighter the closer a product got to delivery. So, for example, looking at baseload products, which have the tightest spreads, the front four seasons (two years) have generally been below 1% in the last two years. For seasons beyond this, spreads are generally wider.[110]

4.104 In Section 5 we consider two questions relating to VI and liquidity: to what extent VI in electricity might reduce liquidity; and whether low levels of liquidity gives vertically integrated firms a competitive advantage.

Provisional conclusions

4.105 We have provisionally not found that there are any features in the wholesale gas market that lead to AECs. Our analysis of the ability and incentive of

[109] See Appendix 6.1: Liquidity, paragraph 61.
[110] See Appendix 6.1: Liquidity, paragraph 68.

generators to exercise unilateral market power indicates that there is no risk of an AEC.

4.106 Section 5 examines in more detail issues arising from market rules and from DECC's interventions through the introduction of the Capacity Market and CfDs. It also examines the question of whether a return to a compulsory centralised dispatch system might enhance competition and the impact on competition of a lack of locations prices for losses and constraints.

4.107 Section 5 examines in greater detail whether VI might damage competition either via raising rivals' costs or by hampering transparency and good regulation.

5. Wholesale electricity market rules and regulations

5.1 The wholesale price of electricity represents just under half the total cost of supplying electricity to customers, and it is therefore important to consider whether competition operates well in the wholesale market. The rules and regulations that underpin the wholesale electricity market have to be more designed and institutionalised than in most markets because of the physical constraints of efficient electricity production on a distributed grid.

5.2 NETA, introduced in 2001, was based on the principle of self-dispatch, which still forms the basis of GB wholesale market operation today. This contrasts with the system that it replaced, the England and Wales Pool, which was centrally dispatched.

5.3 The detailed rules and regulations governing the wholesale market are regularly modified and updated. Three recent reforms are likely to have a significant impact on the nature of wholesale market competition.

5.4 First, DECC's Electricity Market Reforms (EMR), introduced in 2014, have added two new mechanisms aimed at incentivising investment to meet decarbonisation and security of supply goals: CfDs and the Capacity Market. These represent a fundamental shift in the nature of wholesale market competition, towards an approach based on competition for the market, through centrally organised allocation mechanisms. CfDs and the Capacity Market will become increasingly important drivers of both investment decisions and of the costs borne by consumers. By 2020/21, they are likely to account for around £3.5 billion of expenditure a year.

5.5 Second, the EBSCR, approved by Ofgem in 2015, will introduce a series of reforms to imbalance prices – the prices that generators and suppliers face in the wholesale market if they have not fully contracted for all the electricity they generate or consume.

5.6 This section assesses five key elements of the design principles and market rules and regulations that shape competition in GB wholesale electricity markets. Two of these are established characteristics of the electricity wholesale market regulatory framework:

(a) We review the **principle of self-dispatch** that has underpinned wholesale electricity market arrangements since the introduction of NETA and consider whether there would be benefits to competition from a move to a more centralised system of dispatch.

(b) We assess the competition impact of the **absence of locational pricing for constraints and transmission losses**, an issue that has been debated at length since privatisation 25 years ago.

5.7 We also consider three recent reforms that are likely to have a significant impact on the nature of wholesale market competition in the future:

(a) We assess the **reforms to the system of imbalance prices** that Ofgem is currently implementing.

(b) We consider the case for a capacity mechanism and the design of the **Capacity Market** that DECC has recently introduced.

(c) We analyse the likely impact of the **introduction of CfDs** as the principal means of incentivising investment in low carbon generation, with a particular focus on the way in which CfDs are allocated.

5.8 Finally, we present our **provisional conclusions** on whether any of the above areas are likely to give rise to an AEC.

5.9 This section draws on the evidence and analysis set out in appendices: 5.1 (Wholesale electricity market rules); 5.2 (Locational pricing in the electricity market in Great Britain); 5.3 (Capacity); 4.2 (Analysis of generation profitability); and 2.1 (Legal and regulatory framework).

Self-dispatch

5.10 Economic dispatch is the process by which the optimal output of generators is determined, to meet overall demand, at the lowest possible cost, subject to transmission and other operational constraints. The current dispatch mechanism in force in Great Britain, introduced by the NETA/BETTA reforms,[111] was designed as a self-dispatch wholesale electricity market. This contrasts with the system that it replaced, 'the Pool',[112] which was centrally dispatched.

Overview of centralised dispatch and self-dispatch

5.11 In a centralised dispatch system, generators and flexible demand[113] tell the SO the prices at which they are willing to supply to the system and the prices at which they are willing to reduce consumption. These bids come with

[111] See Section 2 and Appendix 2.1: Legal and regulatory framework.
[112] See Section 2 and Appendix 2.1: Legal and regulatory framework.
[113] 'Flexible demand' refers to consumers who have the flexibility to reduce consumption at short notice in response to market signals.

detailed technical information concerning constraints in plant operation. The SO determines what it believes to be the least costly way of matching supply and demand and communicates a planned running order to each participant.

5.12 Sometimes the operating instructions will be determined up to 24 hours ahead of production; sometimes it will be as little as 5 minutes before production. In determining the running order of plant, the SO also determines the system price in each period that is consistent with that running order. Centralised dispatch exists in the Australian national electricity market (NEM)[114] and in some form in most deregulated markets in the USA.

5.13 Under a self-dispatch system, buyers and sellers of electricity contract ahead of time for their anticipated demand at prices that are bilaterally negotiated or determined through demand and supply matching on public exchanges. Generators and suppliers prepare operating plans for their anticipated physical behaviour or that of their customers. The parties communicate their anticipated physical behaviour and their contractual position to the SO. The SO takes central control of balancing supply and demand close to real time, at a point known as ‘gate closure’.

5.14 In Great Britain, gate closure is one hour prior to real time. It is at this point that the SO[115] receives notification of the final physical and contractual positions of each party and the physical constraints and financial parameters under which their plans can be altered by the SO. The SO has the obligation to balance the system at minimum cost and will intervene if it predicts a discrepancy between the amount of electricity produced and demanded in real time. For example, it may require certain generators to produce more or less, for which they will be remunerated according to the financial parameters submitted at gate closure. After the fact, discrepancies between what parties physically did (actual delivery or offtake) and their contractual positions are ‘cashed-out’ at prices determined administratively by Elexon.

5.15 As the above description suggests, in practice there is not a binary distinction between self-dispatch and centralised dispatch. In all electricity markets, the SO intervenes at some point to ensure the system is balanced. The key points of difference are when and how the SO intervenes and how generators and suppliers interact prior to this intervention.

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[114] In the Australian NEM, dispatch is determined 5 minutes ahead of time, rather than one day.
[115] The exact definition and duties of an SO vary from system to system. In the GB system, NGET carries out the SO role.

5.16 In order to assess to what extent the system of self-dispatch as operated in Great Britain impedes effective competition, in the rest of this section we consider three discrete hypotheses:[116]

(a) that self-dispatch reduces technical efficiency;

(b) that self-dispatch reduces price transparency; and

(c) that self-dispatch increases transaction costs for new entrants and smaller players.

Impact on technical efficiency

5.17 The evidence we have seen suggests that bilateral trading is leading to close to technically efficient operation of the system. Several parties have shared with us their modelling approaches based on cost minimisation by the SO and their close fit to actual prices.

5.18 We have reviewed these models in the context of our work on unilateral up-stream market power and we find that their results are convincing. If bilateral contracting were leading to systematic technical inefficiency, we would expect to see this in systematic deviations of forecast and actual prices. We do not see these in the model calibration results. Our own wholesale price modelling[117] suggests that day-ahead prices are well forecast by a cost-minimising assumption.

5.19 We asked National Grid to consider possible sources of savings that might be seen from reverting to centralised dispatch. It concluded that there would not be substantial savings from the point of view of balancing the system. It also commented that in moving from the pool to NETA, it found generation asset owners were now more reluctant to switch plants off than National Grid had been as central dispatcher under the pool. National Grid hypothesised that plant owners may be able to factor in the additional maintenance costs implied by frequent starts and stops more accurately than could the SO under centralised dispatch rules, and that self-dispatch may in this sense be more technically efficient.

Impact on price transparency

5.20 We have found that for most purposes prices are transparent in the GB wholesale electricity market.[118] The N2EX and APX exchanges publish day-

[116] Section 6 considers an additional hypothesis – whether self-dispatch increased incentives for VI.
[117] See Appendix 4.1: Market power in generation.
[118] See Appendix 6.1: Liquidity.

ahead electricity auction prices. The equivalent of approximately 40% of total electricity generation goes through these auctions. The provisional conclusions of our analysis of foreclosure and market power in generation (as set out in Appendices 4.1 (Market power in generation) and 6.2 (Foreclosure)) suggest that parties do not have the ability or incentive to make this price systematically diverge from a competitive spot market price. This suggests that the price signal from these auctions is likely to be robust.

5.21 The N2EX and APX bids and offers are already used for the regulated purpose of determining EU-wide day-ahead prices and allocating interconnection capacity across the EU. It is far from clear that mandating that all electricity be traded in the day-ahead market would improve the quality of the price signal that is generated by the N2EX and APX exchanges.

5.22 Prices of individual trades in the forward market are available for a modest fee from Trayport, the screen-based trading software provider that most traders use. After the day-ahead market has cleared, adjustments to contractual positions are typically made through Trayport in bilateral trades. The prices of these trades are available to participants and subscribers. Our analysis of trading data suggests that 3% of energy traded externally one day ahead of delivery or less is traded through private bilateral contracts that are not visible to all participants. We do not consider that this is a material lack of transparency for participants.

5.23 It has been put to us that part of the value of a system based on centralised dispatch comes from the fact that there is greater public confidence that the prices are the result of supply and demand matching in the whole market. Real-time imbalance prices are made public, as are the BM bids that went to determine those prices. The reforms to imbalance prices that are anticipated in the next three years – and particularly the move to a single imbalance price (as discussed in paragraphs 5.96 to 5.100 below) – should ensure that the imbalance price in most periods is a good measure of a real-time spot market price. In this sense, there will be, post-reform, a market price based on the real-time, mandatory centralised matching of supply and demand that applies to the whole market.[119]

5.24 For all these reasons, we do not believe that there would be a large advantage to competition from the point of view of increasing price transparency by reverting to centralised dispatch.

[119] It is a price based on all bids and offers in the market since any operator that has notified to the SO that it will be producing or consuming electricity is mandated to offer these bids to the SO for any adjustments to their positions that need to be made in real time.

5.25 We consider a separate aspect of transparency – namely, whether the overall costs of the wholesale energy purchases made by the Six Large Energy Firms are auditable by the regulator for the purposes of regulatory and public policy decision-making – in our discussion of the regulatory framework in Section 11 and in Appendix 11.2 (Codes and regulatory governance).

Impact on transactions costs

5.26 A separate advantage claimed for a centralised dispatch system is that it provides a simple route to market for energy: a generator knows that it can sell its output by bidding into a pool; a supplier can buy energy from the gross pool. In the case of a mandatory pool, the entire market participates, so the depth of the market is maximised.

5.27 Under a self-dispatch system, parties are responsible for finding generators or suppliers with whom to trade. This requires, in-house or outsourced, teams of buyers and sellers and may be more complex than participating in a pool. However, even in centralised dispatch systems with gross pools, most of the trading takes place in the forward markets that lead up to bidding in the gross pool. This arises from the need for prudent risk management.[120] Therefore both self- and centralised dispatch systems typically require participants to have trading teams.

5.28 Participation in spot markets in Great Britain involves low transaction costs. The APX and N2EX auctions allow day-ahead trading on a very similar basis to that which would be provided by a gross pool.[121] Moreover, the reforms to the imbalance price regime (especially the elimination of 'dual pricing' discussed below) mean that reliance on the centrally cleared BM for energy will no longer be unattractive by design. This will provide a further low-transaction cost option for buying or selling electricity.

5.29 In light of the above, our initial view is that there would not be significant transaction cost difference between the self-dispatch system in Great Britain and a centralised dispatch alternative.

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[120] See Appendix 6.1: Capacity.

[121] The APX and N2EX require parties to post collateral for their trades. This may be a substantial cost, but we have not found evidence that it is an undue cost. A day-ahead pool would also need to have some insurance mechanism against a party's inability to make good on its commitment.

Provisional finding on self-dispatch

5.30 For the reasons set out above, and especially given the EBSCR reform that will define a single imbalance price, we do not believe that the self-dispatch system in Great Britain, when compared with alternative dispatch systems, reduces price transparency or increases transaction costs. Nor have we found evidence of systematic technical inefficiency arising from self-dispatch.

Absence of locational pricing for constraints and transmission losses

5.31 Due to the limits of the transmission network, electricity that is transported from one part of the country to another incurs losses and may be subject to constraints. The costs of both losses and constraints vary considerably by geographical location – in an area with relatively low levels of demand and high levels of generation, for example, consuming electricity will be associated with low losses and is unlikely to be subject to constraints, while generating electricity will be associated with relatively high losses and high likelihood of constraints.

5.32 Despite this locational variation in the costs of losses and constraints, under the current regulatory regime, these costs are allocated to generators and consumers in a way that takes no account of their geographical location. This section considers the impact that the absence of locational pricing for constraints and losses is likely to have on wholesale electricity market competition.[122]

Locational elements in current network charges

5.33 Table 5.1 provides a breakdown of the different components of transmission and distribution network costs and summarises whether charges for them currently contain locational elements.

[122] This section draws on the analysis set out in Appendix 5.2.

Table 5.1: Geographical variation in GB electricity network costs

Cost category	*Locational elements in current pricing arrangements*
Transmission congestion	No
Transmission losses	No
Transmission network investment	Yes
Transmission connection	Yes
Distribution network	Yes
Distribution losses	Yes

Source: CMA research.

5.34 As can be seen, there are several network cost categories charges which vary by geographical location under the current regulatory regime:[123]

(a) **Transmission network investment costs:** investment costs are driven by location and charges for the use of the network (Transmission Network Use of System charges) vary on a zonal basis.

(b) **Transmission connection costs:** the costs National Grid incurs in connecting generators to the grid are location-specific and connection charges vary by location.

(c) **Distribution network costs:** as with transmission, the costs of investing in the distribution network vary by location. Distribution charges (Distribution Network Use of System Charges) vary by region.

(d) **Distribution losses:** a supplier is charged for the full amount consumed as reconciled through end-point meter readings. This therefore contains losses in the distribution network, which vary by location. There is a levy applied on all suppliers for 'Assistance for Areas with High Electricity Distribution Costs', which currently benefits the North of Scotland.[124]

5.35 These charges provide some locational signals for generation and demand: generators and customers who impose greater costs on the system will pay higher prices. As a result, retail prices paid by domestic and non-domestic customers also vary across Great Britain. The extent of differentiation is set out in paragraphs 7.203 to 7.207.

5.36 However, there are two important elements of network cost that vary by location but for which there are no geographically differentiated charges. These are transmission constraints and transmission losses.

[123] All of these charges are regulated by Ofgem.
[124] See National Grid: Assistance for Areas with High Electricity Distribution Costs.

5.37 **Transmission constraints** arise when power cannot be transmitted to where it is needed, due to congestion at one or more points on the transmission network. This means that it is not possible to generate electricity from the cheapest sources of generation, leading to transmission congestion costs.

5.38 The biggest source of transmission constraints in the GB wholesale electricity market is network capacity between Scotland and England, with there being more relatively cheap generation in Scotland than ability to transport electricity south. This bottleneck has worsened due to the increase in zero incremental cost wind generation in Scotland, which increases the price disparity between Scotland and England and Wales, thus increasing the opportunities for profitable flow of electricity southwards that will sometimes be frustrated by transmission constraints.

5.39 Congestion costs are currently incurred by National Grid through the BM and are averaged over all producers and consumers on a pro rata per MWh basis and included in BSUoS charges. There is no locational element to this cost.

5.40 Some electricity is lost to heat as it is transported over long distances. While losses are smaller over high-voltage transmission lines than over low-voltage distribution lines, **transmission losses** are still appreciable, accounting for 1.7%[125] (5.3 TWh) of total electricity generation in Great Britain in 2014, representing a cost of over £220 million in that year. Losses are greater the longer the distance travelled, so, for example, a given demand in London needs more generation from Scotland to satisfy it than from the Isle of Grain.

5.41 Transmission losses are currently recovered by adjustments to BSC parties' metered volumes, which encourages generators to produce approximately 1% more than they are contracted for and suppliers to contract for approximately 1% more than their customers' demand. There is no locational element to the metered volume adjustments.[126]

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[125] National Grid 2014, Transmission Losses Report: Reporting Period 1 April 2013 to 31 March 2014.

[126] Under the current arrangements, transmission losses are allocated to parties uniformly, and independent of location, based on each party's metered energy: 45% of all losses are allocated to generators and 55% to suppliers. Transmission loss multipliers (TLMs) are used to scale up or down metered volumes for both generation and supply for each settlement period. The current arrangements have provisions to allow for a location-dependent allocation of transmission losses, in the form of locational transmission loss factors (TLFs), but the value of the TLF parameter is currently set to zero. The current system is explained in more detail in Appendix 5.2.

5.42 There have been several attempts to introduce locational charges for transmission losses since the electricity sector was privatised, both during the operation of the England and Wales Pool in the 1990s and since the introduction of NETA and BETTA, with eight BSC modification proposals raised on this issue since 2002.

5.43 In 2003 Ofgem approved P82[127] but this was successfully challenged on judicial review on the basis of procedural flaws. In 2007 Ofgem indicated that it was minded to approve P203[128] but, following a further judicial review, it ran out of time before it could make a final decision. In 2011 Ofgem rejected P229,[129] arguing that the proposals would have a large distributional impact and relatively modest expected benefits.

Impact on competition from lack of locational prices for transmission losses

5.44 The absence of locational prices for transmission losses will affect both generation and demand, in the short and long run. In this section, we consider the likely scale and nature of these impacts, the transitional costs and/or implementation difficulties that a move to locational pricing might create, and the views expressed by parties in response to the initial views set out in our updated issues statement.

5.45 The current system of uniform charging for transmission losses creates a system of cross-subsidisation that distorts competition between generators and is likely to have both short- and long-run effects on generation and demand:

(a) In the short run, costs will be higher than would otherwise be the case, because cross-subsidisation will lead to some plants generating when it would be less costly for them not to generate, and other plants, which it would be more efficient to use, not generating.[130] Similarly, cross-subsidies will result in consumption failing to reflect fully the costs of providing the electricity.

(b) In the long run, the lack of locational pricing may lead to inefficient investment in generation, including inefficient decisions over the

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[127] Ofgem (17 January 2003), Modification to the Balancing and Settlement Code - Decision and Direction in relation to Modification Proposal P82.
[128] Ofgem (26 June 2007), Zonal transmission losses - the Authority's 'minded-to' decisions.
[129] Ofgem decision (28 September 2011), Balancing and Settlement Code (BSC) P229: Introduction of a seasonal Zonal Transmission Losses scheme (P229).
[130] This arises because a generator whose location entails lower transmission losses than a competitor will produce less frequently – and overall system losses and costs will be higher – without locational charging than with.

extension or closure of plant. There could also be inefficiency in the location of demand, particularly high-consumption industrial demand.

Estimates of the size of detriment and distributional impacts

5.46 In relation to the likely size of these impacts, we have reviewed the analyses that were conducted between 2009 and 2011, leading to Ofgem's 2011 decision on P229, and analysis conducted in 2015 that was commissioned by RWE in response to our updated issues statement. Each of these analyses has focused exclusively on estimating the short-run efficiency gains from a move to location pricing for transmission losses; there has been no attempt to quantify the long-run gains.[131]

5.47 The cost-benefit analyses undertaken in relation to P229 were conducted by LE/Ventyx (for Elexon) and Redpoint (for Ofgem), while a third group of experts, Brattle, reviewed the LE/Ventyx work for Ofgem. These report a ten-year net present value (NPV) benefit from the introduction of locational pricing for transmission losses of between £160 million (Redpoint) and £275 million (LE/Ventyx),[132] arising from an average annual reduction in losses of 211 GWh (equivalent to about 5% of losses).[133] These values are based on forward-looking modelling of the sort commonly conducted in energy sector impact analyses and the studies appear to us to be credible and to have been conducted with due rigour and expertise.

5.48 Introducing locational charges for transmission losses would also have a distributional effect, leading to transfers:

(a) from customers in areas of low generation relative to demand to customers in areas of high generation relative to demand;

(b) from generators in areas of high generation relative to demand to generators in areas of low generation relative to demand; and

(c) between generators and customers, as a result of the change in the wholesale price of electricity, with the direction of transfer dependent on whether the price increases (marginal generators pay for a greater share

[131] The methodology is similar in all cases, and involved full electricity market simulations that compared system costs with and without zonal losses. The benefits accrue from the energy saved from more frequently generating electricity closer to its point of consumption. Future scenarios on the location of new investment did not vary by scenario, implying that no benefit was attributed to the possible investment impacts of charging for losses. In this sense, the estimates of the benefits are an underestimate.
[132] A substantial proportion of the savings relate to environmental benefits from sulphur dioxide and nitrogen oxide reductions, arising from the fact that less coal and gas would need to be consumed in order to satisfy demand under a locational loss-charging scheme.
[133] RWE has submitted an updated calculation of net benefits to the CMA. We will review this work in assessing remedies.

of losses under the locational charging regime) or falls (marginal generators pay for a lower share of losses under the locational regime).

5.49 In relation the first effect, LE/Ventyx estimated that there would be a transfer of around £37 million a year (2011 prices) from consumers in the south of England to those in Scotland and the north of England (equivalent to approximately 2% of revenues from the sale of electricity in Scotland). In relation to the second, it estimated that there would be a transfer from generators in Scotland and the north of England to generators in the south of England of about £31 million a year.[134]

5.50 In relation to the third effect, LE/Ventyx found that zonal losses would lead to wholesale price increases and hence transfers from customers to producers. However, both Redpoint and Brattle noted that this was largely an artefact of the simplified modelling approach they used.[135] Brattle concluded that 'our analysis suggests that had Transmission Loss Multipliers been included instead then prices might have instead decreased or, at any rate, stayed broadly constant.'[136] Ofgem's impact assessment, drawing on all three pieces of analysis, concluded 'it is reasonable to conclude that the impact on wholesale prices is likely to be minimal.'[137]

5.51 In relation to implementation costs, these are likely to be low. In its P229 decision, Ofgem expressed the view that the added complexity from changing the rules 'would not be very significant' and that 'implementation costs are low relative to the prospective benefits expected over ten years'.[138] Further, as RWE commented in its response to our working paper on locational pricing, much of the work associated with introducing a zonal transmission losses scheme has already been completed.

Views of parties

5.52 RWE, in its response to our locational pricing working paper, agreed that locational pricing for transmission losses had net benefits to competition.

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[134] Appendix 5.2: Locational pricing in the electricity market in GB notes that Brattle explains that the LE/Ventryx methodology substantially overestimates the average price impact of the modification because of a modelling technicality. We do not believe that the distributional impacts referred to in this paragraph suffer from similar over-estimation.

[135] The simplification in question relates to the treatment of TLFs and TLMs, as explained in Appendix 5.2: Locational pricing in the electricity market in GB.

[136] Both Redpoint and LE/Ventryx model dispatch based only on the unit-specific portion of the losses formula – ie TLFs. These modelled TLFs in fact incorporate a portion of the invariant TLM loss factor. Thus, when looking at the net price impact of incorporating TLFs, it is necessary in the modelling exercises to strip out the locationally invariant portion of losses that is captured in TLMs. This is the adjustment referred to here.

Ofgem, Impact Assessment on RWE proposal 229, seasonal zonal transmission losses scheme, paragraph 4.28.

[138] Ofgem (17 January 2003), Modification to the Balancing and Settlement Code - Decision and Direction in relation to Modification Proposal P82, p5.

Ofgem, Centrica, EDF Energy and Horizon all agreed, to various degrees, that there would be some benefits arising from pricing transmission losses more accurately but expressed concerns about the size of the benefits and costs (including distributional effects) of introducing locational pricing.

5.53 SSE provided four arguments against locational charging of losses:

(a) It would add to existing customer confusion brought about by regional variation in prices.

(b) It would be complex to calculate location-specific loss adjustment factors.

(c) It would affect the economic return of existing generation assets.

(d) It may increase the cost of providing ancillary services to the SO in Scotland.

5.54 In relation to the first argument, it is true that regional variation in prices vitiates the possibility of national advertising campaigns announcing a national price. However, such regional variation would exist with or without locational pricing for transmission losses (due to differential distribution charges). Locational pricing for transmission losses may even reduce price disparities in some cases.[139]

5.55 In relation to complexity, we do not think that the proposal for zonal charging of transmission losses set out under P229 would be complex to implement and note that Ofgem agrees with this view. There may be other, alternative approaches to loss charging that would introduce greater degrees of complexity and we would need to take account of this as part of our consideration of remedies.

5.56 On the impact on existing generation, it is true that any correction that leads to more competitive prices will have some impact on revenues for some participants and will therefore have an impact on asset values (some upwards, some downwards). Ofgem remarked in its consideration of P229 that the introduction of loss adjustments had been debated repeatedly since privatisation, so that the risk of this happening over, at least, the long term should already have been factored into investment decisions.

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[139] For example, customers in parts of Scotland with a low population density and who are located near to generation currently pay high per capita distribution charges but, under locational transmission charging, would pay less for transmission losses.

5.57 Lastly, there may be some effect on the way in which ancillary services are supplied but this does not affect the economic case for cost-reflective pricing.

Our assessment

5.58 Overall, we consider that the absence of locational pricing for transmission losses is likely to create a system of cross-subsidisation that distorts competition between generators and is likely to have both short- and long-run effects on generation and demand:

(a) In the short run, costs will be higher than would otherwise be the case, because cross-subsidisation will lead to some plants generating when it would be less costly for them not to generate, and other plants, which it would be more efficient to use, not generating.[140] Similarly, cross-subsidies will result in consumption failing to reflect fully the costs of providing the electricity.

(b) In the long run, the absence of locational pricing may lead to inefficient investment in generation, including inefficient decisions over the extension or closure of plant. There could also be inefficiency in the location of demand, particularly high-consumption industrial demand.

5.59 While the efficiency gains from a move to zonal loss pricing are likely to be modest in the context of the electricity system as a whole, we have seen no evidence to suggest that such a reform might lead to net loss of efficiency.[141] Further, the analysis that has been conducted has not considered the dynamic benefits from introducing locational loss charges, which, while uncertain, may be significant in the long run. Lastly, the costs of implementing locational charging for transmission losses are not likely to be significant.

5.60 We note that Ofgem, drawing on largely the same evidence base reviewed above, concluded in 2011 that P229 should be rejected. Ofgem concluded that overall P299 would contribute to the BSC objective of 'promoting effective competition in the generation and supply of electricity, and […] promoting such competition in the sale and purchase of electricity'. Ofgem also found that the complexity and implementation cost of introducing

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[140] This arises because a generator whose location entails lower transmission losses than a competitor will produce less frequently – and overall system losses and costs will be higher – without locational charging than with.
[141] No party has suggested this to us in responses to our updated issues statement and we have not seen any argument to that effect in any of the previous code modification proposals regarding locational charging of losses.

charges for losses was likely to be low. Ofgem concluded that ‘on balance P229 […] better facilitates the Applicable BSC Objectives’.

5.61 However, Ofgem ruled against the proposal because it could not satisfy itself that the proposals would operate in the interest of existing and future consumers, on the following grounds:

(a) It would have a large distributional impact.

(b) The impact on wholesale prices and therefore on consumers was very uncertain.

(c) Locational pricing in general might be looked at in the context of market splitting under the EU’s Capacity Allocation and Congestion Management (CACM) mechanism.

5.62 We have found it difficult to reconcile this decision with the evidence and analysis Ofgem commissioned and summarised in its impact assessment. In particular, Ofgem appears to have placed more weight on the prospect of wholesale price increases and hence transfers from consumers to producers than the analysis warranted. In its decision, it stated:

> If either of the P229 proposals were only implemented for a short time, it is not clear that the resultant redistribution of wealth from consumers to generators is in customers’ interests, even if there is an overall NPV benefit because the long-term market efficiencies would not have taken place.[142]

5.63 As noted above, Ofgem’s consultants did not suggest that significant redistribution from consumers to generators was likely. Further, it is not clear to us why Ofgem considered it likely that the P229 proposals would only be implemented for a short time. In particular, we have not seen any evidence to suggest that P229 would be incompatible with the market-splitting changes that Ofgem is evaluating or that the benefits of the modification proposal would not continue to accrue after implementation of any such changes.[143]

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[142] Ofgem, (2011), Balancing and Settlement code (BSC) P229 Introduction of a seasonal Zonal Transmission Losses scheme, p6.

[143] If the CACM process were to lead to a market splitting between Scotland and England and Wales, the two markets would be treated like any two European markets. Prices would be determined within a market and the markets would be ‘coupled’ through day-ahead auctions and the trading of transmission capacity rights. The question of losses would continue to be material: how should generation output metered at the interconnection point be assessed in its contribution to demand? Even if market splitting might require a change to the identity of the supplying unit (no longer a specific plant, but instead an interconnection point), it would still require an adjustment for transmission losses.

Impact on competition of lack of locational prices for constraints

5.64 As with transmission losses, the lack of locational prices for constraints should in principle affect both generators and customers, leading to short- and long-run effects on competition:

(a) There will be a short-run effect through demand response. For example, wholesale prices in export-constrained locations (such as Scotland) will be higher in the absence of congestion charging than they otherwise would be, leading to an under-consumption of electricity relative to other goods and a distortion of competition in favour of other goods. The size of the resultant efficiency loss is a function of the elasticity of demand for electricity, which is relatively low in the short run for households, but may increase with the introduction of smart meters.[144]

(b) The introduction of congestion charging would have longer-run investment impacts. Generators in importing regions, where prices are high, would receive higher energy payments than generators in export-constrained regions (where prices would be lower in constrained periods). In the same way, large consumers would face lower energy costs in export-constrained regions and would therefore be incentivised to locate or expand in those regions. The absence of congestion pricing could therefore lead to some degree of inefficiency in the locational choices of investments. However, we also recognise that the locational decisions of investments can be significantly influenced by the wider network charging methodology.

5.65 We do not think there would be a significant effect from impaired technical efficiency of electricity generation, equivalent to the effect described for transmission losses above. The reason for this is that National Grid currently uses a competitive mechanism to buy balancing services through BM bids and has an incentive to minimise congestion costs.

5.66 Market splitting is the EU's preferred model for dealing with persistent congestion constraints. When markets are split, competitive arrangements determine prices within each market, while energy flows between markets require purchases of transmission capacity rights. The EU already mandates 'market coupling' between interconnected EU markets which facilitates the trade in required transmission capacity rights. Under market splitting, England & Wales and Scotland might become separate zones (or markets)

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[144] See paragraph 7.9, which discusses estimates of the elasticity of demand for electricity. We note that elasticities are likely to increase with the introduction of smart meters.

and be coordinated in the same way as France and Great Britain are currently coordinated

5.67 Some US markets, for example Ercot in Texas, have gone much further with locational pricing and define prices for each supply point and generation point. This requires the use of 'black-box' algorithms to determine incremental balancing costs at each location, and on that basis has been criticised for lacking transparency.

Estimates of the size of detriment and distributional impacts

5.68 There are no comprehensive assessments of the costs and benefits of market splitting in the GB electricity system. The most recent study was a very partial quantification of splitting Scotland from England and Wales by Staffell and Green in 2014.[145] They found that on average domestic consumers in Scotland would benefit by an estimated £64 off their annual energy bills.[146] Generators in Scotland would have lower revenues.[147] Consumers in energy-importing areas (such as south-east England) would face higher prices (an estimated average increase in annual energy bills of up to £14),[148] while generators there would enjoy higher revenues. While this study looked at distributional effects it did not try to estimate a net benefit figure.

5.69 We note that transmission constraints are expected to abate following the implementation of plans for transmission capacity expansion between England and Scotland, which will tend to reduce any short-run benefits for introducing locational pricing to account for constraints.[149]

5.70 In relation to transition and implementation costs, these are likely to be higher than for locational charging for transmission losses because the systems are already in place for the charging of transmission losses but are not for congestion charging. Further, market splitting might potentially lead to reductions in liquidity, with possible impacts on entry and hence dynamic

[145] I Staffell and R Green (2014), *Electricity markets in Great Britain: better together?*
[146] ibid.
[147] This assumes that the market under locational pricing for congestion would be no less competitive. Locational rents are currently controlled to a degree through the Transmission Constraint Licence Condition (TCLC). It would be necessary to make sure that analogous measures were in place to avoid the exploitation of locational rents under split markets.
[148] I Staffell and R Green (2014), *Electricity markets in Great Britain: better together?* This estimate does not take account of benefits that would be passed back to consumers from the elimination of congestion costs in BSUoS charge. The explanatory note further states that, in order to have regard to Ofgem's statutory duties, aims or objectives of the regulator, the remedy contemplated by the CMA must be consistent with the regulator duties.
[149] The links could be completed as early as 2017, which is the date approved by Ofgem under its network pricing regulation. National Grid produces an 'Electricity Ten Year Statement', the latest being from 2014, which forecasts congestion under planned and likely network reinforcement. This does show falling congestion in early years due to these reinforcements, but congestion rises again as renewable generation rises.

efficiency, and lead to concerns about the more effective exercise of market power in the light of small (and therefore more concentrated) areas. We explain some of these in more detail in our discussion of the views of parties.

View of parties

5.71 We did not receive any responses to our working paper in favour of increased locational pricing for transmission constraints. Parties raised a number of concerns about reforms in this direction:

(a) Transactions costs: EDF Energy argued that 'the introduction of zonal pricing [of constraints] increases the complexity and potential cost of hedging and risk management which could act as a barrier to entry for small players'.

(b) Reductions in liquidity: Ofgem, EDF Energy and Scottish Power highlighted this risk, with possible impacts on entry and therefore dynamic efficiency.

(c) One-off transitional costs: SSE and Scottish Power noted that this might be high.

(d) Market power: EDF Energy also pointed to the existence of costs from more effective exercise of market power in small (and therefore more concentrated) zones.

5.72 In addition, SSE and EDF Energy both noted that expected transmission investment was likely to render transmission constraints much less important in the coming years.

Our assessment

5.73 The assessment of the impact on competition of locational pricing for congestion is much less clear cut than it is for transmission losses. Although there are arguments in principle for locational pricing of congestion – through the creation of split markets – no comprehensive cost-benefit analysis has been conducted into even the short-run benefits of such a move. Further, there are complexities of implementation and the potential for unintended consequences (such as a possible reduction in liquidity) (neither of which apply to locational charging for transmission losses).

5.74 We note that there is an EU process commencing this year that will require regular reviews of the best way to configure zones across the EU from the point of view of congestion. Currently the European electricity market is divided into bidding zones, which should be defined in a manner to ensure efficient congestion management and overall market efficiency. Great Britain constitutes one bidding zone for this purpose.

5.75 Under the CACM regulation (expected to be adopted by summer 2015), the Agency for the Cooperation of Energy Regulators (ACER) is required to assess the efficiency of current bidding zone configuration every three years.[150] If the technical or market report published as a result of this assessment reveals inefficiencies in the configuration of zones in a national electricity market, ACER may request the Transmission System Operators (TSOs) for that market (ie for Great Britain National Grid, SSE and Sottish Power Transmission) to launch a review of an existing bidding zone configuration.[151] The CACM includes a preferred European model for congestion charging, where needed, by zonal splitting.

5.76 In view of the above, and considering the above-mentioned changes to be implemented pursuant to the CACM regulation, including the possibility of a review of existing bidding zone configuration, we have decided not to take a view on this issue.

Provisional conclusion on locational pricing for transmission losses and constraints

5.77 The absence of locational pricing for transmission losses is a feature of the wholesale electricity market in Great Britain that gives rise to an AEC, as it is likely to distort competition between generators and is likely to have both short- and long-run effects on generation and demand:

(a) In the short run, costs will be higher than would otherwise be the case, because cross-subsidisation will lead to some plants generating when it would be less costly for them not to generate, and other plants, which it would be more efficient to use, not generating. Similarly, cross-subsidies will result in consumption failing to reflect fully the costs of providing the electricity.

(b) In the long run, the absence of locational pricing may lead to inefficient investment in generation, including inefficient decisions over the extension or closure of plant. There could also be inefficiency in the location of demand, particularly high-consumption industrial demand.

5.78 The current mechanism of averaging the cost of transmission losses irrespective of each generator's and customer's contribution to those losses

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[150] Article 33(1) of the CACM.
[151] Article 34.7 CACM.

results in an approximate cost in NPV terms over ten years to the system of somewhere between £160 million and £275 million.

5.79 Ofgem's published reasons for maintaining this inefficiency are that implementing a solution would have large distributional consequences, transferring funds in the short run from consumers to generators. However, our provisional view is that these concerns do not appear well-founded based on Ofgem's own quantitative work.

5.80 We have not reached a provisional conclusion as to whether the absence of congestion charging is a feature of the wholesale electricity market that gives rise to an AEC. From our initial analysis, this question appears to be finely balanced, with reasons to see both costs and benefits. A process separate from this investigation will require ACER to consider this issue at regular intervals pursuant to a procedure set out in the CACM for this purpose. For these reasons, we have decided not to further investigate this issue within the context of this investigation.

EBSCR reforms to imbalance prices

5.81 Imbalance prices (also known as 'cash-out prices') play a key role in wholesale electricity trading in Great Britain. Ofgem is in the process of implementing fundamental reforms to the system of imbalance prices under the EBSCR. These reforms are:

(a) a move to single imbalance price;

(b) a move to making the imbalance price in all periods equal to the cost of the 1 MWh most costly action in the BM (known as 'price average reference volume of 1 MWh', or **PAR1**), which is a narrowing of the base for the calculation from the previous 500 MWh;[152]

(c) a move to re-price STOR actions (typically periods of tight short-run margins due either to high demand or to supply disruptions)[153] to the probability of lost load multiplied by £6,000/MWh (the 'value of lost load'

[152] This was itself a narrowing from the original design, which was a simple average cost of all balancing actions).
[153] Periods of tight margins are periods when STOR is likely to be used. However, STOR is also used outside of very tight periods. The SO has discretion to use a STOR plant over a BM plant when it is more efficient to do so. STOR may even be used when the system is overall long. RSP, however, is likely to set imbalance prices only in periods when the margin is tight.

(VoLL)),[154] if this is greater than their utilisation price. This is known as 'reserve scarcity pricing', or **RSP**;[155] and

(d) a move to price disconnection or voltage reduction actions equal to the **VoLL**.[156]

5.82 The EBSCR was launched in 2012 and has proved to be a long and involving process, with several parties raising alternative code modification proposals. Ofgem finally approved P305 in April 2015, at the same time rejecting an alternative modification, P316, that involved implementing only the first two elements of the reforms (ie no RSP and VoLL pricing).

5.83 P316 had the approval of the BSC panel, which also concluded that P305 was worse than the status quo. While no appeal was made against Ofgem's decision, several parties have written to us, expressing their concerns about the reforms.

5.84 In this section we consider the likely effect of these reforms on competition in wholesale electricity markets. We first provide some background on the BM and the proposed role of the reformed imbalance prices within it, before assessing the impact of each element of the reform.

Background on the balancing mechanism and imbalance prices[157]

5.85 For any given half-hour settlement period, generators and suppliers may trade with each other up to a point one hour beforehand, known as gate closure. Parties will aim to balance their position for a given settlement period at this time such that the amount of energy they generate or consume matches very closely the amount of energy they sell or buy through contracts.

5.86 Following gate closure, National Grid takes actions to balance the system such that the total amount generated matches the total amount consumed. It does this in the BM by accepting bids and offers submitted (**before** gate closure) by generators or suppliers, to increase or decrease the amount of

[154] The VoLL represents the willingness to pay for an incremental MWh at times of system stress – it is the amount that the consumer of the last MWh is willing to pay to avoid being cut off. The value cannot be measured directly in any sense and is typically estimated once and for all using survey techniques.
[155] As noted above, the imbalance price calculation is applied to the stack of actions.
[156] There is a transitional period during which this will be set to £3,000/MWh.
[157] See Elexon's initial written assessment of P305 – EBSCR.

energy they will produce (or consume).[158,159] It can also take actions outside the BM, such as the use of STOR.

5.87 STOR contracts are procured via a competitive tender process, with three tender rounds per year. National Grid pays an availability payment to STOR service providers, which is paid to the provider regardless of whether it is asked to produce, and a utilisation cost in case of actual delivery. STOR providers agree to make available capacity to National Grid and face contract penalties if the capability cannot be made available. National Grid typically seeks to contract under STOR ahead of time for between 2.2 and 2.3 GW of capacity.[160]

5.88 Following the end of a settlement period, Elexon calculates the 'imbalance volume' for each party, which is the difference between the volume of energy actually generated or consumed and the volume covered by a contract.[161] Any surplus or shortfall that a generator or supplier has is paid for using the relevant imbalance price. Generators and suppliers are charged an imbalance price if they are 'short' (produced too little or consumed too much relative to contract) and paid an imbalance price if they are 'long' (produced too much or consumed too little).

Balancing mechanism and imbalance prices post EBSCR

5.89 The relationship between pricing under the BM and under the cash-out rules as reformed following the recent EBSCR (which is anticipated to come into force in a gradual way over the next three years) is shown schematically in Figure 5.1 below.[162]

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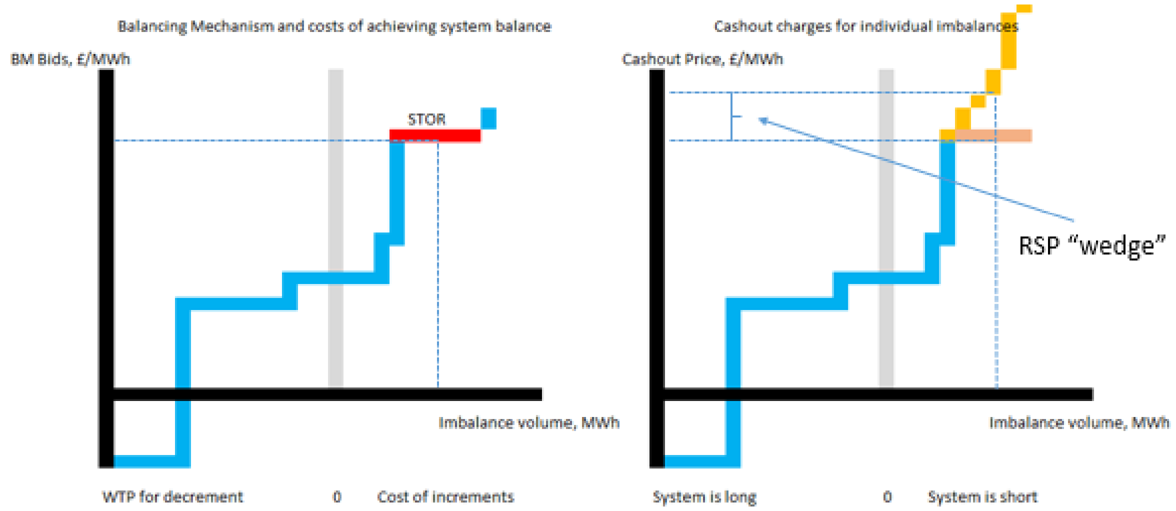
[158] Bids are proposals to reduce generation or increase consumption. Offers are proposals to increase generation or reduce consumption.
[159] An important point to note is that after gate closure, generators have effectively ceded control to National Grid. They have provided Final Physical Notifications, which they are obliged to comply with unless instructed to do otherwise by National Grid, and cannot amend offers or bids.
[160] National Grid (nd), *STOR market information report: tender round 24*.
[161] Account is also taken of any balancing actions taken by National Grid, such that, formally, Imbalance Volume = Energy Produced – (Energy Bilaterally Contracted + Energy Contracted in the Balancing Mechanism). The details are given in ELEXON (2014), *Imbalance pricing guidance*.
[162] This diagram abstracts from many detailed elements of the relationship between BM and cash-out, for example: STOR can be used at times outside periods of system stress; 'tagging' of actions; cost recovery and the RCRC 'beer fund'; and several additional sources of fast response. The diagrams also abstract from the auction design of the BM, which, as a pay-as-bid auction, will not reveal balancing costs in the way assumed in the diagrams. These complications are not central to the arguments that follow.

Figure 5.1: Balancing mechanism and imbalance ('cash-out') prices



Source: CMA analysis.

5.90 The left-hand diagram shows the cost of achieving system balance in the context of the BM auction process. The very short-run supply curve for wholesale electricity is represented as the blue curve. The grey line represents the contracted demand curve (ie the expected point of system balance just before gate closure). The fine dotted lines show what the cash-out price would be if imbalance were such as to require the use of STOR.

5.91 There are always unexpected events on the supply and demand sides between gate closure and delivery which may cause an imbalance, requiring National Grid to buy or sell electricity through the BM. The extent of aggregate imbalance will determine the actions that need to be taken (and therefore the short-run marginal cost of National Grid's intervention to balance the system).

5.92 The short-run marginal cost of energy for balancing is given by the point of intersection of the actual demand for electricity (ie the out-turn imbalance) and the blue and red curve on the left-hand diagram. The blue portions of the curve represent actions that generators bid into the mechanism, and the red portion of the curve represents capacity available to National Grid under STOR contracts.

5.93 Individual parties may or may not themselves be in balance. For small parties, the probability of imbalance is independent of the overall system balance (while the imbalance of large parties is likely to cause overall system imbalance). If a party is not in balance, it will pay an imbalance price derived largely from the weighted average prices of the offers and bids accepted by National Grid through the BM. This is shown in the right-hand diagram.[163]

5.94 Under the EBSCR rule changes, the single imbalance price will be set, as shown in the right-hand diagram, by the intersection of actual demand (ie overall system imbalance) and the supply curve.[164] This follows the supply curve for the BM over most of the range. However, when the system is short at high levels of demand and STOR comes to be used, the rules will introduce a wedge with the balancing market cost (in yellow in the diagram). This is known as RSP.

5.95 In extreme cases where National Grid is not able to balance the system by increasing supply through the balancing auction and STOR contracts, it will force some consumers to consume less energy (ie there will be blackouts or brownouts), and, under the proposed EBSCR reforms, the imbalance price will be set administratively at £6,000/MWh.

Single imbalance price

5.96 **Single imbalance price** is the proposed rule by which there is to be a single price for contractual imbalances. For example, if the system is short and a generator is producing more than contracted, it will receive the same price for its electricity as that paid by a supplier who has not contracted enough electricity. This rule is replacing the current dual imbalance price rule whereby actors who were long when the system was short or vice versa (and were therefore contributing to the rebalancing of the system) were effectively penalised – or at least not rewarded – for doing so.[165]

5.97 The system of dual pricing was designed with the fear that parties might not have sufficient incentives to try to balance their supply and demand positions through bilateral contracts ahead of gate closure. The unattractive charge for beneficial imbalances was designed to encourage parties either to contract ahead of time or to participate in the BM but not to rely on cash-out as a market of last resort (ie taking a long or short physical position into the post-gate closure period voluntarily).

[163] The cost of actions is not always reflected in cash-out prices and the SO goes through a complex ‘tagging’ procedure to determine which actions are properly energy imbalances rather than locational or other system-related effects. We abstract from these features of the mechanism in our analysis.
[164] This change will come into force by winter 2015/16.
[165] This is achieved in the current, pre-reform, system by those in ‘helpful’ imbalance being charged (if short) or paid (if long) an administrative price (the ‘market index price’) that was designed usually to be more (if short) or less (if long) than the corresponding payment or charge incurred in the BM.

5.98 There is some evidence that the single imbalance price reform will be beneficial to smaller generators, to renewable producers and smaller suppliers who tend to be more reliant on cash-out than the large vertically integrated players. To a first approximation, a small player aiming to be in balance will randomly find itself long or short with the same probability;[166] in the long term, under the single imbalance price, any losses made when contributing to the overall system imbalance should be offset by gains made when helping to solve it. Relying on cash-out as a market of last resort will no longer be loss-making by design.[167]

5.99 Some small suppliers rely, even under current rules, to a much greater extent on cash-out than do the larger firms. This is plausibly because the transactions costs of being involved in the on-the-day bilateral markets are high. The move to a single price will make cash-out more attractive for these parties.[168]

5.100 We have received no representations from parties that the move to a single imbalance price will harm entry or expansion. We consider the move to a single price for imbalances to be positive for competition, as it will eliminate the inefficient penalty that has previously been imposed on companies that find themselves in 'helpful' imbalance at any given time.

PAR1

5.101 PAR1 is a rule change by which the calculation for the cash-out price outside times of system stress will be determined by the average cost of the last 1 MWh of balancing actions taken. This will be introduced gradually, with 50 MWh being used next winter and 1 MWh introduced in 2018. This contrasts with the current rule by which the price is determined by the average of the last 500 MWh of actions taken (PAR500). PAR1 is described as making the imbalance price 'more marginal'.

5.102 We have considered three concerns regarding the move to PAR1:

(a) Stephen Littlechild has argued[169] that PAR1 will not necessarily be 'more marginal' (ie a better measure of the marginal cost of an individual imbalance) because balancing actions are not necessarily incremental.

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[166] A small player's own imbalance will not have a significant effect on system imbalance, hence the 'fair bet' involved in cash-out.
[167] Naturally, it still requires that these small players have sufficiently deep pockets or credit lines to balance out runs of bad luck without running out of liquidity.
[168] This is confirmed in Ofgem (2014), *Further analysis to support Ofgem's updated impact assessment*, Figure 3, which shows smaller suppliers benefiting from EBSCR.
[169] Professor Stephen Littlechild (January 2012), *Response to Ofgem's consultation on electricity cash-out issues*.

They may be sequential, or forward-looking (ie reflect expected imbalances in periods outside the period in which the action is taken).

(b) George Yarrow submitted that one of the original rationales for using an average price over a large number of actions was that this made the price less easy to manipulate, raising the concern that PAR1 may create opportunities to exploit market power.

(c) We have received arguments from Utilita, Ecotricty, Haven Power and First Utility that the move to PAR1 will disadvantage smaller players which are more reliant than larger operators on energy purchases in cash-out.

5.103 In relation to first concern, Ofgem has argued to us that the SO's process of 'tagging and flagging' actions, whereby certain bids are excluded from the calculation of cash-out, should help ensure that PAR1 does lead to a better measure of genuine marginal cost, and hence improve efficiency. It has also noted that there will be an opportunity to revisit the modification, should experience suggest that there are real problems.

5.104 On the point of the greater manipulability of a PAR1 price, National Grid has said that 'any attempt to increase an offer price (or reduce a bid price) in the Balancing Mechanism may result in the price of the action being removed from the energy imbalance price stack. This would limit the extent that any individual could know that they will set the imbalance price.' One way of interpreting this point is to observe that National Grid has the ability to learn about the manipulation and the discretion to counter it. With its responsibility to minimise the overall cost of balancing, it is not constrained in any mechanistic implementation of a least cost algorithm. Thus, the present system seems less prone to the sort of micro-manipulation of advantage than was the previous Pool. We accept the view that this considerably reduces the increased risk of manipulation because of a move to PAR1.

5.105 We consider that the argument that the 'sharpening' of imbalance prices, of which PAR1 is one component, is a particular disadvantage to smaller players does have some merit. However, our provisional view is that PAR 1 in combination with a move to a single price may have a relatively small impact on smaller players because they can be expected, in the new regime and outside of RSP periods, to benefit approximately as frequently as they lose.

5.106 The reformed move to PAR 1 is being phased in, with an opportunity to learn from the experience at PAR50. Should this demonstrate that there are real problems with further tightening, the modification could be revisited. We suggest that full advantage of this phasing be taken and that Ofgem should use the opportunity of the move from PAR500 to PAR50 to do a careful empirical analysis of the likely effects of a further move to PAR1.

Reserve scarcity pricing and VoLL

5.107 Ofgem's broad rationale for the introduction of RSP is that it will reduce the cost of ensuring security of supply to consumers by improving the efficiency of balancing and increasing incentives for the market to provide flexibility. In this section, we consider the likely impacts of the move to RSP (including the move to price disconnection or voltage reduction actions equal to the VoLL). Our discussion is structured in two parts:

(a) first, we consider the notion of 'balancing efficiency' and the likely impact of the reforms on this; and

(b) second, we assess the impacts on competition from the move to RSP and VoLL, in particular the incentives of participants to provide flexibility (ie reliable demand or generation capacity which can act quickly in response to price signals).

Balancing efficiency

5.108 Since the introduction of NETA, imbalance pricing arrangements have been designed to create incentives on participants to avoid imbalance, by making it unattractive to participants to rely on imbalance prices as a market of last resort.

5.109 This objective of seeking to minimise the level of imbalance volumes and imbalance costs has come to be known as securing 'balancing efficiency'. This raises a question as to why securing balancing efficiency in this sense (ie minimising a subset of costs) should be an objective over and above that of minimising the overall costs of delivering electricity to consumers.

5.110 While the rationale for pursuing balancing efficiency has not always been explicitly articulated, our understanding is that Ofgem is seeking to minimise the costs that National Grid incurs in operating the BM because of difficulties it has in regulating National Grid's natural monopoly activity of centralised balancing.

5.111 Ofgem has argued that it is increasingly important to have the right incentives in system balancing because 'balancing costs incurred by the System Operator reached approximately £850m last year [2014] and are expected to rise substantially in future.'

5.112 To the extent to which parties are risk-averse, increasing the sharpness of imbalance prices and their volatility should improve balancing efficiency in the sense articulated above. National Grid has said to us that, given an overall reserve requirement, less of it might be purchased through STOR because of behavioural changes induced by EBSCR for the reasons outlined here. However, it is possible that STOR purchases might increase for other reasons. In any case, National Grid anticipates that the impacts of EBSCR on STOR purchases will be small.

Impact on competition

5.113 Ofgem intends that the reforms will provide greater incentives for flexible generation and demand, while several parties (both generators and suppliers) have argued to us that the reforms will expose them to risks that they cannot manage.

5.114 To understand the impact RSP will have on the incentives and risks facing parties, it is important to consider the timescales over which information is likely to become availability concerning the likelihood of STOR being used and of loss-of-load probability (LOLP) being high.

5.115 National Grid will provide a forecast of margin or LOLP at several intervals before gate closure (8, 4 and 2 hours before real time before the final value is determined at gate closure). To the extent to which relevant information becomes clear more than 4 hours ahead of real time, most gas and coal plant should have the ability to start up in response. If the information becomes available between 4 hours and gate closure, then there might be an opportunity for more flexible plant and DSR to respond. If the information becomes available after gate closure (eg due to a sudden and unexpected plant failure), plant cannot respond autonomously (they are bound to follow their final physical notifications). National Grid currently offers DSR customers the opportunity to respond in real time, even after gate closure by submitting 'Customer Demand Management notifications', but nevertheless retains the right to levy an 'information imbalance charge' for inaccurate physical notifications.

5.116 It is the possibility of such sudden events that has caused concerns expressed to us from generators and suppliers. For example, Cornwall Energy wrote to us setting out concerns from independent suppliers about the proposals, which it claimed 'systematically disadvantages small and one-sided players' due to their increased exposure to imbalance prices.

5.117 Utilita and Ecotricty argued that 'adherence to marginal cost pricing cannot be justified […] where the suppliers impacted are unable to respond.' The argument is that where suppliers are settled on average consumer profiles rather than actual consumption, DSR as a response to high cash-out prices makes no sense.

5.118 We sympathise with this argument. However, parties do have options apart from DSR in insuring themselves against high imbalance prices, like contracting for more flexible capacity. Further, some customers metered and settled on a half-hourly basis (currently the larger I&C customers and some smaller business customers) will be able to respond. However, we agree with Utilita and Ofgem on the importance of moving to more comprehensive half-hourly settlement for all customers in order to deliver the flexibility benefits of DSR. This is discussed in Section 8.

5.119 Overall we think that RSP will provide stronger incentives for contracting and forecasting ex ante, and some additional incentives for flexible generation and demand, but there is likely to be an irreducible element of risk that parties cannot directly control. While smaller parties are generally more exposed to imbalance volumes than larger parties, under single pricing they are as likely to benefit from an unexpected event as to lose out. Further, the prevalent use by smaller suppliers of intermediaries should help any such risks be managed.

5.120 On balance, while we have not seen strong evidence in favour of a move to RSP, we believe that there are insufficient grounds to consider that it is likely to lead to an AEC.

Interaction with the Capacity Market

5.121 In the updated issues statement we expressed a concern that there might be unintended interactions between the Capacity Market and EBSCR reforms, potentially leading to overpayment of generators if they failed to take into account the impact of EBSCR in their bids under the Capacity Market.[170] In this section, we examine the interactions between the two sets of reforms.[171]

5.122 Ofgem and DECC have both stated that the Capacity Market and the EBSCR in general are complementary, in that bidders in the Capacity Market should anticipate these potential additional revenues, displacing revenues they would otherwise seek through the Capacity Market, leading to

[170] The EBSCR was originally intended as a set of reforms to improve incentives for investment, although Ofgem's stated rationale for the reforms has changed somewhat following DECC's implementation of the Capacity Market.
[171] We consider to what extent there is a case for policy interventions to improve incentives to invest in the discussion of the capacity mechanism (paragraphs 5.134 and following).

a lower clearing price and lower prices would then be passed through to consumers' bills.

5.123 Within the context of its assessment of the Capacity Market reform under state aid rules, the European Commission received a submission raising concerns regarding overcompensation caused by the coexistence of the Capacity Market and payments under STOR. In response to this submission, the UK government noted that capacity providers could not benefit from both long-term STOR contracts and Capacity Market contracts, and that concerns regarding overcompensation would not be present in the annual STOR auctions. This is because the STOR auction for annual contracts occurs after the Capacity Market auction has taken place, and therefore providers would be able to factor their Capacity Market revenues before bidding in the annual STOR auctions, resulting in no overcompensation. The European Commission accepted that the Capacity Market had been designed to be consistent with the reform of electricity cash-out arrangements.

5.124 We asked the larger bidders in the Capacity Market auction in 2014 how they had assessed future revenue flows from the energy market in determining their bids in order to assess the degree to which we might expect those bids to have reflected the offsetting revenues from EBSCR changes. None of them had [✂] in determining their price forecasts which underlay their bids. We understand that this partly reflects the uncertainty over whether the changes would be implemented. However, one of the Six Large Energy Firms ([✂]) said to us that, even if the reforms had been certain, they would probably have [✂].

5.125 We note that several bidders appear to have made some adjustments to their bids that may take some account of the EBSCR reforms.[172] We also note that the clearing price for the first Capacity Market auction in 2014 was just under £20/kW, considerably below pre-auction estimates of the clearing price. However, this may reflect differences in view (between DECC and the participants in the auction) over any the variables affecting bids.

5.126 Overall, we have not found strong evidence that anticipation of EBSCR reforms resulted in lower bids in the Capacity Market auction in 2014. For the next Capacity Market auction, there may be less uncertainty over the implementation of EBSCR. However, it is still not clear that this will result in materially lower bids.

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[172] [✂]

Provisional conclusion on imbalance price reforms

5.127 Our concern has been to assess whether any aspects of Ofgem's EBSCR reforms lead to an AEC.

5.128 We have found that the move to a single price is positive for competition. We have had no arguments from any parties objecting to this modification.

5.129 We have assessed the move to PAR1 and we have noted:

(a) Ofgem's reassurance that it will assess the impacts of the first phase of the move to PAR50 in order to determine whether or not the move to PAR1 is likely to be beneficial; and

(b) Ofgem's view that National Grid's tagging and flagging will reduce the risk that the PAR price deviates from the marginal cost of energy for the period.

5.130 If, as argued by Utilita, Ecotricty, Haven Power and First Utility, the tightening to PAR50 does impose a substantial burden on smaller parties, there is an opportunity to halt the move from PAR 50 to PAR1. However, if the evidence suggests that PAR1 is a good measure of marginal energy cost in a period, then there is an efficiency argument for it to be the imbalance price, even if it imposes a forecasting and contracting burden on smaller players. Overall, if the tightening to PAR50 does not lead to more efficient, marginal prices, we believe Ofgem should halt the move from PAR 50 to PAR1.

5.131 In relation to RSP, while we have not seen strong evidence for the benefits claimed in terms of improving balancing efficiency, we do not believe on balance that it is likely to create an AEC.

5.132 We have not found strong evidence that anticipation of EBSCR reforms by generators and DSR providers resulted in lower bids in the Capacity Market auction in 2014. For the next Capacity Market auction, there may be less uncertainty over the implementation of EBSCR. However, it is still not clear that this will result in materially lower bids.

5.133 Finally, we note that several parties have criticised the change governance process in rejecting P316 and adopting P305. Questions of governance are considered further in Section 11.

The Capacity Market

5.134 Under the Capacity Market, National Grid holds auctions to secure agreements from capacity providers (generation and DSR) to provide capacity when called upon to do so at times of system stress. The Capacity Market was introduced to address the concern that potential investors in generation might be sceptical about their ability to recover the costs of their investment in an energy-only market, since this would require prices to be allowed to spike to very high levels on occasions of system stress.

5.135 In this section, we review the rationale for the Capacity Market before assessing its design and reviewing its impact on competition.

Rationale for the Capacity Market

5.136 The theory of a well-functioning competitive energy-only electricity market is that generators will fully recover sunk capital costs (eg the costs to build generation capacity) at very occasional peak times – once every 20 years,[173] perhaps.

5.137 At these times, demand is high enough to give the owners of this generation capacity the ability to earn a price far in excess of short-run marginal cost. While these prices will appear high at the time, in an energy-only market they provide the necessary market signals for an investor. Peak capacity, which by definition is used rarely, will require very high prices (during the limited periods in which it is generating) to earn a return sufficient to justify the investment.

5.138 In practice, investors in generation may be sceptical that such peak prices would ever be allowed to arise. Extreme demand periods in Great Britain are most likely to be in a cold winter when the weather amounts to a national emergency and when high demand is compounded by an increased risk of supply outages. Energy companies may not believe that they would be allowed to charge extreme prices in such circumstances and may not even wish to, given the damage to reputation that the appearance of profiteering would cause.

5.139 If owners of generation capacity, especially peak capacity, do not charge extreme prices in extreme demand periods, and if they are competing fiercely on price at other times, then they are unlikely to recover sunk capital

[173] Twenty years is used as an example. In traditional, centrally planned electricity systems, engineers would often define adequacy standards in terms of being able to withstand a 'once in 20 years' winter. It should be emphasised that in practice, peaking plant can earn revenues at other times, for example by supplying essential system stability services unrelated to energy supply.

costs fully and are unlikely to invest. This is the phenomenon widely known in this industry as the 'missing money problem'. To the extent that investors do not have confidence that they will be permitted to charge the prices required to recover their sunk costs, investment will be deterred, with the risk of under-supply at peak periods.

5.140 We note that Great Britain witnessed a considerable amount of new investment in CCGT in the early years of the 21st century. However, the NETA/BETTA system has been in existence for a short period of time relative to the expected frequency of extreme events, and the system has never been tested in terms of extreme conditions (and therefore potential for extreme prices).

5.141 As policy to decarbonise electricity production developed in the 2000s, it became clear that investors in thermal generation would have increasing challenges in recovering sunk capital costs. Low carbon generation mostly has very low short-run marginal costs. In an energy-only market, increased renewable capacity brought on to the system through subsidy is likely to make thermal generators more and more reliant on increasingly infrequent periods of system stress to earn a positive margin. The falls in peak demand due both to recession and to energy efficiency measures have exacerbated the problem for investors in thermal plant and for those with sunk costs that have not yet been recovered.

5.142 Our provisional view is that DECC's introduction of a Capacity Market is based on cogent arguments. The approach adopted by DECC provides a framework for using competitive mechanisms as a means of promoting efficient investment. More tangibly, it will help ensure that an appropriate level of security of supply is maintained. In particular, this should help to improve incentives to invest in and maintain thermal generating capacity at a time of considerable policy change and provide greater incentives for DSR. We have found that since 2009 the Six Large Energy Firms have suffered significant impairment losses in relation to their conventional CCGT and coal generation fleet. Impairment losses are a clear indication that investors do not expect to fully recover the cost of past investments in these technologies.

Capacity Market design

5.143 Under the Capacity Market, the Delivery Body holds a series of auctions to secure agreements from capacity providers to provide capacity when called upon to do so at times of system stress.[174] Winning bidders receive regular capacity payments in exchange for an obligation to provide a previously agreed level of capacity with 4 hours' notice from the SO, National Grid.[175]

5.144 DECC (with input from National Grid and a panel of independent experts) sets the amount of capacity to procure in the Capacity Market for each delivery year, based on its target 'reliability standard'.[176] That is, DECC estimates the amount of capacity needed in any given year to meet its target level of reliability.[177] The Delivery Body then holds auctions to procure this target level of capacity.

5.145 Capacity agreements are allocated via a multiple-round descending clock auction with a single clearing price.[178] Ahead of the auction, DECC announces the demand curve the auctioneer will use to determine the amount of capacity to procure.[179] Rather than simply procuring a fixed amount of capacity regardless of price, setting a demand curve allows DECC to trade off the quantity of capacity it procures with the cost of doing so.

5.146 Figure 5.2 illustrates DECC's demand curve for the first auction. It is important to note that the parameters of any future auction may be different.

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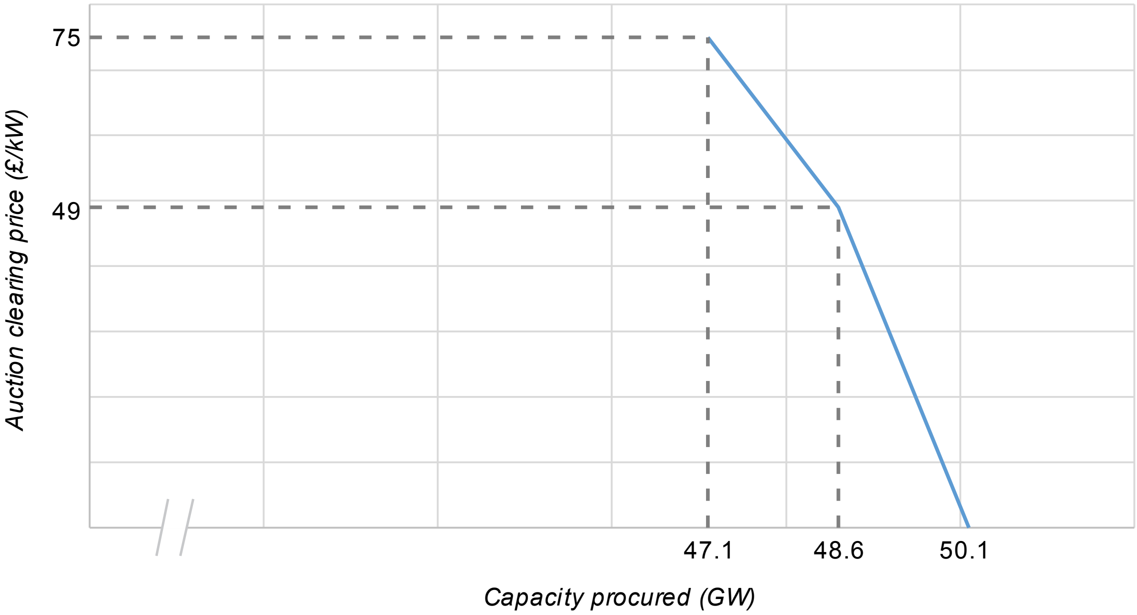
[174] DECC (June 2014), *Implementing Electricity Market Reform (EMR): finalised policy positions for implementation of EMR*.
[175] ibid.
[176] Expressed as loss of load expectation (LOLE): the number of hours during each year for which it is expected (statistically) that supply would not meet demand (absent further intervention from the SO)
[177] DECC (June 2014), *Implementing Electricity Market Reform (EMR): finalised policy positions for implementation of EMR*.
[178] National Grid (July 2014), *Capacity Market user support guide: guidance document for Capacity Market participants*.
[179] DECC (June 2014), *Implementing Electricity Market Reform (EMR): finalised policy positions for implementation of EMR*.

Figure 5.2: DECC's demand curve for the 2018/19 T-4 auction



Source: CMA graph of National Grid data.

5.147 The first auction (for delivery in 2018/19) was held in December 2014, and procured just under 50 GW of capacity at a price of just under £20/kW, considerably below the pre-auction estimates of the clearing price. This will result in capacity payments of just under £1 billion in the delivery year.

Potential concerns

5.148 For the reasons set out above, we believe that DECC's introduction of a Capacity Market is based on cogent arguments. It is based on the principle that competition between bidders for capacity agreements should drive down the level of support required to efficient levels, such that consumers are not paying more than is necessary for the required capacity.

5.149 However, for the Capacity Market to deliver these benefits fully, it must also be designed and operated practically and efficiently. In this section we consider whether aspects of the auction design mean that the benefits of competition might not be fully delivered. In particular, we consider three potential concerns that have been raised with us relating to the design of the Capacity Market.

Length of capacity agreements

5.150 In December 2014, Tempus Energy brought an action before the European General Court seeking the annulment of the European Commission decision to approve the Capacity Market.[180] Also in December 2014, the CMA received a submission from Tempus Energy regarding the role of DSR in the Capacity Market.[181]

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

5.152 Tempus Energy's submission set out that it considered that failure to offer similar terms to DSR providers could foreclose the market to potentially efficient capacity providers.

5.153 We addressed this issue in our discussions with DECC. DECC said that it had sought evidence from the DSR sector on this issue, but had not received compelling evidence that DSR providers required longer-term capacity agreements. DECC is currently undertaking additional research on DSR. If DECC were to find that efficient DSR projects were being excluded by the current arrangements, we would expect it to revise the rules around contract length for DSR providers in the Capacity Market.

5.154 In addition to this specific point regarding the length of agreements available to DSR providers, a number of stakeholders expressed concerns around the broader issue of some projects being eligible for longer capacity agreements than others. We recognise that there are risks associated with offering long (eg 15-year) capacity agreements. For example, it may risk locking in capacity at prices that may not end up offering good value for money to consumers (eg if the same capacity could be procured in future auctions at a lower price).

5.155 DECC developed a methodology for adjusting the price awarded for longer-term contracts based on expectations of clearing prices in future auctions. While it opted not to progress with its original proposals following consultation, we understand that DECC is continuing to consider options to ensure that the trade-offs identified above are better reflected when awarding long-term contracts. We encourage DECC to continue seeking a workable methodology in this area. However, in view of DECC's work in this area and the case pending before the European General Court, we do not intend to carry out further work in this area.

[180] Case T-793/14, *Tempus Energy and Tempus Energy Technology v Commission*, lodged 4 December 2014.
[181] Tempus Energy initial submission.

Recovery of Capacity Market costs

5.156 Tempus Energy's submission also claimed that the way in which the costs of the Capacity Market are recovered from suppliers could harm the ability of DSR providers to compete.

5.157 The submission set out its concerns that DECC's decision to recover Capacity Market costs based on suppliers' share of demand during 4–7pm on working days between November and February, rather than via triads (as originally proposed by DECC)[182] risked reducing the incentives for DSR. It argued that if Capacity Market costs were recovered via triads, it would create stronger incentives to reduce demand in these periods of high demand, further encouraging consumers to be active in managing their demand.

5.158 However, we have not seen specific evidence that recovering Capacity Market costs via triads would be an improvement on the current system. Employing DSR will be efficient where its incremental costs are less than both the incremental costs of additional generation and the VOLL.[183]

5.159 If Capacity Market charges were recovered via triads, and DSR providers were able to reduce demand during triad periods, the latter would be able to avoid significant charges. If DSR providers faced these (non-cost-related) savings from decreasing their demand (ie providing capacity) during triads, but generators did not face the same benefits from providing capacity during these periods, the incentives of DSR providers relative to generators could be distorted. As a result, we consider that recovering the Capacity Market costs through triads might lead to DSR providers securing some capacity agreements for which additional generation may have been a lower cost option. If this is the case, it may result in an inefficient allocation of capacity agreements.

5.160 This is a point that DECC appears to have taken into account in making its decision on recovery of Capacity Market costs. Its October 2013 consultation noted that there may be a 'double advantage' from DSR providers being able to benefit from both Capacity Market payments and avoiding triads.[184]

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[182] Triads are the three half-hour periods of highest demand (on separate days) during the year. Recovering the Capacity Market costs via triads would require suppliers to pay an amount based on their share of demand during these three half-hour periods.
[183] That is, if generators can increase output at less than the cost of DSR, reducing demand (through DSR) will be inefficient. Likewise, if the cost of reducing demand through DSR is greater than the VOLL, voltage reductions and/or customer disconnections would be more efficient than DSR.
[184] DECC (October 2013), *Electricity Market Reform: Consultation on Proposals for Implementation*. While the consultation noted the potential for double payment between CM and triad avoidance, DECC has indicated that the final methodology put in place post-consultation should not have that effect.

For the reasons set out above, we do not plan to undertake further work in this area.

Penalty mechanisms

5.161 Capacity providers with capacity agreements face penalties if they fail to deliver their obligations.[185] These penalties are capped at 100% of the capacity provider's annual capacity market payments.[186] That is, the total penalties a capacity provider faces over the course of a year cannot rise above the revenue it receives from Capacity Market payments in that year.

5.162 We set out in the Capacity working paper that we would consider further whether the penalty arrangements risked providing capacity providers with an upside (of the capacity payment) and no downside (as the worst they could do would be not to receive a capacity payment).

5.163 A number of parties set out that our analysis was an incorrect categorisation of the decisions faced by those entering into capacity agreements. They noted that absent the capacity agreement, a lot of capacity providers would not be in the market, and that they would rely on capacity payments to remain profitable. As a result, they pointed out that a capacity provider losing up to 100% of its capacity payments could have a significant impact on its finances, thereby creating a strong incentive to be available when called upon in times of system stress.

5.164 In addition, a number of stakeholders noted that the high wholesale electricity prices at times of system stress would create strong incentives for those with capacity agreements to be available, reducing the need for further penalties. We recognise that the high level of wholesale electricity price is likely to create additional incentives for capacity providers to be available during these periods.

5.165 We have not seen any specific evidence that the current penalty arrangements would lead to capacity providers entering into capacity agreements when they may not be able to meet their obligations, and do not plan to consider this issue further at present.

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[185] DECC (June 2014), *Implementing Electricity Market Reform (EMR): finalised policy positions for implementation of EMR*.
[186] The Electricity Capacity Regulations 2014, Schedule 1.

Provisional conclusions on Capacity Market

5.166 Our provisional conclusion is that the design of the Capacity Market appears broadly competitive. However, we cannot exclude that there specific aspects of the Capacity Market's design could be improved.

5.167 We have investigated a number of specific issues relating to the Capacity Market design that were raised with us. As regards the recovery of costs and the penalty mechanism, our provisional view is that these two aspects of the Capacity Market design are unlikely to give rise to an AEC. As regards the length of the capacity agreements, and the different treatment of DSR providers, in view of DECC's work in this area and the case pending before the European General Court, we do not intend to carry out further work in this area.

Contracts for Difference

5.168 DECC has introduced CfDs to replace Renewable Obligation Certificates (ROCs) as the main mechanism for incentivising investment in low carbon generation. Unlike ROCs, which take the form of a payment on top of the revenue generators receive from the wholesale electricity market, under CfDs, generators are paid the difference between a strike price (which is fixed in real terms) and a market reference price.[187]

5.169 CfD payments are due to increase steadily, reaching about £2.5 billion a year by 2020/21.[188] DECC has expressed the view that, by insulating low carbon generators from a fluctuating wholesale price, CfDs will allow them to manage risks more effectively, resulting in a lower cost of capital and, in the long run, lower costs to consumers.

5.170 In this section, we set out our provisional views on the structure and design of CfDs and their impact on competition. The discussion is structured as follows:

(a) We describe, by way of background, how CfDs work and consider the rationale for replacing ROCs with CfDs.

(b) We analyse the ways in which CfDs are allocated and the impact on competition.

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[187] The effect is that, if those who have a CfD sell their electricity in the reference market, they will, overall, receive the strike price for each MWh of electricity they generate.
[188] In 2011/12 prices. The remaining budget to 2020/21 under the Levy Control Framework is set out in DECC (October 2014), *Annual energy statement* 2014, p75.

(c) We assess the risk of manipulation of the CfD reference price.

(d) We assess the impact of the Supplier Obligation on suppliers.

(e) We present our provisional conclusions.

Comparison of Renewables Obligation Certificates and Contracts for Difference

5.171 In order to achieve its objective of decarbonising electricity generation, the government has supported renewable electricity generation since 2002 via the RO scheme.[189]

5.172 Under the current RO system, all eligible renewable generators receive a number of ROCs based on their type of generating technology and the amount of renewable electricity they generate. Eligible electricity suppliers are issued an RO, based on a relevant percentage of their supply of electricity to customers in Great Britain, under which they are obliged either to submit a number of ROCs or pay a 'buy-out price' for their remaining RO that they do not meet through submitting ROCs.[190]

5.173 Suppliers therefore have incentives to purchase ROCs from renewable generators, provided they can buy them at a price that compares favourably with paying the buy-out price. In Annex B of Appendix 5.3 we assess the impact on competition from the interactions between sellers and purchasers of ROCs. We have not seen evidence of anti-competitive behaviour in the market for ROC purchases, nor, given the forthcoming closure of the RO scheme to new investments, have we seen a clear route by which any such anti-competitive behaviour would translate into harm for consumers.

5.174 As part of the EMR, DECC is moving away from using ROCs as the main mechanism for supporting additional low carbon generation. Under the new system, low carbon generators (renewable and nuclear generation) can receive payments by entering into a CfD.[191]

5.175 A CfD is a private contract between the holder and the CfD counterparty[192] in which the holder receives from (or pays to) the counterparty the difference

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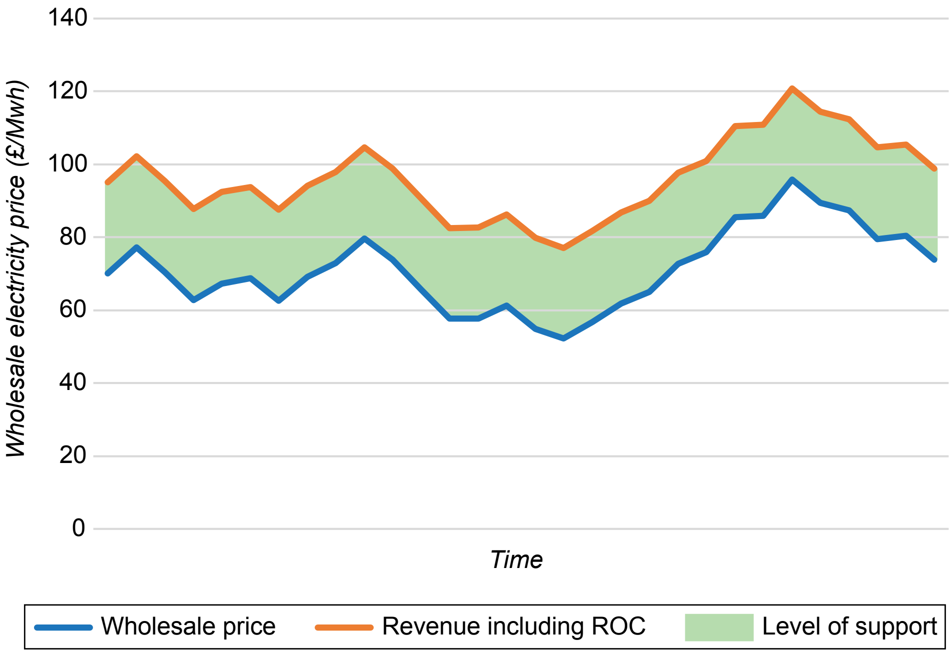
[189] DECC (February 2015), *Increasing the use of low-carbon technologies*.
[190] ibid.
[191] DECC (June 2014), *Implementing Electricity Market Reform (EMR): finalised policy positions for implementation of EMR*.
[192] The CfD counterparty is the Low Carbon Contracts Company (LCCC) – a company wholly owned by the government. Its duties include acting as the counterparty for CfDs issued to low carbon generators. See DECC (August 2014), *Low Carbon Contracts Company Ltd: framework document*.

between a previously agreed strike price and a CfD reference price.[193] The CfD counterparty makes (or receives) a payment per MWh generated, meaning the level of support is based on actual output of low carbon generation (rather than capacity). CfDs typically have a duration of 15 years.[194] Electricity suppliers finance the CfD payments to generators by paying a contribution to the CfD counterparty (the 'Supplier Obligation') based on their share of total metered demand.[195,196]

5.176 Figures 5.3 and 5.4 illustrate the payments under both ROCs and CfDs. Both figures are not based on actual data, and are provided for illustrative purposes only.

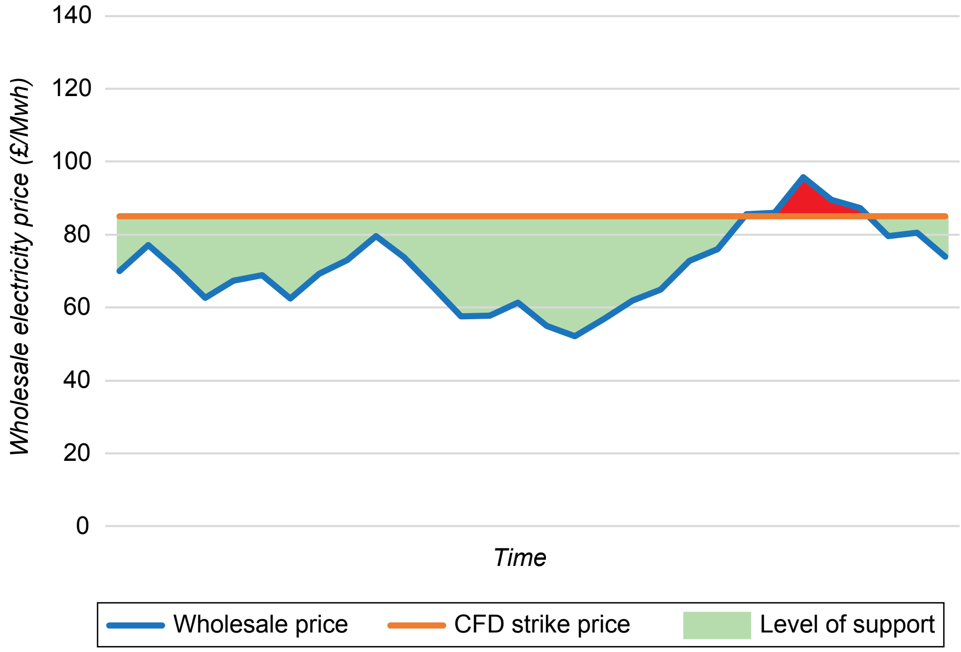
Figure 5.3: Renewables Obligation Certificates



Source: CMA (not actual price data).

[193] For baseload generation, the CfD reference price is the volume-weighted average of season-ahead baseload prices, based on data from the London Energy Brokers' Association (LEBA) Baseload Index and the Nasdaq Baseload Index. For intermittent generation, the CfD reference price is the volume-weighted average of day-ahead electricity prices for the relevant settlement period, based on data from the APX Intermittent Index and the N2Ex Intermittent Index. See FiT Contract for Difference standard terms and conditions for more information.
[194] DECC (August 2013), *Electricity Market Reform: Contract for Difference – allocation methodology for renewable generation*.
[195] The Contracts for Difference (electricity supplier obligations) regulations 2014.
[196] Suppliers pay an amount (fixed per quarter) per MWh of demand, with a process of reconciliation at the end of the quarter to correct any over- or under-recovery. See DECC (June 2014), *Implementing Electricity Market Reform (EMR): finalised policy positions for implementation of EMR*.

Figure 5.4: Contracts for Difference



Source: CMA (not actual price data).

5.177 Figure 5.3 shows that under ROCs the payments that generators receive are independent of the wholesale electricity price, meaning that their overall revenues fluctuate with the wholesale price.[197] In contrast, Figure 5.4 shows that with CfDs, while the payments that generators receive vary, their overall revenues (strike price) remain constant (in real terms) and are unaffected by fluctuations in the wholesale price. CfDs are therefore likely to provide a greater level of certainty for investors compared to ROCs.

5.178 DECC argues that removing this source of uncertainty from low carbon investment returns creates an environment that is more conducive to investment in these technologies, potentially reducing generators' financing costs, in turn reducing the support they require and therefore the cost to consumers.[198] More broadly, the stated rationale for switching from the RO system to CfDs is that it provides a more efficient allocation of risk between investors, consumers and government.[199]

5.179 As discussed in Section 2, an efficient approach to reducing emissions across the economy would be to apply a single carbon price across sectors at a level consistent with overarching emissions reductions targets. We recognise, however, that in the absence of sufficient international political will to increase the stringency of the ETS cap – and given the 2020

[197] The support to generators is driven by the price it receives for its ROCs, as explained above.
[198] DECC (October 2013), *CfD impact assessment*.
[199] ibid.

renewables target to which the UK is subject – there is a case for interim measures to incentivise investment in low carbon generation. In this context, we believe there are relatively strong efficiency arguments for replacing the RO with CfDs.

5.180 As noted in Section 2, the RO has been successful in driving investment in renewable generation, which accounted for just under 20% of all GB generation in 2014.[200] However, it has imposed an increasing burden on bills – even though ROCs are being phased out to new generation from 2017, DECC estimates that ROC payments will reach almost £4 billion per year by 2020/21,[201] and will make up around 8% of the domestic electricity bill in 2020.[202]

5.181 We note that the RO has evolved over time into a highly complicated mechanism for distributing support to renewable generators, which exposes renewable generators both to wholesale price risk and to risks in the ROC market. There is some evidence to support DECC's view that the more attractive risk properties of CfDs will encourage investors to accept a lower level of support per MWh of generation.

5.182 DECC set the Administrative Strike Prices (ASPs) in the first CfD auction at a level slightly below the revenue generators would expect if receiving support through ROCs. This was to reflect the reduced risk from CfDs relative to ROCs, and the lower revenue generators should be prepared to receive as a result. The fact that some generators that would have been eligible for ROCs opted to enter into CfDs at a strike price below the ASP (and therefore below the level of support they would have received under ROCs) implies that these parties may consider the benefits of CfDs over ROCs to be significant.

Analysis of Contracts for Difference allocation

5.183 It is very important that support levels are determined efficiently, as they will become an increasingly important driver of the electricity prices paid by consumers. DECC estimates that CfD support payments will increase steadily, reaching £2.5 billion per year by 2020/21,[203] and will make up

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[200] DECC, Energy Trends March 2015, Section 6.
[201] DECC (October 2014), *Annual energy statement 2014*.
[202] DECC (November 2014), *Estimated impacts of energy and climate change policies on energy prices and bills*. There will also be impacts on the electricity prices paid by industrial and commercial users.
[203] In 2011/12 prices. The remaining budget to 2020/21 under the Levy Control Framework is set out in DECC (October 2014), *Annual energy statement* 2014, p75.

approximately 5% of the domestic electricity bill in 2020, and rise further still thereafter, reaching around 12% of the domestic electricity bill in 2030.[204]

5.184 In our view, a central benefit of the move from ROCs to CfDs is that, while under the RO levels of support are set administratively, under CfDs competition can be used to set the strike price and hence the level of support provided to low carbon generators.

5.185 Under current legislation, CfDs can be allocated to renewable generators via two different routes. First, DECC can hold allocation rounds in which it allocates a certain amount of budget to CfDs, and projects compete with each other to secure support (described below as the 'competitive allocation of CfDs'). Second, in exceptional cases, DECC can also direct the CfD counterparty to award a CfD to a generator directly (described below as the 'non-competitive allocation of CfDs').

5.186 The competitive allocation of CfDs is likely to be a more efficient means of providing support in most cases. The competitive mechanism should put pressure on suppliers to reduce costs in order to be successful in the auction, and avoids the need for DECC to second guess the efficient level of support, and incentivises suppliers accurately to reveal their costs. We therefore believe that DECC's move to a competitive allocation process was a very positive step towards ensuring an efficient allocation of support.

5.187 Bidding for the first competitive allocation round took place in January and February 2015.[205] In the first auction, CfDs were allocated to 27 renewable generation projects, comprising a total of 2.1 GW of capacity, due to commission between 2015/16 and 2018/19. The total amount of support awarded to these projects through CfDs is projected to be approximately £315 million per year in 2020/21.[206]

5.188 We estimate that the amount of support to projects awarded CfDs in the first auction was approximately 25% lower than it would have been had CfDs been awarded to projects at their ASPs. This provides evidence of the potential efficiency gains from the use of competition in setting the strike price and is a strong endorsement of DECC's decision to introduce a competitive allocation mechanism.

5.189 We note, however, that while, in general, a competitive allocation process will provide the best means of achieving an efficient outcome, this will not be

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[204] DECC (November 2014), *Estimated impacts of energy and climate change policies on energy prices and bills*.
[205] Low Carbon Contracts Company (January 2015), *Electricity Market Reform Contracts for Difference: GB implementation plan*.
[206] DECC (February 2015), *Contracts for Difference (CFD) Allocation Round One Outcome.*

the case in all circumstances. If, for example, there are not enough potential bidders to enable an effective competition, then other approaches may be more appropriate. It is, however, important given the scale of the expenditure involved and the impact on consumers' bills that where the allocation deviates from a competitive process, this is justified clearly on the basis of efficiency.

5.190 We are concerned that some elements of the allocation process may restrict the use of competition in setting the strike price and fail to ensure that any deviation from the competitive approach is justified on efficiency grounds. In the following sections, we set out our assessment of three areas of concern surrounding the design of the allocation process and its impact on competition:

(a) The ability of DECC to award contracts outside of the competitive process ('non-competitive allocation').

(b) The design of the competitive allocation process, notably the definition of discrete 'Pots' within which technologies may compete.

(c) The potential impact that the availability of ROCs to investors could have on the extent of competition during the early years of the competitive allocation process.

Non-competitive allocation of CfDs

5.191 The Energy Act 2013 gave DECC powers to award CfDs directly to parties through a non-competitive process. In March 2013, DECC launched a scheme to award an early form of CfDs to renewable generation projects called the Final Investment Decision enabling for Renewables (FIDeR) scheme, with the intention of avoiding investment delays during the transition to the enduring CfD regime.

5.192 DECC signed contracts with eight projects under FIDeR in May 2014. Two of the contracts were for power plants converting from burning coal to biomass, five for offshore wind farms and one for a purpose-built biomass plant providing heat as well as power. The total amount of support that the eight projects awarded CfDs under FIDeR will receive is approximately £1.4 billion per year in 2020/21.[207] The projects are expected to be completed between 2015 and 2021, and will have a combined capacity in excess of 4.5 GW when completed.

[207] Based on DECC's assumptions of a wholesale electricity price of £53.43/MWh in 2020/21.

5.193 In the updated issues statement and capacity working paper, we set out our concerns that these eight renewable generation projects were awarded CfDs with a total value of £16.6 billion over their lifetime outside the competitive auction process under the FIDeR scheme.[208,209,210] In 2013, DECC also agreed key commercial terms with EDF on a CfD for a new nuclear plant at Hinkley Point C.

5.194 The National Audit Office (NAO) report on these early CfDs estimated that these contracts constitute 58% of the total amount of budget available to CfDs until 2020/21.[211,212] The report noted that awarding such a large proportion of the CfD budget in a non-competitive manner 'limited [DECC's] opportunity to secure better value for money through competition under the full regime'.[213] The NAO report also noted that FIDeR projects were awarded CfDs at previously announced strike prices set by DECC, with no consideration of the strike prices the projects actually required, nor their specific costs.[214] The NAO concluded, 'The Department proceeded with the scheme while recognising that it did not bring a clear monetised benefit and acknowledging that competitive pricing might reveal subsequently that some administratively-set strike prices were too high.'[215]

5.195 We have not seen evidence to suggest that it was necessary to award such a large amount of the available budget without price competition, particularly since one of the key benefits of introducing CfDs was to use competition to allocate support to low carbon generators. In awarding CfDs to these eight projects under FIDeR, DECC did not carry out and disclose a clear and

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[208] NAO (June 2014), *Early contracts for renewable electricity*.
[209] We note that the European Commission approved individually under state aid rules the five offshore wind projects (European Commission (July 2014) Letter to the United Kingdom, State aid SA.38758 (2014/N), SA.38759 (2014/N), SA.38761 (2014/N), SA.38763 (2014/N) & SA.38812 (2014/N) – United Kingdom support for five offshore wind farms: Walney, Dudgeon, Hornsea, Burbo Bank and Beatrice) and the biomass combined heat and power (European Commission (January 2015) IP/15/3601 (press release) – decision not yet available). The two biomass projects are currently under review.
[210] DECC's rationale for entering into agreements under FIDeR was to prevent prospective projects being 'cancelled, put at significant risk or delayed' as a result of the transition from ROCs to CfDs. See DECC (December 2011), *Planning our electric future: technical update*, paragraph 157. We note that DECC undertook an impact assessment ahead of implementing the FIDeR scheme (DECC (April 2012) *Electricity Market Reform (EMR) Final Investment Decision (FID) Enabling*.). It noted (page 5) that "*Our central case shows that there is a net welfare gain of £2.1bn (NPV) to 2030 associated with introducing an effective FID-enabling product for nuclear and renewables. This assumes that in the absence of FID Enabling, developers wait until the enduring EMR programme is implemented and reach financial close on low-carbon projects at the earliest in 2014. In the interim, generation from gas-fired CCGT and some unabated coal leads to higher generation and carbon costs.*"
[211] NAO (June 2014), *Early contracts for renewable electricity*.
[212] Falls in DECC's expected future wholesale prices since the NAO report was published suggest that the level of support required by these projects may have increased further, potentially increasing the percentage of total available CfD budget taken by FIDeR projects.
[213] NAO (June 2014), *Early contracts for renewable electricity*, paragraph 17.
[214] ibid.
[215] ibid, p8.

thorough explanation of the basis of its decision to use its powers to allocate CfDs outside a competitive process.[216]

5.196 In the updated issues statement we also set out our concerns that DECC has the power to direct the CfD counterparty to award further CfDs in a non-competitive manner in the future.[217] In this section we consider the likely scale of detriment to consumers from DECC's previous decision to award FIDeR contracts outside the competitive auction process, in order to shed light on the potential risks should DECC award further CfDs without price competition in the future.[218]

- *Scale of detriment of previous decisions under FIDeR*

5.197 In this section we consider whether costs to consumers may have been higher than necessary as a result of non-competitive allocation under FIDeR. Our primary concern is that the strike prices awarded in the FIDeR contracts appear to have been set at a level that does not reflect the underlying costs of those projects (ie those projects were overcompensated). In addition, it is possible that other projects could have delivered at a lower cost (ie the FIDeR projects displaced lower cost projects).

5.198 On the first of these issues, we compared the strike prices awarded to the five offshore wind projects under FIDeR with the strike prices awarded to the two offshore wind projects that were successful in the first CfD auction. FIDeR also awarded contracts to two biomass conversions and a dedicated biomass with CHP plant, but they are not included in our analysis as neither of these technologies were eligible for CfDs in the first auction. Our analysis may therefore understate the extent of overcompensation.[219]

5.199 Under FIDeR, offshore wind projects were awarded CfDs with strike prices of £140–£150/MWh. In the first CfD allocation round, two offshore wind generators, Neart na Gaoithe and East Anglia 1, secured CfDs at strike prices of £114.39/MWh and £119.89/MWh respectively. The significantly

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[216] We note that DECC undertook an impact assessment ahead of implementing the FIDeR scheme. This considered the costs and benefits in general terms of putting in place a mechanism through which DECC could allocate CfDs ahead of EMR being fully implemented. See DECC (April 2012) *Electricity Market Reform (EMR) Final Investment Decision (FID) Enabling*. However, the impact assessment makes it clear that 'The merits of individual projects are not discussed, nether [sic] is the level of support required to bring specific projects or technologies into existence' (p5).
[217] See Energy Act 2013 and Electricity: the Contracts for difference (allocation) regulations 2014.
[218] These potential risks then need to be balanced against the potential benefits that might arise from allocating CfDs to certain specific projects which, in the light of their peculiar characteristics, may not be achieved through a competitive auction process.
[219]The five offshore wind projects in receipt of FIDeR contracts together comprise more than two-thirds of the support allocated under FIDeR (the offshore wind projects together account for approximately £950 million of subsidy per year, out of the total of approximately £1.4 billion for all the FIDeR projects).

lower strike prices awarded in the auction call into question whether the strike prices awarded under FIDeR reflect the projects' underlying costs.

Table 5.2: Comparison of offshore wind projects awarded CfDs via the auction and FIDeR

Allocation mechanism	*Project*	*Capacity (MW)*	*Strike price (£/MWh)*	*Estimated support in 2020/21*		*Estimated overpayment*	
				£/MWh	*£m*	*%*	*£m*
CfD auction	East Anglia 1	714	119.89	66.46	155.3		
	Neart na Gaoithe	448	114.39	60.96	89.4		
FIDeR	Beatrice	664	140	86.57	188.1	30–42	44–56
	Hornsea	1200	140	86.57	340	30–42	79–101
	Burbo Bank Extension	258	150	96.57	81.6	45–58	25–30
	Dudgeon	402	150	96.57	127.1	45–58	40–47
	Walney Extension	660	150	96.57	208.6	45–58	65–77
					Total		**253–310**

Source: CMA calculations.

5.200 Table 5.2 shows that the projects in receipt of FIDeR contracts will receive approximately £87–£97/MWh of support in 2020/21 (the strike price minus the forecast wholesale electricity price), compared with approximately £61–£66/MWh of support to the two offshore wind projects that received CfDs in the auction.[220] This suggests that the cost to consumers for these projects could be approximately 30 to 58% higher than it would have been had they been awarded CfDs at the auction clearing price.

5.201 We estimate, on this basis, that the total cost of supporting these FIDeR projects is approximately £253–£310 million per year higher than it likely would have been had the FIDeR projects been awarded CfDs at the auction clearing price. This is equivalent to approximately a 1% increase on customers' average annual electricity bills for the 15-year length of these contracts.

5.202 These comparisons are indicative, and we note that it is possible that the projects we are comparing are not exactly like-for-like. While we have not undertaken an in-depth comparison of the characteristics of the FIDeR projects and those awarded CfDs in the auction, our initial assessment provides no obvious reason to believe that the five offshore wind projects awarded CfDs under FIDeR have systematically higher costs than those awarded contracts in the first auction.

5.203 The Crown Estate's Offshore Wind Cost Reduction Pathways report[221] estimated the levelised cost of electricity (LCOE)[222] for two different types of

[220] Figures in this section are in 2012 prices. Based on DECC's forecast wholesale electricity price of £53.43 in 2020/21. See DECC (October 2014), *Contract for Difference: Final Allocation Framework for the October 2014 Allocation Round*.
[221] The Crown Estate (2012), *Offshore Wind Cost Reduction: Pathways Study*.
[222] An estimate of the lifetime cost of the project, per unit of electricity generated.

offshore wind project: 'Site A' projects and 'Site B' projects, which differ according to physical site characteristics such as distance from shore, average water depth and average wind speed.[223] The report estimates that Site A (shallower depth but lower wind speed) and Site B (deeper but higher wind speed) projects are likely to face a broadly similar LCOE, with the baseline estimate of costs for Site B projects being slightly higher than those for Site A projects.

5.204 Of the five offshore wind projects awarded CfDs under FIDeR, three (Burbo Bank Extension, Dudgeon, and Walney Extension) would be Site A projects under the Crown Estate's categorisation,[224] while the remaining two (Beatrice and Hornsea) would be Site B.[225] By way of comparison, both projects awarded CfDs in the first auction (East Anglia 1 and Neart Na Gaoithe) would be considered Site B projects.[226]

5.205 We have seen no evidence to suggest that the considerably higher strike prices for FIDeR projects can be explained by differences in the characteristics of the projects. We therefore believe it is likely that the FIDeR projects were awarded contracts significantly above their costs.[227]

5.206 In addition, based on our analysis of bids from the first CfD auction, we consider it likely that alternative offshore wind projects could have been awarded CfDs at a lower strike price than those awarded under FIDeR.[228] We have no reason to believe that the strike prices bid by projects in future CfD auctions would be significantly higher than those in the first auction, where the weighted average bid from offshore wind projects was approximately £[✂]/MWh.

5.207 We therefore think it is reasonable to assume that, had the projects that were successful under FIDeR instead participated in the competitive CfD allocation process, they would have had to bid below the level of support they were awarded under FIDeR in order to secure CfDs.

[223] The Crown Estate report notes that Site A projects are broadly comparable to projects awarded development rights in the Crown Estate leasing rounds 1 and 2, while Site B projects are broadly comparable to those awarded development rights under the Crown Estate leasing round 3, and the Scottish Territorial Waters leasing round.
[224] Burbo Bank Extension is an extension of a leasing round 1 site, Dudgeon is a round 2 site, and Walney Extension is an extension of a round 2 site.
[225] Beatrice was awarded development rights in the Scottish Territorial Waters leasing round, and Hornsea is a round 3 site.
[226] East Anglia 1 and Neart Na Gaoithe were awarded development rights under leasing round 3 the Scottish Territorial Waters leasing round respectively.
[227] It is also worth noting that, unlike projects bidding in the CfD auction, projects applying for FIDeR contracts did not have to have planning permission or transmission agreements in place before bidding.
[228] We issued National Grid with an information request under section 174 of the 2002 Act for the bids from the first CfD auction. Our analysis is set out in Appendix 5.3, Annex A.

5.208 The higher level of support (and therefore additional costs to customers) needs to be balanced against the potential benefits that might have arisen from the early allocation of CfDs to FIDeR projects outside a competitive process. However, DECC has not set out any analysis of any benefits arising from allocating CfDs early through FIDeR. DECC told us that the aim of the FIDeR process was to prevent an investment hiatus during the transition to the CfD regime. However, we note that the projects allocated CfDs through FIDeR did not receive certainty around their support considerably before those awarded CfDs in the first auction.[229,230]

- *DECC's powers to award further CfDs outside the auction*

5.209 In view of the above, we remain concerned that DECC retains the power to award CfDs outside the auction process without sufficient constraints in relation to either the substance of, or the process for making such decisions. In addition, DECC set out in 2014 that it did not intend to place any limitations on its ability to award further CfDs outside the competitive process.

5.210 DECC held a consultation in 2014 on the process through which it can allocate CfDs outside the competitive allocation mechanism. In response to stakeholders setting out concerns that DECC's powers are too broad, and should be constrained, it stated that:

> The Government may consider adding further restrictions to these powers in future amendments to the regulations. However, the immediate objective is to maintain the Secretary of State's flexibility and discretion to determine how best to allocate contracts, this flexibility is particularly valuable in the early stages of the implementation of the CFD framework.[231]

5.211 We recognise that certain projects may be unable to compete in CfD auctions, and bilateral negotiations between DECC and the parties may be the only way of securing investment in these projects. For example, some projects (such as Hinkley Point C) have asset lives considerably longer than those competing in the CfD auctions, potentially making them unsuitable to compete in standard CfD auctions.

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[229] Offshore wind projects that were awarded CfDs under FIDeR gained certainty over their support when they received State aid clearance in July 2014, while those projects that were successful in the first CfD auction gained certainty in February 2015 following the announcement of the first CfD auction results.
[230] One supplier also noted that because of differences in contract terms, FIDeR projects may be able to make final investment decisions later than projects allocated CfDs in the first auction
[231] DECC (June 2014), *Consultation on directions to offer Contracts for Difference: government response*.

5.212 The experience of FIDeR, however, indicates the scale of the potential detriment that can arise when moving away from a competitive process. In our view, therefore, a decision to award contracts outside of the auction process must be made very cautiously, and on the basis of clearly stated rationale explaining why a competitive process cannot be expected to deliver an efficient outcome, and why the alternative process being proposed is superior in this respect.

5.213 If DECC allocates further CfDs outside the competitive process, there is therefore both a risk that they may not be awarded to the most efficient projects, and also that they may be awarded at strike prices above those actually required. Both outcomes are likely to result in detriment to consumers.[232] Such risks might be mitigated in the future by DECC carrying out and disclosing a clear and thorough assessment of the impact of any proposal to use its powers to allocate CfDs outside a competitive process.

Competitive allocation of CfDs

5.214 Under the competitive allocation of CfDs, DECC holds an auction to allocate support to renewable generators. Bidders seeking CfDs submit sealed bids setting out the strike price they would require to enter into a contract. Appendix 5.3 sets out the CfD allocation mechanism in more detail.

5.215 DECC allocates a fixed budget for CfD support in each allocation round, divided into three 'pots', each containing different low carbon electricity generation technologies. Pot 1 contains 'established technologies' (see Table 5.3 below), Pot 2 contains 'less established technologies' (see Table 5.3) and Pot 3 includes biomass conversion.[233] Projects applying for CfDs compete with other projects in the same pot to secure this limited budget.

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

[232] We note that if DECC were to use this power, its decision would be subject to judicial review and to the scrutiny of the European Commission under State aid rules. The CfD scheme was approved by the European Commission under state aid rules (European Commission (July 2014) Letter to the United Kingdom, State aid SA.36196 (2014/N) – electricity market reform – contract for difference for renewables). However, CfDs allocated outside the competitive process mechanism would not be covered by this clearance decision.
[233] Biomass conversion will be integrated into Pot 1 from 1 January 2017 onwards unless the UK can convincingly demonstrate that a separate bidding process for biomass is necessary. See European Commission (July 2014) Letter to the United Kingdom, State aid SA.36196 (2014/N) – Electricity Market Reform – Contract for Difference for renewables, paragraph 14.

5.217 DECC set an ASP for each technology. This serves as a cap on the strike price that any project can receive. Table 5.3 shows the ASP for each technology.

Table 5.3: Administrative strike price per technology

£/MWh

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

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

- *Potential concerns and design principles*

5.218 In the updated issues statement we set out a potential concern that dividing the CfD budget into three separate pots may lead to a situation in which projects from one pot are displaced by more expensive projects from another. In principle, there are two objectives that are relevant in considering the case for segmenting competition in this way:

(a) choosing the most efficient (least costly) projects; and

(b) minimising rents for producers and therefore bill impacts for customers.

5.219 In practice, there are likely to be trade-offs in seeking to design an allocation mechanism for CfDs to meet both of these objectives. In relation to efficiency, a single (technology-neutral) pot, with all projects competing against each other, would ensure that CfDs are awarded to the currently lowest cost projects. Separating the budget into separate pots may prevent support going to the currently lowest cost projects, if some high cost projects are awarded CfDs at the expense of low cost projects.[234]

5.220 Conversely, in relation to minimising rents for producers, it is possible that separating the budget into pots could result in different clearing prices for

[234] To the extent that there are positive externalities to the deployment of renewables in Great Britain there may also be a trade-off between short-term and long-term cost minimisation. That is, deploying some relatively expensive technologies now may be warranted if it could be demonstrated that doing so will reduce long-term costs. We consider this argument in more detail below.

different technology types, reflecting their different levels of underlying cost.[235] This could potentially decrease the rents accruing to producers, and minimise the impact on customer bills.[236]

5.221 However, for government to separate the pots in such a way as to minimise rent while ensuring an efficient allocation of CfDs would require considerable information on the relative costs of different technologies. We note therefore that there is a potentially important trade-off between efficiency and rent minimisation – the more government attempts to discriminate in a granular way between different technologies, the greater the risk that (if its information is inaccurate) more (long-run) expensive projects will be selected in favour of cheaper projects, which will not be in the long-term interests of customers.

- *Assessment of competitive allocation process*

5.222 We have reviewed the competitive allocation process for CfDs against these principles. In relation to efficiency, there is a risk that supporting currently less developed (and more costly) technologies will result in an inefficient allocation of CfDs (ie less efficient projects may displace more efficient ones).

5.223 DECC has argued in general terms that there are dynamic efficiency benefits from protecting less established technologies, as it could enable them to become more efficient over time, to the point where they can compete with established technologies.[237]

5.224 We recognise that the long-run lowest cost path to meeting the government's decarbonisation targets may be to protect certain less developed technologies from competition in the short run, in order to enable them to reduce their costs over time. However, to justify setting aside budget for Pot 2 technologies, DECC would need to demonstrate that support of these currently higher cost technologies is likely to have an incremental effect on their future costs. Supporting more costly Pot 2 technologies can be justified in terms of providing the lowest cost path to meeting decarbonisation targets in the long run only where this can be expected to result in cost reductions that would not have materialised absent the

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[235] As opposed to a single clearing price for an auction with a single pot, set by the most costly technology awarded a CfD, and likely overcompensating low cost projects.
[236] This concern was behind the introduction of ROC banding in 2009 and differing ASPs for CfDs. In the same way, dividing technologies into discrete Pots could be seen as an attempt to minimise rents from competitive allocation.
[237] DECC (January 2014), *Electricity Market Reform: allocation of Contracts for Difference, consultation on competitive allocation*.

support,[238] and where such reductions are likely to outweigh any additional costs incurred in the short run.

5.225 In relation to rent minimisation, in the absence of a clear counterfactual it is impossible to know with confidence whether the allocation of technologies into separate pots has provided a means for appropriating rents that would otherwise have gone to producers.

5.226 One approach we explored was to analyse the sealed CfD bids received by National Grid (in its role as the EMR Delivery Body) to assess the potential impact of separating technologies into discrete pots on the level of support borne by consumers.

5.227 We re-ran the auction with a single budget pot, with CfDs allocated on a technology-neutral basis (but still subject to a technology-specific ASP). This analysis indicated that the level of support per MWh under a single pot was very close to the result under the actual CfD auction (with multiple pots). [✂].[239]

5.228 It is important to note, however, that our analysis of the sealed bids was based on the actual projects that bid for CfDs given the budgets that were set. We consider it is likely that, had more budget been available to Pot 1 technologies (eg through a technology-neutral auction with a single pot), a greater number of low cost projects would have bid for this support, with the result that less support would have gone to high cost projects, potentially reducing the overall level of support per unit of output. It is important to note that any conclusions based on the results of the first allocation round may not apply to future allocation rounds.

5.229 We have engaged with DECC to try to understand how it considered these trade-offs in making its decisions on the allocation of technologies to different pots. We have not seen specific analysis that seeks to weigh up these potential costs and benefits.

5.230 The amount of budget allocated to each pot may be just as important as the initial decision to separate technologies into separate pots. We have not been made aware of any significant analysis undertaken by DECC on the rationale for its decision on how to allocate the budget between the pots. In response to our written information request asking how it decided on the amount of budget to allocate to each pot in the first auction, DECC stated that it was intended to ensure that the amount of capacity procured from Pot

[238] An analysis in relation to offshore wind is set out in Appendix 5.3, Annex A.
[239] [✂]

1 was approximately the same as that procured from Pot 2. We are unclear without further explanation of the logic behind procuring the same amount of capacity from each pot, and why this would lead to the optimal allocation of CfDs.

5.231 Overall, the extent to which supporting less developed technologies is likely to increase the level of subsidy (and therefore costs to consumers) remains unclear and is dependent not only on the underlying costs of each technology but also on DECC's decisions around the allocation of the budget between pots. DECC's decisions around whether (and how much) to support less developed technologies do not appear to have been based on a robust assessment of the likely costs and benefits.

5.232 The extent to which DECC should set aside budget for less developed technologies is likely to evolve over time, as these technologies become more developed and less costly, and therefore able to compete with currently more developed technologies. It is important, therefore, that DECC continues to monitor how appropriate this support is on an ongoing basis.

The impact of ROCs on the competition allocation of CfDs

5.233 Low carbon generation projects that are due for commission before the end of March 2017 have the choice of whether to apply for CfDs or ROCs.[240,241] This potentially puts a floor on the strike price that such projects may be prepared to bid in CfD auctions, limiting the degree of competition in the early CfD allocation rounds.

5.234 The majority of respondents to the updated issues statement and the capacity working paper were strongly in favour of keeping the ROCs scheme open until 2017. They argued that this was crucial to avoid undermining investor confidence, since projects that had made investment decisions before the EMR proposals had been finalised had proceeded on the basis that ROCs would be available until 2017, and had a reasonable expectation of the scheme remaining open.

5.235 We consider that the overlap of ROCs and CfDs may have affected competition in the first auction (for example, we expect that there may have been fewer bidders in Pot 1 as a result of ROCs remaining available). However, since the RO will close to new investments from March 2017, we

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[240] DECC (June 2014), *Implementing Electricity Market Reform (EMR): finalised policy positions for implementation of EMR*.
[241] With the exception of onshore wind, for which the ROC scheme is due to close at the end of March 2016.

do not expect it to have a material adverse effect on competition in future CfD competitive allocation rounds.

Risk of manipulation of reference price

5.236 As set out above, CfD holders receive (or make) payments equal to the difference between the strike price and the CfD reference price. In the issues statement we said we would consider whether large CfD holders may be able to manipulate the CfD reference price down in order to receive higher CfD payments.[242]

5.237 We noted in the capacity working paper that we consider it unlikely that any generator in receipt of CfD payments would have the ability and incentive to manipulate the CfD reference price. Our analysis indicates that the volumes sold by the CfD holder in the reference market[243] to make this profitable would need to constitute a larger proportion of trades in that market than we consider plausible.

5.238 All respondents commenting on this agreed with our initial finding that there is a very low risk of CfD holders manipulating the reference price. We do not plan to pursue this issue further. Annex C to Appendix 5.3 sets out our thinking on this issue in more detail.

Supplier Obligation

5.239 We set out in the Capacity working paper that we would consider First Utility's concerns that the CfD Supplier Obligation left it with risks that it was unable to hedge. First Utility set out its concerns that reconciling the Supplier Obligation at the end of each quarter would leave suppliers exposed to uncertain costs.

5.240 The amount of Supplier Obligation faced by each supplier is driven by the level of renewable output (which suppliers may find difficult to forecast), which First Utility considers it is unable to hedge.

5.241 While we consider that there may be options available to hedge the Supplier Obligation,[244] we also recognise that these risks may not be possible to hedge entirely. We encourage DECC to monitor and continue engaging with

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[242] Energy market investigation: statement of issues.
[243] The market from which the CfD reference price is calculated – discussed in more detail in Appendix 5.3, Annex C.
[244] For example, entering into contracts with renewable generators that are likely to face offsetting risks.

the sector around the impact of the Supplier Obligation on suppliers' risks, and amend the arrangements if necessary in the future.

Provisional conclusions on Contracts for Difference

5.242 We consider that there are cogent arguments for replacing the RO with CfDs and we strongly support DECC's introduction of a mechanism for competitively allocating CfDs. We note that the level of support to projects awarded CfDs in the first competitive auction was approximately 25% lower than it would have been had CfDs been awarded to these projects at the ASP, likely saving customers about £110 million a year.

5.243 However, we consider that DECC's decision to award such a large proportion of the available CfD budget outside the competitive process under the FIDeR scheme is likely to have resulted in higher costs to customers of approximately £250–£310 million per year for 15 years. These higher costs need to be balanced against the potential benefits that might have arisen from the early allocation of CfDs to FIDeR projects outside a competitive process. However, no robust analysis setting out whether such benefits outweigh these higher costs has been disclosed. As the early allocation of CfDs outside a competitive process appears to us to have led to moderate benefits (eg bringing forward some projects) at considerable costs, this may have caused material detriment to consumers. We believe there is a risk that without further constraints on DECC's ability to award contracts outside the competitive process, further contracts may be awarded that do not deliver value for money – either by awarding CfDs to inefficient projects or by offering strike prices above those that could have been achieved through competition.

5.244 We note that any decision to allocate CfDs outside a competitive process must be notified to the European Commission under state aid rules. Also, parties could challenge such a decision by judicial review. However, we are concerned that the absence of requirements on DECC to carry out and disclose a clear and thorough explanation of the basis of any decision to use its powers to allocate CfDs in a non-competitive way might make such challenges more difficult.

5.245 Regarding the division of technologies into pots, we consider that DECC did not support its decision with robust evidence demonstrating how its preferred option could be expected to result in the best outcome for consumers. The extent to which DECC should set aside budget for less developed technologies is likely to evolve over time, as these technologies become more developed and less costly, and therefore able to compete with currently more developed technologies. It is important, therefore, that DECC continues to monitor regularly how appropriate this support is on an ongoing basis.

5.246 As with the allocation of technologies into pots, we consider that DECC did not support with robust evidence its decision around the allocation of budget into separate pots in the previous auction. It is important that DECC provides a clear justification for the allocation of budgets between pots for each auction to ensure that an appropriate amount of support is allocated to technologies at different stages of development.

5.247 Given the large amount of support due to go to renewable generators through CfDs (CfD payments are due to rise to £2.5 billion per year in 2020/21), we regard it as extremely important that DECC bases such decisions on robust analysis, and communicates its findings to stakeholders in a transparent manner.

5.248 Overall, we have reached a provisional finding that the mechanisms for allocating CfDs are a feature of the GB wholesale electricity market giving rise to an AEC due to the absence of an obligation for DECC to:

(a) carry out, and disclose the outcome of, a clear and thorough impact assessment supporting a proposal to use its powers to allocate CfDs outside a competitive process; and

(b) regularly monitor the division of technologies between different pots, which form the basis of CfD auctions, and provide a clear justification when deciding on the allocation of budgets between the pots for each auction.

5.249 At this stage, we do not believe that the overlap of ROCs and CfDs, the risk of CfD holders manipulating the reference price, and the CfD Supplier Obligation are likely to give rise to an AEC.

Provisional conclusions

5.250 This section has reviewed five key elements of the design principles and market rules and regulations that shaper competition in GB wholesale electricity markets.

5.251 In relation to the **principle of self-dispatch**, we do not believe that the self-dispatch system in Great Britain, when compared with alternative dispatch systems, reduces price transparency or increases transaction costs. Nor have we found evidence of systematic technical inefficiency arising from self-dispatch.

5.252 The absence of **locational pricing for transmission losses** is a feature of the GB wholesale electricity market that we provisionally conclude constitutes an AEC, as it is likely to distort competition between generators and is likely to have both short- and long-run effects on generation and demand:

(a) In the short run, costs will be higher than would otherwise be the case, because cross-subsidisation will lead to some plants generating when it would be less costly for them not to generate, and other plants, which it would be more efficient to use, not generating. Similarly, cross-subsidies will result in consumption failing to reflect fully the costs of providing the electricity.

(b) In the long run, the absence of locational pricing may lead to inefficient investment in generation, including inefficient decisions over the extension or closure of plant. There could also be inefficiency in the location of demand, particularly high-consumption industrial demand, such as aluminium smelter.

5.253 The current mechanism of averaging the cost of transmission losses irrespective of each generator's and customer's contribution to those losses is likely to lead to an approximate cost in NPV terms over ten years to the system of somewhere between £160 million and £275 million.

5.254 We have not reached a provisional conclusion as to whether the absence of **locational congestion charging** is a feature of the market that constitutes an AEC. From our initial analysis, this question appears to be finely balanced, with reasons to see both costs and benefits. A process separate from this investigation will require ACER to consider this issue at regular intervals pursuant to a procedure set out in the CACM for this purpose.

5.255 In relation to the **reforms to imbalance prices** brought about through EBSCR, we have found that the move to a single price is positive for competition.

5.256 We have assessed the move to PAR1 and we have noted Ofgem's reassurance that it will assess the impacts of the first phase of the move to PAR50 in order to determine whether or not the move to PAR1 is likely to be beneficial. If, after review, the tightening to PAR50 does not lead to more efficient, marginal prices, we believe Ofgem should halt the move from PAR 50 to PAR1. In relation to RSP, while we have not seen strong evidence for the benefits claimed in terms of improving balancing efficiency, we do not believe on balance that it is likely to create an AEC.

5.257 Our provisional view is that there is a strong argument for DECC's decision to introduce a capacity mechanism, and that the design of the **Capacity Market** is broadly competitive. A number of specific issues were raised with us relating to the design of the Capacity Market. As regards the recovery of Capacity Market costs and the Capacity Market penalty mechanism, our provisional view is that these are unlikely to give rise to an AEC. As regards the length of the capacity agreements, and the different treatment of DSR providers, in view of DECC's work in this area and the case pending before the European General Court, we do not intend to carry out further work in this area.

5.258 Finally, we think there are good arguments for DECC's decision to replace the RO with **CfDs**. However we have concerns about the lack of competitive allocation for some CfDs. In particular, we consider that DECC's decision to award such a large proportion of the available CfD budget outside the competitive process under the FIDeR scheme is likely to have resulted in higher costs to consumers, equivalent to around £300 million a year, or 1% of electricity bills. As the benefits of the early allocation of CfDs outside a competitive process are unclear, we consider that these higher costs may have caused detriment to consumers. We believe that there is a risk that without further constraints on DECC's ability to award contracts outside the competitive process, further contracts may be awarded that do not deliver value for money – either by awarding CfDs to inefficient projects or by offering strike prices above those that could have been achieved.

5.259 Regarding the division of the technologies into separate pots and allocation of budgets to each of these pots, we consider that DECC did not support its decisions with robust evidence demonstrating how its preferred options could be expected to result in the best outcome for consumers. For the reasons set out above, these decisions determine the level of support granted to each technology and therefore are critical to assess the impact, and expected gains, of this support.

5.260 Overall, we have reached the provisional finding that the mechanisms for allocating CfDs are a feature of the GB wholesale electricity market giving rise to an AEC due to the absence of an obligation for DECC to:

(a) carry out, and disclose the outcome of, a clear and thorough impact assessment supporting a proposal to use its powers to allocate CfDs outside a competitive process; and

(b) regularly monitor the division of technologies between different pots, which form the basis of CfD auctions, and provide a clear justification

when deciding on the allocation of budgets between the pots for each auction.

5.261 At this stage, we do not believe that the overlap of ROCs and CfDs, the risk of CfD holders manipulating the reference price, and the CfD Supplier Obligation are likely to give rise to an AEC.

6. Vertical integration

Introduction

6.1 A range of parties have expressed concerns about VI in the electricity sector, both in the context of this investigation and in the wider debate about competition in the energy sector.[245] For example, in its decision to make a market investigation reference, Ofgem said that VI 'can provide efficiency benefits but can also harm competition. A full investigation of the balance between costs and benefits is needed, to establish whether vertical integration is best for competition.'[246]

6.2 In this section we consider a range of costs and benefits of VI, before making some provisional conclusions on whether we consider that VI in electricity is likely to give rise to an AEC. The section is set out as follows:

- **Introduction:** First, we give a brief introduction to VI in the electricity sector, explaining what we mean by VI in the context of electricity, a brief history of the evolution of VI in Great Britain, some of the factors that may have led to VI historically, and what forms it takes (paragraphs 6.1 to 6.20).

- **Potential competitive detriment resulting from VI:** We then go on to consider whether there may be any detriment to competition as a result of the level or form of VI, or the behaviour of VI firms. This includes an assessment of whether VI is likely to lead to any issues around wholesale market liquidity, the likelihood of VI firms being able to foreclose their rivals, and the extent to which VI could lead to issues around the transparency of financial reporting (paragraphs 6.21 to 6.49).

- **Benefits of VI:** Next we consider a range of potential benefits to firms of being vertically integrated, including the concept of the 'natural hedge', which is often cited as an important element of VI, and a range of other benefits. We then consider the extent to which any benefits are likely to be passed through to consumers and whether there are alternatives to full VI that may deliver the same benefits (paragraphs 6.50 to 6.121).

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[245] The level of VI in gas is relatively low (see Section 4), with each of the Six Large Energy Firms being a net buyer of gas. We see very little scope for significant issues around VI in gas and it has not been a focus of our investigation. As a result, this section focuses only on VI in electricity.
[246] Ofgem (June 2014), *Decision to make a market investigation reference in respect of the supply and acquisition of energy in Great Britain*, p4.

- **Provisional conclusions on VI:** Finally we set out our provisional conclusions around the potential costs and benefits of VI (paragraphs 6.122 to 6.130).

The meaning of VI in electricity

6.3 A VI firm is, for our purposes, a firm that has under common ownership electricity generation and electricity retailing activities (to domestic and/or non-domestic customers). The degree of operational integration varies between firms, as we discuss below. These firms may also own other parts of the value chain (eg transmission and distribution assets), however activities relating to these assets are heavily regulated and subject to a requirement to be legally unbundled, or independent, from other energy sector operations. No concerns have been put to us about common ownership of transmission and distribution assets. Therefore we do not consider them further in this section.

6.4 The Six Large Energy Firms are all vertically integrated, and some other energy firms also have a degree of VI.[247]

A brief history of VI in electricity

6.5 In 1990 the Central Electricity Generating Board (CEGB) was broken into four companies. Its generation activities were transferred to three generating companies, PowerGen, National Power, and Nuclear Electric (later British Energy); and its transmission activities to the National Grid Company.

6.6 In 1990 the 12 area electricity boards in England and Wales were changed into independent regional electricity companies (RECs) and privatised. The Scottish boards were privatised in 1991 with the exception of the nuclear plants, which passed to Scottish Nuclear.

6.7 PowerGen and National Power were privatised in 1991, with 60% stakes in each company sold to investors, the remaining 40% being held by the UK government. In 1995, the government sold its 40% stakes, and the assets of Nuclear Electric and Scottish Nuclear were both combined under the control of British Energy, which was privatised in 1996.

6.8 A wave of consolidation took place in the latter half of the 1990s and early 2000s. Some of this was led by generators purchasing supply businesses:

[247] Including Drax (which owns Haven Power), Ecotricity and EDF.

(a) In 1999 PowerGen (now E.ON) completed its purchase of East Midlands Electricity. In 2002 it acquired the UK business of TXU Europe Group, which had previously bought Norweb.

(b) In 1999 National Power bought Midlands Electricity's electricity supply business. In October 2000, National Power demerged to create Innogy and International Power. In 2001, Innogy acquired Yorkshire Electricity and subsequently swapped its interests in Yorkshire Electricity's distribution business for the energy supply business of Northern Electric. In 2002, Innogy was acquired by RWE and later became RWE npower.

(c) In 1999 British Energy bought South Wales Electricity (SWALEC). However, after failing to acquire another retailer at a reasonable price, it sold SWALEC to SSE in 2000.[248]

6.9 Other supply companies integrated horizontally and upwards:

(a) In 1998 Scottish Hydro-Electric (which owned generation assets and a supply business in Scotland) and Southern Electric merged to form SSE. It acquired SWALEC's supply business in 2000. In 2004 it acquired the Fiddlers Ferry and Ferrybridge power stations.

(b) In 2003 EDF Energy in the UK was formed from the acquisition of the retail supply business of South Western Electricity Board (SWEB), the distribution business of Eastern Electricity, the distribution and supply businesses of London Electricity and South Eastern Electricity Board (SEEBOARD), along with two coal-fired power stations and a CCGT power station. In January 2009 EDF acquired British Energy.

(c) Scottish Power, which owned generation and supply assets at privatisation, purchased Manweb in 1995.

6.10 Centrica launched its electricity supply business in 1998 as an expansion of its existing gas supply business. Centrica purchased power plants in each year from 2001 to 2004, and has subsequently constructed more plants.

6.11 The wave of activity described above led to the establishment of the Six Large Energy Firms in much the same form as we know them today, although some have themselves subsequently changed ownership.

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[248] NAO (February 2004), *Risk Management: The Nuclear Liabilities of British Energy plc*, paragraph 2.20.

6.12 Some of this activity coincided with the introduction of NETA (later superseded by the BETTA), the system of market arrangements under which electricity is traded, in March 2001.

6.13 Current trends may indicate that the level of VI in the GB wholesale electricity market is decreasing:

(a) E.ON and Centrica have both announced substantial moves towards de-integration. E.ON is planning to completely separate its renewable energy generation, energy distribution and supply businesses from its conventional generation and trading activities.[249] Centrica is closing some of its gas-powered plants and had tried to sell others.[250] SSE also announced that it was reorganising its operations internally to increase legal separation.[251]

(b) The first Capacity Market auction has provided funding for 15 GW of capacity from firms other than the Six Large Energy Firms.[252,253]

(c) To date, CfDs have been allocated to 4.7 GW of renewable capacity from firms other than the Six Large Energy Firms.[254]

Did self-dispatch increase incentives for VI?

6.14 Under NETA, generators moved from central dispatch to self-dispatch.[255] Some have argued[256] that self-dispatch created an incentive for parties to 'contract with themselves' – effectively, to vertically integrate – which in turn might lead to competition concerns.

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[249] E.ON press release (30 November 2014): New corporate strategy: E.ON to focus on renewables, distribution networks, and customer solutions and to spin off the majority of a new, publicly listed company specializing in power generation, global energy trading, and exploration and production.
[250] Centrica subsequently made the decision to retain CCGT assets following a sales process, as bids received were significantly below its internal valuation.
[251] SSE announced in March 2014 that it intended to reorganise its activities so that there were separately auditable legal entities responsible for its Energy Supply, Energy Portfolio Management and Electricity Generation activities. SSE plc Preliminary results for the year to 31 March 2015, 20 May 2015.
[252] EMR Delivery Body (June 2015), *2014 T-4 Auction Results.*
[253] As noted above, some other firms also have varying degrees of VI, meaning this may overstate slightly the total amount of non-VI capacity.
[254] For results of the FIDeR scheme see DECC (April 2014), *FID Enabling for Renewables - Successful Projects offered an investment contract*; for results of the first CfD auction see DECC (February 2015), *CFD Auction Allocation Round One.*
[255] Under a self-dispatch system, buyers and sellers of electricity contract ahead of time for their anticipated demand at prices that are bilaterally negotiated or determined through demand and supply matching on public exchanges. Generators and suppliers prepare operating plans for their anticipated physical behaviour or that of their customers. The parties communicate their anticipated physical behaviour and their contractual position to the SO. The SO takes central control of balancing supply and demand close to real time, at a point known as 'gate closure'. See Section 5 for more details on self- vs central dispatch.
[256] For example, Dieter Helm (2014), *The return of the CEGB?* The argument has been picked up by the Institute for Public Policy Research (September 2014), *A new approach to electricity markets*.

6.15 The causal chain proposed is that the designers of NETA/BETTA were worried that participants would not have sufficient incentive to enter into bilateral contracts ahead of time and that this would entail a larger role for the SO. The designers, keen to minimise natural monopoly elements in the system, therefore introduced a mechanism whereby electricity purchases or sales that were not covered by bilateral contracts would be settled at a price that was **by design** unattractive: finding oneself in imbalance would be costly compared with what a bilaterally contracted party could have achieved.[257] SSE has argued that this design decision was compounded by the fact that, at the introduction of NETA, there was material uncertainty about the manner in which energy trading would take place and the commercial consequences of this highly significant change in market operation.

6.16 These arguments are plausible explanations for the attractions of VI at the time of NETA's introduction. However, these factors do not appear to apply in the current market conditions. We have provisionally found that:

(a) near-term bilateral and exchange-based energy markets are liquid, so there is no real fear that parties will be unable to contract with third parties in the run-up to gate closure;[258]

(b) levels of self-supply, especially in near-term markets, are low, which suggests that VI is not a substantial advantage in this respect; and

(c) the cash-out rules which made imbalance unattractive *by design* have been gradually taken away, with the latest reforms (described in more detail in Section 5) making cash-out a 'fair' market with a single price; in most periods, cash-out should, after the reforms, provide an attractive alternative to trading very close to gate closure.

6.17 We therefore do not believe that a self-dispatch system in the current market conditions provides significant incentives to VI. The fact that about 30% of generation and 12% of supply are in the hands of non-vertically integrated firms suggests that any such incentives are not insuperable and do not prevent operation of a competitively sustainable stand-alone generation or supply business.

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[257] The design philosophy that sought to make bilateral contracting more attractive by design is confirmed and described by Professor Stephen Littlechild (January 2012), *Response to Ofgem's consultation on electricity cash-out issues*.
[258] Appendix 6.1: Liquidity, paragraphs 34 & 35.

Varying models of VI

6.18 Models of VI vary in practice, and VI firms organise their business units in a range of different ways. It is common for VI firms to have a single trading arm serving both generation and supply activities, and in some cases this trading arm acts as a conduit between the two latter activities which have little direct dealing. For example, RWE's trading arm is part of its global wholesale energy and commodity trading activities, which provides a direct route to market for the trading requirements of its GB generation and supply businesses.

6.19 Within a VI structure, there are different types of interactions. For example, a supply arm may buy wholesale electricity directly from the generation arm; a trading arm may buy wholesale electricity directly from the generation arm and sell directly to the supply arm (and may or may not match those trades); and a trading or supply arm may buy capacity directly from the generation arm and make decisions as to how the relevant plant runs.

6.20 There is also not a common division of activities into different arms. For example, some firms may consider power purchase agreements (PPAs) to be part of their generation activities, while others class PPAs under their trading or supply arms.

Potential competitive detriment resulting from vertical integration

6.21 A range of parties have expressed concerns over the degree of VI in the energy sector. In this section we consider three broad areas where it is argued that VI could theoretically result in AECs.[259] First we consider whether VI is likely to have any significant impact on wholesale market liquidity. We then consider whether VI firms may be able to foreclose either the generation or supply markets. Finally we consider whether firms' VI structures raise concerns relating to a lack of transparency around firms' levels of profitability.

Liquidity

6.22 In this section we consider the links between VI and liquidity. 'Liquidity' can have a number of meanings, but we primarily use this term to mean good

[259] In this context, we observe that the Six Large Energy Firms (which are the largest VI firms) are also the long-established suppliers, with high shares of supply partly derived from their status as incumbents at privatisation (or, in Centrica's case, its successful transition from the incumbent supplier of gas to a major supplier of electricity). Therefore it is important to distinguish incumbency effects from the effects of VI.

availability of products that market participants wish to trade.[260] As noted in the Liquidity appendix, if liquidity is poor, independent suppliers or generators may be less able to hedge their demand or output, increasing their risk or causing them to pay a premium to reduce risk.[261] This disadvantage may in turn affect competition in retail markets or generation.

6.23 A significant amount of the recent entry into the energy sector has been from independent suppliers and generators. If the prevalence of firms with a vertically integrated structure adversely affected the level of liquidity, it is possible that it could result in barriers to entry for both independent suppliers and generators. If efficient firms are excluded as a result of not having a VI structure, it could be to the detriment of consumers in the long run.

6.24 We consider two questions relating to VI and liquidity. Firstly, we assess the extent to which the prevalence of VI in electricity could reduce liquidity in the wholesale electricity market, and secondly we consider whether VI firms are better able to deal with low levels of liquidity.

Does VI reduce the level of liquidity?

6.25 We consider in the section below on benefits arising from VI whether VI firms have an in-built natural hedge against wholesale market volatility, and whether they may therefore trade less as a result. If we found that VI was leading to a lower level of trading, it is possible that VI could reduce wholesale market liquidity, potentially to the detriment of independent suppliers and generators.

6.26 However, our provisional conclusion is that VI is unlikely to have a significant impact on the extent to which products are available to trade on the wholesale electricity market. That is, VI firms still have to trade externally to a significant extent in order to hedge their exposure to wholesale market volatility. We found that all of the Six Large Energy Firms externally trade multiples of their combined generation and supply volume in electricity (and therefore make a net positive contribution to liquidity).[262] We also saw similar patterns of trading behaviour between gas and electricity, even though there

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[260] In effect, we are assessing whether the market offers products that parties want to trade, whether these products are available in 'reasonable' quantity, and whether prices are well defined. In other words, in a liquid market for a particular product, parties will have a reasonable expectation that they could buy (or sell) a 'reasonable' quantity without affecting the price. In a liquid market, parties are able to engage in trading with the reassurance that they would also be able later to sell back to (or buy back from) the market at a similar price, unless new information has justifiably caused prices to change. See Appendix 6.1: Liquidity, paragraphs 8–10.
[261] See Appendix 6.1: Liquidity, paragraph 101.
[262] See Appendix 6.1: Liquidity, Table 2.

is a much lower degree of VI, and liquidity is generally held to be better, in gas than in electricity.[263]

6.27 As a result, we consider that VI does not appear to affect liquidity in a way that would prevent an efficient independent supplier or generator from being able to trade basic products that are necessary to participate in upstream or downstream electricity markets.

Do VI firms have a competitive advantage relating to liquidity?

6.28 As noted in the Liquidity appendix, First Utility claimed that VI firms enjoyed a competitive advantage relative to independent suppliers because they could trade internally even when products were not available externally.[264]

6.29 If this were the case, VI firms could hedge earlier in volumetric or shape terms, reducing their risk and thus imposing a comparative 'risk premium' on independent suppliers. In other words, VI firms would be at an effective cost advantage over independent suppliers. A similar theory could apply with regard to VI firms having advantages over independent generators.

6.30 We examined this issue by seeking to assess whether, based on product availability, independent firms have the ability to hedge in the same way as the Six Large Energy Firms actually do. For the purpose of this assessment, we examined volume, annual shape (ie the way demand varies over the year) and daily shape (ie the way demand varies over the day).[265]

6.31 We focused on two questions in this area. First, we considered whether independent firms currently hedged in the same way as the Six Large Energy Firms. We then considered whether, if they did not, the Six Large Energy Firms could reach their current hedged positions using their trades in externally available products.

6.32 A positive answer to either of these questions could suggest that the current level of liquidity in GB wholesale electricity is sufficient to allow independent firms the ability to replicate the hedging strategies of VI firms. If so, that would suggest that liquidity does not distort competition, nor raise barriers to entry and expansion.

6.33 We assessed the extent of liquidity in the GB wholesale electricity market by gathering data from suppliers, generators and brokers. Our analysis indicated that the Six Large Energy Firms' trading and hedging patterns

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263 See Appendix 6.1: Liquidity, paragraphs 145–149.
264 See Appendix 6.1: Liquidity, paragraph 31.
265 See Appendix 6.1: Liquidity, paragraph 108.

were, in the main, broadly similar to each other but differed from those of independents. In particular, they generally hedged more volume further ahead than independent operators.

6.34 We did not, however, find evidence that product availability was likely to be causing this.[266] The Six Large Energy Firms generally conducted their hedging strategies using products that were available and traded; there was no indication that they were gaining an advantage by systematically using internal trades of products that were not available to other, non-integrated (or less integrated) parties.[267]

6.35 In addition, Ofgem's Secure and Promote licence conditions also serve to further dampen concerns about the impact of VI on liquidity, because they ensure the availability of the products that were most widely used for hedging by the Six Large Energy Firms.[268]

6.36 Lastly, we compared the situations in relation to gas and electricity. We found that the Six Large Energy Firms did not hedge further ahead in gas (where product availability is generally better) than in electricity, which we would expect to be the case if VI were distorting their hedging strategies in electricity, or if liquidity in electricity were a serious constraint on their trading.[269]

6.37 As a result, we have reached the provisional conclusion that VI firms do not appear to be experiencing a significant competitive advantage in relation to liquidity at present.

Foreclosure

6.38 We considered whether VI firms might distort competition at one part of the value chain at the expense of non-integrated rivals operating at another part. The following section provides a summary of our work in this area – a more detailed assessment is contained in the Foreclosure appendix.[270]

6.39 Foreclosure is the central competition concern that is commonly considered in the context of VI.[271] It refers to the situation where a VI firm might sacrifice some profit in one part of its business (say, wholesale) in order to distort

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[266] See Appendix 6.1: Liquidity, paragraphs 119–139.
[267] See Appendix 6.1: Liquidity, paragraphs 39–51.
[268] See Appendix 6.1: Liquidity, paragraphs 89–98.
[269] See Appendix 6.1: Liquidity, paragraphs 145–147.
[270] See Appendix 6.2: Foreclosure.
[271] *CC3*, p59.

another market (say, retail) in such a way that independent firms are made worse off, to the overall benefit of the VI firm.

6.40 The CMA's guidelines for market investigations set out that we would have to find three elements in order for this type of issue to be a concern:[272] The VI firm must have the ability to make independent companies worse off; it must have an incentive to do so (in the example above, it would have an incentive if the benefit in retail is greater than the sacrifice in wholesale); and there must be a negative effect on consumers.

6.41 There two types of foreclosure: customer foreclosure and input foreclosure, which we describe in turn below. Both of these were set out in the updated issues statement.[273] We note that we did not receive responses to indicate that these were major concerns to parties; nor did we see plausible mechanisms for the harm suggested.

6.42 **Customer foreclosure** in this context involves a vertically integrated supplier causing harm to upstream competitors by strategically reducing their ability to sell their output. In electricity, these upstream competitors are independent generators. We considered a range of possible mechanisms for customer foreclosure: a refusal to sign contracts; to trade wholesale electricity or green certificates; or despatching generation when the plant was out of merit to drive down wholesale prices.

6.43 Our provisional view is that vertically integrated firms do not have the ability to foreclose generators (acting either unilaterally or through coordination), primarily on the basis that we could not identify a plausible mechanism allowing VI firms to do so (see Foreclosure appendix, paragraphs 20 to 46). We are also doubtful that the incentive and effect conditions are met: generally, the costs (or opportunity costs) of any such strategy are likely to be high relative to the rewards.[274] We noted that independent generators represent nearly 30% of upstream volumes, and independent firms have continued to invest in new generating plants in recent years.[275] This indicates that widespread foreclosure is not currently occurring. Taken together, our current view is that customer foreclosure is unlikely to be an issue.

6.44 We then considered **input foreclosure**, which would involve a vertically integrated firm taking action in an upstream market to disadvantage independent retailers. We considered two ways this might happen. First, we

[272] *CC3*, p58.
[273] Energy market investigation updated issues statement.
[274] See Appendix 6.2: Foreclosure, paragraphs 47–59.
[275] See Appendix 6.2: Foreclosure, paragraphs 55.

considered whether vertically integrated generators might change their generation patterns to push up energy prices, in order to make independent suppliers less competitive. We thought this would be a costly strategy with limited potential gain, and therefore it was unlikely that VI firms would have clear incentives or the ability to act in this way.[276]

6.45 Secondly, we considered whether a VI firm might try to reduce liquidity (beyond the natural reduction that VI brings, discussed above) in order to increase independent suppliers' costs. Given the substantial share of independent generation, and a range of evidence suggesting that no such action was taking place, we provisionally conclude that it is unlikely that any firm would have the ability to carry out such a strategy, especially under the Secure and Promote licence conditions.

6.46 Furthermore, we did not see any reason why such a strategy would not adversely affect its own supply arm along with independent suppliers, and so an incentive to do so also seemed unlikely.[277] Therefore we provisionally conclude that input foreclosure does not appear to be an issue in GB electricity.

6.47 Our provisional conclusion is that the evidence does not indicate a problem arising from foreclosure.

Transparency of financial reporting

6.48 Finally, in considering the potentially harmful effects of VI, we have considered whether there were any financial transparency issues arising from firms' VI structures, which might in turn lead to detriment to consumers. We note that a number of stakeholders have raised concerns regarding financial transparency and summarise our consideration of this issue in Section 11 and in more detail in Appendix 11.1.

Benefits of vertical integration

6.49 VI can also result in a range of potential benefits to firms, mostly in the form of increased efficiency relative to non-vertically integrated firms. By aligning the incentives of firms at different points in the supply chain, or reducing transaction costs, VI can create efficiencies leading to lower costs and potentially lower prices for customers.[278]

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[276] See Appendix 6.2: Foreclosure, paragraphs 66–82.
[277] See Appendix 6.2: Foreclosure, paragraphs 83–93.
[278] *Merger Assessment Guidelines* (CC2/OFT1254), especially paragraphs 5.6.4 and 5.7.10–5.7.12.

6.50 Typically, potential efficiencies from VI relate to the ability of the firm to take an integrated view when setting prices, so as to avoid the problem of double marginalisation.[279] We do not consider this to be a significant benefit of VI in the GB electricity sector, since it would rely on there being some degree of market power in both supply and generation. As set out in Section 4 and Appendix 4.1: Market power in generation, our provisional conclusion is that the GB wholesale electricity market appears to be competitive, meaning that this particular benefit is unlikely to materialise to any significant extent.[280]

6.51 In this section we identify the ways in which electricity firms may benefit from being vertically integrated, including the natural hedge and associated benefits, benefits relating to cost of capital, and benefits from preventing duplication of resources.

6.52 However, we note that there has been a recent move away from VI between electricity supply and generation, which potentially calls into question the scale of any benefits from adopting this structure.

The natural hedge

6.53 It is often claimed that the 'natural hedge' is an important feature of VI in electricity. In short, the concept is that the returns from generation are negatively correlated with the returns from supply, and so a vertically integrated company is less exposed to certain risks than an independent supplier or generator. In this section we set out in more detail the circumstances under which a natural hedge may arise, and consider whether VI firms are likely to benefit from a natural hedge.

6.54 We begin by examining further the sources of wholesale market risk for suppliers and generators that are relevant when considering the potential benefits of a natural hedge from VI, before considering whether common ownership is likely to reduce these risks. Broadly, there are two kinds of risk that may be relevant:

(a) price risk: the risk to both suppliers and generators resulting from volatile wholesale electricity prices; and

[279] Whereby both the upstream and downstream firms price above marginal cost, when the profit-maximising behaviour of a VI firm that aims to maximise profits across both levels of the supply chain may be to charge a lower retail price than would result from non-vertically integrated firms. Avoiding this may therefore benefit both the VI firm and consumers.
[280] However, to the extent that such benefits arise, we would expect these to increase efficiency, to the benefit of consumers.

(b) volume risk: the risk that customer demand will change relative to expected levels.

Suppliers' risks

6.55 Suppliers are constrained in the speed and frequency with which they can change their retail prices, due to the costs and practical considerations of doing so, the impact on their reputations and also because many contracts are set at a fixed price for a fixed term. To this extent, they are unable to pass through to customers changes to electricity wholesale prices over the short term. This leaves suppliers exposed to risks around the level of the wholesale price, which can be volatile.

6.56 Suppliers therefore assume risks around the level of the wholesale price in the short term. In the medium term, they can change retail prices to reflect any changes in the wholesale price, so this risk is likely to be relatively short-lived.

6.57 Suppliers tend to hedge their exposure to wholesale prices by buying electricity forward. Broadly speaking, they do so by entering into contracts with generators to secure the electricity they will need to meet expected demand ahead of time, thereby removing (or reducing) the risk of lower profits if wholesale prices increase.[281]

6.58 Suppliers are also exposed to volume risk. This falls broadly into two categories: system-wide (eg weather-related) demand risk, and risks resulting from volatile customer numbers.

6.59 In the event of an increase in the level of demand across the system (eg unexpectedly cold weather), even if a supplier has hedged its expected level of demand, it faces the risk that actual demand will be different to the level it expected. If demand is higher than expected, it will have to purchase additional electricity (or go short into cash-out). If the increase in demand is the result of a system-wide event, it will be buying any additional electricity it requires at a time when wholesale prices are likely to be particularly high (likely putting downward pressure on its returns).

6.60 Likewise, if a supplier has hedged its expected level of demand, but demand is lower than expected, it may have to sell back the electricity it over-purchased. As above, if demand was lower as a result of a system-wide

[281] This is an oversimplification of suppliers' hedging behaviour, but is sufficient to examine the benefits of the natural hedge.

event, it will be selling electricity back at a time when the wholesale price is likely to be low (also putting downward pressure on its returns).

6.61 Suppliers may also face volume risk resulting from volatile customer numbers. That is, over the period for which the firm is limited in its ability to change its retail prices, it is also unable to predict with certainty the number of customers it will have at the time of delivery. While this does place a risk on suppliers, in these cases, periods of unexpectedly high (or low) demand for a given supplier are unlikely to be systematically associated with high (or low) wholesale prices. As a result, suppliers' returns may be less exposed to this risk than they are to system-wide changes in volume.

6.62 Overall, suppliers may be able to hedge their price risk by buying forward in the wholesale market. However, volume risk may be harder to hedge. Having hedged its price risk, a supplier is likely to remain exposed to changes in demand, especially those that are associated with system-wide events. This is because forward contracts specify a certain volume of electricity, and volume risk results from suppliers' inability to forecast accurately the volume of electricity they require.

6.63 The precise nature of the risks suppliers face is likely to depend on their customer base. For example, suppliers serving non-domestic customers may face less risk around unexpected changes in demand due to weather, because those customers' demand is less temperature-related. In addition, the period for which retail prices are effectively fixed may vary between domestic and non-domestic customers.

Generators' risks

6.64 Generators are also exposed to risks around the level of wholesale electricity price. The revenues a generator makes from the wholesale electricity market form the majority of most generators' revenues. As a result, a generator's returns may fluctuate with the level of the wholesale electricity price.

6.65 The extent to which generators are exposed to wholesale price risk varies by generation type. As set out in Section 4, the wholesale price is broadly set at any point in time by the marginal cost of the marginal generator (ie the most expensive generator that is producing electricity at that time). At most times, the marginal plant tends to be a thermal generator (coal or gas).

6.66 Changes in the wholesale price that are caused, for example, by changes in the price of gas will shield gas generators from wholesale price risk, as their input costs are likely to move in line with the changes in the wholesale electricity price. That is, a gas generator will be exposed to the spread between the wholesale electricity price and its fuel costs; if these move together, its returns will be less affected by fluctuations in the wholesale price. As a result, coal and gas generators may be less exposed to changes in the wholesale electricity price than other technologies (such as nuclear).

6.67 Conversely, other generating technologies (such as nuclear and potentially some renewable technologies) are likely to be more exposed to changes in the wholesale electricity price. Since they do not face input costs that fluctuate with the wholesale electricity price, they are not shielded from the volatile wholesale market in the same way as coal and gas generators.

6.68 Similarly to suppliers, generators wishing to hedge their exposure to wholesale price risk sell forward their output, thereby fixing the price they receive, and removing the risk of further changes in the wholesale price.

6.69 Most generators also face considerable volume risk.[282] The level of demand on the system determines the identity of the marginal generator that sets the wholesale price. This can affect both whether a given generator is in merit (and therefore making money), and the wholesale price the generator receives.

6.70 Generators also face a range of other longer-term risks, as they make substantial investments to earn a return over a long period. They are therefore exposed to risk over the margin that they earn over the long term. This will be affected by the make-up of generation capacity in Great Britain, and by changes in relative fuel prices changing the merit order.[283]

How does the natural hedge mitigate suppliers' and generators' risks

6.71 We set out above in general terms the range of risks that suppliers and generators face in relation to their exposure to the wholesale electricity market. In this section we consider the extent to which common ownership of both supply and generation businesses could reduce a VI firm's overall

[282] This may be less true for nuclear generators that are always in merit, and able to predict their output with a reasonable degree of certainty.
[283] For example, the investment in renewable technology in recent years has resulted in an increase in low marginal cost generation. Other things equal, this would be expected to reduce wholesale prices for all generators. As well as reducing wholesale prices, this will also have the effect of pushing thermal generators lower down the merit order, reducing the number of periods in which they could be expected to generate and therefore earn a return. In addition, in recent years coal has become cheaper than gas, which has reduced output for gas plants. Also, coal plants are being decommissioned for environmental reasons, which would (other things equal) increase wholesale prices for all generators at times when those plants would have been producing.

risk, relative to stand-alone supply and generation businesses. This concept is referred to as the 'natural hedge'.

6.72 It is possible that some of the risks faced by suppliers and generators identified above offset each other. To this extent there would be a negative correlation between the returns to supply and generation businesses. For example, changes in the wholesale market that have a negative effect on suppliers' returns may have a positive effect on generators' returns (and vice versa). If this is the case, it would reduce the need of a VI firm to hedge its exposure to the wholesale market actively (eg by trading electricity forward) compared with stand-alone suppliers and generators.

6.73 We consider below the extent to which VI could reduce the risks identified above.

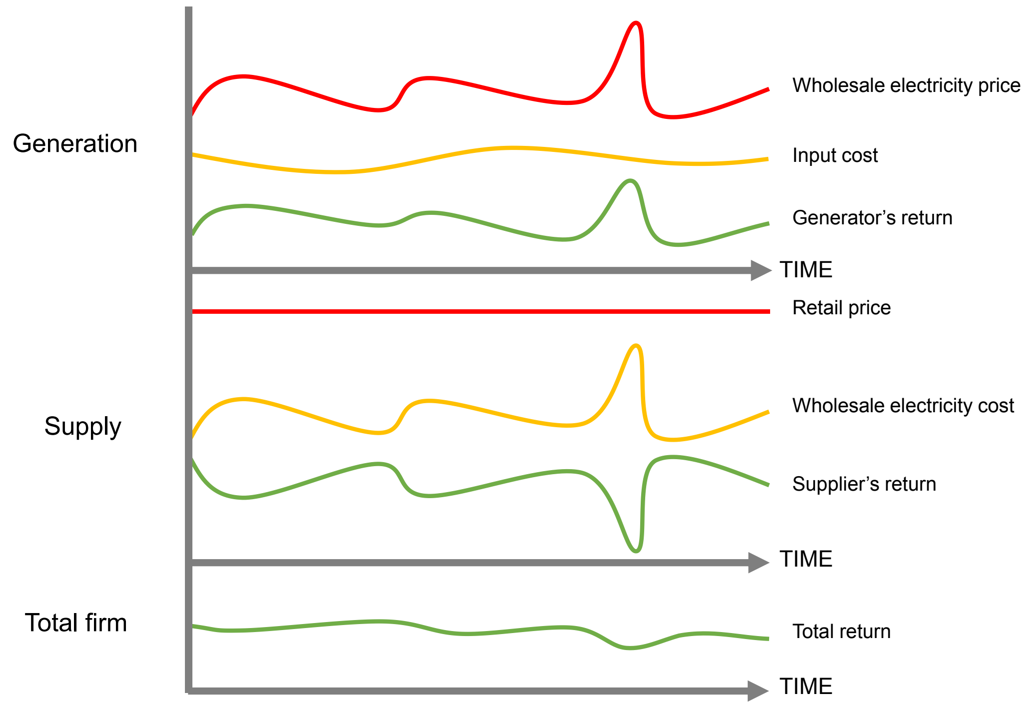
- *Price risk*

6.74 If changes to the wholesale price that reduce returns to a VI firm's supply business also have the effect of increasing returns to the firm's generation business (and vice versa), common ownership of supply and generation could result in a degree of in-built (natural) hedge. VI firms with a natural hedge have an in-built mechanism that reduces the firm's overall exposure to wholesale price, and may be less reliant on trading externally to manage their risks as a result. By contrast, independent suppliers (generators) can only reduce or remove price risk by buying (selling) electricity ahead, which is likely to impose some costs compared with common ownership.

6.75 In an extreme example, where the supply and generation businesses are of the same size, and the impact of changes in wholesale price on the returns of the two business units is perfectly negatively correlated, a VI firm may not be exposed to electricity wholesale prices at all. As a result, such a firm would not need to undertake any active hedging in order to remove wholesale price risk; it is already hedged. This is a very extreme example, and is not reflective of any firm in the GB electricity sector, however it serves to demonstrate the intuition behind the natural hedge.

6.76 Figure 6.1 illustrates why the returns to a supply and generation business may be negatively correlated, and how this could reduce a VI firm's exposure to fluctuations in the wholesale price.

Figure 6.1: Example of negatively correlated supply and generation returns



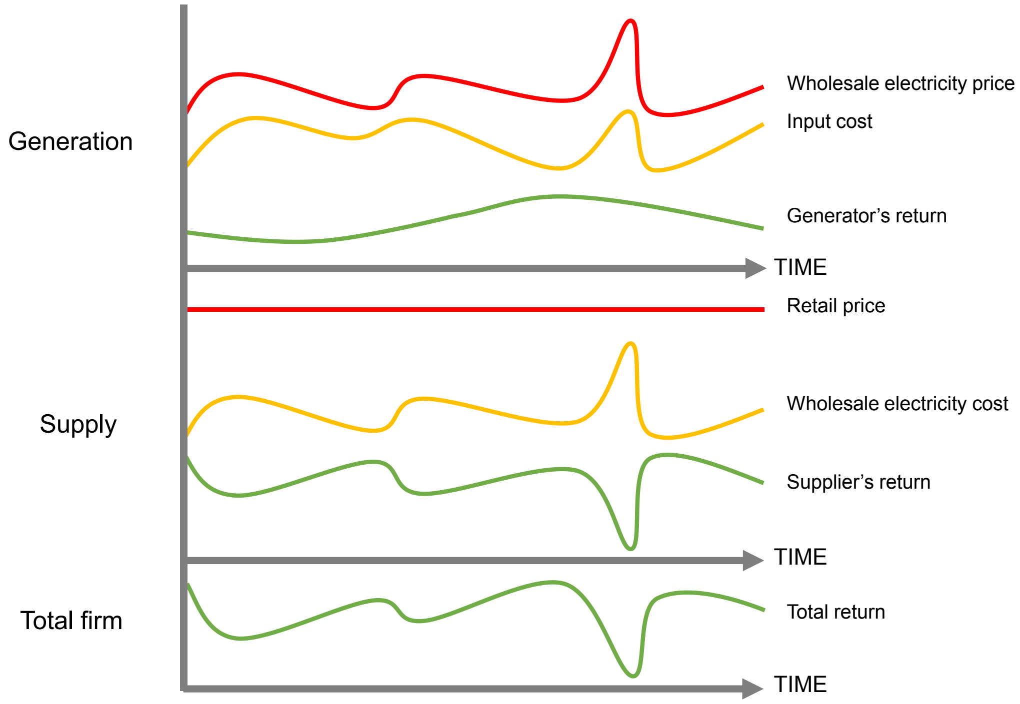
6.77 Figure 6.1 shows how the natural hedge can reduce a VI firm's exposure to price risk. A generator's revenue fluctuates with the wholesale market price, meaning that (in the example set out in Figure 6.1) the generator's returns also move in line with the wholesale market. Conversely, since the wholesale electricity price constitutes a cost for the supply arm, increases in wholesale price result in reductions in the supplier's returns. Overall, while considered separately, the supplier and generator's returns are exposed to the wholesale market price; when the returns are combined, the VI firm is considerably less exposed to the wholesale market (as shown by the relatively stable total returns to the VI firm). This could potentially reduce the VI firm's need to trade in order to hedge its price risk.

6.78 In practice, the extent to which the natural hedge is a substitute for active hedging (trading) is likely to be limited, as it is likely to arise only under certain specific circumstances, as discussed below.

6.79 The type of generation technology a VI firm owns is likely to have a significant impact on whether or not it benefits from a natural hedge with regards to wholesale price risk. As noted above, coal and gas generators generally have less exposure to risks around the wholesale electricity price than other types of generation, because their input prices tend to move in line with the wholesale electricity price.

6.80 As a result, the impact of wholesale price risk on suppliers' returns (which are exposed to wholesale prices) may not be negatively correlated with the impact of price risk on these generators. That is, the risks faced by the supply and generation businesses in this case may not be offsetting; there may not be a natural hedge from joint ownership of these businesses. Figure 6.2 illustrates this point for a VI firm that owns gas-powered generation.

Figure 6.2: Example of supply and gas-powered generation returns



6.81 Unlike in the example shown above (in Figure 6.1), for a gas generator the wholesale electricity price tends to move broadly in line with the cost of gas.[284] As a result, the generator's returns do not move in line with the wholesale electricity price. The overall returns of the VI firm therefore remain exposed to the wholesale electricity price, and the firm does not enjoy a natural hedge.

6.82 As set out above, nuclear generators are likely to be more exposed to price risk than coal and gas generators. This means that nuclear generation is more likely to have returns that are negatively correlated with those of a supply business: increases in wholesale price can be expected to increase returns to nuclear generation, but decrease returns to suppliers. That is, a VI firm with nuclear generation is likely to be more in line with Figure 6.1 than Figure 6.2 above. As a result, nuclear generation is likely to provide a stronger natural hedge against price risk than coal and gas generation.

[284] This is particularly the case in periods when gas is the marginal generator, as it tends to be at present (under normal demand conditions).

6.83 The same is likely to be true for other generating technologies for which their input prices do not tend to move with the wholesale price. Examples may include biomass and hydroelectric generation.

6.84 The situation is less clear for intermittent renewable generation (eg wind). While its input costs are unrelated to the electricity wholesale price (indeed its marginal cost is close to zero), so might otherwise be expected to provide a good natural hedge, the extent of any benefits resulting from a natural hedge may be limited if output is uncertain. Since a supplier cannot count on wind to produce output at times when prices are high, it is unclear the extent to which VI between a supplier and a wind generator would be a substitute for hedging through trading.[285]

6.85 The introduction of CfDs will remove suppliers' exposure to the level of wholesale price for that particular generation asset (as each MWh receives a fixed 'strike price' consisting of the wholesale price and the support). However, it introduces an additional risk to suppliers around the amount of renewable generation in a given period, and therefore the amount of support a supplier has to pay through its Supplier Obligation.[286] High levels of renewable (eg wind) generation will increase the level of support suppliers are obliged to pay (putting downward pressure on returns). However, high levels of wind generation are also likely to increase returns for owners of wind generation; the returns of suppliers and renewable generators may be negatively correlated. As a result, it is possible that there could be a natural hedge resulting from common ownership of certain types of renewable generation and supply.

6.86 Therefore, the main beneficiaries of the natural hedge against price risk are likely to be VI firms with predictable generation other than coal and gas (primarily nuclear), and potentially renewables. To the extent that this matches their expected demand, the VI firm would not need to hedge exposure to wholesale price by trading on the wholesale market as much as independent suppliers and generators might. A VI firm benefiting from this natural hedge could therefore potentially avoid some costly trading activity.

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[285] It is possible that wind provides a hedge on a probabilistic basis, even if it cannot be relied upon to generate at any particular point in time.
[286] The Supplier Obligation mechanism is a compulsory levy on electricity suppliers to meet the cost of CfDs. See DECC, Electricity Market Reform: CFD Supplier Obligation.

6.87 We consider it likely that for the majority of VI firms, this would not apply to a significant extent, since their nuclear and renewable portfolios are in most cases small compared with the demand of their supply businesses.[287]

6.88 Moreover, any benefits resulting from a natural hedge for price risk are likely to be limited. The Liquidity appendix provisionally finds that wholesale market liquidity is good in the key products used for volumetric hedging against price risk (discussed previously).[288] As a result, if VI firms benefit from a natural hedge against wholesale price risk, this is likely to result only in a reduced need to hedge actively through the wholesale market, rather than an absolute ability to be better hedged overall. That is, our assessment of GB wholesale electricity market liquidity suggests that independent suppliers and generators are able to replicate through trading any benefits of the natural hedge that relate to price risk. As a result, the only benefits from a natural hedge against price risk stem from VI firms' ability to reduce their level of trading in the wholesale electricity market.

- *Volume risk*

6.89 As set out above, in addition to risks around the level of wholesale price, both suppliers and generators face risks around the level of demand. As with price risk, if the impact of the level of demand on a supplier's returns is negatively correlated with the impact on a generator's returns, a VI firm may have a natural hedge against this risk.

6.90 As noted, there are two main sources of volume risk: system-wide (eg weather-related) volume risk, and risks resulting from volatile customer numbers.

6.91 Regarding the impact of system-wide (eg weather-related) volume risk, if expected demand increases, a supplier would need to buy additional electricity (either by buying forward or by paying cash-out prices), at a time when prices are likely to be relatively high because all other suppliers also need to buy more (changing the marginal generator to one with a higher marginal cost, thereby increasing the wholesale price).[289]

6.92 Conversely, it is possible that under certain specific conditions, a generator's returns might increase as a result of unexpectedly high demand. A generator with some capacity that would have been out of merit at the originally

[287] The one possible exception is EDF Energy, which has a considerable amount of nuclear generation capacity (which may provide a natural hedge for its supply business).
[288] See Appendix 6.1: Liquidity, paragraph 99.
[289] As noted above, firms may be less exposed to weather-related risks in serving non-domestic customers.

expected level of demand, but that is in merit (and making positive returns) at the actual level of demand may benefit from this unexpected increase in demand.

6.93 This could be either pre- or post-gate closure. That is, it may be that a VI firm that enjoys a natural hedge in this area would be less exposed to balancing costs post-gate closure.

6.94 This means that under this particular scenario, the returns of a supply business and a generation business may be negatively correlated. As a result, there may be a natural hedge between generation and supply regarding volume risk in this instance. However, this is a very specific situation, that relies on the generation arm having unused (out of merit) capacity at the originally expected level of demand, that would be in merit and making positive profits under the actual level of demand. As a result, we consider that any benefit in this area is unlikely to have a significant impact on a VI firm's risks.

6.95 The claimed advantage of VI regarding the risk of volatile customer numbers is that the supplier can deal with an increase in customer numbers by sourcing electricity from its own generation fleet rather than buying in the market. We do not consider this a plausible benefit in practice. Movement of customers between suppliers should not affect total demand, and therefore the efficient merit order of generation should not change.

6.96 As a result, it is unlikely that the supply arm of a VI firm obtaining additional customers would change its generation business's incentives around the profitable level of generation. If generating additional output was profitable, the generator would do so, regardless of whether its supply arm had a higher-than-expected number of customers. This means that the returns to the generation arm should be unaffected by increases in the number of customers served by the supply arm, if there is no impact on the overall level of demand on the system. A natural hedge in this area is therefore unlikely.

6.97 As noted above, generators are likely to be exposed to a broader range of longer-term risks, given the long timescales over which they seek to recoup their investments. For example, they are exposed to changes in the merit order resulting from the level and type of investment in generation, and changes in the relative input costs of different technologies. However, since suppliers can adjust their retail prices over the medium term,[290] we consider it unlikely that suppliers are exposed to similar long-term risks. As a result,

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[290] See paragraphs 6.56 & 6.57 above.

these risks faced by generators are not likely to be strongly correlated with the risks faced by suppliers. Therefore, VI is likely to be a poor hedge for these types of risk.

6.98 For the reasons mentioned above, while it is possible that there may be a natural hedge for VI firms regarding exposure to volume risk (both system-wide and customers volatility), this is likely to materialise only in limited circumstances (as set out above), and so is likely to result in limited benefits to a VI firm.

6.99 However, as noted above, unlike price risk, which suppliers and generators can hedge through wholesale market trading, suppliers may be unable to hedge against volatile demand through trading standard forward electricity contracts. As a result, any natural hedge from VI relating to volume risk may constitute a greater benefit than any natural hedge of price risk.

- *Broader benefits related to the natural hedge*

6.100 As set out above, if a VI firm benefits from a natural hedge, it may reduce its need to trade wholesale electricity. If this is the case, there may be a range of associated benefits, including in relation to transaction cost savings, liquidity and collateral.

  - *Transaction cost savings*

6.101 Any reduction in the amount of external trading is likely to reduce the transaction costs faced by a VI firm. Such costs may include brokerage and exchange fees.

6.102 In addition, separate supply and generation firms that have to hedge by buying and selling electricity on the wholesale market may also be exposed to the 'spread' between buy and sell prices, which VI firms would avoid for any volumes they do not have to trade externally (which may be a more material benefit than avoiding brokerage and exchange fees). Firms benefiting from a natural hedge that opt to trade internally may face some transaction costs, but we consider it likely that these would be lower than would be the case for the equivalent level of external trading.

  - *Liquidity*

6.103 VI firms that enjoy a natural hedge have less reliance on trading to hedge their exposure to the wholesale electricity market. As a result, they may be less restricted by the availability of products on the external market (since they have less need to trade). However, this is only a benefit if the natural hedge removes risks that an independent supplier or generator would be unable to hedge on the wholesale market, which may not arise very often. We found that liquidity for key products on which the majority of volume is traded is generally good (and currently protected by Ofgem's Secure and Promote obligations). Therefore we believe that this is likely to be a small benefit.

6.104 Some of the Six Large Energy Firms told us that historically there had been a benefit of improved security of supply from VI, but with the evolution of a well-functioning wholesale market, this has ceased to be a material benefit.

- *Collateral*

6.105 If a VI firm is able to reduce the amount of trading it does as a result of the natural hedge, it may reduce its need to post collateral. Also, in the event that the VI firm trades externally and is both buying and selling on the same exchange or with the same party, the collateral it has to post for the buy and sell will offset, and its net exposure will be lower. In addition, parties have to post mark-to-market collateral when prices move between the time of a trade and the delivery date. At any one time, only a buyer or a seller will be exposed, not both; and since VI firms will both buy and sell, their net risk is lower. This can be considered another manifestation of the natural hedge, where wholesale price movements that are detrimental to the supply arm are beneficial to the generation arm (and vice versa).

- *Summary of the natural hedge and related benefits*

6.106 We can see some potential benefits from VI in the form of a natural hedge. On price risk, any benefits are likely to accrue mostly to those with nuclear and potentially renewable generation; on volume risk, any benefits are most likely to accrue to VI firms that have some generating capacity at or near the margin at a given point in time.

6.107 Overall, while there may be a benefit to VI firms from a natural hedge (on both price risk and volume risk), we consider that any benefit is likely to be limited, given the very limited circumstances under which benefits (over and above what can be achieved through trading) are likely to materialise.

6.108 Any natural hedge against wholesale electricity price volatility could be expected to reduce VI firms' need for trading relative to separate supply and generation businesses, thereby reducing the associated costs. However, we consider that in practice the limited scope for a natural hedge means that any impact on trading is likely to be limited.

6.109 It is important to note that any benefits associated with the natural hedge appear to result from increases in VI firms' efficiency (ie reduced costs as a result of any reduction in trading). Therefore, to the extent that these efficiencies are passed through to customers (discussed below), we would expect this to benefit consumers.

Other benefits of VI

6.110 In addition to the natural hedge and related benefits, we have identified a number of possible benefits that may arise from VI between supply and generation. We asked the Six Large Energy Firms to comment on each of these, and found that there was little consensus – all firms identified some advantages, but there was no single factor that all six agreed was material. This may reflect the varying models of the Six Large Energy Firms when it comes to VI. It may also be that the benefits have changed over time. For example, one of the Six Large Energy Firms ([✄]) told us that the primary strategic reason for VI in its case had changed from [✄], to diversity of earnings during the 2000s, and was now cost synergies. In this section we summarise some of these other potential benefits of VI.

Cost of capital and lower risk capital requirements

6.111 We did not see evidence that VI led to a lower equity beta (for more detail see the cost of capital appendix) and therefore to a lower cost of equity. However, the combination of 'asset light' energy retail activities with those of generators results in a stronger balance sheet which may lead to benefits such as a better credit rating, increased ability to raise debt and/or less need to post collateral when trading as compared with a stand-alone energy supplier.

6.112 We note that there may be other ways of achieving a strong credit rating – for example, integration with large firms in other sectors is likely to give a similar effect (eg Co-operative Energy, which benefits from its parent company's balance sheet). We therefore consider that any effect on cost of capital is therefore as a result of increased size and balance sheet strength, rather than VI in itself.

Sharing common resources

6.113 VI firms may benefit from being able to share certain fixed costs across supply and generation (notable examples would include the cost of trading divisions, and regulatory and other management personnel), and from the ability to share skills and knowledge. That is, there may be economies of scope resulting from VI between supply and generation.

Whether advantages are likely to be passed on to customers

6.114 We considered whether advantages of VI are likely to be passed on to customers, both domestic and non-domestic. Our general view of pass-through is that cost savings are more likely to be passed on if they are savings to marginal costs rather than fixed costs, and if competition works effectively. In this section we consider whether VI is likely to lead to marginal cost savings for a supply business.[291] We have provisionally found that competition in the retail energy markets is not working effectively for some customers (see Sections 7 and 8), which may limit the current extent of pass-through.[292]

6.115 Some of the cost savings we have identified above have the potential to affect the marginal costs of supply, including the natural hedge and associated benefits and the benefits relating to lower cost of capital and lower collateral requirements.

6.116 In contrast, we consider that some other benefits (such as sharing common resources) are less likely to affect the marginal costs of supply materially, and may therefore be less likely to be passed through to consumers.

Alternatives to common ownership

6.117 It is possible that independent suppliers and generators could contract with each other (beyond merely trading forward contracts) in order to replicate some of the benefits of VI (such as the natural hedge). When an independent supplier and generator face offsetting risks, we consider it likely that they could enter into contracts that reduce both firms' exposure to the wholesale market. In addition, we do not see any significant barriers to them entering into such contracts. If non-vertically integrated firms can replicate the benefits of VI through contracting with each other, it is likely to reduce the benefits of full VI.

6.118 For example, Centrica told us that tolling contracts (where the buyer has the responsibility for providing the fuel and the right to dispatch the physical power station, and receives the resulting electricity) could replicate many of the advantages and disadvantages of asset ownership.

6.119 Furthermore, dynamic trading of forward contracts may enable an independent supplier to replicate the cash flows of owning generation

[291] Marginal cost savings to a generation business in general may be passed through to suppliers and then to customers, but only if that generator is setting the price of wholesale electricity at the margin. Pass-through of this kind of saving is less direct and less certain than suppliers' marginal cost savings.
[292] However, failure to pass through cost reductions relating to VI should not be seen as a problem with VI; cost reductions that are only partially passed on to consumers are likely to be preferable to a situation in which these cost reductions do not materialise at all.

capacity. This goes beyond merely hedging expected output, and may enable independent suppliers to replicate the full benefits of VI. However, this is a very capital-intensive strategy, and it is not clear how feasible this would be for an independent supplier in practice.

Provisional conclusion

6.120 In this section, we have considered the various means by which VI could potentially harm competition and cause harm to consumers.

6.121 We found that VI does not appear to have a significant impact on liquidity. We noted that while in theory the natural hedge could reduce the amount of trading VI firms undertake on the wholesale market, given the relatively limited scope for the natural hedge, any impact is unlikely to be significant in practice. In addition, our analysis of wholesale market liquidity suggests that liquidity is sufficient for independent firms to hedge their exposure to wholesale market risk in a similar way to VI firms.

6.122 We considered whether VI firms would have the ability and incentive to foreclose markets to rival independent firms and found that this is unlikely.

6.123 We also considered whether there were any financial transparency issues arising from firms' vertically integrated structures, which might in turn lead to detriment to consumers. While not a result purely of firms' VI structures, we provisionally find that a lack or regulatory requirement for clear and relevant financial reporting is a feature of the wholesale and retail energy markets that, in combination with other features of these markets, give rise to an AEC.

6.124 Alongside this, we considered a range of potential benefits to firms of VI. Our provisional view is that while such benefits do appear to exist, in practice they are likely to be relatively modest. We concluded that there may be a potential benefit to VI firms resulting from the natural hedge, whereby certain outcomes that may be detrimental to the VI firm's supply arm may be beneficial to its generation arm (and vice versa). However, we set out that these benefits are likely to materialise only under fairly specific circumstances, and as a result are likely to be limited in scale.

6.125 We also set out some other potential benefits from VI that are not directly related to the natural hedge. For example, we note that the combination of 'asset light' energy retail activities with those of generators results in a stronger balance sheet which may lead to benefits such as a better credit rating, increased ability to raise debt and/or less need to post collateral when trading as compared with a stand-alone energy supplier.

6.126 We also note that some of the Six Large Energy Firms are moving away from a VI structure, giving further weight to the view that any benefits from VI are likely to be reasonably limited.

6.127 Lastly, we recognise that benefits to a firm from VI that result from genuine efficiencies have the potential to be passed on as benefits to consumers. While it is not clear to what extent these benefits are likely to be passed through, overall, consumers are likely to be better off than they would be if these efficiencies were not present.

6.128 Overall therefore, our provisional view is that VI does not have a detrimental impact on competition for independent suppliers and generators, and that there are likely to be some modest efficiencies resulting from VI, that may be passed through to consumers. As a result, our provisional conclusion is that vertical integration does not give rise to an AEC.

7. Nature of competition in domestic retail energy markets

7.1 This section describes the nature of competition in domestic retail energy markets. Its purpose is: to analyse the competitive pressures that are brought to bear on energy suppliers in selling gas and electricity to domestic customers; to assess how effective competition has been in meeting customers' needs; and to identify any specific areas of concern that we considered warranted more detailed investigation. These areas of concern are analysed in more detail in Section 8.

7.2 This section is structured as follows:

(a) We summarise the key characteristics of suppliers and customers and set out our understanding of the **basic parameters of retail competition**.

(b) We explain the importance of the **regulatory framework** for domestic retail market competition and provide a brief history of regulatory interventions in the years since the gas and electricity sectors were liberalised.

(c) We review the evidence on **customer activity and engagement**.

(d) We summarise recent trends in **market shares**, including the increase in the shares of the mid-tier suppliers.

(e) We analyse the **nature and extent of price competition**, distinguishing between SVTs and non-standard tariffs, and between the Six Large Energy Firms and the mid-tier suppliers, and assess the extent to which changes in costs, notably wholesale costs, are **passed through** into changes in prices.

(f) We assess the **gains from switching** available to domestic customers.

(g) We identify any differences in outcomes that we observe between the **devolved nations and between regions**.

(h) We set out our approach to **market definition**.

(i) Finally, we present our **provisional conclusions and implications for issues** to be investigated in Section 8.

Demand and supply characteristics and the parameters of retail competition

7.3 This section sets out our understanding of the fundamental characteristics of domestic energy consumers and retail energy suppliers, which will frame our analysis of competition in domestic retail energy markets. Drawing on this analysis, we then set out our assessment of the sorts of outcome we would expect effective competition in retail markets to lead to.

Demand characteristics

7.4 We consider the key characteristics of domestic energy demand to be the following:

(a) Energy is a fundamental requirement of households, and can be characterised as a 'necessity good'.

(b) The gas and electricity that customers consume is a homogeneous good, in that the products themselves are unaffected by the choice of supplier, which means that customers are likely to attach a particular importance to the price of energy.

(c) Households are also likely to place some value on other attributes of the supplier and/or tariff, including the convenience of payment method and the quality of customer service offered by the supplier.

(d) Traditional meters do not allow for short-term demand response and are likely to create other barriers to engagement in energy markets.

Energy is a necessity good

7.5 Reliable and continuous access to energy is a fundamental requirement of households, necessary for heating, lighting and the use of appliances. If demand for electricity and gas is not satisfied instantaneously, customers incur severe costs.[293] As a result, domestic customers generally receive continuous supply of gas and electricity, whether or not they have made an active choice of supplier, tariff or payment method.[294]

7.6 Gas and electricity can be characterised as 'necessity goods', which are goods that are considered indispensable for maintaining a certain standard of living. Such goods have a low income- and price-elasticity of demand.

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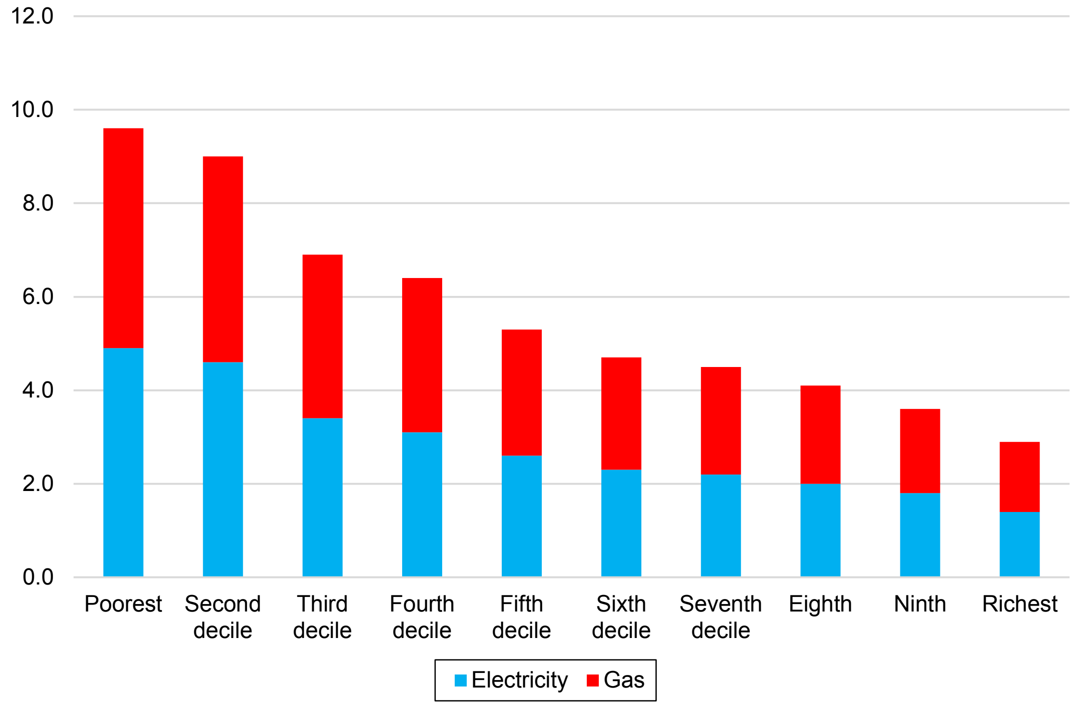
[293] The VoLL for electricity has been estimated at around £17,000/MWh (over 100 times the retail price of electricity), while the VoLL of gas has been estimated at around £14/therm (over ten times the retail price of gas). See DECC (September 2014), Electricity Market Reform – Capacity Market. Impact Assessment and Ofgem (23 September 2014), *Gas Security of Supply Significant Code Review*.
[294] Cutting off households from electricity and gas supply is a step that can be taken only in extreme circumstances, which are prescribed by legislation. Schedule 2B to the Gas Act 1986 and Schedules 6 and 7 to the Electricity Act 1989 provide for suppliers' rights to discontinue supply in certain situations. Exercise of these rights is subject to further restrictions in suppliers' SLCs.

Figure 7.1 below shows the relationship between income and gas and electricity consumption.

Figure 7.1: Household expenditure on gas and electricity (% of total expenditure) by disposable income decile



Source: ONS, Family Spending 2014.

7.7 As can be seen in the figure, the poorest 10% of the population spend almost 10% of total household expenditure on electricity and gas, while the richest 10% spend about 3% of total household expenditure on electricity and gas. For the poorest 10%, expenditure on energy is the second highest item of expenditure, after housing.[295] This relationship between expenditure on energy and income explains part of the concern around energy price increases – they have a highly regressive impact.

7.8 Domestic price elasticity of demand for electricity and gas[296] is low, but is likely to increase over longer time frames. In the very short run, when the wholesale price changes, there is no domestic customer response, since customers on standard meters are not exposed to the wholesale price. In the slightly longer term, as cost changes are fed through into tariffs, price elasticities are still likely to be low, as there is very limited substitutability, certainly for electricity. In the long run, as domestic customers are able to

[295] ONS Family Spending 2014.
[296] This means that domestic energy consumption only reduces slightly in response to an increase in price. It does not mean that domestic energy customers are not responsive to differences in the prices offered by energy suppliers.

respond to increased prices through the installation of energy efficiency measures (and heating and cooking systems, for which there is a degree of substitutability between gas, electricity and other fuel sources) price elasticity is likely to be higher.

7.9 A survey of studies looking at residential energy provides some support for this characterisation. Espey and Espey (2004)[297] find that, in the short run,[298] a 1% rise in domestic electricity prices reduces demand by around 0.35% whereas in the long run demand falls by 0.85%. Gillingham, Newell, and Palmer (2009) review other studies on short- and long-run elasticities across households for electricity and gas and conclude, 'Long-run price elasticities are larger than short-run […] On average, natural gas price elasticities are greater than electricity or fuel oil elasticities.'[299]

Homogeneity and the importance of price

7.10 Gas and electricity are extreme examples of homogenous products in that the energy that customers consume is entirely unaffected by the choice of retailer. We would expect, therefore, that price would be the most important product characteristic to a customer in choosing a supplier and/or tariff.

7.11 This view is supported by our customer survey, which suggests that price is, by far, the most important driver of choice of energy supplier, with 81% of respondents identifying factors related to 'cost/tariff/price/rate' as important to them, followed by 50% of respondents identifying 'good quality service'.[300]

7.12 We understand price in this context to mean the average amount paid per kWh of gas and electricity, taking into account any discounts. We also note that the risk associated with the cost of energy is likely to be important to some customers, particularly those for whom the cost of energy is a high proportion of their disposable income. For such customers, an energy tariff that provided certainty over the price might be preferred to one in which the price was highly volatile, even if the latter was, in expected terms, cheaper.

7.13 A further implication of homogeneity is that customers may be less interested in engaging in the markets for electricity and gas supply than in other markets, where there is quality differentiation of products. This is discussed further in Section 8.

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[297] Espey, JA and Espey, M (2004), 'Turning on the Lights: A Meta-Analysis of Residential Electricity Demand Elasticities', *Journal of Agriculture and Applied Economics,* 36(01).
[298] This is a longer time period that the 'very short run' discussed above.
[299] Gillingham, K, Newell, R and Palmer, K (2009), 'Energy efficiency economics and policy', Resources for the Future Discussion Paper 09-13.
[300] Appendix 8.1: Customer Survey.

Non-price factors

7.14 It is possible to identify three types of non-price factor that are likely to be of importance to certain customers.

7.15 First, convenience is likely to be a relevant consideration to many customers. Certain payment options, such as direct debit, require less effort on the part of the customer, for example. Product bundling may also be attractive (notably buying gas and electricity from the same supplier), as this minimises the number of supplier interactions required.

7.16 Second, quality of customer service (notably accuracy of billing and appropriate handling of complaints) is also likely to be important. Customer service can be considered a 'hygiene factor' – customers are likely to require a minimum standard (accuracy), beyond which it ceases to become a relevant discriminating factor in the choice of supplier. The survey results provide some support for this view: 32% of respondents considered good service 'essential' (more than any other supplier feature).[301]

7.17 Third, customers may value certain value-added and bundled services such as advice on energy efficiency. Our survey found that only 4% of respondents take into account the additional features and services provided when choosing a supplier. Although when asked how important a number of pre-selected factors were in relation to their choice of supplier, 8% considered the range of other services available 'essential' and 17% considered it 'very important'.[302] The scope for such advice and services is likely to grow with the full roll-out of smart meters.

Traditional meters

7.18 Traditional gas and electricity meters used in households do not record at what time energy is used and are only read infrequently.[303]

7.19 This means that households have no reason to adjust their use of gas or electricity in response to short-term wholesale price changes. Further, as a result of the infrequency of meter reads, customer bills are typically based on estimates rather than actual consumption, which can create barriers to

[301] Appendix 8.1: Customer Survey.
[302] Appendix 8.1: Customer Survey.
[303] Suppliers are required to read and inspect meters at least every two years, although some suppliers may do so more frequently. Source: Ofgem factsheet, Meter accuracy and billing disputes.

understanding and engagement in the domestic retail markets, as discussed in more detail in Section 8.[304]

Supply characteristics

7.20 Retail energy suppliers do not own or operate any of the physical assets required for the delivery of gas or electricity to their customers' homes. They are engaged, rather, in financial and commercial activities relating to the sale of energy to customers. These activities can broadly be characterised as follows:

(a) **Energy procurement**, which involves purchase on the open wholesale market of the gas and electricity that its customers use;

(b) **Network access**, which involves securing access to and paying for the distribution and transmission networks as necessary for their customers to have electricity and/or gas supply;

(c) **Sales and marketing**, which involves the marketing and sale of energy to customers (including entering into a contract with customers based on a specific **tariff**, which determines the price they pay for the energy they use and how they pay for it) and the acquisition of new customers;

(d) **Metering**, which comprises the installation and maintenance of gas and electricity meters and the collection of meter readings;

(e) **Billing and customer service**, which involves billing customers for the energy they use and dealing with customer queries and complaints;

(f) The delivery, on behalf of DECC, of **obligations relating to environmental and social policy objectives**; and

(g) The provision of a range of **value-added products and services**.

7.21 Below we describe these activities in greater detail (with a particular focus on whether the costs associated with them are likely to be controllable by the supplier or not) and summarise available information on the structure of the costs associated with them.

[304] Further information on the processes for gas and electricity settlement can respectively be found in Appendix 8.6: Gas and electricity settlement and metering, Annexes A and B.

Wholesale purchases of gas and electricity

7.22 The procurement of gas and electricity in the wholesale market is discussed in Section 4. It is one of the key functions of the retailer and, as described below, the largest single cost item in the price of domestic electricity and gas.

7.23 The key objective in relation to wholesale purchases is one of risk management – retailers should, in principle, purchase energy wholesale in a way that best allows them to manage the risks to which they are exposed in retail markets. These risks are essentially volume risks (that they will sell more or less energy to customers than expected) and price risks (that wholesale prices will change rapidly without the suppliers being able to pass through costs into retail prices).

7.24 In principle, an efficient retailer should be able to manage these risks at lower costs than a less efficient retailer. However, even with an efficient procurement strategy, a supplier is unlikely to be able systematically to beat the market – meaning long-term wholesale price movements should generally be reflected in costs for all retailers in the long run.[305] Overall, therefore, we would expect retailers to have only a moderate degree of influence over the overall level of wholesale costs that they bear for a given volume of demand in the long run.[306]

7.25 The extent of pass-through of wholesale costs into retail prices has been an area of some controversy, with Ofgem, for example, suggesting that the tendency of suppliers to raise prices more quickly when costs increase than they reduce prices when costs fall may be indicative of tacit coordination.[307] We review the evidence on the nature and extent of wholesale cost pass-through and draw implications for the extent of competitive pressures later in this section (paragraphs 7.152 to 7.173 following) and consider the evidence on tacit coordination in Section 8.

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[305] In Appendix 10.5 we note that reported wholesale electricity costs have diverged quite significantly between the Six Large Energy Firms over the past five years and consider the impact of transfer pricing and hedging on these costs

[306] We would expect this influence to increase with the full roll-out of smart meters and time-of-use tariffs for electricity, since this will provide suppliers with a means of incentivising customers to shift demand from times when electricity is expensive to periods when it is cheaper. This is discussed in more detail in Section 8.

[307] Ofgem (June 2014), *Decision to make a market investigation reference in respect of the supply and acquisition of energy in Great Britain*.

Network access

7.26 Network charges are a large and growing part of the overall costs facing suppliers. Distribution Use of System and Transmission Use of System charges are regulated by Ofgem – the supplier has no influence over the price paid. We therefore consider retailers to have a low degree of influence over network costs.[308]

Sales and marketing

7.27 Sales and marketing is a central function of an energy retailer, based largely around the design of gas and electricity tariffs, which differ according to their average price level and their risk properties (notably whether they are fixed for a certain period or can be varied). Tariffs are central to our analysis of competition in energy retail markets and are discussed in some detail in paragraphs 7.66 to 7.9973 and 7.114 to 7.180 below.

7.28 Retailers employ a variety of different methods for acquiring customers – including in-bound and outbound telephone calls, the supplier's own website, and the use of TPIs such as PCWs. Evidence on the current use of acquisition channels by the Six Large Energy Firms is set out in paragraphs 7.107 to 7.112.

7.29 Retailers have a high degree of influence over sales and marketing costs.

Metering

7.30 Suppliers are responsible for installing and maintaining gas and electricity meters and for the roll-out of smart meters. We note that some suppliers have used the roll-out of smart meters as a point of competitive differentiation from their rivals. We consider suppliers to have a moderate degree of influence over the costs of metering.

Billing and customer service

7.31 Billing and customer service is a key function that requires IT systems and people, and the facilities required to accommodate and support these systems and people. We note that billing and customer service problems have been largely responsible for recent increases in customer complaints, as discussed in Section 2.

[308] Again, we would expect the introduction of smart meters to give suppliers greater influence, since Time of Use Tariffs to encourage load shifting could help reduce network as well as generation costs.

7.32 We consider that suppliers have a high degree of influence over these costs (such that an efficient supplier will tend to incur lower costs than a less efficient supplier).

Environmental and social obligations

7.33 Retail suppliers also act on behalf of government in the delivery of environmental and social obligations and objectives, notably the RO, ECO, small-scale FITs and the Warm Home Discount.

7.34 Appendix 7.1 discusses these obligations in more detail. We consider that suppliers are likely to have the greatest degree of control over the costs of ECO and lower control over the costs of the other obligations.[309]

Value-added products and services and bundling

7.35 Energy suppliers sometimes provide a range of value-added products and services: information and advice, particularly on energy consumption and means of improving energy efficiency; the provision of technology for monitoring and controlling energy usage; and bundled services such as boiler and home maintenance services. Some suppliers are also engaged in the retail of other utility services (such as telecoms).

7.36 We consider that suppliers have a high degree of influence over such costs.

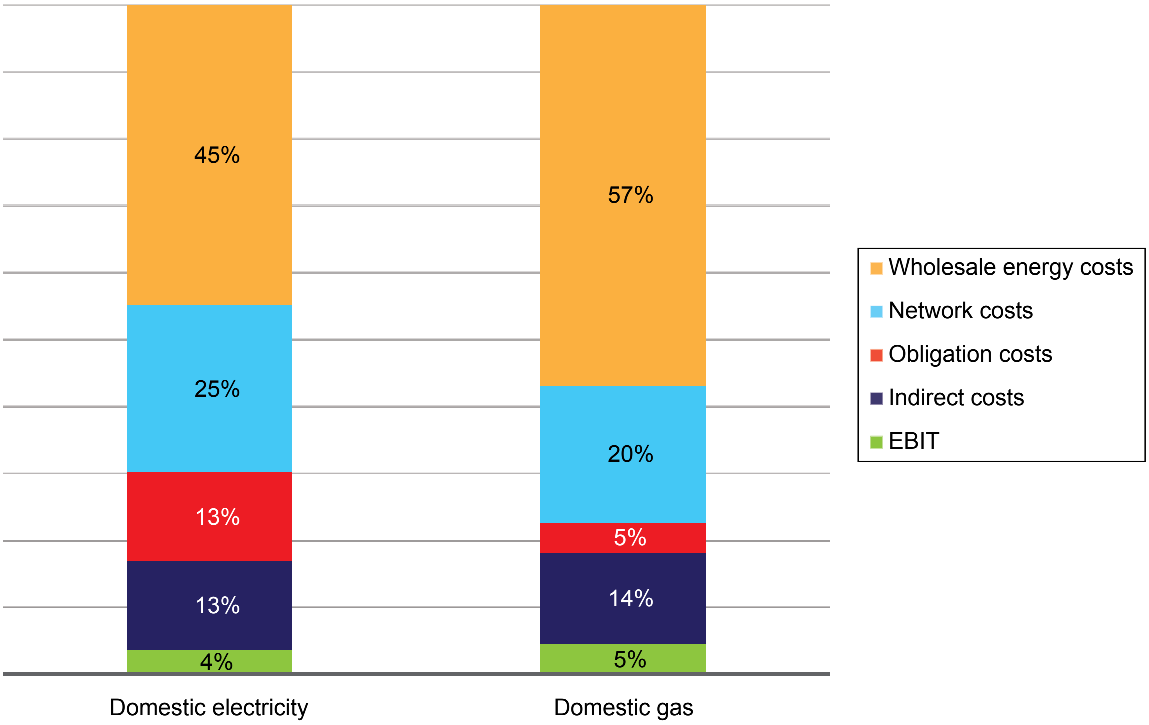
The cost structure of an energy supplier

7.37 The services offered by energy suppliers are reflected in the main direct cost items (energy, network and social and environmental obligations) and indirect cost items (metering, bad debt, sales and marketing, customer service) for suppliers.

7.38 This is shown in Figure 7.2, which breaks down the average price of gas and electricity to domestic customers in 2013 into its constituent cost components (excluding VAT at 5%).

[309] We note that part of the rationale for ECO through suppliers was to create an incentive to bear down on the costs of delivery.

Figure 7.2: Structure of the costs incurred by the Six Large Energy Firms to supply domestic gas and electricity customers



Source: CMA analysis of P&L data submitted by the Six Large Energy Firms. Excludes VAT.

7.39 It can be seen that the single biggest cost item for both electricity and gas is the cost of wholesale energy, followed by network costs.

7.40 For electricity, obligation costs are a large (and growing) proportion of total costs.[310] The data we have received from the Six Large Energy Firms does not allow us to break down these costs into those associated with individual obligations. However, analysis by DECC suggests that in 2014, of the four obligations imposing a cost on electricity, 55% of the cost was imposed by the RO and just under 25% of the cost was imposed by ECO. For gas, about 75% of obligation costs were imposed by ECO.[311]

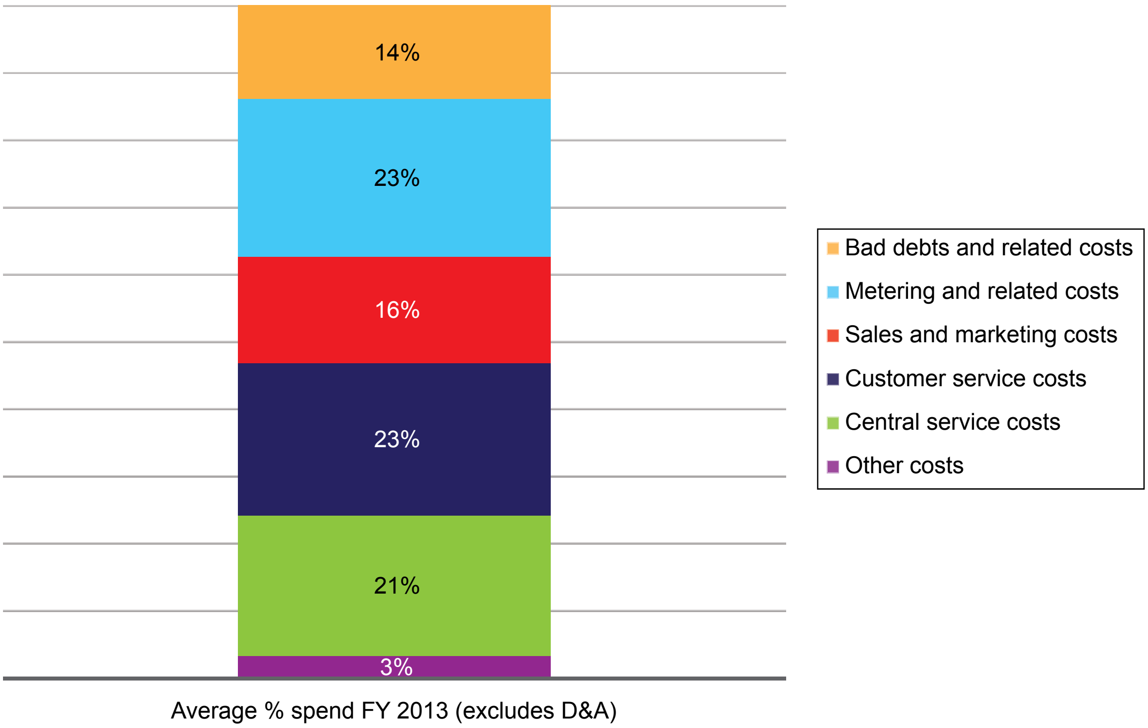
7.41 The gross margin (ie the sum of indirect costs plus EBIT) is the component of costs over which suppliers have greatest control. In 2013, the gross margin across the Six Large Energy Firms was 17% for electricity and 19% for gas.

7.42 The second figure further breaks down indirect costs into separate items (note that this is an average across the domestic, SME and I&C markets, and across electricity and gas, since no further disaggregation was

[310] We note that obligation costs do not include all the policy costs associated with electricity. As discussed in Section 2, the EU ETS and the carbon price floor add to the wholesale cost of electricity, while the RO is likely to depress the wholesale price on the occasions when renewables are marginal.
[311] Source: DECC, Price and Bill Impacts, 2014.

possible). The cost categories identified broadly map onto the activities identified above (with the exception of central service costs, where it has not proved possible to allocate costs to discrete categories). The biggest indirect cost categories are metering and related costs and customer service costs.

Figure 7.3: Breakdown of the indirect costs of the Six Large Energy Firms



Source: CMA analysis of P&L data submitted by the Six Large Energy Firms.

The parameters of retail competition

7.43 This section draws on the analysis of supply and demand characteristics in assessing the outcomes we would expect if competition is effective in energy supply markets.

7.44 We would expect competition to be largely on price, with competitive pressures bearing down on elements of the overall costs of energy supply, in particular suppliers' gross margin (ie the combination of indirect costs and net profit). This is currently around 17% of the cost of electricity and 19% of the cost of gas.

7.45 We would also expect a (more limited) degree of competitive pressure on wholesale costs and obligation costs, which together comprise 58% of the costs of electricity and 62% of the costs of gas. After the smart meter roll-out we would expect suppliers to have a greater degree of influence over wholesale costs[312] and some limited influence over network costs.

7.46 We would expect competitive pressures to be such that customer service meets certain minimum required standards, notably accurate billing.

7.47 Lastly, we would expect some degree of innovation, around tariff design, convenience and value-added services such as advice on improving energy efficiency. We consider that the scope for such innovation could expand significantly with the full roll-out of smart meters and greater potential for demand response.

Influence of regulation in shaping retail competition

7.48 The nature of price competition between the Six Large Energy Firms has changed several times since liberalisation, due in large part to changes in the regulatory regime.[313]

7.49 We have found that, post-liberalisation, competition was initially focused on the SVT. Centrica aimed to grow its retail business by converting its existing gas domestic customers to dual fuel and attracting new dual fuel domestic customers. Similarly, the incumbent electricity suppliers aimed to convert domestic customers in their 'home' areas to dual fuel and to attract new dual fuel domestic customers in other areas. In both cases, a key element of the strategy was to offer a SVT that was cheaper than the one offered by the incumbent supplier.

7.50 Over the last six years, three major interventions by Ofgem have changed the nature of retail competition significantly.

Prohibition on regional price discrimination

7.51 Following an investigation in 2008, Ofgem concluded that:[314]

(a) former incumbent electricity suppliers were earning significantly higher margins in electricity than in gas, and on in-area domestic customers than out-of area;

(b) proactive domestic consumers were most likely to secure attractive deals, but suppliers' ability to differentiate their prices meant that these

[312] Through encouraging load shifting through time-of-use tariffs.
[313] This is described in more detail in Appendix 7.3: The pricing strategies of the large energy firms and Appendix 2.1: Legal and Regulatory framework
[314] See Energy Supply Probe – Initial Findings, 2008, p52.

customers did not act as a competitive constraint on prices in the rest of the retail market;

(c) many inactive domestic consumers were unlikely to ever switch;

(d) electricity-only domestic consumers tended to pay higher margin electricity prices but were unable to benefit from keener pricing on gas or from dual fuel discounts;

(e) standard credit domestic customers were paying a premium over direct debit that did not appear to be fully cost justified; and

(f) rebalancing of margins across domestic customers would benefit vulnerable consumers and improve the prospects of new entrants.

7.52 In response to these findings, in 2009 Ofgem implemented Standard Licence Condition (SLC) 25A, which prohibited regional price discrimination.[315] However, it provided exemptions for promotional tariffs, which offered temporary discounts on the SVT (including percentage discounts to SVTs and cheaper fixed-price tariffs and capped tariffs, all of which defaulted to the SVT at the end of term). We understand that this may have led to an increase in the number of tariffs, with the Six Large Energy Firms offering non-standard tariffs with lower margins in some areas (for the incumbent electricity suppliers, margins were more likely to be lower out-of-area).[316]

7.53 The prohibition lapsed in 2012. However, suppliers told us that, following a communication from Ofgem warning against ‘pricing practices which are unjustified […] returning to the market’, they continued to adhere to the principles of SLC 25A in their pricing of SVTs. In December 2014 Ofgem wrote to suppliers to confirm that SLC 25A had lapsed and that suppliers were not bound by it in any way.

7.54 We analyse the likely impact of SLC 25A in Section 8.

Doorstep selling

7.55 Until 2011 doorstep selling and other face-to-face channels such as stands in and outside retail outlets were important routes to market for all the Six Large Energy Firms. In 2009 Ofgem[317] introduced a number of new licence requirements on suppliers designed to improve the quality and accessibility of the information available to domestic consumers and small businesses

[315] It also introduced SLC 27.2A, which prohibited undue discrimination by payment methods.
[316] See Appendix 7.3: The pricing strategies of the large energy firms, paragraphs 31–33.
[317] Ofgem letter (19 October 2009): Standards of conduct for suppliers in the retail market.

and to empower them to engage effectively in the retail market. To complement these new rules, it also introduced a set of overarching standards of conduct that it expected suppliers to take all reasonable steps to adhere to when marketing to domestic and small business customers. In particular:

(a) suppliers must not sell a domestic and small business customer a product or service that they do not fully understand or that is inappropriate for their needs and circumstances;

(b) suppliers must not change anything material about a domestic and small business customer's product or service without clearly explaining to them why;

(c) suppliers must not prevent a domestic and small business customer from switching product or supplier without good reason;

(d) suppliers must not offer products that are unnecessarily complex or confusing; and

(e) suppliers must make it easy for domestic and small business customers to contact them and act promptly and courteously to put things right when they make a mistake.

7.56 As a consequence of these licence conditions, enforcement action and media and political pressure in opposition to doorstep sales, during 2011 and 2012 all the Six Large Energy Firms withdrew from doorstep selling. This contributed to online channels (both PCWs and suppliers' own websites) becoming more important acquisition channels[318]. Suppliers told us that this contributed to the decline in the number of customers switching energy suppliers in 2012, as compared with previous years. They said that doorstep selling and other face-to-face channels had been effective ways of reaching customers who would otherwise have a low propensity to switch suppliers.[319] However, we note that there were real concerns that some switching decisions based on doorstep selling may have been of poor quality.

Retail Market Review

7.57 In 2013, partly in response to the increase in tariffs, Ofgem proposed changes to a number of licence conditions with the objective of making the

[318] See Appendix 8.3: Price comparison websites and collective switches
[319] See Appendix 7.3: The pricing strategies of the large energy firms.

market simpler, clearer and fairer to customers. These reforms are generally known as the Retail Market Review (RMR) reforms. The RMR reforms that took effect in 2014 introduced a number of obligations on suppliers, including several provisions relating to tariffs, notably:

(a) having four core tariffs for gas and four for electricity;

(b) having one structure for tariffs – a unit rate (or unit rates for time of use tariffs) and standing charge, which can be zero; and

(c) offering a maximum of two cash discounts, one for dual fuel (where a domestic consumer takes gas and electricity from the same supplier) and one for managing their account online.

7.58 We understand that some of the actions taken by energy suppliers to be RMR-compliant have included: the removal of discounted variable tariffs, which means that all fixed-period tariffs also now fix the price for the term of the tariff; the removal of premium green, two-tier and bundled tariffs; and the withdrawal of prompt-pay discounts and of discretionary credits and rebates and cashback offers.

7.59 Our understanding of the implication of the four-tariff rule, combined with the other licence conditions to which suppliers are subject, is as follows:

(a) Gas and electricity suppliers must offer domestic customers at least one evergreen tariff (the SVT) for both gas and electricity.[320] In addition to their evergreen tariffs, they can under RMR offer a further three electricity and three gas tariffs per metering arrangement per region.

(b) Suppliers have a choice over whether a specific tariff is made available to both single fuel customers and dual fuel customers, or to dual fuel customers only. All single fuel tariffs can be offered as dual fuel bundles with a maximum of 16 (4 X 4) permutations (per metering arrangement per region) – although suppliers are unlikely in practice to offer all combinations, due to differences in product features (eg a deal for one-year fixed gas and two-year fixed electricity).

(c) Suppliers are able to offer gas and electricity tariffs in a dual fuel bundle, even if these are not available as single fuel tariffs. Any such dual-fuel-only tariffs count towards the cap of four tariffs they are able to offer under RMR. Dual fuel customers may receive a dual fuel discount, which is not constrained to be cost-reflective.

[320] SLC 22.

(d) Suppliers are allowed to offer any number of fixed-term tariffs into each collective switching scheme, in addition to any of their four core tariffs, provided that such schemes fulfil certain requirements.

7.60 We assess the impact of the RMR reforms, particularly those relating to tariffs, in Section 8.

Customer activity and engagement

7.61 As of 31 January 2015, there were 27 million domestic electricity customers and 23 million domestic gas customers. Where customers use both electricity and gas, they often take both fuels from the same supplier – 19 million customers currently purchase their energy in this way (these are called 'dual fuel customers'). There were 8 million single fuel electricity customers and 3.5 million single fuel gas customers.

7.62 Before liberalisation, each customer would have been a single fuel customer of the monopoly gas and electricity supplier.[321] This section considers the extent of customer activity and engagement in retail energy markets since then. Activity can be measured along several dimensions:

(a) Choice of tariff – notably whether the customer is on the SVT or a non-standard tariff.

(b) Choice of payment method – standard credit, direct debit or prepayment.

(c) Choice of supplier, for one or both of electricity and gas.

7.63 In this section, we first summarise some key findings from our customer survey that suggest that substantial numbers of customers are either not aware that they can choose along each of these dimensions or have never considered doing so. We then review trends in customer activity along each of these dimensions since liberalisation, before summarising the current position.

[321] The monopoly gas supplier was Centrica (British Gas). The companies that have acquired the businesses of the monopoly electricity suppliers are: EDF Energy (London, South East, South West); E.ON (East Midlands, East Anglia, North West); RWE (Midlands, North East, Yorkshire); Scottish Power (South Scotland, Merseyside and North Wales); SSE (North Scotland, Southern, South Wales).

Evidence of disengagement through our customer survey

7.64 Our customer survey provides material evidence of domestic customers' lack of understanding of, and engagement in, retail energy markets.[322] For example:

(a) 36% of respondents either did not think it was possible or did not know if it was possible to change one (or more) of the following: tariff; payment method or supplier;

(b) 34% of respondents said they had never considered switching supplier;

(c) 56% of respondents said they had never switched supplier, did not know it was possible or did not know if they had done so; and

(d) 72% said they had never switched tariff with an existing supplier, did not know it was possible, or did not know if they had done so.[323]

7.65 We regard this as evidence of a material degree of disengagement and in Section 8 we assess to what extent this can be explained by a range of barriers to engagement.

Tariff type

7.66 The SVT[324] is the default tariff – ie the tariff energy customers will pay if they have not made an active decision to change tariff. Unlike other tariffs, the SVT has no end date – customers will be on the SVT indefinitely unless they make an active decision to change. In the analysis that follows, we sometimes compare the SVT with all other tariffs combined, which we call 'non-standard tariffs'.

7.67 We have observed that, for the Six Large Energy Firms, gas and electricity revenues per kWh from the SVT are consistently higher than average revenue from non-standard (generally fixed-price) tariffs. Over the period 2011 to 2014, average revenue per kWh from the SVT was around 10% and 13% higher than average revenue from non-standard tariffs for electricity and gas respectively across the Six Large Energy Firms. We have found that SVT tariffs have generated more revenue per kWh than non-standard tariffs

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[322] Appendix 8.1: Customer Survey provides a detailed description of the results of the survey.
[323] Appendix 8.1: Customer Survey.
[324] Information presented below on SVTs includes dual and single fuel customers unless otherwise stated.

over this period for each of the Six Large Energy Firms, for both gas and electricity.[325]

7.68 Despite this, a large proportion of customers of the Six Large Energy Firms are currently on the SVT – an average of 71% for electricity and 69% for gas in 2014.[326] The trend in the proportion of customers of the Six Large Energy Firms who are on the SVT is shown in the figure below.

Figure 7.4: Proportion of the domestic customers of the Six Large Energy Firms on the SVT by supplier and by month – electricity and gas*

[✂]

Source: CMA analysis based on suppliers' response to CMA Supply Questionnaire.
[✂]

7.69 While there has been a long-term reduction in the proportion of customers on the SVT, the trend in recent years is less clear and quite divergent across the Six Large Energy Firms: [✂].

7.70 We note that in general an electricity customer with the historical incumbent supplier is more likely to be on the SVT than a customer of an entrant. As shown in Figure 7.5, this relationship holds for all of the historical electricity incumbent suppliers with the exception of [✂].

Figure 7.5: Share of SVT customers by incumbent/entrant region

[✂]

Source: CMA analysis of data submitted by the Six Large Energy Firms.

7.71 We note that is it not necessarily the case that current SVT customers have always been on the SVT. Customers may have chosen a specific tariff in the past, and, at the end of its fixed term, defaulted back to the SVT. The table below sheds some light on this.

[325] While we do not have data for all suppliers before 2011, for those suppliers for which we do have data, we found that SVT tariffs have generated more revenue per kWh than non-standard tariffs in all years since 2008, with the exception of one of the Six Large Energy Firms, in two years for its electricity SVT tariffs. For further details on data definitions, see Appendix 7.5 Descriptive Stats (Retail).
[326] This is based on customer number data submitted by the Six Large Energy Firms, in contrast to the data presented in Tables 7.2 and 7.3 below, which is based on CMA analysis of tariff data submitted by the Six Large Energy Firms for Q2 2014.

Table 7.1: Average length of time on the SVT (excluding prepayment customers) with existing supplier for the Six Large Energy firms

		%
Time on SVT with current supplier	*Gas*	*Electricity*
6 months or under	13.7	14.5
7–12 months	10.7	12.0
13–24 months	13.0	12.3
25–60 months	24.1	29.9
61 months or more	34.8	30.9

Source: CMA analysis of data submitted by the Six Large Energy Firms.

7.72 The table shows that around 25% of the gas and electricity SVT credit and direct debit customers of the Six Large Energy Firms have been on the SVT with the same supplier for a year or less. Such customers may have been on a non-standard tariff with the same supplier and defaulted back to the SVT at the end of the term or they may have been acquired by the supplier on the SVT.[327] Around 60% have been on the SVT with the same supplier for more than two years and over 30% have been on the SVT with the same supplier for more than five years.

7.73 The SVT plays an important role in the pricing strategy of the Six Large Energy Firms, as discussed in greater detail in paragraphs 7.115 to 7.129 below.

Payment type

7.74 Three types of payment regime exist for energy customers:

(a) standard credit

(b) direct debit

(c) prepayment

7.75 Most customers have a choice as to whether to pay by standard credit or direct debit. The Six Large Energy Firms have offered a variety of discounts to customers who pay by direct debit over the years. SLC 27.2A, introduced in 2009, requires any such discounts to be cost-reflective. Since 2009, these discounts have typically ranged in value from £20 to £50 per fuel each year.[328] We understand that the average standard credit premiums for a dual

[327] Paragraphs 7.107–7.112 below analyse the different acquisition methods employed by the Six Large Energy Firms, including those which may be considered 'active' moves on the part of the customer or 'passive' (including home moves or new home purchases).
[328] A full description of the discounts and incentives offered by the Six Large Energy Firms is set out in Appendix 7.3: The pricing strategies of the Six Large Energy Firms.

fuel SVT customer are currently £75–£80 per year.[329,330] In addition, payment by direct debit offers convenience benefits over standard credit.

7.76 Prepayment, in contrast, is not generally a choice on the part of the customer: all customers on prepayment meters must pay by prepayment. Prepayment meters are generally installed where a customer has a poor payment history or in specific types of accommodation such as holiday homes and student accommodation. If a customer moves into a property with a prepayment meter they may request it to be replaced with a standard meter but the supplier may require them to pay for the costs of doing so.

7.77 We understand that the average prepayment premiums for a dual fuel SVT customer are currently about the same as those for standard credit – about £75–£80 per year.[331,332]

7.78 We note that SLC 27A requires that any differences in SVT rates by payment method must not exceed any differences in cost. Further, nearly all prepayment customers have been on the SVT.[333] These specific constraints on prepayment customers are an important feature of the market that we consider in greater detail later in this section and in Section 8.

7.79 The chart below shows the evolution in the proportions of gas customers using different payment methods, using statistics collected by DECC. In the mid-1990s the majority of customers paid by standard credit but since then there has been a significant shift towards payment by direct debit, with 57% of customers choosing to pay by this method in 2014 and only 28% of customers paying by standard credit. The proportion of customers on prepayment meters doubled over the period, from 7% in 1996 to 15% in 2014.[334]

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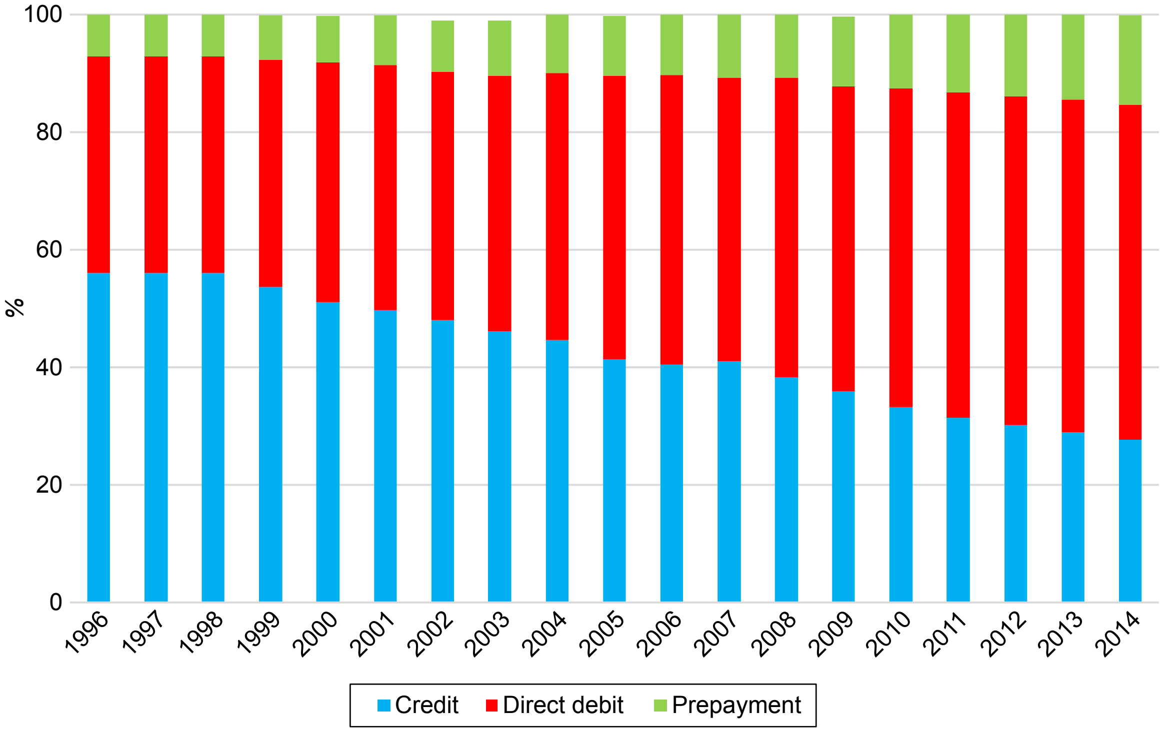
329 Source Ofgem based on dual fuel, typical consumption customer (applying the current definition).
330 The Six Large Energy Firms, with the exception of EDF Energy, said that Ofgem's analysis was a reasonable basis for assessing the differential. They also provided further details on the discounts they give to their direct debit, dual fuel customers. These are in the range of £70 to £90 a year.
331 Source Ofgem based on dual fuel, typical consumption customer (applying the current definition)
332 The Six Large Energy Firms, with the exception of EDF Energy, said that Ofgem's analysis was a reasonable basis for assessing the differential. They also provided further details on the discounts they give to their direct debit, dual fuel customers. These are in the range of £70 to £90 a year.
333 This is due to technical constraints imposed by certain types of prepayment meter. We understand that these will be addressed with the introduction of smart prepayment meters.
334 Percentages in 2014 differ somewhat from those presented in Table 7.1, reflecting different sources of data.

Figure 7.6: Change in percentage of gas customers in Great Britain using different payment methods, 1996 to 2014



Source: DECC Quarterly Energy Prices, March 2015.

7.80 A very similar set of trends and final outcomes are observed in electricity. In December 2014, 27% of domestic electricity customers in Great Britain were on standard credit, 57% of customers on direct debit and 16% on prepayment.[335]

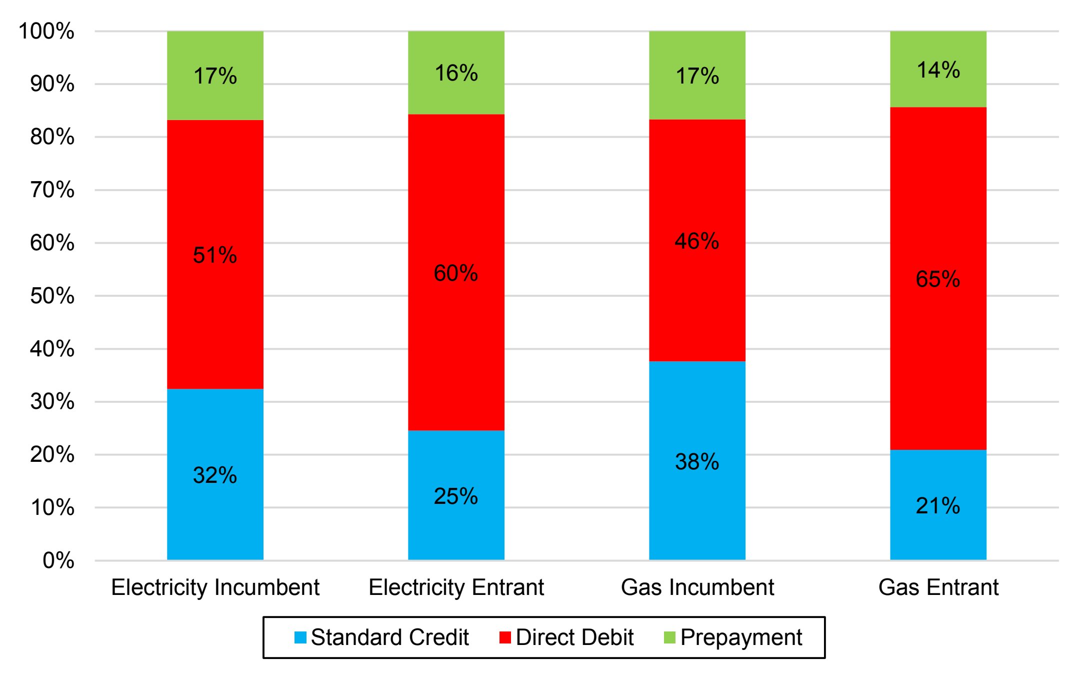
7.81 A particular question of relevance to this investigation is whether those domestic customers who have not switched from standard credit to direct debit should be considered inactive or whether, conversely, this represents an active choice on the part of customers to pay by standard credit (for example, to have greater visibility of the payments they are making), notwithstanding the convenience and cost benefits of direct debit.

7.82 On the one hand, we note that the flexibility of timing of payment available to those who pay by standard credit may be of real benefit to the cash-constrained. We also note, however, that paying by standard credit appears to be correlated with several indicators of inactivity. For example, Figure 7.7 shows that those who pay by standard credit are more likely to be with the incumbent gas or electricity supplier, which suggests that those who pay by

[335] Source: DECC, Quarterly Energy Prices, March 2015.

standard credit may have a greater propensity to be inactive than those who pay by direct debit.

Figure 7.7: Payment methods of domestic customers of gas and electricity incumbents and entrants, 2014



Source: CMA Analysis of DECC Quarterly Energy Prices, March 2015.
Notes:
1. Electricity figures are derived from the percentage of domestic electricity customers split by supplier type which includes both standard electricity and economy 7 electricity customers, and variation of payment method for standard electricity.
2. Gas figures are derived from the percentage of gas customers split by supplier type and variation of payment method for gas.
3. Data for payment method are derived from a survey of the six major suppliers and is not adjusted to account for survey coverage.

7.83 Further, we note from our survey that:

(a) 7% of those on standard credit have switched in the last year (compared with 13% of all respondents);

(b) 15% of those on standard credit have switched in the last three years (compared with 25% of all respondents);

(c) 46% of those on standard credit are either not aware it possible to switch or have never considered switching (compared with 34% of all respondents); and

(d) 52% of those on standard credit are unlikely to consider switching in the next three years (compared with 42% all respondents).

7.84 This issue is considered in greater detail in Section 8.

Choice of supplier

7.85 The proportion of domestic customers who have changed supplier is a potentially important indicator of customer activity and engagement. This section considers three measures of this: the proportion of customers on dual fuel tariffs; trends in quarterly switching rates; and the length of time customers have been with their current supplier.

Dual vs single fuel

7.86 Since, before liberalisation, all domestic customers had separate suppliers for gas and electricity, it follows that, if a customer is on a dual fuel tariff currently, they must have either changed the supplier for at least one of their fuels at least once or moved to a home supplied under a dual fuel tariff.

7.87 Early forms of competition post-liberalisation were focused on encouraging this dual fuel switch and suppliers provided quite substantial discounts for buying both electricity and gas from them. Dual fuel discounts initially ranged from between about 2% and 8% but have fallen in recent years to between 0% and 2% of the bill.[336]

7.88 Unlike discounts for payment methods, the level of dual fuel discounts is not constrained by Ofgem, although RMR requires dual fuel discounts to be available to all customers who purchase both fuels from the same supplier regardless of payment type and whether these are invoiced together.

7.89 Currently around 82% of gas customers and 69% of electricity customers are supplied under a dual fuel tariff, which suggests that the majority of customers are likely to have switched the supplier of at least one fuel once.[337]

Switching rates

7.90 Figure 7.8 shows data on quarterly switching numbers collected by DECC. There is a steady upwards trend in switching until 2008 followed by a decline, to levels below those in 2003. There are a number of potential reasons for this, including the prohibition of regional price discrimination through SLC 25A in 2009 and companies' decision to stop doorstep selling in 2011. There is also a very noticeable spike in switching towards the end of 2013, which may have been due to the high level of political controversy

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[336] See the Appendix 7.3: The pricing strategies of the Six Large Energy Firms.
[337] There may some customers on a dual fuel tariff who have not actively chosen to switch supplier – for example if they have moved home and simply adopted the prevailing supplier and tariffs at their new address.

surrounding energy prices at that time and the launch of the State of the Market Assessment.[338] In 2014 there were around 3.1 million electricity transfers and 2.3 million gas transfers. This represents around 11% of all electricity meters and 10% of all gas meters in 2014.

Figure 7.8: Quarterly domestic electricity and gas transfers in Great Britain

[✂]

Source: DECC, Quarterly Energy Prices, March 2015.
Notes: Transfer statistics refer to the number of customers switching from one energy supplier to another. For electricity and gas (from January 2014) this includes all suppliers. Previous to this gas transfer only covered the six large energy firms.

Length of tenure with current supplier

7.91 Despite initial activity around the dual fuel switch, a significant proportion of the domestic customers of the Six Large Energy Firms have been with their supplier for a long time. This is shown in Figure 7.9 below.

7.92 Between about 20 and 28% of the domestic electricity customers of the Six Large Energy Firms (excluding SSE[339]) have been with their current supplier for more than ten years. For gas, the range is wider – between 10% for [✂] and almost 40% for [✂]. The evidence suggest that incumbents have a higher proportion of such customers: regarding electricity supply, around 35 to 45% of the domestic customers of incumbent suppliers within each region have been with their supplier for ten years or more.[340])

Figure 7.9: Length of domestic customer relationship with the Six Large Energy Firms

[✂]

Source: CMA analysis of data submitted by the Six Large Energy Firms.
Note: Tenure data is based on 'individual within a meterpoint' except for SSE where length of tenure is driven by how long a site is supplied by SSE. See Appendix 7.5: definitions.

7.93 It is interesting to note also that around 20% of [✂] electricity customers have been with them for over ten years. This would imply that [✂] acquired substantial numbers of customers in the initial years after liberalisation, since when they have not switched supplier.

[338] Ofgem (27th March 2014), *State of the Market Assessment*.
[339] SSE is excluded from the statistics in this paragraph as the data definitions it supplied for tenure are not comparable with other suppliers. However, we note that around [✂]% of SSE sites have been supplied by SSE for ten years or more.
[340] For SSE, for electricity supply, around [✂] of domestic sites in its incumbent regions have been with SSE for ten years or more.

Customer characteristics and current levels of engagement

7.94 This section draws together the preceding analysis to present a snapshot of current levels of engagement among gas and electricity domestic customers in Great Britain.

7.95 Our customer survey suggests that material numbers of customers appear fundamentally disengaged in that they either are not aware of their ability to switch or have never considered switching. We have noted that domestic customer engagement should not be regarded as a binary phenomenon: customers can be considered to be relatively engaged or disengaged along various different dimensions of choice. The following tables show the impact of those choices on the current mix of domestic gas and electricity customers.

Table 7.2: GB domestic gas customers of the Six Large Energy Firms by tariff, fuel and payment type, Q2 2014

Tariff type	*Single or dual fuel*	*Payment type*	*Percentage of total domestic GB gas customers*		
Standard variable			67		
	Dual			51	
		Direct debit			26
		Standard credit			13
		Prepayment			11
		Other			1
	Single			16	
		Direct debit			5
		Standard credit			6
		Prepayment			4
Non-standard			33		
	Dual			31	
		Direct debit			26
		Standard credit			4
		Prepayment			1
	Single			2	
		Direct debit			1
		Standard credit			1
		Prepayment			0
Total			**100**	**100**	**100**

Source: CMA analysis of Six Large Energy Firm tariff data.
Note: Numbers in columns may not add up to 100% due to rounding.

Table 7.3: GB domestic electricity customers of the Six Large Energy Firms by tariff, fuel and payment type, Q2 2014

Tariff type	*Single or dual fuel*	*Payment type*	*Percentage of total domestic GB electricity customers*		
Standard variable			69		
	Dual			43	
		Direct debit			22
		Standard credit			11
		Prepayment			10
	Single			25	
		Direct debit			9
		Standard credit			10
		Prepayment			6
Non-standard			31		
	Dual			26	
		Direct debit			22
		Standard credit			3
		Prepayment			1
	Single			6	
		Direct debit			4
		Standard credit			2
		Prepayment			0
Total			**100**	**100**	**100**

Source: CMA analysis of Six Large Energy Firm tariff data.
Numbers in columns may not add up to 100% due to rounding.

7.96 The tables suggest that there is a degree of correlation between different dimensions of inactivity, notably: being on the SVT; being on a single fuel tariff; and paying by standard credit.[341]

7.97 While there are relatively few customers who pay a single fuel SVT by standard credit (10% of electricity customers and 6% of gas customers) we note that there may be other customers who have never actively chosen to switch supplier, tariff or payment method – for example, those who have joined the market since liberalisation or who have moved home during this period and simply adopted the prevailing supplier and tariffs at their new address. In addition, there are likely to be other customers who, even if they have exercised an element of choice in the past, can now be considered fundamentally disengaged in that they no longer consider exercising choice in retail energy markets or are no longer aware of their ability to do so.

7.98 Our survey suggests that the number of these fundamentally disengaged customers is substantial: over half the survey respondents either said they had not switched, did not know if they had done so or did not know it was possible. We analyse the survey results in greater detail in Section 8, considering in particular how different measures of engagement vary with respondents' demographic characteristics, attitudes, features of their energy supply and preferences for particular attributes in suppliers. We also explore

[341] It should be noted that a proportion of electricity customers are not connected to the gas grid and so will inevitably be on a single fuel tariff.

potential barriers to engagement and switching, drawing on survey and other evidence.

7.99 In Section 8 we also consider additional evidence of the extent of customer disengagement: our analysis of the potential gains to domestic customers from switching that currently go unexploited.

Market shares and acquisition channels

7.100 We have reviewed the evidence on the market shares of energy suppliers and the channels they use to acquire customers. A particular focus is on recent trends, including the rapid expansion in the mid-tier suppliers and the increased use of TPIs such as PCWs.

Market shares

7.101 Figure 7.10 shows the evolution in the market shares of energy suppliers over the past four years. There has been a rapid expansion in the market shares of suppliers outside of the Six Large Energy Firms, from less than 1% at the beginning of the period to almost 10% in gas and electricity in the second quarter of 2015.

Figure 7.10: Quarterly market shares of domestic electricity and gas customers

[✀]

Source: Cornwall Energy data submitted to the CMA.

7.102 This expansion has led to falling levels of concentration in retail supply, with the HHI[342] in gas falling from around 2,450 at the beginning of the period to 1,950 in 2015 and the HHI in electricity falling from around 1,800 to its current level of around 1,500.

7.103 The position as of Q1 2015 is shown in Table 7.4. British Gas currently has, by some way, the largest share of both gas and electricity customers, followed by SSE and E.ON. The largest of the mid-tier suppliers are First Utility, Ovo Energy and Utility Warehouse, which, despite their rapid growth, still have a much lower market share than any of the Six Large Energy Firms.

342 The Herfindahl-Hirschman Index, an indicator of market concentration calculated as the sum of the squares of the market shares of the companies in a market. In this case we have computed the HHI based on the shares of the Six Large Energy Firms. Our market investigation guidance indicates that we are likely to regard any market with an HHI in excess of 2,000 as highly concentrated, and any market with an HHI in excess of 1,000 as concentrated.

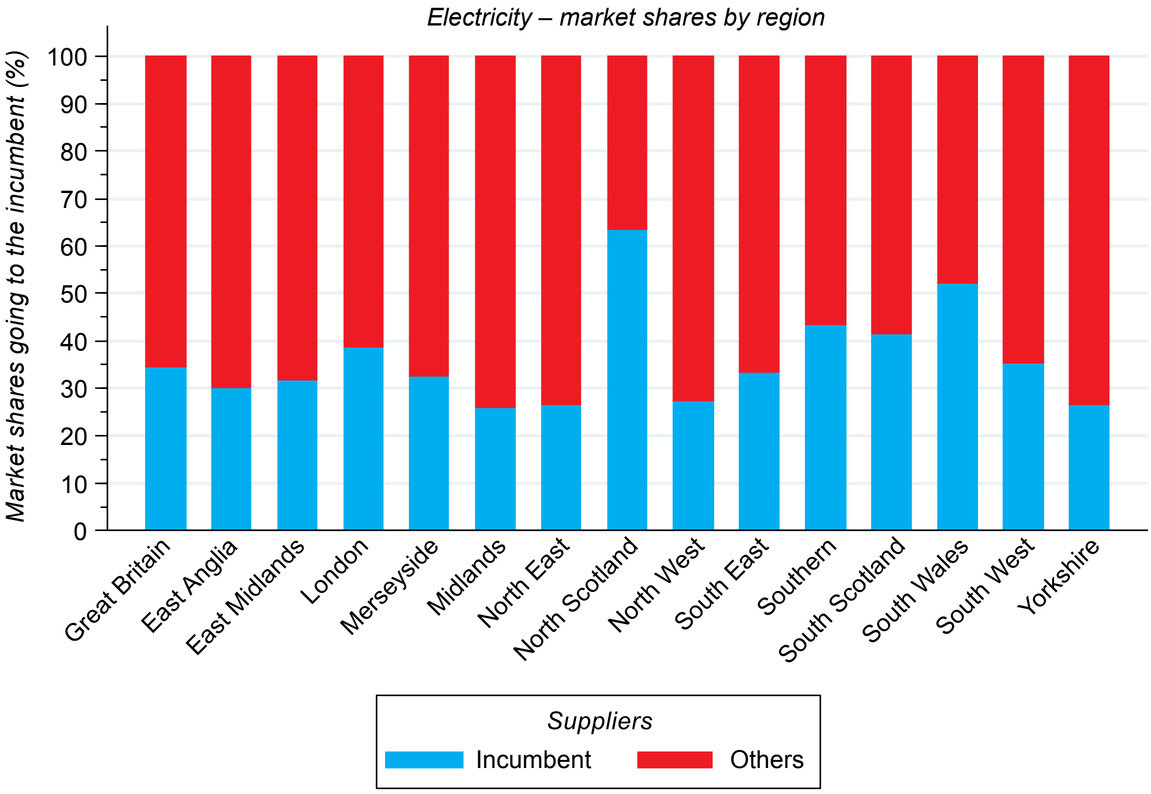
Table 7.4: Supplier market shares for Q1 2015 (% of GB total) – meter points

Supplier	*Electricity*	*Gas* (%)
British Gas	23.5	36.5
EDF Energy	12.8	9.2
E.ON	15.5	12.5
RWE	11.1	9.4
Scottish Power	11.4	9.3
SSE	16.2	13.3
Independents	9.5	9.8
of which:		
First Utility	2.6	3.0
Ovo Energy	1.5	1.6
Utility Warehouse	1.9	1.9
Other suppliers	3.4	3.4

Source: Cornwall Energy data submitted to the CMA.

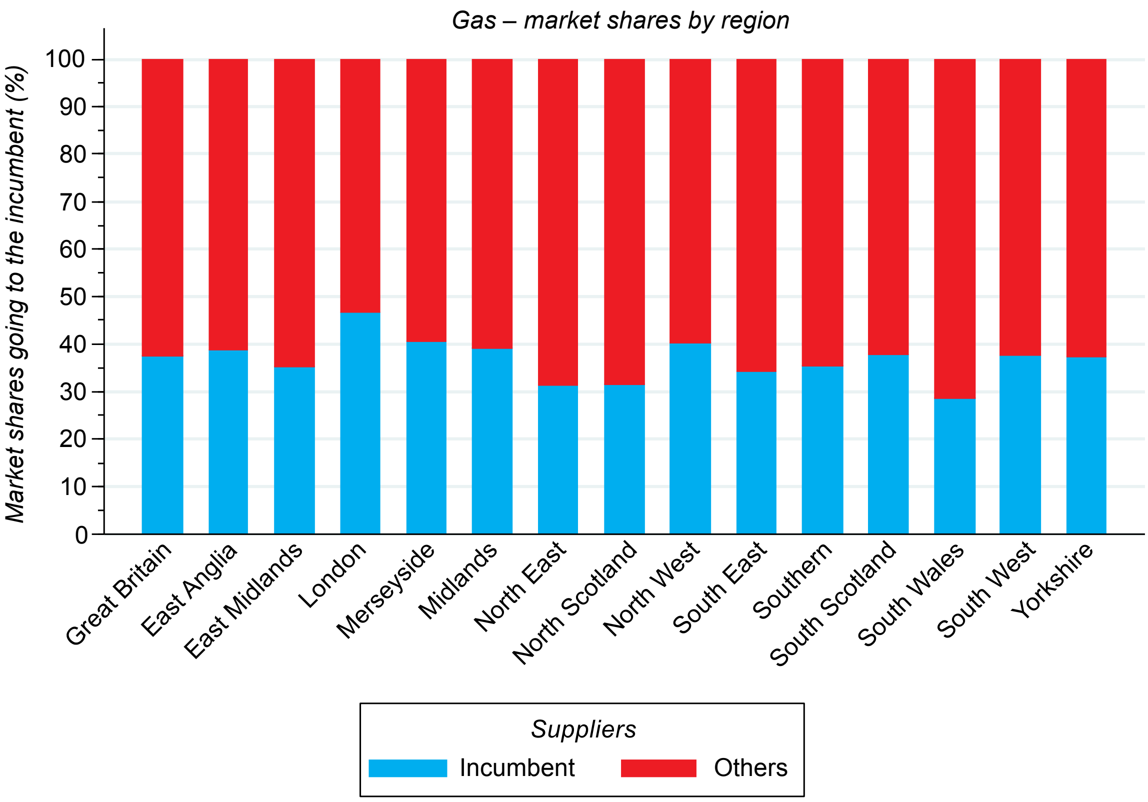
7.104 The figures below show the market shares of the electricity and gas incumbents in each of the GB regions.

Figure 7.11: Market share of electricity incumbents in 2014



Source: CMA analysis of Cornwall Energy data.

Figure 7.12: Market share of gas incumbent in 2014



Source: CMA analysis of Cornwall Energy data.

7.105 In relation to electricity, there are two regions – North Scotland and South Wales – where the incumbent (in both cases, SSE) has a market share of over 50%. In all but three of the electricity regions (Midlands, North West and Yorkshire), the historical incumbent still has the highest market share. In relation to the supply of gas, in all but two regions – South Wales and North Scotland – British Gas, the former national monopolist, has the highest share.

7.106 We explore the evidence on differences in competitive pressures between the devolved nations and between regions in paragraphs 7.195 to 7.211. We have drawn on this analysis in setting out our provisional views on market definition in Section 3.

Acquisition channels

7.107 Energy suppliers use a variety of sales channels to acquire domestic customers. Tables 7.5 and 7.6 show for each of the Six Large Energy Firms a breakdown of domestic customer acquisitions by channel in 2014.

Table 7.5: Percentage of electricity acquisitions by acquisition channel, domestic, 2014

%

Channel	*British Gas*	*EDF Energy**	*E.ON*	*RWE*	*Scottish Power*	*SSE*
Face to face	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]
Telesales	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]
Own website	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]
Home movers	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]
PCWs	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]
Cashback website (CBWs)	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]
Collective switches	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]
White-labels and partnerships	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]
Win back/recovery	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]
Other (including relationships with property industry)	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]
Total number of acquisitions	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]

Source: CMA analysis of supplier information request.
*We note that home movers are also counted in the telesales or own website channels, win backs are also counted in the telesales channel. Other only includes acquisitions made through relationships with the property industry and are also counted in telesales, white-labels and partnerships will also be counted in telesales or PCWs. However, the proportions provided in the tables are ‘true’ proportions for each channel as a percentage of total acquisitions.
Notes: [✂]

Table 7.6: Percentage of gas acquisitions by acquisition channel, domestic, 2014

%

Channel	*British Gas*	*EDF Energy**	*E.ON*	*RWE*	*Scottish Power*	*SSE*
Face to face	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]
Telesales	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]
Own website	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]
Home movers	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]
PCWs	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]
Cashback website (CBWs)	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]
Collective switches	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]
White-labels and partnerships	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]
Win back/recovery	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]
Other (including relationships with property industry)	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]
Total number of acquisitions	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]

Source: CMA analysis of supplier information request. See notes to Table 7.5.

7.108 [✂][343,344]

7.109 There are substantial differences between the acquisition channels of the Six Large Energy Firms. For example, there are substantial differences between the acquisition channels of the Six Large Energy Firms. For example, the most significant acquisition channel for [✂] was relationships with the property industry. In contrast, the remaining [✂] Six Large Energy Firms all used PCWs extensively and did not use relationships with the property industry to any great extent.

[343] [✂]
[344] We note that E.ON has a relationship with Countrywide estate agency, acquisitions through which are included in its home-moves channel.

7.110 An important new development is the rapid expansion in the use of PCWs as a means of acquiring domestic customers over the past five years. Figures 7.13 and 7.14 show for each of the Six Large Energy Firms and the four largest of the smaller suppliers the proportion of their total domestic customer acquisitions that was made via a PCW in each of the last six years.

Figure 7.13: Percentage of total domestic customer acquisitions made via PCWs (including PCW websites and call centres) for electricity, by supplier

[✄]

Source: CMA analysis of supplier information request.
Note: [✄].

Figure 7.14: Percentage of total domestic customer acquisitions made via PCWs (including PCW websites and call centres) for gas, by supplier

[✄]

Source: CMA analysis of supplier information request.
[✄]

7.111 As the figures show, the importance of PCWs to suppliers as a source of customer acquisitions has generally increased over the period, but varies significantly between suppliers.[345] In 2014, the proportion of total acquisitions to the Six Large Energy Firms facilitated by a PCW ranged [✄].

7.112 Of the ten major PCWs for which we received switching data, two PCWs – uSwitch and MoneySuperMarket[346] – accounted for around 70% of energy supplier switches in 2014. The next largest PCWs in terms of the number of energy supplier switches facilitated are [✄] and Compare the Market.[347]

7.113 In Section 8 we consider the impact that Ofgem's RMR reforms and reforms to the PCW Code are likely to have on the ability of PCWs and other TPIs to compete effectively and improve customer engagement in domestic retail energy markets.

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345 The data shows a spike in the proportion of SSE's acquisition secured through PCWs in 2013. SSE told us that in January/February 2013 it did offer fixed-term variable-rate tariffs at a 10% discount, at time of launch, but concluded that [✄].
346 Switching data from MoneySuperMarket includes customers switching via MoneySavingExpert's Cheap Energy Club which are passed to MoneySuperMarket's website. The MoneySuperMarket Group operates MoneySuperMarket and MoneySavingExpert. MoneySavingExpert operates as an independent business unit. However, MoneySuperMarket manages energy supplier relationships (and back-end operations) on behalf of MoneySavingExpert.
347 This is based on data received from ten PCWs (uSwitch, [✄], Confused.com, Compare the Market, MoneySuperMarket, Switch Gas and Electric, Gocompare.com, My Utility Genius, ThePeoplesPower and Which?) on the number of confirmed energy switches they enabled in 2014.

Nature and extent of price competition

7.114 This section reviews evidence on the nature and extent of price competition between energy suppliers:

(a) We consider the approach adopted by the Six Large Energy Firms to setting the SVT.

(b) We assess the approach adopted by the Six Large Energy Firms to setting non-standard tariffs, noting the interrelationship between the SVT and non-standard tariffs.

(c) We compare the Six Large Energy Firms with the mid-tier suppliers.

(d) We assess the evidence on cost pass-through.

(e) Finally, we draw provisional conclusions and identify implications for the investigation.

Approach of the Six Large Energy Firms to setting the SVT[348]

7.115 As noted above, the SVT is the default tariff – ie the tariff domestic energy customers will pay if they have not made an active decision to change tariff. Unlike other tariffs, the SVT has no end date – customers will be on the SVT indefinitely unless they make an active decision to change. Around 70% of the customers of the Six Large Energy Firms pay the SVT in 2014, despite the fact that, over the last four years average revenues from the SVT have been 10% higher for electricity and 13% higher for gas than average revenues from their non-standard tariffs.[349]

7.116 Under current rules, suppliers must offer an SVT for gas and for electricity. British Gas, E.ON and Scottish Power offer a dual fuel discount for supplying both fuels, although we estimate that the current value of the discount is relatively modest (between 0 and 2% of the bill).

Acquisitions on to the SVT

7.117 Our understanding is that the SVT is generally not an acquisition tariff, with the exception of prepayment customers (for whom until recently there were no other tariffs available except for the SVT). Four of the Six Large Energy Firms have confirmed this. In particular:

[348] See generally Appendix 7.3: The pricing strategies of the Six Large Energy Firms.
[349] CMA analysis of profiled revenue data submitted by the Six Large Energy Firms.

(a) EDF Energy told us that it did not price its SVT to win customers and that [✂]% of customer gains were on to a fixed-price tariff with the remaining [✂]% being on to the SVT ([✂]% prepayment customers and [✂]% cash, cheque or direct debit).

(b) E.ON described its current fixed-price tariffs, particularly those that were more heavily discounted, as its 'acquisition tariffs' (although they are also open to existing customers);

(c) One of the six large energy firms ([✂]) said that the vast majority of acquisitions were on to its non-standard tariffs and that with the increased importance of PCWs there had been an increased focus on short-term price competition (ie fixed-term tariffs) in order to attract customers;[350] and

(d) Scottish Power said that since 2009 fixed-term tariffs had been its main acquisition tool, accounting for [✂]% of gains.

7.118 Tables 7.7 and 7.8 show for each of the Six Large Energy Firms the percentage of acquisitions that were on to the SVT over the period 2009 to 2014 for gas and electricity. This shows that overall the percentage has fallen over the period, but that there are substantial differences between suppliers. For the four firms mentioned above, SVT acquisitions have fallen over the period. In 2014 SVT acquisitions were less than [✂]% of total acquisitions for EDF Energy, RWE and Scottish Power.

7.119 For British Gas, until 2013 over [✂]% of acquisitions were on to the SVT, [✂]% in 2014. [✂] the percentage of acquisitions on to the SVT has increased over the period with the exception of 2013 (the year in which it offered discounted tariffs through PCWs) and reached around [✂]% in 2014.

Table 7.7: Percentage of acquisitions on to SVT by year and supplier – electricity

%

Year	*British Gas*	*EDF Energy*	*E.ON*	*RWE*	*Scottish Power*	*SSE*
2009	[✂]		[✂]	[✂]	[✂]	[✂]
2010	[✂]		[✂]	[✂]	[✂]	[✂]
2011	[✂]		[✂]	[✂]	[✂]	[✂]
2012	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]
2013	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]
2014	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]

Source: CMA analysis based on suppliers' response to CMA Supply Questionnaire.

[350] Appendix 7.3: The pricing strategies of the Six Large Energy Firms.

Table 7.8: Percentage of acquisitions onto SVT by year and supplier – gas

%

Year	*British Gas*	*EDF Energy*	*E.ON*	*RWE*	*Scottish Power*	*SSE*
2009	[✂]		[✂]	[✂]	[✂]	[✂]
2010	[✂]		[✂]	[✂]	[✂]	[✂]
2011	[✂]		[✂]	[✂]	[✂]	[✂]
2012	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]
2013	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]
2014	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]

Source: CMA analysis based on suppliers' response to CMA Supply Questionnaire.
Note: Acquisitions data is based on meter points or (sites for SSE – see Descriptive Statistics definitions) except for Scottish Power where data is based on 'individual within a meter point' ie each period of 'occupancy' of a supplied meter point is considered to be a 'customer'.
For SSE these figures include customers paying the SVT on loyalty tariffs.

7.120 We note that a substantial proportion of SVT acquisitions in 2014 were for prepayment customers, for whom, as discussed above, there are very few non-standard tariffs available. This is shown, for 2014, in the chart below, which splits SVT acquisitions into prepayment and non-standard tariffs. Depending on the supplier, prepayment customers account for around 30 to 50% of SVT acquisitions for electricity and 25 to 50% for gas.

Figure 7.15: Proportion of acquisitions across payment type and tariff type, 2014

[✂]

Source: CMA analysis based on suppliers' response to CMA Supply Questionnaire.
Note: Acquisitions data is based on meter points except for Scottish Power where data is based on 'individual within a meter point' ie each period of 'occupancy' of a supplied meter point is considered to be a 'customer'. For British Gas the figures include acquisitions by the Sainsbury's energy brand and for SSE the figures include acquisitions by the M&S tariffs.

7.121 However, we note that for [✂] of the Six Large Energy Firms there were still substantial proportions [✂] of acquisitions onto the SVT for non-prepayment customers. For [✂] we note that a high proportion of acquisitions on to the SVT were secured via relationships with house builders and housing associations. [✂] Such acquisitions do not represent an active decision on the part of the customer to choose the SVT.

7.122 Overall, our provisional view is that the SVT is an acquisition tariff for prepayment customers, who have a very restricted choice of non-standard tariffs. For non-prepayment customers, the SVT is generally no longer an acquisition tariff for some of the Six Large Energy Firms. For the remaining Six Large Energy Firms, a substantial proportion of SVT acquisitions were via channels such as relationships with house builders and housing associations, where the customer is not making an active decision to choose the SVT.

Approach of the Six Large Energy Firms to setting the price of the SVT[351]

7.123 The price of the SVT can be changed by the supplier at any time, with the condition that, if the price is to be increased, they must give 30 calendar days' notice to customers of their intention to do so.[352] The Six Large Energy Firms typically make public statements, in advance of implementation, of intentions to change the price of the SVT. These announcements will typically give a 'headline' rate change and an implementation date.[353]

7.124 SVT prices have generally changed once or twice a year. The Six Large Energy Firms have told us that the frequency and size of the changes are driven by:

(a) changes in the cost base;

(b) the increased risks to suppliers of losing customers when they increase prices; and

(c) the costs to suppliers of changing tariffs (which are higher when prices are being increased due to regulatory requirements).

7.125 [✂]

7.126 In deciding on whether to change the price of the SVT, the Six Large Energy Firms [✂].[354]

7.127 As can be seen in Figure 7.16, the SVTs of each of the Six Large Energy Firms track each other quite closely. This is likely the result of the two above observations: they have similar hedging strategies and hence similar wholesale costs; and they monitor their SVT price relative to that of their rivals.

7.128 Some suppliers have argued that the firm that announces price increases first risks losing more customers than those that follow, which would provide an explanation for observations of clustering in pricing behaviour. We consider an alternative hypothesis – that public price announcements provide a mechanism for tacit coordination on the SVT – in Section 8 and Appendix 8.5.

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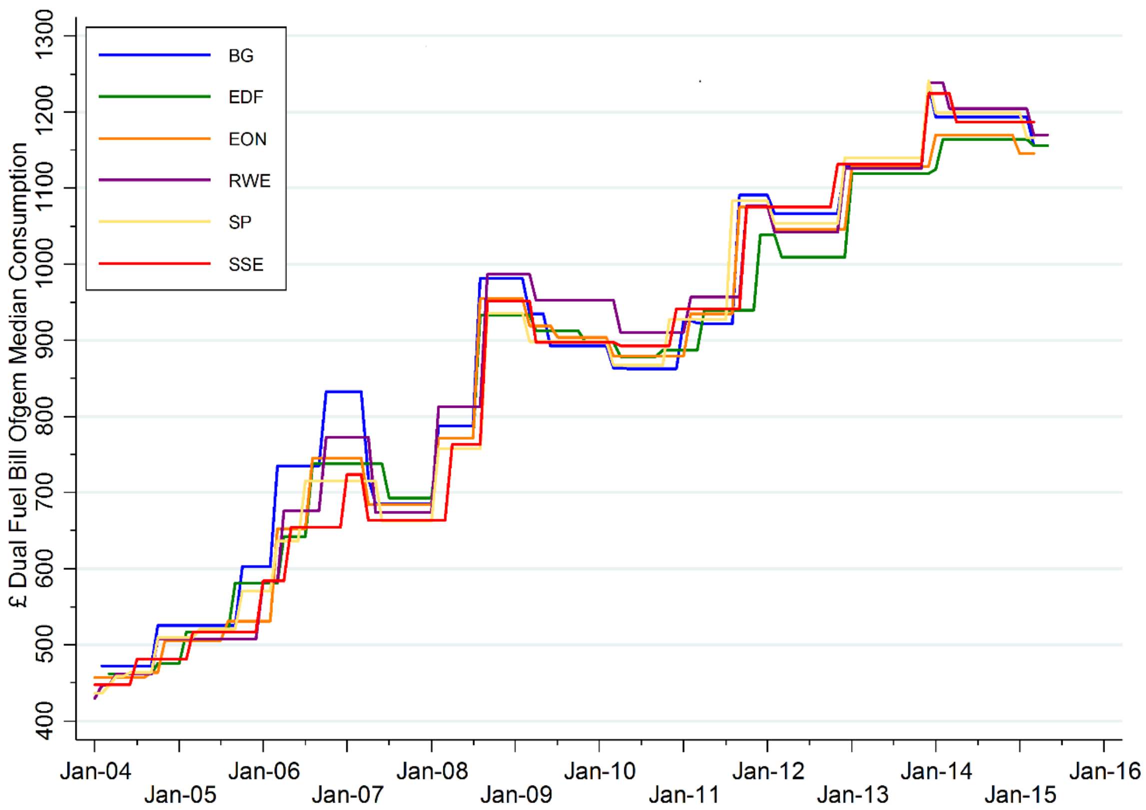
[351] See Appendix 7.3: The pricing strategies of the Six Large Energy Firms
[352] SLC 23 (formerly 44) of gas and electricity supply licences.
[353] The 'headline' rate is typically an average across regions and based on the change in bill for a dual fuel domestic customer, paying by monthly direct debit with 'typical' consumption.
[354] These comparisons are often based on a dual fuel, direct debit, typical consumption customer.

Figure 7.16: Change in the SVT for the Six Large Energy Firms (based on the annual bill for a dual fuel, direct debit typical consumption customer)



Source: CMA analysis based on data submitted by the Six Large Energy Firms. Assumes a direct debit dual fuel bill using current definition of typical consumption.

7.129 [✂]

Approach of the Six Large Energy Firms to setting non-standard tariffs

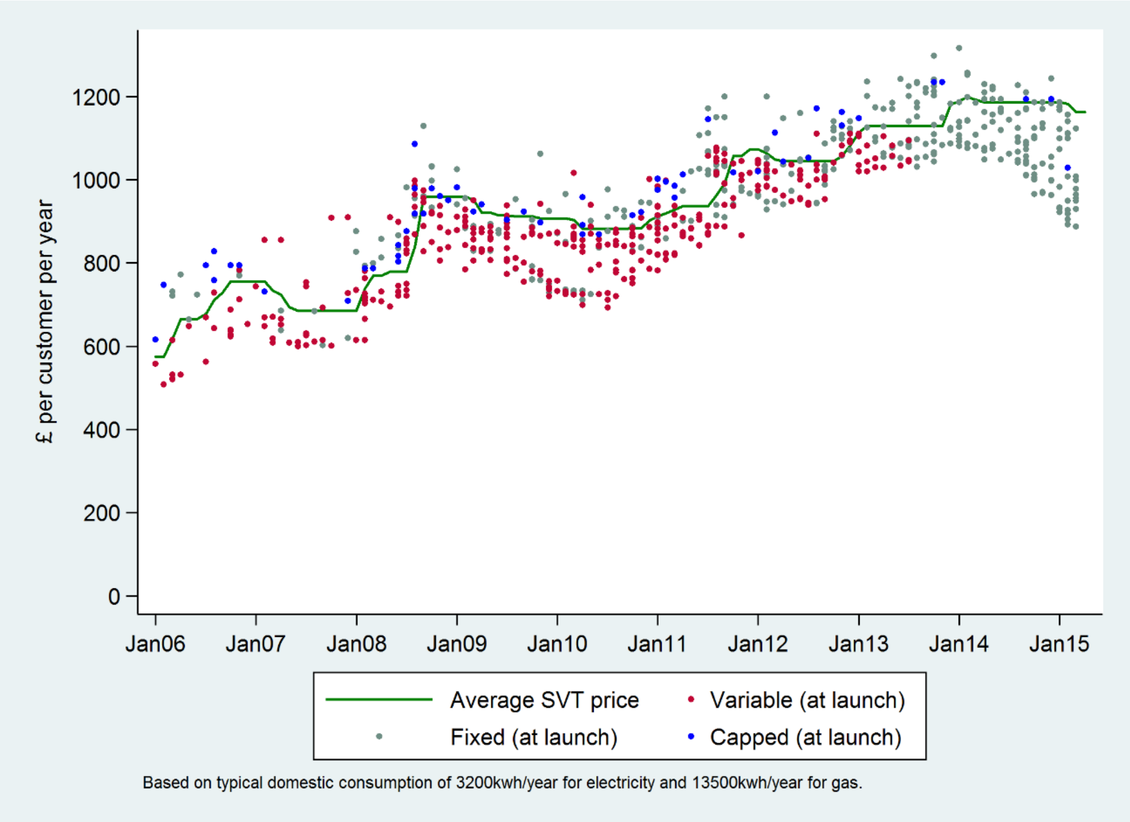
7.130 Non-standard tariffs come in a variety of forms, including fixed-rate and capped tariffs. One-year fixed-rate products are currently the most popular form of non-standard tariff.

7.131 In contrast to the SVT, non-standard tariffs are acquisition tariffs. The majority are priced at significant discounts to the SVT, with an explicit strategy of ensuring that they achieve a good position on the PCW rankings. There are, however, some non-standard tariffs, such as longer-term price fixes, which are more expensive than the SVT.

7.132 The Six Large Energy Firms have different strategies for purchasing energy for non-standard tariffs. [✂] The others would normally purchase (or commit) [✂].

7.133 The chart below compares the non-standard tariffs launched by the Six Large Energy Firms with the flat average SVT across each of the Six Large Energy Firms.

Figure 7.17: SVT and non-standard tariffs offered by the Six Large Energy firms (based on the annual bill for a dual fuel, direct debit, typical consumption customer)



Source: CMA analysis of data collected from the Six Large Energy Firms and Ofgem.

7.134 For the majority of this period, up to the end of 2012, there were many non-standard variable tariffs, which offered some of the cheapest rates. Fixed-rate and capped products were often sold at a premium – as might be expected, given the fact that they reduce the risk to which the customer is exposed. With the introduction of RMR, non-standard variable products were banned[355] and fixed products have taken their place as the cheap acquisition product.

7.135 Over the last year, the disparity between the SVT and the cheapest non-standard products offered by the Six Large Energy Firms has increased, to around £300 on the typical consumption customer bill in some cases, as they have begun to compete more vigorously with the mid-tier suppliers in the non-standard space.

[355] Non-standard tariffs can still vary under RMR, but only according to a predetermined schedule or in relation to an exogenous index. They cannot be expressed as a discount on the SVT.

7.136 Several of the Six Large Energy Firms have told us that there is a strong interrelationship between their pricing of the SVT and of their non-standard products. In particular, one of the six large energy firms ([✂]) told us that to attract customers it had to offer discounts on its SVT and that fixed-term discounted tariffs were therefore priced to attract customers, recognising that a certain proportion of customers would revert to the SVT at the end of the product's term.[356] [✂] also told us that they assumed that a certain proportion of customers would revert to the SVT (for which there was a bigger margin) at the end of the product's fixed term.[357] [✂] argued that it was only because some customers reverted to its SVT that it could offer the cheapest of its non-standard products. Therefore, it argued, the pricing of the SVT and non-standard products should not be seen as discrete decisions.

7.137 There is a potential further interaction between the price of the SVT and non-standard products for the Six Large Energy Firms: if non-standard products are set at too low a level, there is a risk that they will cause previously inactive SVT customers to engage, and either take up the cheaper tariff offered by the supplier or leave the supplier altogether. The risk of such 'cannibalisation' is greater given the RMR requirement that suppliers inform customers of their cheapest tariffs.

7.138 This risk may in part explain both the use of online tariffs and the increasing use of white labels on the part of several of the Six Large Energy Firms.[358] As shown in the figure below, tariffs sold through these channels are often pitched at the cheaper end of the spectrum. Marketing such tariffs through a different brand name or restricting their sale (and/or management) to online channels may be an effective means of reducing the risk of cannibalisation, particularly since RMR rules do not require partner suppliers to inform their customers of white-label tariffs.[359] We note that white labels are used predominantly by Centrica and SSE, the two suppliers that do not discount heavily under their own brand name. However, from the end of October 2015 suppliers will be required to include their white label tariffs in the cheapest tariff messaging.

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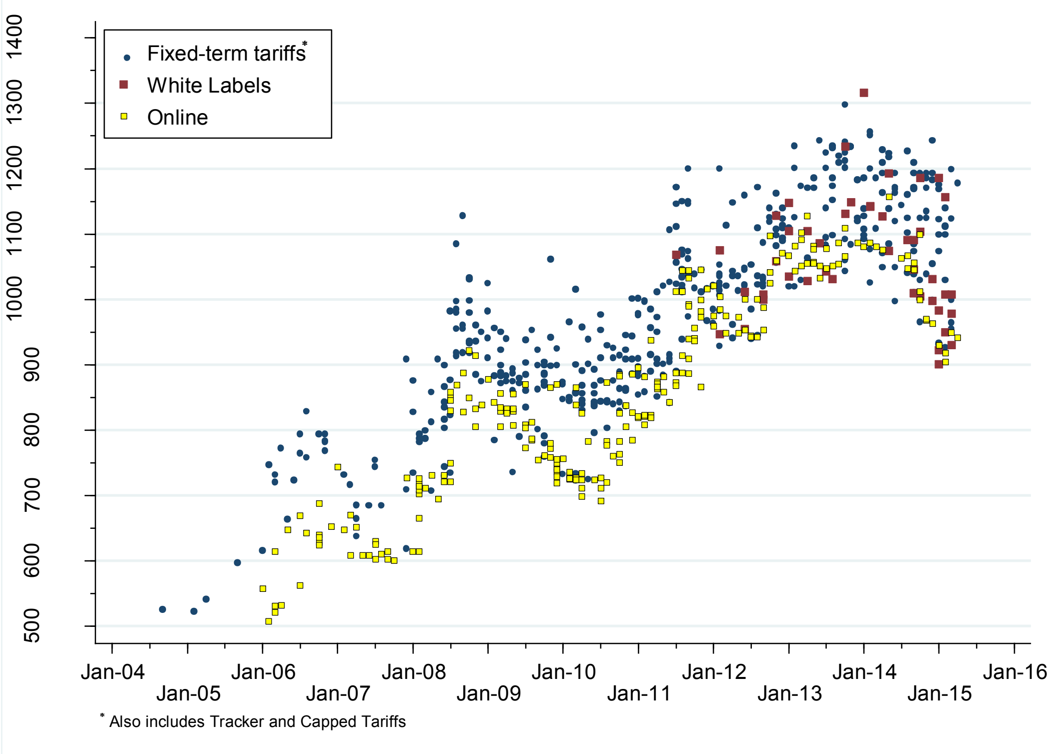
356 See Appendix 7.3: The pricing strategies of the Six Large Energy Firms
357 See Appendix 7.3: The pricing strategies of the Six Large Energy Firms
358 British Gas has had a white-label arrangement with Sainsbury's Energy since 2011; SSE has white-label arrangements with M&S and Ebico, and has its Atlantic online brand; E.ON has a commercial relationship with Age UK and offers tariffs under the Age UK brand; and Scottish Power has a partnership with Cancer Research UK.
359 This is the situation under the temporary arrangements included in SLC 31D but this is likely to change from July 2015.

Figure 7.18: Online and white-label tariffs of the Six Large Energy Firms (based on the annual bill for a dual fuel, direct debit, typical consumption customer)



Source: CMA analysis of data collected from the Six Large Energy Firms.

Average revenues

7.139 We observed earlier that over the period 2011 to 2014, average revenues from the SVT have been on average 10% and 13% higher for electricity and gas respectively than average revenues from non-standard tariffs. The charts below break down these results for each of the Six Large Energy Firms over the past five years, for gas and electricity.

7.140 We note that there is variation in the approach adopted by the Six Large Energy Firms. EDF Energy, E.ON, RWE and Scottish Power ([✂]) have all engaged in substantial levels of discounting on the SVT over the past five years. This is in contrast to SSE, which has generally engaged in lower levels of discounting.[360] [✂]

Figure 7.19: Average gas revenues of the Six Large Energy Firms*

[✂]

Source: CMA analysis of profiled revenue data submitted by the Six Large Energy Firms.
*See footnote to Figure 7.4.

[360] See Appendix 8.4: Price discrimination.

Figure 7.20: Average electricity revenues of the Six Large Energy Firms*

[✄]

Source: CMA analysis of profiled revenue data submitted by the Six Large Energy Firms.
*See footnote to Figure 7.4.

7.141 The average revenue figures are likely to be affected by various compositional effects, including in relation to the proportion of customers on different payment methods for each supplier and differences in distribution of each supplier's customer base across different regions. The latter may influence the average revenue comparison across suppliers because there are differences in distribution cost and consumption levels across regions.

7.142 We have calculated the average revenue figures for different payment methods for each supplier over the same period. The results of this analysis are presented in Appendix 7.5. For the SVT, average revenue tends to be lowest for direct debit and highest for prepayment, with average revenue for standard credit tending to fall between the other two payment methods.

7.143 We have also analysed using regression analysis how domestic customer bills differ between suppliers controlling for a range of price drivers. The results are discussed in Section 10 and Appendix 10.7.

Comparison of the Six Large Energy Firms and the mid-tiers

7.144 We noted earlier that the market share of the mid-tier suppliers has increased significantly over the last three years. One important feature that distinguishes them from the Six Large Energy Firms is that they do not have a large stock of customers who have been inactive for several years.

7.145 We have focused on the three largest mid-tier suppliers – First Utility, Utility Warehouse and Ovo Energy.[361] It is worth noting that, while First Utility and Ovo Energy are both fully independent of the Six Large Energy Firms, Utility Warehouse was until December 2013, a white-label provider in collaboration with RWE. Currently Utility Warehouse has a supply and services agreement with RWE which takes away wholesale and other risks.

7.146 There are other important differences in business model between Utility Warehouse and the other two. [✄]

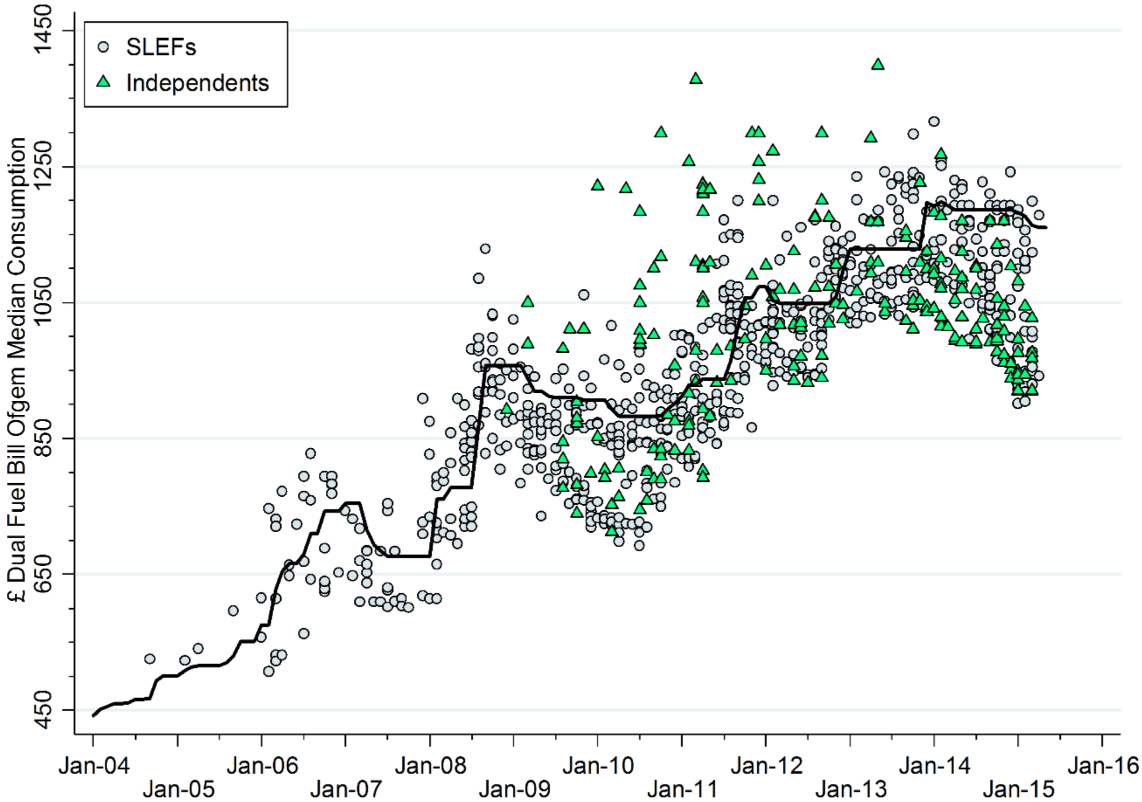
7.147 Figure 7.21 shows the tariffs offered by the mid-tier suppliers (green triangles) compared with those offered by the Six Large Energy Firms. It shows that in the early years of operation some suppliers (in this case [✄])

[361] We excluded data from Co-operative Energy at this stage given the difficulty of getting data consistent with the required definitions within the required deadline.

offered some expensive niche products at a premium to other available tariffs alongside cheaper tariffs.

7.148 In the last year, as a larger volume of sales has been achieved, the focus has moved increasingly to competitively-priced fixed products. Over the last year, virtually all of the tariffs offered by these suppliers were below the average SVT of the Six Large Energy Firms.

Figure 7.21: Tariffs offered by the mid-tier suppliers and Six Large Energy Firms



Source: CMA analysis of data collected from the Six Large Energy Firms, mid-tier suppliers.
Note: For First Utility five tariffs identified as developer tariffs have been excluded from the chart.

7.149 Figure 7.22 shows the average domestic revenue earned by the mid-tier suppliers compared with the Six Large Energy Firms. It can be seen that the average price offered by [✂] has been below that offered by the Six Large Energy Firms since it commenced operations in 2009. In 2014, [✂] domestic electricity and gas prices were 11% and 12% respectively below the average of the Six Large Energy Firms.

7.150 For [✂] average gas prices have been consistently cheaper than those of the Six Large Energy Firms and in 2014, the average price for gas was [✂]% below the average for the Six Large Energy Firms. [✂] average electricity prices were above those of the Six Large Energy Firms in 2012, but since then have become cheaper. In 2014, the average revenue/kWh sold for [✄] was [✄]% below the average for the Six Large Energy Firms for electricity.

7.151 [✄]

Figure 7.22: Comparison of annual average revenue per kWh across suppliers: electricity and gas

[✄]

Source: CMA analysis of profiled revenue data submitted by the Six Large Energy Firms.
Notes: Figures for the Six Large Energy Suppliers are an average across the suppliers weighted by customer numbers.

Cost pass-through

7.152 We have reviewed the evidence on cost pass-through – the extent to which changes in costs are passed through into changes in domestic retail prices.[362] This has been an area of some controversy, with concerns that suppliers appear to raise domestic retail prices more quickly when costs increase than they reduce prices when costs fall.[363] We consider two measures of costs – forward-looking costs and historical costs (ie those actually incurred by firms)[364] – and draw implications for the nature of price competition.

Forward-looking costs

7.153 In a competitive market we would generally expect prices to reflect marginal costs,[365] and this in turn will give efficient signals to market participants about consumption and production decisions. Similarly, in a competitive energy market, we would expect domestic retail prices to change in response to expected marginal costs rather than historical costs (which are sunk).

7.154 An energy supplier's expectations of its costs of delivering a certain amount of energy at a point in time in the future can be considered to consist of:

(a) the cost that the supplier has already incurred for future delivery by purchasing some of the expected volume in advance (the 'closed' position); and

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[362] A full description of the analysis we have carried out is set out in Appendix 7.2: Cost pass-through. Part A of that appendix describes the analysis with respect to forward-looking costs, whereas Part B focuses on historical costs.
[363] See, for example, Ofgem (June 2014), *Decision to make a market investigation reference in respect of the supply and acquisition of energy in Great Britain*.
[364] Appendix 7.2: Cost pass-through, Table 1, provides an overview of the differences between these two analytical approaches.
[365] The change in total costs arising from a marginal increase in output.

(b) the cost that the supplier expects to incur in purchasing the remaining expected volume (the 'open' position). These expectations are informed by forward prices of future products.

7.155 In principle, only the energy cost in *(b)* should matter to a profit-maximising supplier when setting its prices, regardless of the cost of the energy that has already been purchased (although the cost in *(a)* will affect its realised profits).

7.156 In relation to wholesale costs, we consider that forward prices are a good benchmark of the expected marginal cost, since forward prices are a measure of: the expected cost of supplying energy to a newly acquired domestic customer in the future; and the expected value, or opportunity cost, at a point in time, of the energy the supplier has already procured for future delivery.[366]

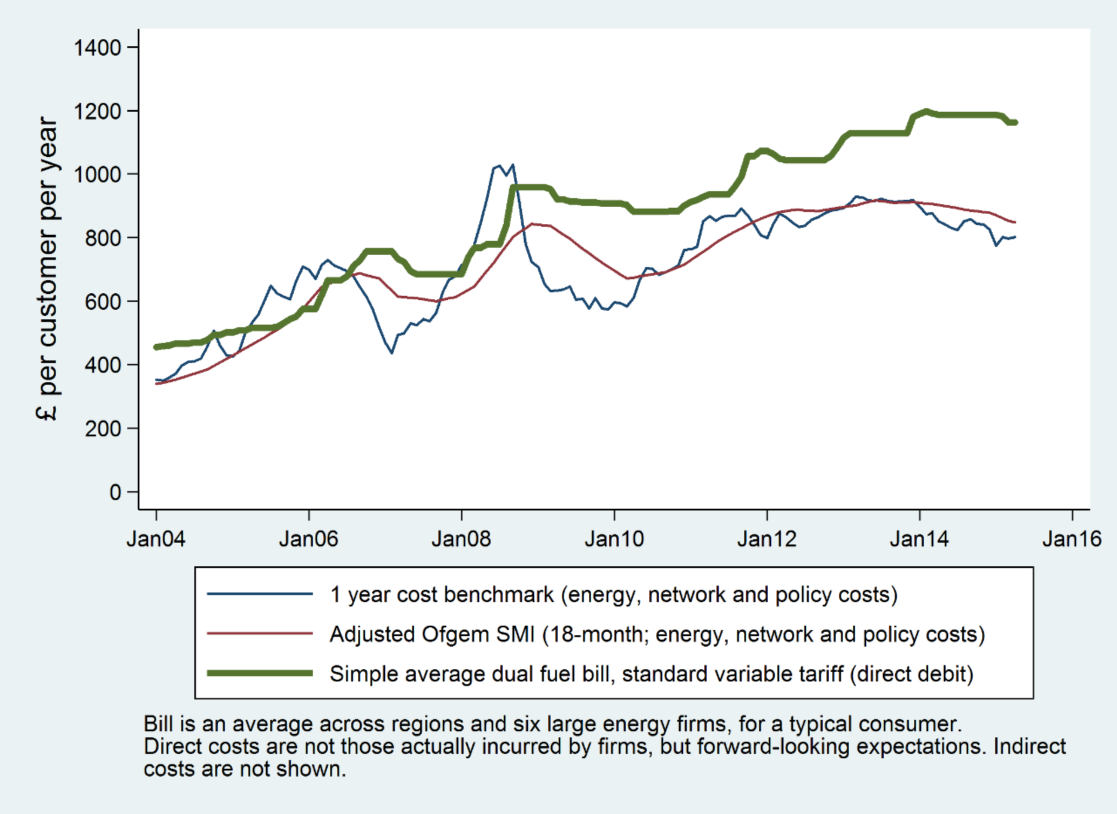
7.157 We also consider expectations concerning other categories of direct costs to be relevant to domestic retail pricing, including: transmission and distribution costs; environmental and social obligations; and balancing services use of system (BSUoS) charges (for electricity only).

7.158 Based on these principles, we constructed a series of forward-looking industry cost benchmarks for the period between 2004 and March 2015. These benchmarks approximate the economic opportunity cost and do not make any assumptions about hedging. We constructed one-year, 18-month and two-year cost benchmarks, each of which produced very similar results. Figure 7.23 shows the relationship between the average price of the SVT (based on the annual bill for a dual fuel direct debit typical consumption customer) offered by the Six Large Energy Firms and the one-year cost benchmark, which tracks the cost that a supplier would incur if it were to purchase energy for a typical customer for the following 12 months, based on the prevailing energy prices in that month in the market.

7.159 The figure also shows Ofgem's Supply Market Indicator (SMI), which is not a purely forward-looking measure, but tracks the expected cost by assuming that the supplier has already purchased some of the expected volume in the past through a stylised hedging strategy.

[366] If a supplier lost a domestic customer and had to sell the energy it previously purchased for that customer back to the market, the price at which this energy could be sold is the forward price in the market at that point in time.

Figure 7.23: Average SVT price (based on the annual bill for a dual fuel direct debit typical consumption) and a forward-looking industry-level benchmark of direct costs



Source: CMA analysis of data collected from the Six Large Energy Firms, Ofgem and ICIS.

7.160 The one-year cost benchmark is more volatile than the SMI, particularly from 2006 to 2010, but it follows the same broad trend. The measures track each other closely from 2012 onwards. Regarding the relationship between forward-looking direct cost and domestic retail price changes, we observe the following:

(a) SVT price changes have generally been less frequent and smaller in magnitude than the movements in the one-year benchmark and appear to lag changes in the benchmark.

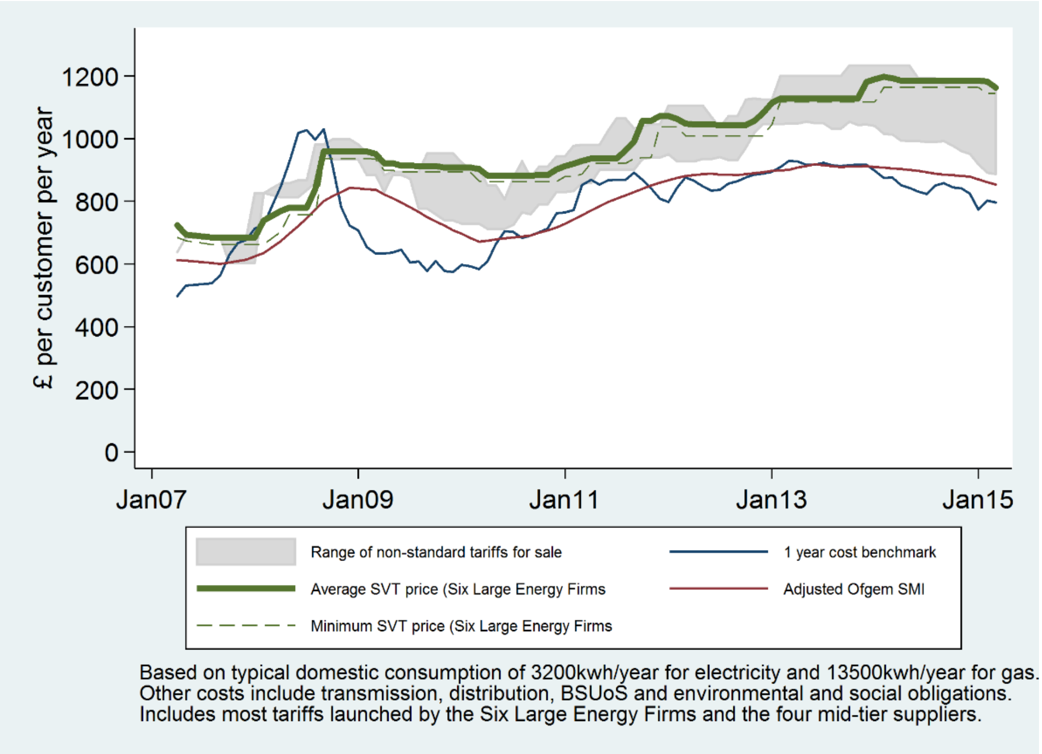
(b) The gap between the measures of direct costs and the average SVT widens over time, and particularly from around 2009 onwards.

(c) The gap narrows somewhat in 2011, with increases in wholesale gas costs, but then increases again in 2014 as reductions in wholesale gas costs are not passed through into commensurate reductions in the SVT.

7.161 The evidence appears to be consistent with a potential weakening of competition over the SVT over time, and particularly from 2009, as the gap between the SVT and underlying costs appears to widen.

7.162 The chart below is based on the same data but also includes the range of one-year fixed tariffs offered by the Six Large Energy Firms and the mid-tier suppliers. The grey area in the chart shows the range of tariffs available for sale to customers at any point in time.

Figure 7.24: The range of one-year fixed tariffs on sale, average SVT price and a forward-looking industry-level benchmark of direct costs



Source: CMA analysis of data collected from the Six Large Energy Firms, mid-tier suppliers, Ofgem and ICIS.

7.163 We observe that the cheapest one-year fixed tariffs appear to have followed expected costs more closely than the SVT. For example, the cheapest one-year fixed price decreased more than the SVT price during the period following the cost reduction in 2009, and followed more closely the recent cost reduction in 2014 while the SVT price remained flat.[367]

7.164 However, there is still a relatively wide range of one-year fixed tariffs for sale, with some above the average SVT price. In Section 8, we consider the implications of these relatively expensive, non-standard tariffs.

7.165 Parties have argued that our analysis is flawed because the cost measures used are unrealistic. In particular, as:

[367] While we note that the SVT presented in the chart is an average of the SVT of all the Six Large Energy Firms, the SVTs of each of the firms track each other closely, as shown in Figure 7.16 above.

(a) the forward-looking cost benchmark ignores the way suppliers purchase energy over time (hedge) and the actual costs incurred as a result;

(b) the cost measures exclude some direct cost items (such as metering costs, the increasing costs of the smart metering programme, electricity imbalance costs, gas reconciliation by difference, demand forecast errors and unbilled volume costs) and all indirect costs, some of which are marginal; and

(c) Ofgem's measures of CERT/CESP and ECO costs, used in our analysis, have historically underestimated the actual cost of delivering the schemes at different stages in each programme.

7.166 The parties said that because of this there was no widening of the gap between prices and costs over time, or the widening of the gap was likely to be overstated, or that any difference in the gap between the periods before and after 2009 reflected a period of unsustainably low profits before 2009.

7.167 We respond to these and other points in detail in Appendix 7.2 paragraphs 75 to 82. We make two observations here.

7.168 First, while some indirect costs are marginal and therefore relevant to pricing, we do not believe that the omission of indirect variable costs is likely to affect the conclusions drawn from our analysis. In particular, we have looked at the evolution of metering costs, which are the largest proportion of indirect costs, and did not find them to vary materially over time (see Annex B, Figure B12). We have also looked at the evolution of total domestic indirect costs per customer over the period 2007 to 2013, and find that on average these have fallen over this period.

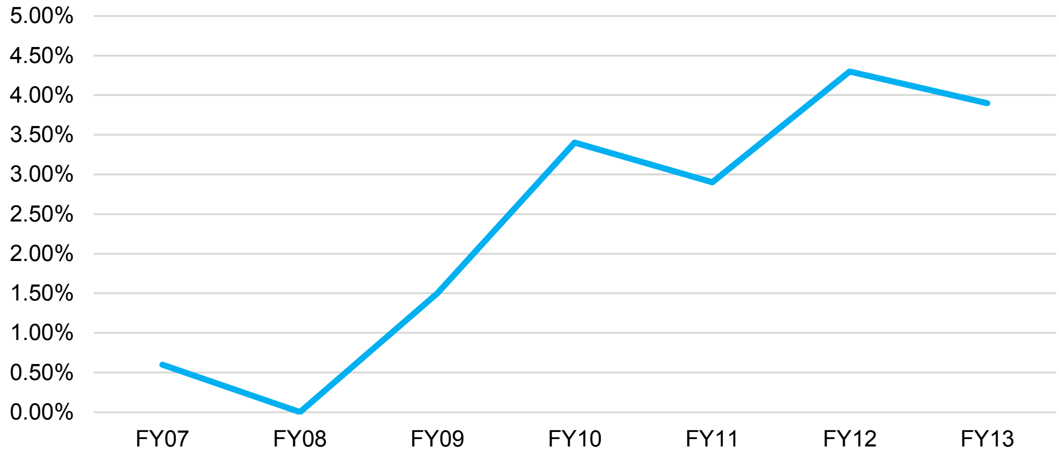
7.169 Second, some of the concerns expressed appear to assume that, in our cost pass-through analysis, we have attempted to estimate the costs that firms have actually incurred in supplying energy to customers. This is not the case, as we discuss below.

Historical costs

7.170 It is important to note that our analysis of forward-looking costs is intended to provide insight into the extent of the competitive pressures to which firms are subject in setting different prices: the cost benchmarks we have calculated show the cost signal perceived by the industry when prices were set. Our analysis of cost pass-though is not an analysis of the actual costs incurred by individual firms or the actual profit margins earned by firms.

7.171 Our analysis of the actual costs and profits earned by the Six Large Energy Firms is set out in Sections 2 and 10 and Appendices 10.2 and 10.5. As shown in Figure 7.25, net margins for the sale of electricity and gas to domestic customers were relatively low in 2007 and 2008 and have increased thereafter, although there is no obvious trend from 2010 to 2013.

Figure 7.25: Total domestic supply margins 2007 to 2013



Source: CMA analysis of data submitted by the Six Large Energy Firms.

7.172 Average gross margins earned by the Six Large Energy Firms from sales of gas and electricity to the domestic customers have not shown a clear trend over the period 2007 to 2013.[368] Figure 7.26 shows the average unit revenues and average direct costs per unit actually incurred by the Six Large Energy Firms, on average across all tariffs and customers and separately for SVT. The gap between the revenue and cost measures can be interpreted as a gross margin.

Figure 7.26: Average unit revenues and average unit direct cost, on average across the Six Large Energy Firms, between 2011 and 2014

[✄]

Source: CMA analysis of profiled revenue and cost data submitted by the Six Large Energy Firms.

7.173 With regard to the relationship between forward-looking costs and actual costs, we would expect a supplier's actual costs, at a point in time, to reflect movements in forward energy prices over the previous two to three years. With regard to revenues, we would expect a supplier's actual revenues from its SVT customers to reflect its current SVT prices, but actual revenues from its non-SVT customers to reflect the price of fixed-term tariffs on sale over the previous one to two years or longer if a supplier has customers on tariffs with terms of more than two years. Overall, therefore, we would expect there

[368] Appendix 10.2: Retail profit margin analysis.

to be a lag in the relationship between: any widening of the gap between measures of direct costs and the average tariff; and increases in observed gross margins.

Provisional conclusion on nature of price competition and implications for the investigation

7.174 We have observed that the SVT is a default tariff while non-standard tariffs are acquisition tariffs.[369] Further, we have noted that there are significant disparities in the prices between the SVT and non-standard tariffs. While some non-standard tariffs are more expensive, a significant number are sold at substantial discounts to the SVT.

7.175 We have also noted that the SVT has risen over the last three years, despite that fact that forward-looking measures of direct costs have on average fallen over the period, particularly over the last 12 months. In contrast, the cheapest non-standard tariffs have tracked changes in expected direct costs more closely.

7.176 Several of the Six Large Energy Firms have argued that the SVT and non-standard tariffs are not set independently. Rather, they set non-standard acquisition tariffs at a discounted level, in expectation that a proportion of customers will revert to the SVT at the end of the fixed term. (The evidence suggests that around 25% of their gas and electricity SVT customers have been with them for a year or less, which partly reflects the effect of such reversion.) Further, if the disparity between the SVT and the non-standard tariff is too high, there is a risk of cannibalisation; some firms have responded to this by marketing discounted tariffs through white Labels or through online channels.

7.177 We recognise that such interrelationships are likely to exist. Customers are unlikely to fall into discrete categories of engaged and disengaged customers – some customers will be active in the market for a period of time and then revert to the SVT, while others may not have made an active choice in the market for a long time, if at all. (We note that roughly a third of the SVT customers of the Six Large Energy Firms have been with the same supplier and tariff for more than five years.)

7.178 Finally, we have observed that the mid-tier suppliers have increased market share considerably in recent years and that the average price for gas and

[369] The SVT is also an acquisition tariff for prepayment customers and for customers acquired through routes such as relations with the housing industry and housing associations.

electricity offered by two of these suppliers – [✂] – was about 10% lower than the average price of the Six Large Energy Firms in 2014.

7.179 Appendix 10.5 and Section 10 consider the sustainability of the tariffs of the mid-tier suppliers and consider what implications we can draw from them about the competitive retail benchmark price.

7.180 The Six Large Energy Firms have argued that the smaller suppliers benefit from an unfair subsidy due to the exemptions they have from meeting the full costs of certain government social and environmental obligations. We consider the strength of these arguments in Appendix 7.1.

Gains from switching

7.181 We noted above that there is a significant variation in the prices that domestic customers pay for energy. In this section, we quantify the potential gains available from switching, considering the different dimensions of choice discussed in paragraph 7.62:

(a) Choice of tariff type[370] from the customer's existing supplier.

(b) Choice of payment method – standard credit or direct debit.

(c) Choice of supplier, for one or both of electricity and gas.

7.182 In order to assess the potential savings along these different dimensions of choice, we consider a number of scenarios, which differ according to the extent to which they restrict the choices available to domestic customers. The scenarios are:[371]

(a) Scenario 1: Change tariff type but keep supplier and payment method.

(b) Scenario 2: Change tariff type and payment method (except for prepayment customers) but keep supplier.

(c) Scenario 3a: Change supplier (only to one of the Six Large Energy Firms) but keep tariff type[372] and payment method.

[370] By choice of tariff type we mean tariff structure (variable, fixed and capped), contract length (in case of fixed tariffs) and preference for online/offline tariffs.
[371] See Appendix 17 – Analysis of the potential gains from switching, for a full description of the parameters that can be changed/held fixed when switching.
[372] We note that customers can switch to offline/online tariffs.

(d) Scenario 3b Change supplier (to one of the Six Large Energy Firms or mid-tier suppliers) but keep tariff type[373] and payment method.

(e) Scenario 4a: Change supplier, tariff type and payment method (except for prepayment customers) but restrict online tariffs to those currently on online tariffs.

(f) Scenario 4b: Change supplier and tariff type but keep payment method.

(g) Scenario 5: Change supplier, tariff type and payment method (except for prepayment customers).

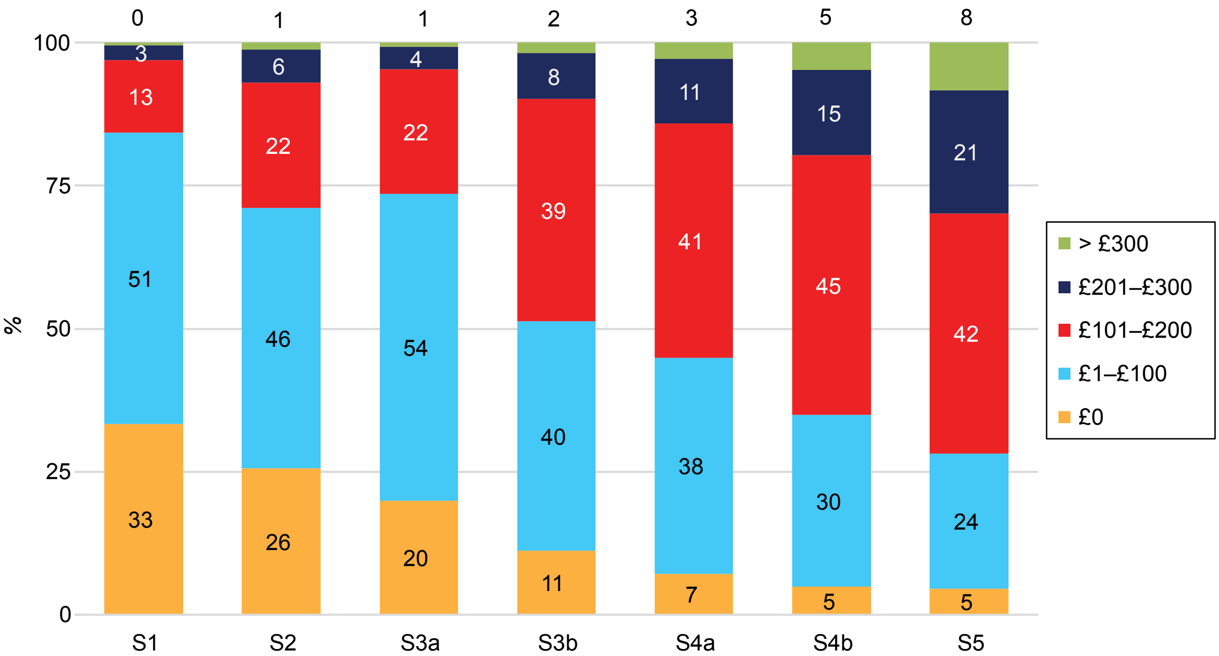
7.183 Moving from Scenario 1 to 5, the choice set becomes larger and the potential gains from switching increase. It should be noted that moving from prepayment to a different form of payment is not allowed in any scenario, given the difficulties and costs customers face in moving from a prepayment meter, as discussed at paragraph 7.76.[374]

Results

7.184 We calculated potential savings on the above basis over the period Q1 2012 to Q2 2014. The distribution of average annual savings for all of the dual fuel customers of the Six Large Energy Firms and for each scenario is set out in Figure 27. On average, all these customers could have gained £159 over this period (equivalent to 14% of the bill) under scenario 5 and £137 (equivalent to 12% of the bill) under scenario 4b.[375]

[373] See footnote 372.
[374] For further information setting out the data used and methodology applied, see Appendix 7.4: Analysis of the potential gains from switching.
[375] The reported average includes customers who could make no gains from switching.

Figure 7.27: Distribution of potential annual savings for dual fuel customers of the Six Large Energy Firms (average proportions across firms and quarters)



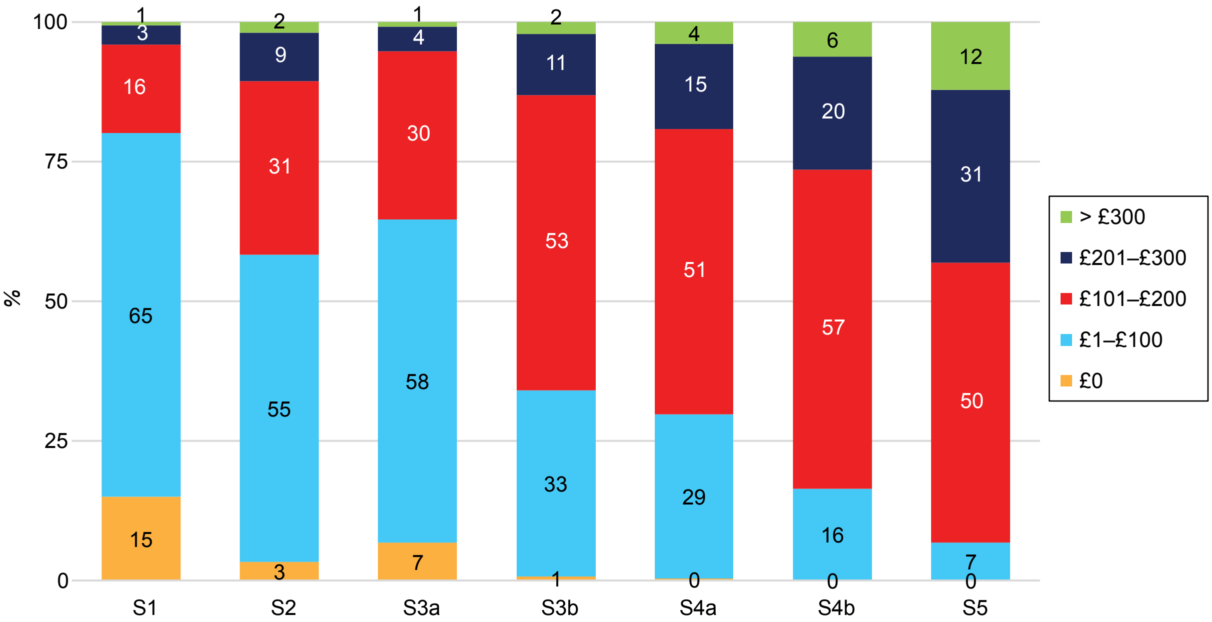
Source: CMA analysis.

7.185 The above results include some customers who have chosen to be on relatively expensive non-standard tariffs, which may have certain characteristics, such as longer-term fixed products. Because many customers on the SVT will not have actively chosen that tariff, we have a particular interest in the gains that could be made by these customers.

7.186 The dual fuel SVT customers of the Six Large Energy Firms could have gained an average of £171 a year over this period (equivalent to 15% of the bill) under scenario 5 and £143 (equivalent to 13% of the bill) under scenario 4b. The savings are somewhat higher than those for dual fuel customers on the SVT (savings equivalent to 12% of the bill under scenario 5 and 11% of the bill under scenario 4b).

7.187 The results for SVT customers include a relatively high number of customers on prepayment meters, for whom the gains from switching are more modest, reflecting the limited choice of tariffs they have. Average gains for prepayment SVT customers were the equivalent of 8% of a dual fuel bill under scenario 5. In contrast, the non-prepayment dual fuel SVT customers of the Six Large Energy Firms could have gained an average of £202 over this period (equivalent to 18% of the bill) under scenario 5 and £166 (equivalent to 14% of the bill) under scenario 4b. The distribution of these gains is shown in Figure 28.

Figure 7.28: Distribution of potential annual savings for dual fuel SVT customers (no pre-payment) of the Six Large Energy Firms



Source: CMA analysis.

7.188 For customers on single fuel tariffs, considering only the gains from switching from one single fuel tariff to another, we calculate that the single fuel electricity customers of the Six Large Energy Firms (across all tariffs and payment types) could have gained an average of £86 over this period (equivalent to 15% of the bill) under scenario 5 and £71 (equivalent to 13% of the bill) under scenario 4b. Gas customers could have saved an average of £107 over this period (equivalent to 18% of the bill) under scenario 5 and £88 (equivalent to 15% of the bill) under scenario 4b.

7.189 Bringing the above results together, Table 7.9 shows how gains from switching differ for customers on different tariff and payment types with the Six Large Energy Firms, under scenario 5 and scenario 4b.

Table 7.9: Average savings under scenario 5 for customers on different tariff and payment types Q1 20212 to Q2 2014

Dual or single fuel	*Tariff type*	*Payment type*	*% of total gas customers*	*% of total electricity customers*	*Average savings under S5, £*	*Average savings under S5, %*	*Average savings under S4b, £*	*Average savings under S4b, %*
Dual	Non-standard	All	30	25	137	12	124	11
Dual	SVT	DD	27	22	183	15	183	15
Dual	SVT	SC	13	11	232	22	139	14
Dual	SVT	Prepayment	11	10	69	8	69	8
Single gas	All	All	18	0	107	18	88	15
Single electricity	All	All	0	31	86	15	71	13

Source: CMA analysis.

7.190 The table shows that – considering the most liberal scenario 5 for switching– the savings relative to the bill are highest for standard credit SVT customers and single fuel (particularly single fuel gas) customers. The gains from switching for prepayment customers are relatively low, which reflects the restricted availability of tariffs for such customers.

7.191 We also note that there appears to be a rising trend in available savings and that the most recent 12 months, which appear to be characterised by a wider disparity in tariffs, is not included in the current analysis. We will include this period in updates to our analysis before publication of the final report.

Implications for the investigation

7.192 Our finding of material potential savings that are persistent over time, available to a significant number of domestic customers and that go unexploited, provides evidence of weak customer response in the domestic retail markets for electricity and gas in Great Britain. While gains from switching are likely to be present in most markets, we attach particular significance to the fact that they are available at such levels for domestic gas and electricity customers (which are homogenous goods and constitute a significant proportion of household expenditure).

7.193 In Section 8 we consider in greater detail to what extent we can infer from this analysis that customers are disengaged. In particular, we consider the merits of competing explanations for the gains from switching that go unexploited – namely that customers attach value to features of tariffs, suppliers and payment methods that are not reflected in our analysis.

7.194 Finally, we note that this analysis has focused purely on the implications of gains from switching for customer engagement. We consider the implications of this and other evidence for the likely level of competitive benchmark prices in Section 10.

Competition in the devolved nations and regional competition

7.195 In this section, we consider whether there are material differences in outcome between Scotland, Wales and England and between different regions within Great Britain, considering in particular evidence on customer activity and engagement, market shares and average prices.

7.196 Our survey suggests that there are some moderate differences in levels of activity and engagement between customers in Scotland, Wales and England. In general, we found that customers in Scotland and Wales were somewhat less likely to have been active in the market against the key indicators of engagement than those in England. For example, we found that:

(a) 40% of respondents in Scotland had never considered switching supplier compared with 33% in England;

(b) 65% of respondents in Wales had never shopped around compared with 58% in England;

(c) 63% of respondents in Scotland had never switched supplier compared with 55% in England; and

(d) in both Scotland and Wales, 49% of respondents said they were unlikely to consider switching supplier in the next three years compared with 40% in England.[376]

7.197 We also found that in Scotland and, in particular, Wales, customers were somewhat more likely to express satisfaction with their current supplier and to trust them. For example:

(a) in Wales, 71% of respondents said they trusted their own energy supplier compared with 61% in England;

(b) in Wales, 83% of respondents said they were satisfied with their energy supplier compared with 73% in England and 75% in Scotland (dual fuel customers only); and

(c) in Scotland and Wales, 61% and 68%, respectively, of respondents would recommend their supplier, compared with 56% in England (dual fuel customers only).[377]

7.198 A relatively high proportion of customers in both Scotland and Wales (29%) had been with their supplier for more than ten years (compared with 21% in England). Further, in Scotland and Wales, 65% and 61%, respectively, of respondents were with an incumbent supplier (for at least one fuel) compared with 53% in England.

7.199 Market concentration is higher in Scotland and Wales compared with the GB average, and lower in England, as shown in Table 7.10.

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[376] Appendix 16.
[377] Appendix 16.

Table 7.10: HHIs in Scotland, Wales and England for 2014

Area	*Electricity*	*Gas*
Great Britain	1,557	2,034
England	1,583	2,045
Wales	1,851	2,059
Scotland	2,272	2,281

Source: CMA analysis of data submitted by Cornwall Energy.
Note: HHI calculations are based on the shares of the Six Large Energy Firms.

7.200 We noted above that the two regions in Great Britain where the electricity incumbent has a market share of over 50% are North Scotland and South Wales, which, as of January 2015, had HHIs of 4,301 and 3,049 respectively, making them the two most concentrated regions in Great Britain.

7.201 The above results are consistent with higher degrees of incumbent brand loyalty in Scotland and Wales (and in particular North Scotland and South Wales). A further question we have considered is whether the higher concentration observed in these regions translates into higher prices and, more broadly, whether there are marked regional differences in prices across Great Britain.

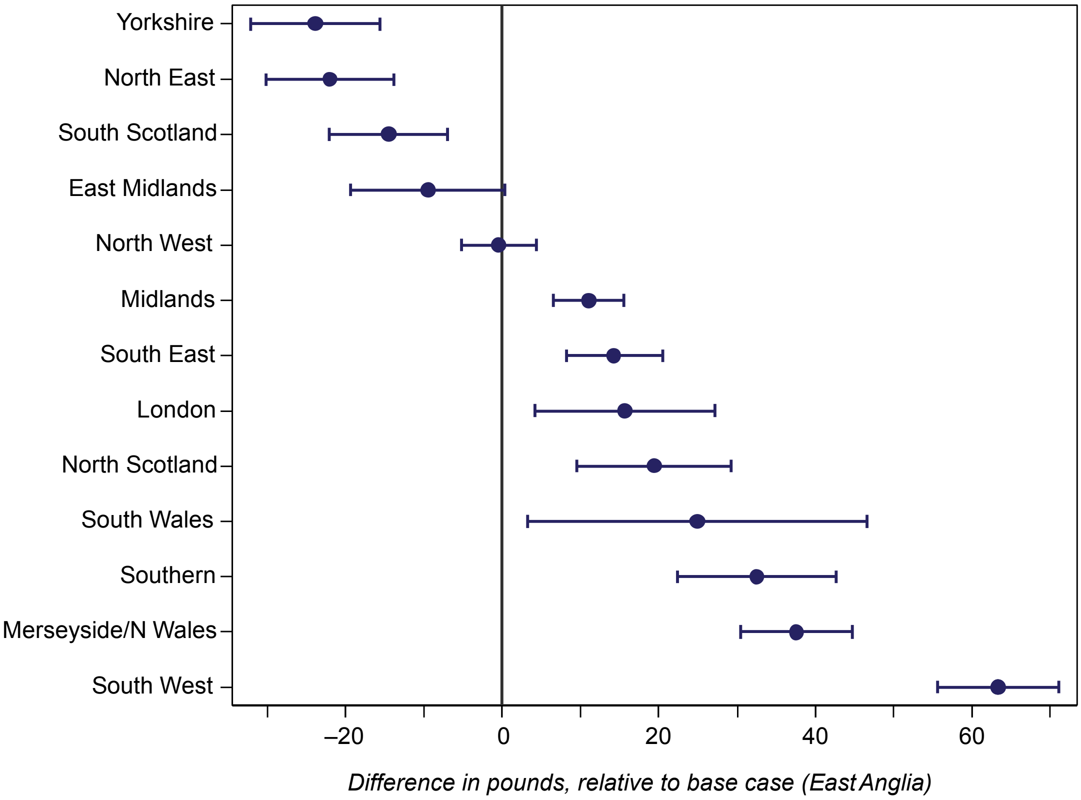
7.202 We have not been able to calculate robust regional average revenue figures for all suppliers due to data issues.[378] We intend to revisit this after the provisional findings. For the purpose of the provisional findings, we have analysed domestic bills using the regression analysis to control for a range of price drivers, including regional customer mix. This analysis is described in Appendix 10.7, and the main results are presented in section 10.

7.203 Using this analysis we have considered whether prices vary regionally after controlling for consumption levels and payment method mix. The dependent variable is an annual bill and the explanatory variables are the identity of the supplier; the level of annual consumption; payment method; whether the tariff is economy 7; and region.

7.204 Figure 7.29 presents the estimated difference in bills across regions controlling for supplier, consumption, payment method and economy 7 status relative to the base case region of East Anglia (ie the regional coefficients from the regression). For each region there is a point estimate (in pounds) and a 95% confidence interval around that estimate.

[378] Scottish Power were unable to provide a full regional disaggregation for revenue data and British Gas recently advised the CMA that their regional data would need to be resubmitted.

Figure 7.29: Differences across regions controlling for supplier, consumption, payment method, and economy 7 status



Source: CMA analysis of supplier data.
Notes:
1. Based on regression estimates for dual fuel customers.
2. The confidence intervals presented are 95% confidence intervals.
3. See Appendix 10.7: Domestic pricing analysis for further detail on the regression analysis.

7.205 The average bill in Yorkshire is the cheapest (about £25 cheaper than the base case region, East Anglia) though the 95% confidence intervals around that estimate overlap with those for the next three cheapest regions: the North East, South of Scotland and the East Midlands.

7.206 South West is the most expensive and by some margin – about £65 more expensive than the base case. The next most expensive region is Merseyside/North Wales with the difference of around £40 relative to the base case region.

7.207 The observed differences in regional bills, after controlling for the factors listed above, could be due to a range of factors, including regional gas and electricity distribution charges, but also regional competitive dynamics. We will explore those issues as part of our work on the final report.

7.208 Overall, our provisional view is that retail consumers in Scotland, Wales and England are likely to face a broadly similar range of issues, albeit with somewhat higher levels of disengagement in Scotland and Wales. We are aware, however, of two specific constraints relating to metering that are likely to affect customers in Scotland and Wales to a greater extent than customers in the rest of Great Britain.

7.209 First, we were told when we visited Scotland of the challenges imposed by Dynamic Teleswitched (DTS) meters, which are used to provide electric heating by homes off the mains gas grid. They are located almost entirely in three regions: North Scotland, South Scotland and the East Midlands. Ofgem research suggests that the level of market engagement among DTS customers is particularly low and that DTS customers face particular barriers to switching.[379] Further, incumbent suppliers have a particularly high market share of DTS customers in Scotland.[380]

7.210 Second, we have observed from our survey that there is a higher proportion of customers on prepayment meters in Wales (18% of respondents prepay) compared with England (11%).[381] We have noted in this section that prepayment customers generally pay more and have lower choice than customers on direct debit. We consider the specific nature of the constraints faced by prepayment customers in more detail in Section 8.

7.211 We have drawn on the preceding analysis in setting out our provisional views on market definition in Section 3.

Provisional conclusion

7.212 This section has analysed the nature of competition in domestic retail energy markets. We have identified three broad areas of concern.

7.213 The first relates to **inactive customers**. We have noted that there are various dimensions of activity, and that most customers have engaged with the market in some way since liberalisation. However:

(a) our survey suggests that around a third of domestic customers have never considered switching supplier;

(b) we have observed that around a third of domestic customers have been on the default tariff with their supplier for over five years; and

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[379] Report prepared for Ofgem (November 2014), *Understanding the consumer experience of dynamically teleswitched (DTS) meters and tariffs.*
[380] Ofgem (2013), *The state of the market for customers with dynamically teleswitched meters*.
[381] The corresponding results for Scotland and Great Britain are 15% and 12% respectively. The survey definition of prepayment customers is different from that used by DECC and in other CMA analysis. In particular, the survey definition does not include customers who receive gas and electricity from the same supplier and who prepay for one fuel but pay by another method (eg direct debit) for the other fuel. See Appendix 8.1, Annex C, for further detail on definitions.

(c) there are substantial gains from switching that currently go unexploited, which we consider to be particularly significant given the homogenous nature of gas and electricity.

7.214 The second relates to **supplier behaviour**. Suppliers charge substantially varying prices for each of electricity and gas with, in particular, significant divergence from a forward-looking industry-level benchmark of direct costs, which suggests they may have unilateral market power arising from having a significant proportion of inactive customers.

7.215 The third relates to **regulatory interventions**. We have observed that regulation has had a substantial impact on the nature of competition in retail domestic markets, including the prohibition on regional price discrimination and the RMR reforms.

7.216 In the next section, we analyse these three areas in greater detail, and present our provisional views on whether they lead to an AEC.

8. Domestic retail: weak customer response, supplier behaviour and regulations

Introduction

8.1 This section provides our analysis and provisional conclusions on whether any feature, or combination of features, of the domestic retail energy markets in Great Britain have an AEC. We consider the evidence on three areas where we expressed some concerns in the last section that domestic retail markets may not be working well for customers:

(a) **customer inactivity and lack of engagement** with domestic retail energy markets;

(b) **supplier behaviour**; and

(c) the **regulatory framework** governing retail market competition.

8.2 We consider each of these areas in turn and then present provisional conclusions on whether any of these areas leads us to provisionally find one or more features that, alone or in combination, give rise to one or more AECs.

Customer inactivity and lack of engagement

8.3 In Section 7, we identified domestic customer inactivity and lack of engagement as a potential source of competitive harm in the domestic retail energy markets. We noted that there are various dimensions of activity, and most domestic customers have engaged with the markets in some way since liberalisation, However:

(a) our survey suggests that around a third of domestic customers have never considered switching supplier;

(b) we have observed that around a third of SVT customers have been on the default tariff with their supplier for over five years; and

(c) perhaps most significantly, there are substantial gains from switching that currently go unexploited, which we consider to be particularly significant given the homogenous nature of gas and electricity.

8.4 The objective of this section is to consider whether the lack of customer engagement is such that there is inadequate competitive constraint on energy suppliers, leading to an AEC. It is structured as follows:

(a) First, we consider which types of customer are likely to be less engaged, drawing in particular on our customer survey.

(b) Second, we analyse the gains from switching analysis in more detail, considering whether there are alternative explanations for the gains that we observe that do not rely on lack of customer engagement.

(c) Third, we assess the likely barriers to engagement that customers face.

(d) Finally, we present our provisional conclusions.

Breakdown of engagement and activity by customer characteristics

8.5 The analysis set out in Section 7 suggests that customer engagement and activity is not a binary phenomenon: customers can be considered to be relatively engaged or disengaged along various different dimensions of choice, including choice of tariff; choice of payment type; and choice of supplier for one or both of their fuels. However, there is a degree of correlation between different dimensions of inactivity. For example, those on an SVT are more likely than those on non-standard tariffs: to be on a single fuel tariff; to pay by standard credit; and to be supplied by the historical incumbent.

8.6 The customer survey we conducted provides further evidence of the extent of customers' understanding of, and engagement in, domestic retail energy markets.[382] Notably:

(a) 34% of respondents said they had never considered switching supplier;

(b) 36% of respondents either did not think it was possible or did not know if it was possible to change one (or more) of the following: tariff; payment method or supplier;

(c) 56% of respondents said they had either never switched supplier, did not know it was possible or did not know if they had done so; and

(d) 72% said they had never switched tariff with an existing supplier, did not know it was possible, or did not know if they had done so.

8.7 In this section we use the survey results to consider how different measures of engagement vary with respondents' demographic characteristics, attitudes, features of their energy supply and preferences for particular attributes in suppliers.

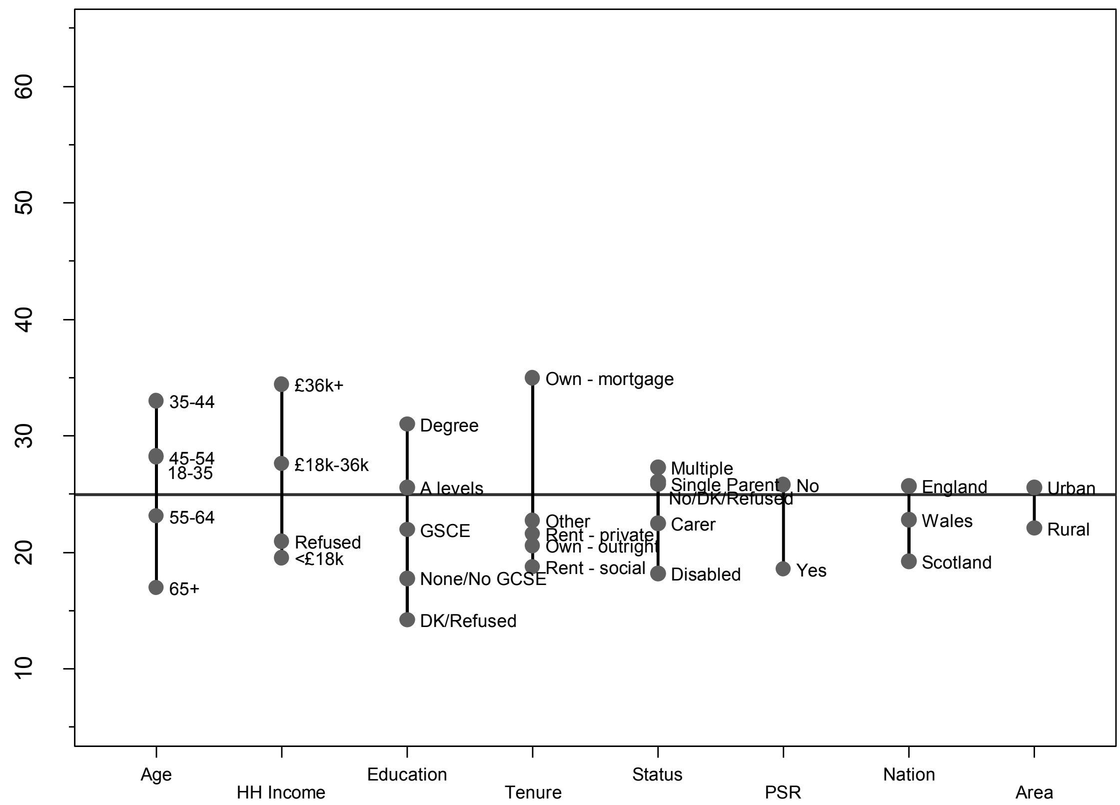
[382] Appendix 8.1: Customer survey, provides a detailed description of the results of the survey.

Summary of results

8.8 In Appendix 8.1 we show how several key indicators of engagement and activity differ by demographic and household characteristics. These indicators are whether the respondent has: ever considered switching; shopped around in the last three years; switched supplier in the last three years; switched tariff with their existing supplier; and is likely to consider switching in the next three years.

8.9 Figure 8.1 shows the results for one of these indicators – the proportion of respondents who switched supplier in the last three years – broken down by certain demographic and household characteristics.

Figure 8.1: Proportion of supplier switching in the last three years by demographic and household characteristics



Source: CMA analysis of survey and supplier data.
Note: Derived from responses to questions K1, K3, K4, K5, K6 and records provided by supplier. PSR indicates whether respondent is on the Priority Services Register. Those who were unable to respond to relevant questions (ie answered 'do not know') have been excluded.
Base: age 6901, income 6999, education 6665, tenure 6999, status 6999, PSR 6990, nation 6999, area 6976.

8.10 We find that the proportion of respondents who have switched supplier in the last three years is between 15% and 35% for different customer groups defined by their demographic and household characteristics, compared with 25% for all respondents (the horizontal line in this figure). We find that the groups of respondents who are less likely to have switched supplier in the last three years are those with any of the following characteristics:

household incomes under £18,000 a year; living in rented social housing; without qualifications; aged 65+; with a disability or registered on the PSR.[383]

8.11 For age, income, education and tenure, the differences are both statistically significant[384] and material. For example, 35% of those whose household incomes were above £36,000 had switched supplier in the last three years, compared with 20% of those whose household incomes were below £18,000. 32% of those with degree level qualifications had switched in the last three years compared with 18% of those with no qualifications.

8.12 Respondents with the characteristics described in paragraph 8.10 above are also more likely to have never considered switching and are less likely to have shopped around in the last three years, and are less likely to consider switching in the next three years. The degree of association between these measures of engagement and demographic characteristics is similar to that set out in Figure 8.1.

8.13 Of the indicators of engagement that we considered, the one that had the weakest association with these demographic characteristics was the proportion of respondents who had switched tariff with their existing supplier. We found that respondents aged 65+, those with a disability and/or those on the PSR are no more or less likely to have switched tariff with their existing supplier compared with all respondents.

8.14 We also found that there is an association between the demographic characteristics described in paragraph 8.10 above and being on a dual fuel or single fuel SVT.[385] We find that 68% of all respondents are on an SVT. The proportion of those on the SVT is higher among those who: live in social (83%) and private rented housing (76%); have no qualifications (73%); have household incomes below £18,000 (75%); and are disabled (74%). However, the proportion is lower (58%) among those on the PSR.[386]

8.15 One interpretation for this last result is that suppliers are proactive in encouraging vulnerable customers on the PSR to move to a more favourable tariff than the SVTs. This would also help explain our earlier observation that respondents aged 65+, those with a disability and/or those on the PSR are

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[383] Under their licences, suppliers and electricity distributors must maintain a 'Priority Services Register' and put consumers from certain eligible groups on the register when they request it. The eligible groups include people of pensionable age, disabled people and those who are chronically sick. Suppliers must offer non-financial help to these customers.

[384] Our approach to statistical significance is discussed in Appendix 8.1: Customer Survey, Annex C.

[385] As set out in Appendix 8.1, this excludes those who are on the SVT for one fuel and non-standard tariffs for the other.

[386] The proportion is also lower among those aged 65+ (64%). However, those aged over 65 comprise 30% of respondents but 68% of those on the PSR. For those over 65, the rate of SVT usage is 55% among those on the PSR and 68% for those not on the PSR, not significantly different from the average for all respondents.

no more or less likely to have switched tariff with their existing supplier compared with all respondents (ie their lower levels of engagement on other metrics are offset by suppliers proactively encouraging them to switch to a better tariff).

8.16 We found that three suppliers – EDF Energy, RWE and Centrica – took steps to encourage PSR customers to move on to more favourable tariffs. EDF Energy told us that during winter 2014/15 it contacted all its PSR customers to encourage them to contact an adviser to find out if it could offer them a cheaper tariff. EDF Energy said that, as a result of this and other activities[387], a higher proportion of its PSR customers were on fixed-term tariffs ([✄]%) compared with non-PSR customers ([✄]%). RWE said that when PSR customers contacted it, it might also offer information on alternative payment methods and tariffs and it had proactively contacted all customers in receipt of the Warm Home Discount, to inform them of alterative tariffs and promote the PSR.

8.17 Centrica said that it had a specialist team dedicated to supporting vulnerable customers (which will include those on the PSR) and that team would have discussions about more favourable tariffs and payment methods. Centrica also said that it worked with third parties and partners,[388] promoted the PSR and the Warm Homes Discount scheme and funded an independent charity (British Gas Energy Trust) that provided financial support (including advice on more favourable tariffs via the third parties associated with the scheme).

8.18 The other three of the Six Large Energy Firms did not take steps, specifically targeted at PSR customers, to encourage them to move to cheaper tariffs.[389]

8.19 The survey evidence also suggests that consumers living in social rented housing are less engaged. We will consider the possible reasons for this further following provisional findings, in particular the relationship between suppliers and the property industry and also housing associations.

8.20 In relation to payment method, we have considered the demographic characteristics of those who pay by prepayment. Some of the key results are set out in the figure below.

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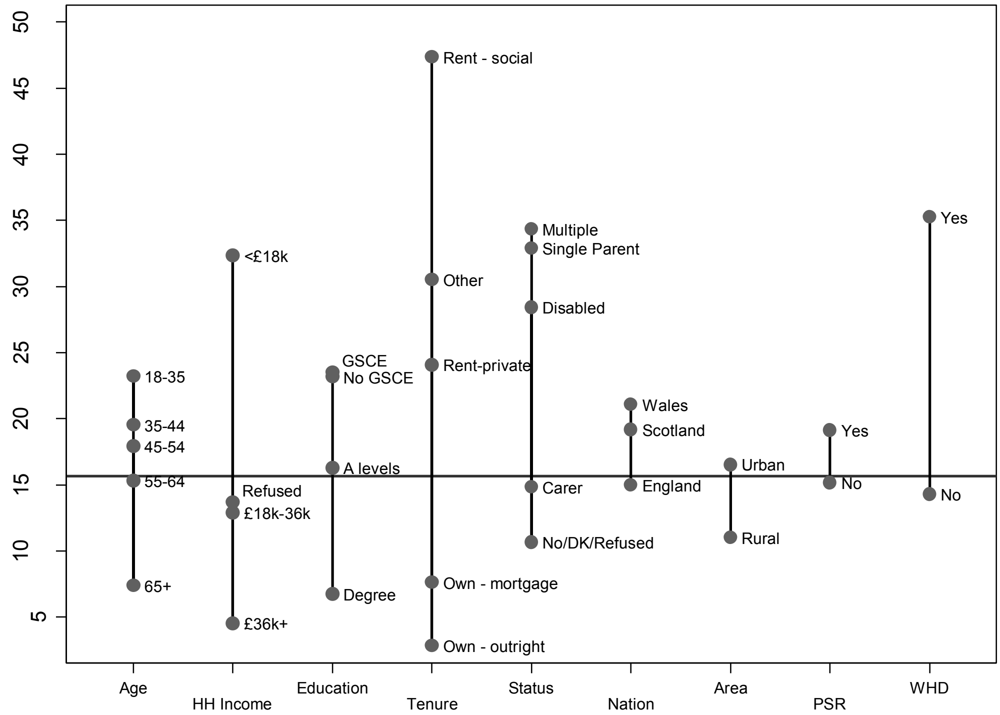
[387] EDF Energy's Personalised Support Service has been available to customers since the end of 2012.
[388] Including StepChange, Debt Advice Charity, Shelter, MacMillan, Islington Council, Foundations and the Scottish Government
[389] E.ON said that it discussed tariff options with customers calling in to E.ON if they indicated they had a concern around their ability to pay and would go through the choice of E.ON tariffs available (a process known as 'Best Deal For You') and enable the customer to choose the best tariff for their individual needs.

Figure 8.2: Proportion of customers who prepay for at least one fuel by demographics (the horizontal line is the proportion for all respondents to the relevant question)



Source: CMA analysis of survey data.
Note: Payment type info based on supplier data. See also notes in Figure 8.1.
Base = 6999 except for age (6901), education (6665), area (6976), PSR (6990) and WHD (6990).

8.21 Figure 8.2 shows that 16% of all respondents prepay for either gas or electricity or both. There are clear patterns between respondents' demographics and their likelihood of falling into this category. We find the proportion is highest among those respondents:

(a) aged 18–35 (23%);

(b) with household incomes below £18,000 (32%);

(c) whose highest qualification is a GSCE (24%) or below (23%);

(d) living in rented social housing (47%);

(e) who are single parents/guardians (36%);[390]

(f) who are disabled (29%);[391] or

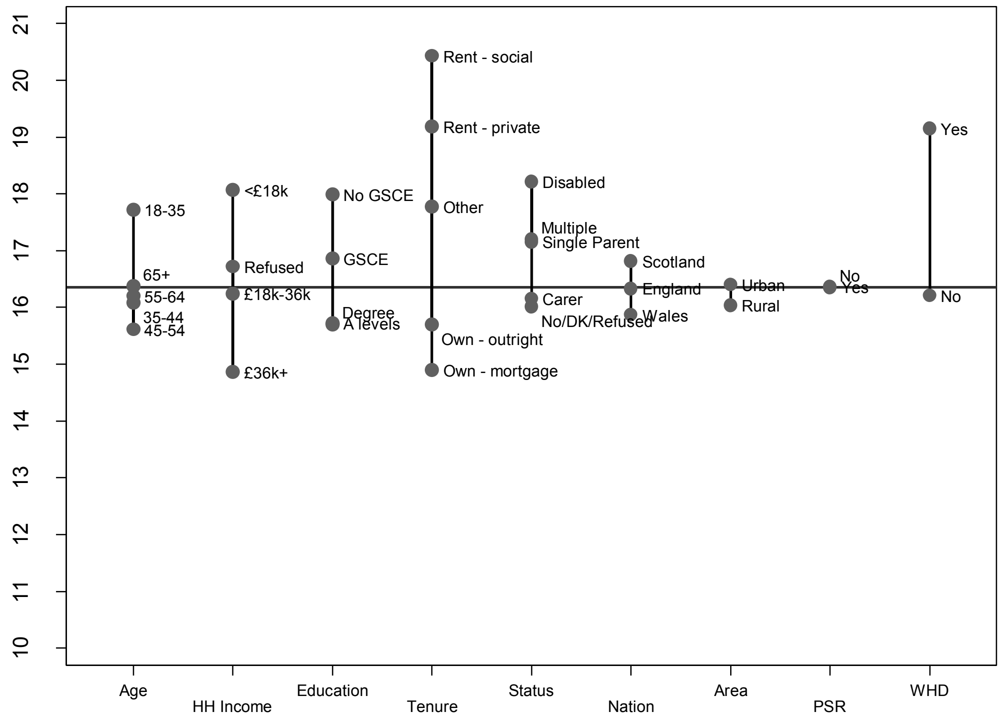
(g) who receive Warm Home Discounts (35%).

390 This includes customers who are also either disabled or carers. Figure 8.1 includes these respondents separately in the 'multiple' category.
391 This includes customers who are also either single parents/guardians or carers. Figure 8.2 includes these respondents separately in the 'multiple' category.

8.22 We note that our survey results suggest that prepayment customers are not more or less likely to have switched supplier in the last three years compared with all respondents. On other measures of engagement, however, those who prepay appear to be less engaged. They are less likely to have shopped around (25% compared with 37% of all respondents), switched tariff with their existing supplier (16% compared with 29% of all respondents), to consider switching supplier in the next three years (31% compared with 46% of all respondents), and more likely to have not considered switching supplier in the past (45% compared with 33% of all respondents).

8.23 We also assessed to what extent the gains from switching were associated with demographic characteristics. We noted in Section 7 that prepayment customers face a very restricted range of tariffs – and hence lower gains from switching. We have therefore calculated the relationship between gains from switching and demographic characteristics for dual fuel customers excluding prepayment customers. The results are shown in the figure below, for scenario 5 (in which customers can change supplier, tariff and payment method).

Figure 8.3: Scenario 5 – Demographics (dual fuel customers with gains available from switching), excluding those who prepay for either fuel



Source: CMA analysis of supplier and survey data.
Note: See note in Figure 8.1. Bases= 3820, 3868, 3691, 3868, 3868, 3868, 3865, 3868, 3868.

8.24 There are statistically significant differences in savings against various demographic characteristics including household income and tenure. The greatest difference is by tenure type with gains of 20% of the bill for those in social rented housing and 19% of the bill for those in private rented housing compared with 16% for those who own their homes outright and 15% for those who have a mortgage on their home. There is also a statistically significant difference between the gains available to those on incomes below £18,000 (18% of the bill) and those on more than £36,000 (15% of the bill) and between the gains available to those who received the Warm Home Discount (19%) compared with those who do not (16%).

8.25 Overall, we find that, excluding prepayment customers, those households who are: in rented accommodation; have incomes below £18,000; or in receipt of a Warm Home Discount rebate[392] have higher gains from switching. By implication, such customers are on average paying a somewhat higher price for their energy than those customers who do not fall into these categories.

Provisional conclusion

8.26 The survey results suggest that there is a material percentage of customers who are disengaged in the domestic retail energy markets. The survey results also suggest that, in particular, those who have low incomes, have low qualifications, are living in rented accommodation – particularly social rented housing – or who are above 65 are less likely to be engaged in the domestic retail energy markets against a variety of indicators of engagement.

8.27 We observe that the disengaged are not limited to these demographic groups: there are many households who are disengaged who do not fall into these categories. We also note the comments of parties on this. For example:

(a) EDF Energy said that while there were some significant correlations between 'never switched' groups and some of the characteristics that could contribute to vulnerability (eg age), it was not correct simply to equate the concepts.[393]

(b) E.ON said that it recognised that there might be a more vulnerable segment of customers who tended not to switch and hence were more likely to be on an SVT, but that competition to retain those on an SVT

[392] As noted in Section 2, those on the Guarantee Credit element of Pension Credit receive automatic Warm Home Discount rebates. Energy companies can set their own rules about which other vulnerable groups can apply for a rebate, typically those on means-tested benefits with young children or a disabled member.
[393] EDF Energy response to the updated issues statement, paragraph 19.1.

who have switched in the past and would or may do so again in the future provided protection to those who were vulnerable and perhaps less active.[394]

8.28 However, we consider these results to be important, as they help to shed some light on the possible reasons for inactivity and lack of engagement in the markets. Had we found that it was generally higher-income households who did not engage, we might have concluded that saving money through switching was of relatively low importance to them.

8.29 The fact that this is not the case – indeed, there appears to be a higher proportion of households on lower incomes who are disengaged and inactive – makes the above hypothesis more difficult to sustain, particularly given the fact that, as discussed in Section 7, expenditure on energy constitutes a high proportion of the total expenditure for the poorest households.

Interpretation of the evidence on gains from switching

8.30 As set out in Section 7 and Appendix 7.4, we estimate that there were significant gains from switching that went unexploited by domestic energy customers over the period Q1 2012 to Q2 2014. We calculated the savings available from the key different dimensions of choice – choice of tariff type;[395] choice of payment method; and choice of supplier, for one or both of electricity and gas – considering a number of scenarios, which differ according to the extent to which they restrict the choices available to customers.[396]

8.31 The scenarios are:

(a) Scenario 1: Change tariff type but keep supplier and payment method.

(b) Scenario 2: Change tariff type and payment method (except for prepayment customers) but keep supplier.

(c) Scenario 3a: Change supplier (only to one of the Six Large Energy Firms) but keep tariff type[397] and payment method.

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[394] E.ON response to the updated issues statement, paragraph 14.
[395] By choice of tariff type we mean tariff structure (variable, fixed and capped), contract length (in case of fixed tariffs) and preference for online/offline tariffs.
[396] See Appendix: 7.4: Analysis from the potential gains from switching for a full description of the parameters that can be changed/held fixed when switching.
[397] We note that customers can switch to offline/online tariffs.

(d) Scenario 3b Change supplier (to one of the Six Large Energy Firms or mid-tier suppliers) but keep tariff type[398] and payment method.

(e) Scenario 4a: Change supplier, tariff type and payment method (except for prepayment customers) but restrict online tariffs to those currently on online tariffs.

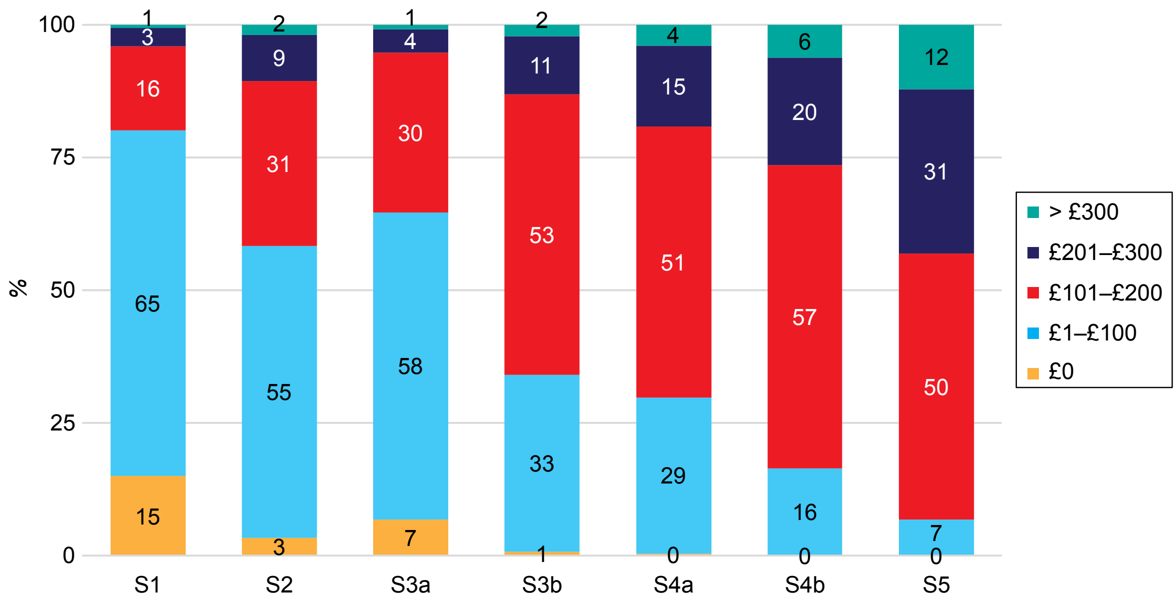
(f) Scenario 4b: Change supplier and tariff type but keep payment method.

(g) Scenario 5: Change supplier, tariff type and payment method (except for prepayment customers).

Summary of analysis

8.32 Moving from scenario 1 to 5, the choice set becomes larger and the potential gains from switching increase, as shown in the chart below, which shows the distribution of results for the dual fuel customers of the Six Large Energy Firms currently on an SVT, paying by either standard credit or direct debit. 43% of these customers could have gained over £200 under scenario 5 (in which they are allowed to change tariff type, payment type and supplier) while only 4% of these customers could have gained over £200 under scenario 1 (in which they are allowed to change only tariff type, but not payment method or supplier).

Figure 8.4: Distribution of potential annual savings for dual fuel SVT customers (no pre-payment) of the Six Large Energy Firms



Source: CMA analysis.

398 See footnote 397.

8.33 We also found that the gains available differed significantly for customers on different tariff and payment types with the Six Large Energy Firms. This is shown in the table below for scenario 5 (the most liberal scenario for switching) and 4b (in which customers can switch tariff and supplier but not payment method).

Table 8.1: Average savings under scenarios 5 and 4b for customers on different tariff and payment types Q1 2012 to Q2 2014

Dual or single fuel	*Tariff type*	*Payment type*	*% of total gas customers*	*% of total electricity customers*	*Average savings under S5, £*	*Average savings under S5, %*	*Average savings under S4b, £*	*Average savings under S4b, %*
Dual	Non-standard	All	31	26	137	12	124	11
Dual	SVT	DD	26	22	183	15	183	15
Dual	SVT	SC	13	11	232	22	139	14
Dual	SVT	Prepayment	11	10	69	8	69	8
Single gas	All	All	18	0	107	18	88	15
Single electricity	All	All	0	31	86	15	71	13

Source: CMA analysis.

8.34 The table shows that – considering the most liberal scenario (scenario 5) for switching – average savings relative to the bill are highest for dual fuel standard credit SVT customers and single fuel (particularly single fuel gas) customers. They are lowest for prepayment customers, reflecting the restricted availability of tariffs for such customers. The table also shows – comparing the results for scenarios 4b and 5 – that savings are higher for standard credit SVT customers, as compared to direct debit SVT customers, because of their choice of payment method.

Response of parties

8.35 We noted in Section 7 that this finding – of material potential savings that are persistent over time, available to a significant number of domestic customers and that go unexploited –provides evidence of weak customer engagement in the domestic retail markets for electricity and gas in Great Britain.

8.36 However, in response to similar analysis that we published alongside our updated issues statement,[399] several of the Six Large Energy Firms argued that there are competing explanations for gains from switching that go unexploited – namely that customers attach value to features of tariffs, suppliers and payment methods that are not reflected in our analysis.[400]

[399] See Gains from switching working paper (24 February 2015).
[400] Centrica, EDF Energy, RWE, SSE and Scottish Power argued that our scenarios, and in particular the most flexible scenario S5, do not sufficiently account for customers' preferences for a number of tariff characteristics, and therefore overstate the potential gains from switching.

According to these arguments, a failure to switch to exploit financial gains is not necessarily an indication of a lack of engagement, but may be an active choice, taking into account non-price characteristics.

8.37 Since publishing the working paper we have refined the methodology as explained in the appendix. We note here that we have: limited the available tariffs to those offered by the Six Large Energy Firms[401] and the mid-tier suppliers; and estimated the gains using data on the distribution of energy consumption by 'families' of tariffs.

8.38 Regarding the decision to restrict available tariffs to those offered by the Six Large Energy Firms and the mid-tier suppliers, several parties argued that some of the switches that we modelled were not plausible since they had restrictive conditions (for example, requiring advanced payment, or online only) attached to them which means that most customers would not be able to switch to them in practice. We reviewed these tariffs and agreed that some appeared to have relatively restrictive conditions (eg requiring large upfront payments). They tended to be offered by smaller suppliers and, to be conservative, we excluded all such smaller suppliers from our analysis of gains from switching. We note that this is a conservative assumption, involving the exclusion of 16 suppliers, many of the tariffs offered by whom did not have such restrictive conditions. Accordingly, the results presented in this document may somewhat understate the financial gains available.

8.39 In Appendix 7.4, we set out our detailed response to parties' comments, and we consider here one set of comments made that raise important points of interpretation. Parties have argued that our results overstate potential savings by in effect, assuming that domestic customers should switch every quarter to whichever supplier is offering the best deal for them at the time.

8.40 We consider that this is a misinterpretation of the analytical exercise we have undertaken and of the conclusions we have drawn from the results. We consider that the estimates of gains from switching show that a consistently large proportion of domestic customers could make substantial savings if they were to engage in the markets and take advantage of the choices available to them. We calculate these gains at regular intervals over the period Q1 2012 to Q2 2014 and present results averaging over this period to help ensure that the results are not sensitive to the market conditions prevailing in a particular quarter.

[401] We have also the included the white-label suppliers of the Six Large Energy Firms, which are Sainsbury's Energy (Centrica) and Ebico and Marks and Spencer (SSE).

8.41 In the rest of this section, we assess the merit of the arguments put to us by the Six Large Energy Firms concerning other elements of the interpretation of the analysis, namely, that the gains from switching evidence does not indicate that there is a problem relating to inactive customers since it does not consider non-price characteristics (relating to tariff type, payment method or choice of supplier) that customers might be expected to take into account in deciding whether to switch or not. We consider first non-price characteristics relating to tariff type, then payment method and finally supplier.

Tariff characteristics

8.42 As noted in Section 7, the most important tariff characteristic for customers is likely to be the price (in p/kWh).[402] However, tariffs also have other aspects that customers may value, notably in relation to risk and the extent to which they insulate customers from price volatility. We consider first the characteristics of non-standard tariffs and then the SVTs.

- *Non-standard tariffs*

8.43 As can be seen in Table 8.1 above, while the gains for those on non-standard tariffs are substantially below those on SVTs[403], there were still appreciable gains to be made for those on non-standard tariffs – equivalent to an average 12% of the bill over the period we reviewed for scenario 5.

8.44 Such customers have actively chosen their tariffs, which may in part be because of their attractive risk properties. Most non-standard tariffs are, post-RMR reforms, fixed-term, fixed-price tariffs, which offer a degree of insulation from price risk.[404] The tables below show, for the total gas and electricity fixed-term, fixed-rate tariff customer base of the Six Large Energy Firms as of Q2 2014, the product term at launch.[405]

[402] We express this as an average because, in the presence of standing and variable charges, the actual price that a customer pays will be a function of his or her consumption, which is not known exactly in advance.
[403] Excluding SVT prepayment customers, for whom the gains from switching are considerably lower, as discussed in more detail below.
[404] There are some fixed-term tariffs (for example, British Gas's Fix and Fall tariffs) which allow for the tariff to be reduced if the supplier reduces its SVT.
[405] Fixed tariffs have either a fixed termination date (regardless of when the customer subscribed) or fixed duration of the contract that takes effect from the time the customer subscribes to the tariff. For tariffs with the former type of contract, we calculated the contract length as the difference, in months, between the date the tariff was first introduced and the date the contract terminates. For tariffs which were available for a long period of time before being withdrawn, this may overestimate the actual length of the contract.

Table 8.2: Tenor of fixed rate gas tariffs in Q2 2014, by supplier and customer shares

Firm	*Total*	*With term at launch 1 year %*	*Term at launch 1–2 years %*	*Term at launch of more than 2 years %*
Centrica	[✂]	[✂]	[✂]	[✂]
EDF Energy	[✂]	[✂]	[✂]	[✂]
E.ON	[✂]	[✂]	[✂]	[✂]
RWE npower	[✂]	[✂]	[✂]	[✂]
Scottish Power	[✂]	[✂]	[✂]	[✂]
SSE	[✂]	[✂]	[✂]	[✂]
Six Large Energy Firm average		[✂]	[✂]	[✂]

Source: CMA analysis.

Table 8.3: Tenor of fixed rate electricity tariffs in Q2 2014, by supplier and customer shares

Firm	*Total*	*With term at launch 1 year %*	*Term at launch 1–2 years %*	*Term at launch of more than 2 years %*
Centrica	[✂]	[✂]	[✂]	[✂]
EDF Energy	[✂]	[✂]	[✂]	[✂]
E.ON	[✂]	[✂]	[✂]	[✂]
RWE npower	[✂]	[✂]	[✂]	[✂]
Scottish Power	[✂]	[✂]	[✂]	[✂]
SSE	[✂]	[✂]	[✂]	[✂]
Six Large Energy Firm average		[✂]	[✂]	[✂]

Source: CMA analysis.

8.45 The evidence shows that, while practice differs between the Six Large Energy Firms, overall about three-quarters of fixed-term tariffs were of between one and two years length, with around a quarter of fixed-term tariffs of over two years length.

8.46 The extent to which consumers have been willing to pay more for some of these tariffs due to the lower price risk associated with them is very hard to identify from the current market. As discussed in Section 7, when suppliers offered both variable-rate and fixed-rate contracts, generally the fixed-rate tariffs were more expensive, at launch, than the variable-rate tariffs. However, as just seen, the fixed-rate tariffs that customers are currently on are by and large of a relatively short duration. The largest additional risk benefit (which might justify some customers paying a premium) is therefore likely to be fixing prices for three years as opposed to one year.

8.47 Overall, we think it is likely that some customers on non-standard tariffs over the period have opted for more expensive tariffs because of their perceived beneficial risk properties. However, this does not explain the majority of the gains from switching for such customers – gains for non-standard customers under scenario 3b (which reflects the gains from switching to a different supplier, but keeping the same tariff and payment type) are still £79 or 7% of the bill (as compared with £137 under scenario 5). This suggests that, while active in the sense of having chosen a tariff, some customers may not be fully engaged in the sense of having fully considered the option of switching supplier.

- *Standard variable tariffs*

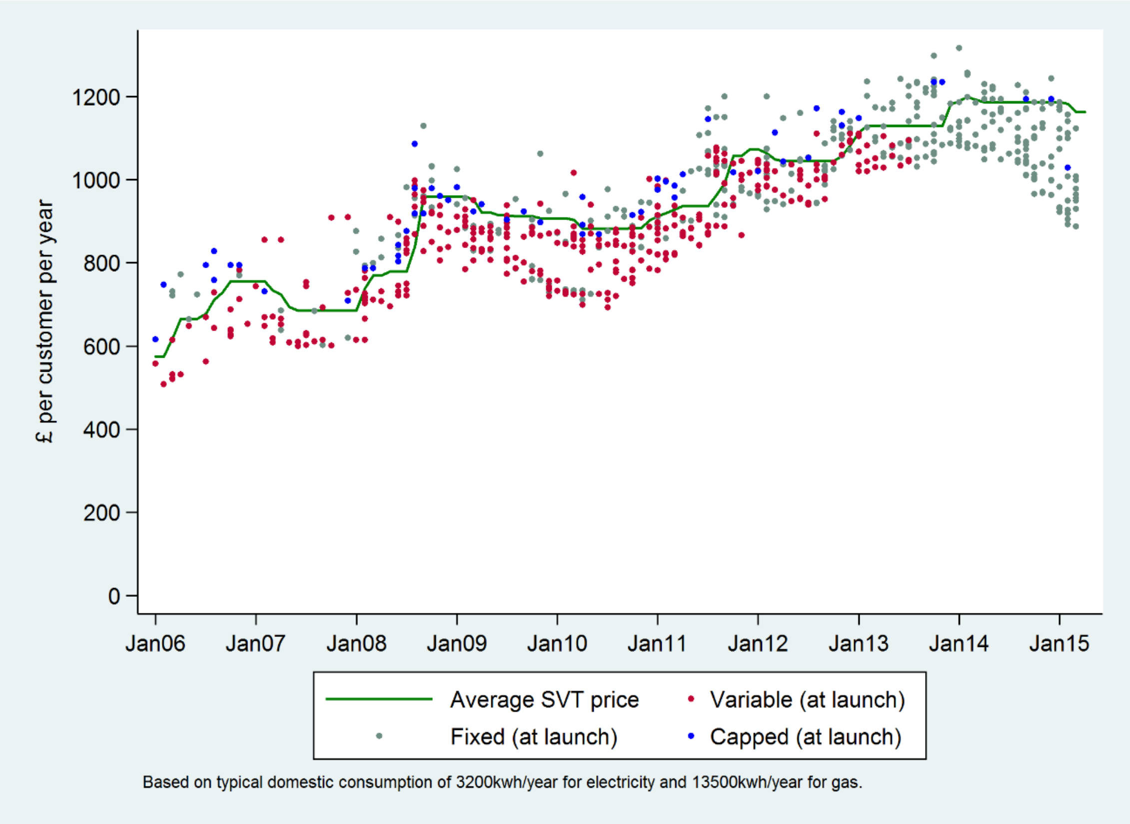
8.48 We noted in Section 7 that an SVT is a default tariff. Unlike non-standard tariffs, relatively few customers outside of prepayment customers currently make an active choice to move onto an SVT.[406] However, it is still possible in principle that customers are choosing not to switch from an SVT because of beneficial non-price attributes that it has.

8.49 Centrica suggested to us that customers valued an SVT because it offered the customer lower volatility than being on a fixed tariff and E.ON that customers valued suppliers hedging wholesale costs because it offered the customer lower volatility than being exposed to the wholesale market. We do not find this a plausible argument. As noted above, fixed-price fixed-term tariffs offer beneficial risk properties, as they fix the price for a fixed period, unlike the SVTs, which move on average once or twice a year.

8.50 If a customer were to adopt a simple strategy of buying the market's cheapest fixed tariff and then switching at the end of the term to the market's cheapest fixed tariff prevailing at that time, there would be no volatility within the term of the tariff, but potentially a significant jump (up or down) at the end of the tariff's term. However, as shown in the chart below, even if this strategy does result in increased volatility, this is only because the SVTs are consistently and substantially more expensive than the cheapest fixed tariffs.

[406] We noted that, while [✄] still have [✄] proportions of non-prepayment SVT acquisitions, [✄].

Figure 8.5: Tariffs offered by the Six Large Energy Firms and mid-tier suppliers, 2006 to 2015



Source: CMA.

8.51 A separate attribute that an SVT has that some customers may value is the fact that there are no exit fees for leaving an SVT. It may therefore be attractive to customers who want to avoid feeling locked in to a tariff.

8.52 We have found that, on average, over the period Q1 2012 to Q2 2014, around 50% of customers on fixed-term tariffs were on tariffs with exit fees, typically of around £10 to £30 per fuel. However, exit fees do not currently apply to the non-standard tariffs of [✂].[407,408] This suggests that substantial gains would still be available to customers on an SVT even if they wished to avoid exit fees.[409]

Payment method

8.53 Payment method is a further potential dimension of choice to which customers may assign value. As noted in Section 7, paying by direct debit offers greater convenience to the customer than paying by standard credit.

[407] With the exception of RWE npower's In Control tariff, which provides a Nest Learning Thermostat.
[408] Paragraph 8.63 discusses what we mean by cheap in this context.
[409] We also note that such exit fees are often waived in practice – although this is perhaps unlikely to affect customers' preferences in advance. See Appendix 7.4: Analysis from the potential gains from switching.

8.54 A particular question of relevance to this investigation is whether those customers who have not switched from standard credit to direct debit should be considered inactive or whether, conversely, this represents an active choice on the part of customers to pay by standard credit (for example, to have greater visibility of the payments they are making and flexibility over timing), notwithstanding the convenience and cost benefits of direct debit.

8.55 We noted in Section 7 that those who pay by standard credit are more likely to be with the incumbent gas and electricity supplier than those who pay by direct debit, which suggests that they may have a greater propensity to be inactive than those who pay by direct debit. We also note from our survey that paying by direct debit rather than standard credit is associated with other indicators of engagement. For example, 30% of customers paying by direct debit switched supplier in the last three years, while only 15% of customers paying by standard credit switched supplier in the last three years.

8.56 Overall, the evidence suggests that a proportion of customers who pay by standard credit may not have made an active decision to do so. However, we also note that some customers who currently pay by standard credit may do so because they value the flexibility over the timing of payments it affords them. Overall, therefore, we think scenarios 5 and 4b are both relevant as potential indicators of the lack of engagement implied by our gains from switching analysis.

8.57 Prepayment is not generally a choice on the part of the customer: all customers with prepayment meters are only able to pay by prepayment. Prepayment meters are generally initially installed where a customer has a poor payment history or in specific types of accommodation such as holiday homes and student accommodation.

8.58 The gains from switching are much smaller for prepayment customers than for other customers and in Section 7 we explore the barriers to engagement that prepayment customers are likely to face.

Quality of service offered by different suppliers

8.59 The quality of customer service offered by different suppliers may also be a characteristic to which customers assign value. To the extent to which they do, then the total gains from switching (including non-monetary benefits) may differ from those presented in our analysis, and could be either higher or lower.[410]

8.60 To investigate this hypothesis we considered whether there was any evidence that those suppliers that offered the cheapest tariffs (and hence were primarily responsible for the gains from switching results) offered particularly poor (or good) quality of service.

8.61 [✂]

Table 8.4: Suppliers offering the best deal to dual fuel customers (simple average across quarters)*

%

	RWE	*SSE*	*EDF Energy*	*First Utility*	*Ebico*	*Co-op Energy*	*Centrica*	*Scottish Power*	*Ovo Energy*	*E.ON*	*Other*
S4b	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]
S5	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]

Source: CMA analysis.
*The average includes all quarters including those quarters where suppliers might have not offered the cheapest deal.

8.62 [✂]

8.63 [✂] Overall, against all measures, the mid-tier suppliers look relatively cheap, in particular [✂].

8.64 There is limited evidence on quality of service by which we could test this hypothesis. However, most of the Six Large Energy Firms regularly collect data on what is called the net promoter score (NPS), both for themselves and for their competitors.[411] This is a standardised measure of customer loyalty that ranges between –100 (all your customers are detractors) and 100 (all your customers are promoters). Several of the Six Large Energy Firms told us that they used the NPS for benchmarking their performance relative to their competitors and for internal performance management, as it was a better discriminator than traditional customer satisfaction surveys.

8.65 We reviewed the NPS data collected by Centrica, EDF Energy, E.ON and RWE. Although covering different time periods and collected by different companies, the results were broadly consistent. An example, using data collected by EDF Energy, is shown in the chart below.

[410] The quality of service offered by a particular supplier cannot be a factor explaining differences in the tariffs offered by that supplier to different customers.
[411] Customers are asked 'How likely is it that you would recommend [the company] to a friend or colleague on a scale of 1–10, with 10 being the most likely?' The NPS is the percentage of customers who gave a response of 9 or 10 minus the percentage who gave a score of 1–6.

Figure 8.6: Net promotor scores of the Six Large Energy Firms and the small suppliers, 2011 to 2015

[✂]

Source: [✂]

8.66 Two trends are clear. First, the smaller suppliers have consistently higher NPS than the Six Large Energy Firms. This was true of all the data we reviewed, including one survey that produced results for individual mid-tier suppliers, each of which performed better than the Six Large Energy Firms. The second observation is [✂].

8.67 We see no clear relationship between the cheapest supplier and customer service, as proxied by the NPS score. [✂]

8.68 Overall, we have seen no evidence to suggest that we have systematically overstated the (financial and non-financial) gains from switching by not taking into account differences in customer service. Nor have we received any evidence from the Six Large Energy Firms to suggest that this might be the case.

Provisional conclusion

8.69 Overall we have not seen evidence that we have significantly overstated the gains from switching in our analysis.

8.70 In relation to customers on non-standard tariffs, we note that they have actively chosen their tariff, and that some non-standard tariffs have risk properties that might warrant a level of premium. However, this does not explain the majority of the gains from switching for such customers. This may suggest that, while active in the sense of having chosen a tariff, some customers may not be fully engaged in the sense of having fully considered the option of switching supplier.

8.71 While there may be a degree of disengagement in the behaviour of customers on the non-standard tariff, we are more concerned about levels of engagement from those customers who are currently on an SVT, as most of these customers have not actively chosen this tariff, and the potential gains from switching for these customers is considerably higher. We have not seen any characteristics of an SVT to which customers might attach substantial value.

8.72 On choice of supplier, we have seen no evidence to suggest that suppliers offering the cheapest tariffs have worse quality of service than those offering more expensive tariffs.

8.73 Finally, in relation to payment methods, the evidence suggests that a proportion of customers who pay by standard credit are not likely to have made an active decision to do so. It is plausible, however, that there are others who have an active preference for paying by standard credit, and are likely to assign some value to this payment method. Overall, therefore, we think scenarios 4b and 5 are both relevant as potential indicators of the extent of lack of engagement implied by our gains from switching analysis.

8.74 Our finding of material potential savings that are persistent over time, available to a significant number of domestic customers and that go unexploited provides evidence of weak customer engagement in the domestic retail markets for electricity and gas in Great Britain. While gains from switching are likely to be present in most markets, we attach particular significance to the fact that they are available at such levels for gas and electricity (which are homogenous goods and constitute a significant proportion of household expenditure).

Barriers to engagement

8.75 In this section we consider the barriers to engagement that customers are likely to face in domestic retail energy markets. The figure below sets out a simplified schematic of the different stages of engagement and the barriers that are likely to inhibit or restrict engagement at each stage. The figure focuses on the stages of engagement and barriers relating to the choice of whether or not to switch supplier.[412]

[412] The fundamental barriers relevant to stage 1 – which are likely to affect whether customers are aware of their ability to switch or have ever considered switching – are also likely to be relevant for choice of tariff and choice of payment method.

Figure 8.7: Stages of engagement and barriers to engagement in domestic retail energy markets

Stages of and barriers to engagement

	Stage of engagement	Barrier to engagement
1	Awareness of ability to switch Consider switching	Fundamental characteristics of energy consumption, homogeneity and traditional meters
2	Access information Assess information	Non-use of internet; Non-use of PCWs / TPIs Complexity; Non-use of PCWs / TPIs
3	Act on information	Actual barriers to switching; Perceived barriers to switching Constraints for prepayment customers (low benefits from switching)
4	Fully engaged	

8.76 The schematic provides a simplified framework for understanding the nature of consumer choice and engagement. Customers in stage 1 are either not aware that they can switch or have never considered switching. Customers in stage 2 have considered switching but have difficulty either in accessing information on choices or in assessing it. Customers in stage 3 are able to shop around but choose not to act on this as a result of real or perceived barriers to switching. Customers in stage 4 can be considered to be fully engaged in that they shop around and act on the basis of this, not experiencing any material barriers to engagement.

8.77 A particular concern that we have identified in this investigation is the number of customers who appear to be in stage 1. We have observed that there are material numbers of customers who appear to be fundamentally disengaged from the domestic retail energy markets in the sense that they are either not aware of their ability to exercise choice in the markets or have not considered exercising choice in the markets. We note in particular that:

(a) 34% of respondents said they had never considered switching supplier;

(b) 36% of respondents either did not think it was possible or did not know if it was possible to change one (or more) of the following: tariff; payment method or supplier;[413] and

(c) 56% of respondents said they had either never switched supplier, did not know it was possible or did not know if they had done so.

8.78 An important question for this investigation is to understand why so many customers appear to be in stage 1. We note that, of those respondents who had never considered switching tariff, 41% said that they were satisfied with their existing tariff. Similarly, for those respondents who had never considered switching supplier, 41% said that they were satisfied with their existing supplier. However, this expression of satisfaction is unlikely to be based on an understanding of the alternatives available to them – because these respondents had not considered switching or shopped around.

8.79 Indeed, we find that the gains to be had from switching are materially higher for those respondents who have not engaged. We find average gains (for those who can gain from switching) of 17% of their bill for those who have not considered switching or never switched compared with average gains of 12% for those who have switched in the last three years and 11% for those

[413] As explained in Appendix 8.1: Customer Survey, 11% did not think or did not know if it is possible to switch supplier, 19% did not think or did not know if it is possible to change payment method, 24% did not think or did not know if it is possible to change tariff and 36% did not think or did not know if it is possible to change at least one of these.

who switched in the last year, under scenario 5. When those who pre-pay for either fuel or are on the PSR are excluded, the average gains available for those who could have gained under scenario 5 are 19% for those who have never considered switching and 15% for those who have considered switching supplier.

8.80 In summary, the survey evidence suggests that there are material numbers of customers who do not move beyond stage 1 – ie do not consider switching supplier or tariff. We also found that those who have engaged less tend to pay higher prices on average.

8.81 The rest of this section is structured as follows:

(a) First, we consider two fundamental characteristics of energy consumption that are likely to mean **customers have limited awareness of and interest in their ability to switch** energy supplier: the homogenous nature of gas and electricity; and the role of traditional meters and bills.

(b) Second, we consider **actual and/or perceived barriers to accessing and assessing information**, including the difficulties domestic customers may encounter in understanding and searching for the right deal including the complex information provided in bills, the structure of the tariffs, and the potential role of TPIs in overcoming or adding to such barriers.

(c) Third, we consider **actual and/or perceived barriers to switching suppliers**, including the time taken to switch and the possibility of switching going wrong.

(d) Fourth, we consider the **impact of domestic customers' perceptions** of the difficulties of switching.

(e) Fifth, we consider specific constraints on choice encountered by **prepayment customers**.

(f) Finally, we present our provisional conclusions on a combination of features of the markets for domestic retail supply of gas and electricity in Great Britain that give rise to an AEC through an overarching feature of weak customer response which, in turn, gives suppliers a position of unilateral market power concerning their inactive customer base which they are able to exploit through their pricing policies or otherwise.

Fundamental characteristics of energy consumption.

8.82 In this section we consider two fundamental characteristics of energy consumption that might help to explain the apparently widespread lack of engagement in and understanding of domestic retail energy markets, notably the material proportion of customers who appear not to have moved beyond stage 1 of engagement noted in Figure 8.7 above. These fundamental characteristics are: the homogenous nature of gas and electricity; and the role of traditional meters and bills.

- *Homogenous nature of gas and electricity*

8.83 As noted in Section 7, gas and electricity are extreme examples of homogenous goods in that the quality of the product is entirely unaffected by the choice of supplier.

8.84 The homogenous nature of gas and electricity has two important and countervailing implications for customer engagement. On the one hand, as already discussed in Section 7, product homogeneity means that price should be the most important consideration in the choice of tariff and or supplier. This view is supported by our customer survey, which suggests that price is, by far, the most important driver of choice of energy supplier, with 81% of respondents identifying factors related to 'cost/tariff/price/rate' as important to them. On the other hand, the fact that there is no quality differentiation of gas and electricity may fundamentally reduce consumers' enthusiasm for, and interest in, engaging in the domestic retail energy markets, leading to customer inertia.

8.85 Gas and electricity homogeneity may therefore lead to a situation in which domestic customers care about price but do not engage to find the best price. This is likely to apply across customer characteristics but particularly for those on lower incomes. While, as noted in Section 7, for customers in the lowest income decile, expenditure on energy is the second highest item of expenditure, after housing (which would suggest that such customers would benefit substantially from being engaged), as noted above, those on lower incomes are more likely to have never considered switching and are less likely to have shopped around in the last three years, and are less likely to consider switching in the next three years.

8.86 We have considered whether the survey sheds light on the potential impact of product homogeneity on customer engagement. Of those respondents who had never considered switching tariff, 14% said that they could not be bothered or it was too much effort, and 13% said they were not interested. Similarly, for those respondents who had never considered switching supplier, 15% said they could not be bothered or it was too much effort, and 14% said they were not interested. However (as discussed previously in relation to respondents' expressions of satisfaction as a reason for not considering switching), we note it is likely to be inherently difficult for respondents to answer the question, 'why have you not ever considered switching?'

- *The role of traditional meters and bills*

8.87 The role of traditional meters and bills (which give rise to a disparity between actual and estimated consumption, and are complex in their own right) are a fundamental characteristic that gives rise to inaccurate and confusing information for customers which dissuades them from engaging. This may explain why we see such a significant proportion of domestic customers who are not engaged.

8.88 Traditional meters are not very visible or immediately informative to the customer, as a result of which customers are generally not aware of how much gas and electricity they consume, when they consume it and which uses require the most energy.

8.89 Furthermore, meters are traditionally read infrequently by the customer or the supplier, which adds considerably to the complexity and opacity of gas and electricity bills. This is largely because these bills have to reconcile a number of different variables simultaneously: the amount of energy the supplier estimates the customer has consumed since the last read; the amount of money that should have been paid given that volume and the price prevailing at the time; the amount of money that actually was paid given the payment regime the customer has in place (itself likely a reflection of previous estimates of what the customer was likely to consume); and the outstanding balance, positive or negative, given past inaccuracies in and disparities between any of the above variables.[414] In addition, traditional meters do not report the same unit of usage as bills.

8.90 For many customers, the combination of these factors may be leading to considerable confusion as they try to understand and assess the relationship between the energy they consume and the amount they ultimately pay for it.

[414] We note that these are fundamental characteristics of electricity and gas bills given traditional meters. Interventions to improve the comprehensibility of bills – such as those introduced through Ofgem's RMR reforms – will not change these fundamental characteristics. The impact of meters on customer billing is described in greater detail in Appendix 8.6.

This may be deterring such customers from engaging in the market and searching for better deals.[415]

8.91 Some of the Six Large Energy Firms told us that customers find their bills confusing and that this is a barrier to engagement. In particular:

(a) Centrica noted that bills could be confusing and estimated readings a source of frustration, saying ‘the very basic function of creating an accurate bill […] is the biggest single bugbear in the industry.’ Centrica said that the roll-out of smart meters would allow suppliers to provide an accurate bill, resulting in fewer complaints and customers being more engaged.[416]

(b) RWE said that much more accurate billing with the roll-out of smart meters would promote a better understanding of consumption and engagement.

(c) EDF Energy said that energy bills were complicated and SSE said that its customers found their bills confusing.

(d) Uswitch said that the main reason for a customer making use of its telephone service was that they could not extract the information they needed from their bill. The main problems were that bills might not identify the tariff that a customer was on and that a large proportion of bills were estimated, contributing to a lack of trust in search results.

8.92 Overall, our provisional view is that traditional meters and bills (which do not report the same unit of usage as the traditional meter, and are complex in their own right) are likely to have a harmful impact on engagement, and may be leading to a lack of visibility of energy consumption for many domestic customers. These fundamental characteristics may particularly affect certain categories of customer (eg those who are elderly, live in social and rented housing or have relatively low levels of income or education) who we observe are less likely to have considered engaging than others. While it is difficult to assess the precise magnitude of these effects, we note that the roll-out of smart meters (through which energy consumption will become more visible and billing more accurate) has the potential to have a significant positive impact on engagement.

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[415] It may also be one of the reasons for the perceived lack of trust in the sector, as customers have difficulty in being able to verify the accuracy of the bill.
[416] Centrica also said that customers really struggled to engage with the bill, in particular, that Ofgem required billing in kilowatt hours which required metered units multiplied by calorific value and other factors, but most customers did not understand what a kilowatt hour was.

Barriers to accessing and assessing information

8.93 Barriers to accessing and assessing information (both actual and perceived) are most prominent at the stage of searching for alternatives, influencing the extent to which customers engage in the process of shopping around for the best deal. In this section we assess: to what extent having no access to the internet is an actual barrier to engagement; the potential importance of the complex information provided in bills and the structure of tariffs for a domestic customer seeking to distinguish between the different energy tariffs available in the markets as an actual barrier to engagement; and the role of TPIs in overcoming or adding to the actual or perceived barriers to engagement.

- *Barriers to accessing information*

8.94 The internet has significantly reduced search and comparison costs in recent years, but there appear to be specific barriers to engagement for those who either do not have access to the internet or do not feel confident using it. Our survey found that 70% of respondents are confident in using the internet, 12% lack confidence in using the internet and 17% have no access to the internet. Of those respondents who lacked confidence in using the internet, 60% said that they were not confident in making the right switching decision (in comparison with those who are confident using the internet, only 21% were not confident of making the right switching decision).[417]

8.95 Figure 8.8 shows the proportion of respondents with no internet access by different measures of customer engagement in the energy sector.[418] 17% of respondents to our survey did not have access to the internet. We find that:

- respondents who have never considered switching supplier or tariff are more likely to have no internet access; and

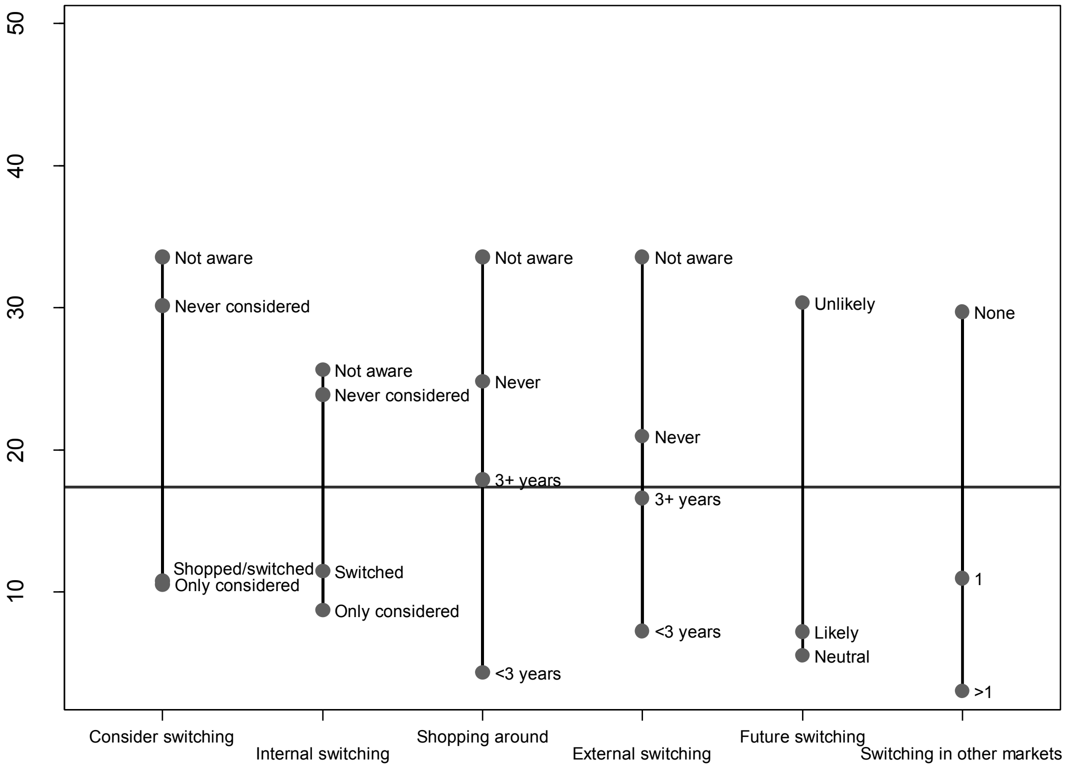
- respondents who have shopped around in the last three years, ever switched tariff with their existing supplier, switched supplier in the last three years and are likely to consider switching supplier in the next three years are more likely to have access to the internet.[419]

8.96 We also found that 11% of respondents with no access to the internet had switched supplier in the last three years compared with 29% of respondents with internet access. Generally, respondents who are less engaged in the

[417] CMA Customer Survey.
[418] Appendix 8.1: Customer Survey, paragraph 156.
[419] Appendix 8.1: Customer Survey, paragraph 157.

domestic retail energy markets are more likely to be among those who have no access to the internet or lack confidence in using the internet, indicating that a lack of access to the internet appears to be an actual barrier to engagement.

Figure 8.8: Relationship between internet access and customer engagement



Source: CMA Customer Survey.

- *Complexity*

8.97 In addition to the complexity deriving from customers having difficulties with assessing their own energy usage patterns, and therefore making an informed assessment of whether their current tariff is best suited to their needs, there is further potential complexity in shopping around to compare energy tariffs and suppliers. This was one of the main rationales for Ofgem's introduction of the RMR reforms in 2014. We consider the rationale for, and the impact of, the RMR reforms in more detail in Appendix 8.2 and paragraphs 8.218 to 8.248 of this section.

8.98 One potential source of complexity arises from the structure of tariffs. Given the high proportion of fixed costs in the electricity and gas sectors, there are arguments on the grounds of efficiency (ie to give the correct marginal signals to customers) for tariff structures with a fixed and variable component. This structure is likely to be more difficult for a domestic customer to understand than a tariff with just a variable component. In the presence of complex tariff structures, domestic customers' lack of understanding of their own energy consumption levels can add a further layer of complexity.

8.99 EDF Energy said that its experience pointed to some customers facing real or perceived barriers to engaging, with some perceiving that it was difficult to compare tariffs and as a result they were not sure that they would make the correct decision.[420] EDF Energy said that its and our survey results suggested that a lack of trust in other energy suppliers may be a barrier to change for those who were uncertain[421] and that 'behavioural' factors (such as loss aversion and status quo bias) had become increasingly important with a reduction of 'push' sales channels such as doorstep selling and outbound sales calls.[422]

8.100 Our customer survey found that the majority of respondents (67%) who shopped around in the last three years found the process of shopping around to be very or fairly easy. Of those (24%) who found it either fairly or very difficult:[423]

(a) 85% found it difficult to make comparisons between suppliers;

(b) 74% found it difficult to understand the options available to them;

(c) 42% found it difficult to find out information about other suppliers; and

(d) 31% found it difficult to find out information about their own supplier.

8.101 Respondents who had shopped around in the last three years were also asked what, if anything, they disliked about shopping around. Among those who found the task of shopping around difficult,[424] 53% said they did not understand or found it difficult to compare the tariff options and 33% said it is difficult to find information.

8.102 Ofgem's baseline customer survey,[425] which was carried out in February and March 2014,[426] and the year one survey which was carried out a year later also contain evidence on various indicators of complexity and perceived complexity. The year one survey found that 38% of customers believed it was easy to compare tariffs (compared with 37% the year before) and 36% believed it was difficult to compare tariffs (compared with 39% the year

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420 EDF Energy response to the updated issues statement, paragraph 17.6.
421 ibid, paragraphs 1.6 & 19.8.
422 ibid, paragraph 19.9.
423 Appendix 8.1: Customer survey, paragraph 136.
424 Appendix 8.1: Customer Survey, paragraph 138.
425 TNS BMRB (2014) *Retail Market Review Baseline Survey: Report Prepared for Ofgem*.
426 The RMR rules came into force in phases from August 2013 through June 2014. Some individual RMR remedies were therefore introduced in the months before the baseline survey fieldwork.

before). This indicates that some customers face perceived or actual difficulties comparing tariffs, which may stem from complex tariff structures.

- *The role of third party intermediaries*

8.103 TPIs such as PCWs can significantly reduce search and switching costs for domestic customers by providing an easy means to gain personalised quotes, on a comparable basis from a range of different suppliers.

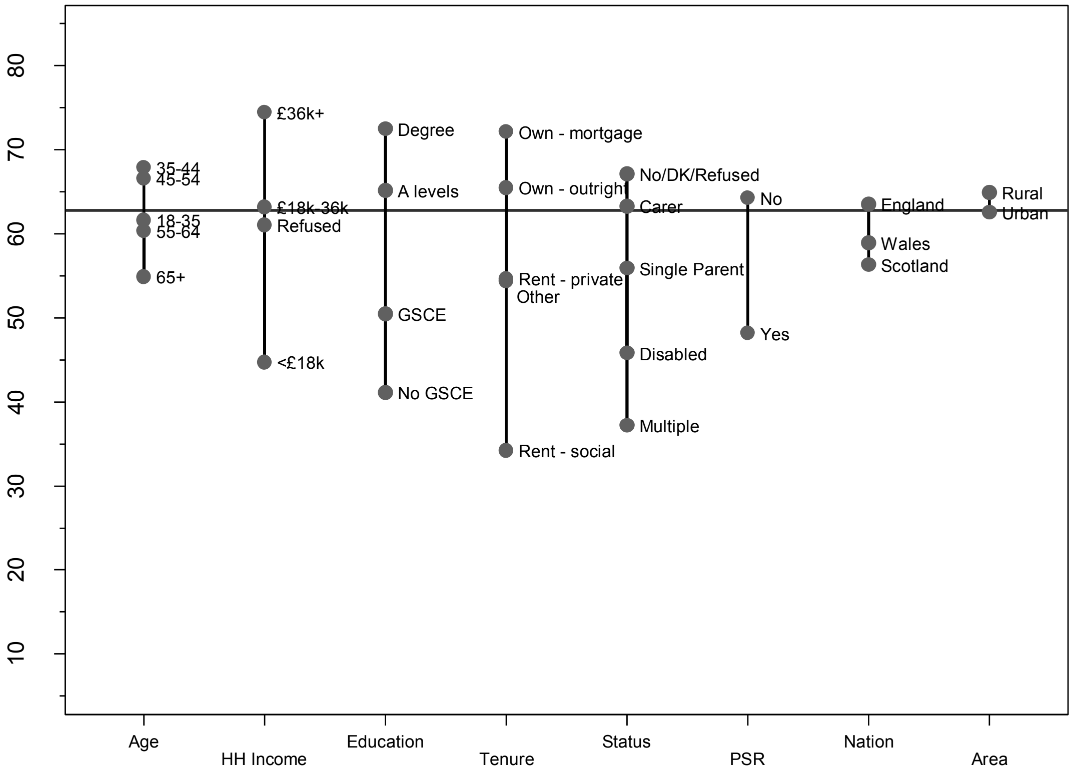
8.104 As discussed in Section 7 and Appendix 8.3: Price comparison websites and collective switches, the use of PCWs as a means of switching supplier has increased rapidly over the past five years. In 2014, they accounted for around 30% of the domestic customer acquisitions of four of the Six Large Energy Firms, and around 70% of the domestic customer acquisitions of two of the mid-tier suppliers. In our customer survey, 62% of respondents who switched supplier in the last three years used a PCW for searching last time they switched, and of those respondents 53% made the switch via a PCW.

8.105 Given the importance of PCWs as a means of unlocking customer engagement, it is important to understand what barriers there might be to their further expansion.

8.106 One potential issue relates to confidence and trust. In our survey, 55% of respondents said they were confident that they would be able to get the right energy deal using a PCW, while 27% were not confident, and 17% have no internet access. Of the group who are not confident, 43% said they did not trust or believe PCWs (ie 12% of all respondents). We note that over the last year there has been some high-profile public criticism, both in the press and by politicians, relating to the role of PCWs in energy markets, and at the start of 2015 Ofgem amended the PCW Confidence Code. We consider the potential impact of the Code in paragraphs 8.255 to 8.261 below.

8.107 Second, respondents with certain demographic characteristics appear less likely to use PCWs. This is shown in the chart below, which shows, for respondents who switched supplier in the last three years, the percentage who used PCWs to search. Customers on low income and with low levels of education are less likely to use PCWs.

Figure 8.9: Proportion of PCW use by demographic and household characteristics



Source: CMA analysis of survey and supplier data.
Base: Age 2158, HH income 2187, education 2105, tenure 2187, status 2187, PSR 2178, nation 2187, area 2184.

8.108 It has been put to us that third party access to the consumption data is necessary for PCWs to continue to compete and provide switching services for customers with smart meters. PCWs need to be able to give an accurate estimation of charges under available tariffs. This issue is particularly important with the introduction of TOU tariffs as PCWs cannot offer these tariffs unless they have access to HH customer data. PCWs have also raised concerns with us about the conditions under which they will be permitted to access smart meter data files when a customer is considering a switch.

8.109 For customers who do not have access to the internet, collective switching schemes may be a viable alternative. These involve customers grouping together to buy their energy supply. Generally, customers register their interest with a collective switching scheme organiser. Suppliers then take part in a reverse auction, bidding to supply energy to the group of customers registered with the scheme organiser. Many collective switching schemes have been aimed at vulnerable and disengaged customers and have targeted participants using offline sign-up methods.[427]

[427] Ofgem (2014), *Protecting consumers in collective switching schemes*.

8.110 There has been growth in the number of collective switching schemes since 2012, but these have generally been smaller in terms of the number of participants. The proportion of customer acquisitions made via collective switches was less than 2% across the Six Large Energy Firms and the four largest of the mid-tier suppliers in 2014, except for E.ON where the proportion of acquisitions made via collective switches was [✂]. Components of RMR appear to be providing an environment that promotes the organisation of collective switch schemes, as we discuss in paragraph 8.240 below.

8.111 Overall, our provisional view is that some customers face actual and perceived barriers to accessing and assessing information arising, in particular, from:

(a) the complex information provided in bills and the structure of tariffs, which combine to inhibit the value-for-money assessments of available options, particularly on the part of customers that lack the capability to search and consider options fully (in particular, those with low levels of education or income, the elderly and/or those without access to the internet); and

(b) a lack of confidence in, and access to, PCWs by certain categories of customers, including the less well-educated and less well-off. For some customers this lack of confidence in PCWs may arise from a lack of trust in PCWs. We note that alternative forms of TPIs, such as collective switching schemes, may be increasingly important for such customers.

Barriers to switching

8.112 In this section, we consider the evidence on actual and/or perceived barriers to switching, focusing on the time it takes to switch supplier and the possibility that things will go wrong (erroneous transfers) and issues arising from uncertified meters. The discussion is structured as follows:

(a) We review the evidence on the time it takes to switch supplier.

(b) We review the evidence on erroneous transfers.

(c) We examine whether there is a particular issue related to uncertified meters.

- *Time taken to switch*

8.113 When a customer decides to switch supplier the current change of supplier processes involve a number of pieces of data being exchanged between the incumbent supplier and newly appointed metering agent.[428] The electricity switching process, in particular, is very complex. This complexity can lead to delays, errors and costs, which, in turn, may have an impact on customer confidence and the propensity to switch. During 2013, Ofgem reported that 80% of gas switches and 20% of electricity switches had taken longer than five weeks (including the cooling-off period).[429]

8.114 Ofgem has recognised the problems in its recent decision on fast and reliable switching.[430] It has made certain improvements to the current processes and is planning to ensure as far as possible that the benefits from smart meter roll-out are realised by enabling faster switching with less complexity and scope for errors.

8.115 Changes introduced at the end of 2014 have reduced switching timescales from five weeks to 17 days.[431] This means that a customer will be switched three days after their cooling-off period ends.

8.116 Ofgem has recently announced its decision to introduce reliable next-day switching by 2019. This will build on the new arrangements introduced to support smart metering.[432] It is proposed that the Data Communications Company (DCC) will provide a central registration service which will facilitate the change of supplier process for all gas and electricity supply points. This should increase the reliability and speed of switching, as well as reducing its complexity and cost. Significant changes are needed to licences and industry codes in order for this to happen, and Ofgem is therefore currently of the view that it should use its ‘significant code review’[433] process.

8.117 Ofgem appears to have had more success in driving through faster switching times than in some other areas of regulatory change and in Section 11 we consider what conclusions can be drawn from this in terms of the structure and governance of the regulatory framework.

- *Erroneous transfers*

8.118 Erroneous transfers occur when a customer has their supplier switched without their consent, which can cause confusion and distress, and damage

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[428] Metering agents are appointed to maintain gas and electricity meters. For electricity, metering agents are also appointed to obtain and process meter reads and to send data in for settlement.
[429] Ofgem (2013), *Enforcing three week switching* (letter to interested parties, 3 December).
[430] Ofgem (2015), *Moving to reliable next-day switching*.
[431] This consists of a 14-day cooling-off period followed by three weeks for the switching process.
[432] Ofgem (2015), *Moving to reliable next-day switching*.
[433] See legal and regulatory framework overview working paper.

customers' perception of the retail energy market.[434] Resolving erroneous transfers and returning the customer to their previous supplier is also costly for both suppliers.

8.119 Ofgem[435] indicates that for the period January to September 2014 1% of all completed domestic gas and 1.4% of all completed domestic electricity switches were erroneous transfers. For the domestic gas and non-half-hourly settled electricity consumers affected in 2014, 76% of erroneous transfers for gas and 77% for electricity happened because the wrong metering point was selected and 18% for gas and 17% for electricity because the incumbent supplier did not process the customer's cancellation request in time. The remainder were linked to the way in which contracts were sold to consumers.

8.120 Smaller suppliers highlighted that erroneous transfers caused them both financial costs and reputational damage. They submitted that, because they were growing their customer base, they were bearing the costs of these transfers disproportionately. First Utility has suggested that the performance assurance measures, that include the error and resolution arrangements in the Balancing and Settlement could usefully considered for other industry codes to assist with reducing the number of erroneous transfers.

8.121 We also note in Appendix 8.3 that there are a variety of reasons why switching failure via a PCW may occur, including errors in meter and postcode data, and errors in the information entered by customers. One PCW said that errors in meter and postcode data resulted in switching failure and hence frustration among customers. It said that suppliers' incentive to update data was limited as there were limited sanctions for not updating the data.

8.122 On 9 April 2014, Ofgem also published a statutory consultation to prevent erroneous transfers.[436] The new proposal extended the scope of suppliers' requirements to take all reasonable steps to prevent erroneous transfers. These changes were implemented in September 2014.

8.123 Going forward, smart meter data could further help lower the number of erroneous transfers and could provide significant improvements in the current arrangements. With the data being held by the DCC, it is expected that the number of erroneous transfers will be dramatically reduced. For example, meter readings taken remotely could be used by the new supplier

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[434] Ofgem (2013), *Preventing erroneous transfers* (letter to interested parties, 3 December).
[435] Ofgem submission.
[436] Ofgem (2014), *Statutory consultation on licence modifications to enforce three week switching and prevent erroneous transfers* (letter to interested parties, 9 April).

to set up billing records and by the old supplier to send an accurate final bill to the customer.

8.124 Ofgem's September 2014 reforms may have improved suppliers' incentives, although no data is available yet to assess their effectiveness. Given the importance of easy, accurate switching to the effectiveness of the competitive process, and the potentially significant detriment to those who suffer from erroneous transfers, we have some concerns regarding the apportionment of responsibility between gaining and leaving suppliers.

8.125 Overall, we provisionally find that erroneous transfers have the potential to cause material detriment to those who suffer from them. Erroneous transfers may thereby impact customers' ability to switch as well as their perception of switching.

- *Distortions in the switching process arising from uncertified meters*

8.126 Both gas and electricity meters must be certified periodically. However, there is some chance that a customer who has switched finds themselves with an uncertified meter. We consider the consumer harms that this can lead to.

8.127 First Utility submitted to us its concerns regarding the number of customers with uncertified electricity meters it gained from other suppliers through switching. It estimated that in 2014, it gained approximately [✄] customers with uncertified meters from other suppliers. This caused First Utility to incur additional costs in terms of certification or meter replacement when the previous suppliers must have ensured the meter was either re-certified or exchanged. In addition to the costs of dealing with uncertified meters, First Utility noted that the customer was inconvenienced, having to arrange for an engineer visit. In its view, this situation risked causing the customer to regret having switched and added to the perceived 'hassle factor' of switching.

8.128 Furthermore, First Utility pointed out that a similar situation arises for gas, where gas suppliers must ensure that meters are inspected every two years. We note that British Gas has been granted a derogation from this obligation. As a result, British Gas can instead inspect meters every five years.

8.129 We would welcome views in relation to these concerns, and whether they might have a negative impact on customers in relation to their experience of switching.[437]

[437] Appendix 8.6 also considers whether the current system of derogations may have a distortionary effect on competition between suppliers through distorting the allocation of costs between suppliers.

Domestic customers' perception of the searching/switching process

8.130 Our survey suggests that most of those who have switched recently found the process relatively easy: the majority of respondents (83%) who switched supplier in the last three years found it very or fairly easy to switch. However, 33% of respondents who switched supplier in the last three years encountered one or more difficulties with the switch. The main difficulty cited was delays to the process, cited by 11% of all those who switched, followed by the previous supplier delaying the process (6%) and meter readings (5%).

8.131 We agree with the views expressed by some parties that the perception of problems by those who had not attempted to switch appears to be somewhat greater than the experience of problems by those who had. In contrast to the experience of those who shopped around or switched, 66% of those who did not shop around or switch in the last three years agreed that 'switching is a hassle I do not have time for' (compared with 40% of those who had shopped around or switched in the last three years) and 57% agreed 'I worry things will go wrong if I switch' (compared with 37% of those who had shopped around or switched in the last three years). We consider it likely that such problems will reduce with the full roll-out of smart meters.

8.132 Our survey provides an indication that domestic customers may perceive there to be material barriers to accessing and assessing information and switching. We asked respondents how much they would need to expect to save to consider switching. For those respondents who could answer this question, the median saving required was £120 per year. While we are aware that such hypothetical questions are inherently difficult to answer – and so place limited weight on the precise values given – this does provide some indication that customers may perceive there to be material barriers to engagement and switching.

8.133 Overall, we provisionally find that there is some evidence indicating that the process of searching for an alternative supplier and successfully switching has been problematic for some consumers. However, the perception of the complexity and burden of the process is worse than the reality, which may further dissuade domestic customers from shopping around and/or switching.

Prepayment customers

8.134 As noted previously, prepayment customers experience particular constraints on engaging with the market in terms of the number of tariffs available to switch to. The number of prepayment customers has grown steadily over the past few years, to its current level of about 15% of gas customers and 16% of electricity customers. About 300,000 prepayment meters were installed in 2014, with 60% of these installed due to debt problems.

8.135 Customers are charged for the costs involved in installing the meter and those currently on a prepayment meter generally incur costs if they wish to have the prepayment meter removed. Eleven out of 18 suppliers charge to remove meters, with costs ranging between £45 and £160[438] although in practice 85% of meters removed in 2014 were removed for free. In addition, customers often need to pay a security deposit if they fail a credit check when the meter is removed.[439]

8.136 An analysis of the dual fuel SVTs from the Six Large Energy Firms suggests that average prepayment premiums for typical consumption customers are of the order of £75–£80 per year, similar to the premium[440] paid by standard credit customers.[441,442]

8.137 Despite this, we found that prepayment customers have significantly lower potential gains from switching than other customers (potential savings from Q1 2012 to Q2 2014 are equivalent to 8% of the bill for dual fuel SVT prepayment customers compared with 18% for dual fuel SVT customers on standard credit and direct debit).

8.138 The reason for this disparity is that there are fewer tariffs available to prepayment customers compared with other customers and those tariffs that are available are generally SVT tariffs, which are generally more expensive than the equivalent SVT tariffs for standard credit and direct debit customers.[443]

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[438] Ofgem (23 June 2015), *Prepayment review: understanding supplier charging practices and barriers to switching*.
[439] All of the Six Large Energy Firms except for EDF Energy require a security deposit to be paid.
[440] RWE told us that it is more appropriate to refer to the price differential between direct debit and non-direct debit customers as a ‘discount’ than as a ‘premium’. RWE said that this price differential simply reflects the lower costs associated with serving direct debit customers and is thus closer to a discount than a premium. Further, RWE said that this discount was specifically structured so as to comply with the exception to the prohibition on non-cost reflective discounts set out in electricity supply SLC 22B.7 and SLC 27.2A. We consider that, for the purposes of our investigation, there is no material difference in describing this price differential as either a ‘premium’ paid by standard credit customers or a ‘discount’ available to direct debit customers and we use both of these terms in the present document.
[441] An Ofgem analysis based on the annual bill for dual fuel, typical consumption customer. Five of the Six Large Energy Firms charge the same premium for standard credit and prepayment relative to their own direct debit prices, but Scottish Power charges standard credit more than prepayment customers.
[442] The Six Large Energy Firms, with the exception of EDF Energy, said that this analysis provided a reasonable basis for assessing the differential. They also provided further details on the discounts they give to their direct debit, dual fuel customers. RWE said that these were in the range of £40–£100 a year. The other Six Large energy Firms said the range was £70–£90 a year.
[443] All suppliers with more than 50,000 customers are required to offer prepayment tariffs.

8.139 Our understanding is that there may be some technical constraints deriving from the prepayment meter that limits the number of tariffs that can be offered to prepayment customers. We have been told that certain non-smart prepayment meters may have a technical limitation on the number of tariff slots that can be supported.

8.140 According to the Prepayment review, the availability of prepayment tariffs is improving somewhat:[444]

- Eighteen suppliers are offering prepayment tariffs, including five suppliers below the 50,000 customer threshold.
- A small but growing number of suppliers are offering innovative tariffs to prepayment customers. This includes tailored social tariffs for customers in vulnerable situations.
- Prepayment customers have access to approximately 75% of the number of SVTs available to direct debit customers but still significantly less choice for fixed tariffs. There are four fixed tariffs available to prepayment customers compared with 27 for direct debit customers. Only three suppliers offer fixed tariffs for prepayment customers with Economy 7 meters.

8.141 We would expect the situation to improve further with the phased introduction of smart meters. These can be set to work on prepayment mode and should reduce, if not eliminate entirely, any additional costs to the supplier of a sort that might justify higher prices. Indeed, since customers are pre-paying, the credit risk is lower and to this extent at least the overall costs to the supplier may be lower.

8.142 In the interim, Ofgem has recently published a report[445] setting out its findings in relation to prepayment customers including the limited availability of tariffs for prepayment customers and the reasons for this, and suppliers' practices in relation to prepayment customers. Ofgem's stated aim of this work is to ensure that prepayment customers can switch easily, are treated fairly and that costs do not fall disproportionately on those who can least afford them. Ofgem also aims to enable prepayment customers to access the best deals for them.

8.143 Ofgem has decided to consult on strengthening protections for prepayment customers. Ofgem identified good practice in relation to charging practices

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[444] Ofgem (23 June 2015), *Prepayment review: understanding supplier charging practices and barriers to switching*.
[445] ibid.

and will consult on further identifying good practice and extending this to all suppliers. Ofgem will seek views on ending prepayment meter installation charges, including warrant-related charges for all or some customers and ending prepayment meter removal charges. Ofgem will also consult on ending the use of security deposits. Ofgem has started a review to further understand the potential technical constraints on tariff availability and whether this is limiting competition.

8.144 We also note from our survey that respondents in certain types of accommodation – particularly rented accommodation and social housing – exhibit lower degrees of engagement against a range of metrics compared to other respondents. We will consider the possible reasons for this further following provisional findings.

8.145 Overall, our provisional finding is that prepayment meters place technical constraints on customers from engaging fully with the markets, which contributes to such customers facing higher costs and a more limited choice of tariffs. Prepayment meters therefore reduce customers' ability and incentive to engage in the markets and search for better deals. We expect these problems to be partly addressed with the full roll-out of smart meters..

Views of parties

8.146 Centrica, E.ON, RWE and SSE said that barriers to switching supplier were low. EDF Energy said that its experience pointed to some customers facing real or perceived barriers to engaging.

8.147 Centrica said that our survey results indicated that in practice barriers to switching were low even if the perception among customers who had not switched was that this was difficult. In particular: of those surveyed who had not switched (externally or internally) in the past three years, the majority were satisfied with their current supplier; a significant proportion intended to switch supplier within the next three years and were confident that they could find a good deal by doing so; leaving around 5% of dissatisfied customers who did not intend to consider switching or who were not confident that they would be able to do so effectively.

8.148 Centrica also said that these customers were less likely to be in vulnerable categories than the wider sample, and more likely to have internet access, but had in common being distrustful of energy suppliers and a lack of confidence in the ease of the switching process and in their ability to use switching (including via PCWs) to obtain a good outcome.

8.149 E.ON said that the survey did not provide evidence of significant barriers to switching supplier. In particular: most people were aware they could switch (89% knew); 70% were confident they would make the correct decision when switching; and of those customers who did not switch to a supplier that approached them, 39% said they did not switch because their existing tariff was satisfactory compared with 9% who indicated that they did not switch because it was too much effort.[446]

8.150 RWE said that the survey results indicated that barriers to switching were low. In particular:

(a) of those customer who switched in the last three years, only 10% thought switching was difficult and two-thirds stated that they were likely to switch in the future;

(b) the fieldwork was done before Ofgem's faster-switching reforms were fully implemented and the time required for a customer to transfer between suppliers had decreased from five weeks to just over two weeks;

(c) whilst 56% of customers agreed that switching was a hassle, the question was leading and other results contradicted this finding;[447]

(d) the survey evidence was consistent with the effort involved in switching decreasing over time with 63% of customers who switched in the last year disagreeing with the statement that switching is a hassle;

(e) the results indicated that the effort involved in switching was not driving a problematic degree of consumer disengagement, with 67% of customers who had switched in the past three years and 36% of customers who had not switched in the past three years stating that they were likely to switch in the future; and

(f) less than 25% of those customers who had shopped around in the past three years thought that shopping around had been a difficult task.

8.151 SSE said that there were no material barriers to switching for any customer group. In particular: the CMA's survey indicated that 67% of customers who

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[446] E.ON response to the updated issues statement, paragraphs 14 and 173–80.
[447] In particular, RWE noted that: 89% of customers knew they had the option to switch suppliers; 44% had exercised their option to switch suppliers; only 10% of those who switched in the last three years thought switching was difficult; two thirds of those who had switched in the past three years stated that they were likely to switch in the future; and those who had switched were considerably less likely to agree that switching was a hassle than were consumers who had considered switching but not shopped around.

had switched previously were likely to switch again, suggesting that switching was not onerous or off-putting; and improvements in the switching process, the increasing penetration of PCWs, and the opportunities offered by smart meters will make switching even easier.[448]

8.152 We note that some of the Six Large Energy Firms have pointed to the survey as providing evidence of a high degree of satisfaction among domestic energy customers and suggested that this was an explanation for why there was not more active engagement.

8.153 For example, Centrica said that key findings were that 70% of customers were confident that they were on the right deal and just 9% of customers were dissatisfied with their supplier. However, our view is that relatively low weight can be given to these results as for many respondents these were not informed beliefs. For example, of those respondents who said they were confident that they were on the right energy deal, 52% had never shopped around.

Conclusion on barriers to engagement

8.154 We have noted that there are material numbers of customers who appear to be fundamentally disengaged in the sense that they either no longer consider exercising choice in the markets or no longer appear to be aware of their ability to exercise choice in the markets. Around a third of respondents to our survey said that they had never considered switching.

8.155 In a market investigation, we are required to decide whether any feature, or combination of features, of each relevant market prevents, restricts or distorts competition. In this section, based on the preceding analysis, we set out our provisional finding of the features that lead to an AEC in the domestic retail energy supply markets.

8.156 Our provisional finding is that we have identified a combination of features of the markets for the domestic retail supply of gas and electricity in Great Britain that **give rise to an AEC through an overarching feature of weak customer response**[449] which, in turn, gives suppliers a position of unilateral market power concerning their inactive customer base which they are able to exploit through their pricing policies or otherwise. These features act in combination to deter customers from engaging in the domestic retail gas and electricity markets, to impede their ability to do so effectively and

[448] SSE response to the updated issues statement, section 6.
[449] We refer to weak customer response as an overarching feature as synonymous with it being a source for an AEC (*CC3*, paragraph 170).

successfully, and to discourage them from considering and/or selecting a new supplier that offers a lower price for effectively the same product.

8.157 More particularly, these features are as follows:

(a) Customers have **limited awareness of and interest in their ability to switch energy supplier**, which arises in particular from the following fundamental characteristics of the domestic retail gas and electricity supply markets:

(i) the homogeneous nature of gas and electricity, which means an absence of quality differentiation of gas and electricity and which may fundamentally affect the potential for customer engagement in the markets; and

(ii) the role of traditional meters and bills, which give rise to a disparity between actual and estimated consumption. This can be confusing and unhelpful to customers in understanding the relationship between the energy they consume and the amount they ultimately pay. The full roll-out of smart meters over the next five years may have a potentially significant positive impact on engagement, although we have limited evidence concerning the likely magnitude and timescales of any such impact.

These fundamental characteristics may particularly affect certain categories of customer (eg those who are elderly, live in social and rented housing or have relatively low levels of income or education) who we observe are less likely to have considered engaging than others.

(b) Customers face **actual and perceived barriers to accessing and assessing information** arising, in particular from the following aspects of the domestic retail gas and electricity markets:

(i) the complex information provided in bills and the structure of tariffs which combine to inhibit the value-for-money assessments of available options, particularly on the part of customers who lack the capability to search and consider options fully (in particular, those with low levels of education or income, the elderly and/or those without access to the internet); and

(ii) a lack of confidence in, and access to, PCWs by certain categories of customers including the less well-educated and the less well-off. We note that alternative forms of TPIs, such as collective switching schemes, may become increasingly important for such customers.

(c) **Certain customers face actual and/or perceived barriers to switching**, such as where they have uncertified meters or experience erroneous transfers which have the potential to cause material detriment to those who suffer from them. Erroneous transfers may thereby impact customers' ability to switch as well as their perception of switching. This is again an area where the introduction of smart meters should in the fullness of time help bring improvements.

(d) **Prepayment meters**, which place technical constraints on customers on such meters from engaging fully with the markets, and which reduce customers' ability and incentive to engage in the markets and search for better deals. Prepayment meters therefore contribute to such customers facing higher costs and more limited choice of tariffs. We expect these problems to be partly addressed with the full roll-out of smart meters and, in the intervening period Ofgem has recently published a report setting out measures to address the limited availability of tariffs for prepayment customers.

8.158 These are the central contributory features to weak consumer engagement that we have identified. With a view to assessing potential remedies, however, we note two points. First, that some of these features are the result of the intrinsic and irreducible properties of energy. Secondly, that there will be other less tangible factors driving the behaviour of different consumers. To this extent there is a case for exploring remedies that extend beyond those targeted at the specific features listed above, and directly targeted on the effects of disengagement.

Supplier behaviour

8.159 In this section we consider to what extent supplier behaviour may be leading to a separate AEC or contributing to the AEC we have provisionally found above. We consider two hypotheses:

(a) That some suppliers have a position of unilateral market power, arising from the extent of customer lack of engagement in the market, and suppliers in such a position have the ability to exploit such a position, for example, through price discrimination by pricing their SVTs materially above a level that can be justified by cost differences from their non-standard tariffs and/or pricing above a level that it is justified by the costs incurred with operating an efficient domestic retail supply business.

(b) That suppliers are tacitly coordinating in the retail market through public price announcements.

Price discrimination

8.160 The Six Large Energy Firms have since 2009 consistently offered fixed-term tariffs at discounts, at time of launch, to their SVTs to non-prepayment customers. We have also seen that a large proportion of customers on these discounted tariffs pay by direct debit. Practice differs to a degree between the Six Large Energy Firms, both in terms of the extent of discounting and whether discounts are offered under the supplier's brand name or through a white-label supplier.

8.161 The purpose of this section is, first, to set out the size of the discounts offered, to consider whether these price differentials are justified by differences in costs and to draw a conclusion as to whether the Six Large Energy Firms are price discriminating over customers.[450] We then summarise the evidence on the impact of price discrimination on the revenue earned by the Six Large Energy Firms from their SVT and non-standard tariff customers.

Past and current pricing strategies of the Six Large Energy Firms

8.162 Price discrimination appears to have been a consistent feature of retail domestic energy supply in Great Britain.

8.163 Prior to 2009, incumbent electricity suppliers offered lower SVTs out of area; and British Gas offered SVTs for electricity that were more competitively positioned than their gas tariffs.

8.164 In 2009 Ofgem found that the incumbent electricity suppliers were earning significantly higher margins in electricity than in gas, and higher margins in-area than out of area.[451] In an attempt to address this, Ofgem implemented the SLC 25A which prohibited undue regional price discrimination. This originally applied to all tariffs, but Ofgem's guidance subsequently provided for the use of discounted fixed-term tariffs to allow suppliers to attract and retain domestic customers.

8.165 Following implementation of SLC 25A, the number of fixed-term tariffs launched by the Six Large Energy Firms increased. These tariffs included both variable-rate tariffs and fixed-rate tariffs. The former took various structural forms, including percentage discounts and minimum guaranteed percentage discounts to the SVTs and capped tariffs. The effect of this

[450] This section summarises the analysis contained in Appendix: 8.4 Price discrimination.
[451] See Energy Supply Probe – Initial Findings, 2008, p52.

appears to have been to focus competition on price on a narrower segment of the market, ie non-prepayment (and, in particular, direct debit) customers.

8.166 We asked the Six Large Energy Firms to explain the approach taken to setting prices for their SVTs and non-standard tariffs.[452]

(a) One of the six large energy firms ([✂]) said that it offered discounted tariffs to acquire and retain customers but that it could only do this if a sufficient proportion of customers moved to the SVTs for a period; and that it might lose money on customers who left it in a shorter period of time.

(b) EDF Energy said that it could only continue to offer fixed-term tariffs at current levels while the portion of the market addressed by fixed-price tariffs remained marginal.

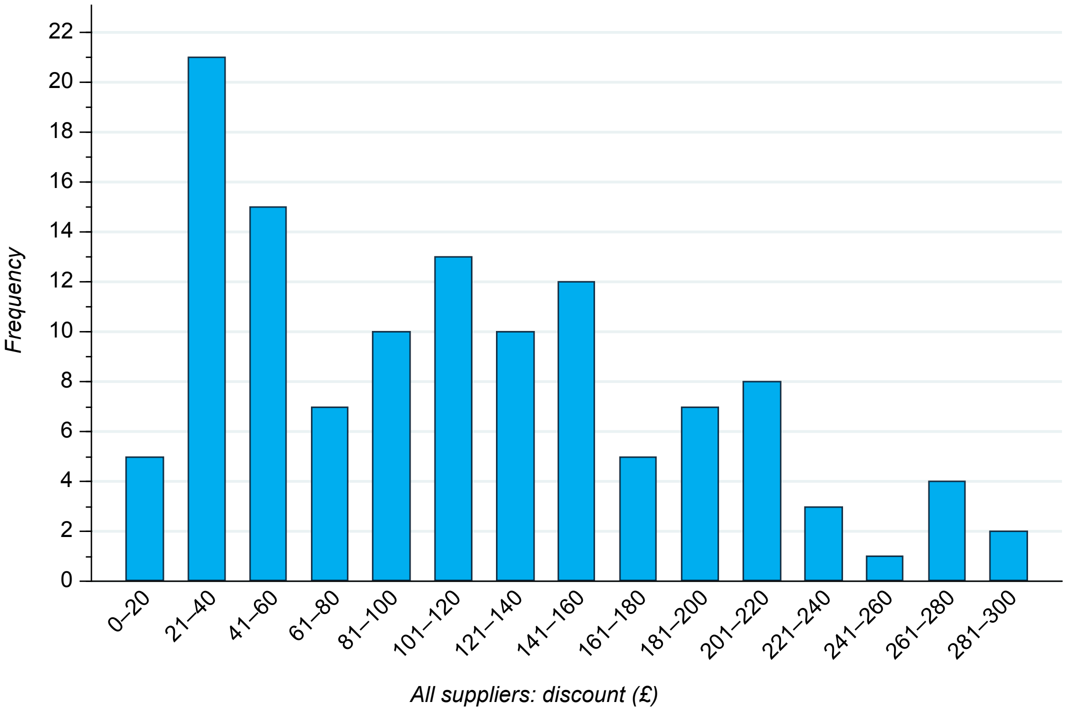
(c) SSE said that it did not segment its customer base so that some customers subsidised short-term deals made available to others.

Evidence on price differentials

8.167 Figure 8.10 provides results on the size of discounts, at time of launch, for discounted fixed-term tariffs launched since mid-2013 (this analysis does not therefore include tariffs priced at a premium to the SVT[453]). These fixed-term tariffs typically have a term of up to one or two years at time of purchase. The figure shows that discounts ranged in value from £20 or less to as much as £281–£300 on an annual bill. We estimate that over 50% of discounted fixed-rate tariffs (including white-label tariffs) were priced at a discount of more than £100 on an annual bill.

[452] The full findings are set out in Appendix 7.3: The pricing strategies of the Six Large Energy Firms.
[453] The purpose of this analysis was to understand the extent to which the availability of tariffs offered at a discount was justified by lower costs of supply.

Figure 8.10: Distribution of fixed-term tariffs offered by Six Large Energy Firms at a discount, at launch, to the SVTs, mid-2013 to March 2015, £ discount



Source: CMA. Based on annual bill for duel fuel, direct debit typical consumption customer.

8.168 We calculate that just over 40% of discounted fixed-tariffs were priced at a discount of 10% or more on the SVTs. The extent of discounting varies between the Six Large Energy Firms:

(a) Nine out of 11 of the SSE fixed-term tariffs offered a discount at launch of 10% or less.

(b) Eleven out of 19 of the E.ON fixed-term tariffs offered discounts of 4% of less.

(c) Around [✂]% of the EDF Energy discounted fixed-term tariffs offered discounts of more than 10%.

(d) [✂]

(e) Around 50% of the British Gas and Scottish Power discounted fixed-term tariffs offered discounts of more than 10% on the SVTs. Many of the British Gas and SSE discounted tariffs in this period are white-label tariffs (Sainsbury's Energy and Ebico and M&S Energy respectively).

Evidence on gains from switching

8.169 Our analysis of the gains from switching under scenario 1 provide further evidence on the levels of discounting by supplier for the period Q1 2012 to

Q2 2014. Scenario 1 calculates gains from switching tariff but not supplier or payment method. We would therefore expect that the gains from switching for SVT customers under Scenario 1 would be larger the greater the levels of tariff discounting by their existing supplier (including white-label tariffs). For each of the Six Large Energy Firms we consistently see material gains to be had from SVT customers switching to non-standard tariffs offered by their existing supplier. In particular, for dual fuel direct debit customers these gains are, on average, largest for [✄] (at £117) followed by [✄] (at £99), [✄] (at £92), [✄] (at £76), [✄] (at £61) and then [✄] (at £43).

Evidence on average revenue

8.170 In Section 7 we considered the evidence on the average revenue earned by the Six Large Energy Firms from their SVT and non-standard customers. The evidence shows that over the period 2011 to 2014, average revenues from the SVT have been 10% and 13% higher for electricity and gas respectively than average revenues from non-standard tariffs.

8.171 We have further broken down the average revenue by payment type to control for the fact that a higher proportion of customers on the SVT pay by standard credit and prepayment, both of which are more expensive than direct debit. Direct debit is the preferred payment method for the significant majority of customers on non-standard tariffs (see Section 7).

8.172 Our calculations show that for customers using the direct debit payment method, average revenues from the SVT, over the period between 2011 and 2014, have been 7% and 8% higher for electricity and gas respectively than average revenues from non-standard tariffs. For customers using the standard credit payment method, these figures are 9% and 14%. We note that, in contrast to the tariff data presented above, the differences in average revenues will include the effect of more expensive longer-term non-standard tariffs. This implies that average revenue comparisons will understate the extent of tariff discounting overall.

8.173 In this section we consider evidence on the extent to which costs to suppliers are likely to vary between SVT customers and those on non-standard tariffs.

8.174 The main costs items in retail domestic supply are: *(a)* direct costs comprising wholesale energy costs, transmission and distribution costs, and environmental and social obligation costs; and *(b)* indirect costs comprising costs to serve (billing, customer service, metering, bad debt), acquisitions, sales and marketing, and an allocation of central costs. As discussed in

Section 7, direct costs account for around 85% of total costs and indirect costs the remaining 15%.

- *Direct costs*

8.175 In relation to direct costs, we have seen no evidence to suggest that transmission and distribution charges and costs of meeting social and environmental obligations are unlikely to differ between customers subscribing to the SVTs and fixed-term tariffs.

8.176 [✂][454] Centrica said that price movements may still occur as a result of increase in other costs such as network costs and environmental and social obligation costs.

8.177 For their fixed-term tariffs the Six Large Energy Firms have adopted a range of different strategies. [✂] The others normally purchase [✂].[455]

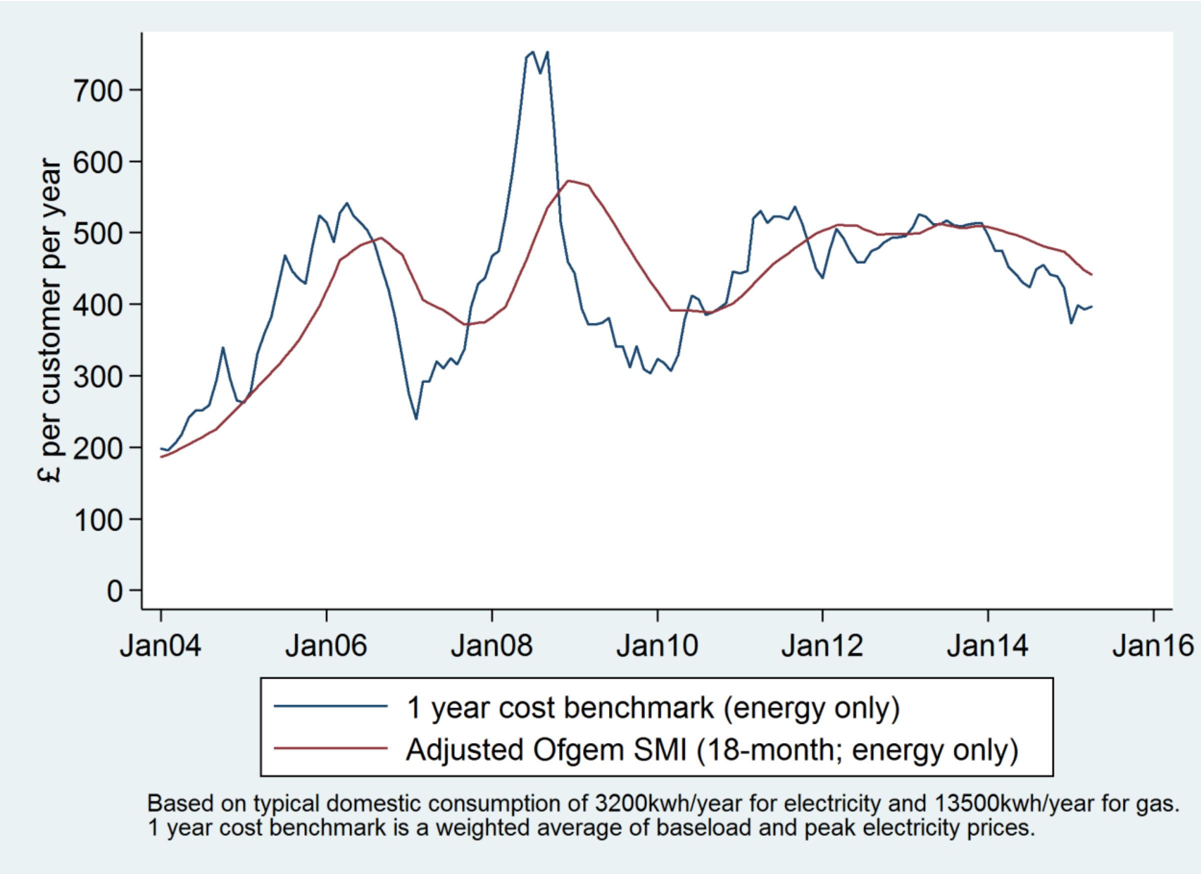
8.178 To the extent to which the Six Large Energy Firms have different purchasing strategies for their SVTs and fixed-term tariffs, their expectations in relation to future energy costs may differ between SVTs and fixed-term tariffs.

8.179 However, our comparison of various forward-looking energy cost bench-marks and a stylised 18 months hedging strategy in Appendix 7.2 shows that no cost indicator results in systematically higher or lower expectation of wholesale costs. The chart below compares the one-year forward-looking cost benchmark that we have calculated[456] with the SMI (the 18-month hedge that Ofgem uses to approximate the average hedging strategy of the Six Large Energy Firms).

8.180 As the chart shows, the one-year forward-looking cost benchmark sometimes implies higher expected costs than the SMI (for example in 2011) and sometimes lower (for example in 2014).

[454] See Appendix 8.4: Price discrimination for a summary of energy purchasing strategies.
[455] See Appendix 8.4: Price discrimination for a summary of energy purchasing strategies.
[456] The two-year benchmark is very similar to the one-year benchmark.

Figure 8.11: Comparison of wholesale costs implied by SMI and one-year forward-looking benchmark



Source: CMA analysis.

8.181 Further, in Appendix 8.4 on price discrimination we analyse the intrinsic risks associated with the SVTs and non-standard tariffs. We find that there are differences in the risks. For example, a supplier can withdraw a fixed-term tariff from sale at any time but it cannot increase the price for customers signed up to the tariff in-term, whereas a supplier can in principle change the price for existing standard variable customers at any time (subject to giving required notice). However, our provisional view is that there are no reasons to expect that downside risks associated with purchasing energy costs are inherently and systematically higher in the provision of SVTs as compared with fixed-term, fixed rate tariffs.

- *Indirect costs*

8.182 Centrica said that it would expect average indirect costs to be higher for customers subscribing to standard variable when compared with customers subscribing to non-standard tariffs owing to differences in the way in which customers transact with British Gas (ie online or offline) or their choice of pay type (and thus relative level of bad debt).

8.183 The other Six Large Energy Firms confirmed that they would expect both cost to serve[457] and indirect costs for direct debit, dual fuel customers subscribing to a SVT to be much the same as those for direct debit, dual fuel customers subscribing to a non-standard tariff. SSE said that this would be the case comparing customers with similar consumption levels. E.ON added that indirect costs were driven by customer behaviour and payment method.

8.184 The Six Large Energy Firms confirmed that the key drivers of cost differences were payment methods. As discussed above (see paragraph 8.136), at typical consumption the Six Large Energy Firms apply average premiums of around £75–£80 for dual fuel customers who pay by standard credit and prepayment (compared to dual fuel customers who pay by direct debit), which we take for the purposes of this analysis to be an estimate of the additional costs of serving such customers.[458]

8.185 This does not affect our analysis of the size of discounts, at time of launch, for discounted fixed-term tariffs launched since mid-2013.

Provisional conclusion

8.186 We have observed that there are significant disparities in the tariffs charged by the Six Large Energy Firms that cannot be fully explained by differences in cost.

8.187 Specifically in relation to discounts on the SVTs, we have found that, over the period July 2013 to March 2015 just over 40% of discounted non-standard tariffs were priced at a discount of more than 10% on the SVTs. The extent of discounting differs between firms. The biggest discounter over the period, measured by the number of tariffs offered at a discount of more than 10%, is British Gas, followed by RWE npower and Scottish Power, and then EDF Energy and E.ON. SSE has generally discounted to a lesser extent than the other Six Large Energy Firms in recent years.

8.188 We have two further sources of information on the extent of price discrimination by suppliers: our analysis of the potential gains from switching for the period Q1 2012 to Q2 2014; and information on average revenues by suppliers, tariff type and payment type for the period 2010 to 2014. We note that the gains analysis does not suggest that [✂] has generally engaged in lower levels of discounting. This result seems to be driven largely by periods

[457] This includes: costs associated all telephone calls, enquiries and direct communications; billing and account management; home moves, account transfers and change of supply; costs related to unpaid bills; customer mailing and complaints; and meter reading.
[458] SLC 27.2A requires that any differences in charges as between payment methods shall reflect the different costs to the suppliers of the methods.

Q1 to Q3 2013 when [✂] offered heavily discounted tariffs and those for prepayment customers.

8.189 In short, the extent of discounting differs both between firms and over time. SSE, for example, said that in the past it had offered discounted tariffs. From 2006 to 2009, it was one of the cheapest suppliers due to [✂]. However, since then, rivals had enjoyed a number of cost advantages and had been able to offer cheaper tariffs. SSE said that it repositioned itself to differentiate itself from other suppliers by reference to its policy of fairness to all customers to build trust. SSE said that its strategy was based on a belief that customers were looking for a supplier that offered them prices that were stable as well as competitive. In January/February 2013 SSE did offer (SSE-branded) fixed-term variable-rate tariffs at a 10% discount,[459] at time of launch, but swiftly concluded that [✂].

8.190 All of the Six Large Energy Firms said that fixed-term tariffs were not determined by reference to the price of SVTs and expectations in relation to the relative cost of supplying customers subscribing to standard and non-standard tariffs. Rather, all suppliers have said that their fixed term tariffs are determined by strategic objectives on competitive positioning and therefore by the prices of rivals' tariffs, subject to an expected positive contribution to fixed costs.

8.191 With regard to direct costs, we conclude that transmission and distribution charges and costs of meeting social and environmental obligations do not differ between customers subscribing to standard variable and non-standard tariffs. In relation to energy costs, our provisional view is that there is no evidence that energy costs are systematically and materially higher for SVTs as compared with fixed-term, fixed rate tariffs.

8.192 With regard to indirect costs, suppliers have said that they would expect indirect costs to be much the same for customers subscribing to standard variable and non-standard tariffs. Our analysis suggests that any differences are unlikely to explain the observed differentials in the annual dual fuel bill.

8.193 Finally, that there are material differentials in prices for SVTs and fixed-term, fixed-rate tariffs that are not explained by differences in costs is consistent with statements made by most of the Six Large Energy Firms in relation to the strategic positioning of fixed-term tariffs as acquisition and retention products.

[459] Based on typical consumption customer.

8.194 Our provisional view is that suppliers are charging some customer segments prices that are higher than can be justified by costs, which suggests that they enjoy a position of unilateral market power over certain customer segments. We note that the extent of discounting differs between firms and over time. We also note that some suppliers have argued that they can only afford to discount some non-standard tariffs in expectation that a proportion of customers will revert to the SVT at the end of that tariff's term. Accordingly, in Section 10 we also consider the extent of the evidence (including evidence on profitability and the prices offered by the mid-tier suppliers) that the average prices offered by the Six Large Energy firms have been above those that we would expect to prevail in a well-functioning competitive market.

8.195 Overall, our provisional view is that the overarching feature of weak customer response, in turn, gives suppliers a position of unilateral market power concerning their inactive customer base. In relation to unilateral market power, our provisional finding is that suppliers in such a position have the ability to exploit such a position, for example through price discrimination by pricing their SVTs materially above a level that can be justified by cost differences from their non-standard tariffs and/or pricing above a level that is justified by the costs incurred with operating an efficient domestic retail supply business.

Tacit coordination

8.196 This section sets out our analysis of whether the Six Large Energy Firms use public announcements of their intentions to change prices as a mechanism for tacitly coordinating in the supply of gas and electricity to domestic customers.[460]

8.197 The State of the Market Assessment[461] found that several characteristics of the markets for the retail supply of gas and electricity were conducive to coordinated behaviour. It also found that aspects of the behaviour of the Six Large Energy Firms appeared to be consistent with tacit coordination between them, including the announcement of price changes around the same time and of a similar magnitude and convergence of domestic supply margins.

8.198 Tacit coordination may arise in a stable market where firms interact repeatedly and come to be able to anticipate each other's actions, allowing them to

[460] Appendix 8.5: Coordination the retail market facilitated by price announcements provides greater detail on the analysis we conducted.
[461] Ofgem State of the Market Assessment.

coordinate behaviour without reaching any agreement to do so. Such coordination involves firms competing less aggressively over time and forgoing the possibility of higher individual profits in the short term (by cutting prices unilaterally), in the expectation that this will lead to higher profits in the longer term.

8.199 The rest of this section is structured as follows:

(a) We assess whether characteristics of the retail supply of gas and electricity to domestic customers are conducive to tacit coordination.

(b) We then consider whether there is evidence of tacit coordination facilitated by price announcements.

(c) We consider whether market outcomes are consistent with tacit coordination.

(d) Finally, we present our provisional conclusions.

Conditions for coordination

8.200 The Guidelines state that three conditions need to be satisfied for coordination to be sustainable:[462]

(a) Firms need to be able to reach an understanding and monitor the terms of coordination. When there is no explicit agreement, firms need to have sufficient awareness of each other and be able to anticipate each other's reactions so as to identify a mutually beneficial outcome.

(b) Coordination needs to be internally sustainable among the coordinating group – ie the firms have to find it in their individual interests to adhere to the coordinated outcome; and they must lack an incentive, or have a positive disincentive, to compete because they appreciate how each other will react.

(c) Coordination also needs to be externally sustainable, in that coordination is unlikely to be undermined by competition from outside the coordinating group or from the reactions of customers.

8.201 Our provisional view, applying the criteria set out in the Guidelines, is that there are some characteristics of the market that may be conducive to tacit coordination.[463] In particular: the degree of transparency on the prices

[462] Paragraph 250.
[463] Appendix 8.5, paragraphs 16–49, give the views of the Six Large Energy Firms on whether market characteristics are conducive to tacit coordination.

offered by suppliers and other terms and conditions, and on the suppliers to and from whom domestic customers are lost and gained; and the degree of similarity in the cost structures and business models offered by suppliers.

8.202 However, we have also found that: there are some differences in the business models of suppliers; there will be short- to medium-term differences in energy costs reflecting differences in purchasing strategies; and there are groups of domestic customers, including those subscribing to fixed-rate products, who are more price-sensitive. We would expect these differences to make it more difficult to align and maintain incentives to coordinate across the group of Six Large Energy Firms.

8.203 We also note that smaller suppliers have recently achieved significant growth in the share of domestic customers, particularly in the fixed-priced/fixed-period segment of the market, which is another significant factor that reduces the likelihood of coordination in the retail market.

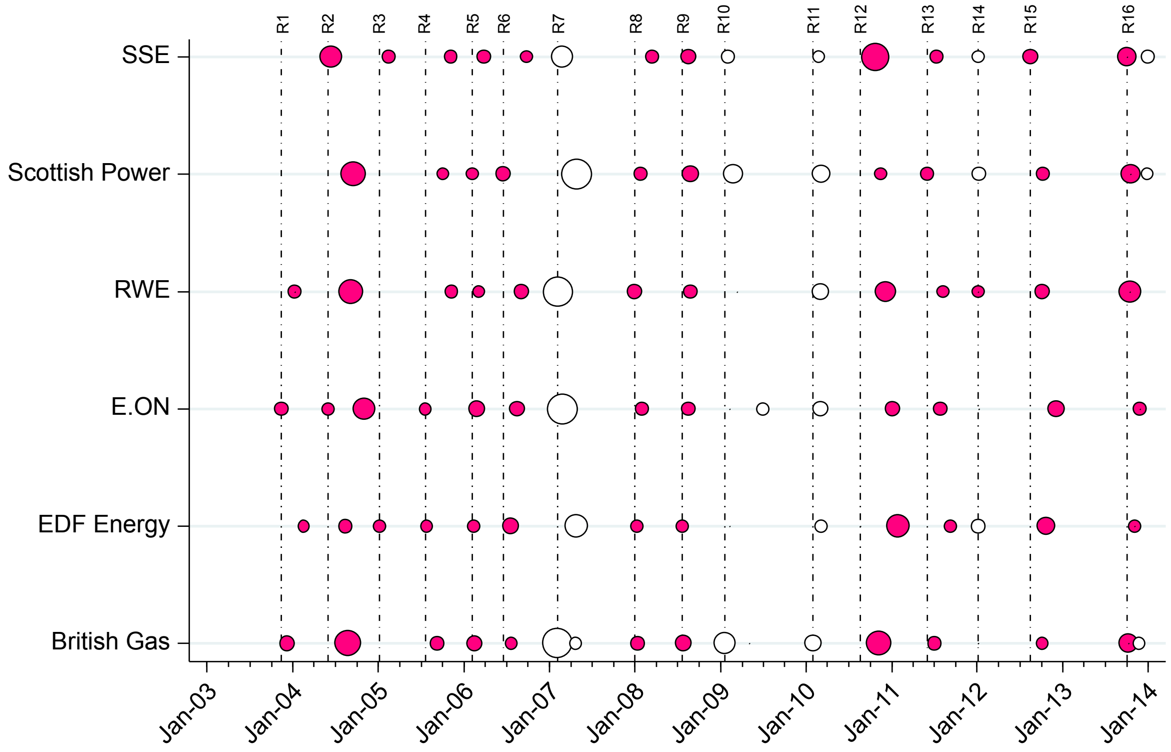
Evidence of tacit coordination through public price announcements

8.204 The Six Large Energy Firms make public statements, in advance of implementation, of intentions to change the price of their standard variable product. These announcements will typically give a ‘headline’ rate change and an implementation date. The ‘headline’ rate is typically an average across regions and based on the change in bill for a dual fuel domestic customer, paying by monthly direct debit with ‘typical’ consumption.

8.205 Figures 8.12 and 8.13 below show for the period 2004 to 2014 the timing of the announcement of changes to gas and electricity prices, the direction of the announced changes (pink denotes an increase and white a reduction), and their size (the larger the diameter of the circle the larger the increase relative to other announcements.

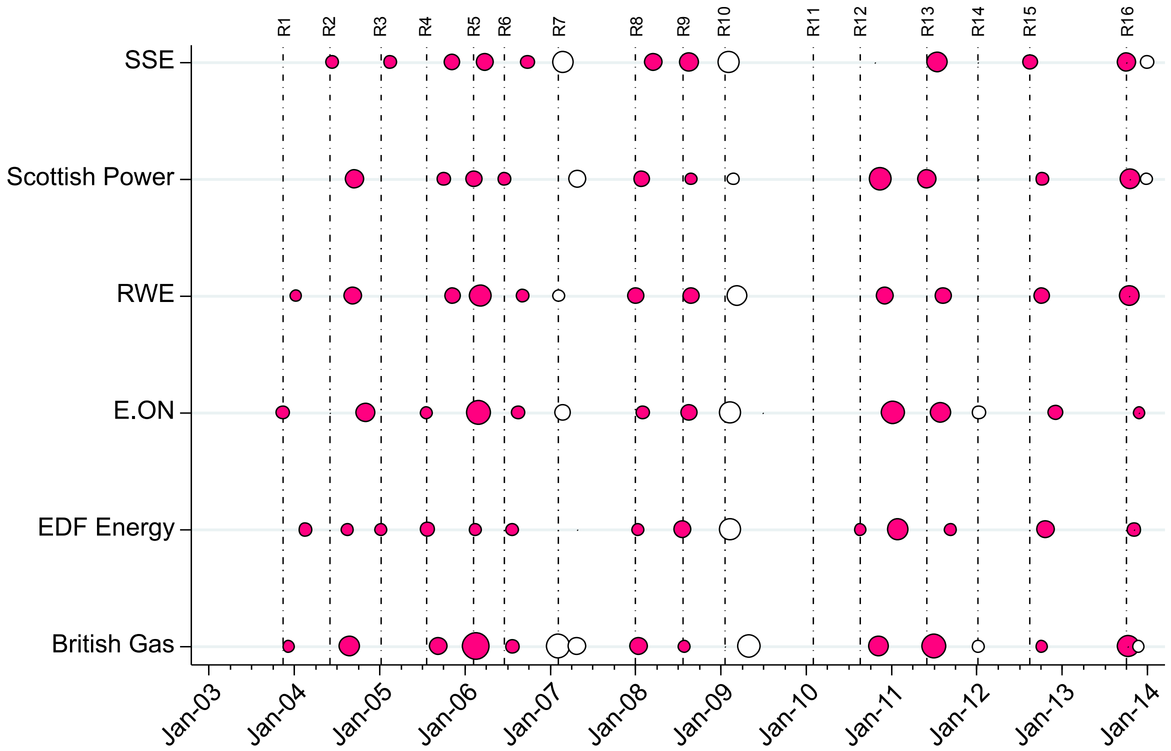
8.206 It can be seen that the announcements do, to a certain extent, seem to be clustered: the dotted lines identify what appear to be ‘rounds’ of price changes. However, the figures also show that within rounds there are differences between suppliers in the size of the announced changes. The time period over which announcements have been made has varied, from around 40 days to 160 days. No single supplier has consistently been the first in announcing price changes.

Figure 8.12: The timing, direction and size of announced changes in SVT gas prices, 2004 to 2014



Source: CMA analysis.
Note: Pink circles denote positive gas price changes and white circles denote negative gas price changes.

Figure 8.13: The timing, direction and size of announced changes in SVT electricity prices, 2004 to 2014



Source: CMA analysis.
Note: Pink circles denote positive gas price changes and white circles denote negative gas price changes.

8.207 In considering whether the public pre-announcement of 'headline' changes to SVT prices could be a practice facilitating tacit coordination, we have considered: the scope of the price announcements; whether there is any evidence that suppliers have used these announcements to signal their intentions to rivals, such that rival suppliers can adjust their behaviour accordingly; and alternative explanations for why suppliers might publicly announce intended changes to prices for SVTs.

8.208 The Six Large Energy Firms all said that their public announcements concerned the SVTs. Some said that they also made public announcements concerning changes to certain discounted variable and capped tariffs.[464]

8.209 We consider the length of the period between a supplier announcing a price change and *(a)* notifying domestic customers or *(b)* implementing the change to be key to our analysis of whether price announcements may be used by suppliers to signal their intentions to rivals, and for rival suppliers to be in a position to adjust their behaviour accordingly. The shorter the period between an announcement and notification and/or implementation the less opportunity there is for suppliers to use the public announcement of changes as a device for coordinating on the size or timing of a change.

8.210 We generally found that the period between the Six Large Energy Firms' public announcements of a price change and starting to notify domestic customers or implementation has since mid-2011, which is when SLC 23 came into effect, been at most around ten days. Before this date there were instances when the period was longer, but we did not identify any particular patterns in the behaviour.

8.211 We also assessed whether there was any evidence of announced pricing plans changing in response to subsequent announcements made by rivals to be significant.

8.212 The Six Large Energy Firms told us that they were, in effect, committed to a change once they started notifying their domestic customers. While a supplier could theoretically reverse or modify its decision, this would be an unattractive option because it could be costly in management time, damaging to the firm's reputation with domestic customers and delay a price change for which presumably there were good commercial reasons. Centrica, EDF Energy, E.ON, RWE and SSE confirmed that there were no occasions on which they had modified the level or timing of price changes between announcement and implementation. Scottish Power said that it had

[464] Appendix 8.5 Coordination the retail market facilitated by price announcements.

not identified any occasions when its plans in relation to a change in price changed materially following the public announcement.

8.213 The Six Large Energy Firms told us that in announcing price changes their objectives were, in broad terms, to manage their relationships and reputation with domestic customers, regulators and politicians, and to meet market regulatory requirements.[465] Our initial provisional view is that these explanations appear consistent with the documentary evidence we have received.

8.214 Our provisional findings in relation to these outcomes are as follows:

(a) Market shares: As explained above, we found that market shares have been relatively stable nationally and at a regional level, although the mid-tier suppliers have increased their market shares considerably over the last two years.

(b) Prices: We observed in Section 7 that SVTs do move together. While we do not see a consistent convergence of tariffs over time, it appears that in 2013 and 2014 the range of tariff prices was typically narrower than that seen in the years 2006 to 2012.

(c) Profitability and margins: We noted in Section 2 that EBIT margins of the Six Large Energy Firms increased after 2009. In Section 10 we consider the evidence on whether current levels of profitability are excessive.

8.215 We note that none of these outcomes would by themselves be evidence of tacit coordination. In particular, some of these outcomes could also be consistent with weak competition arising from unilateral market power (eg stable market shares and high profitability), and some could be consistent with a competitive market (eg price parallelism).

Provisional conclusions on tacit coordination

8.216 Based on the evidence set out above, our provisional finding is that the evidence suggests that there is no tacit coordination between the domestic retail energy suppliers in relation to price announcements. In particular, we note the following:

(a) There are some characteristics of the supply of gas and electricity to domestic customers that may be conducive to coordination. However, we have also identified factors that may make it more difficult for firms to reach and sustain coordination.

[465] Appendix 8.5: Coordination in the retail market facilitated by price announcements, paragraph 65.

(b) There is no evidence of suppliers using price announcements as a mechanism to signal their intentions in relation to the pricing of their SVT to rival suppliers to determine their prices accordingly.

(c) We do find some evidence of certain outcomes consistent with coordination, but we note that those outcomes can also be attributed to the exercise of unilateral market power in a market with inactive customers. As such there are other plausible explanations for these outcomes.

Regulations

8.217 The supply of electricity and gas is heavily regulated, and the form that regulation takes has a profound effect on the shape of competition in retail energy markets. In this section we consider several elements of the regulatory regime that may have a potential impact on competition between suppliers to serve customers:

(a) The RMR reforms introduced in 2014 in an attempt to promote customer engagement.

(b) The prohibition on regional price discrimination brought about through SLC 25A.

(c) Ofgem's amended PCW Confidence Code, introduced in 2015.

(d) The settlement system for gas and electricity.

(e) The rules that exempt small suppliers from delivering the ECO, FITs and the Warm Home Discount.

Retail Market Review reforms

8.218 Ofgem launched the RMR in late 2010 due to concerns that retail energy markets were not working effectively for consumers. The stated purpose of RMR was to promote customer engagement in energy markets in order to improve the competitive constraint provided by customer switching.[466]

8.219 The RMR reforms package that took effect in 2014 (the RMR rules) includes three broad components:

[466] Ofgem (27 March 2013), The Retail Market Review – Final domestic proposals.

(a) simpler choices – designed to make it simpler for customers to understand and compare the energy tariffs offered by suppliers and, accordingly, to encourage customer engagement;

(b) clearer information – to help customers understand the information they receive from suppliers; and

(c) fairer treatment – to help rebuild customer confidence in the energy market, suppliers must follow new standards of conduct.

8.220 In this section we analyse the impact on competition of the 'simpler choices' component of the RMR rules, which includes the following measures: *(a)* the ban on complex tariffs; *(b)* a maximum limit on the number of tariffs that suppliers will be able to offer at any point in time; and *(c)* the simplification of cash discounts.[467] In the rest of this section we assess available evidence on:

(a) the impact of the RMR rules on customer engagement;

(b) the impact of the RMR rules on the tariff offerings of the Six Large Energy Firms and on their ability to compete;

(c) the process of derogation from the RMR rules; and

(d) the impact of the RMR rules on the ability and incentives of TPIs to compete

Impact of the RMR rules on customer engagement

8.221 We reviewed the results from Ofgem's baseline survey, which was carried out in February and March 2014,[468] and the year one survey which was carried out a year later. We focused on the evidence related to various measures of consumer engagement and barriers to engagement.

8.222 The comparison of the results indicates that there are no material differences in various indicators of engagement between the two surveys. All changes are within three percentage points.[469] We also note that the results are consistent with the results from our own survey which was conducted in the period between the two RMR surveys. We had broadly similar findings across a number of measures of engagement to the RMR surveys.

[467] A more detailed analysis of RMR is provided in Appendix 8.2: Impact of RMR.
[468] The RMR rules came into force in phases from August 2013 through June 2014. Some individual RMR remedies were therefore introduced in the months before the baseline survey fieldwork.
[469] The results are given in Appendix 8.2: Impact of RMR.

8.223 We note that RMR has been recently introduced, and that it is therefore a relatively early stage to be considering its impact on engagement. However, we do have broader doubts about the long-term impact on engagement of the 'simpler choices' element of the reforms.

8.224 Even after the introduction of the four-tariff rule, suppliers can still offer a maximum of 16 dual fuel permutations for a customer on a standard meter, implying that, with around 30 active suppliers, there could be up to as many as 500 permissible dual fuel choices for each customer, although in practice there have been substantially fewer than this. Nevertheless customers are likely to have a wide choice with each supplier allowed to offer a customer on a standard tariff up to four tariffs, which might also give customers options in relation to how they pay and how they manage their account. Customers who use both fuels also have the option of taking both fuels from the same or different suppliers.

8.225 The implication is that any customer who wishes to find the cheapest tariff on the market will in practice need to use a TPI, with or without the four-tariff rule. We think it is doubtful, therefore, that this rule will have a significant beneficial effect on customer engagement. Similar doubts have been expressed to us by Stephen Littlechild,[470] Professor Catherine Waddams and the University of Exeter Energy Policy Group.[471]

8.226 In relation to complexity, we recognise that the two-part structure prescribed by RMR rules[472] is simpler to understand than multi-rate tariffs that vary by consumption, for example. However, in practice a customer will still need to understand their consumption levels and calculate – or have a PCW calculate for them – the cheapest tariff.

Impact of RMR on tariff offerings and discounts

8.227 As a result of RMR, many tariffs were removed, including several that had large numbers of customers.[473] British Gas said it removed two tariffs in order to comply with RMR. Scottish Power said it removed three tariffs as a result of RMR. EDF Energy said that one tariff was removed as a result of RMR. British Gas, RWE npower, Scottish Power, EDF Energy and E.ON all removed green energy tariffs as a result of RMR. SSE said that green tariffs

[470] Stephen Littlechild (15 August 2014), *Promoting or restricting competition? Regulation of the UK retail residential energy market since 2008*.
[471] Response to Statement of Issues, University of Exeter, Energy Policy Group, 14 August 2014.
[472] As described in Section 7, each tariff offered by suppliers must be presented in the form of a standing charge and a unit rate, each of which may vary in a predefined way by time of year, week or day or in line with an independent published index, such as the Retail Prices Index (RPI) or rate.
[473] A more comprehensive list of tariffs withdrawn is set out in Appendix 8.2: Impact of RMR.

had limited appeal and thus were no longer commercially viable under the tariff cap.

8.228 RWE removed variable discount tariffs which offered a percentage discount to the SVT – in 2013 there were over [✂] accounts on these types of tariffs. E.ON removed two fixed-bill tariffs, including the StayWarm tariff, implemented in October 2013 (with around 200,000 accounts). The removal of these tariffs was driven primarily because of the experience customers would receive due to RMR changes which would require customers to renew to SVT at the end of their contract.

8.229 Scottish Power, SSE, British Gas, EDF Energy and E.ON all said that they removed prompt payment discounts in order to comply with RMR. Scottish Power said that its prompt payment discount was valued by many of its credit customers, including older customers. The alternative of a late payment surcharge, which is allowed under RMR, was not considered to have customer appeal.

8.230 The Six Large Energy Firms have made several comments in relation to the impact of RMR on their ability to attract different types of customers – particularly their offering to low-consumption and vulnerable customers – and their ability to innovate.

8.231 Scottish Power removed two-tier tariffs that benefited very low-consuming customers. Scottish Power said that the ban on two-tiered tariffs meant that low consumption households now paid more. SSE removed nil standing charge tariffs aimed at low-usage customers. SSE said that its ability to offer tariffs aimed at low-consumption/vulnerable customers had been severely curtailed.

8.232 Regarding innovation, several suppliers have noted that the four-tariff rule affects innovation, since suppliers cannot afford to use up a tariff slot on a small-scale innovative product. RWE said the complexity of rules around RMR had reduced its incentive to launch innovative or niche tariffs due to the need to appeal to the mass market with the four tariffs on offer. It said that it could not trial more innovative offers such as Energycare [✂].

8.233 Some mid-tier suppliers have also told us that RMR has restricted their ability to innovate. Ovo said 'we think much of the regulatory intervention, particularly RMR, has damaged competition and stifled innovation. In particular, the four tariff rule […] has hindered innovation in providing a commercial, competitive answer to the problem of inactive customers.' Utility Warehouse said that the four-tariff rule had stifled innovation. It said that the four-tariff rule was restrictive if all you were doing was selling energy; if you were trying to create innovative bundles of energy with other services, it was impossibly restrictive. There were lots of innovative things it would like to do, but could not. First Utility said it did not believe the four-tariff rule had limited innovation and Co-operative Energy said there was a question mark over whether the four-tariff rule restricted innovation.

8.234 Several suppliers told us that they had concerns that the four-tariff rule would be a particular constraint in the future on their ability to offer innovative products to customers with smart meters.

The process of derogation from the RMR rules

8.235 Suppliers can receive a derogation from the RMR rules on application to GEMA, which will consider the case for a derogation where a licensee is able to demonstrate that compliance with one or more of the relevant RMR rules would have substantial unintended or unanticipated negative consequences for consumers. However, several suppliers have told us that there has been a lack of clarity over exemptions to the four-tariff rule and over the way in which the four-tariff rule applies to white-labelling.

8.236 RWE said that white-labelling was something that was not initially allowed under RMR, then was allowed for some suppliers and might now be allowed. British Gas said that when RMR was first proposed it believed the proposals would discourage suppliers from developing white-label offerings.

The impact of the RMR rules on the ability and incentives of TPIs to compete

8.237 We consider the effect of RMR on the ability of suppliers to offer tariffs exclusively available via a particular PCW in Appendix 8.3: Price comparison websites and collective switching.

8.238 One very significant aspect of RMR is that TPIs are effectively prevented from offering discounts on the suppliers' tariffs, as doing so would increase the number of tariffs being offered. In this respect, RMR has similar properties to resale price maintenance. This is of concern as in a well-functioning TPI market competition between TPIs will lead them to compete away their commission rates by offering higher discounts to consumers.

8.239 We note that the RMR rules effectively prevent suppliers from being able to offer tariffs exclusively available via a particular PCW,[474] which limits the scope for commission negotiation and passing on savings to consumers.[475]

8.240 We also note that components of RMR appear to be providing an environment that promotes the organisation of collective switch schemes, notably the derogations from the four-tariff rule for tariffs offered via collective switch schemes, which do not apply to tariffs offered via PCWs.[476] EDF Energy said collective switch schemes were being artificially encouraged by being exempt from the four-tariff rule[477] and First Utility said they were concerned that collective switch schemes might be used as a way to circumvent RMR requirements.[478]

8.241 Finally, we note that Ofgem's initial view not to allow cashback as part of the RMR rules resulted in many suppliers ending their use of cashback websites to acquire customers. Ofgem has since decided to allow cashback where the cashback is offered by a TPI and not directly from a supplier and if the cashback is not linked to a particular tariff. Topcashback.co.uk said that it stopped working in the energy market due to Ofgem's initial view not to allow cashback as part of RMR. It started working with First Utility following what it understood to be Ofgem's decision to allow cashback via TPIs. However, it said that First Utility was then contacted by Ofgem saying the scheme was violating RMR rules. There therefore appears to be ongoing uncertainty over whether cashback offered via TPIs is permissible or not.

Provisional conclusion

8.242 The stated purpose of RMR was to promote customer engagement in the retail energy markets in order to improve the competitive constraint provided by customer switching. However, some of the RMR measures restrict the behaviour of suppliers and constrain the choice set for consumers in a way that may have an adverse impact on competition and consumer welfare.

8.243 The RMR rules have not been in place long enough for us be able to assess with full confidence its overall impact on consumer engagement and competition. That said, the evidence in hand at this stage is not particularly encouraging. There are few if any signs that consumer engagement is

[474] uSwitch has offered a tariff only available via uSwitch, supplied by E.ON. It has been able to do this as the tariff offered is a collective switching tariff that is exempt from RMR requirements.
[475] Due to uncertainty over whether cashback was permitted under RMR, many suppliers stopped working with cashback websites.
[476] Appendix 8.2: Impact of RMR, paragraph 61.
[477] Appendix 8.3: Price comparison websites and collective switches, paragraph 117.
[478] Appendix 8.3: Price comparison websites and collective switches, paragraph 117.

improving materially, either in terms of direct consumer activity (eg switching, shopping around) or their experience and perception (eg views on tariff complexity). Those who were disengaged before the RMR appear to remain so. Further we have doubts that the four-tariff rule will have a benefit on engagement in the long term.

8.244 The introduction of the RMR rules and specifically the four-tariff rule, has had an impact on the 'active' side of the market as a result of the Six Large Energy Firms withdrawing a number of tariffs and discounts, and changing tariff structure which may have made some customers worse off. In particular:

(a) Some innovative tariffs were withdrawn. A good example of that is E.ON's StayWarm tariff for the over 60s (approximately 200,000 customer accounts), which helped customers budget their energy payments and gave them the reassurance that costs would not rise if more energy was used during the course of the year (for example, because of harsh winter).

(b) Various discounts were removed by the Six Large Energy Firms as a result of RMR rules, including those that reflect cost savings to suppliers from consumer behaviour. An example of this is prompt pay discounts which were used by all of the Six Large Energy Firms before the RMR, except RWE npower.

(c) RMR curtailed the ability of the Six Large Energy Firms to offer attractive tariffs for low-volume users (tariffs with no or low standing charge). As a result, many of those customers may now be paying more for their energy, especially if they were migrated on to SVTs.

8.245 We agree with much of what the Six Large Energy Firms said in relation to the adverse impact of the RMR rules on innovation. We consider that the restrictions imposed by the RMR four-tariff rule limits the ability of suppliers to innovate and provide products which may be beneficial to customers and competition. This is of particular concern over the longer term as RMR rules could potentially stifle innovation around smart meters.

8.246 The impact of the RMR rules on the intensity of price competition between suppliers is less clear. While the suppliers no longer offer discounted variable-rate tariffs, price competition now takes place in the fixed-term, fixed-rate space where many tariffs are priced at a sizeable discount to SVTs. This is documented in our work on cost pass-through, gains from switching and pricing policies appendices.

8.247 One area where the impact of the RMR appears to be harmful to price competition is in relation to PCWs. PCWs can no longer attract customers by sacrificing commission, either directly by way of cashbacks,[479] or indirectly by securing exclusive tariffs from suppliers because of the four-tariff rule.

8.248 Overall, our provisional finding is that the ‘simpler choices’ component of the RMR rules (including the ban on complex tariffs, the maximum limit on the number of tariffs that suppliers will be able to offer at any point in time, and the simplification of cash discounts) is a feature of the markets for the domestic retail supply of electricity and gas in Great Britain that gives rise to an AEC through reducing retail suppliers’ ability to innovate in designing tariff structures to meet customer demand, in particular, over the long term, and by softening competition between PCWs.

Prohibition on regional price discrimination SLC 25A

8.249 As noted in Section 7, in 2009 Ofgem implemented SLC 25A, in an attempt to address concerns that certain groups of customers were not benefiting from competition. The prohibition lapsed in 2012. However, suppliers told us that, following a communication from Ofgem warning against ‘pricing practices which are unjustified […] returning to the market’, they continued to adhere to the principles of SLC 25A in their pricing of SVTs. In December 2014, Ofgem wrote to suppliers to confirm that SLC 25A had lapsed and that suppliers were not bound by it in any way.

8.250 The decision to introduce the prohibition in 2009 has been heavily criticised by two former regulators, Stephen Littlechild and George Yarrow, both of whom argued to us in hearings that the licence change had the effect of restricting competition to the detriment of customers. We note also that some academic work has been conducted on this topic.[480] One independent supplier told us that the prohibition reduced competition in incumbents’ in-area regions and focused competition on the active customer, further segmenting the markets.

8.251 We note that our analysis of the relationship between the SVT and measures of direct costs (see paragraphs 7.152 following) is suggestive of an apparent softening of competition in SVTs from 2009 onwards (in that the

[479] Ofgem now allows TPIs to offer cashback but not if they are linked to a particular tariff. Following RMR, most suppliers no longer work with cashback websites.
[480] Work by Waddams and Zhu (Catherine Waddams Price and Minyan Zhu, *Pricing in the UK Retail Energy Market, 2005 to 2013*, ESRC Centre for Competition Policy and Norwich Business School) analysed the pattern of SVT pricing behaviour among the Six Large Energy Firms before and after the introduction of the non-discrimination clause and found that there was less-effective rivalry between the regional incumbents and large regional competitors following its introduction.

gap between the average SVT and total costs appears to widen since 2009) and that this broadly coincides with the introduction of the prohibition. We also note that other important changes have taken place over this period – notably the withdrawal of the Six Large Energy Firms from doorstep selling – which may also have contributed to the pattern observed. We also note that the gap between the average SVT and measures of direct costs was low before 2009.

8.252 As noted in our updated issues statement, we considered conducting an econometric analysis to compare the evolution of prices for domestic energy customers with those of a control group before and after the imposition of SLC 25A but, after a process of consultation with parties and other stakeholders, we decided not to carry out this analysis due to the lack of a suitable counterfactual to which to compare domestic energy prices.

8.253 We asked suppliers whether they had any plans to reintroduce regional price differentials on the SVT now that Ofgem has confirmed that there is no longer a prohibition in force. RWE told us that there had been several products launched since Ofgem's clarification at the end of 2014 for which it had [✄].

8.254 Overall, we think it is likely, on the basis of the evidence that we have seen, that SLC 25A contributed to a softening of competition on the SVT, although other factors may also have had an impact. However, since Ofgem has confirmed that this licence condition is no longer in place, we do not consider that it currently leads to an AEC.

PCW Confidence Code

8.255 The Confidence Code, for which Ofgem is responsible, is a voluntary code of practice that governs independent PCWs offering an energy comparison and switching service. It is underpinned by four main principles: independence, transparency, accuracy and reliability. The purpose is to give assurance to customers using accredited PCWs that the service they receive will meet these principles.

8.256 Ofgem recently amended the Confidence Code, following consultation, such that from the end of March 2015 Code-accredited PCWs would no longer be able to present as a default only fulfillable (a fulfillable tariff is one for which a PCW can facilitate the switch and is paid a commission for doing so) tariffs. Instead PCWs must present all available tariffs as a default unless a customer makes an active and informed choice to see filtered results. The aim of this amendment was to promote customer trust and confidence in accredited PCWs. The wording of this choice given to site users must be clear and simple. Sites must test their message with customers and provide results of this testing to Ofgem. Otherwise, the PCW will have to show all tariffs.

8.257 In response to the Ofgem consultation on the Confidence Code[481] the Six Large Energy Firms were generally in favour of PCWs being required to display as a default the whole of the market, but there was less consensus among the smaller suppliers.

8.258 PCWs are concerned about the new requirement, including that it will:

(a) change the relationship between PCWs and energy suppliers to favour suppliers (uSwitch and My Utility Genius);

(b) benefit suppliers by providing them with free advertising of tariffs that are listed on a PCW but are not fulfillable via the PCW (uSwitch); and

(c) lead to an increase in the number of unfulfillable tariffs as suppliers may remove specific tariffs from PCWs (My Utility Genius) or may choose not to enter into commercial relationships with PCWs at all (uSwitch).

8.259 We consider that the effect of the Confidence Code change depends on customer behaviour. uSwitch said its own analysis suggested that since the announcement of the Confidence Code changes the majority of customers saw the full market view.

8.260 uSwitch said that its monthly tariff fulfillability report was starting to show an emerging trend of declining fulfillability levels among the most price-competitive tariffs on the more common payment types. Out of the top 10 results displayed on uSwitch for monthly direct debit, dual fuel tariffs, five were fulfillable in June 2015 compared with 7 in April 2015.

8.261 We consider that it is too early to assess the impact of the change on the Confidence Code. It is unclear whether the requirement to display the whole of the market will result in more consumers using PCWs as trust in PCWs increases, or whether it will lead to an increasing number of suppliers not entering into commercial relationships with PCWs at all, resulting in a withdrawal of PCWs from the market. We therefore do not consider that the amended Confidence Code currently leads to an AEC. We will need to consider the appropriateness of the Confidence Code in light of other possible remedies we may consider.

[481] Ofgem (2014), *Domestic third party intermediaries: Confidence Code and wider issues*.

Gas and electricity settlement and metering

8.262 Settlement is the system by which disparities between the volumes of energy covered by suppliers' contracts and the volumes their customers actually use are identified and paid for. This section considers whether the regulatory framework governing gas and electricity settlement and metering provides the right incentives to ensure that suppliers can compete effectively and to encourage product innovation.

Gas settlement

8.263 Xoserve is responsible for ensuring that gas transportation charges invoiced to gas shippers and traders are accurate and in line with Uniform Network Code. Xoserve is also responsible for monitoring the balance between shippers' inputs to and offtakes from the gas network and for generating the resultant energy balancing charges.

8.264 Gas settlement is based on daily positions. However, for the majority of customers who do not have their meter read on a daily basis (non-daily metered (NDM) customers), their consumption for the purposes of network transportation charging and energy balancing are derived from an allocation of the total system throughput after daily metered quantities and shrinkage have been deducted. Each meter has an Annual Quantity (AQ) assigned to it, which is the expected annual consumption of the meter point. This expectation is based on the historical metered volumes and seasonal normal weather conditions. The AQ value can only be adjusted during a specified AQ review period and only if meter reads demonstrate that actual consumption is at least 5% higher or lower than the AQ value.

8.265 Total NDM gas in each Local Distribution Zone (LDZ) is allocated to all NDM supply points using industry agreed usage profiles that take account of differing consumer reactions to weather conditions and other factors. There is currently no individual meter point level reconciliation for smaller supply points, which means that 'unidentified gas' in the settlement process is spread between shippers based on their market share of smaller supply points in each LDZ. This process is called Reconciliation by Difference (RbD).

8.266 We expressed concerns in our updated issues statement that the inaccuracy of AQs and the lack of reconciliation may not provide the correct incentives to suppliers and in particular may:

(a) disadvantage certain types of supplier – notably those that have been particularly effective in helping their customers reduce their gas consumption; and

(b) lead to gaming opportunities (whereby a supplier may delay adjusting an AQ value if it would be to its disadvantage).[482]

8.267 Several responses to our updated issues statement echoed these concerns. The main points that were put to us in relation to the gas settlement process were as follows:[483]

(a) EDF Energy said that the current gas settlement process was inadequate and could result in shippers being faced with inaccurate charges, and that there was potential for gaming the AQ system.

(b) Centrica agreed that the current system created the risk of gaming, and said that it had led to prepayment meter customers being over-allocated costs.

(c) SSE said that, although there was a systematic bias in gas settlement, this operated to the disadvantage of all domestic suppliers. This did not impact on competition between domestic suppliers. SSE argued that any additional disadvantage to suppliers that were successful in encouraging customers to reduce consumption was small compared with errors arising from customer gains and losses.

(d) First Utility agreed that the current system did penalise those companies whose customers reduced their gas consumption and that there was an incentive for shippers to place a higher priority on adjusting AQs down and to delay adjusting AQs up.

(e) Utilita told us that the inaccurate profile used for prepayment allocation had resulted in a transfer of cost from credit to prepayment customers.

8.268 We note that a significant upgrade of the gas settlement system is planned, in an attempt to address some of these issues, called Project Nexus. The changes will include replacement of RbD with reconciliation at all individual meter points and the opportunity for monthly rather than annual update of the AQs (also referred to as rolling AQs).

8.269 Under Nexus a party has the opportunity for monthly rather than annual update of the AQs. But it might still gain financially, in terms of reduced

[482] Appendix 8.6: Gas and electricity settlement and metering, sets out these concerns in more detail.
[483] A full summary of responses is given in Appendix 8.6: Gas and electricity settlement and metering.

imbalance and settlement costs, from its ability to delay updates, particularly if this would lead to an upward revision of an AQ. Further, the incentive for a party to place a higher priority on adjusting AQs down reduces that particular party's settlement costs, but would increase the cost of settlement for all other parties due to the unidentified gas mechanism. Incentives for suppliers to encourage demand-responsiveness in their customers are dampened.

8.270 Ofgem told us that 'individual supply point reconciliation will mitigate, but not entirely remove, the possibility of gaming AQ amendments', since parties may still gain financially by withholding reads. It is currently working on developing a performance assurance regime to help address such concerns. As yet, it is not clear what form such a regime might take.

8.271 Centrica said that the problem of prepayment customers being over allocated costs had been addressed with the introduction of a new prepayment meter profile. However, Utilita submitted that the weather-adjustment in the new prepayment meter profile still resulted in inaccurate allocation to prepayment meters, as the underlying profile was very similar to the credit meter profile and the cold weather adjustments overestimated the demand increase of customers with these meters.

8.272 As discussed in Appendix 8.6, Project Nexus has taken a long time to develop. The Project Nexus work group began meeting in 2009 and the most recent deadline for Nexus reforms becoming operational (October 2015) is likely not to be met. To our knowledge, no revised deadline has been set. In its response to our working paper, Ofgem said 'this is another example of where industry governance processes may not facilitate the timely implementation of reforms that will improve efficiency and benefit consumers.'

8.273 Overall, our provisional finding is that the current system of gas settlement is a feature of the market for domestic retail gas supply in Great Britain that gives rise to an AEC through the inefficient allocation of costs to parties and the scope it creates for gaming, which reduces the efficiency and, therefore, the competitiveness of domestic retail gas supply. While we note that Project Nexus is likely to address most of the current inefficiencies in the gas settlement system identified, we are concerned at the slow pace of the implementation, the lack of a deadline and the fact that some players might have been adversely affected by these delays. Moreover, we are concerned that the incentives that shippers face to place a higher priority on adjusting AQs down and delaying adjusting AQs up will still be present after Project Nexus is implemented.

8.274 The current system of gas settlement also applies to microbusiness gas customers. Accordingly, our provisional view concerning the market for domestic gas supply also applies to the market for SME retail gas supply in Great Britain (see Section 9).

Electricity settlement

8.275 The electricity settlement process is set out in the Balancing and Settlement Code (BSC). Elexon administers the BSC and provides and procures the services needed to implement it.[484]

8.276 Electricity settlement takes place every half hour but the vast majority of customers do not have meters capable of recording half-hourly consumption. Therefore, their consumption must be estimated on an ex ante basis. This is done by assigning customers to one of eight profile classes, which are used to estimate a profile of consumption over time and allocate energy used to each half-hour period.

8.277 Our main concern in relation to electricity settlement is that the current profiling system of settlement distorts incentives. The use of load profiling to estimate each supplier's demand fails to charge suppliers for the true cost of their customers' consumption. This could mean that suppliers are not incentivised to encourage their customers to change their consumption patterns, as the supplier will be charged in accordance with their customer's profile. This in turn may distort suppliers' incentives to introduce new innovative products.[485]

8.278 In principle, smart meters should remove the need for profiling in electricity, since they provide accurate half-hourly meter reads which could be used for settlement. However, we are concerned that there are currently no concrete proposals for using half-hourly consumption data in the settlement of domestic electricity customers, even after the full roll-out of smart meters.

8.279 This may distort incentives in a number of ways – notably, if suppliers are not settled on a half-hourly basis they will not be incentivised to encourage their customers to change their consumption patterns (as suppliers will be charged in accordance with the profile patterns). This may in turn reduce suppliers' incentives to innovate and bring in new products and services such as time-of-use tariffs, which reward customers for shifting consumption away from peak periods. Since peak load shifting has the potential to reduce

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[484] ELEXON is currently fully owned by National Grid.

[485] Further, as a result of this system, suppliers spend resources forecasting profile demand rather than the actual demand expected from the characteristics of their customer base, which can add to inefficiencies.

costs to the electricity sector substantially, this risks increasing costs to the sector and hence the price paid by customers overall.

8.280 We have reviewed the evidence on the potential value of load shifting through time-of-use tariffs. DECC, drawing on the results from several trials, estimated that domestic peak load shifting could be expected to generate savings of the order of £900 million through reducing the need for investment in generation (the majority of savings) and the distribution network.[486] DECC has commissioned further work through Frontier to assess the potential for domestic load shifting, which is due to report this summer.

8.281 In relation to the views of parties on this issue:

(a) Centrica agreed that the use of profiles to allocate costs could distort the incentives on suppliers to innovate and bring in new products and support the principle of moving towards half-hourly settlement for all meters. It considered that aggregate benefits associated with half-hourly settlement would become significant after 2018, when both 60% of domestic customers would have a smart meter and when customers may start to demand the dynamic time-of-use tariffs that realise the benefits of half-hourly settlement. Until then, it believed that the material costs of half-hourly settlement would vastly outweigh the benefits realised by those with smart meters.

(b) Utilita [✂].

(c) SSE regarded the current use of demand profiles in electricity settlement as adequate, and did not believe that the cost of managing imbalance was significantly higher as a result of this approach. However, once the roll-out of smart meters was suitably advanced, it would welcome a move towards half-hourly settlement for all profile classes.

(d) Tempus submitted [✂].

(e) RWE said that it believed that elective half hourly settlement would achieve change and that this should only be made mandatory if progress was insufficient until at least 2020.

8.282 In relation to the argument by RWE that elective half-hourly settlement would achieve sufficient change, Utilita put to us that [✂].

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[486] DECC (2014), *Smart meter roll-out for the domestic and small and medium non-domestic sectors (GB) impact assessment*.

8.283 Utilita considered that the strict regulatory standards DCAs had to comply with and the significant uncertainty on the roll-out of smart meters (including implications for the future role of DCAs) prevented competitors from entering this market and hence allowed the existing DCAs to charge such high fees. Utilita suggested that more cost-reflective charging should be considered across the board for both non-half-hourly and half-hourly meters in electricity.

8.284 In relation to the arguments concerning the timing of a shift to half-hourly settlement for all domestic customers, we agree with parties that this should be determined by an assessment of overall costs and benefits, which themselves will partly be a function of the number of domestic customers that have smart meters. Ofgem has told us that it is undertaking initial thinking about half-hourly settlement as part of its demand-side flexibility strategy, due to be published in summer 2015. We will review this initial thinking, alongside the analysis that DECC has commissioned, when they are available.

8.285 Even if the correct date for a wholesale move to half-hourly settlement is, as Centrica argues, from 2018 onwards, the experience set out in Section 11 and Appendix 11.2 suggests that progressing the required code modification could take a long time. We therefore remain concerned at the lack of concrete plans for a move to half-hourly settlement, and the fact that no modification process on this has begun. Further, as discussed above, the lack of clarity over the regulatory regime for half-hourly settlement is likely to be inhibiting cost-effective elective half-hourly settlement.

8.286 Therefore, our provisional finding is that the absence of a firm plan for moving to half-hourly settlement for domestic electricity customers and of a cost-effective option of elective half-hourly settlement is a feature of the market for domestic retail electricity supply in Great Britain that gives rise to an AEC through the distortion of suppliers' incentives to encourage their customers to change their consumption profile, which overall reduces the efficiency and, therefore, the competitiveness of domestic retail electricity supply.[487]

8.287 The absence of a firm plan for moving to half-hourly settlement and of a cost-effective option of elective half-hourly settlement also affects the majority of microbusiness electricity customers.[488] Accordingly, our

[487] As noted above, there are a number of other factors in addition to the non-availability of half-hourly settlement that may also prevent the introduction of innovative products and the attainment of demand-side response (DSR), including the RMR four-tariff rule.

[488] The majority of microbusinesses are currently assigned to profile classes 3–4, ie Non-Domestic Unrestricted Customers and Non-Domestic Economy 7 Customers.

provisional finding concerning the market for domestic electricity supply also applies to the market for SME retail electricity supply in Great Britain (see Section 9).

Small supplier exemptions

8.288 Some government policies to deliver social and environmental objectives are delivered through energy suppliers. These policies put obligations on suppliers to require them to meet certain carbon reduction targets and recover the cost of doing so from consumers through energy bills. The Six Large Energy Firms as well as three of the mid-tier suppliers currently fully comply with these initiatives but exemptions exist for smaller energy suppliers.

8.289 The three main exemptions relate to:

(a) the ECO, a policy to improve domestic energy efficiency;

(b) FITs, which are the government's main financial incentive to encourage uptake of small-scale renewable electricity-generating technologies to meet the renewable energy targets; and

(c) the Warm Home Discount, which requires participating domestic energy suppliers to provide support to those who are in (or at risk of) fuel poverty.

8.290 ECO represents the single largest obligation cost – in excess of a billion pounds a year across the suppliers to which it applies – and is the main focus of discussion here.[489]

8.291 The ECO applies to all licensed gas and electricity suppliers that have 250,000 domestic customers or more, and supply more than 400 GWh hours of electricity or 2,000 GWh of gas to domestic customers, in any relevant year. Suppliers below this level of customer accounts are exempt from complying with the scheme. The government's rationale for introducing the threshold was that both the Green Deal and ECO should not be a significant barrier to entry to small firms.

8.292 When a supplier exceeds the threshold on 31 December of any given year, it is required to comply with ECO as of 1 April of the following year. To minimise the impact from entry into the scheme from disproportionate increased

[489] Appendix 7.1: Social and environmental obligations and policy cost, on which this section draws, assesses the regime for FITs and the Warm Home Discount as well.

costs, a tapering effect is in place for suppliers passing through the threshold for the first time.

8.293 We have considered the potential effect of these exemptions on competition, considering two concerns in particular:

(a) The Six Large Energy Firms have all expressed concerns around how these exemptions affect their competitiveness against the smaller suppliers, suggesting that the exemption is an unwarranted subsidy that distorts competition.

(b) That the exemptions might provide a barrier to expansion. Several smaller suppliers have said that they slowed their rate of customer acquisitions to delay passing the obligation thresholds. [✂] all mentioned delaying their expansion plans for a short time because of the threshold.

8.294 The larger suppliers estimate the cost of the ECO obligation (and hence the benefit of the ECO exemption) as around £50–£60 per duel fuel account. DECC estimated that the cost is lower, at £36 for a duel fuel customer, taking into account the 2013 Autumn Statement changes. The Warm Home Discount and FIT costs are smaller than the cost of ECO and some smaller suppliers have opted into delivering these schemes. We consider that these two schemes are not material in relation to cost exemptions.

8.295 We note that the government has taken steps to reduce the burden of ECO on the larger suppliers. On 2 December 2013, in the Autumn Statement the government announced plans to reduce the impact of complying with ECO. The scheme was extended to 2017 to allow the suppliers more time to meet their targets and changed the qualifying measures needed to meet primary targets. This decision should reduce the burden on the larger suppliers over the remaining life of the scheme.

8.296 In relation to the argument that the exemption provides an unwarranted subsidy, we note that DECC's rationale for introducing the threshold was that the cost to the smaller suppliers associated with complying with the programmes represented a higher proportion of their overall costs than for larger suppliers. The majority of respondents to its consultation in 2011 agreed with this,[490] and that these disproportionately high costs would reduce competition as they could be a factor in deterring new businesses from entering the market and that they reduced incentives on smaller market

490 DECC (June 2011), *Government response to the consultation on raising the threshold at which energy suppliers are required to participate in DECC environmental and social programmes*.

participants to grow. DECC introduced the threshold of 250,000 customer accounts based on evidence it received to the public consultation.

8.297 We consider it likely that the start-up costs and ongoing fixed costs associated complying with the ECO, FIT and Warm Home Discount policy obligations would fall disproportionately on small and new market entrants if there were no thresholds. Therefore our provisional view is that some level of threshold is reasonable and unlikely to distort competition in the way that some firms argue.

8.298 In relation to the argument that the exemptions might provide a barrier to expansion, we note that, to minimise the impact of reaching the threshold, compliance is tapered up to 500,000 customers. We also note that three of the smaller suppliers have passed the 500,000 threshold (see Appendix 7.1) Further, any delays to expansion are not likely to have exceeded a few months at most. This appears to indicate that these exemptions are not acting as a material barrier to expansion and the two suppliers that have most recently passed the threshold have indicated they have no immediate plans to increase the price of their variable tariffs.

8.299 Overall, our provisional view is that there is a legitimate rationale for providing some degree of exemption. Without these exemptions, the cost of delivering any scheme would fall disproportionately on small suppliers and therefore make entry into the market more difficult. We also note the benefits that entry has brought to the sector in terms of increased competition. Given the relative strength of firms above the exemptions thresholds compared with new entrants, due for instance to the existence of an established customer base and experience in dealing with regulatory requirements, we do not believe that the impact of the current exemptions are likely to be market-distorting. Our provisional conclusion is, therefore, that we do not believe that ECO causes an AEC.

Provisional conclusions

8.300 Our provisional finding is that we have identified a combination of features of the markets for the domestic retail supply of gas and electricity in Great Britain that **give rise to an AEC through an overarching feature of weak customer response**[491] which, in turn, gives suppliers a position of unilateral market power concerning their inactive customer base which they are able to exploit through their pricing policies or otherwise. These features act in combination to deter customers from engaging in the domestic retail gas and

[491] We refer to weak customer response as an overarching feature as synonymous with it being a source for an AEC (*CC3*, paragraph 170).

electricity markets, to impede their ability to do so effectively and successfully, and to discourage them from considering and/or selecting a new supplier that offers a lower price for effectively the same product.

8.301 More particularly, these features are as follows:

(a) Customers have **limited awareness of and interest in their ability to switch energy supplier**, which arises in particular from the following fundamental characteristics of the domestic retail gas and electricity supply markets:

(i) the homogeneous nature of gas and electricity which means an absence of quality differentiation of gas and electricity and which may fundamentally affect the potential for customer engagement in the markets; and

(ii) the role of traditional meters and bills, which give rise to a disparity between actual and estimated consumption. This can be confusing and unhelpful to customers in understanding the relationship between the energy they consume and the amount they ultimately pay. The full roll-out of smart meters over the next five years may have a potentially significant positive impact on engagement, although we have limited evidence concerning the likely magnitude and timescales of any such impact.

These fundamental characteristics may particularly affect certain categories of customer (eg those who are elderly, live in social and rented housing or have relatively low levels of income or education) who we observe are less likely to have considered engaging than others.

(b) Certain customers face **actual and perceived barriers to accessing and assessing information** arising, in particular from the following aspects of the domestic retail gas and electricity markets:

(i) the complex information provided in bills and the structure of tariffs, which combine to inhibit the value-for-money assessments of available options, particularly on the part of customers that lack the capability to search and consider options fully (in particular, those with low levels of education or income, the elderly and/or those without access to the internet); and

(ii) a lack of confidence in, and access to, PCWs by certain categories of customers, including the less well-educated and the less well-off. We note that alternative forms of TPIs, such as collective switching schemes, may become increasingly important for such customers.

(c) **Customers face actual and/or perceived barriers to switching**, such as where they have uncertified meters or experience erroneous transfers which have the potential to cause material detriment to those who suffer from them. Erroneous transfers may thereby impact customers' ability to switch as well as their perception of switching. This is again an area where the introduction of smart meters should in the fullness of time help bring improvements.

(d) **Prepayment meters**, which place technical constraints on customers on such meters from engaging fully with the markets, and which reduce customers' ability and incentive to engage in the markets and search for better deals. Prepayment meters therefore contribute to such customers facing higher costs and more limited choice of tariffs. We expect these problems to be partly addressed with the full roll-out of smart meters and, in the intervening period Ofgem has recently published a report setting out measures to address the limited availability of tariffs for prepayment customers.

8.302 The above overarching feature of weak customer response, in turn, gives suppliers a position of **unilateral market power** concerning their inactive customer base. In relation to unilateral market power, our provisional finding is that suppliers in such a position have the ability to exploit such a position, for example, through price discrimination by pricing their SVTs materially above a level that can be justified by cost differences from their non-standard tariffs and/or pricing above a level that is justified by the costs incurred with operating an efficient domestic retail supply business.

8.303 The above AEC is reinforced by our provisional finding on the consumer detriment identified in Section 10.

8.304 In relation to **tacit coordination**, our provisional finding is that our current evidence suggests that there is no tacit coordination between the domestic retail energy suppliers in relation to price announcements. In particular, we note the following:

(a) there are some characteristics of the supply of gas and electricity to domestic customers that may be conducive to tacit coordination. However, we have also identified factors that may make it more difficult for firms to reach and sustain coordination;

(b) we do not have evidence of suppliers using price announcements as a mechanism to signal their intentions in relation to the pricing of their SVT to rival suppliers to determine their prices accordingly; and

(c) we do find some evidence of outcomes consistent with coordination, but we note that those outcomes can also be observed in markets that are not subject to coordination.

8.305 In relation to the regulatory framework governing domestic retail energy markets, our provisional view is that:

(a) The **'simpler choices' component of the RMR rules**, (including the ban on complex tariffs, the maximum limit on the number of tariffs that suppliers will be able to offer at any point in time, and the simplification of cash discounts) is a feature of the markets for the domestic retail supply of electricity and gas in Great Britain that gives rise to an AEC through reducing retail suppliers' ability to innovate in designing tariff structures to meet customer demand, in particular, over the long term, and by softening competition between PCWs.

(b) The **current system of gas settlement** is a feature of the markets for domestic and SME retail gas supply in Great Britain that gives rise to an AEC through the inefficient allocation of costs to parties and the scope it creates for gaming, which reduces the efficiency and, therefore, the competitiveness of domestic retail gas supply. While we note that Project Nexus is likely to address most of the current inefficiencies in the gas settlement system identified, we are concerned at the slow pace of the implementation, the lack of a deadline and the fact that some players might have been adversely affected by these delays. Moreover, we are concerned that the incentives that shippers face to place a higher priority on adjusting AQs down and delaying adjusting AQs up will still be present after Project Nexus is implemented.

(c) **The absence of a firm plan for moving to half-hourly settlement for domestic electricity customers** and of a cost-effective option of elective half-hourly settlement is a feature of the market for domestic retail electricity supply in Great Britain that gives rise to an AEC in the domestic retail electricity market through the distortion of suppliers' incentives to encourage their customers to change their consumption profile, which overall reduces the efficiency and, therefore, the competitiveness of domestic retail electricity supply.

(d) We do not believe **that the current system of exemptions** on small suppliers from complying with certain social and environmental obligations is likely to be market-distorting.

9. Microbusinesses

9.1 This section discusses the retail supply of energy to microbusinesses.

9.2 This section is structured as follows:

- We explain the **definition of a microbusiness**.
- We describe how **competition to supply energy** to microbusinesses takes place.
- We review the evidence on microbusinesses' **engagement** with the supply of energy.
- We assess the degree of **transparency** around available products and pricing.
- We summarise the **margins** being earned by the Six Large Energy Firms from supplying energy to SMEs (including microbusinesses).
- We explore the **outcomes for microbusinesses**, primarily in terms of price and type of tariff, and whether this evidence indicates that competition is not working effectively for some customers.
- Finally, we present our **conclusions**.

Microbusinesses and other SMEs

9.3 The terms of reference for this market investigation[492] cover the supply of energy to microbusinesses, applying Ofgem's definition of a microbusiness (based on employees, turnover and energy consumption). In practice, suppliers provide electricity and gas to a wide range of SMEs, including microbusinesses. Where possible, we have focused our analysis on customers within the microbusiness definition (although generally with reference only to the consumption requirement for practical reasons), and gathering information specific to this.

9.4 Ofgem defines a microbusiness as a non-domestic customer that meets at least one of the following criteria:

(a) it employs fewer than ten employees (or their full-time equivalent) and has an annual turnover or balance sheet no greater than €2 million; or

[492] Ofgem (2014), *Decision to make a market investigation reference in respect of the supply and acquisition of energy in Great Britain*, p30.

(b) it consumes no more than 100,000 kWh of electricity per year; or

(c) it consumes no more than 293,000 kWh of gas per year.[493]

9.5 However, information is not always specifically available for microbusinesses. In various places, this appendix refers to evidence in the following categories:

- non-domestic customers (all business customers, including those in the I&C markets);
- SMEs (smaller businesses – although there is no industry standard definition); or
- microbusinesses (applying all or part of the Ofgem definition).

9.6 This issue is partly due to the fact that suppliers generally do not distinguish between microbusinesses and SMEs.[494] Suppliers we have spoken to apply the additional microbusiness requirements to all customers that they categorise as SMEs unless they are explicitly identified as not being microbusinesses.[495] Furthermore, each of the Six Large Energy Firms categorises SMEs in a different way, and these differ from the Ofgem microbusiness definition.

9.7 Ofgem reported last year that microbusinesses accounted for an estimated 1.6 million electricity meter points and 0.55 million gas meter points.[496]

Parameters of competition

9.8 There are many similarities between domestic and microbusiness energy supply. This section does not repeat the extensive description of the domestic supply markets given in Section 7, in particular, concerning the role of traditional meters and bills, which are also a fundamental characteristic of the SME retail energy supply markets, and which may be leading to a lack of visibility of energy consumption for many microbusiness customers which, in turn, can be confusing and unhelpful to such customers in understanding the relationship between the energy they consume and the amount they ultimately pay. Instead, we focus on identifying some of the key differences in the SME markets, and specifically in the microbusiness segment, as

[493] If a non-domestic customer qualifies under only one of the consumption criteria, it is regarded as a microbusiness only for that fuel.
[494] We understand that this is partly because it is difficult for suppliers to collect and update information on customers' turnover and employee count.
[495] RWE npower told us [✄].
[496] Ofgem (2014), *Proposals for non-domestic automatic rollovers and contract renewals*, pp40 & 41.

compared with the domestic markets. We then describe the main types of tariff that are available. In this section we also report estimates of shares of supply within the SME markets, and statistics on how long customers have been with their current provider.

Customer differences

9.9 Some microbusinesses are much larger than domestic customers. The upper threshold of Ofgem's microbusiness volume definition for electricity is around 30 times typical domestic consumption. These upper bounds of energy consumption would typically cost a business around £10,000 per fuel (before VAT).[497]

9.10 However, some microbusinesses spend similar amounts to domestic customers. 24% of microbusinesses reported that they spent less than £1,000 a year on electricity, and 27% less than £1,000 a year on gas.[498] This compares with a mean figure for electricity and gas combined of £1,276 for domestic customers.[499]

9.11 Microbusinesses do not only vary by the amount of energy they consume. Microbusinesses cover a range of sectors – this may affect their energy needs. The proportion of a microbusiness's costs that energy accounts for may also vary substantially.

9.12 In the domestic markets, there are public policy concerns about the impact of energy prices on the poorest customers. Some of our work in the domestic markets has also looked at whether vulnerable customers are less likely to switch or consider switching supplier. These concerns do not apply for business customers.

9.13 We also note that gas is a smaller market than electricity for SMEs. In the domestic markets, most customers have both a gas and an electricity supply. In contrast, only 40% of microbusinesses and small businesses use both mains electricity and mains gas.[500]

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[497] As of Q1 2012. Ofgem (2012), *The Retail Market Review – draft impact assessment for the updated proposals for businesses*.
[498] The Research Perspective and Element Energy (2013), *Quantitative research into non-domestic consumer engagement in, and experience of, the energy market* (report for Ofgem), pp73 & 74.
[499] TNS BMRB (2014), *Retail Market Review baseline survey: report prepared for Ofgem*, cited in Ofgem, Micro-Business Consumers Memo, p6.
[500] BMG Research (2015), *Micro and small business engagement in energy markets* (report for Ofgem), p11.

Differences between supply to microbusinesses and domestic customers

Contracts

9.14 Unlike the domestic markets, we understand that microbusiness contracts are largely single fuel, even among customers using both fuels. This may be due to non-domestic customers using varying proportions of gas and electricity, meaning that a dual fuel tariff would be less well-suited for many.

9.15 Microbusinesses are primarily on fixed-term, fixed-price contracts. In the domestic markets, the majority of customers are on SVTs. In contrast, in 2013, variable-price products only covered 19% of electricity customers treated by suppliers as microbusinesses and 26% of gas customers treated by suppliers as microbusinesses.[501]

9.16 Tariffs for non-domestic customers are or can be set on an individual basis, unlike the domestic sector where there is a limited number of tariffs available (due to licence conditions limiting tariffs). New contracts and renewals can be negotiated on an individual basis, or can be set using a number of price points; evergreen contracts and contracts renewed without negotiation may also still be set individually. In contrast, domestic prices are published (and therefore not subject to negotiation).

9.17 When an existing fixed-term contract comes to an end, small business customers have the right to negotiate a new contract or switch supplier. It has historically been the case that many small business customers have not done so and have instead been moved to an 'auto-rollover' contract: a new fixed-term, fixed-price contract which is likely to include a different price to the original contract, and which customers cannot leave mid-term (see paragraph 9.28).[502] Since 2013, the largest suppliers of energy to small businesses (including the Six Large Energy Firms and Opus Energy) have gradually withdrawn auto-rollovers, as a result of pressure from Ofgem[503] and the government.[504] In their place, suppliers have introduced a variety of different replacement tariff types for SME customers who do not take action at the end of their contracts (including evergreen tariffs and fixed-term contracts, both of which a customer can give notice to leave at any time, unlike auto-rollovers).

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[501] Ofgem (2014), *Proposals for non-domestic automatic rollovers and contract renewals*, p41.
[502] Ofgem has set the maximum length of an auto-rollover to be one year. At the end of that term, the customer may again be rolled over on to a further one-year term if it does not take action. This may be repeated indefinitely.
[503] Opus Energy told us that there had been pressure from Ofgem and the government for it to stop using auto-rollovers.
[504] Number 10 and DECC launched a small business energy working group.

9.18 Finally, bad debt is a more substantial issue for suppliers in the SME markets, due to the risk of businesses ceasing trading. This is particularly the case since some customers will be supplied without the supplier having any details of the customer or payment arrangements (on 'deemed' tariffs, described below).

Suppliers

9.19 There are more suppliers active in the SME markets than in the domestic markets. The Six Large Energy Firms are important players in both markets, but some of them only have small SME gas supply activities.

9.20 In the domestic markets, PCWs are an important acquisition channel for suppliers, particularly those outside the Six Large Energy Firms. PCWs have a limited role at present in the microbusiness segment (and more generally across the SME markets) – here the most important acquisition route is instead TPIs (brokers) providing a telephone-based service.

Regulatory and policy context

9.21 The supply of energy to microbusinesses is subject to a level of regulation that falls between the larger number of supply licence conditions which apply in the domestic markets, and the smaller number that apply to non-domestic supply more generally.

9.22 This means that there are some significant differences between domestic and non-domestic regulation. For example, a non-domestic customer can conclude a binding contract over the phone, without a cooling-off period. There are also fewer restrictions on the tariffs that suppliers can offer to microbusinesses – for example, Ofgem's Retail Market Review reforms did not impose a four-tariff limit in the SME markets.

9.23 Ofgem has recently imposed extra regulation on microbusinesses relating to contract renewals to ensure that customers have relevant information. With effect from 31 March 2014, suppliers must give clear information on bills such as the contract end date and the last date a customer can give notice of termination. With effect from 30 April 2015, suppliers must provide current prices and annual consumption details on renewal letters. The supplier can roll the customer over to a new contract if the customer takes no action.[505]

[505] The maximum notice period a supplier can require to not roll over a customer at the end of a fixed-term contract is 30 days. This standardises the process for renewals of fixed-term contracts. A customer now receives a renewal letter 60 days before its contract expires. The customer then has a 30-day window to arrange a new contract. If the customer has taken no action by the end of this window, then at the end of its current contract the supplier will place it on the default option set out in the renewal letter.

Ofgem decided not to formally ban a particular type of contract known as 'auto-rollovers', although it said that it would carry out further work in this area,[506] and the maximum length of auto-rollovers has been restricted to one year since 2009.

9.24 The level of regulation in the microbusiness segment, which as noted above is generally less prescribed than in the domestic markets, is partly a reflection of the degree of political and media interest. News about domestic energy bills tends to attract a high level of public interest. In contrast, microbusiness energy supply has a lower profile, although there have been instances of high-level political activity in this area.[507]

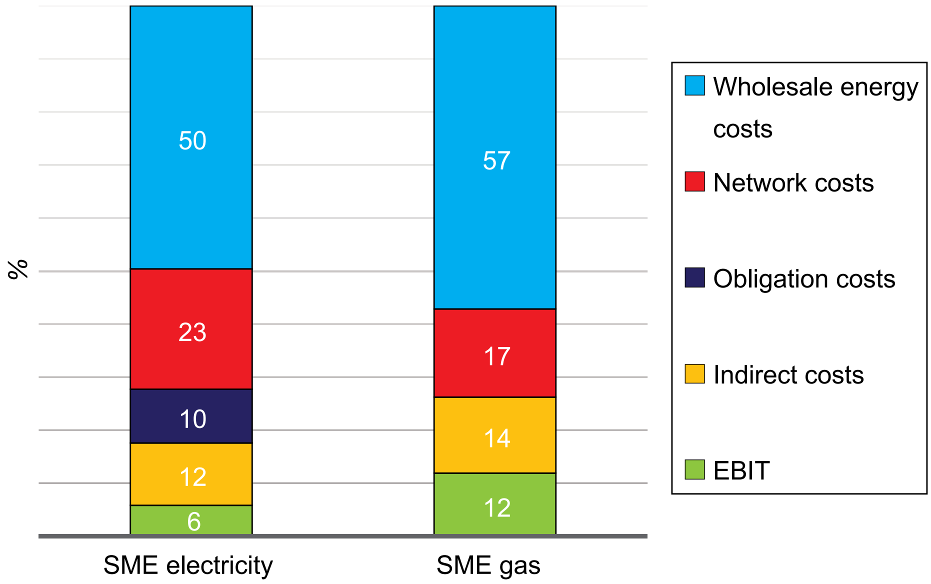
Costs and prices

9.25 Unit revenues are slightly lower for SME customers than for domestic customers. For example, in FY13, the average unit revenue across the Six Large Energy Firms was £121/MWh in the SME markets, compared with £138/MWh in the domestic markets.[508] However, there are some differences between these markets (eg applicable environmental obligations), so we cannot draw definitive conclusions from these particular figures. In addition, these figures do not include VAT (which is a higher rate for domestic customers), so post-tax prices will be more similar.

9.26 Figure 9.1 shows the structure of the costs incurred by the Six Large Energy Firms in supplying SME customers. This chart can be compared with the equivalent in Section 7 for the domestic markets. While the cost categories and sizes are relatively similar, there are some differences. For example, there are no obligation costs in SME gas supply, whereas there are in domestic gas supply.

[506] Ofgem (2014), *Decision on automatic rollovers and contract renewals for micro-business consumers (letter to interested parties)*, p5.
[507] See footnote 504.
[508] See Appendix 10.2: Retail profit margin analysis.

Figure 9.1: Structure of the costs incurred by the Six Large Energy Firms to supply SME electricity and gas customers (FY2013)



Source: CMA analysis of P&L data submitted by the Six Large Energy Firms.
Note: Figures do not include VAT.

9.27 In addition, some of the costs of supplying microbusiness customers may differ from those of supplying domestic customers. For example, suppliers told us that microbusiness customers had higher bad debt costs than domestic customers, given that a significant proportion of start-up businesses failed within the first few years of operation.[509]

Tariff types

9.28 The broad tariff types available to microbusinesses[510] are:

(a) Tariffs with fixed prices:

(i) Fixed-term contracts: These contracts have fixed prices which are valid for the whole contract period. Suppliers generally offer fixed-term contracts to new customers (ie acquisition fixed-term contracts) or existing customers at the end of the fixed-term period (ie retention fixed-term contracts). These contracts are typically offered for a duration of one to four years and are generally the cheapest option available to non-domestic customers at acquisition or contract renewal. The majority of non-domestic customers are on these contracts. Unlike a domestic customer, a non-domestic customer

[509] Section 7 presented a breakdown of the indirect costs of the Six Large Energy Firms across their entire supply business. This data was not available at the level of domestic or SME customers.
[510] In general, the same broad tariff types are offered by the Six Large Energy Firms and other suppliers.

does not generally have the option of leaving during a fixed-term contract.

(ii) Auto-rollovers: When a non-domestic customer's existing fixed-term contract comes to an end, in some cases this will automatically be followed by an extension of the duration of the existing fixed-term contract or a new fixed-term contract, if the customer takes no action. The customer will receive a notification of the terms of the new (or extended) fixed-term contract, which is likely to include a different price to the original contract. The Six Large Energy Firms and Opus Energy have stopped offering these tariffs recently (in most cases, in 2014).[511] We use the term 'replacement products' to refer to the broad set of tariff types that suppliers now use in place of auto-rollovers. Some suppliers have replaced auto-rollovers with fixed-term contracts which a customer can leave after giving notice ('notice products'). We consider that these notice products differ from auto-rollovers.

(b) Tariffs with variable prices:

(i) Evergreen contracts: These contracts have no termination date and the prices are changed periodically.[512] We understand that these tariffs are of limited importance for acquiring new non-domestic customers.

(ii) Deemed tariffs: These tariffs apply to non-domestic customers that have not signed up to a contract but consume energy. This may occur in two instances: when a non-domestic customer moves into a new property and starts to consume energy without a contract with a supplier; or when a fixed-term contract is terminated (other than in circumstances where a customer becomes out of contract (OOC), see below), but the supplier continues to supply the customer. This second possibility can arise if the original contract does not expressly say what will happen after termination and the existing customer continues to consume energy at the premises. A contract is deemed to exist, and a non-domestic customer will remain on this tariff, unless it takes action to switch, with price changes being applied automatically. There is a specific licence condition for

[511] Some customers currently remain on these tariffs until their existing contracts expire.
[512] These may also be known as 'tariff' or 'variable' products.

deemed tariffs, which requires suppliers to ensure that the terms of these tariffs are not unduly onerous.[513]

(iii) OOC: This applies to non-domestic customers that have terminated their contracts, but have not yet switched to a new supplier. Non-domestic customers are defaulted to this type of tariff after termination[514] and will remain on this tariff unless they take action to switch, with price changes being applied automatically.

Shares of supply

9.29 There was no single comprehensive or accurate source of shares of supply information for either the SME markets or the microbusiness segment, and therefore we considered a range of sources (see Appendix 9.1). The general pattern was fairly consistent across them, but we view our share estimates as indicative.[515] Below we present charts based on information from 14 of the largest suppliers of energy to SMEs to estimate shares of supply among electricity meters consuming up to 30 MWh annually and gas meters consuming up to 100 MWh annually.[516] We report below the results for 2014.

9.30 We look first at electricity. For the smallest electricity meters (with under 30 MWh of annual consumption), Figure 9.2 shows that three suppliers ([✂], [✂] and [✂]) had a share by volume of around 20% or higher. One other supplier had a share above 10%, and there were a further three suppliers with a share of 5% or more. The HHI in this category was just under 1,800.

Figure 9.2: Shares of supply by volume to electricity meters with an annual consumption under 30 MWh, 2014

[✂]

Source: CMA analysis of data from the Six Large Energy Firms, Corona, Extra Energy, Gazprom, GDF Suez, Haven Power, Opus Energy and Total.

9.31 In gas, [✂] also had the largest share, as shown in Figure 9.3, of around 40% by volume. There were two more suppliers with a share over 10%, and a further four with a share of around 5% or more. The HHI in this consumption band was over 2,300. These figures suggest that concentration

[513] Standard Licence Condition 7 of the Electricity/Gas Supply Standard Licence Conditions.
[514] This will have been provided for in the original contract.
[515] In particular, the charts below will tend to overestimate the share of the suppliers that provided information to us. We believe that the shares of omitted suppliers are small individually and collectively, and so this overestimate should not be substantial.
[516] For practical reasons, we only asked suppliers to provide information on customers held in their SME (as opposed to I&C) systems. This means that some meters were not included in our data. We do not report results for consumption above these levels because the number of meters excluded from each supplier's data may vary depending on how they allocated customers between SME and I&C systems.

is fairly high, and that there is higher concentration for supply to smaller microbusinesses in gas than in electricity.

Figure 9.3: Shares of supply by volume to gas meters with an annual consumption under 100 MWh, 2014

[✄]

Source: CMA analysis of data from the Six Large Energy Firms (except EDF Energy), Corona, Dong Energy, Extra Energy, Gazprom, GDF Suez, Opus Energy and Total.
Note: Scottish Power is included in the 'other' category.

Time with current supplier

9.32 Some SME customers have spent a substantial period of time with their current supplier. For some of the Six Large Energy Firms, around half their SME customers have not switched supplier in at least the past five years. Some customers have even remained with the same supplier since privatisation.

9.33 A 2014 survey for Ofgem also found that a sizeable minority of microbusinesses had not switched supplier over the past five years. 39% of businesses with one to four employees, and 28% of businesses with five to nine employees had not switched supplier over the past five years.[517]

9.34 A customer that stays with a supplier for a long time could be satisfied with the tariff offering and service provided. This customer may also have actively switched between tariffs from the same supplier. However, it is also possible that this customer has remained with the same firm due to inertia.

Engagement

9.35 We considered a range of evidence on engagement. This evidence suggests that the level of engagement by some microbusinesses appears to be low. We recognise that there is a spectrum of engagement, and that other microbusinesses do take an active interest in their energy supply contracts by switching or searching. We consider a number of indicators of engagement, including: type of tariff; degree of switching in the past year; contract search activity; and the effect of regional incumbency.

Tariff types

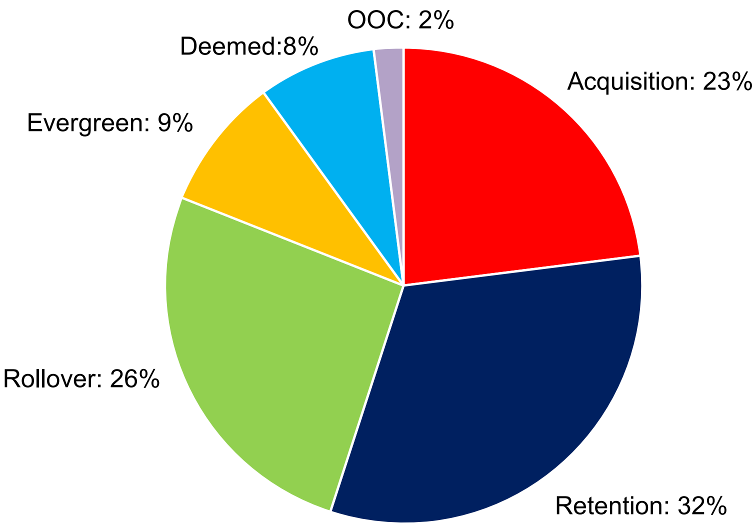
9.36 A substantial minority of microbusiness customers did not arrive on their current tariff as a result of an active decision. We refer to these products as

[517] BMG Research (2015), *Micro and small business engagement in energy markets* (report for Ofgem), p36.

default tariffs. Within this category, we include the following tariff types: auto-rollovers, evergreen, deemed, and OOC. As we report below, prices are generally significantly higher on these default tariffs. We therefore view spending more than transitory periods on them as a sign of a possible lack of engagement. (There are some parallels with the domestic markets, and the observation that there are potential gains from switching away from more expensive products, such as SVTs.)

9.37 To illustrate this, Figure 9.4 shows the split of tariff types in 2013 for customers treated by suppliers as microbusinesses.[518] In electricity, 45% of microbusinesses were on default tariffs. The largest proportion of these were on auto-rollovers (26% of microbusinesses). Our more recent data obtained from the Six Large Energy Firms suggests that default tariffs are still highly prevalent.

Figure 9.4: Tariff types for microbusinesses on 1 April 2013 – electricity



Source: Ofgem (2014), *Proposals for non-domestic automatic rollovers and contract renewals*, p41.

Switching within the past year

9.38 We have made a number of observations about switching among microbusinesses:

(a) 20% of businesses with one to four employees and 24% of businesses with five to nine employees switched supplier in the past year (according to a 2014 survey for Ofgem).[519] (These categories both fall within Ofgem's microbusiness definition.)

[518] Although, as noted above, suppliers do not apply a common definition of microbusinesses.
[519] BMG Research (2015), *Micro and small business engagement in energy markets* (report for Ofgem), p37.

(b) This level of switching among microbusinesses is higher than the level found in the domestic markets.[520]

(c) However, switching among microbusinesses is lower than among larger SMEs.[521]

(d) Switching among microbusinesses is comparable to the switching rate among small business insurance customers.[522]

(e) The reported switching rate for microbusinesses increased between the two surveys carried out for Ofgem in 2013 and 2014.

9.39 There are a variety of potential causes for the recent increase in switching. These could include: several suppliers ending the use of auto-rollovers, the regulations around contract renewals recently introduced by Ofgem,[523] increased broker activity targeting small businesses, and/or increased media and political interest in energy. We do not have sufficient evidence to determine which (if any) of these explanations was responsible for the increase in switching. It is possible that a combination of factors contributed to the result.

9.40 As noted in paragraphs 9.32 to 9.34 above, some SME customers have not switched supplier for a significant period of time.

Contract search activity

9.41 Customers may display a degree of engagement by considering whether to change their contract, even if they do not end up switching. A 2014 survey for Ofgem found that half of businesses with one to nine employees had looked into switching supplier or changing their contract within the past year.[524] However, there was a proportion of customers who had never considered switching. This varied by customer size, with 26% of businesses with zero employees (ie owner-operators) having never considered switching, compared with 10% of businesses with 10 to 49 employees.[525]

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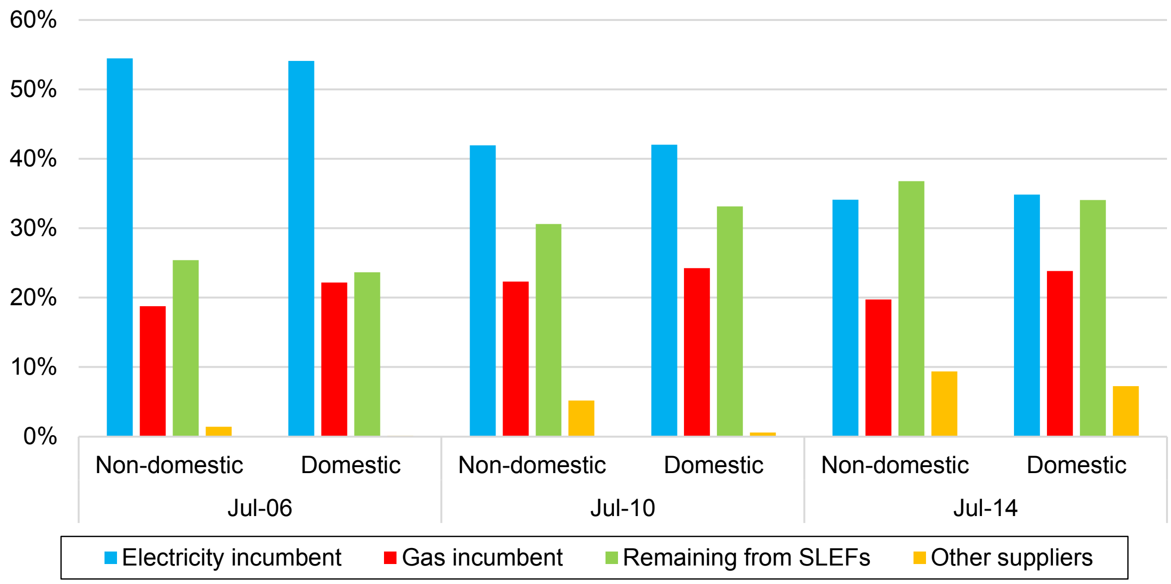
[520] TNS BMRB (2014), *Retail Market Review baseline survey: report prepared for Ofgem*, p10.
[521] BMG Research (2015), *Micro and small business engagement in energy markets* (report for Ofgem), p37. The pattern of microbusinesses being less likely to switch than other non-domestic customers was also noted in a survey for Ofgem in 2013 (The Research Perspective and Element Energy (2013), *Quantitative research into non-domestic consumer engagement in, and experience of, the energy market* (report for Ofgem), p42).
[522] Datamonitor (2013), *Switching on the rise in SME insurance.*
[523] Described in paragraph 9.23 above.
[524] BMG Research (2015), *Micro and small business engagement in energy markets* (report for Ofgem), p29.
[525] ibid, p38.

Regional incumbency

9.42 The average share of the former electricity incumbent in each region has fallen over time. (Figure 9.5 below). However, there is some evidence from this chart that the former electricity incumbents are still more important in their home regions than elsewhere. In July 2014, 34% of SME electricity meter points in Great Britain were supplied by the former electricity incumbent, which was only slightly less than the average share of the other four electricity incumbents put together (37%). Similarly, Centrica still has the highest share of gas accounts nationally. This suggests that incumbency may still be a significant factor, and may be a sign of a lack of engagement among some customers.

Figure 9.5: Non-domestic and domestic electricity supply shares of meter points



Source: CMA analysis of Distribution Network Operator data on number of meters per supplier by region.
Note: SLEFs = Six Large Energy Firms.

9.43 We looked specifically at evergreen tariffs because customers who had remained on the same tariff since privatisation would be on these tariffs. We found that in home regions, a high share by volume was supplied via evergreen tariffs compared with other regions. All five of the former electricity incumbents supplied a greater proportion of their microbusiness volumes through evergreen tariffs in their home regions compared with other areas: overall, evergreen tariffs represented 13% of the volume supplied by the former incumbent suppliers to microbusinesses in their home regions, but only 2% of the volume supplied by these firms to microbusinesses in other regions.

Summary – engagement

9.44 Based on the evidence above, we can see that some microbusinesses do engage in choosing their energy contracts. We also note positive signs of a recent increase in switching between suppliers (although we are unsure of the cause of this).

9.45 However, we remain concerned that some microbusinesses appear to show limited engagement and that they have limited interest in their ability to switch energy supplier. As observed in Section 8, the role of traditional meters and bills (which give rise to a disparity between actual and estimated consumption, and are complex in their own right) is a fundamental characteristic which may be leading to a lack of visibility of energy consumption for many microbusiness customers. This can be confusing and unhelpful to customers in understanding the relationship between the energy they consume and the amount they ultimately pay. This lack of visibility and high complexity may deter customers from considering whether to switch energy supplier. There is an important change with the full roll-out of smart meters over the next five years, although we have limited evidence concerning the likely magnitude of impact this will have and the timescales over which any such impact will take effect.

9.46 As we go on to discuss below, outcomes appear to be significantly worse for customers who do not engage and end up on default tariffs.

Transparency

Importance of transparency

9.47 Transparency is important for microbusiness customers (and other types of customers), and its absence may lead to customer harm by creating actual and/or perceived barriers to customers accessing and assessing the information needed to search for and switch to competing suppliers and/or tariffs.

9.48 Customers with lower visibility of market prices may be less likely to try to switch supplier or tariff, as they may not be aware that there are better deals available. For customers that do decide to investigate their options, a lack of transparency may increase their search costs.[526] If a customer ends up in a negotiation with a supplier, it may be in a weak position if it has limited knowledge of its other options in order to benchmark offers. For example, a new microbusiness may begin its energy supply with a deemed tariff – which

[526] However, RWE said that it would only take half an hour to get a tailored quote.

tends to be high, as we discuss further below – and use that as a starting point for its expectation of its first agreed tariff. Other things being equal, with sufficient transparency, the business would have clear expectations concerning its agreed tariff, including whether or not it would be substantially lower than the deemed tariff.

9.49 In this section we examine what information on prices is available from suppliers, TPIs, and PCWs.

Information from suppliers

9.50 In general, prices for business customers are negotiated individually and rarely published by energy suppliers. Many suppliers publish their deemed contract prices and some publish other variable contract prices, but we understand that these are unlikely to be the best deals available.

9.51 The Six Large Energy Firms and some other suppliers offer online quote services. These may be a useful tool for microbusiness customers. However, as some suppliers have started to provide these only very recently, the effects may not be visible in our data on margins and outcomes (which we summarise in paragraphs 9.66 to 9.109 below).

Information from third party intermediaries

9.52 One way of overcoming a lack of transparency is to receive assistance from an intermediary. TPIs act as intermediaries between non-domestic customers and energy suppliers.

9.53 TPI usage appears to vary by size of business. The 2014 survey carried out for Ofgem reported that 25% of businesses with one to nine employees used a broker as their main source of information when choosing their current contract. Slightly larger small businesses (10 to 49 employees) were more likely to use a broker: 37% of them gave this as their main source.[527]

9.54 There are two reasons why smaller businesses may be less likely to use TPIs:

(a) The first is that TPIs may focus more on larger customers, as commission payments can be a function of a customer's annual consumption. However, the 2014 survey for Ofgem reported that only 15% of microbusinesses and small businesses said that they had not

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[527] BMG Research (2015), *Micro and Small Business Engagement in Energy Markets* (report for Ofgem), p49.

been contacted by a TPI in the past year.[528] The 2014 survey also suggested that there had been an increase in approaches by brokers.

(b) The second is that many smaller customers appear to distrust TPIs. The 2014 survey found that only 20% of businesses with one to nine employees had a positive view of energy brokers.[529]

9.55 The lack of trust in brokers is partly driven by long-standing concerns about the behaviour of some TPIs. These have emerged from a variety of sources, including: consumer research from Ofgem, research for Consumer Focus, complaints to various official bodies, a BBC investigation, suppliers, and other TPIs. Some of the issues mentioned include TPIs making misleading claims, using pressure sales techniques, or even claiming to be acting for official purposes, making statements such as 'you have to register your meter with us'. [530] Poor behaviour by some TPIs may reduce trust in TPIs more generally, and lead to customers being less engaged.

9.56 Many parties also raised concerns about the commission paid to TPIs. Commission is often added to the unit rate paid by a non-domestic customer, with the rate determined by the TPI. This process does not seem to be well-understood by non-domestic customers. The 2014 survey reported that only 5% of microbusinesses and small businesses who had used a broker reported that they had been charged for this service.[531] Some suppliers place caps on the amount of commission that TPIs can charge – this suggests that non-domestic customers themselves are not exerting strong downward pressure on commissions (eg by multi-homing).

9.57 Several parties have said that TPIs may face incentives to sell certain products, which would result in non-domestic customers not being offered the most appropriate rates. Similarly, many TPIs will not have the full range of suppliers to offer. If customers are not aware of these issues then they will not see an incentive to take countervailing action (eg multi-homing), and as a result competition between TPIs may not work effectively.

9.58 Due to concerns about poor customer experience of using TPIs and the potential negative impact on future engagement that this may have, Ofgem has developed a draft code of practice for non-domestic TPIs. Many parties told us that they supported the introduction of regulation in this area. In addition, Ofgem acquired powers under the Business Protection from

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[528] ibid, p51.
[529] ibid, pp57 & 58.
[530] Last quote from Cornwall Energy (2011), *Brokerage services for micro-business energy consumers*, report for Consumer Focus, p16.
[531] BMG Research (2015), *Micro and Small Business Engagement in Energy Markets* (report for Ofgem), p53.

Misleading Marketing Regulations in November 2013, which it can use to address certain forms of poor behaviour by TPIs.

Summary on third party intermediaries

9.59 TPIs have the potential to help customers engage with energy markets and reach good outcomes provided TPIs pursue ethical and sound business practices. However, this may be undermined if customers do not trust TPIs – particularly if this lack of trust applies to TPIs as a group (rather than individual TPIs). At present, given the long-standing concerns about the conduct of some TPIs, the lack of trust in TPIs that many microbusiness customers report may be justified (in the case of some TPIs). Customers also appear to lack information about how TPIs charge them. If customers avoid TPIs because they do not trust them and/or understand how they charge, then this may lead to lower levels of engagement than would otherwise be the case.

Information from price comparison websites

9.60 There is a very limited availability of PCWs for business energy customers. We are aware of one non-domestic PCW (Energylinx for Business), which provides a service through its own website and also provides the underlying technology to Confused.com.

9.61 As well as being a direct channel for customer switching, PCWs may generally help to make customers more informed. For example, a customer may be able to obtain an online quote as a benchmark for quotes from a supplier or broker. This transparency may help to sharpen competition between suppliers and between TPIs.

9.62 We have investigated why PCWs are not more prevalent for non-domestic energy supply. On the one hand, there may be demand for online price comparison services in the SME markets – it also appears that there are firms which could provide a business energy PCW with modest investment and/or time (such as firms operating domestic energy PCWs that also provide online insurance comparisons to businesses).

9.63 On the other hand, we received a number of suggestions for potential issues that could make it more difficult to develop PCWs. The most common reasons we heard related to the complexity of the SME markets, compared with the domestic markets.[532] However, these reasons did not appear to indicate that developing and promoting a non-domestic energy PCW would be impossible.

Summary on price comparison websites

9.64 It is clear that PCWs could deliver benefits for microbusiness energy customers through providing increased transparency over prices. However, the current limited presence of PCWs, and the potential issues mentioned above, suggest that it may be more challenging to operate a non-domestic PCW than a domestic one. However, on the basis of the evidence we have seen, it appears that there could be a viable business model for a non-domestic energy PCW.

Summary – transparency

9.65 Based on the evidence above, our provisional finding is that customers face actual and perceived barriers to accessing and assessing information arising, in particular, from the following aspects of the markets for retail energy supply to SMEs:

(a) a general lack of price transparency concerning the tariffs that are available to microbusinesses, which results from many microbusiness tariffs not being published; a substantial proportion of microbusiness tariffs being individually negotiated between customer and supplier; and the nascent state of PCWs for non-domestic customers (although transparency may be improving with the introduction of online quotes and PCWs); and

(b) the role of TPIs, in relation to which:

(i) a number of complaints have been made by non-domestic customers to various official bodies concerning alleged TPI malpractice, which may have reduced the level of trust in all TPIs and discouraged engagement more generally (although this situation may improve if Ofgem implements a code of practice for non-domestic TPIs that is currently in draft form); and

(ii) we have noted a lack of transparency as well as the existence of incentives not to give non-domestic customers the best possible

[532] Both in terms of extra information needed from SME customers, and the greater number of available tariffs for SMEs. We were also told that it may be more expensive to attract SME customers to a PCW than domestic customers. See Appendix 9.1.

deal. We are concerned that customers are not aware of this and therefore do not take steps to mitigate it (for example by consulting more than one TPI or seeking other benchmark prices). This is exacerbated by the lack of easily available benchmark prices, and the fact that many tariffs are not published.

Margins

9.66 Our analysis of retail profit margins[533] found that there were substantial differences in EBIT margins between retail markets for the Six Large Energy Firms. Over the years[534] 2009 to 2013, EBIT margins were over twice as large in the SME markets as in the domestic or I&C markets:

(a) The combined EBIT margin for the Six Large Energy Firms in the SME markets was 8.4%, compared with 3.3% in the domestic markets.

(b) The combined EBIT margin was lowest in the I&C markets at 2.0%.

9.67 We also looked at combined EBIT margins by fuel. The margin was larger for SME gas supply (10.1%) than for SME electricity supply (7.9%).

9.68 Several suppliers put forward explanations for additional risks they face in the SME markets (compared with the domestic and/or I&C markets), which they said would justify higher margins.[535] In our view, the SME markets would have to be much more exposed to systematic risk,[536] or require a much higher level of capital employed than other markets, in order to justify the extent of the difference in EBIT margins. Our provisional view is that the risks mentioned are not sufficient to justify such a large gap in EBIT margins between markets, and we have not seen any analysis or evidence to suggest otherwise.

9.69 We also investigated whether prices[537] and gross margins were higher for specific categories of customers. Based on our initial work, we identified the following areas of interest:

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[533] Appendix 10.2: Retail profit margin analysis.
[534] These years are the financial reporting years for each firm, which differ in some cases from the calendar year.
[535] Appendix 10.6: Retail profit margin comparators.
[536] For example, higher levels of bad debt among SMEs than in other segments would not justify higher EBIT margins, because those costs should be deducted before the calculation of EBIT margins – the only relevant risk factor would be if the variability of bad debt were higher among SMEs.
[537] There is a large range of microbusiness products, and many prices are the result of negotiation or otherwise set individually for individual customers. This means that it was impracticable to look at individual prices. Instead, we used average revenues.

(a) default products (rollover,[538] evergreen, deemed and OOC);

(b) smaller customers; and

(c) former incumbent regions (for electricity).

9.70 Figures 9.6 to 9.9 below show average revenues and gross margins[539] for gas and electricity. For each fuel, we defined four bands[540] based on annual consumption. Three of these fell within the microbusiness volume definition, and the fourth (E4 and G4) was a group of larger SMEs. We asked suppliers to allocate meters to these consumption bands.[541] The main results were:

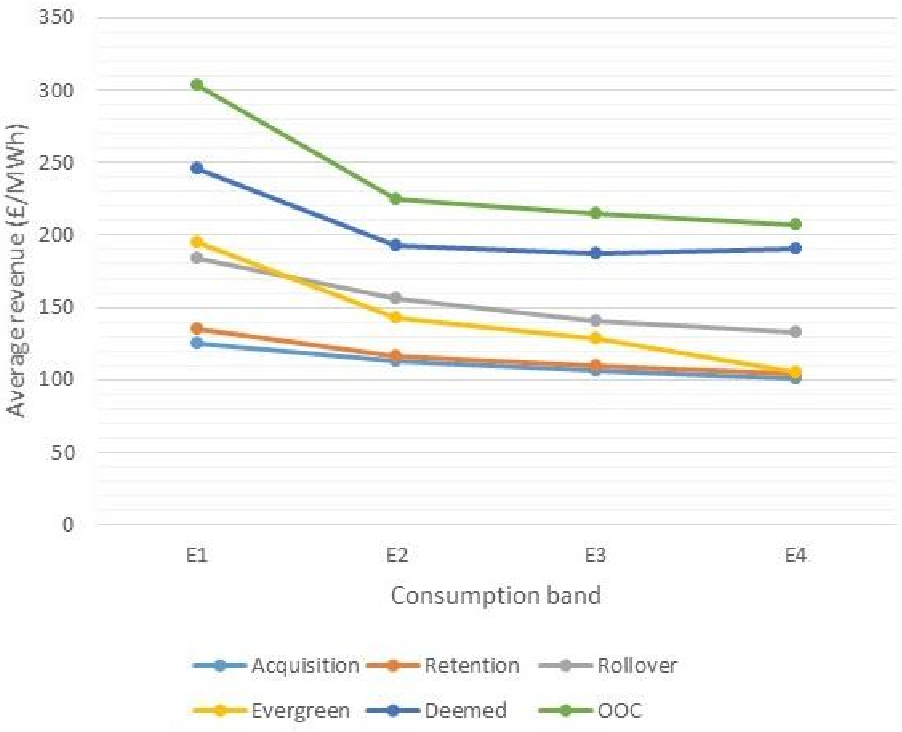
(a) We observed higher average revenues and gross margins for smaller business customers compared with larger ones. This applied to some extent across consumption bands, though it was particularly noticeable for small microbusinesses.

(b) The highest average revenues and gross margins were on deemed and OOC tariffs. Average revenues and gross margins were also higher on rollover and evergreen tariffs, compared with acquisition and retention tariffs. Acquisition and retention tariffs had very similar average revenues and gross margins. The differences in average revenues between tariffs were substantial in places – this implies that most of these customers could benefit from switching between tariffs.

9.71 These broad points were largely consistent across suppliers (see Appendix 9.1, Annex a).

[538] By 'rollover' we include all tariffs that customers are rolled over on to by default. This includes, but is not limited to, auto-rollovers. For example, a customer could be rolled over on to an evergreen contract, or a fixed-term contract with an exit clause.
[539] For the purposes of these illustrations, we examine both gross margins according to our uniform definition, and those labelled by parties according to their own definitions.
[540] E1 was meters with annual consumption below 10 MWh; E2 was meters with annual consumption between 10 MWh and 30 MWh; E3 was meters with annual consumption between 30 and 100 MWh; E4 was meters with annual consumption between 100 and 500 MWh.
G1 was meters with annual consumption below 30 MWh; G2 was meters with annual consumption between 30 and 100 MWh; E3 was meters with annual consumption between 100 and 293 MWh; E4 was meters with annual consumption between 293 and 1,500 MWh.
[541] We used meters rather than customers due to data availability. This means that some of these meters will belong to larger multi-site customers, whose total consumption might be in a different volume band. Conversely, some larger SMEs may qualify as microbusinesses due to their balance sheet or number of employees.

Figure 9.6: Overall average revenues by tariff type and consumption band – electricity

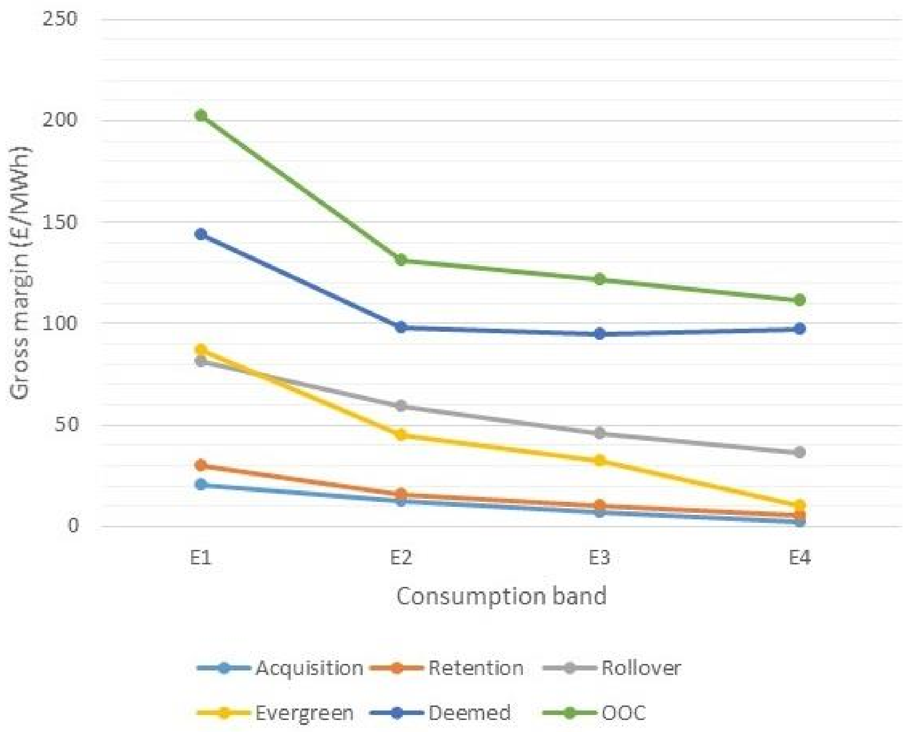


Source: CMA analysis of data from the Six Large Energy Firms (except SSE), Gazprom, Opus Energy, and Total Gas and Power.

Notes:

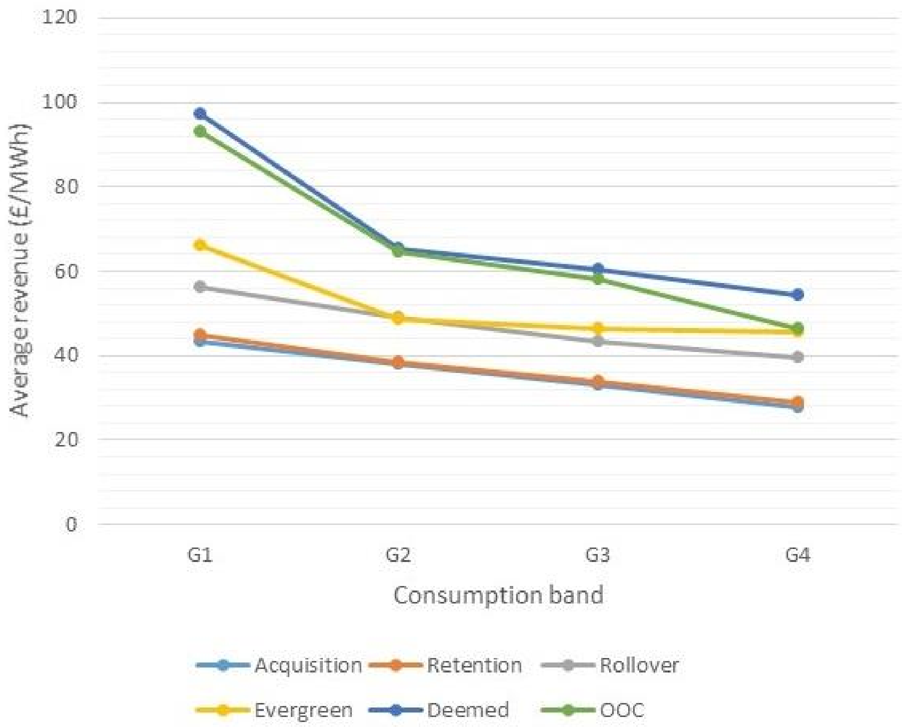
1. Data is 2012–2014, except Scottish Power (2014 only).
2. Consumption bands: E1 was meters with annual consumption below 10 MWh; E2 was meters with annual consumption between 10 MWh and 30 MWh; E3 was meters with annual consumption between 30 and 100 MWh; E4 was meters with annual consumption between 100 and 500 MWh.
3. A few suppliers included an ‘other’ tariff type. We do not report this in these charts, as it was not consistently defined.
4. Average revenues are volume-weighted averages across suppliers.
5. SSE provided average revenue data, but not gross margins. We therefore excluded SSE from this chart for comparability with the gross margin chart. SSE’s average revenue results are included in Appendix 9.1.
6. Average revenues are before tax (ie excluding VAT and CCL).
7. The rollover category is mostly made up of customers on auto-rollovers, but also includes the replacement products for a couple of suppliers.

Figure 9.7: Overall gross margins by tariff type and consumption band – electricity



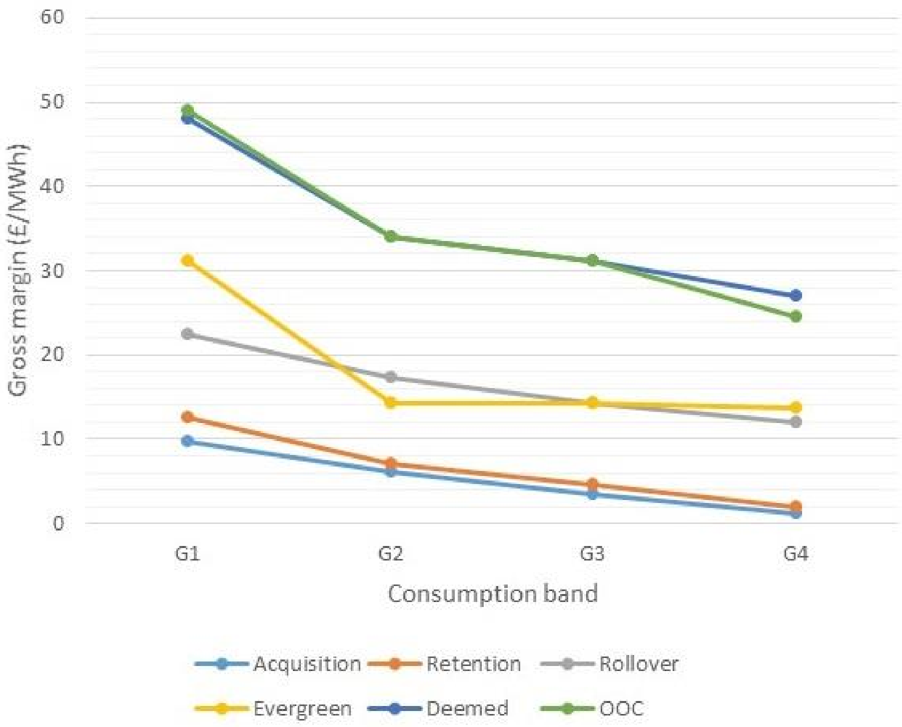
Source: CMA analysis of data from the Six Large Energy Firms (except SSE), Gazprom, Opus Energy, and Total Gas and Power.
Notes:
1. Data is 2012–2014.
2. Gross margins are volume-weighted averages across suppliers.
3. The rollover category is mostly made up of customers on auto-rollovers, but also includes the replacement products for a couple of suppliers.

Figure 9.8: Overall average revenues by tariff type and consumption band – gas



Source: CMA analysis of data from the Six Large Energy Firms (except EDF Energy and SSE), Gazprom, Opus Energy, and Total Gas and Power.
Notes:
1. Data is 2012–2014, except Scottish Power (2014 only).
2. Consumption bands: G1 was meters with annual consumption below 30MWh; G2 was meters with annual consumption between 30 and 100MWh; E3 was meters with annual consumption between 100 and 293MWh; E4 was meters with annual consumption between 293 and 1,500MWh.
3. SSE provided average revenue data, but not gross margins. We therefore excluded SSE from this chart for comparability with the gross margin chart. SSE's average revenue results are included in Appendix 9.1.
4. Average revenues are before tax (ie excluding VAT and CCL)
5. The rollover category is mostly made up of customers on auto-rollovers, but also includes the replacement products for a couple of suppliers.

Figure 9.9: Overall gross margins by tariff type and consumption band – gas

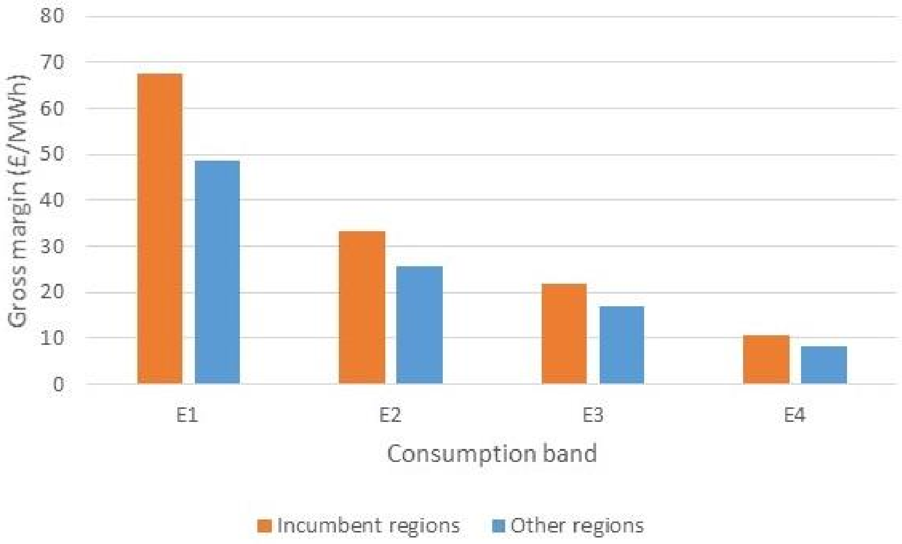


Source: CMA analysis of data from the Six Large Energy Firms (except EDF Energy and SSE), Gazprom, Opus Energy, and Total Gas and Power.
Notes:
1. Data is 2012–2014, except Scottish Power (2014 only).
2. The rollover category is mostly made up of customers on auto-rollovers, but also includes the replacement products for a couple of suppliers.

9.72 We also looked at gross margins on a regional basis in electricity, to look for potential incumbency effects. Figure 9.10 shows the volume-weighted average of gross margins by consumption band for former incumbent suppliers in their home regions, and for the same parties in other regions. In each consumption band, gross margins were higher in home regions than in other regions. This pattern of regional gross margins was also largely consistent across suppliers (see Appendix 9.1, Annex a).[542]

[542] We cannot look at incumbency in gas on a regional basis, because Centrica was the former national gas incumbent. The appendix includes discussion of potential incumbency effects in gas.

Figure 9.10: Overall gross margins by consumption band and whether incumbent region – electricity



Source: CMA analysis of data from EDF Energy, E.ON, RWE and Scottish Power.
Notes:
1. SSE was unable to provide gross margin data.
2. Data is 2012–2014, except for Scottish Power (2014 only).

9.73 Our findings (both nationally, and regionally for electricity) were largely consistent across suppliers (see Appendix 9.1, Annex a). However, we recognise that differences in gross margins may be justified by differences in costs.

9.74 We therefore examine this in the following section, where we analyse whether differences in margins are cost-justified. Where this was not the case, we investigated whether suppliers are earning higher returns on the types of customers we have found to be less engaged, for whom competition may not be working effectively.

Outcomes

9.75 This section examines the groups of business customers who are paying, on average, higher prices, and investigates whether the higher prices are cost-justified and whether those higher prices are likely to signal competition concerns. We look in turn at auto-rollovers; deemed and OOC tariffs; smaller business customers; and regional incumbency.

Outcomes: auto-rollovers

9.76 The majority of non-domestic contracts have a fixed term. This creates an issue as to what happens at the end of that term if the customer does not take any action. Business customers may be rolled over on to one of four types of 'default tariffs':

- Auto-rollovers: the customer is rolled over on to a new fixed-term contract with no exit clause.
- Notice contract: as above, but the customer can give notice (usually one month, with no termination fee after serving notice) at any time.
- Evergreen contract: the customer is rolled over on to a variable price contract[543] but can give notice at any time (with no termination fee after serving notice).
- Out of contract: the customer could be moved on to OOC terms.

9.77 In each case,[544] the price the customer pays can be individual to that customer and need bear no relation to the price under the previous contract. Customers can also be rolled over multiple times (after each auto-rollover or notice term ends) and the price may change each time.

9.78 As noted above, until 2013,[545] auto-rollovers were widespread in the SME markets. Since then, the largest energy companies (including the Six Large Energy Firms and Opus) have gradually withdrawn auto-rollovers in favour of replacement (notice or evergreen) contracts.

9.79 We have some continuing concerns in principle about auto-rollovers in the SME markets. The OFT has in the past found that auto-rollovers (in general) could reduce switching because of inertia and/or increased switching costs, and that this could potentially dampen competition.[546] Our concern here is that they reduce the customer's window to engage with choosing an energy tariff, and prevent switching outside that window (a customer effectively has a 30-day period to switch tariff and/or supplier, and if it does not do so, it will not be able to switch for the next year). We observed some indications that switching has increased since the suppliers noted above withdrew these tariffs, although we cannot attribute this directly to that change.

9.80 Many smaller suppliers[547] continue to offer auto-rollovers, which may to some extent give those suppliers an unfair competitive advantage: their auto-rollover customers are unable to switch away during the rollover term, whereas other suppliers' contractually rolled-over customers are not locked in to any rollover term and can now switch without penalty. We note that the

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[543] This has some similarities to a domestic SVT. However, in this case prices may be personalised to an individual microbusiness.
[544] Except OOC, which is a published rate.
[545] EDF Energy stopped automatically renewing customers in October 2013.
[546] OFT (2013), *Key issues in ongoing contracts: a practical guide*, p10.
[547] In Appendix 9.1: Microbusinesses we identify six such suppliers that together accounted for 3% of electricity and 20% of gas volumes in 2014 among small and medium microbusinesses.

removal of auto-rollovers by the suppliers noted above has been due to informal pressure (from Ofgem and the government[548]), and that, absent regulation or legislation formally prohibiting such contracts, they could in principle be reintroduced by these suppliers.

9.81 However, the issue of poor outcomes stemming from a lack of engagement is broader than just certain business customers being locked into an auto-rollover term. We also have some concerns about default tariffs in general. It is possible that some business customers on default tariffs have engaged and made a well-informed decision to roll over on to that tariff, but these default tariffs are also the destination of some business customers who have not engaged, are not well-informed, and have not made an active decision.

9.82 As noted above, we observed much higher average unit revenues and gross unit margins on auto-rollovers compared with acquisition or retention tariffs.[549] We did not receive any suggestions that cost differences could explain the size of these differences in average revenues and gross margins.[550] The combination of unengaged and inactive customers with these relatively high prices could indicate that competition may not function as an effective constraint.

9.83 The removal of auto-rollovers by some suppliers means that their customers that are now on replacement tariffs are no longer locked into their supplier during the replacement contract term (ie the term on to which the customer is rolled over). If the customer's ability to terminate the contract during the replacement contract term increases those customers' engagement during that term, then competition could operate more effectively and may lead to lower prices on default products, and increased competition on acquisition and/or retention products more generally. We have very limited evidence on outcomes under the default products that have specifically replaced auto-rollovers, because this change is so recent.[551] We looked at the average prices paid by customers of some suppliers (Centrica, RWE and SSE[552]) since they discontinued auto-rollovers.[553] This analysis suggested that customers who had moved on to a supplier's replacement product were not seeing better prices as a result of the removal of the auto-rollover term. This view was supported by evidence in internal documents from some suppliers.[554] We do not therefore have evidence at present that the move

[548] Number 10 and DECC launched a small business energy working group.
[549] Figures 9.6–9.9.
[550] Discussed in more detail in Appendix 8.1.
[551] Replacement tariffs have been introduced gradually, as customers came to the end of their existing auto-rollovers.
[552] Centrica's replacement is an evergreen tariff, RWE's is a notice contract, and SSE applies OOC rates.
[553] Appendix 9.1, Annex C describes the caveats to and limitations of this data, and gives full results.
[554] See Appendix 8.1: Customer survey.

away from auto-rollovers has led to lower prices for customers on default products.

Outcomes: deemed and out of contract

9.84 We expect any competitive constraint on the pricing of deemed or OOC tariffs to be weak. A customer does not make an active choice to end up on these tariffs – and any customer who does engage should in principle be able to move to a less expensive tariff. This is illustrated by the fact that prices for these types of tariffs are significantly higher than other tariff types (see Figures 9.6 and 9.8 above). The expected lack of effective competitive constraint explains why there is a licence condition relating to the pricing of deemed tariffs.[555] However, there is no equivalent licence condition for OOC tariffs.

9.85 These tariffs only apply to a minority of customers. Based on data from some of the Six Large Energy Firms, deemed and OOC tariffs together represented around 6% of electricity and 7% of gas supplied to microbusinesses.[556]

9.86 In a well-functioning market, we would expect to see evidence that customers only stayed on these high price tariffs for transitory periods (eg when setting up a new business, changing premises, or changing supplier). If that were the case then the higher prices on these tariffs would have only a transitory effect on business customers. However, the evidence summarised below shows that many customers who use these tariffs stay on them for a substantial period of time.

9.87 Based on data from 2013, Ofgem noted that the median duration of micro-business customers' stay on deemed and OOC terms was over one year.[557] This did not apply to all suppliers, but did apply to many: Ofgem's data showed that the median customer tenure on deemed and OOC tariffs was over 300 days for most of the Six Large Energy Firms.

9.88 As noted above, we observed higher gross margins on deemed and OOC tariffs compared with other tariff types. Below, we compare this with retention tariffs, which are an example of a product taken up by engaged customers. For each supplier (where we had data), we calculated the difference in average gross unit margins between deemed and retention

[555] See paragraph 9.28.
[556] See the discussion of outcomes on deemed and out-of-contract tariffs in Appendix 8.1: Customer Survey.
[557] Ofgem (2014), *Proposals for non-domestic automatic rollovers and contract renewals*, p43.

tariffs, and between OOC and retention tariffs. Table 9.1 reports the median differences across suppliers.

Table 9.1: Median gross margin difference across suppliers, comparing deemed and OOC tariffs against retention tariffs – for medium microbusinesses

	Electricity		*Gas*	
	£/MWh	*%*	*£/MWh*	*%*
Deemed minus retention	66	378	17	179
OOC minus retention	74	537	21	350

Source: CMA analysis of data supplied by the six large energy firms.
Notes:
1. Electricity scope – meters with an annual consumption between 10 and 30 MWh (consumption band E2).
2. Gas scope – meters with an annual consumption between 30 and 100 MWh (consumption band G2).
3. Percentages calculated using retention gross margin as the denominator.
4. Data from Centrica, EDF Energy (electricity only), E.ON, Gazprom, Opus Energy, RWE, Scottish Power and Total.
5. Data covers 2012–2014 for all suppliers except Centrica (2012 to Q3 2014) and Scottish Power (2014 only).
6. Gross margins for individual tariff types are shown in Figures 9.7 and 9.9 above.

9.89 Our data also showed higher average revenues on deemed and OOC tariffs compared with other tariff types. Along similar lines, previous Ofgem research found that the average annual electricity (gas) bill for a typical microbusiness on a deemed contract was 75% (58%) higher than on a retention contract.[558] This suggests that customers on these tariff types were substantially worse off than those who engaged to choose retention products.

9.90 However, these tariff types may also have higher indirect costs associated with them. In particular, there are high levels of bad debt (creating write-offs, debt collection costs and working capital requirements). We therefore examined whether the gross margins on deemed and OOC tariffs were the result of tariff-specific indirect costs.

9.91 We found that bad debt write-offs for SME customers, among suppliers that were able to provide data, was on average around 27% of billed product revenue for deemed and 23% for OOC, compared with 1% for fixed tariffs. To recover this cost, deemed prices would need to be set 35% higher than the prices for fixed contracts. We estimate that this would translate to around £50/MWh for electricity and £15–£18/MWh for gas. These figures should be regarded as approximate, due to the limited data available and assumptions we had to make (described in more detail in the Outcomes section of Appendix 9.1). Comparing them with the figures in Table 9.1 (and making the same comparison for individual suppliers[559]), it appears that bad debt write-offs could explain some (but in most cases not all) of the above

[558] All figures from Ofgem (2014), *Proposals for non-domestic automatic rollovers and contract renewals*, pp42 & 43.
[559] See Appendix 9.1: Microbusinesses for individual results.

difference in gross margins between deemed and retention tariffs, and between deemed and OOC tariffs.

9.92 Deemed prices vary noticeably between suppliers. In March 2015, electricity deemed unit rates varied between £132/MWh and £247/MWh, and OOC unit rates varied between £132/MWh and £257/MWh.[560] Including the standing charge, the annual bill for a 10 MWh deemed customer would be 71% higher with the most expensive supplier compared to the least expensive supplier. This equates to an annual bill difference of over £1,000.

9.93 In theory, we would not expect the riskiness of deemed customers to vary significantly between suppliers. However, we observed large differences in write-off rates between suppliers. This could indicate that some suppliers have deemed customers who are at higher risk of default; or that suppliers have varying rates of success in collecting debt.

9.94 We also observed a tendency for suppliers with higher write-off rates to charge higher deemed prices. This suggests that differences in prices may partly be justified by differences in bad debt.

9.95 We note that there is already a specific licence condition in relation to deemed tariffs, which requires suppliers to ensure that the terms of these contracts are not unduly onerous. However, this appears to allow some latitude for suppliers to set high prices for these tariffs; and there is no equivalent condition for OOC. Ofgem has not assessed deemed prices recently.

9.96 Taken together, these factors suggest that although customers on deemed and OOC tariffs are paying high prices, the increment above other tariff types is partly cost-justified, and a relatively small number of customers are on these tariffs. However, we do not believe that competition can be working effectively to constrain these tariffs, given that some microbusiness customers do remain on them for a considerable period of time despite significantly cheaper tariffs being available.

Outcomes: customer size

9.97 Several parties told us that we should look at outcomes by customer size. For example, Ofgem said that a key question was whether competition was working effectively for the very smallest non-domestic customers.[561] As

[560] Unit rates applying to customers in profile classes 3 and 4 in the London region. Standard metering and non-direct debt payment options selected (where offered). See Appendix for more detail.
[561] Ofgem, initial submission, 21 July 2014, p67.

noted above, there is less switching among microbusinesses than larger SMEs, and some TPIs prefer to focus on larger businesses. This may indicate lower engagement among smaller businesses and, in turn, the possibility that competition may work less effectively for them.

9.98 We saw above (paragraph 9.70) that gross margins on a given tariff tended to be higher the smaller the customer. This section examines whether these gross margin differences between customers of different sizes are cost-justified. We break this down into two elements: looking at the smallest microbusinesses in particular, which generated particularly high per unit gross margins, and then looking at differences between microbusiness/SME customers of other sizes, where the differences were smaller.

Small microbusinesses

9.99 We observed above (paragraph 9.70) that we found the highest average revenues and gross margins for customers we classified as small micro-businesses.[562] However, our other evidence suggests that this does not translate into higher profits or NPVs.

9.100 The differences in prices and gross margins may be explained by indirect costs which are incurred on a per customer basis, especially metering, customer service and marketing. This is because these costs would need to be spread over a small number of units for small microbusinesses. We found that the likely scale of those costs was similar to the difference in gross margins we observed.

Comparing medium-sized microbusinesses and larger SMEs

9.101 We also observed[563] higher gross margins for medium microbusinesses[564] than for larger SMEs.[565] Again, one reason for this was costs that are incurred on a per customer basis.

9.102 We found that for acquisition and retention contracts, per customer costs may largely account for higher electricity gross margins for medium microbusinesses than larger SMEs.[566] However, rollover electricity contracts for some suppliers have average gross margin differences which are four or more times larger than the estimated difference in per customer costs. One

[562] Meters with an annual consumption below 10 MWh of electricity or 30 MWh of gas.
[563] See Appendix 9.1: Microbusinesses and specifically the section ‘Outcomes: by customer size’.
[564] Meters with an annual consumption between 10 and 30 MWh of electricity (E2), or between 30 and 100 MWh of gas (G2).
[565] Meters with an annual consumption between 100 and 500 MWh of electricity (E4), or between 293 and 1,500 MWh of gas (G4).
[566] See Appendix 9.1: Microbusinesses, and specifically the section ‘Outcomes: by customer size’.

possible explanation for the larger differences on these tariffs might be if suppliers expect medium microbusinesses to have lower engagement than larger SMEs, and thus offer them worse rollover rates.

9.103 It also appears that differences in per customer costs could broadly explain differences in average gross margins in gas between medium microbusinesses and larger SMEs.[567]

9.104 We also found indication for specific suppliers that NPVs were higher on medium microbusinesses than larger SMEs. We considered whether bad debt might be a factor, but the evidence suggests that any difference between customers of different sizes was small.[568]

9.105 Based on the range of evidence available, there are some indications that supplying medium microbusinesses may be more profitable than supplying larger SMEs. We do not consider that the evidence on this point is conclusive. However, to the extent that this is true, it may be linked to lower engagement among microbusinesses than other SME customers. It would also be consistent with low transparency increasing switching costs, as these costs would be higher (relative to the cost of energy) for medium microbusinesses compared with larger SMEs.

Outcomes: regional incumbency

9.106 We found that the former electricity incumbents generally had higher gross margins in their home regions than elsewhere.[569] This gross margin difference should not be the result of cost differences: the main costs which vary regionally are network charges, and these are deducted in the calculation of gross margin. We have not received clear evidence that indirect costs vary systematically on a regional basis.

9.107 We looked specifically at evergreen tariffs because customers who had remained on the same tariff since privatisation would be on these tariffs. As noted above, we found that evergreen tariffs were more common in home regions. We also found higher gross margins (in most cases) on evergreen tariffs in home regions compared with other regions, especially for the smallest microbusinesses.[570] The weighted average across four[571] suppliers was £19/MWh higher gross margin in home regions for the smallest microbusinesses, £6 for medium microbusinesses, and £4 for the largest

[567] See Appendix 9.1: Microbusinesses, and specifically the section 'Outcomes: by customer size'.
[568] See Appendix 9.1: Microbusinesses, and specifically the section 'Outcomes: by customer size'.
[569] See Appendix 9.1: Microbusinesses, and specifically the section 'Outcomes – regional incumbency'.
[570] See Appendix 9.1, and specifically the section 'Outcomes – regional incumbency'.
[571] SSE was unable to provide gross margin data.

class of microbusinesses. For larger SMEs, there was no significant difference.

9.108 For products other than evergreen tariffs, the differences in average unit gross margins between home regions and other regions were mostly smaller than on evergreen tariffs, and were less consistently in the same direction. Table 9.1 compares the differences for medium microbusinesses.[572] This suggests that suppliers are not systematically receiving much higher gross margins on other tariff types in their home regions compared with elsewhere.

9.109 We provisionally concluded that regional incumbency is a sign of low engagement among certain business customers, and that this may lead to worse outcomes for customers who have not engaged recently. However, the data suggests that the harm from this may relate primarily to higher prices for evergreen customers in home regions, who represent a small proportion of suppliers' microbusiness volumes.

Provisional conclusions

9.110 We have provisionally found that a substantial number of microbusinesses are achieving poor outcomes in their energy supply. EBIT margins were generally higher in the SME markets than other markets (beyond what appears to be justified by risk).[573] We observed that average revenues are substantially higher on the default tariff types that less engaged microbusiness customers end up on, compared with acquisition or retention tariffs, which require an active choice by customers. These differences in revenues between tariffs go beyond what is justified by costs. We therefore have concerns that the less engaged customers on these tariffs are not exerting sufficient competitive constraints on energy suppliers. Our concerns are particularly about the various types of default tariffs that customers can be automatically moved on to if they have not actively engaged with their energy supply (auto-rollovers and replacement contracts), or if they are receiving energy supply in circumstances where they have not agreed a contract (deemed and OOC tariffs).

9.111 Overall, our provisional finding is that we have identified a combination of features of the markets for retail supply of gas and electricity to SMEs in Great Britain **that give rise to an AEC through an overarching feature of weak customer response from microbusinesses**[574] which, in turn, give

[572] Those with an annual electricity consumption between 10 and 30 MWh.
[573] As explained in the section on margins above (paragraphs 9.66-9.74), suppliers were only able to provide EBIT margin information for SMEs, rather than for microbusinesses specifically.
[574] We refer to weak customer response as an overarching feature as synonymous with it being a source for an AEC (*CC3*, paragraph 170).

suppliers a position of unilateral market power concerning their inactive microbusiness customer base which they are able to exploit through their pricing policies or otherwise. These features act in combination to deter microbusiness customers from engaging in the SME retail gas and electricity markets, to impede their ability to do so effectively and successfully, and to discourage them from considering and/or selecting a new supplier that offers a lower price for effectively the same product.

9.112 More particularly, these features are as follows:

(a) Customers have **limited awareness of and interest in their ability to switch energy supplier**, which arises from the following fundamental characteristic of the markets for retail energy supply to SMEs:

(i) the homogeneity of gas and electricity, which means an absence of quality differentiation of gas and electricity and which may fundamentally affect the potential for customer engagement in the markets; and

(ii) the role of traditional meters and bills, which give rise to a disparity between actual and estimated consumption. This can be confusing and unhelpful to customers in understanding the relationship between the energy they consume and the amount they ultimately pay. The full roll-out of smart meters over the next five years may have a potentially significant positive impact on engagement, although we have limited evidence concerning the likely magnitude and timescales of any such impact.

(b) Customers face **actual and perceived barriers to accessing and assessing information** arising, in particular, from the following aspects of the markets for retail energy supply to SMEs:

(i) a general lack of price transparency concerning the tariffs that are available to microbusinesses, which results from many microbusiness tariffs not being published; a substantial proportion of microbusiness tariffs being individually negotiated between customer and supplier; and from the nascent state of PCWs for non-domestic customers (although transparency may be improving with the introduction of online quotes and PCWs); and

(ii) the role of TPIs, in relation to which:

- a number of complaints have been made by non-domestic customers to various official bodies concerning alleged TPI malpractice, which may have reduced the level of trust in all TPIs and discouraged engagement more generally (although this situation may improve if Ofgem implements a code of practice for non-domestic TPIs that is currently in draft form); and

- we have noted a lack of transparency as well as the existence of incentives not to give non-domestic customers the best possible deal. We are concerned that customers are not aware of this and therefore do not take steps to mitigate it (for example, by consulting more than one TPI or seeking other benchmark prices). This is exacerbated by the lack of easily available benchmark prices, and the fact that many tariffs are not published.

(c) Some microbusiness customers are on **auto-rollover tariffs** (where customers are signed up for an initial period at a fixed rate, with an automatic rollover for a subsequent fixed period at a rate they have not negotiated with no exit clause), and are given a narrow window in which to switch supplier or tariff, which may limit their ability to engage with the markets. This practice has recently been discontinued by the largest suppliers, but not by some of the smaller ones (which still account for a significant share of supply of gas to microbusinesses).

9.113 For the reasons given in Section 8 in relation to the regulatory framework governing the markets for domestic retail gas and electricity supply, we have provisionally found that:

(a) The current system of gas settlement is a feature of the market for SME retail gas supply in Great Britain that gives rise to an AEC through the inefficient allocation of costs to parties and the scope it creates for gaming, which reduces the efficiency and, therefore, the competitiveness of microbusinesses retail gas supply. While we note that Project Nexus is likely to address most of the current inefficiencies in the gas settlement system identified, we are concerned at the slow pace of the implementation, the lack of a deadline and the fact that some players might have been adversely affected by these delays. Moreover, we are concerned that the incentives that shippers face to place a higher priority on adjusting AQs down and delaying adjusting AQs up will still be present after Project Nexus is implemented.

(b) The absence of a firm plan for moving to half-hourly settlement for the majority of microbusinesses[575] electricity customers and of a cost-

[575] The majority of microbusinesses are currently assigned to profile classes 3–4, ie Non-Domestic Unrestricted Customers and Non-Domestic Economy 7 Customers.

effective option of elective half-hourly settlement is a feature of the market for SME retail electricity supply in Great Britain that gives rise to an AEC through the distortion of suppliers' incentives to encourage their customers to change their consumption profile, which overall reduces the efficiency and, therefore, the competitiveness of microbusinesses retail electricity supply.

9.114 We discuss our provisional finding on the detriment arising from the above AEC in Section 10.

10. Profitability analysis and competitive benchmarking in retail energy supply

10.1 In Sections 7 and 8 we set out our provisional finding that a combination of features of the markets for the domestic and SME retail supply of gas and electricity in Great Britain give rise to two AECs in these markets through an overarching feature of weak customer response which, in turn, gives suppliers a position of unilateral market power concerning their inactive customer base and gives them the ability to exploit such a position through their pricing policies.

10.2 In this section we assess the potential level of detriment arising from these AECs, by considering whether there is evidence that the overall price levels have been higher over the past few years than they would have been under a well-functioning market in which costs and profits are competed down to efficient levels.

10.3 In addressing this question we have considered the evidence in three areas:[576]

(a) whether firms have earned excessive levels of profits;

(b) whether firms have operated with inefficiently high levels of costs; and

(c) in relation to domestic prices we have considered whether the prices offered by the mid-tier suppliers provide an indication of competitive benchmark prices, and how they compare with prices offered by the larger suppliers.

10.4 We also considered whether there were any trends in profits over recent years that might indicate deteriorations or improvements in the competitive environment.

10.5 We analysed the supply of electricity and gas to customers as a whole with a specific focus on the domestic and SME[577] markets. These markets represent around 70 to 80% of total supply based on revenues and profits, with I&C customers accounting for the remaining 20 to 30%.[578]

10.6 In this section, we concentrate on the most recent five-year period from 2009 to 2013. In Section 7 we note our view that competitive conditions changed significantly around 2009 and hence we consider that evidence from the

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[576] The work that we conducted in this area is based on the methodology set out in Appendix 10.1.
[577] Firms were unable to separate microbusiness customers from their SME customer base.
[578] Appendix 10.2.

period subsequent to that is more informative about the state of the market today than evidence from prior periods. In some of our supporting analysis we considered a longer period of time including 2007 and 2008 and we have referred to the results for the seven-year period where appropriate. We will update our figures for 2014 following the publication of these provisional findings.

10.7 Analysis of profitability and efficiency involves judgements and assumptions due to difficulties in accurately measuring the profits that the sector has earned, estimating the level of efficient costs, and estimating a 'fair' return for the activity in question. In this investigation, these problems were compounded by the difficulties in obtaining good quality financial information from some firms. (See further Appendix 10.3 Retail ROCE and Appendix 11.1 Financial Transparency). We have sought to make reasonable judgements and assumptions in coming to our views, but we acknowledge that there is nevertheless a degree of imprecision involved in making such assessments. In order to allow us to have sufficient confidence in our findings we have approached the analysis from a number of angles in order to avoid placing undue reliance on any single approach.

10.8 One important question for this investigation is to examine how competition functions in particular market segments as well as across the retail markets as a whole. To compare levels of profitability over time and between market segments we have considered profits generated as a percentage of revenue, or 'profit margins'. Profit margins are a partial measure of profitability because they do not include the costs of capital employed; however they are useful to inform our view of relative profitability between segments and over time.

10.9 ROCE is the CMA's standard approach to measuring out-turn profitability, as it takes account of the capital required to operate a business. Providing appropriate adjustments are made, it can give an economically meaningful measure of profitability on an ex-post basis, which can be compared with the WACC. A situation in which firms representing a substantial part of the market have persistently earned profits in excess of the cost of capital[579] can indicate limitations in the competitive process, resulting in prices that have been too high.

10.10 High prices can also result from inefficiency. In addition to considering out-turn profitability, we have also considered the extent to which firms may have operated with inefficient costs. This is done by benchmarking each

[579] We describe such profits as 'profits in excess of the cost of capital' in the remainder of this section.

firm's costs against those of apparently more efficient firms. Having done so, we form a view of the revenue that each firm would require in order to cover its efficient costs and provide it with a fair return on capital employed. This in turn can be used to derive an illustration of prices that we would expect to see had the market functioned effectively, ie in which competition had driven costs and profits down to efficient levels. A comparison can then be made against out-turn revenues in order to estimate the extent to which prices have exceeded benchmark 'competitive' levels.

10.11 Because the parties have claimed that retail energy supply is an asset-light industry, making ROCE a potentially unstable measure, we have considered using profit margin comparators to supplement the evidence on profitability outcomes. Unlike ROCE, which can be compared with the WACC, profit margins do not take the cost of capital into account and lack a theoretically ideal competitive benchmark. We have considered evidence on margins from other industries or countries as possibly indicative of appropriate margins, as well as margins in different segments of the GB retail energy markets.

10.12 We have also considered evidence on the prices, costs and margins generated by the mid-tier suppliers.

10.13 The remainder of this section is structured as follows:

(a) First we set out our calculations of out-turn margins for the supply business as a whole and for the domestic, SME and I&C markets.

(b) Second we set out the results of our analysis of out-turn profitability, based on our assessment of ROCE, for the supply business as a whole.

(c) Third we discuss the results of our analysis of competitive prices and costs, based on our cost benchmarking assessment, for the domestic and SME segments.

(d) Fourth we discuss the evidence on comparative profit margins based on our margin benchmarking analysis.

(e) Fifth we discuss the evidence on the levels of prices charged by Six Large Energy Firms and independent suppliers in recent years.

(f) Lastly we summarise our provisional views on the interpretation of our analysis.

Analysis of out-turn margins

10.14 We compared margins in different market segments to provide information about relative profitability of different parts of the supply markets.

10.15 We asked suppliers to provide us with a breakdown of revenues and costs to allow us to calculate profit margins on the following bases:

(a) by domestic, SME and I&C markets; and

(b) domestic and SME by gas and electric markets.

10.16 From this analysis, the detail of which is set out in Appendix 10.2 Profit margin analysis, we observed the following in relation to the five-year period 2009 to 2013:

(a) SME EBIT margins were noticeably higher than domestic and I&C margins. The period average EBIT margin in SME supply was 8.4% compared with 3.3% in domestic supply and 2.0% in the I&C markets. The average EBIT margin for the total supply business was 3.4% and 4.0% for the domestic and SME retail supply markets.

(b) In the domestic and SME markets, EBIT margins were generally higher in gas than in electricity. Six Large Energy Firm averages for the domestic market were 4.4% in gas and 2.2% in electricity; and for the SME market were 10.1% in gas and 7.9% in electricity.

10.17 Parties told us that SME margins were higher because the SME business was higher-risk than other markets due to greater exposure to bad debts and downturns in the economy. We were not convinced that bad debt risk was intrinsically higher for SME customers; for example, SME customers could be disconnected for non-payment (in contrast to domestic customers). We also noted that the period over which we had observed high margins for these customers had been one of weak economic growth; a pattern which does not suggest cyclicality. However, we agreed that in theory the SME and I&C business was likely to be more exposed to the economic cycle than domestic customers and we took this into account in estimating the required WACC for the retail energy business as a whole.[580]

10.18 In view of the above, we consider that the scale of the margin differential between domestic and SME is sufficiently large that it was implausible that it

[580] Appendix 10.4.

could be explained by differences in costs or risks that we had not already taken account of.

10.19 As for the differential in margins between gas and electricity, we considered that this pattern in domestic gas was driven by Centrica whose margins were considerably higher than the average of the Six Large Energy Firms ([✂] vs 4.4%). We saw no clear cost or risk-related justification for the higher margins earned by Centrica on gas.

Analysis of out-turn profits

10.20 As described above, one method by which we assessed out-turn profits was by calculating the ROCE and the amount by which returns have exceeded the cost of capital.[581]

10.21 Our approach was to start with accounting profits and the balance sheets for the Six Large Energy Firms' retail supply businesses and then make adjustments to arrive at an economically meaningful measure of ROCE. Profits in excess of the cost of capital can differ from accounting profits, with adjustments most commonly required to the value of capital employed to *(a)* ensure that all assets required for the operation of the business, including intangible assets, are included on the balance sheet; and *(b)* the value at which these assets are included in the capital base reflects the current opportunity cost of owning the asset.

10.22 Following this approach, we based our assessment[582] on information on the revenues, costs and capital employed in the Six Large Energy Firms' retail supply businesses (including I&C as well as domestic and SME businesses), with appropriate adjustments to reflect economic costs, the most important of which were as follows:

(a) We adjusted the wholesale energy costs for two of the Six Large Energy Firms ([✂]) to remove significant transfer pricing premia.[583]

(b) We added a small percentage ([✂]%) uplift to wholesale energy costs to estimate the additional costs that would be incurred as a stand-alone retailer trading in the wholesale markets, and without the benefits of a parent company with a large balance sheet. This adjustment is designed to reflect an appropriate internal transfer charge for business risks borne elsewhere within the group, which we understood was not reflected in

[581] This approach is set out in *CC3*.
[582] Appendix 10.3.
[583] Appendix 10.5, Annex A.

the accounting information that the Six Large Energy Firms gave to us for their retail supply businesses. We did not make further adjustments for cash collateral or 'notional capital' (contingent equity capital or other contingent capital).

(c) In order to reflect the value of customer relationships, we capitalised the amounts spent in each year by each supplier on customer acquisition costs and assumed an amortisation period of eight years (we assumed that the opening balance at the beginning of the period over which we conducted the analysis was equivalent to four times customer acquisition costs in the first year).

(d) We calculated working capital in each year using the average of suppliers' quarterly balance sheet figures, rather than the year-end figure, in order to take some account of seasonal fluctuations.[584]

(e) We calculated the cost of capital employed by applying a WACC sufficient to compensate for the level of systematic risk facing an energy retail business. We allowed for a nominal pre-tax WACC of 10%, reflecting our view of the return that an equity investor in a stand-alone energy retail firm would require.

10.23 We did not allocate capital employed between I&C customers and domestic customers and SMEs (including microbusinesses) in this analysis. Whilst it would be possible to make reasonable assumptions in order to do so, our preferred approach was to make only limited adjustments to firms' data; therefore we have analysed ROCE for the retail business as a whole, including the I&C business. Given that there are lower competition concerns in I&C (it was excluded from our terms of reference) we consider that it is reasonable to assume that any profits in excess of the cost of capital arise predominantly in the domestic and SME segments.

Summary of approach

10.24 Many of the Six Large Energy Firms had limited financial information about their supply businesses:

(a) The firms did not routinely prepare information for the supply business in the form we required it; and the regulatory segmental accounts[585]

[584] We note that this is an approximation of average working capital over the year. In theory, daily working capital balances would be required to calculate a more representative average balance.
[585] Consolidated Segmental Statements.

included only limited revenue and cost information, and required no balance sheet information.

(b) Firms were uncertain about the balance sheet of the supply business (and one could initially provide no information); and firms could not apportion the balance sheet by customer segment or fuel type.

(c) Capital employed, particularly working capital, appears to fluctuate considerably over time and between suppliers and suppliers have not fully explained the reasons for this.

(d) Some firms argued that the supply businesses' capital employed included large amounts of 'notional capital'.

10.25 The lack of routinely prepared segmental management accounting information, or audited statutory accounting information, created difficulties in assessing the reasonableness of the data that firms gave us, particularly in relation to the balance sheet.

10.26 'Notional capital' was a material issue in this regard. Some of the Six Large Energy Firms told us that a stand-alone supplier would face significant 'business risks', in particular the risk of having to post substantial amounts of cash collateral to support trading on the wholesale markets, which would require it to hold large sums of cash or cash equivalents in order to remain solvent thus substantially increasing capital employed. They argued that a stand-alone firm would have limited access to lines of credit, hence the need for 'on balance sheet' sources of finance.

10.27 Firms' estimates of this balance varied widely and there was no consistent approach to its calculation. This was partly driven by uncertainty about whether the Six Large Energy Firms employed notional capital in their existing businesses. Some of the Six Large Energy Firms said notional capital was employed, but held at the group level. However, one of the Six Large Energy Firms ([✂]) disagreed, and said that balance sheet strength made the holding of notional capital unnecessary, and any riskiness from the supply business was reflected in the cost of capital. Two firms' ([✂]) calculations of the amount of the 'notional capital' were sufficiently large to bring their returns down close to their cost of capital. We noted that had we adopted one firm's ([✂]) methodology for calculating the cost of holding notional capital, the other five large suppliers would have been loss-making.

10.28 We analysed the need for such 'notional capital' by assessing how two stand-alone independent suppliers that had achieved a degree of scale managed their business risks. We found that they did not hold large sums of cash or cash equivalents and instead had entered into an arrangement with

Shell who acted as an intermediary to trade on their behalf in return for a fee, thus avoiding the need to post cash collateral. These independents manage other business risks through efficient risk management, and, in addition, are able to access a credit facility through the intermediary if the need arises. Compared with the Six Large Energy Firms' estimates of notional capital, the intermediary arrangements of the independent suppliers appear to be significantly more cost-effective. We found that the independents paid a fee equivalent to a small proportion ([✂]%) of wholesale energy costs. This compared favourably with the Six Large Energy Firms' estimates of the cost of notional capital which were several times higher. We considered that the fee paid by the independents provided a reasonable approximation of the costs that the retail businesses of the Six Large Energy Firms would face if stand-alone, hence we applied a small uplift of [✂]% to wholesale energy costs to take this into account. We consider that the fee that we applied is likely to be towards the upper end of the range of costs that would be incurred by a large supplier, based on evidence from one intermediary, Shell, which indicated that the percentage would be likely to fall as volumes increased.

10.29 The Six Large Energy Firms said that the ROCE approach was unsuitable for an 'asset light' business such as energy retail and encouraged us to focus on margin comparisons.

10.30 We consider that the ROCE approach has a solid theoretical underpinning and can be applied to the energy retail business, provided appropriate adjustments are made to ensure that capital employed is appropriately measured so that it is not understated. Therefore, we have made appropriate adjustments to accounting information to reflect the value of intangible assets and ensure that other capital items are stated appropriately. Having done so, we consider that the results of our ROCE calculations provide a meaningful measure of profitability in energy retail, which takes account of the cost of risk capital. We do not agree that a low level of capital employed makes a ROCE analysis less meaningful. Investors expect to earn a return on the capital they put at risk; which is limited to their equity or debt holding in a firm with limited liability. As noted in paragraph 10.7 we consider the results of this analysis alongside other sources of evidence on profitability.

10.31 We also note that one large supplier ([✂]) calculated economic profits, which are closely based on ROCE, for its supply business and used them as a performance measure to remunerate its executives. The calculation used by the supplier did not include an allowance for notional capital.

10.32 Details of our methodology are set out in Appendix 10.3 and Appendix 10.4.

Industry return on capital employed

10.33 The results of our analysis are that on a combined basis the Six Large Energy Firms earned a ROCE of 28% on average[586] across the five-year period from 2009 to 2013. Four firms, ([✂]) earned a ROCE of 44% on average across the five-year period. [✂] average ROCE was 58%; [✂] was 29%; [✂] was 66%; and [✂] was 32% on average over the same period. Two firms, ([✂]) earned profits below the cost of capital with [✂] earning returns of 5% and [✂] earning negative returns of –13% on average across the period. Table 10.1 sets out the results of the ROCE analysis.

Table 10.1: Out-turn ROCE (2009 to 2013)

						%
ROCE (£m)	*2009*	*2010*	*2011*	*2012*	*2013*	*Average*
[✂]	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]
[✂]	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]
[✂]	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]
[✂]	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]
Subtotal average	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]
	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]
[✂]	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]
[✂]	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]
Subtotal average	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]
	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]
Average	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]

Source: CMA analysis.

10.34 Our assessment indicates that four of the Six Large Energy Firms ([✂]) generated combined profits in excess of the cost of capital over the period of approximately £5.4 billion or £1.0 billion a year. Two of the Six Large Energy Firms ([✂]) made combined losses, after taking into account the cost of capital employed, of around £1.0 billion over the period or £0.2 billion a year. We discuss the reasons for these losses in paragraph 10.68.

Table 10.2: Profits in excess of the cost of capital (2009 to 2013)

							£m	
	2009	*2010*	*2011*	*2012*	*2013*	*Average*	*Total*	*%*
[✂]	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]
[✂]	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]
[✂]	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]
[✂]	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]
Profits in excess of the cost of capital	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]
	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]
[✂]	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]
[✂]	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]
Losses	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]
	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]
Net	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]

Source: CMA analysis.

586 Average ROCE = Total EBIT/Total capital employed - for the firms over the relevant five-year period.

10.35 We estimated that the cost of capital was around 10%. Therefore, average ROCE at 28% was substantially above the cost of capital over the period 2009 to 2013. The four profitable Six Large Energy Firms ([✂]) earned levels of profits that were between three and six times more than our estimate of the level of profits that would provide a reasonable return on capital. Two firms were loss-making, hence the average level of returns was 28% or approximately three times our calculation of the level of profits that would provide a reasonable return on capital.

10.36 There was no noticeable upwards or downwards trend in ROCE over the period among the Six Large Energy Firms. Returns were variable due to factors including temperature related revenue and cost impacts, and fluctuations in working capital. As a result we consider that it is more meaningful to consider average returns over the five-year period.

10.37 As noted in paragraph 10.6 we consider that the five-year period from 2009 to 2013 is likely to be more informative in regards to recent competitive conditions than earlier years. In Appendix 10.3 we set out the results of our ROCE analysis for the seven-year period from 2007 to 2013, alongside those of the five-year period. The average ROCE was slightly lower at 24% over the seven-year period compared with 28% over the five-year period. The average ROCE for the four profitable Six Large Energy Firms was slightly lower at 40% over the seven-year period compared with 44% over the five-year period.

10.38 We consider that the broad results of this analysis are not very sensitive to inaccuracies or differences in assumptions:

(a) We accept that there may be some uncertainties around the precise level of capital employed in the retail business in relation to items such as customer relationships, IT systems, tangible fixed assets and working capital. However, we note that capital employed would have had to increase by approximately £10 billion (a threefold or 300% increase) to bring the ROCE down to the cost of capital for the four of the Six Large Energy Firms that made profits in excess of the cost of capital over the period.

(b) Even if there is some uncertainty around the precise level of our benchmark 'trading fee' for a stand-alone supplier of the scale of the Six Large Energy Firms, we note that the 'trading fee' would have to increase by several hundred per cent in order to bring the ROCE down to the cost of capital for the four of the Six Large Energy Firms that made profits in excess of the cost of capital over the period. Furthermore, as noted in paragraph 10.28, we hold the view our benchmark

‘trading fee’ reflects an upper bound for how much it would cost stand-alone suppliers of scale.

10.39 The margin that is implied by our ROCE analysis can be calculated by applying the WACC to capital employed. This produces an average implied EBIT margin across the Six Large Energy Firms of 1.3%. We discuss the reasonableness of this result in paragraphs 10.101 and 10.102.

Results for individual firms

10.40 [✄] earned more than half of the combined profits in excess of the cost of capital (around £0.6 billion a year or £3 billion in total). Three other firms ([✄]) earned the remainder. Two firms ([✄]) made losses over the period.

10.41 We found that there were several factors behind the observed differences in profitability between suppliers, most notably:

(a) differences in average achieved prices when compared on a per MWh basis. These are discussed further in Appendix 8.4;

(b) differences in wholesale energy costs when compared on a per MWh basis;

(c) differences in indirect costs when compared on a per customer basis; and

(d) differences in levels of capital employed and working capital when compared on a like-for-like basis (for example, debtors as a proportion of revenue and creditors as a proportion of direct costs).

10.42 We discuss the reasons for differences in wholesale energy costs, indirect costs, and differences in levels of capital employed, and how we have sought to control for these differences in our analysis of the competitive benchmark price described below.

Analysis of competitive benchmark prices and costs

10.43 In this part of the analysis we sought to control for the differences described in paragraph 10.41 to inform our view of the level of prices that suppliers would have required in order to cover reasonably efficient levels of costs and earn a fair rate of return on capital employed. We term this the ‘competitive benchmark’ on the basis that, had competition functioned more effectively over the period, we would expect prices to have been driven down to this level. As such we consider that this provides an illustration of price levels in a better functioning, but not necessarily perfectly competitive, market. The details of this assessment are set out in Appendix 10.5.

Wholesale energy cost benchmarking

10.44 We found that the Six Large Energy Firms' wholesale energy costs varied considerably when compared on a per MWh basis. Possible explanations for the observed variation are differences in the wholesale products purchased and differences in the way that those products are priced. In practice these two factors are closely linked. We consider wholesale energy purchasing in further detail in Appendix 10.5 Annex A.

10.45 In relation to the nature of products purchased, we found that the wholesale energy costs for four of the Six Large Energy Firms reflected, to some extent, bespoke products rather than standard products that were traded on open wholesale markets such as near-term exchanges and forward OTC trading markets. Bespoke purchases included longer-term multi-period purchases such as tolls and PPAs and shaped products before they were available on open wholesale markets.

10.46 In relation to transfer pricing, given that four of the Six Large Energy Firms reported wholesale energy costs that were, at least to some extent, based on bespoke products that were not traded on wholesale markets, the reported costs of these suppliers would not fully reflect open market prices. As noted in paragraph 10.22(a), in our ROCE analysis we adjusted the energy costs of these two suppliers ([✄]) whose reported costs included significant transfer pricing premia.

10.47 To illustrate this issue, if a firm enters into a long-term toll or PPA as a result of a bilateral negotiation with a generator, the price it pays under that agreement would be a function of expectations of the forward energy price curve at the time the agreement is struck and the relative negotiating strength of the parties. If expectations change, this may result in the firm in future paying either above or below the prevailing wholesale market price. We consider that the gap between the price paid under such an arrangement and the open market price (eg that facing an independent supplier purchasing standard products on the wholesale markets) could be regarded as a trading profit or loss for the purposes of our analysis, rather than a profit or loss that has been incurred in running the retail business.

10.48 In our view, basing the costs of the retail business on market products traded on open wholesale markets *(a)* is more likely to reflect the costs that would have faced an equivalent stand-alone retail firm sourcing all their energy in this way; and *(b)* separate out trading profitability from retail profitability, thereby giving a meaningful split of financial performance between the retail business and the trading business.

10.49 We found that the approach of two firms ([✂]) to wholesale energy transfer pricing was more likely to reflect the costs of products traded on open wholesale markets over the period, than those of other suppliers. This is because the wholesale energy cost base of these two firms ([✂]) reflected a higher proportion of standard traded products than those of other suppliers, whose cost base comprised a proportion of bespoke products. We therefore used the average wholesale energy costs of these two firms as one benchmark scenario.

10.50 In addition to the scenario based on the average wholesale costs of two firms ([✂]) we also considered a lower quartile scenario. We considered that this scenario was justified on the basis that the mid-tier suppliers tended to have wholesale energy costs that were below or at the lower quartile of the larger firms, despite their small scale.

10.51 However, in view of the uncertainty in this area we considered it was prudent to use the average of the two alternative benchmark scenarios using average wholesale energy costs based on [✂] costs and lower quartile costs.

10.52 Consistent with our ROCE analysis, as discussed in paragraph 10.28, we added a small uplift of [✂]% of total wholesale energy costs to reflect the costs of trading directly on the wholesale markets.

Indirect cost benchmarking

10.53 We found that there was a significant gap between the level of indirect costs incurred by different firms on a per customer account basis. We also found that the differential between the lowest and highest cost firms was wide and persistent, although we noted that two suppliers ([✂]) made significant improvements over the period.

10.54 Several firms indicated that there were further areas to improve efficiencies in their retail businesses. For example:

(a) [✂] told us that it had made continued efforts to get costs under control over the last five years, but had recently stepped up its efforts in this regard. It added that to be in the middle of the 'pack', it would have to reduce its costs by 25 to 30%.

(b) [✂] told us that its indirect costs were higher than those of some independents due to legacy IT systems.

(c) [✄] told us that its higher indirect costs were partly a reflection of how it was formed from a number of regional electricity companies. It added that since realising its costs were higher by around £35 per customer than the other large suppliers, it had put through a number of cost-saving initiatives, and had reduced this differential to £19 per customer. It added that by the end of 2015, it was aiming to lower its costs to below the 'market average'.

10.55 We also noted that two of the mid-tier suppliers ([✄]) had indirect cost ratios around the lower quartile of the Six Large Energy Firm levels, despite having high customer acquisition costs and not benefiting from economies of scale. As a result we consider that the cost levels of these independent suppliers tend to support the use of a lower quartile assumption in our benchmarking analysis.

10.56 Given the evidence from the Six Large Energy Firms and mid-tier suppliers suggesting inefficiency in indirect costs, we used the lower quartile indirect cost per customer account in our analysis of the competitive benchmark price.

Other costs and capital employed

10.57 The treatment of other costs, and of capital employed, had less impact on the results of this analysis and is summarised briefly below. Further details are in Appendix 10.5.

Summary of benchmarking approach

10.58 We calculated benchmark cost levels using the average of various combinations of cost scenarios. For example:

(a) wholesale energy costs were based on lower quartile or the costs of two suppliers (RWE and EDF Energy)[587] on a per MWh basis, with a small uplift of [✄]%;[588]

[587] The lower quartile is the (n + 1) ÷ 4 th value of a distribution. We considered scenarios using lower quartile and two specific firms' costs ([✄]) on the basis that these were more likely to be representative of traded market prices.

[588] An uplift of [✄]% was applied on the basis of the likely costs faced by an independent supplier trading via an intermediary in order to avoid posting initial collateral and margin, and to access a contingent credit facility. See Appendix 10.3

(b) indirect costs were based on the lower quartile of the distribution between the highest and lowest per customer cost across the Six Large Energy Firms;

(c) depreciation was based on that of one large supplier ([✂]) which had recently invested in its systems, adjusted for relative customer numbers (see 10.59(b));[589] and

(d) other costs were as reported.

10.59 We calculated benchmark levels of capital employed using the following assumptions:

(a) Working capital was based on the lower quartile or average of the distribution between the highest and lowest per customer cost across the Six Large Energy Firms.

(b) Billing systems and other fixed assets were based on the book value reported by one large supplier that had recently invested in its systems, adjusted for relative customer numbers.

(c) Other balance sheet items were assumed to be as stated in our ROCE analysis.

Caveats

10.60 As mentioned above in paragraph 10.24, suppliers could not provide us with a split of capital employed between the domestic, SME, and I&C business. We performed our own allocation of capital employed based on appropriate drivers such as revenue and direct costs for debtors and creditors respectively and customer numbers for fixed assets. We consider that this is a reasonable basis on which to allocate capital but recognise that it may not be wholly accurate.

10.61 In addition there are some more general limitations with simplified efficiency benchmarking of the type we have carried out:

(a) Suppliers may legitimately operate different business models, for example by targeting different customer groups, which may influence

[589] This resulted in an increased depreciation charge for many suppliers. We considered that there may be a link between investments in IT and billing systems and lower costs to serve (although in practice the link was not clear as some firms with low costs to serve had not recently invested in systems). To take this possible link into account we adjusted capital employed upwards to reflect recent investment in IT systems. As a consequence, the depreciation charge was also increased to reflect this higher level of investment. We consider that this is consistent with an assumption of lower quartile indirect costs, including cost to serve.

costs. By equating lower quartile costs with efficient costs without controlling for differences in the customer base, we may overstate or understate the potential for cost savings.

(b) Our analysis relies on cost allocations being reasonably consistent across the Six Large Energy Firms, at least in the categories that we have focused on. For example, if the variability in certain cost categories is due to differences in cost allocation rather than efficiency, then our analysis may overstate the potential for cost savings.

10.62 However, we do not think that these limitations invalidate our analysis. Those suppliers with higher than average levels of indirect costs told us that they recognised that they were inefficient and were working to improve cost efficiency. This suggests to us that the differences in indirect costs are primarily the result of differences in efficiency and not merely as a result of differences in business models or cost allocation.

10.63 In relation to wholesale energy costs, there is some evidence that higher than average levels of wholesale energy costs reported by some suppliers result from a combination of transfer pricing anomalies, and the purchase of non-standard or 'bespoke' products.

10.64 As a result, having taken into account the caveats and the evidence from suppliers, we consider that our analysis provides a reasonable estimate of the margin by which domestic and SME prices may have exceeded the competitive level over the last five years. The analysis provides an indication that the total level of profits in excess of the cost of capital[590] that firms have earned over the period may be higher than that indicated by the ROCE analysis based on out-turn costs.

Table 10.3: Competitive benchmark revenues

	Out-turn revenues (£bn)			*Benchmark revenues (£bn)*			*Out-turn vs. benchmark (% difference)*		
	5YP Dom	*5YP SME*	*5YP Sum*	*5YP Dom*	*5YP SME*	*5YP Sum*	*5YP Dom*	*5YP SME*	*5YP Comb'd*
Centrica	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]
E.ON	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]
RWE	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]
EDF Energy	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]
SSE	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]
Scottish Power	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]
Combined	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]

Source: CMA analysis.

[590] Profits in excess of the cost of capital can be defined as the amount by which revenues have exceeded opportunity costs of production.

10.65 The above analysis suggests that prices may have been above our benchmark levels by the following amounts over the period 2009 to 2013:

(a) Domestic gas and electricity – 5%; or around £60 on a typical duel fuel bill of around £1,200.[591]

(b) SME gas and electricity – 14%.

10.66 This equates to customers paying approximately £1.7 billion per year more than they would have done had prices and costs been at benchmark levels, or £8.5 billion over the five-year period.

10.67 We note that the averages disguise material differences between firms. Two firms' ([✄]) revenues had exceeded benchmark levels by between 7 and 9%. Other firms' ([✄]) revenues had exceeded benchmark levels by between 1 and 5%.

10.68 This analysis indicates that those suppliers who had made economic losses over the period ([✄]) had done so because of inefficient levels of indirect costs, and not because their prices were below the competitive level.

10.69 On a per customer basis we calculate that the average domestic customer paid approximately £36 (3%) more per year on a typical[592] dual fuel bill of £1,200 than might have been the case had the markets functioned more effectively. For SME customers the figures are considerably larger; approximately £298 and £244 more per year on typical gas and electricity bills respectively.

10.70 The gross margins implied by this analysis were approximately 15% for domestic supply and 9% for SME supply. The net margins were approximately 1 to 2% for domestic supply and 1% for SME supply.

The wholesale spot scenario

10.71 We also calculated what prices would have been had suppliers purchased all their electricity needs on the spot markets.

10.72 In Appendix 10.5, Annex B we compared firms' reported electricity costs with the costs they would have incurred had they purchased all their electricity requirements on the spot markets. This analysis indicated that on average,

[591] 2013.
[592] 2013.

over the period 2009 to 2013, the reported cost was approximately 17% higher than the spot cost.

10.73 We found that the reason for this difference was primarily due to the fact that firms purchase much of their electricity needs on the forward markets, and that forward costs had systematically exceeded spot costs over the period. Suppliers argued that there were good reasons for purchasing energy on the forward markets, to insulate themselves against volatile spot prices and because customers would not want to be exposed to volatility in bills. They also said that spot markets were insufficiently deep to provide the necessary volumes.

10.74 We considered that the spot price was a possible measure of the opportunity cost of energy over the period on the basis that it would have been cheaper to purchase energy in this way, at least over the period that we reviewed. However, we accept that there are benefits in moderating risk through hedging and we note that independent suppliers also hedge their energy needs in advance. We have found it difficult to assess the extent to which customers benefit from the forward purchasing of energy. We note in Appendix 8.4 that the justification for hedging in relation to variable tariffs, the prices of which can in theory be changed readily, is less apparent that for fixed price tariffs.

10.75 Our analysis indicates that, taking the spot cost of electricity into account, the competitive benchmark domestic electricity price would have been around 12% lower than actual prices over the period, and SME electricity prices would have been around 27% lower.

Margin benchmarking

10.76 Parties put forward a range of comparators which they said could be used to indicate a reasonable level of EBIT margins in GB energy supply. These ranged from 2 to 25%. We assess the validity of the various comparators put forward in Appendix 10.6.

10.77 In our view, for this type of analysis to be meaningful the comparators need to exhibit similar cost structures and risk profiles to GB energy retailers. This is because the sales margin, by itself, is an incomplete descriptor of profitability.[593]

[593] Where profitability is defined as return on assets. Return on assets can be decomposed into sales margin x asset turnover (the Du Pont equation).

10.78 Many of the comparators proposed by parties were in different industries where both cost structure and risk were likely to differ considerably from energy retail. For example, grocery retailers would have considerably higher fixed assets (stores and stock). Parties did not put forward a proposal for how such differences should be measured and adjusted for.

10.79 As a result we consider that comparators within the GB energy retail sector are most informative in this regard. We considered the following comparators:

(a) margins of mid-tier suppliers; and

(b) margins on I&C customers.

10.80 We also considered regulatory precedents from Australia and Ireland.

Margins earned by mid-tier suppliers

10.81 We considered evidence from mid-tier suppliers on the levels of margins that they had earned over the period, and on the levels of margins that they considered necessary to remunerate the risk capital that had been invested.

10.82 We considered that comparisons of gross margins would be more instructive than EBIT margins for three reasons:

(a) Rapid customer growth over the period 2009 to 2013 meant that these suppliers had incurred disproportionately large customer acquisition costs in comparison with the Six Large Energy Firms.

(b) Upfront investments in staff costs and facilities required to support future growth were likely to distort operating costs.

(c) Mid-tier suppliers were exempt from ECO obligations during part of the period.

10.83 Turning to gross margins, we noted a wide range of reported gross margins from 23% to 9%. [✂]

10.84 The remaining mid-tier suppliers ([✂]) had earned average gross margins over the period of between 11 and 23%. The period average of the Six Large Energy Firms' gross margins were 17 and 18% in domestic electricity and gas respectively. The average of the Six Large Energy Firms' gross margins on non-SVTs was approximately 10% (see Appendix 10.2).

10.85 We considered the EBIT margins of the mid-tier suppliers over the period. These were generally negative, reflecting the substantial customer acquisition costs incurred by these suppliers to support their rapid growth. Considering EBIT margins before customer acquisition costs, we noted a wide range of period average EBITC2A[594] margins from 0.2 to 10.1%.

10.86 Ovo Energy told us that 12% and 3% were reasonable gross margins and EBIT margins respectively for a retail energy supplier operating with efficient levels of costs. Ovo emphasised that a firm operating with inefficient levels of costs should expect to earn lower margins than that. EDF Energy and Co-operative Energy both said that 3% was a fair EBIT margin for an energy retailer.

10.87 Other suppliers (SSE, RWE, Scottish Power) said that they 'targeted' margins of [✂]%, and Centrica said that it targeted [✂].

10.88 We note that target margins are aspirational and may therefore exceed the competitive level at which suppliers earn no more than the cost of capital.

10.89 We considered the views of trading intermediaries on the required level of margin for an independent energy retailer. Trading intermediaries are concerned to ensure that their counterparties are creditworthy to minimise the risk of a default, particularly when the counterparty is trading on an uncollateralised basis. As a result the independent supplier is contractually obliged to stay within healthy business parameters to ensure that it remains solvent. One independent supplier told us that it was required to maintain a gross margin of 12% as [✂].[595]

10.90 The Six Large Energy Firms told us that comparisons with mid-tier suppliers were not appropriate because *(a)* their customer bases were different to those of the mid-tier suppliers and were higher-cost; and *(b)* mid-tier suppliers would accept lower margins in the short term to gain market share, but in the longer term would need to generate higher returns.

10.91 We are not persuaded that energy retailers have such different customer bases as would warrant significantly higher ROCE and by implication higher EBIT margins. Whilst we accept that standard credit customers and prepayment meter customers are more costly to serve and acknowledge that the larger suppliers have a higher proportion of such customers, we are not persuaded that such customers require substantially higher levels of capital employed or have materially higher systematic risk such as would justify higher returns than those of the independent suppliers.

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[594] Earnings before interest, tax, depreciation and customer acquisition costs.
[595] See Appendix 10.6.

10.92 As to whether the mid-tier suppliers that we have looked at will need to generate higher margins to survive, we consider that EBIT margins for many mid-tier suppliers have been very low or negative largely because of high customer acquisition costs. Having added back these costs, we note a wide range of EBITCA margins. Gross margins are generally higher than those of the Six Large Energy Firms on non-SVT tariffs (which averaged 10%) and we have seen no evidence to suggest that they are unsustainable.

10.93 The evidence from the mid-tiers suggests that 'competitive' gross margins are likely to be around 12%. Actual EBIT margins are difficult to interpret due to customer acquisition costs and high growth. We consider that the target EBIT margins of 3% mentioned by some suppliers may indicate an aspirational margin for a supplier operating with an efficient level of capital employed and operating costs. A supplier that had not invested in systems to the same degree or had not achieved comparable efficiencies should not expect to realise the same level of profitability.

Margins on industrial and commercial customers

10.94 EBIT margins on I&C customers were on average around 2%. Suppliers said that I&C was a less risky business due to having more scope for cost pass-through, less shaping risk, and lower bad debt costs. In relation to bad debt risk, we note that I&C is likely to be more correlated with the economy than is domestic supply,[596] but possibly less so than SME. On balance, it was not clear to us that bad debt risk was clearly lower in I&C than for the combined SME and domestic business, such as would justify a lower margin on I&C. In relation to shaping risks and wholesale energy cost risks, we accept that a significant proportion of I&C customers are on tariffs which vary with wholesale prices to a greater extent than domestic and SME tariffs. This may increase suppliers' domestic and SME wholesale energy costs due to increased hedging, balancing, and demand forecasting costs. However, we do not consider that this justifies higher EBIT margins on domestic and SME tariffs, than on I&C.

10.95 Further, we note that I&C margins reported by the Six Large Energy Firms must be sufficient to remunerate the group for the costs of any implicit guarantee at group level. All things equal, the EBIT margin would be lower if the firm had properly accounted for the implicit benefit of the VI structure,

[596] Domestic customers who get into financial difficulties are more likely to continue using energy but at lower volumes and/or on a prepayment meter rather than stop using energy; whereas I&C customers may reduce demand significantly in an economic downturn or close down leaving large debts.

which we have approximated as less than or equal to [✄]% of wholesale energy costs.

10.96 On balance we consider that I&C EBIT margins are one possible indicator of the competitive margin in the domestic and SME markets.

Regulated margins

10.97 We considered two recent international precedents in Northern Ireland and New South Wales (NSW), Australia, as well as some older GB regulatory decisions. Suppliers argued that in a competitive market one would require higher margins to compensate for higher risks, and therefore regulated EBIT margins should be seen as a lower bound, eg 0.5 to 2.2%. Our view is that it is not automatic that a supplier in a competitive market will be more exposed to revenue and cost fluctuations relating to economic conditions than a regulated firm would be as this could depend on the regulatory arrangements and the extent to which suppliers in both types of market were exposed to risk. We note that GB energy retailers appear to have some ability to pass through costs to customers.[597] In addition we were not persuaded that the cost structure of Power NI or the NSW suppliers was sufficiently comparable to that of GB suppliers to enable a like-for-like margin comparison. Since, for an asset-light business, the required margin is sensitive to small absolute changes in capital employed, this latter point is important.

Our provisional view on margin benchmarking

10.98 In relation to gross margins, the evidence from the mid-tier suppliers suggests that gross margins of around 12% may be regarded as one measure of the 'competitive benchmark'. This is lower than the 15% domestic gross margin implied by our competitive price benchmarking exercise (see paragraph 10.70).

10.99 In relation to EBIT margins, the above evidence from independent suppliers suggests to us that competitive EBIT margins in energy supply are relatively low and likely to be 3% or less depending on the level of investment and the level of cost efficiency.

10.100 I&C margins indicate that an EBIT margin of around 2% is reasonable, and possibly lower for a fully independent supplier once the costs of trading on the wholesale markets are factored in.

[597] See Appendix 10.5, Annex B, and Appendix 7.2.

10.101 The competitive margin that is implied by our ROCE analysis (see paragraph 10.39) can be calculated by applying the WACC to capital employed. This produces an average implied EBIT margin across the Six Large Energy Firms of 1.3%.[598]

10.102 Low margins are consistent with energy retail being a low capital business as retailers do not own or operate any of the physical assets required for the delivery of gas or electricity. The main activities are sales and marketing, metering, and billing and customer service. Fixed assets are confined to IT and buildings and working capital can be managed through the use of effective credit control and debt management. We consider that energy retailers face low demand risk because energy is an essential good and is largely non-cyclical, particularly for domestic customers. Retailers can manage residual demand risks and wholesale price risks through the use of effective forecasting and hedging. There is a degree of cost pass-through in relation to much of the cost base including wholesale energy costs, and network costs. However, we note that the calculation of the competitive EBIT margin is very sensitive to the level of capital employed in such an 'asset light' business. We would therefore caution against inferring a precise estimate for the competitive EBIT margin from this analysis. Margins in the range of 1 to 3% would appear to provide a guide to the competitive EBIT margin based on current business models.

Analysis of average prices offered by suppliers to domestic customers

10.103 We have noted that there is a substantial variation in the prices paid by domestic customers, which provides evidence of significant degrees of disengagement. We also note that some of the Six Large Energy Firms have said that they can only afford to offer the cheapest non-standard tariffs if a proportion of customers revert to the more expensive SVT at the end of the tariffs' term. An important further question for this investigation is therefore whether the average domestic prices offered by each of the Six Large Energy Firms are above those that would prevail in a well-functioning competitive market.

10.104 In considering this question, we have compared the average domestic prices offered by different suppliers, notably those offered by the Six Large Energy Firms and the mid-tier suppliers. We have considered two sources of information:

[598] Similarly low margins are implied by our benchmarking analysis.

(a) The average revenues (p/kWh) earned by suppliers on their sales of gas and electricity to domestic customers, which we have calculated using data submitted by the Six Large Energy Firms and three of the mid-tier suppliers.

(b) The data that we have used to estimate the gains available to domestic customers from switching, which is a list of all tariffs to which customers of the Six Large Energy Firms were subscribing at end-of-quarter snapshots between Q1 2012 and Q2 2014.

Average revenues

10.105 In Section 7 we compared the average revenue earned by the mid-tier suppliers with the Six Large Energy Firms. We also considered whether the average revenue differs between the Six Large Energy Firms.

10.106 The average revenue earned by [✂] has been below that offered by the Six Large Energy Firms over the last few years. In 2014, [✂] average electricity and gas revenues were 11% and 12% respectively below the average of the Six Large Energy Firms.

10.107 For [✂] average gas revenues have been consistently lower than those of the Six Large Energy Firms and in 2014, the average revenue for gas was 20% below the average for the Six Large Energy Firms. [✂] average electricity revenues were above those of the Six Large Energy Firms in 2012, but since then have become cheaper. In 2014, the average revenue / kWh sold for [✂] was 4% below the average for the Six Large Energy Firms for electricity.

10.108 For [✂], average revenues for electricity and gas have been close to, and in some cases exceeded, average revenues for the Six Large Energy Firms.

10.109 Turning to the comparison between the Six Large Energy Firms, in Section 7 we observed that [✂] has earned consistently lower revenue per kWh than other firms across both SVT and non-standard tariffs.

10.110 We note that these results may reflect in part the impact of compositional factors, including differences in the location of suppliers' customers (which will affect average revenue through differences in regional distribution charges) and differences in the proportion of customers using particular types of payment methods. We will attempt to control for these differences in the next phase of our investigation.

Gains from switching data

10.111 We calculated the gains from switching available to the customers of each of the Six Large Energy Firms over the period Q1 2012 and Q2 2014. These are shown in the table below, for each of the scenarios described in Section 7, with the exception of scenarios 1 and 2 (which consider internal switches only). In general, the higher the gains available from a particular supplier, the more expensive the average prices offered by that supplier.[599]

Table 10.4: Weighted average potential savings available to dual fuel customers of the Six Large Energy Firms*

£

	Centrica	*EDF Energy*	*E.ON*	*RWE*	*Scottish Power*	*SSE*
S3a	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]
S3b	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]
S4a	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]
S4b	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]
S5	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]

Source: CMA analysis.
*The average is a simple average across the quarters. Within each quarter the weighted average is calculated using data on the distribution of consumption and the weights reflect the number of accounts that belong to each tariff. Base: all dual fuel customers.

10.112 The results suggest that, over the period, [✂] is the most expensive supplier, followed by [✂] in that order. The ranking is the same irrespective of the scenario chosen. We also note that the difference between scenario 3a and 3b implies that the cheapest tariff offered by the mid-tier suppliers over the period was around £30 to £40 cheaper than the cheapest tariff offered by the Six Large Energy Firms.

10.113 We do not currently have the data to include the mid-tier suppliers within this analysis. We will look to collect and analyse this data before publication of our final report. However, using our survey data we were able to calculate the gains from switching available to customers of the Six Large Firms and the mid-tier suppliers at Q2 2014. The results are shown, for dual fuel respondents to the survey, in the table below.

599 We note that this analysis does not control for the proportion of customers on different tariff types. Therefore, a higher level of gain could be composed of a mixture of two elements: a higher proportion of customers on a higher tariff; and a higher average level of tariffs. In the analysis that follows, we have not separated these two components, since our interest is in average levels of bills at average levels of consumption.

Table 10.5: Gains by supplier (dual fuel respondents to survey)

	Scenario 3b	*Scenario 5*
Supplier	*Mean gains (% bill)*	*Mean gains (% bill)*
[✄]	[✄]	[✄]
[✄]	[✄]	[✄]
[✄]	[✄]	[✄]
[✄]	[✄]	[✄]
[✄]	[✄]	[✄]
[✄]	[✄]	[✄]
[✄]	[✄]	[✄]
[✄]	[✄]	[✄]
[✄]	[✄]	[✄]
[✄]	[✄]	[✄]

Source: CMA analysis of supplier and survey data.
Note: The reported mean gains are for both those who could gain from switching and those who cannot. The gains for those who cannot gain from switching are coded 0..2. Base (by column) = 4460, 4587.

10.114 The results show that in Q2 2014 gains for survey respondents who use both [✄] and [✄] were substantially lower than those for respondents who use the Six Large Energy Firms. The gains for respondents who use [✄] and [✄] were broadly similar to those for respondents who use the Six Large Energy Firms.

10.115 Overall, the results suggest that, in the quarter considered, respondents who use two of the mid-tier suppliers ([✄]) were paying around 8% less than the respondents using the cheapest of the Six Large Energy Firms ([✄]). Keeping both payment method and tariff constant (Scenario 3b) respondents with these two mid-tier suppliers were paying around 4% less than those with the cheapest of the Six Large Energy Firms.

Regression analysis of domestic bills

10.116 To control for factors not already controlled for in the scenario analysis[600] (such as differences in average consumption levels), we carried out a regression analysis, in which the dependent variable is an annual bill and the explanatory variables are: the identity of the supplier; the level of annual consumption; payment method; whether the tariff is economy 7; and region. This analysis includes dual fuel customers only.

10.117 We have estimated a pooled regression over the data from each quarter from Q1 to 2012 to Q2 2014. The computed differences between suppliers are therefore an average across quarters. We have also tested the robustness of our results using a number of different specifications and time periods. The results from the pooled regression are summarised below:

[600] This is described in Appendix 7.4, Annex G.

(a) The weighted average bill for the data included in the analysis is £1,150.

(b) [✂] is the most expensive supplier (about £20 more expensive than [✂] which is the second most expensive supplier, or about 2% of the weighted average bill). The differences in the average bill between [✂] and other suppliers are statistically significant in all comparisons except that with [✂].[601]

(c) [✂] is cheaper than both [✂] (by about £95, or about 8% of the weighted average bill) and [✂] (about £75, or about 7% of the weighted average bill), and those differences are statistically significant.

(d) [✂] is the cheaper than both [✂] (by about £55, or about 5% of the weighted average bill) and [✂] (about £35, or about 3% of the weighted average bill), and those differences are statistically significant.

(e) Other suppliers fall between [✂], but the differences between them are not statistically significant.

10.118 The pattern of results in alternate specifications which we used as sensitivity tests are broadly consistent with our main regression when all periods are pooled. However, the quarterly regressions show that the gap between [✂] and other suppliers diminishes in the last three quarters of the sample.

Provisional conclusions on price comparisons

10.119 The evidence we have reviewed suggests that [✂] has been the cheapest of the Six Large Energy Firms, offering prices about £95 (approximately 8% of a typical bill) cheaper than the most expensive of the Six Large Energy Firms.

10.120 While we do not have the data to include the mid-tier suppliers within this analysis, the evidence from our survey suggests that in Q2 2014, both customers of [✂] were paying around 8% less than the customers of the cheapest of the Six Large Energy Firms, and around 4% less controlling for both payment method and tariff type.

10.121 In relation to whether the prices offered by the mid-tier suppliers represent an appropriate competitive benchmark against which to assess the prices of the Six Large Energy Firms, we note that the EBIT margins of both [✂] are low (in 2012 and 2013 their EBIT margins were [✂]) but this partly reflects the high level of customer acquisition costs and indirect costs they are

[601] The threshold for statistical significance is a p-value of 5% or lower (two sided test).

incurring as a result of their rapid growth. We also note that in 2014 [✂] was fully exempt from ECO while [✂] was partially exempt. As discussed in Section 7, full exemption is likely to be worth about £36 (or about 3% of typical bill).

10.122 We will take account of such factors in developing our views of whether the prices offered by the mid-tier suppliers provide evidence of an appropriate competitive benchmark in the next phase of our investigation.

Provisional views on interpretation of financial and profitability analysis

10.123 Our key findings in relation to financial and profitability analysis are summarised as follows.

10.124 Out-turn profits for the supply business as a whole were significantly above the cost of capital: the average ROCE was 28% against a weighted average cost of capital of 10%.

10.125 We quantified the level by which profits had exceeded the cost of capital at around £4.4 billion over the five-year period or £900 million a year. This is around 2% of total annual supply business revenues of £45 billion; or around 3% of total domestic and SME revenues of £33 billion.

10.126 There were significant differences between firms: four firms ([✂]) earned an average ROCE of 44%, over four times above the cost of capital. One firm ([✂]) made returns below its cost of capital; and one firm ([✂]) made losses over the period.

10.127 We calculated that profits had exceeded the cost of capital by £5.4 billion over the period for the four profitable firms ([✂]).

10.128 [✂], has earned a large proportion (around 60%) of these profits. Its high margins on [✂] have been a factor in this.

10.129 Whilst we did not agree with some firms who said that there were large ‘notional’ capital balances that needed to be reflected in capital employed, we accept that there may be some uncertainties around the precise level of capital employed in the retail business in relation to items such as customer relationships, IT systems, tangible fixed assets and working capital. However, we note that capital employed would have had to increase by approximately by £10 billion (a threefold or 300% increase) to bring the ROCE down to the cost of capital for the four firms that made profits in excess of the cost of capital over the period.

10.130 Due to data availability, our ROCE analysis was based on the supply business as a whole including I&C. Since I&C was excluded from our terms of reference on the grounds that it was more competitive than domestic and SME, we have made the assumption that any excess profits have been derived principally from the domestic and SME segments. Our analysis of EBIT margins supports this assumption: we found that average EBIT margins were lowest in I&C at 2% compared with 3.3% in domestic and 8.4% in SME.

10.131 Our margin benchmarking analysis suggests that competitive EBIT margins in energy supply are relatively low, consistent with energy retail being a low capital 'asset light' business with relatively low demand risk, particularly in the domestic sector. We note that EBIT margins are very sensitive to the level of capital employed and would caution against a precise estimate, however margins in the range of 1 to 3% would appear to provide a reasonable guide for what is required to cover efficient levels of capital employed and operating costs. We would emphasise that whilst average out-turn domestic margins of 3.3% are only slightly above this range, the average disguises wide variations in profit margins between suppliers.

10.132 We found that there were several factors behind the observed differences in profitability between suppliers, including: differences in achieved revenues per MWh; differences in wholesale energy costs per MWh; differences in indirect costs per customer; and differences in levels of capital employed. We sought to control for some of these differences in our analysis of the 'competitive benchmark' prices that suppliers would have required to cover reasonably efficient levels of costs and earn a fair rate of ROCE. We also performed an allocation of capital employed in this analysis in order to estimate the effect on domestic and SME prices separately.

10.133 Our analysis of competitive benchmark prices indicates that out-turn profits are an underestimate of the level of economic rent that the industry has earned over the period and that the combination of high profits and inefficiency is likely to have raised average prices over the period by around 3 and 15% in the domestic and SME markets respectively.

10.134 On a per customer basis we calculate that the average domestic customer paid approximately £60 (5%) more per year on a typical dual fuel bill of £1,200 than might have been the case had the markets functioned more effectively. For SME customers the figures are considerably larger; approximately 14% or £298 and £244 more per year on typical gas and electricity bills respectively. We will develop our thinking on this area of analysis in the next phase of the investigation.

10.135 We also note that the evidence on prices offered to domestic customers by different suppliers suggests that:

(a) One of the Six Large Energy Firms ([✂]) had lower prices than the other five of the Six Large Energy Firms (around 8% cheaper on average than the most expensive). [✂].

(b) Two of the mid-tier suppliers had lower prices than the cheapest of the Six Large Energy Firms (8% on average, or 4% controlling for payment method and tariff type) and lower gross margins of around 11 to 15% compared with 17 to 18% on average for the Six Large Energy Firms.

10.136 We consider that the preponderance of evidence discussed above is consistent with weak competitive conditions in the retail energy markets. It is consistent with our provisional finding that there is an overarching feature of weak customer response in each of the domestic and SME retail energy markets which, in turn, gives suppliers a position of unilateral market power concerning their inactive customer base. Suppliers in such a position have the ability to exploit such a position through their pricing policies. As regards the domestic retail energy markets we provisionally found that suppliers in a position of unilateral market power concerning their inactive customer base have the ability to price their SVTs materially above a level that can be justified by cost differences from their non-standard tariffs.

10.137 Overall, our provisional finding is that there is a range of evidence that suggests that average prices paid by domestic customers have been above the levels that are justified by the costs incurred with operating an efficient domestic retail supply business. For SMEs, the evidence suggests that average prices have been substantially above the levels that are justified by the costs incurred with operating an efficient SME retail supply business.

10.138 We note the difficulty in conducting this type of analysis but gain assurance that different sources of evidence on profitability give broadly consistent results. This evidence comprises one part of our overall evidence base and we have assessed the extent to which it is consistent with other parts of the evidence base in arriving at our provisional findings.

11. Structure and governance of the regulatory framework

Introduction

11.1 The regulatory framework governing the gas and electricity sectors is set out variously in legislation, in licence conditions and in industry codes. In the preceding chapters we have observed that this framework has had a profound effect on the nature of competition in wholesale and retail energy markets.

11.2 We noted in Section 2 that the regulatory framework that has been established since privatisation has helped to deliver positive outcomes on several fronts. Notably, there has been substantial progress on electricity decarbonisation and there have been no significant security of supply problems in recent history. However, prices have increased rapidly leading to widespread public concern.

11.3 We have identified some specific regulations and policies that we consider are likely to have led to detrimental outcomes for consumers and competition. These include the non-competitive allocation of some early CfD contracts, the prohibition of regional price discrimination and the introduction of the simpler choices element of the RMR. We have also identified changes to regulations and policies that we consider would have improved competition and consumer welfare, and yet were not implemented, including the locational pricing of transmission losses, and half-hourly settlement for customers on smart meters.

11.4 In this section, we consider whether aspects of the structure and governance of the regulatory framework – including the roles and responsibilities of institutions, the design of decision-making processes and the availability of appropriate information – are likely to increase the risk of policies being developed in the future that are not in consumers' interests or inhibit the development of policies that are in their interests.

11.5 We consider two aspects of this question:

(a) First, we consider whether particular elements of the broader regulatory and institutional framework increase the risk of policies that lead to suboptimal outcomes for consumers and competition.

(b) Second, we consider whether the current system of code governance delivers timely change that is needed to support competition, innovation and wider policy objectives.

Broader regulatory framework

11.6 In this section we identify three broad aspects of the regulatory and policy framework that may have led to poor outcomes for competition and consumers:

(a) A lack of transparency about the causes of price increases.

(b) Government policies that appear to have achieved a suboptimal balance between different energy policy objectives.

(c) Regulatory interventions by Ofgem that have not promoted effective competition.

11.7 In each case, we set out our observations on the nature of the problem including the potential detriment to energy consumers, and our provisional assessment of potential features of the regulatory and institutional regime that increase the risk of such problems arising in the future.

Lack of transparency about the factors affecting price changes, including policy costs, wholesale energy costs and energy firm profits

11.8 As noted in Section 2, domestic energy prices have increased substantially since 2004, shortly after full liberalisation. Average annual domestic electricity prices rose by around 75% in real terms between 2004 and 2014, and average annual domestic gas prices rose by around 125% in real terms over the same period. This has caused public and political concern and is likely one of the high level contributory factors leading to our current investigation.

11.9 We have observed that there is a lack of shared understanding of the factors that have led to price increases, in particular the relative contribution of wholesale energy costs, network costs, policy costs and profits in excess of the cost of capital.

11.10 It is possible that, if the public debate is poorly informed about the factors driving price increases, and in particular the relative importance of factors that are outside of the control of firms (including exogenous wholesale costs and network costs) compared with those that are within their control (notably profits and indirect costs), this will increase the risk of poor policymaking. This might take the form of regulatory interventions that address perceived problems that do not exist in reality or that fail to address real problems that are not observed.

11.11 In considering the strength of the above hypothesis, we have assessed the availability of financial information on the factors affecting price changes, including policy costs, wholesale costs and profits in excess of the cost of capital.

Price and bill impacts of policies

11.12 In relation to the availability of information, we note that various analyses are conducted on a regular basis of the price and bill impacts of climate and energy policies. Both DECC and the Committee on Climate Change produce annual estimates of the current and expected future impacts of climate and energy policies on gas and electricity prices and bills.[602] Further, impact assessments of individual policy proposals typically set out, in addition to social costs and benefits, distributional impacts and transfers, including price and bill impacts.[603]

11.13 The evidence therefore does not suggest that there is a broad lack of information in the public domain on the price and bill impacts of policies. The analyses generally cover a relatively wide range of policies, although there are some omissions. It is possible, however, that some of the results could be communicated more effectively and clearly to a broader audience.

Costs and profitability

11.14 Trusted and transparent information on revenues, costs and the profits earned by energy firms may help to inform the public debate and reduce the risk of errors in policymaking, by providing clearer information about whether and where intervention is required. It may also help to improve confidence in the regulator on the part of policymakers and the general public, which itself may improve the stability of the regulatory regime.

11.15 The absence of such trusted and transparent information is a potentially material problem, undermining regulatory stability. Parliamentary committees, consumer groups, policy think tanks, Ofgem and political parties, among others, have all expressed their dissatisfaction with the status quo concerning the transparency of financial reporting. This is particularly troubling given the importance of these bodies in contributing to the general perception of the industry and policy relating to it.

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[602] See, for example, Committee on Climate Change (December 2014), *Energy prices and bills – impacts of meeting carbon budgets 2014* and DECC, Policy impacts on prices and bills.
[603] As noted in Section 5, no impact assessments were conducted of the decision to let early renewable contracts under the FIDER framework to eight renewable projects although DECC did set out in broad terms the arguments for providing greater certainty to investors.

11.16 In 2013, the House of Commons Energy and Climate Change Committee (ECCC) investigated the reasons for the substantial increase in household energy bills since 2007. It noted in its *Energy Prices, Profits and Poverty* report that the Six Large Energy Firms' operations were complex, with several different divisions performing different roles – generating, trading and supplying energy. The complex vertically integrated structure of these firms made it difficult to determine where profits and losses were being made within them and how they might relate to energy price rises. The ECCC concluded that greater transparency was urgently needed to reassure consumers that high energy prices were not fuelling excessive profits.

11.17 The consumer body, Which?, told us that its view was that vertically integrated firms could move and split profits within and between their business segments, so that they could balance low profits in one segment with higher ones elsewhere and so deliver an overall positive financial performance at group level. Which? believed they could do this at a national level or even, where relevant, at an international level. These practices raised questions for Which? about whether such firms were pushing profits into the generation parts of their business to make the retail market look less attractive to prospective entrants and to 'justify' the level of energy prices. Which? argued that the result of firms managing profits in this way would be that prospective investors or new entrants would not get a true picture of the likely returns and so could be deterred.

11.18 In 2012, the Institute for Public Policy Research (IPPR), a policy think tank, published a report, *The True Cost of Energy*, in which it investigated the reasons for the rise in energy bills in recent years using data published by Ofgem, the Six Large Energy Firms and industry associations, among other sources. In the conclusion it noted that in the process of completing its analysis it had encountered a lack of transparency and a dearth of publicly available data on which to base estimates of such firms' costs. It argued that it was in the public interest that Ofgem published a more thorough and comprehensive account of the costs of retail supply in aggregate so that analysis of the market would be based on the most recent and comprehensive data available.

11.19 Ofgem recently told us that transparency remained an issue. There was some doubt as to whether people trusted the figures that came from the industry. These figures included the profit and loss statements for the Six Large Energy Firms' generation and retail supply businesses that it required them to produce to its specification.

11.20 Many firms including the Six Large Energy Firms operate in several different markets, often across a vertical or horizontal value chain. Where there is no trusted source of relevant profitability information, and where trust in the sector is in general already low, it is easy for people to come to believe that profits are being hidden.

11.21 We hope that the findings of this investigation will help to provide transparency over revenue, costs and profitability of the Six Large Energy Firms. In this exercise we have had the benefit of legal powers enabling us to gain information, and even so considerable additional analysis has been necessary to draw clear conclusions form this information. Yet we recognise that in a few years' time, concerns may resurface unless there is an enduring regime that provides transparency over revenues, costs and profitability. In relation to the profitability of generation, for example, we have found that between 2009 and 2013 returns were generally in line with or below the cost of capital once adjustments are made to reflect the deprival value of the assets. However, we have also noted that the regulatory regime underpinning wholesale electricity markets has recently undergone fundamental changes, which would imply that this historical evidence may not be a clear indicator of market conditions in the future.

- *Information currently available*

11.22 As noted in Appendix 11.1[604] Ofgem has taken several measures since 2008 to get a better understanding of costs, profits and profitability. Following the Energy Supply Probe in 2008/09, Ofgem required the Six Large Energy Firms to publish separate profit and loss accounts for gas and electricity retail supply and generation and to reconcile such accounts to GB group EBITDA.[605] These sets of profit and loss statements are described as the Consolidated Segmental Statements (CSS). All accounting policies would need to be consistent with, and reconcilable to, the policies that such firms had adopted in their statutory accounts. Ofgem then issued guidance in May 2011 that the data provided should explain how the transfer pricing methodology related to open market prices and/or a cost plus methodology.

11.23 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).

[604] See Appendix 11.1: Our experience of financial transparency.
[605] Earnings before interest tax, depreciation and amortisation.

11.24 As set out in more detail in Appendix 11.1, the SMI reflected a blend of approaches to determining costs and charges, mixing forecast with historically known pricing data and accounting information. In particular, the approach to determining wholesale energy costs could be seen as a forecast of the costs that the Six Large Energy Firms would have reported as 'actuals' had they pursued the purchasing strategy assumed in the methodology.

11.25 Some of the Six Large Energy Firms have criticised the use of the SMI on the basis that its projections of future profits have tended to overstate the profits that they actually earned in practice. On 22 May 2015 Ofgem announced that it had suspended SMI as part of its review of the information it collected and published so that in future it could develop a better basis for providing greater transparency about the market to inform the energy debate.

11.26 In 2011 Ofgem also tried to assess retail profitability (ie ROCE) 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 vertically integrated firm and as a stand-alone retail supplier. In the absence of actual balance sheet information, Ofgem estimated on a bottom-up basis the operating capital employed of the Six Large Energy Firms including collateral requirements both as a VI firm and a stand-alone retail supplier. Ofgem did not publish this piece of analysis. We understand that this was in part because it was not confident that it had dealt effectively with the capital employed/collateral issue.

- *Our assessment*

11.27 As set out in more detail in Appendix 11.2, our provisional view is that improvements could be made to the regulatory framework for financial reporting that would improve the robustness of information available to Ofgem, and hence overall transparency of revenues and cost of capital employed (and hence profitability). Some of the issues we encountered within the context of our market investigation were that:

(a) some generation activities were accounted for in the trading divisions of some of the Six Large Energy Firms;

(b) some of the Six Large Energy Firms had included within their results for retail supply the costs of wholesale energy products other than products available on the open wholesale market; and

(c) some of the Six Large Energy Firms had difficulties providing us with a full balance sheet for generation and retail supply.

11.28 We should note that this is not necessarily criticism of how the Six Large Energy Firms have chosen to organise their business or 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. Rather, it implies that the regulatory reporting requirements imposed by Ofgem may not be sufficiently robust to provide the degree of transparency over revenues, costs and profitability needed to improve regulatory stability and reduce the risk of poor policymaking.

11.29 It seems that Ofgem itself has recognised that there are shortcomings in the limited form of regulatory financial reporting that it has introduced for the Six Large Energy Firms following its Energy Supply Probe in 2008.[606] Ofgem did explore alternative ways of getting to an understanding of the Six Large Energy Firms' profitability through the SMI and its own profitability analysis, but these did not prove to be substitutes for clear, relevant and trusted analysis of profitability based on out-turn accounting information.

11.30 The accounting information that the Six Large Energy Firms initially supplied to us had generally been directly derived from information prepared to help them run their business on divisional lines. This information was therefore rooted in the divisional structures of each individual firm, rather than reflecting the financial performance of generation and retail supply as stand-alone businesses selling their output and procuring their energy on the open wholesale market. In the course of our investigation we sought to address those issues surrounding the financial information initially provided to us that are material to our provisional conclusions. We did this by requiring parties to provide us 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.[607]

11.31 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 businesses. From the perspective of the public policy debate and wider regulation, however, this latter, market-orientated, perspective is a much

[606] The (then) chief executive of Ofgem (Alistair Buchanan) told the Energy and Climate Change Select Committee in February 2013 that some areas of the Consolidated Segmental Statements were 'deeply confusing and difficult to get to the bottom of' (Question 47, p14, Uncorrected House of Commons Oral Evidence, Energy and Climate Change Committee, Ofgem Annual Report and Accounts, 26 February 2013 (cross reference provided by Which? in its Balance of Power: Wholesale Costs and Prices report, July 2013).
[607] We set out the detail how we did this across Appendices 11.1–11.2 and Appendix 4.2.

more relevant basis for considering the profitability of the Six Large Energy Firms. It also leads to a much higher degree of comparability of the financial reporting across them. Such an analysis should help provide a clearer view in the future as to what extent, for example, any future retail price increases are driven by increased levels of profitability on the part of retail suppliers and/or generators.

11.32 Based on our experience, we consider that most of the Six Large Energy Firms' reporting systems are currently unable readily to provide all the market-orientated financial information that regulators and policymakers require primarily for the following reason. Where the segmentation of the energy value chain on market lines differs from firms' existing divisional reporting lines, firms will need to re-cut their financial information. Unless 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.

11.33 Our analysis shows that the main issue is the lack of clear, relevant and consistent demarcation of activities between generation, trading and retail supply. The current regulatory framework for financial reporting set out by Ofgem fails to require the Six Large Energy Firms to prepare financial information (including balance sheet information) on market lines consistently delineated across these firms. This in turn would have led to a degree of misattribution of profits and losses across this value chain for the purposes of our analysis, had we simply looked at the relevant divisional results of each of the Six Large Energy Firms.

11.34 Some stakeholders have attributed the lack of financial transparency to the vertically integrated nature of the energy value chain, in particular between generation and retail supply. We do not consider that the problem is inherent to common ownership across the value chain. We consider, rather, that the problem arises from a lack of relevant and consistent accounting across each part of the relevant value chain.

11.35 We recognise that moving to a more rigorous and relevant regulatory framework for financial reporting would be a significant change that would impose costs on energy firms.

Suboptimal balance between different energy policy objectives

11.36 In Section 2 we noted that there are three key overarching policy objectives for the energy sector:

(a) reducing emissions;

(b) ensuring security of energy supply; and

(c) ensuring energy prices are affordable.

11.37 These three policy objectives are sometimes characterised as the 'energy trilemma', since policies put in place to meet one of the objectives can have the effect of undermining achievement against the other objectives. For example, policies to support low carbon generation often have the effect of increasing costs and hence energy prices. Policy and regulatory design, whether at an EU or UK level, has therefore often involved a trade-off between these objectives.

11.38 In this section we identify some policies that appear not to have achieved an efficient trade-off between these objectives and consider whether a lack of independent scrutiny of such policies might be one of the factors that increases the risks of suboptimal policy design in the future.

Examples of policies that may have led to poor outcomes for consumers

11.39 In Section 5 we discussed the non-competitive allocation of renewables contracts through the FIDeR scheme. This appears to us to be an example of a policy decision that led to a moderate benefit against one objective at a considerable cost against another objective (a 1% increase in electricity bills).

11.40 The tax regime applying to domestic electricity and gas consumption is a further area that appears to have led to inefficient trade-offs between policy objectives. As noted in Section 2, domestic electricity and gas consumption attract a lower rate of VAT (5%), representing a substantial subsidy of around £5 billion a year. This results for domestic consumers in relatively low carbon prices for electricity and in a significant negative carbon price for gas.[608]

11.41 We consider that an efficient approach to tackling climate change is likely to be based on imposing a single carbon price across the economy, at a level consistent with the damage caused by greenhouse gas emissions. This should result in the least cost approach to reducing emissions, minimising costs for customers in aggregate.

11.42 In contrast, the current system, in the absence of strong carbon taxes, is required to make up the difference through a mix of subsidies and levies, which in aggregate may be more expensive, more complex and harder to

[608] Institute for Fiscal Studies (2013), *Energy use policies and carbon pricing in the UK.*

design. To give one example, under the current system, to compensate for the negative carbon price for gas that on its own provides a subsidy to consumption, further subsidies are provided through the Renewable Heat Incentive to move away from gas heating towards renewable heating.

11.43 We are aware that there is a clear distributional rationale for subsidising VAT on energy consumption, since, as noted in Section 7, gas and electricity are necessity goods, and energy taxes are regressive. However, we also note that some studies have argued that it is possible to design a package of energy carbon taxes and benefits that would reduce emissions, be progressive across the majority of the income and expenditure distribution, and leave surplus revenue for other expenditure priorities.[609]

11.44 Such a reform would, of course, be difficult politically, largely because of the challenges involved in communicating to the public the complex package of policy changes that would be required to demonstrate that the reform was not only efficient, but fair.

Lack of information and analysis about policy impacts/lack of independent institutions

11.45 As the above examples suggest, there is a rationale for independent institutions to scrutinise elements of current energy policy and suggest where it could be improved to better meet the needs of customers. The need for such an institution is likely to be greater, the higher the benefits from reform and the greater the political difficulty of implementing it.

11.46 In this section, we consider the hypothesis that there is a lack of:

(a) a new independent institution to scrutinise the trade-offs made within policies; and

(b) sufficient information on which to base decisions around trade-offs.

11.47 RWE submitted to us a report it had commissioned from Vivid Economics that called for the creation of an Office of Energy, which would provide clear and trusted analysis of performance against energy policy priorities. The report argues that a lack of trust is preventing effective debate in the energy sector and that:

[609] See, for example, Institute for Fiscal Studies (2013), *Energy use policies and carbon pricing in the UK* and analysis by the Green Fiscal Commission (March 2010), *Achieving Fairness in Carbon Emissions Reduction: The Distributional Effects of Green Fiscal Reform*.

Affordability and energy security do not receive the same reporting attention as, say, decarbonisation does from the Committee on Climate Change (CCC), and nowhere are these three priorities subject to a careful analysis of their tradeoffs. Therefore, a clear and trusted analysis of performance against policy priorities, and how performance changes over time, would help facilitate rational debate in the energy sector.

11.48 We note that there are already several independent institutions that either have a specific focus on the energy sector or include energy sector analysis and/or scrutiny of energy sector policies within a broader remit:

(a) In addition to its core regulatory functions, Ofgem carries out analysis on a wide range of areas, including security of supply, energy prices and profits. It does not scrutinise government policies.

(b) The Committee on Climate Change scrutinises progress against emissions reduction goals across the economy, with a substantial focus on the energy sector (which accounts for a significant proportion of UK emissions), including assessment of the price and bill impacts of energy policies.

(c) The NAO scrutinises the value for money of government expenditure and policies and has recently examined key DECC policy decisions including the early contracts for renewable energy under the FIDER scheme.[610]

(d) The Regulatory Policy Committee provides external, independent scrutiny of the impacts of new regulatory proposals

(e) Other organisations, such as the IPPR, the Policy Studies Institute, Policy Exchange and the Institute for Fiscal Studies, scrutinise aspects of government policy including recent analyses of energy policy.

11.49 In short, there are several institutions already providing independent scrutiny of energy sector impacts. In relation to the availability of information on the costs and benefits of different policies, we note that these are generally set out in impact assessments relating to policy proposals. In addition, occasional publications (for example, analyses underpinning White Papers and reports produced by the Committee on Climate Change) bring together analysis of the relative impacts of different policies as a package.

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[610] NAO (27 June 2013), *Early contracts for renewable electricity*.

11.50 In our view, however, these analyses should be communicated more effectively to a wider audience, in particular interactions between policies and policy trade-offs within policies. Clearer communication around these issues may increase the transparency of the information already available and improve the quality of the public debate and policy decision-making.

Regulatory interventions by Ofgem that have not promoted effective competition

11.51 We have noted elsewhere in this report that Ofgem has taken some decisions that we consider have not had the effect of promoting effective competition. The examples that we have discussed are:

(a) The decision not to implement P229, which would have introduced locational charging of losses, even though Ofgem found that the modification would contribute to the objective of 'promoting effective competition in the generation and supply of electricity, and […] promoting such competition in the sale and purchase of electricity'.

(b) The decision to introduce SLC 25A prohibiting regional price discrimination, which has been criticised by previous regulators, one of whom resigned from Ofgem's board as a result, and which we have found has likely had the effect of softening competition on the SVT.

(c) The decision to introduce the simpler choices component of the RMR reforms, which we have provisionally found has reduced retail suppliers' ability to innovate in designing tariff structures to meet customer demand and softened competition between PCWs.

11.52 We have considered two hypotheses concerning Ofgem's duties and roles that might help explain these decisions and, more importantly, increase the risk of decisions that do not promote effective competition in the future:

(a) That the objectives and duties of Ofgem are unclear, inconsistent or hinder the promotion of effective competition.

(b) That Ofgem's role and functions overlap excessively with DECC's role and functions.

Ofgem's duties and objectives

11.53 In its written response to our updated issues statement, Ofgem said that:

> Under this theory of harm, we would also encourage the CMA to consider the legislative framework within which Ofgem operates. We welcome the CMA's thoughts on whether Ofgem's regulatory

duties are sufficiently clear to guide our regulation of the market, as well as our interactions with other bodies in the energy policy sphere.[611]

11.54 In hearings with us, Ofgem has suggested that it had a complex set of objectives and duties of which the promotion of competition was only one. Ofgem has also explained that in line with this legal framework, interventions have been made to pursue objectives other than the promotion of competition, for example the introduction of the undue discrimination licence condition, SLC 25A, which was influenced by its duty to protect vulnerable customers. Further, it suggested that, if we recommended that it should be more focused on improving competition, then we would need to look at the structure of its duties, and consider whether they are consistent with such a recommendation.

11.55 Specifically in relation to SLC 25A, the Chair of Ofgem stated:

> Looking back on why the decision was made, it was clearly driven more by consumer protection duties in the knowledge and acceptance that it might have problems for competition. The context at the time was one in which the Government was busy preparing to take powers to do it themselves if Ofgem did not do it, and so there was quite a combination of things, I think, affecting the Authority decision that were not driven from a competition viewpoint. […] I think the potential damage to competition was recognised.

11.56 In contrast George Yarrow, who was a non-executive member of the board at the time, but resigned as a result of the decision over SLC 25A, told us that the board neither considered the impact on competition nor the potential trade-offs between competition and consumer protection. He told us that he believed that the board acted in this way because it did not feel that either competition or consumer protection issues were at stake.

11.57 In commenting on its objectives and duties, Ofgem had in particular noted how its competition duty had been progressively downrated relative to other duties over the last ten years, in particular with the addition of new duties and the qualification introduced in the Energy Act 2010 (EA10) that required it to look at any other action it could take before deciding on a competition route. Ofgem highlighted the need, if we suggested it should change its

[611] Ofgem response to the updated issues statement.

policies towards improving competition, for our conclusions and remedies to be reconciled with the structure of its duties.

- *Our assessment*

11.58 The EA10 expanded Ofgem's primary objective, to include the protection of the interests of existing and future consumers taken as a whole, including their interests in the reduction of greenhouse gases; and their interests in the security of the supply of energy. It also removed from paragraph 1 of sections 4AA of GA86 and 3A of EA89 (which set out Ofgem's principal objective) the reference to pursuing the principal objective 'wherever appropriate by promoting effective competition between persons engaged in, or in commercial activities connected with, the generation, transmission, distribution or supply of [gas/electricity]'. This duty was reinserted as part of the general duties as to how Ofgem is to carry out its functions.

11.59 Moreover, the EA10 introduced a further requirement on Ofgem to consider to what extent the interests of consumers referred to under the principal objective are protected by actions focused on the promotion of competition, and if there is any other manner (whether or not it would promote competition) in which the Secretary of State or Ofgem could carry out those functions which would better protect the interests of consumers.

11.60 We note that, before the EA10, the words 'wherever possible by promoting effective competition' gave a wide margin of appreciation as to when it is appropriate for Ofgem to pursue its principal objective by promoting effective competition. The additional requirement referred to in paragraph 11.59 above qualifies the words 'wherever possible by promoting effective competition' in a way that may constrain Ofgem's margin of appreciation. Similarly, the repositioning of these words, as described above, suggests that less emphasis should be placed by Ofgem on competition when pursuing consumers' interests.

11.61 Our interpretation of this qualification to Ofgem's objectives and duties is therefore that, this additional requirement referred to in paragraph 11.59, coupled with the repositioning of the words 'wherever appropriate by promoting effective competition …', may constrain Ofgem's ability to promote competition.

11.62 If Ofgem considers that these duties impose a constraint in practice on its ability to pursue competition-based policies (for example, through placing a priority on approaches that do not promote competition), we regard this as a significant cause for concern. This may have caused Ofgem to carry out inefficient trade-offs between competing objectives, which in turn might have led to decisions that adversely impact competition.

11.63 In relation to the clarity of Ofgem's regulatory duties, we also note that in April 2011 the Department for Business, Innovation and Skills (BIS) published its Principles of Economic Regulation document which states that 'economic regulators should have clearly defined, articulated and prioritised statutory responsibilities focussed on outcomes rather than specified inputs or tools.' In view of the above, we consider that the role of competition in pursuing Ofgem's objectives could be considered to be unclear and in need of clarification.

Overlap between Ofgem's roles and functions and those of DECC

11.64 We have also considered whether: Ofgem's role and functions overlap excessively with DECC's role and functions, leading to suboptimal decision-making; and whether the coincidence of DECC and Ofgem's roles risks undermining Ofgem's independence.

- *Suboptimal decision-making*

11.65 Energy 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 code self-regulation). In principle, DECC is responsible for setting policy objectives. However, in view of its powers, duties and objectives, Ofgem inevitably takes decisions which develop further these policy objectives, and go beyond mere implementation.

11.66 In Appendix 11.2 we describe three case studies illustrating situations in which implementation of policy goals was delayed (or suboptimal) due to a lack of coordination between DECC, Ofgem and the industry.

11.67 The decision to move to 17-day switching and P272 (half-hour settlement for certain categories of customer) were both seen as two measures necessary to deliver certain important benefits of smart meters. However, in both cases DECC used its power to only partially implement policy changes such that later intervention by Ofgem was needed to fully implement these policy changes. If implementation had been entirely delegated to Ofgem, Ofgem could have arguably implemented more efficiently the necessary changes to allow faster switching and half-hourly settlement for profile 5–8 customers.

11.68 A third illustration of the interplay between DECC's and Ofgem's measures relates to the EBSCR reform carried out shortly after DECC's proposals for a

Capacity Market. In this case, Ofgem's intervention to reform cash-out rules, although covering a different aspect of the market, interacted with the Capacity Market, in that both measures originally sought to remedy the 'missing money' problem.[612]

11.69 We have identified concerns arising from the interaction of the two measures which might lead to unintended consequences – for example, 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.

11.70 In summary, we note that the delineation between the powers and roles of DECC, Ofgem and the industry can be blurred. We note that there is a mechanism introduced by the Energy Act 2013 – the Strategic Policy Statement (SPS) – by which DECC can provide more clarity about the respective roles of Ofgem and government, in an attempt to ensure that policy and regulation will be consistent and coherent. DECC published a draft SPS in August 2014, but has not yet exercised its power to designate that document.

- *Independence and the overlap of DECC and Ofgem's roles*

11.71 We note that Ofgem's decisions to implement both SLC 25A and RMR were taken against a backdrop of DECC taking powers – or stating its readiness to take powers – to implement changes in primary legislation in the event that Ofgem did not act.

11.72 In relation to SLC 25A, the government said in March 2009, 'The Government has consistently stated its intention to act – potentially through legislation – should Ofgem's action not achieve the necessary changes in the near future.'[613] In relation to RMR, DECC's backstop power to modify SLCs in order to restrict the number of tariffs provided by suppliers is provided by section 139 of the Energy Act 2013. Ofgem first consulted on a four-tariff cap in October 2012, while DECC followed with its own consultation on a four-tariff cap (to be included within the pending Energy Bill) in November 2012. DECC's May 2013 response to the November

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[612] See Section 5.
[613] Energy policy: future challenges: Government Response to the Committee's First Report of Session 2008-09 – Business and Enterprise Committee.

consultation withdrew the four-cap rule (in favour of a general power to restrict number of tariffs) and concluded that 'we do not currently see a need to use the powers immediately, but we will be ready to do so should Ofgem's proposed reforms be unduly delayed or frustrated.'[614]

11.73 We do not know how material this context was in influencing Ofgem, but it is possible that institutional pressure from DECC was one of the factors behind one or both of these decisions. Further, the coincidence of DECC and Ofgem's actions risks creating the perception of a lack of independence on the part of Ofgem.

11.74 In this section, we consider the importance of independent regulation, and consider whether any elements of the current regulatory regime – particularly relating to Ofgem and DECC's respective roles – may undermine Ofgem's independence or the perception of Ofgem's independence. This is a topic that Ofgem invited us to comment on, noting that it was very important that independent regulation was seen as a cornerstone of how the sector worked, and expressing the hope that the investigation would recognise the importance of independence and reinforce its role in the regulation of the sector.

11.75 The broad rationale for the creation of independent economic regulators in privatised sectors of the economy is to provide greater certainty to potential investors that they will have a reasonable opportunity to earn a return on their investments if they operate efficiently. The expectation is that this will reduce ex ante estimates of the risks of investment and hence the return on investment investors will require, reducing overall costs borne by customers. Government is effectively constraining its own discretion – committing not to interfere – by delegating authority over certain decisions to an independent, technocratic authority that will make decisions according to a clear set of criteria established in advance.

11.76 This is the context within which Ofgem takes decisions on natural monopoly regulation, notably the regulation of transmission and distribution charges. However, as noted above, Ofgem also has powers and roles that coincide with those of DECC. In view of its powers, duties and objectives, Ofgem inevitably takes decisions which go beyond mere implementation and into policy development. An important question concerns the nature and extent of Ofgem's independence in pursuing such activities.

[614] DECC (17 May 2013), *Ensuring a better deal for consumers: Government response to consultation on DECC's discussion document*, paragraph 2.9.

11.77 We note that DECC has a number of direct and indirect powers which 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);[615]

(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;[616]

(d) pursuant to the powers granted to it in primary legislation, to modify directly licence conditions and to veto an Ofgem decision to approve a code modification proposal; 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.[617]

11.78 In summary, 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.

11.79 We are concerned that, in the absence of such formal powers, DECC may pursue option 11.77(c) above (exert institutional pressure on Ofgem by stating that it will act to address a certain issue in the event that Ofgem does not itself act to address the issue in question). We consider that the use of such an informal approach – if it encourages Ofgem to implement changes that it would not pursue in the absence of such pressure – risks harming transparency and the independence of regulation.

11.80 It is neither realistic nor credible for DECC always to refrain from exercising its discretion over elements of policy and we note that it is always possible that DECC and Ofgem will disagree on a particular area of policy. However,

[615] Schedule 1 of the Utilities Act 2000.
[616] Section 34(3)(b) of GA86 and section 47(2)(b) of EA89.
[617] Section 34(3)(a) of GA86 and section 47(2)(a) of EA89.

where this is the case we think that the absence of a mechanism through which such disagreements can be surfaced transparently, in particular allowing Ofgem to set out its views on particular DECC policy proposals and seek formal direction from DECC to pursue certain regulatory activities, so that stakeholders can understand why a particular decision is being made, leads to a lack of robustness and transparency in regulatory decision-making. We believe that such mechanisms may facilitate rational debate and promote regulatory stability.

Our provisional views on the broader regulatory and institutional framework

11.81 We have reviewed a range of elements of the broader regulatory and institutional framework and considered whether they increase the risk of policies being developed that lead to poor outcomes for consumers and competition in the future.

11.82 In relation to information on costs and profits, we consider that the Six Large Energy Firms' current reporting systems are currently unable readily to provide the market-orientated financial information that regulators and policymakers require. The lack of a regulatory requirement for clear and relevant financial reporting has in our view contributed to a lack of financial transparency in the information available to Ofgem, which may lead in the future to regulatory decisions that do not give appropriate weight to potential impacts on competition in the wholesale and/or retail gas and electricity markets, and hence on consumers.

11.83 In relation to the impact of government policies, we have considered whether there is a lack of independent institutions to scrutinise the costs and benefits of different proposed and existing policies, and to expose the trade-offs between different policy objectives, and/or a lack of information and analysis on which to base robust decisions. Our provisional view is that there are already several independent institutions that scrutinise these costs and benefits and no obvious lack of analysis. However, it is likely that clearer communication around these issues would increase the transparency of the information already available and improve the quality of the public debate and policy decision-making and possible that the creation of a new independent institution might help achieve this.

11.84 Lastly, in relation to regulatory interventions by Ofgem, Ofgem has told us that it interprets its statutory objectives and duties as being a potential impediment to pursuing pro-competitive outcomes. We have noted that recent changes to Ofgem's duties and objectives constrain Ofgem's ability to pursue its principal objective 'wherever possible by promoting effective competition'. This may have caused Ofgem to carry out inefficient trade-offs between competing objectives, which in turn might have led to decisions that adversely impact competition.

11.85 We have also noted that the overlap of roles between DECC and Ofgem can lead to delays to implementing certain policies. Further, the absence of any formal mechanism through which Ofgem can set out its views on particular DECC policy proposals may risk harming transparency, the independence of regulation, and consumers' confidence in the regulatory and policy decisions that are taken.

11.86 On the basis of our assessment to date, we have provisionally found that a combination of features of the wholesale and retail energy markets in Great Britain give rise to an AEC through an overarching feature of lack of robustness and transparency in regulatory decision-making which, in turn, increases the risk of poor policy decisions which have an adverse impact on competition. More particularly, these features are as follows:

(a) The lack of a regulatory requirement for clear and relevant financial reporting concerning generation and retail profitability.

(b) The lack of effective communication on the forecast and actual impact of government and regulatory policies over energy prices and bills.

(c) Ofgem's statutory objectives and duties which, in certain circumstances, may constrain its ability to promote effective competition.

(d) The absence of a formal mechanism through which disagreements between DECC and Ofgem over policy decision-making and implementation can be addressed transparently.

The governance of industry codes

11.87 In this section we consider whether aspects of the current system of code governance might act as a barrier to entry and a barrier to pro-competitive innovation and change.[618] It is structured as follows:

(a) We provide brief background on the current system of industry codes.

(b) We consider whether the complexity of codes and the number of codes act as a barrier to entry.

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618 This section draws on Appendix 11.2: Codes and regulatory governance, which provides further detail on the current system of code governance.

(c) We assess whether the current system of code governance fails to deliver timely change that is needed to support innovation and wider policy objectives, due to conflicting interests within the industry and the limited powers Ofgem has to influence the modification and implementation process.

The current system of codes

11.88 Regulation of a number of technical and commercial aspects of the energy markets is governed by industry codes, which are managed by industry participants. The industry codes standardise the technical standards applicable to all industry participants and the terms and conditions which serve as the basis of commercial industry transactions.

Overview of codes

11.89 For electricity, the codes include:

(a) Balancing and Settlement Code (BSC);

(b) Connection and Use of System Code (CUSC);

(c) System Operator/Transmission Code (STC);

(d) Distribution and Connection Use of System Agreement (DCUSA);

(e) Master Registration Agreement (MRA);

(f) Grid Code (GC); and

(g) Distribution Code (DC).

11.90 The GC and the DC have the principal aim of ensuring the efficient transmission, distribution and supply of energy and can be considered to be 'technical codes'. In contrast, the BSC, CUSC, STC, DCUSA and MRA can be considered to be primarily 'commercial codes', as they were developed by DECC as a means to set out the foundational rules and regulations necessary for an increasingly liberalised energy sector. The commercial codes have a broader scope, which includes both technical aspects and commercial relationships between undertakings. Some of these provisions may interact directly with policy choices made by Ofgem or DECC, such that code modification proposals are sometimes necessary for the implementation of such policies.

11.91 For gas, the codes include:

(a) Uniform Network Code (UNC);

(b) Independent Gas Transporter UNC (iGT UNC); and

(c) Supply Point Administration Agreement (SPAA).

Ofgem and DECC's powers to modify and enforce industry codes

11.92 Ofgem has decided, as a matter of policy, not to include the full substantive provisions of the industry codes within licence conditions, we understand due to the following practical and procedural issues:

(a) undertakings are better equipped than Ofgem or DECC to administer such technical and commercial matters; and

(b) by nature, technical standards and commercial rules constantly evolve to reflect industry developments and this would put severe pressure on Ofgem's resource, due to its statutory duty to initiate a consultation process every time it modifies licence conditions.

11.93 Ofgem has chosen to incorporate the industry codes into licence conditions by reference and, in effect, has established the substantive provisions of the industry codes as a domain of limited industry self-regulation within the wider regulatory framework.

11.94 Ofgem has the general power to modify standard licence conditions[619] but does not have an equivalent power to directly modify industry codes.[620] It plays, however, a key role within the modification arrangements of each of the industry codes as it must approve or reject any material modification proposal, as discussed below.

11.95 DECC's ability to influence the industry codes is concentrated in its power to designate the initial version of each industry code, with the result that once an industry code is formally designated DECC has no further ability to influence its content. Through the choice of this arrangement, Ofgem and DECC have signalled that industry will be responsible for the ongoing substantive development of the industry codes.

11.96 Governance and modification rules for each industry codes are set out in the codes themselves. Ofgem has set out a formal structure that industry must

[619] Section 23 of GA86 and section 11A of EA89.
[620] This statement is subject to one exception, found in section 36C of GA86, which gives Ofgem the power to modify the UNC for the purpose of implementing modifications related to gas security of supply.

follow in developing the industry codes through the inclusion of the following provisions within standard licence conditions:

(a) A list of objectives unique to each industry code.[621] Prescribed objectives serve to define the purpose of each industry code and to ensure that the industry codes develop in a way that is consistent with the wider system of regulation.

(b) A set of common modification and governance processes. These processes include mechanisms which are intended to ensure adequate representation of stakeholders, to increase accessibility and transparency of information and increase process efficiency. The aim is to ensure that the industry codes are not susceptible of being changed in a way that might promote the interests of certain categories of industry participant rather than the interest of the market as a whole.

11.97 Having modified standard licence conditions to require licensees to maintain, become party to, or comply with, certain industry codes, Ofgem can sanction an industry participant for breach of an industry code as it can for the breach of any licence condition.

Complexity and number of codes

11.98 In our updated issues statement, we solicited views from parties on whether the fragmentation of industry codes relating to the electricity market[622] has had the effect of raising barriers to entry or expansion for independent generators or suppliers. As an example, we noted that collateral requirements under each industry code might lead to unnecessary duplication of costs.

Views of the parties

11.99 In the responses to our updated issues statement, several parties including Ofgem argued that the complexity of the industry codes reflected the complexity of the industry, and was not a fundamental barrier to entry or innovation.[623] The consolidation of substantive provisions into one single code (as for gas) would have limited benefits.

[621] The one industry code that currently does not have a set of prescribed objectives is the MRA. Ofgem has decided to introduce a set of objectives into the MRA via licence changes to take effect from 23 June 2015. The objectives of each industry code are based on the duties of transmission and distribution licensees which are set out in section 9 of GA86 and section 9 of EA89.
[622] Compared to the gas market, where the bulk of code regulation is carried out through the UNC.
[623] The views of parties are set out in more detail in Appendix 11.2: Codes and regulatory governance.

11.100 Some parties noted, however, that certain limited areas might benefit from some form of 'streamlining' coordination, pointing in particular to three broad categories of concerns:

(a) the number of panel meetings, procedures and industry credit/collateral rules to be followed and understood, which might add to the administrative burden on parties;

(b) the risk of duplication in relation to collateral requirements; and

(c) the difficulties arising when modifications proposals have consequential impact on other codes ('cross-code modifications').

11.101 On the first concern, Ofgem noted that it had taken action to reduce the costs associated with industry code compliance by introducing the Licence Lite option,[624] which helps new suppliers to enter the electricity supply market. Indeed, under this regime, entrants may partner with an existing larger supplier as an alternate form of compliance with certain of the industry codes (specifically the MRA, DCUSA and BSC).

11.102 Centrica also argued that, to save resources, parties could use collective participation and representation arrangements (eg Energy UK provides GC representation on behalf of smaller generators and Cornwall Energy represents the interests of smaller suppliers at various fora).

11.103 As regards the risk of duplication in relation to collateral requirements, EDF Energy noted that any saving from rationalisation was likely to be modest – principally netting of the surpluses paid across the codes. Moreover, DECC is currently reviewing the collateral requirements in codes. Within this context, it commissioned a report from Cornwall Energy[625] which noted that no two codes were identical in their credit and collateral rules, although there were some similarities in principle in areas such as balancing or transmission and distribution (reflecting Ofgem's best practice guidelines[626]).

Our assessment

11.104 The general scheme of industry self-regulation has led to a decentralised system for governance and development of the industry codes. As a result, each of the industry codes has bespoke governance and modification arrangements. Although differences across codes may very well be justified,

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[624] Ofgem introduced the Licence Lite option by modifying electricity supply standard licence condition 11.3. See Ofgem's Licence Lite guidance document.
[625] Cornwall Report on Credit and collateral in the GB energy markets.
[626] See Ofgem's Best practice guidelines for gas and electricity network operator credit cover.

this means that industry participants must become acquainted not just with the substance of each of the industry codes but also with the unique governance and modification arrangements for each industry code. We agree in principle that such differences in governance and modification arrangements across codes might lead to an unnecessary additional burden on parties, and in particular on smaller players, when they are not justified by the nature and purpose of each code.

11.105 We note that, in recent years, Ofgem has taken the initiative, through code governance reviews, to harmonise certain governance and modification arrangements across codes. It has also given a more central role to code administrators which as a result must now assist small parties to navigate the different codes and processes.[627] We believe that these initiatives are helpful and note that Ofgem is currently consulting on a new phase of its code governance review in order to assess, among other things, whether further harmonisation, or wider institutional reform, is required.

11.106 Overall, it appears to us that, to some extent, the complexity of the code structure reflects the complexity of the industry and the technical and commercial relationships between market players. We do not believe that a consolidation of codes in electricity would per se have a positive impact on competition, but recognise the potential benefits of increasing harmonisation of certain governance and modification arrangements, as well as improving the coordination between code administrators. We investigate these aspects further in Appendix 11.2.

11.107 As regards the specific issue relating to collateral requirements under industry codes, we note that a number of recent modification proposals[628] to improve the efficiency of the credit requirements are currently under investigation in the context of certain industry codes. In our view some savings could be expected from cross-code coordination of collateral requirements if liabilities under one code tended to be negatively correlated with liabilities under another code. However, we do not think such savings are likely to be substantial, since liabilities under the different codes in general rise with energy prices and energy demand.[629] Finally, we note that collateral requirements under energy codes are significantly smaller than

[627] These are described in Annex E – Overview of principles set out in the Code Administration Code of Practice of Appendix 11.2: Codes and regulatory governance.
[628] For instance, BSC modification proposal P308, which was raised on 14 June 2014 and is currently undergoing assessment, proposes to introduce a new method of securing credit under the BSC.
[629] Suppliers may find some offsetting collateral requirements once CfD payments become an important portion of their costs, since the anticipated CfD payments are negatively correlated with price (but positively correlated with demand).

those under energy trading contracts. For these reasons, we do not intend to explore this issue further.

Code modification

11.108 The GB energy industry is undergoing a period of significant change, driven not only by the need to tackle climate change but also by factors such as technological development (for example, the smart meter agenda and the development of demand-side response technologies). In order for industry and consumers to capture the benefits of change and minimise the costs of transition, it is necessary that industry codes develop at the same rate as the energy industry.

11.109 While, as noted above, we believe the current system of Ofgem-supervised self-regulation is appropriate for the purpose of regulating many aspects of the regulatory framework, there are risks attached to self-regulation, in particular in circumstances in which the industry has conflicting interests or where the industry lacks sufficient incentives to carry out changes. If self-regulation fails to ensure that industry codes keep pace with market developments and wider policy objectives, then it is possible that these industry codes become a barrier to pro-competitive change and/or innovation.

11.110 Our central concern is that the limited ability of Ofgem to influence the development and implementation processes might cause certain changes that are in consumers' interest not to be delivered in a timely and efficient way. We start with a summary description of a number of case studies that illustrate our concerns before considering the code development and implementation processes that might be implicated in some of the problems we highlight.

Case studies

11.111 In order to understand better the mechanisms that might be hindering timely change, we examined in detail six modification proposals. These were not randomly selected; instead, they were selected specifically because they might provide illustrations of some of the issues which various parties had raised about the difficulties of the code modification process and, in one case, as an example of change that happened relatively swiftly.

11.112 Appendix 11.2 describes the six case studies in detail. They are:

(a) P272 – half-hourly metering and settlement for SMEs (profile classes 4 to 8) in electricity;

(b) Project Nexus – metering and settlement in gas, including modifications to allow the full benefits of smart meters to be realised;

(c) 17-day switching – a reduction in the time taken to switch customers;

(d) transmission losses – aimed at reducing the overall cost of wholesale electricity;

(e) the Gas Significant Code Review (SCR) – aimed at incentivising gas security of supply; and

(f) the Electricity Balancing SCR (EBSCR) – aimed at incentivising 'balancing efficiency' and electricity security of supply.

11.113 We find that each one of these case studies provides some important insights into difficulties in the code modification process. We concentrate here particularly on the first two, which provide the strongest illustration of severe delay in code development and implementation in cases required for the achievement of wider policy goals.

11.114 In both of these cases studies there were clear beneficial policy objectives, but in each case the modification process to amend the relevant industry codes has been particularly slow. In both cases, changes are likely to have substantial but possibly unpredictable effects on the costs and revenues of suppliers. The impacts will differ depending on customer mix. This supports our hypothesis that the current system of self-regulation of the industry does not work well when the changes being considered are associated with costs and benefits that are unequally distributed between industry participants.

11.115 Many of the parties involved in the process have no incentive to prioritise these changes, in spite of the public benefits that could arise from them. The slow progress and the likely delays to the implementation of these modification proposals means that measures that support public policy objectives (smart metering roll-out), and that are deemed by Ofgem to be beneficial to competition (by allowing innovative business models and removing inefficiencies) and ultimately to consumers, will materialise later than they might have done.

11.116 The industry's failure to make the necessary preparations to implement these modifications in good time followed a similar path. In both cases, Ofgem decided not to lead the process despite the fact that it might have done under its powers of SCR.

11.117 We have tried to assess whether Ofgem could have avoided some of the delays of P272 or Project Nexus by playing a more active role, either by using its power to amend licence conditions or through the SCR process. The case study relating to 17-day switching provides an example of a relatively smooth and quick change (see Appendix 11.2, Annex A). Ofgem's decision to use its powers to enforce three-week switching through licence condition modifications (and the threat of additional government regulations) pushed the industry to act quickly. As a result, industry initiated, developed and implemented the necessary code modification proposal in a period of about a year.

11.118 However, this process related to a less complex set of issues than P272 and Project Nexus, with limited or no divergent financial impacts for suppliers, in the sense that the policy was unlikely to impact the costs and revenues relating to different customer bases in different ways. Moreover, no impact assessment was needed during the modification process, since costs and benefits had already been considered within the context of the licence condition modification by DECC. Although Ofgem's intervention seems to have been helpful in shortening the process in the case of 17-day switching, it is unclear whether Ofgem would be able (or willing) to force more complex changes through licence modifications, as evidenced through the P272 and Project Nexus case studies.

11.119 We have also considered two further case studies which were initiated through an SCR in order to assess whether the extra powers Ofgem has under an SCR mechanism (see Appendix 11.2, paragraphs 89 to 93 and 104 to 107 for details) has been effective in accelerating the modification process: the Gas SCR, relating to security of supply (in which Ofgem was able to use its powers under GA86 to direct the development and implementation of code modifications), and the EBSCR (where Ofgem could not rely on such additional powers). Regardless of this difference in powers, both processes have been very long.

11.120 It took Ofgem 45 months, since it launched the Gas SCR (January 2011), to reach its final policy decision (February 2014), direct and approve changes to the UNC and gas shipper and supplier licences (September 2014) and implement the Gas SCR (May 2015). Similarly, the timescale for completing the EBSCR has been longer than the indicative timetable anticipated by Ofgem (18 months). Both phases of the EBSCR (ie the Ofgem-led assessment and the industry-led modification process) have taken longer than expected. The overall process, since Ofgem's initial issue paper in November 2011, has taken 42 months to date, and is not yet completed.

11.121 Most of the delay in developing the Gas SCR can be attributed to the complexity of the reform package, which required several consultations, and incurred strong opposition from industry. During the SCR process Ofgem consulted extensively with industry stakeholders. Over 20 workshops and seminars were held between January 2011 and March 2014. Moreover, stakeholders had the opportunity to provide formal input during six separate consultations. Other factors might have also played a role in delaying the process. In a recent letter, Ofgem recognised that it ‘might have underestimated the level of analysis and resource necessary for delivering the type of complex reforms that are taken forward under an SCR’.

11.122 While a certain amount of resistance to changes can be expected when there are large and unevenly distributed financial consequences for the parties involved, these case studies support the hypothesis that the current governance structure is inadequate for delivering major reforms which might be necessary to implement policy decisions or support innovation on a timely basis. We now examine the detail of the process of code modification in order to identify the features that cause delays.

The code governance and modification arrangements

11.123 Each industry code contains a common governance structure which includes certain key entities, namely the code panel and the code administrator.

11.124 The code panel functions as the sole decision-maker within the code’s governance structure. In practice this means that the code panel takes decisions concerning the development and recommendation of modification proposals.

11.125 In general, the composition of industry panels does not show a fundamental bias towards the Six Large Energy Firms which would allow those firms to dominate code governance processes. Our current view is that the current representation of industry participants on code panels, in the light of the nature of each code, achieves a fair balance.

11.126 We do, however, have some concerns that relate to the costs for (smaller) suppliers and generators to play an active role in the governance of the code modification processes. This problem is susceptible to arise in the context of each of the codes and is one that is not entirely solved by means of ensuring the representation of independent suppliers and/or generators on code panels. Therefore, the governance structure of each industry codes should provide a mechanism designed to facilitate the engagement by independent firms, in particular with respect to changes that are required to achieve positive outcomes for consumers. Currently, in relation to each industry code, that mechanism is the code administrator.

11.127 Each of the industry codes contains provisions which require that a private entity be designated to the role of code administrator. Code administrators have two overarching roles: firstly, Ofgem's Code Administration Code of Practice (CACoP) means that they must facilitate the engagement of the industry in modification arrangements; and, second, they are responsible for delivering the implementation of approved code modification proposals. The CACoP also establishes an oversight mechanism whereby the success of code administrators in performing these roles can be assessed annually against a prescribed series of metrics (for details see Appendix 11.2, Annex C).

11.128 We note that there is no legal requirement that the code administrators be functionally or legally independent from the influence of industry participants and that there is not a uniform process by which code administrators are designated to certain industry codes, such as by means of a competitive tender process. There also does not appear to be a consistent method (as to both who pays and how much) by which the code administrators are remunerated for the services that they provide. Similarly, there is no consistency in relation to working arrangements and corporate purpose (eg not-for-profit vs commercial entities).

11.129 These characteristics are likely to impact on the ability and incentives of code administrators to effectively and independently assist code parties (in particular, independent firms with limited resources to engage in code governance) and therefore to achieve the governance objectives set out in the CACoP. Moreover, for code administrators which are not subject to licence conditions, compliance with the CACoP is not a legal requirement and therefore Ofgem has limited powers to direct them or sanction them for poor performance against the CACoP objectives. Therefore, even after approval by Ofgem of a modification proposal, there is a potential risk that implementation of approved modification proposals is delayed due to resource constraints or lack of incentives of the code administrator/delivery body.

11.130 Ofgem has been active in trying to solve some of the issues identified above. Within the context of its Code Governance Review (CGR), which it initiated in 2007, Ofgem identified two main deficiencies with the code arrangements as they stood at the time:

(a) the code governance arrangements incorporated an unnecessary amount of barriers and red tape; and

(b) the code modification arrangements failed to support large-scale and complex change.

11.131 In order to address these two deficiencies, Ofgem decided to implement – in two phases (2010 and 2013) – a package of measures seeking to improve the governance and modification arrangements of the industry codes, including:

(a) the introduction of the SCR process, which allows Ofgem to lead reviews of complex cross-code and licence issues;

(b) the establishment of the CACoP, which sets out 12 high-level principles developed jointly by Ofgem and code users. These principles concern the code governance and modification processes, which are individually governed by the code panel of each of the industry codes;

(c) the introduction of regular and fast-track self-governance modification procedures; and

(d) the incorporation of charging methodologies into certain industry codes.

11.132 Ofgem has recently expressed its concerns that the CGR measures have not fully addressed the systemic issues which it first identified in 2007 and, as a result, it is considering whether wider institutional reform, beyond the mere strengthening of the CGR measures, is required. For this purpose, Ofgem has opened discussions with DECC concerning whether Ofgem should receive further executive powers to direct changes to the industry codes in order to implement specific policy objectives. Ofgem has also posed to us that it may be necessary for there to be a single entity (either Ofgem, or a newly created statutory body) which is responsible for the development and implementation of modification proposals that are beneficial to consumers.

11.133 We support attempts by Ofgem or the industry to extend best practice across all codes (including in relation to selection processes and remuneration). We also believe that accountability of those code administrators (and delivery bodies) vis-à-vis Ofgem which are not licensees is insufficient.

11.134 More generally, the modification process must ensure that certain changes that are necessary to deliver innovative solutions or wider policy changes are delivered in a timely manner. However, we recognise that this objective must be balanced against the need to ensure legal certainty and robust decision-making, which in turn requires a robust modification process that includes relevant impact assessments and consultation processes.

11.135 In general, the modification process contains the following four stages:

(a) initiation (by means of a modification proposal);

(b) development (including consultation) by industry;

(c) Ofgem approval; and

(d) implementation by industry.

Table 11.1: Alternative processes for modifying codes

	Modification stage			
Modification procedure	*Initiation**	*Development*	*Decision*	*Implementation*
Ordinary	Industry	Industry	Ofgem	Industry (network owner†)/ code administrator
Self-governance (fast-track and regular)	Industry	Industry	Industry	Industry (network owner)/ code administrator
SCR	Ofgem	Ofgem first then industry	Ofgem	Industry (network owner)/ code administrator

*The use of the word initiated rather than proposed is deliberate. In the context of the SCR modification procedure, it is Ofgem that initially researches an issue that later forms the basis of a modification proposal that is formally proposed by an industry participant (which is technically directed to do so by Ofgem. For details on this process see below).
†As noted above, the SLCs which incorporate the industry codes into the licences of the network owners require the network owners to prepare and maintain in force the industry codes. Those same SLCs also specify that changes to the industry code can only be made by the network owner.

11.136 We note in particular that the SCR process grants Ofgem the power to launch an in-depth assessment of a defined issue or set of issues and direct certain licensees to raise appropriate modification proposals (‘SCR modification proposals’) to one or more industry codes following the conclusion of that assessment. Ofgem introduced the SCR process in order to allow it to take the lead on developing code modifications to resolve complex and cross-code issues. However, Ofgem’s SCR power does not enable it to intervene in the development or implementation of SCR modification proposals (for details on the SCR process see Appendix 11.2, paragraphs 89 to 93).

11.137 Each industry code prescribes the entity or entities that are entitled to raise a modification proposal by submitting it to the designated secretary of that industry code. We note that the technical codes have relatively restrictive arrangements in this regard.

11.138 Development. In general, code panels control how to develop modification proposals, including whether they should be stayed or merged and whether they should be submitted for ‘urgent’ or self-governance status (either for fast-track or regular self-governance). Additionally, code panels decide whether to establish a working group for the purpose of assessing the modification proposal and whether to submit the modification proposal directly to industry consultation or require further assessment beforehand.

11.139 We note that, in theory, the general ability of code panels to exercise discretion concerning whether to require further assessment of a modification proposal, and to decide on the composition of working groups, could potentially be abused by an individual code panel. This could be part of a deliberate tactic by that code panel to delay the development of a particular modification proposal or to favour a particular group or industry participants. However, we have not seen evidence of code panels using such tactics, nor do we have reason to believe they have.

11.140 We consider two separate issues relating to the development phase: whether it acts as a barrier to engagement of small parties and whether it causes modification proposals to be unnecessarily delayed.

11.141 In practice, code modification processes are a resource-intensive activity with the consequence that independent firms may decide not to participate on the grounds of resource constraints. The costs of participation in the modification process could in practice act as a barrier to the development of innovative business models for which a modification proposal is required. This issue might be exacerbated in the coming years by the need to implement the EU network codes, which could consume industry resources and create congestion across the code modification processes.

11.142 This risk is only in part mitigated by the requirements set out in the CACoP by which the code administrator must administer the consultation process and ensure that parties have a sufficient amount of time to consider the relevant information and provide an informed response. (For further procedural details see Appendix 11.2.)

11.143 The case studies discussed above and in Appendix 11.2 clearly show that, in the absence of incentives to develop modification proposals, the timeline might extend as a result of challenges and alternative modification proposals being raised. This is likely to be the case when the modification proposals have large and uneven financial implications for parties. Although these challenges are legitimate, they have the effect of delaying the development of changes, including in circumstances where the change is necessary to support innovation or wider policy objectives, and the level of analysis available is sufficient for Ofgem to make a decision.

11.144 We note that Ofgem lacks the power to force a modification proposal to progress through this stage, except in the limited case relating to gas security of supply where primary legislation allows it to do so. Ofgem could possibly choose to impose mandatory timetables for the development of modification proposals within licence conditions but has chosen not to do so.

11.145 As part of the CACoP, Ofgem introduced a non-binding indicative modification timetable. In general, this modification timetable has not been incorporated through the code modification processes as a binding requirement into each of the codes. As a result, there is no overarching common time frame for the development of modification proposals, and the time frame that applies to a modification proposal depends on the context in which it is developed (ie the industry code to which it applies).

11.146 Centrica said that previous SCR processes had taken a long time due to the sheer complexity of the issues involved, the far-reaching impact on the industry, the lack of clearly defined objectives at the outset, as well as in some cases the need for substantial revisions to initial analysis and impact assessments. This is confirmed, in particular for the BSC and the UNC, by data provided to us by code administrators. Centrica therefore suggested that it would sometimes be helpful for Ofgem to provide a clearer directional steer in the early phases of an SCR rather than allowing the industry to conduct detailed assessments of proposals which are ultimately rejected for reasons that were not apparent at an early stage. It suggested that there might be inefficient duplication of work due to code administrators and Ofgem both carrying out extensive evaluation and impact assessment of the same modification proposals.

11.147 We note that a number of binding European network codes are currently being developed for the purpose of facilitating a fully liberalised internal energy market and will have to be transposed into national law in the coming years. As a result, any conflicting provisions within the current GB industry codes, licence conditions and legislation will have to be amended.

11.148 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. Significant resources, as well as close coordination between DECC, Ofgem and the industry, is therefore necessary in order to identify the areas where change is needed and ensure a consistent and efficient implementation. This circumstance might exacerbate the risks of delays in implementing change that would have positive effects for innovation and consumers.

11.149 Decision. For each industry code, Ofgem must approve or reject every materially important modification proposal. As part of its decision to approve or reject a modification proposal, Ofgem must consider whether it has sufficient information to take the decision, the prescribed objectives set out in the relevant industry code and its own wider statutory objectives, as set out in GA86 and EA89.

11.150 Implementation. In order to implement a modification proposal that it has approved, Ofgem must direct relevant licensees to make the resultant changes to the industry code in question. With the exception of National Grid, code administrators (or delivery bodies) are not licensees and therefore Ofgem has limited powers to direct them. None of the industry codes contains provisions which establish a general deadline for approved modification proposals to be implemented. Ofgem could possibly choose to impose mandatory timetables for the implementation of modification proposals within licence conditions but has chosen not to do so, although such timetables would only apply to licensees and not to certain code administrators/delivery bodies which are generally responsible for the implementation phase.

11.151 Therefore, even after approval by Ofgem of a modification proposal, there is a risk that implementation of the approved modification proposal may be delayed due to resource constraints or lack of sufficient incentives of the code administrator/delivery body. Code administrators are accountable to code parties, but Ofgem told us that it would be reluctant to hold code parties jointly responsible for a code administrator's failure to implement an approved modification proposal on a timely basis (Project Nexus, discussed above, is an example of such delays).

11.152 Modification proposals initiated by Ofgem through an SCR, and therefore likely to pursue a policy objective, are implemented in the same fashion as under the ordinary modification procedure.

11.153 An additional layer of complexity, which may exacerbate some of the concerns identified above in relation to single code modifications, can arise where change requires modification proposals to be independently developed and implemented in the context of two or more industry codes. This may occur when the introduction of a significant new technology, UK government policy or EU law clearly impacts several elements of the energy markets, or when a modification proposal relating to one industry code necessitates consequential changes to another industry code.

11.154 We note that a number of measures are in place to facilitate cross-code modification measures (see Appendix 11.2). Our concern, however, is that these measures simply seek to improve the coordination between parallel independent processes, but do not provide a formal overarching change mechanism which would allow change to be carried out through a single process administered by one entity.

Our provisional view on code modification

11.155 Industry codes contain detailed technical and commercial provisions. Detailed knowledge of the industry is needed to navigate such rules, which suggest that self-regulation is appropriate to govern and modify such rules. However, as shown by our case studies, modifications to these provisions are often necessary to ensure the delivery of policy decisions driven by DECC, Ofgem and/or EU institutions. In some cases, the introduction of innovative solutions that would increase consumer welfare, will require code modifications. It is essential that industry codes keep pace with market developments and with wider policy changes in order for the energy markets to function well.

11.156 We have seen evidence that the existing governance and modification arrangements can lead to inconsistent or delayed outcomes, and create material burdens on parties, in particular smaller ones, which could undermine their incentives to promote changes. We believe that Ofgem has taken important steps to prevent or mitigate these risks through its CGR. In particular, the CACoP has increased transparency and the role of 'critical friend' assigned to code administrators has facilitated the engagement of (small) parties. Similarly, the introduction in the code modification arrangements of the self-governance procedures (fast-track and regular), SCR and other ancillary mechanisms (eg Ofgem's power to send back a modification proposal for further analysis) seem to have facilitated a more efficient allocation of time and resources between the industry and public bodies.

11.157 However, despite Ofgem's reforms, there are still circumstances where the current model does not allow code modifications to be developed and/or implemented efficiently. This is the case in particular where a proposed change has significant and unevenly distributed impacts on market participants.

11.158 In our view, the inefficient development and/or implementation of significant code modification proposals may cause consumer detriment where a change is needed to achieve policy objectives or to support competition and innovation (eg Project Nexus, which facilitates the development of tariffs that rely on smart meters). Ofgem's ability to influence the development and implementation of modification proposals, even in the context of an SCR, is insufficient to ensure that industry codes keep pace with market developments or wider policy objectives.

11.159 Even when changes are needed to achieve a clear public policy objective, their development and implementation is left in some cases to unlicensed entities, with limited direct tools available to public bodies to accelerate and/or streamline the process. We also note that, in view of the number of modification proposals that will need to be implemented in the coming years (for instance to implement the European network codes), and the time and resource implications for the regulator and the industry, this issue is likely to be exacerbated if resources are not efficiently prioritised. The current code modification arrangements do not contain an effective mechanism to ensure efficient prioritisation.

11.160 This inefficiency, in our view, dampens competition and innovation, and leads to the energy sector failing to keep pace with market developments and wider policy objectives.

11.161 We have provisionally found a combination of features of the wholesale and retail gas and electricity markets in Great Britain that are related to industry code governance and which give rise to an AEC through limiting innovation and causing the energy markets to fail to keep pace with regulatory developments and other policy objectives. These features are as follows:

(a) parties' conflicting interests and/or limited incentives to promote and deliver policy changes; and

(b) Ofgem's insufficient ability to influence the development and implementation phases of a code modification process.

12. Features and findings

12.1 As described in paragraph 1.1, on 26 June 2014 Ofgem made a reference to the CMA for an investigation into the energy market in Great Britain. Section 134(1) of the 2002 Act requires us to decide whether 'any feature, or combination of features, of each relevant market prevents, restricts or distorts competition in connection with the supply or acquisition of any goods or services in the United Kingdom or a part of the United Kingdom'. If that proves to be the case, under the 2002 Act, this constitutes an AEC.[630]

12.2 In Section 5, we have provisionally found that the absence of locational pricing for transmission losses is a feature of the wholesale electricity market in Great Britain that gives rise to an AEC, as it is likely to distort competition between generators and to have both short- and long-run effects on generation and demand:

(a) In the short run, costs will be higher than would otherwise be the case, because cross-subsidisation will lead to some plants generating when it would be less costly for them not to generate, and other plants, which it would be more efficient to use, not generating. Similarly, cross-subsidies will result in consumption failing to reflect fully the costs of providing the electricity.

(b) In the long run, the absence of locational pricing may lead to inefficient investment in generation, including inefficient decisions over the extension or closure of plant. This could also lead to inefficiency in the location of demand, particularly high-consumption industrial demand.

12.3 In Section 5, we have also provisionally found that the mechanisms for allocating CfDs are a feature of the wholesale electricity market in Great Britain giving rise to an AEC through increasing the risk of inefficient allocation of financial support to generation capacity and which adversely impacts competition. More specifically, this is due to the absence of an obligation for the DECC to:

(a) carry out, and disclose the outcome of, a clear and thorough impact assessment supporting a proposal to use its powers to allocate CfDs outside a competitive process; and

(b) regularly monitor the division of technologies between different pots, which form the basis of CfD auctions, and provide a clear justification

[630] Section 134(2) of the 2002 Act.

when deciding on the allocation of budgets between the pots for each auction.

12.4 In Section 8, we have provisionally found that a combination of features of the markets for domestic retail supply of gas and electricity in Great Britain give rise to an AEC through an overarching feature of weak customer response[631] which, in turn, gives suppliers a position of unilateral market power concerning their inactive customer base which they are able to exploit through their pricing policies or otherwise. These features act in combination to deter customers from engaging in the domestic retail gas and electricity markets, to impede their ability to do so effectively and successfully, and to discourage them from considering and/or selecting a new supplier that offers a lower price for effectively the same product.

12.5 More particularly, these features are as follows:

(a) Customers have limited awareness of and interest in their ability to switch energy supplier, which arises in particular from the following fundamental characteristics of the domestic retail gas and electricity supply markets:

(i) the homogeneous nature of gas and electricity which means an absence of quality differentiation of gas and electricity and which may fundamentally affect the potential for customer engagement in the markets; and

(ii) the role of traditional meters and bills, which give rise to a disparity between actual and estimated consumption. This can be confusing and unhelpful to customers in understanding the relationship between the energy they consume and the amount they ultimately pay. The full roll-out of smart meters over the next five years may have a potentially significant positive impact on engagement, although we have limited evidence concerning the likely magnitude and timescales of any such impact.

These fundamental characteristics may particularly affect certain categories of customer (eg those who are elderly, live in social and rented housing or have relatively low levels of income or education) who we observe are less likely to have considered engaging than others.

[631] We refer to weak customer response as an overarching feature as synonymous with it being a source for an AEC (CC3, paragraph 170).

(b) Certain customers face actual and perceived barriers to accessing and assessing information arising, in particular from the following aspects of the domestic retail gas and electricity markets:

(i) the complex information provided in bills and the structure of tariffs, which combine to inhibit the value-for-money assessments of available options, particularly on the part of customers that lack the capability to search and consider options fully (in particular, those with low levels of education or income, the elderly and/or those without access to the internet); and

(ii) a lack of confidence in, and access to, PCWs by certain categories of customers, including the less well-educated and the less well-off. We note that alternative forms of TPIs, such as collective switching schemes, may become increasingly important for such customers.

(c) Customers face actual and/or perceived barriers to switching, such as where they have uncertified meters or experience erroneous transfers which have the potential to cause material detriment to those who suffer from them. Erroneous transfers may thereby impact customers' ability to switch as well as their perception of switching. This is again an area where the introduction of smart meters should in the fullness of time help bring improvements.

(d) Prepayment meters, which place technical constraints on customers on such meters from engaging fully with the markets, and which reduce customers' ability and incentive to engage in the markets and search for better deals. Prepayment meters therefore contribute to such customers facing higher costs and a more limited choice of tariffs. We expect these problems to be partly addressed with the full roll-out of smart meters and, in the intervening period Ofgem has recently published a report setting out measures to address the limited availability of tariffs for prepayment customers.

12.6 The above overarching feature of weak customer response, in turn, gives suppliers a position of unilateral market power concerning their inactive customer base. In relation to unilateral market power, our provisional finding is that suppliers in such a position have the ability to exploit such a position, for example, through price discrimination by pricing their SVTs materially above a level that can be justified by cost differences from their non-standard tariffs and/or pricing above a level that is justified by the costs incurred with operating an efficient domestic retail supply business.

12.7 For the reasons given in Section 8, in relation to the regulatory framework governing the markets for domestic and/or SME retail gas and electricity supply, we have provisionally found that:

(a) The 'simpler choices' component of the RMR rules (including the ban of complex tariffs, the maximum limit on the number of tariffs that suppliers will be able to offer at any point in time, and the simplification of cash discounts) is a feature of the markets for the domestic retail supply of electricity and gas in Great Britain that gives rise to an AEC through reducing retail suppliers' ability to innovate in designing tariff structures to meet customer demand, in particular, over the long term, and by softening competition between PCWs.

(b) The current system of gas settlement is a feature of the markets for domestic and SME retail gas supply in Great Britain that gives rise to an AEC through the inefficient allocation of costs to parties and the scope it creates for gaming, which reduces the efficiency and, therefore, the competitiveness of domestic and microbusiness retail gas supply. While we note that Project Nexus is likely to address most of the current inefficiencies in the gas settlement system identified, we are concerned at the slow pace of the implementation, the lack of a deadline and the fact that some players might have been adversely affected by these delays. Moreover, we are concerned that the incentives that shippers face to place a higher priority on adjusting AQs down and delaying adjusting AQs up will still be present after Project Nexus is implemented.

(c) The absence of a firm plan for moving to half-hourly settlement for domestic and the majority of microbusiness electricity customers and of a cost-effective option of elective half-hourly settlement is a feature of the markets for domestic and SME retail electricity supply in Great Britain that gives rise to an AEC through the distortion of suppliers' incentives to encourage their customers to change their consumption profile, which overall reduces the efficiency and, therefore, the competitiveness of domestic and microbusiness retail electricity supply.

12.8 In Section 9, we have provisionally found that a combination of features of the markets for retail supply of gas and electricity to SMEs in Great Britain give rise to an AEC through an overarching feature of weak customer response from microbusinesses[632] which, in turn, give suppliers a position of unilateral market power concerning their inactive microbusiness customer base which they are able to exploit through their pricing policies or

[632] We refer to weak customer response as an overarching feature as synonymous with it being a source for an AEC (*CC3*, paragraph 170).

otherwise. These features act in combination to deter microbusiness customers from engaging in the SME retail gas and electricity markets, to impede their ability to do so effectively and successfully, and to discourage them from considering and/or selecting a new supplier that offers a lower price for effectively the same product.

12.9 More particularly, these features are as follows:

(a) Customers have limited awareness of and interest in their ability to switch energy supplier, which arises from the following fundamental characteristics of the markets for retail energy supply to SMEs:

(i) the homogeneous nature of gas and electricity which means an absence of quality differentiation of gas and electricity and which may fundamentally affect the potential for customer engagement in the markets; and

(ii) the role of traditional meters and bills, which give rise to a disparity between actual and estimated consumption. This can be confusing and unhelpful to customers in understanding the relationship between the energy they consume and the amount they ultimately pay. The full roll-out of smart meters over the next five years may have a potentially significant positive impact on engagement, although we have limited evidence concerning the likely magnitude and timescales of any such impact.

(b) Customers face actual and perceived barriers to accessing and assessing information arising, in particular, from the following aspects of the markets for retail energy supply to SMEs:

(i) a general lack of price transparency concerning the tariffs that are available to microbusinesses, which results from many microbusiness tariffs not being published; a substantial proportion of microbusiness tariffs being individually negotiated between customer and supplier; and the nascent state of PCWs for non-domestic customers (although transparency may be improving with the introduction of online quotes and PCWs); and

(ii) the role of TPIs, in relation to which:

- a number of complaints have been made by non-domestic customers to various official bodies concerning alleged TPI malpractice, which may have reduced the level of trust in all TPIs and discouraged engagement more generally (although this situation may improve if Ofgem implements a code of practice for non-domestic TPIs that is currently in draft form); and

- we have noted a lack of transparency as well as the existence of incentives not to give non-domestic customers the best possible deal. We are concerned that customers are not aware of this and therefore do not take steps to mitigate it (for example, by consulting more than one TPI or seeking other benchmark prices). This is exacerbated by the lack of easily available benchmark prices, and the fact that many tariffs are not published.

(c) Some microbusiness customers are on auto-rollover tariffs (where customers are signed up for an initial period at a fixed rate, with an automatic rollover for a subsequent fixed period at a rate they have not negotiated with no exit clause), and are given a narrow window in which to switch supplier or tariff, which may limit their ability to engage with the markets. This practice has recently been discontinued by the largest suppliers, but not by some of the smaller ones (which still account for a significant share of supply of gas to microbusinesses).

12.10 In Section 11 we have provisionally found a combination of features of the wholesale and retail gas and electricity markets in Great Britain that give rise to an AEC through an overarching feature of a lack of robustness and transparency in regulatory decision-making which, in turn, increases the risk of poor policy decisions which have an adverse impact on competition. More particularly, these features are as follows:

(a) the lack of a regulatory requirement for clear and relevant financial reporting concerning generation and retail profitability;

(b) the lack of effective communication on the forecasted and actual impact of government and regulatory policies over energy prices and bills;

(c) Ofgem's statutory objectives and duties which, in certain circumstances, may constrain its ability to promote effective competition; and

(d) the absence of a formal mechanism through which disagreements between DECC and Ofgem over policy decision-making and implementation can be addressed transparently.

12.11 In Section 11, we have provisionally found a combination of features of the wholesale and retail gas and electricity markets in Great Britain that are related to industry code governance and which give rise to an AEC through limiting innovation and causing the energy markets to fail to keep pace with regulatory developments and other policy objectives. These features are as follows:

(a) parties' conflicting interests and/or limited incentives to promote and deliver policy changes; and

(b) Ofgem's insufficient ability to influence the development and implementation phases of a code modification process.

12.12 We have therefore provisionally found, pursuant to section 134(1) of the 2002 Act, that there are features of the relevant markets, which alone or in combination prevent, restrict or distort competition in the supply of electricity and gas in the United Kingdom, and accordingly that there are various AECs within the meaning of section 134(2) of the 2002 Act. These features are those that we have identified in Sections 5, 8, 9 and 11 of this provisional findings report.

Consumer detriment

12.13 We have considered the likely nature and potential scale of the harm to energy customers arising from the AECs that we have provisionally found. Further details of our analysis of this issue are set out in Sections 5 and 8 to 11, and Appendices 10.3 ('Analysis of retail supply profitability – ROCE and economic profit') and Appendix 10.5 ('Assessment of the competitive benchmark in retail energy supply').