

Energy market investigation

Final report

24 June 2016

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The Competition and Markets Authority has excluded from this published version of the 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 [✂]. Some numbers have been replaced by a range. These are shown in square brackets. Non-sensitive wording is also indicated in square brackets.

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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.
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. Where we find that there is an AEC, we have a duty to decide whether we should take action ourselves and/or whether we should recommend others to take action to remedy, mitigate or prevent the AEC or any resulting detrimental effects on customers. In deciding these questions we have a duty to achieve as comprehensive a solution as is reasonable and practicable to the AEC and any resulting detrimental effects on customers.
4. This is the final report of our investigation. Alongside it, we have prepared an overview document,³ which sets out a summary of the approach we have adopted in undertaking our investigation and our key findings.

Overview of GB energy markets and key outcomes

5. 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.
6. 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

¹ [Energy market investigation terms of reference.](#)

² Section 134(2) of the Enterprise Act 2002.

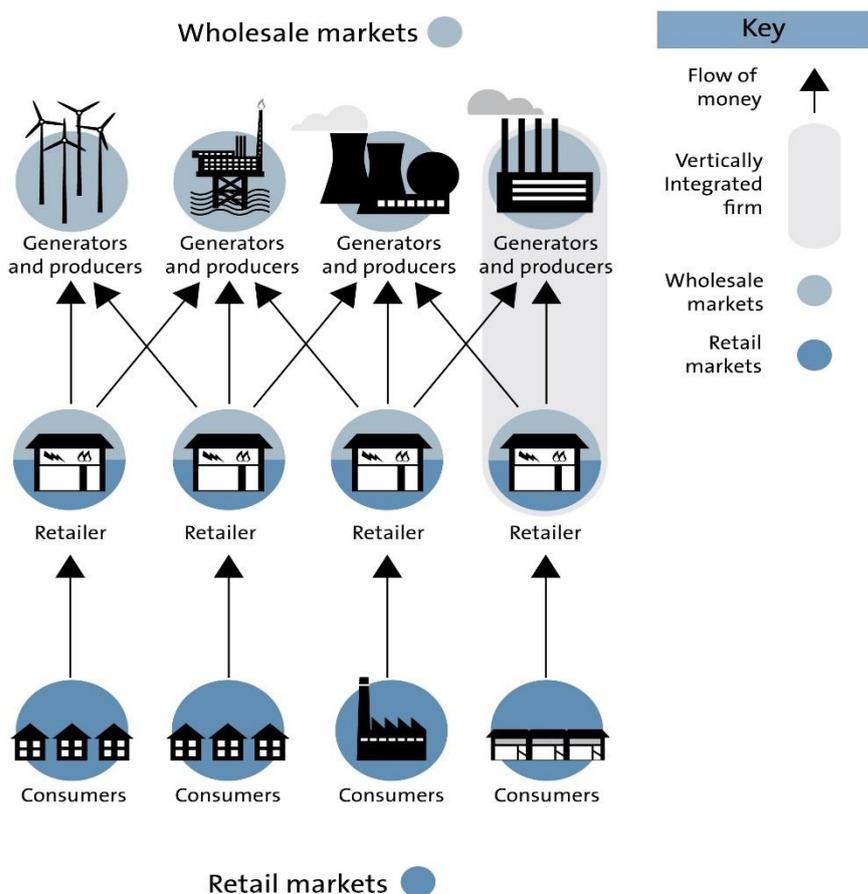
³ [Energy market investigation overview.](#)

renewable deployment has increased substantially. 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.

Market structure and participants

7. 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 customers 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 customers via high pressure transmission pipes and low pressure distribution pipes.
8. The chart below provides a high level overview of the financial flows and market arrangements in the gas and electricity sectors.
9. 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.
10. Retail markets provide the strongest point of commonality between gas and electricity, since the products are often sold together by retailers through 'dual fuel' tariffs. Moreover, the regulatory regime applying to retail functions generally applies equally to gas and electricity. As of 31 January 2016, there were 28 million domestic electricity customers and 23 million domestic gas customers. There were 20 million dual fuel customers, 8 million single fuel electricity customers and 3 million single fuel gas customers.

Figure 1: Financial flows and market arrangements



11. 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.
12. Together, the Six Large Energy Firms currently supply energy to just under 90% of the domestic customers in Great Britain and generate about 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.
13. In relation to retail, there are currently 34 suppliers selling both electricity and gas to households and a larger 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, First Utility and Ovo Energy (which, together with Co-operative Energy, we collectively call the 'Mid-tier Suppliers').

14. The single biggest cost item for both electricity and gas is the cost of wholesale energy (about 40 to 50% of the costs of supplying electricity and gas to domestic customers), followed by network costs (about 25%). The costs associated with retailing (including a profit margin) are around 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 (around 15%) than gas (around 5%).

Regulatory and policy framework

15. 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.
16. 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

17. 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, which accounted for about 25% of total electricity generated in 2015. 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.

18. 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 2014 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.
19. Greenhouse gas emissions from the power sector were roughly 40% lower in 2014 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 roughly 20% lower, partly as a result of policies to improve domestic energy efficiency.

Prices, costs and profits

20. 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.
21. 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. In 2015, the upwards trend halted, with electricity prices roughly flat and gas prices falling nearly 5% in real terms.
22. We have reviewed financial data submitted by the Six Large Energy Firms, for the period 2009 to 2014. This suggests that, for electricity, the main drivers of domestic price increases from 2009 to 2014 were the costs of social and environmental obligations and network costs. Reported wholesale costs remained flat while profit (EBIT⁴) margins fell sharply in 2010 and rose steadily year on year thereafter. For gas, there was 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 3.5% over the period. Average EBIT margins on sales of gas (4.5%) were higher than those on sales of electricity (2.5%).
23. We have noted that there is a wide variation in the prices that different domestic customers pay for energy, which is particularly striking since

⁴ Earnings before interest and tax, or gross profit less indirect costs.

electricity and gas are entirely homogenous products. We calculate that, over the period Quarter 1 (Q1) 2012 to Quarter 2 (Q2) 2015, most customers of the Six Large Energy Firms could have made considerable savings from switching a combination of suppliers, tariffs and payment methods: for some categories of customer, the average gains from switching were equivalent to more than 20% of their bill over the period.

24. We have also noted that, over the period 2011 to mid-2015, average revenue per kWh earned by the Six Large Energy Firms from customers on the standard variable tariff – which about 70% of the customers of the Six Large Energy Firms pay – was around 11% higher for electricity and 15% higher for gas than average revenue earned from customers on other tariffs.
25. EBIT margins from retail sales to SMEs (including microbusinesses) 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 (7%).

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 sixfold between 2008 and 2014 before falling by 20% in 2015. 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. 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 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.
28. We 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, comprising, at least, prepayment and restricted meter segments;
- (d) the retail supply of gas to domestic customers in Great Britain, comprising, at least, prepayment and restricted meter segments;
- (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.

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 customers 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 not found any features in wholesale gas markets that give rise 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 in the gas markets. 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 vertical integration – 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 the wholesale electricity market

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 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. The profitability analysis does not therefore provide evidence that overall, the Six Large Energy Firms earned excessive profits from their generation businesses over the period or that wholesale market prices were above competitive

levels. This evidence is consistent with our conclusion that generators do not have unilateral market power.

Wholesale electricity market rules and regulations

39. We have 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. These cover both established characteristics of the electricity wholesale market regulatory framework and recent reforms that are likely to have a significant impact on the nature of wholesale market competition in the future:
- (a) the principle of self-dispatch introduced about 15 years ago;
 - (b) the reforms to the system of imbalance prices that Ofgem has recently approved;
 - (c) 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 demand-side response (DSR);
 - (d) the introduction of Contracts for Difference (CfDs) as the principal means of incentivising investment in low carbon generation; and
 - (e) the absence of locational pricing for transmission losses and constraints, an issue that has been debated at length since privatisation 25 years ago.

Self-dispatch

40. 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.
41. 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. In our view, the evidence does not support such a conclusion. 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.

Imbalance price reforms

42. 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.
43. 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 wrote to us, expressing their concerns about the reforms. 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) 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' (RSP).
 - (d) A move to price disconnection or voltage reduction actions equal to VoLL.
44. 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.
45. 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.

46. 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 have not found that it leads to an AEC.

Capacity Market

47. 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.
48. We believe 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.
49. 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 view is that the design of the Capacity Market is broadly competitive. As regards the recovery of Capacity Market costs and the Capacity Market penalty mechanism, our view is that these do not 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 did not carry out work in this area.

Contracts for Difference

50. 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.
51. The Renewables Obligation (RO) has been successful in encouraging investment in renewable generation, which accounted for just under 25% of all GB generation in 2015. 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.
52. CfDs have been introduced to replace the RO as the main mechanism for incentivising investment in low carbon generation. CfD payments are due to increase steadily, reaching about £2.5 billion a year by 2020/21. 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. 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.
53. 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.
54. 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 customers around £110 million a year.

55. 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 customers. 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.
56. 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 customers 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 customers 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.
57. 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.
58. 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 the budget is allocated into each of these different pots. Decisions on both of these parameters influence the intensity of competition and the level of support provided through the scheme.

59. 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 customers. 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 different pots.
60. 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 found that the mechanisms for allocating CfDs are a feature of the wholesale electricity market in Great Britain giving rise to an AEC increasing the risk of inefficient allocation of financial support to generation capacity and which adversely impacts competition**. In particular, the AEC arises from 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) 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.

Absence of locational prices for transmission losses

61. Energy is lost when electricity is transported from one part of the country to another, and the greater the distance travelled, the higher the losses. The costs of these transmission losses therefore 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 generating electricity will be associated with high losses. However, despite this locational variation in the costs of losses, under the current regulatory regime, these costs are allocated to generators and customers in a way that takes no account of their geographical location.
62. 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 customer 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.
- 63. We have carried out a modelling exercise to assess the costs that are likely to arise as a result of the absence of locational charges for transmission losses. The results are similar, overall, to those from previous modelling exercises and show that total efficiency costs vary between around £130 million and £160 million over the period 2017 to 2026, with these results robust to a variety of assumptions regarding fuel input costs. We also found a moderate environmental cost arising from the absence of locational charges for transmission losses in the form of increased SO₂ and NO_x emissions, valued at between around £1 million and £15 million over the period.
- 64. Our view is that **the absence of locational pricing for 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.**

Wholesale electricity market remedies

- 65. We have decided on remedies to address both aspects of the regulatory regime governing wholesale market operation that lead to AECs:
 - (a) the mechanisms for allocating CfDs; and
 - (b) the absence of locational charging for transmission losses.
- 66. While the remedies are quite different, they have a similar high-level objective: to help ensure that competitive pressures are brought fully to bear on the wholesale cost of electricity, reducing the prices paid by electricity customers.

Allocation of Contracts for Difference

67. We noted that the cost of supporting projects through an early form of CfDs (under the FIDeR framework) allocated outside the context of a competitive auction is £250–310 million per year higher than it likely would have been had the projects been awarded CfDs through a competitive auction. This illustrates the significant impacts that DECC’s decisions in this area can have on the costs faced by energy customers. It is essential, therefore, when DECC makes such decisions in the future, that they are based on rigorous analysis, and that the impacts are communicated in a clear and transparent manner. We believe our remedies will help ensure that this happens.

DECC to undertake, and disclose the outcome of, an impact assessment before awarding CfDs outside the auction mechanism

68. The aim of this remedy is to ensure that, in the future, if DECC is considering allocating a CfD outside the competitive auction process, it undertakes a clear and rigorous analysis of the impact of doing so and consults on this basis before reaching a final decision.

69. We note that, in principle, there may be circumstances under which allocating CfDs outside the competitive auction process could result in lower costs to customers. For example, there may be cheap projects with a lifespan and other operating characteristics that are so different to the characteristics of potentially competing projects that it is difficult to compare them within an auction framework. Since an element of judgement will be required in making these assessments we have not considered it appropriate to recommend imposing absolute rules determining the situations in which non-competitive allocation would be allowed.

70. However, we are recommending that, before deciding to allocate support on a non-competitive basis, DECC should set out clearly in an impact assessment why it considers that it is not feasible for the project to compete in the competitive auction process and why the benefits to customers of non-competitive allocation are likely to exceed the costs.⁵

71. We are recommending that DECC consult on the basis of an impact assessment before entering into negotiations with prospective generators, in order to identify the possible costs and the benefits that may arise from supporting a given technology. We also recommend that DECC publish an

⁵ We note that no such assessment was carried out in relation to the FIDeR projects. If any such assessment had been carried out, we do not believe that it would have led to the conclusion that it was in customers’ interests to allocate the FIDeR projects outside of the auction.

impact assessment after the negotiations with prospective generators and the provisional agreement of a strike price, to expose the specific impacts on customers expected to arise from the proposed contract.

DECC to undertake and consult on a clear and thorough assessment of the appropriate allocation of technologies and CfD budgets between pots

72. In allocating CfDs on a competitive basis, DECC separates technology into separate 'pots', to which it assigns separate budgets. Since only technologies within the same pot compete against each other, decisions on these parameters influence the intensity of competition and the level of support provided through the scheme.
73. We are recommending that DECC undertake a clear and thorough assessment and consult before allocating technologies between pots and the CfD budget to the different pots. As part of its analysis and consultation, DECC should estimate the extent to which the short-run costs of supporting low carbon generation are affected by its decision. This can then be weighed against any long-run benefits (eg cost reductions of future projects), to assess overall impacts on customers.
74. We are recommending that DECC should undertake an assessment of the appropriate allocation of technologies and budgets to pots prior to each CfD auction and consult on this basis.

Locational adjustments for transmission losses

75. Given that we have found that the absence of locational pricing for transmission losses gives rise to an AEC, our remedy will introduce locational charging for transmission losses in Great Britain. Its aim is to improve the accuracy with which the avoidable costs of variable transmission losses are borne by those who cause them, thus reducing waste, reducing the cost of electricity generation, and ultimately reducing total bills to end customers. The design of the remedy will be identical in its technical aspects to the P229 code modification previously assessed in 2011, including notably the use of semi-marginal (rather than full marginal) transmission loss factors.
76. The modelling exercise that we have conducted suggests that the introduction of locational charges for losses will reduce the total costs of meeting the electricity demand of customers in Great Britain by between £130 million and £160 million over the period 2017 to 2026, as well as producing a modest environmental benefit of between £1 million and £15 million. The results of our modelling are similar, overall, to those from previous modelling exercises conducted in support of previous proposals to

introduce locational charging for transmission losses. We have not attempted to model the dynamic benefits from the remedy, in terms of more efficient investment, due to the complications and uncertainties of such modelling. All in all, the expected benefits from the remedy – considering both benefits we have modelled and those we have not – exceed by far the expected implementation costs, which are substantially less than £10 million.

77. Introducing locational pricing for losses would also have a distributional effect, leading to transfers: from customers in areas of low generation relative to demand to customers in areas of high generation relative to demand; and from generators in areas of high generation relative to demand to generators in areas of low generation relative to demand. This pattern is borne out in our modelling: customers in the North of Scotland tend to benefit to a greater extent than customers in the South of England, for example.
78. In summary, based on the modelling work we have conducted and other analysis, our conclusion is that introducing locational charging for transmission losses will reduce costs and be in the long-term interests of customers.
79. Experience to date shows that it has been extremely difficult to introduce locational charging for transmission losses through code modification processes. We believe that this is largely due to the differential impact of the introduction of locational pricing for losses on some producers, who have found it to be in their commercial interest to slow down the pace of change. We will therefore implement the remedy by means of an order imposed on National Grid, as system operator, to calculate imbalance charges taking into account transmission losses calculated on a locational basis.

Vertical integration

80. A range of parties have expressed concerns about vertical integration 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.’
81. 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.

82. We have examined three main ways in which vertical integration might harm competition in wholesale and retail electricity markets.
83. First, it could mean that independent (non-vertically integrated) generators are not able to compete effectively because of the prevalence of vertically integrated suppliers. The concern here is that independent generators would be harmed because vertically integrated 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.
84. Secondly, if vertically integrated generators refuse to supply independent (non-vertically integrated) suppliers, or supply them on worse terms, it could mean that independent suppliers have to pay higher costs for wholesale electricity than vertically integrated suppliers. As a result they may be unable to compete effectively, resulting in harm to customers. The lack of unilateral market power makes it implausible that vertically integrated 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.
85. Lastly, vertical integration could raise barriers to entry and growth by new suppliers if they were unable to secure sufficient wholesale electricity. However, our analysis of wholesale market liquidity suggests that vertically integrated firms carry out extensive external trading, and liquidity in the products that vertically integrated firms use to hedge their exposure to wholesale market risk is sufficient for independent firms to hedge in a similar way.
86. One concern that has been expressed in relation to vertical integration is the lack of financial transparency. We consider the broader issue of financial transparency and the need for robust market-orientated financial information in our assessment of the governance of the regulatory framework below.
87. We have also considered whether there are potential cost savings associated with vertical integration. For instance, there may be a potential benefit to vertically integrated firms resulting from the 'natural hedge', whereby certain outcomes that may be detrimental to the vertically integrated firm's supply arm may be beneficial to its generation arm (and vice versa). This would reduce the volatility of a vertically integrated firm's returns. However, we considered that these benefits are likely to materialise

only under fairly specific circumstances, and as a result are likely to be limited in scale.

88. Some other potential benefits from vertical integration are not directly related to the natural hedge. Vertical integration is a form of diversification which may improve vertically integrated firms' credit ratings (thereby potentially reducing vertically integrated 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 vertical integration between supply and generation (such as shared trading or management personnel). While these benefits may not be passed through in full to customers, overall customers are likely to be better off than they would be if these efficiencies were not present.
89. We have not sought to quantify precisely the scale of the benefits identified above, but they are likely to be modest. The fact that some of the Six Large Energy Firms are moving away from a vertically integrated structure gives further weight to our conclusion that any benefits from vertical integration are likely to be limited (although they may have been greater in the past when integration took place).
90. Overall, we have not identified any areas in which vertical integration 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 vertical integration, which may be passed through to customers. As a result, our conclusion is that firms' vertically integrated structure does not give rise to an AEC.

Nature of retail market competition

Demand and supply characteristics and the parameters of retail competition

91. 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.
92. 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 spends almost 10% of total household expenditure on electricity and gas, while the richest 10% spends about 3% of total household expenditure on electricity and gas.

93. 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 and this is supported by evidence from our survey of 7,000 customers. 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.
94. 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 markets.
95. 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.
96. 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 18% 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 and reforms of the gas and electricity settlement systems, we would expect suppliers to have a greater degree of influence over wholesale costs and network costs.
97. 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

98. 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 variable tariffs. 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 resulting in a number of obligations on suppliers, including several provisions relating to tariffs, notably restricting the number of core tariffs.

Customer activity and engagement

99. Domestic customer activity can be measured along several dimensions:
- (a) Choice of tariff – notably whether the customer is on a standard variable tariff 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.
100. 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:
- (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; and 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.

Choice of tariff

101. Standard variable tariffs are the default tariff – ie the tariff energy customers will pay if they have not made an active decision to change tariff. Unlike other tariffs, standard variable tariffs have no end date – customers will be on a standard variable tariff indefinitely unless they make an active decision to change.
102. We have observed that, for the Six Large Energy Firms, gas and electricity revenues per kWh from standard variable tariffs are consistently higher than average revenue from non-standard (generally fixed-price) tariffs. Despite this, around 70% of the customers of the Six Large Energy Firms are currently on a standard variable tariff. We also note that a customer on a standard variable tariff is more likely to be with the historical incumbent supplier.

Choice of payment method

103. 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 58% of customers choosing to pay by this method in 2015 and only 27% of customers paying by standard credit. The proportion of customers on prepayment meters doubled over the period, from 7% in 1996 to 16% in 2015.
104. 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 27.2A, introduced by Ofgem in 2009, requires any such discounts to be cost-reflective. We understand that dual fuel standard variable tariff customers paying by standard credit currently pay about £75–£80 per year more than if they paid by direct debit.
105. 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 rented accommodation. We understand that the premiums paid by dual fuel standard variable tariff prepayment customers are currently about the same as those for standard credit – about £75–£80 per year. Nearly all prepayment customers are on standard variable tariffs, reflecting the limited choice of non-standard tariffs they face.

Choice of supplier

106. We have observed a steady upward 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 Standard Licence Condition 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. In 2015, there were around 3.4 million electricity transfers and 2.7 million gas transfers, which represents around 12% of all electricity meters and gas meters in 2015.
107. 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.

Market shares and acquisition channels

108. As of Q1 2016, British Gas had the largest share of both gas (36%) and electricity (23%) domestic customers, followed by SSE and E.ON (both around 12% of gas customers and 15% of electricity customers). There has been a rapid expansion in the market shares of suppliers outside of the Six Large Energy Firms, from less than 1% in 2011 to around 13% in gas and electricity in the first quarter of 2016. The largest of the Mid-tier Suppliers are First Utility, Ovo Energy and Utility Warehouse.
109. Suppliers use a range of acquisition channels to gain new customers, including face-to-face sales, telesales and price comparison websites (PCWs). The use of PCWs has increased over the last six years, but its importance as an acquisition channel varies considerably between suppliers.

Nature and extent of price competition

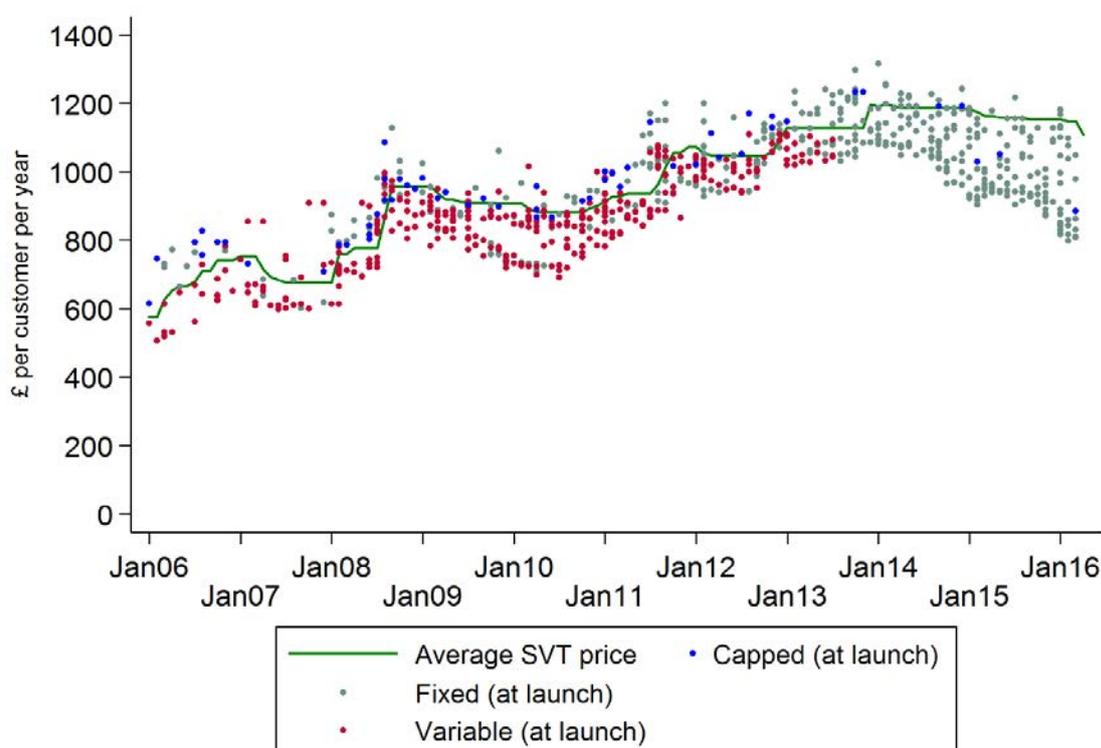
110. The price of a standard variable tariff can in principle be changed by the supplier at any time, with the condition that, if the price is to be increased, it must give 30 calendar days' notice to customers of its intention to do so. The Six Large Energy Firms typically make public statements, in advance of implementation, of intentions to change the price of standard variable tariffs. Standard variable tariff prices have generally changed once or twice a year. The standard variable tariff is an acquisition tariff for prepayment customers, who have a very restricted choice of non-standard tariffs. For non-

prepayment customers, standard variable tariffs are generally not an active acquisition tariff.

Comparison of standard variable tariffs and non-standard tariffs

111. Non-standard tariffs come in a variety of forms, including fixed-rate and capped tariffs. One- to two-year fixed-rate products are currently the most popular form of non-standard tariff. In contrast to standard variable tariffs, non-standard tariffs are acquisition tariffs. The majority are priced at significant discounts to standard variable tariffs, with a strategy of ensuring that they achieve a good position on PCWs. There have, however, historically been some non-standard tariffs such as longer-term price fixes, which have been more expensive than standard variable tariffs.
112. The chart below compares the non-standard tariffs launched by the Six Large Energy Firms with the flat average standard variable tariff across each of the Six Large Energy Firms.

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



Based on typical domestic consumption of 3200kwh/year for electricity and 13500kwh/year for gas.

Source: CMA analysis of data collected from the Six Large Energy Firms and Ofgem.

113. 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

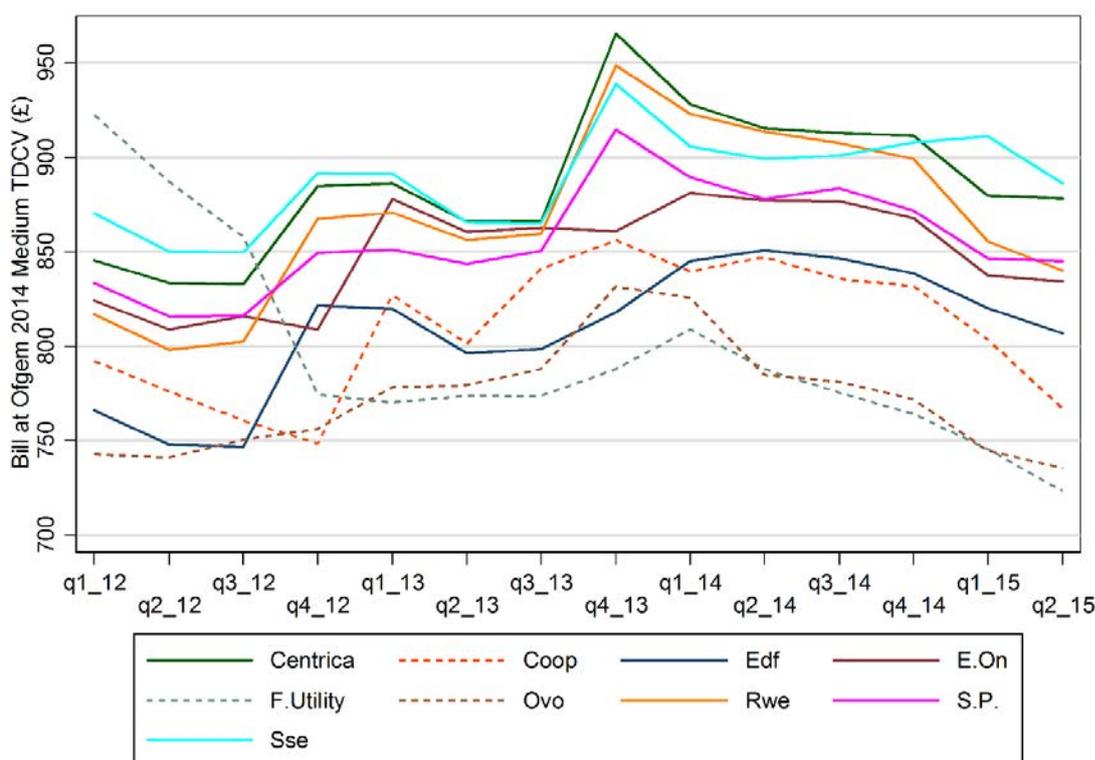
expected, given the fact that they reduce the risk to which the customer is exposed. With the introduction of the RMR rules, discounts on standard variable tariffs were banned and fixed products have taken their place as the cheap acquisition product. Over the last two years, the disparity between standard variable tariffs and the cheapest non-standard products has increased substantially.

114. Several of the Six Large Energy Firms have told us that there is an inter-relationship between their pricing of standard variable tariffs 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 a standard variable tariff (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.

Comparison of the Six Large Energy Firms and the Mid-tier Suppliers

115. We have analysed how domestic customer bills differ between suppliers controlling for exogenous cost differences (network charges and the costs associated with different payment methods), and assuming a typical level of domestic consumption.

Figure 3: Comparison of average dual fuel bills for medium TDCV domestic customers controlling for network and payment method costs



Source: CMA analysis of data provided by the Six Large Energy Firms and the Mid-tier Suppliers.

Notes:

1. A supplier's average price is calculated taking into account all the standard variable and non-standard tariffs that their customers (with standard and Economy 7 meters) were on at the end of each quarter (subject to some exclusions as set out in Appendix 10.2), and the number of customers on each on these tariffs.
2. For each supplier, tariffs offered by white-label partners are included (in particular, the analysis of Centrica tariffs includes British Gas and Sainsbury Energy tariffs, and the analysis of SSE tariffs includes SSE and M&S and Ebico tariffs).
3. We have excluded results for Utility Warehouse from the graph. This is because, for the purposes of the comparison of bills analysis and the gains from switching analysis, we excluded all bundled tariffs (see Appendix 9.2). For Utility Warehouse this had the effect of excluding the majority of its fixed-term tariffs.

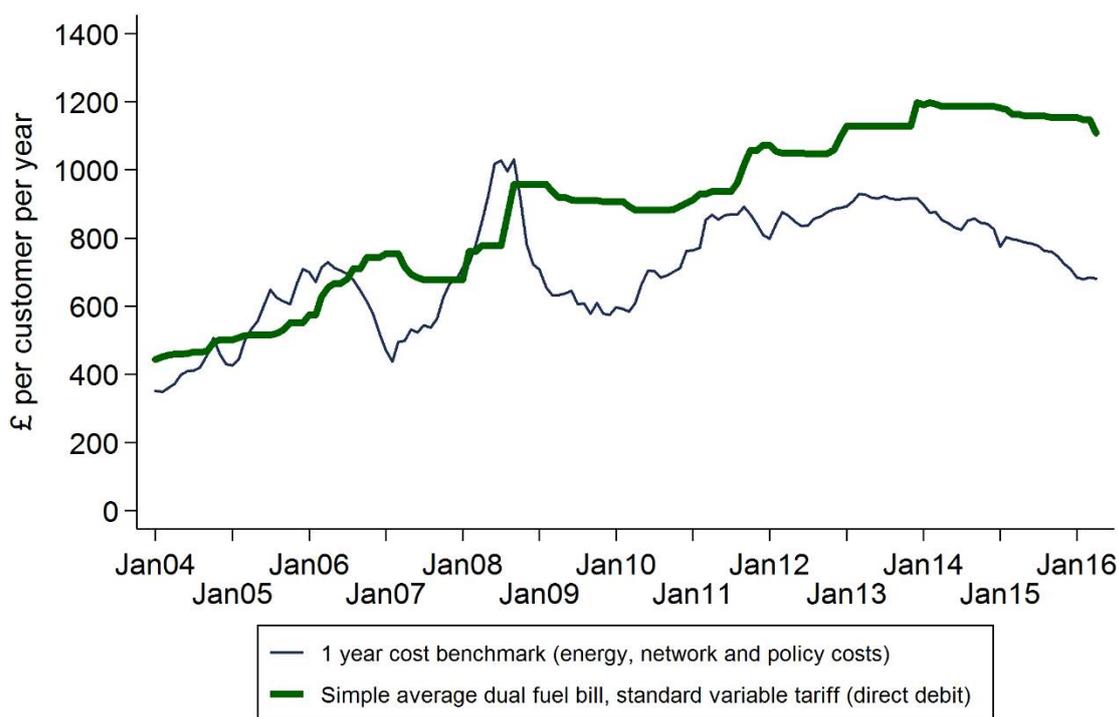
116. As can be seen in the figure above, after controlling for key exogenous costs, three of the Mid-tier Suppliers (Ovo Energy, First Utility and, to a less marked extent, Co-operative Energy) offered consistently lower average prices than the Six Large Energy Firms over the last 18 months of the period under review. EDF Energy offered consistently the lowest average prices paid by customers of the Six Large Energy Firms, with the customers of SSE, Centrica and RWE generally paying the highest average prices, over the period Q1 2012 to Q2 2015.⁶

⁶ We note that these average prices were calculated based on medium TDCV for dual fuel customers. Results may differ based on actual consumption and we look at the results based on high and low TDCV in Appendix 10.2.

Cost pass-through

117. 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. This has historically 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. In a competitive market we would generally expect prices to reflect marginal costs, and this in turn will give efficient signals to market participants about consumption and production decisions, rather than historical costs (which are sunk).
118. The Figure below shows the relationship between the average price of the standard variable tariff (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.

Figure 4: 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



Bill is an average across regions and six large energy firms, for a typical consumer. Direct costs are not those actually incurred by firms, but forward-looking expectations. Indirect costs are not shown.

Source: CMA analysis of data collected from the Six Large Energy Firms, Ofgem and ICIS.

119. The gap between the measures of direct costs and the average standard variable tariff widens over time, from around 2009 onwards. The gap narrows somewhat in 2011, with increases in wholesale gas costs, but then

increases again from 2014 as reductions in wholesale gas costs are not passed through into commensurate reductions in the standard variable tariff. In contrast, the cheapest non-standard tariffs have tracked changes in expected direct costs more closely. The evidence appears to be consistent with a weakening of competition over the standard variable tariff over time. This is particularly apparent from 2009 which broadly coincides with the introduction of the prohibition on undue regional price discrimination. The withdrawal of the Six Large Energy Firms from doorstep selling in 2011 and 2012 may have also contributed to this pattern.

Competition in the devolved nations and regional competition

120. 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.
121. 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.
122. 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 share of supply of over 50% are North Scotland and South Wales. Further, we calculated average dual fuel bills for customers on typical consumption, controlling for network costs and the costs associated with different payment methods, and found that average bills were higher in these two regions than in any other GB region.
123. These results are consistent with higher degrees of incumbent brand loyalty in Scotland and Wales. Overall, our view is that retail customers 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. However, we have identified two specific constraints relating to certain meter types that are likely to affect customers in Scotland and Wales to a greater extent than customers in the rest of Great Britain: restricted meters, which are particularly prevalent in North and South Scotland; and prepayment meters, which are used by a higher proportion of customers in Wales and Scotland compared to England.

Domestic retail AECs

124. We have investigated four broad areas in which we had concerns that domestic retail markets may not be working well for customers:
- (a) weak customer response and lack of engagement with domestic retail energy markets;
 - (b) price discrimination and tacit coordination on the part of suppliers;
 - (c) supply-side barriers to entry and expansion in the prepayment segments; and
 - (d) the regulatory framework governing domestic retail market competition, notably the RMR reforms and the settlement systems for gas and electricity.

Weak customer response and lack of engagement

125. Our domestic 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

126. We estimate that there were significant gains from switching that went un-exploited by domestic energy customers over the period Q1 2012 to Q2 2015. 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.
127. 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) (scenario 5x).⁷

Table 1: Average savings under scenario 5x for domestic customers of the Six Large Energy Firms on different tariffs and payment methods, Q1 2012 to Q2 2015

<i>Dual or single fuel</i>	<i>Tariff type</i>	<i>Payment type</i>	<i>Average savings (£)</i>	<i>Average savings (%)</i>
Dual	Non-standard	All	109	9
Dual	SVT	Direct debit	205	16
Dual	SVT	Standard credit	245	23
Dual	SVT	Prepayment	70	8
Single gas	Non-standard	All	96	14
Single gas	SVT	Direct debit	132	19
Single gas	SVT	Standard credit	142	24
Single gas	SVT	Prepayment	48	13
Single electricity	Non-standard	All	55	9
Single electricity	SVT	Direct debit	95	15
Single electricity	SVT	Standard credit	118	23
Single electricity	SVT	Prepayment	45	8

Source: CMA analysis. Scenario 5x.
Note: SVT = standard variable tariff.

128. Overall, we calculated that the average gains to all the dual fuel customers of the Six Large Energy Firms over the entire period was £164 under this scenario. The gains available to customers differ quite substantially according to the scenario chosen and category of customer concerned (and in particular, the supplier they are with, the type of tariff they are on and the payment method they employ). Overall, the results demonstrate that:
- (a) there were material, persistent savings available to customers of the Six Large Energy Firms over the period;
 - (b) the savings available to customers on standard variable tariffs were, on average, larger than the savings available to non-standard tariff customers; and
 - (c) the savings available to standard credit customers were, on average, higher than those available to customers on other payment methods.
129. We also note that the savings available to customers on prepayment meters were, on average, substantially lower than those available to other customers, reflecting the more restricted range of tariffs available to them. This is discussed further below.

⁷ In this scenario, customers are able to switch supplier, tariff, payment method (except for prepayment customers, reflecting the greater barriers they face in using other payment methods), and gains are reduced to reflect the exit fees a customer may incur in moving from a non-standard tariff. Appendix 9.2 presents the results of a broad range of scenarios, which differ according to the parameters of choice available to the customer.

130. We have also assessed how the potential savings to customers have evolved over time. The annual potential savings from switching available to the dual fuel standard variable tariff customers (excluding those on prepayment meters) of each of the Six Large Energy Firms have risen substantially over the past two years, and have reached their highest level in the most recent period of the analysis, Q2 2015, reaching an equivalent of around £330. There is a similar trend for the standard variable tariff customers of the Mid-tier Suppliers, although there is a bigger disparity in the positions of individual suppliers.
131. We note that in February 2016, the Six Large Energy Firms announced a reduction in the price of their standard variable gas tariffs, ranging from 5 to 5.4%, to come into effect from February to March 2016.⁸ However, we do not believe this will materially change the pattern of results seen in our gains from switching analysis. Indeed, gains may even have increased further, since we would expect the acquisition tariffs to follow more closely the reduction in wholesale gas and electricity prices, which comprise roughly 50% of the total costs incurred in supplying gas and electricity and have fallen around 31% and 15% since Q2 2015, respectively.
132. Parties made a variety of comments on our analysis, including that we have omitted factors that are relevant to customer decision-making and hence overstated the gains to be made from switching supplier. We have not seen evidence that we have overstated the gains from switching in our analysis. In particular:
- (a) we have not identified characteristics of a standard variable tariff 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.
133. 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 available to customers from switching suppliers and tariffs alone, keeping the payment method fixed. The main difference is

⁸ EDF Energy announced a price cut of 5%; British Gas announced a price cut of 5.1%; E.ON announced a price cut of 5.1%; RWE npower announced a price cut of 5.2%; SSE announced a price cut of 5.3% and Scottish Power announced a price cut of 5.4%.

that savings for dual fuel customers of the Six Large Energy Firms on standard variable tariffs who pay by standard credit are lower – equivalent to 15% of the bill (as opposed to 23% for those prepared to switch to direct debit) over the period.

134. 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

135. 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 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.
136. 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.
137. 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.

138. The fact that this is not the case – indeed, there is 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.
139. We have also reviewed the available evidence on the extent to which customer disengagement applies to customers on prepayment meters. The evidence suggests that a higher proportion of prepayment customers are less engaged than direct debit customers (but not less engaged than standard credit customers), particularly in terms of whether they have ever considered switching or are likely to consider switching in the next three years, and their awareness of their ability to switch.
140. There are a number of factors that may explain this, including that prepayment customers include higher proportions of individuals with a range of demographic characteristics that we have found to be associated with low levels of engagement in the domestic retail energy markets, and notably: low levels of income; low levels of education; living in social rented housing; and having a disability. In addition, we have identified that prepayment customers face higher barriers to accessing and assessing information and additional actual and perceived barriers to switching. While the need to top up prepayment cards regularly is likely to increase awareness of domestic retail energy markets among prepayment customers, low levels of engagement may have in part been influenced by the lower gains from switching available to prepayment customers.
141. The overall weight of evidence supports a finding that disengagement and weak customer response is a more significant problem among prepayment customers compared with domestic customers on direct debit.

Barriers to engagement

142. We have identified a number of barriers to engagement that customers face in domestic retail energy markets. We have found that meter type can have a significant influence on such barriers and have distinguished in our analysis, between domestic customers on ‘conventional meters’,⁹ customers on prepayment meters and those on certain types of restricted meter.

⁹ By ‘conventional meters’, we mean single rate (as opposed to time-of-use) and credit (as opposed to prepayment) meters.

Customers on conventional meters

143. 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 customers' 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.
144. 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.
145. 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.
146. 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 customers. 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.

Customers on prepayment meters

147. We have identified additional aspects of the prepayment segments that strengthen the barriers to engagement faced by customers on prepayment meters, which support our finding that disengagement and weak customer response is a more significant problem among prepayment customers

compared with domestic customers on direct debit. We have found that prepayment customers face:

- (a) higher actual and perceived barriers to accessing and assessing information about switching arising, in particular, from relatively low access to the internet and confidence in using PCWs;
- (b) higher actual and perceived barriers to switching arising, in particular, from:
 - (i) the need to change meter to switch to a wider range of tariffs (and the obstacles associated with this requirement such as perceptions of complexity of the meter replacement process); and
 - (ii) restrictions arising from the Debt Assignment Protocol hindering indebted prepayment customers' ability to switch supplier.

Customers on restricted meters

- 148. Restricted meters include any metering arrangement whereby a domestic customer's consumption at certain times and, in some cases, for certain purposes (for example, heating) is separately recorded. These meters allow for customers to be charged lower rates for electricity used at times when overall demand is lower.
- 149. There are currently over 4 million restricted meters (around 17% of all customer accounts) of which around 700,000 (about 2% of all customer accounts) are non-Economy 7 restricted meters.¹⁰ Our analysis has focused on the position of non-Economy 7 restricted meters, about which we have heard specific concerns (and henceforth refer to this group as 'customers on restricted meters' unless otherwise specified).
- 150. Our analysis shows that there are aspects of the restricted meter segment that strengthen the features that customers face actual and perceived barriers to accessing and assessing information, and that customers face actual and perceived barriers to switching supplier and/or tariff for restricted meter customers.
- 151. We have found that customers on restricted meters face higher actual and perceived barriers to accessing and assessing information arising, in particular, from a general lack of price transparency concerning the tariffs that are available to them, which results from restricted meter tariffs not

¹⁰ Economy 7 customers are included in our assessment of gains from switching discussed above.

being supported by PCWs or suppliers' online search tools. We have also found that customers on restricted meters face higher barriers to switching supplier and/or tariff. We have been told that many restricted meter customers do not have a choice of supplier offering bespoke tariffs. They can in principle switch to a single-rate or an Economy 7 tariff offered by their supplier or rival suppliers, but some suppliers would require their existing meter to be replaced at a cost to the customer and loss of functionality. Changing meters might also involve some rewiring in the home.

152. All this means that, for customers on restricted meters, understanding the options available to them and switching supplier is substantially more difficult than it is for customers on other meter types. Reflecting this, we have found that, across Great Britain the historical incumbent supplier's share of supply in restricted meters is 79% which is significantly higher than the equivalent figure for all electricity (33%) and gas (37%) customers.
153. Despite the cost advantages to suppliers of serving customers on restricted meters, we have found that, for Q2 2015, 67% of standard credit and direct debit customers on restricted meters would have had lower bills if they were on the cheapest single-rate tariffs available on the market and that those who could have saved would have saved an amount equivalent to around 17% of their bill (equivalent to around £154 a year). This is an increase on Q2 2014 where 50% of standard credit and direct debit customers on restricted meters would have had lower bills and these customers could have saved an amount equivalent to around 14% of their bill (equivalent to around £120 a year). We note that the results differ significantly depending on the supplier in question – for two of the Six Large Energy Firms, over 85% of their standard credit and direct debit customers, at Q2 2015, would have been better off on the cheapest single-rate tariff.

AEC finding on weak customer response

154. **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 (the Domestic Weak Customer Response AEC).

Price discrimination and tacit coordination

155. 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 standard variable tariffs 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 markets through public price announcements.

Unilateral market power

- 156. 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. 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.
- 157. 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 view is that there is no evidence that energy costs are inherently or systematically higher for standard variable tariffs as compared with fixed-term, fixed-rate tariffs.
- 158. Our 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 standard variable tariffs materially above a level that can be justified by cost differences from their non-standard tariffs.
- 159. 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 a standard variable tariff 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.

160. Overall, our 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 standard variable tariffs 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. 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.

Tacit coordination

161. Our 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 standard variable tariff 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.

Supply-side barriers to entry and expansion in the prepayment segments

162. We have identified particular supply-side constraints affecting supply to customers on 'dumb' (ie non-smart) prepayment meters and which limit the extent of competition in the prepayment segments. These constraints, arising from the dumb prepayment infrastructure, take the form of limitations on the number of tariffs that suppliers can offer due to the limited number of gas and electricity tariff 'slots'. We have found these constraints to be particularly binding for new entrants in gas on account of the low availability of gas tariff slots – over 80% of which are currently held by the Six Large Energy Firms, including a large proportion that they are not using.
163. We have also found softened incentives for all suppliers, and in particular new entrants, to compete to acquire all prepayment customers, whether on smart or dumb prepayment meters. This is due to actual and perceived higher costs to engage with, and acquire, these customers compared with

other customers, and the low prospect of successfully completing the switch of indebted customers (who represent up to 10% of prepayment customers).

164. Our analysis of the prepayment segments suggests that competition is significantly weaker than in the wider GB domestic retail energy markets. We find that the range of tariffs available to prepayment customers is significantly more limited than those available in the credit meter segments, and that the cheapest tariffs that are offered by suppliers to prepayment customers are significantly higher (even accounting for differentials in the costs to serve) than the cheapest tariffs in the direct debit segments.
165. We observe that the gains from switching available to dual fuel customers on prepayment meters have been fairly static, with gains available as of Q2 2015 of between £70 and £120, depending on the customer's supplier. This is in contrast with a sharp increase in the gains available to prepayment customers if they were to switch to a credit meter, which roughly doubled between 2013 and 2015, reaching between £290 and £370 as of Q2 2015, depending on the supplier.
166. We also conducted a search on a PCW in order to look at the most recent pricing data. We found that, as of 28 April 2016, there were large differences between the cheapest prepayment and direct debit tariffs, between £260 and £320, depending on the region. This is well in excess of our estimate of the cost differential between the two payment methods of £63.
167. Overall, **our view is that a combination of features concerning energy supply specifically to the prepayment segments gives rise to an AEC through reducing suppliers' ability and/or incentives to compete to acquire prepayment meter customers and to innovate by offering tariff structures that meet customers' demand** (the Prepayment AEC). These features are certain technical constraints limiting the number of tariffs that suppliers can offer to customers on dumb prepayment meters and softened incentives for all suppliers, and in particular new entrants, to compete to acquire all prepayment customers, whether on smart or dumb prepayment meters arising from actual and perceived higher costs to engage with, and acquire, such customers and a lower prospect of successfully completing the switch of indebted customers.

Regulations

168. 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

169. Ofgem launched the RMR in late 2010 due to concerns that retail energy markets were not working effectively for customers. The stated purpose of RMR was to promote customer engagement in energy markets in order to improve the competitive constraint provided by customer switching.
170. We have analysed the impact on competition of the 'simpler choices' component of the domestic 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.
171. 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 customers in a way that may have distorted competition and reduced customer welfare.
172. The evidence we have on the impact of the RMR rules is not particularly encouraging. There are few, if any, signs that customer engagement is improving materially, either in terms of direct customer 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.
173. 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 the RMR rules; and the RMR rules curtailed the ability of the Six Large Energy Firms to offer attractive tariffs for low volume users.
174. We consider that the RMR four-tariff rule limits the ability of suppliers to compete and 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.
175. We also consider that the RMR rules, more generally, dampen price competition by limiting the ability and incentives of suppliers to respond to

competition by offering cheaper tariffs or discounts (which means that they, in turn, put less competitive pressure on their rivals).

176. A further area where the impact of the RMR rules appears to be harmful to price competition is in relation to PCWs. The RMR rules stop PCWs from negotiating cheaper exclusive tariffs with retail energy suppliers (possibly in exchange for lower commission rates), or offering discounts or cashback offers funded by the commissions they receive from suppliers. The RMR rules therefore limit the pressure competition between PCWs to attract customers could put on energy prices.
177. Overall, **our finding is that certain aspects of 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) are 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 compete and innovate in designing tariff structures to meet customer demand, in particular, over the long term, and by softening competition between PCWs.

Gas and electricity settlement

178. Energy suppliers generally attempt to purchase in advance the electricity and gas that they expect their customers to consume, to help them manage price and volume risks. But both gas and electricity demand are driven by a range of factors that are difficult to predict accurately, such that there will always be some disparity between the volumes of energy covered by suppliers’ contracts and the volumes their customers actually use in real time. Settlement is the system by which such disparities are identified, reconciled and paid for.
179. Accurate and timely settlement is fundamental to well-functioning retail energy markets, since without this, suppliers will not have the right incentives to minimise the overall costs of energy – which are ultimately borne by customers. 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

180. 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.

181. 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).
182. 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 2016) 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.
183. Overall, **we have found that 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.

Electricity settlement

184. 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.
185. 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. Further, Standard Licence Condition 47 currently prohibits suppliers from collecting consumption data with greater than daily granularity unless a customer has given explicit consent to do so. We believe that this opt-in clause is a major barrier to the development of static and dynamic time-of-use tariffs.

186. 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. 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.
187. Therefore, **we have found that the absence of a firm plan for moving to half-hourly settlement for domestic electricity customers is a feature of the market 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.

Assessment of detriment arising from the domestic retail AECs

188. To assist us in deciding on appropriate remedies, we have assessed the nature and extent of detrimental effects on domestic energy customers resulting from the AECs that we have identified in the retail energy markets, and in particular, the Domestic Weak Customer Response AEC and Prepayment AEC.
189. Our approach to assessing the scale of detriment is to consider to what extent the outcomes that we have observed in the retail energy markets are worse than we would expect to see in well-functioning competitive markets, including the extent to which domestic energy customers are, on average, paying higher prices than they would do in well-functioning competitive markets and receiving poorer quality of service. Most of our analysis has focused on the first source of detriment – excessive prices – since we believe that this is likely to be the most significant form of detriment suffered by energy customers, given the homogenous nature of gas and electricity.

190. We have adopted two approaches to assessing the extent to which prices have exceeded those we would expect in a well-functioning market:
- (a) a 'direct' approach, which involves comparing the average prices charged by different suppliers, while controlling for those differences in each supplier's customer base that are likely to affect costs; and
 - (b) an indirect approach, which involves assessing both:
 - (i) suppliers' levels of profitability (and in particular whether the Return on Capital Employed by suppliers exceeds their cost of capital); and
 - (ii) the extent to which suppliers have incurred costs inefficiently (ie whether costs are higher than we estimate an efficient supplier would incur).
191. The benefit of the direct approach is that it gives us a more direct measure of customer detriment based on actual market prices – and prices are ultimately what matter to a customer, rather than a supplier's level of profitability or cost efficiency. Further, the direct approach allows for a much more granular breakdown of detriment, not just by supplier but by customer type, including type of tariff and payment method.
192. The indirect approach provides information on profitability and cost efficiency which can be a useful proxy for customer detriment. It can therefore provide a useful independent cross-check on our direct analysis, as it is based on a separate data set and methodology.

Direct approach

193. Our direct approach to assessing detriment involves calculating the average prices offered by the Six Large Energy Firms to their customers and comparing these to a 'competitive benchmark price', which is based on the average prices offered by the most competitive suppliers. In establishing the competitive benchmark price, and then making this comparison, we made certain adjustments to observed prices to ensure the comparison is on a broad like-for-like basis. These included adjustments for exogenous cost differences relating to network costs and the costs associated with different payment methods, adjustments to reflect the fact that the suppliers in our benchmark are growing rapidly, and hence incurring higher acquisition and indirect costs but lower obligation costs than they would in steady state, and adjustments to achieve a benchmark level of profitability.
194. Using this approach, we estimated the detriment from excessive prices to the domestic customers of the Six Large Energy Firms to be about £1.4

billion a year on average over 2012 to 2015, the entire period for which we had data, with an upwards trend, reaching almost £2 billion in 2015. We consider this our headline estimate of the annual detriment arising from high domestic retail market prices.

195. We have also considered the extent to which the scale of excessive pricing by the Six Large Energy Firms varies between different payment methods. This is shown in the table below.

Table 2: Comparison of dual, single fuel electricity and gas bills by supplier and payment method, calculated at Ofgem 2014 Medium TDCV

<i>Dual or single fuel</i>	<i>Direct debit (% of bill)</i>	<i>Standard credit (% of bill)</i>	<i>Prepayment (% of bill)</i>	<i>All (% of bill)</i>
Dual fuel	8%	7%	12%	9%
Single fuel electricity	6%	5%	11%	7%
Single fuel gas	16%	13%	13%	14%

Source: CMA analysis. Analysis based on Ofgem's medium Typical Domestic Consumption Values. Bills are calculated net of network costs and adjusted for the costs of different payment methods.

196. For dual fuel customers (the majority of all the customers of the Six Large Energy Firms) and single fuel electricity customers (31% of their electricity customers), we found that the detriment across all of the Six Large Energy Firms is significantly higher for prepayment customers. This does not hold for single fuel gas (19% of their gas customers), although we note that our benchmark for single fuel gas is based on far fewer accounts than the benchmark for dual fuel and single fuel electricity.
197. We also note that there is considerable variation (both within the Six Large Energy Firms and the Mid-tier Suppliers) in the extent to which individual suppliers price above the competitive level. For the Six Large Energy Firms, for example, average detriment experienced by their dual fuel customers over the period ranges from between 2% and 11% of the bill depending on the supplier.
198. We have estimated the detriment suffered by customers on restricted meters using a higher-level approach, and based on snapshots as of Q2 2015 and end Q2 2014. For Q2 2015 the bills of around 68% of customers on restricted meters were higher than they would have been using the competitive single-rate tariff. On average the difference was around £158 per customer or 17% of their average annual bill, a detriment in the order of £42 million a year, an increase on the detriment we estimated for Q2 2014 (£28 million a year).

Indirect approach

199. We have also estimated customer detriment from excessive prices indirectly from the financial results of the Six Large Energy Firms, which involved assessing both suppliers' profitability and the extent to which suppliers have incurred costs inefficiently.
200. The analysis using the indirect approach yields a total estimate of customer detriment from excessive prices of £720 million a year over the period 2007 to 2014, in our base case. One explanation for why the indirect approach gives a lower estimate of detriment than the direct approach is that we have taken a conservative approach to identifying the level of profits above the industry cost of capital made and the efficient indirect cost base of the Six Large Energy Firms.
201. In addition, the indirect approach covers a longer time span which includes two years when several of the Six Large Energy Firms made losses. In the last three years of the relevant period, ie between 2012 and 2014, which corresponds more closely to the period over which we have estimated detriment using the direct approach, the central indirect estimate of detriment is around £1.1 billion (of which excess profits earned on domestic customers are around £650 million per year). If we were to use a more stringent efficiency benchmark, the indirect measure of detriment increases to £1.5 billion over the period.
202. Overall, we place greater weight on the direct approach, as it is a more relevant and granular measure of domestic customer detriment, although some aspects of our analysis using the indirect approach are important components of our analysis using the direct approach. We note also that detriment calculated under the direct approach is similar to the net profits earned by the Six Large Energy Firms from their sales to domestic customers from 2012 to 2014, but significantly higher than our estimate of excess profits from domestic sales over this period. The implication is that there is a material degree of inefficiency in current prices.

Quality of service and innovation

203. In relation to quality of service, we observed that there are several metrics which suggest that energy customers receive a poorer quality of service from the Six Large Energy Firms than they would do in well-functioning competitive markets. Those include the data which shows that the smaller suppliers have achieved consistently higher net promoter scores than the Six Large Energy Firms, and that there has been a marked increase in recorded customer complaints between 2008 and 2015 which resulted in a

number of enforcement actions brought by Ofgem against the Six Large Energy Firms.

204. We have also found that some regulatory interventions, in particular the recent RMR rules, have served to reduce innovation in recent years, and that the absence of an accurate settlement system has inhibited the development of time-of-use tariffs which could bring substantial benefits in terms of reduced costs.

Summary

205. Overall, we consider there to be a material customer detriment arising from the AECs that we have identified in retail energy markets. We have estimated that the customer detriment associated with high prices was about £1.4 billion a year on average for the period 2012 to 2015 with an upwards trend. We also found evidence which is indicative of harm to customers from poor quality of service and restrictions on innovation, but by its nature this type of harm is less readily quantifiable.

Domestic retail remedies

206. We have drawn on the above analysis in developing our remedies and in assessing the proportionality and effectiveness of the package of remedies as a whole. At a high level, our package of remedies for domestic customers comprises three strategic components:
- (a) creating a framework for effective competition;
 - (b) helping customers to engage to exploit the benefits of competition; and
 - (c) protecting customers who are less able to engage to exploit the benefits of competition.
207. The different elements of the package are mutually reinforcing: energy markets in which suppliers operate free of inefficient restrictions can help drive down prices for customers, but only if customers are sufficiently engaged to make informed decisions about the choices available to them. Given the level of detriment we have observed for prepayment customers, we have also decided to introduce a price cap for these customers during an interim period while our remedies take full effect. While this creates potential tensions with the aims of promoting competition and engagement, we have designed the cap in such a way as to allow competition to coexist with it.

The impact of smart meters on competition and engagement

208. The roll-out of smart meters to domestic customers is due to be substantially completed by the end of 2020. In designing our remedies we have been mindful of the fact that smart meters are likely to have a positive impact in helping to address some of the supply- and demand-side problems we have identified in the domestic retail energy markets.
209. The introduction of smart meters will address the technical constraints arising from the dumb prepayment infrastructure. Notably, the problems arising from tariff slots, and their allocation between suppliers, will cease to exist. We also consider that the introduction of fully functional (SMETS 2) smart meters should address, at least in part, suppliers' reduced incentives to compete to acquire prepayment customers, and also the specific barriers to engagement experienced by customers on restricted meters. In relation to customer engagement more generally, we consider it likely that smart meters will help improve customer engagement by making the relationship between prices and consumption more visible and improving the accuracy of bills, although the extent of this effect is uncertain.
210. In view of the benefits of smart meters for competition and engagement, and more specifically for helping to address some of the features we have identified, we believe it is vitally important that the prescribed timetable for their roll-out is adhered to. Ofgem has the power to impose penalties on suppliers in the event that the prescribed timetables are not met and we would expect it to use these tools effectively to ensure that suppliers comply with their obligation to take all reasonable steps to substantially complete the roll-out by 2020. We have also designed our remedies to mitigate the adverse effects of any delay to the roll-out programme.

Creating a framework for effective competition

211. If competition in retail energy markets is to serve customers' interests, it is vital that the regulatory and technical framework allows suppliers to compete effectively. Provided customers are sufficiently engaged, this will help drive down prices and improve quality of service.
212. We have identified a number of aspects of the regulatory framework that we believe undermine effective and efficient competition and are introducing three categories of remedy that we believe will help improve this framework:
- (a) the withdrawal of certain aspects of the simpler choices component of the RMR rules;
 - (b) reform of the settlement systems for gas and electricity; and

- (c) measures to address the technical and regulatory constraints impeding competition for prepayment meter customers.

Withdrawal of certain aspects of the simpler choices component of the RMR rules

213. We believe that certain aspects of the ‘simpler choices component’ of the RMR rules have reduced the ability and incentives of suppliers to compete and innovate in designing tariff structures to meet customer demand. We also consider that certain aspects of the simpler choices component of RMR rules (in particular the four-tariff rule) limit the scope for competition between PCWs for customers switching energy suppliers to exert downward pressure on energy prices. We have therefore decided on a remedy, the aim of which is to:
- (a) promote competition and innovation between retail energy suppliers in the retention and acquisition of domestic customers by allowing them to offer a wider range of tariffs, including tariffs designed to benefit certain customer groups; and
 - (b) facilitate competition between PCWs by allowing them to negotiate exclusive tariffs with domestic energy suppliers and to offer discounts funded by the commissions they receive from suppliers.
214. Our remedy takes the form of a recommendation to Ofgem to remove a number of standard licence conditions relating to the simpler choices component of the RMR rules. These include: the ban on complex tariff structures; the four-tariff rule; the restrictions on the offer of discounts; and the restrictions on the offer of bundled products.

Electricity settlement reform

215. Our main concern in relation to electricity settlement is that the current system of profiling fails to charge suppliers for the true cost of their customers’ consumption, which in turn distorts 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. Further, Standard Licence Condition 47 currently prohibits suppliers from collecting consumption data with greater than daily granularity unless a customer has given explicit consent to do so, which is a major barrier to the development of static and dynamic time-of-use tariffs.
216. We have been encouraged to note that, since the publication of our provisional findings report, progress has been made by both DECC and Ofgem towards developing a concrete plan for the introduction of half-hourly

settlement. Our remedies package builds on this momentum, comprising recommendations: to DECC to consider removing any potential barrier for suppliers to collect consumption data with greater granularity than daily in the context of the review of the Data Access and Privacy frameworks; to Ofgem that it conduct a full cost-benefit analysis of the move to mandatory half-hourly settlement and consider options for reducing the costs of elective half-hourly settlement; and to DECC and Ofgem that they publish and consult jointly on a plan setting out timescales and responsibilities relating to the introduction of half-hourly settlement.

Gas settlement reform

217. Our concern in relation to the current system of gas settlement is that it leads to an inefficient allocation of costs to parties and creates scope for gaming, which reduces the efficiency and, therefore, the competitiveness of domestic retail gas supply. Since publication of our provisional decision on remedies, we have heard that Project Nexus, which would address most of our concerns, may be delayed. We are concerned that the delivery of Project Nexus may be delayed yet again, as this means that the clear deficiencies in the gas settlement system will persist beyond October 2016.
218. Our remedies in relation to gas settlement comprise: a recommendation to Ofgem to ensure implementation of Project Nexus by 1 February 2017 (or as soon as possible after that date, once Ofgem is satisfied that IT systems are ready for effective implementation and do not pose risks to customers); an order on gas suppliers to submit all meter readings for non-daily metered supply points in Great Britain to Xoserve as soon as they become available and at least once a year, except for smart meters where meter readings must be submitted monthly; and a recommendation to Ofgem to take the appropriate steps to ensure that a performance assurance framework concerning unidentified gas is established within a year of our final report .

Remedies to address constraints on competition for prepayment customers

219. In relation to the constraints imposed by the dumb prepayment infrastructure, we have decided upon a range of remedies that will make better use of the available tariff slots, so as to reduce the impact of the dumb prepayment meter technical constraints on the ability of suppliers, and in particular new entrants, to innovate by offering tariff structures that meet demand from prepayment meter customers who do not have a smart meter.
220. The remedies include recommendations to Ofgem that it: take responsibility for the efficient allocation of gas tariff pages; and change gas suppliers' standard licence conditions to impose a cap on the number of gas tariff

pages that any supplier can hold and to enable Ofgem to mandate the transfer of gas tariff codes to another supplier.

221. To further mitigate the impact of tariff codes on competition for customers on dumb prepayment meters, we are recommending that Ofgem change Standard Licence Condition 22B.7(b) to allow suppliers to set prices to prepayment customers on the basis of grouping regional cost variations and deprioritise potential enforcement action against suppliers in relation to this licence condition pending the change. This will allow suppliers to make better use of their limited tariff codes.
222. We are also introducing a remedy to enhance prepayment customers' ability and incentives to engage in the markets and to switch to other suppliers (including by switching to standard meters). This takes the form of a recommendation to Ofgem to take appropriate steps to ensure that changes to the Debt Assignment Protocol (currently being developed by Ofgem and the industry) are implemented by the end of 2016, and in particular in areas relating to objection letters, complex debt and issues relating to multiple registrations.

Helping customers engage to exploit the benefits of competition

223. Engaged customers are an essential component of well-functioning energy markets. If customers are not fully aware of the options available to them, unable to make an informed choice about the relative merits of those options or, having made a choice, are unable to switch, then competitive pressures on suppliers to reduce prices and improve quality of service will be substantially reduced.
224. We have developed a wide range of remedies that attempt to improve domestic customer engagement by addressing aspects of the features contributing to the Domestic Weak Customer Response AEC. Our remedies package consists of five broad categories of remedy, which focus on the role of different participants in the retail markets – namely, Ofgem, the customer's own supplier, third party intermediaries (TPIs), and rival suppliers – in strengthening domestic customer engagement. In particular, the remedies provide for:
- (a) the establishment by Ofgem of a programme to provide customers – directly or through their own suppliers – with information to prompt them to engage;

- (b) creating an Ofgem-controlled database of ‘disengaged customers’ on default tariffs, to allow rival suppliers to prompt these customers to engage in the retail energy markets (the Database remedy);
 - (c) enhancing the ability and incentives of TPIs to promote customer engagement in the retail energy markets;
 - (d) Ofgem making greater use of principles rather than prescriptive rules in addressing potential adverse supplier behaviour concerning the comparability of their tariffs; and
 - (e) requiring all suppliers to make all their single-rate tariffs available to domestic customers on any type of restricted meter, without making switching conditional on a restricted meter being replaced and to provide additional information to customers on restricted meters.
225. The different market participants identified above differ substantially in terms of the incentives they have to engage customers and their ability to do so and our range of remedies reflects this.

Regulatory interventions to improve engagement

226. We consider that customers’ current suppliers have the ability to engage their customers – through the regular communications they send to them – but are likely to face limited incentives to do so in a way that encourages customers to engage in the markets. Indeed, since those customers that have not engaged in the markets recently are both less likely to switch and generally on higher tariffs than those who have recently engaged, their suppliers are likely to face a financial incentive to keep them as disengaged as possible.
227. In these circumstances, we recognise that there is an argument for Ofgem to intervene directly to facilitate customer engagement, through influencing the form, content and frequency of communication between suppliers and customers. Ofgem has also recognised the importance of clear information in facilitating customer engagement and introduced the ‘clearer information’ component of the RMR rules in an attempt to ensure that suppliers’ routine communications to customers were clear, easy to understand and personalised to them.
228. However, our concern with these provisions is that they were not subject to adequate testing prior to (or after) their introduction. Without adequate testing it is not possible to know which approach will work best in practice. Further, even if testing is conducted ex ante, changes in technology and cultural practices are likely to mean that what works changes over time.

Ofgem-led programme

229. Our remedies therefore call for a more evidence-based approach to developing such interventions in the future, through the use of rigorous testing and trialling, where appropriate through Randomised Controlled Trials, with a recommendation to focus such trials on a priority list of measures. If such trials are to provide relevant information that can provide a robust basis for regulatory changes, it is essential that suppliers be required to participate, where the trial design requires it, and our remedies therefore seek to ensure such participation.
230. In particular, the remedies comprise recommendations to Ofgem to: establish an ongoing programme of identifying, testing and implementing measures to promote engagement in the domestic retail energy markets; and introduce a licence condition requiring suppliers to participate in the programme.

Harnessing the incentives of rival suppliers and TPIs to engage customers

231. Where market participants have an active incentive to engage customers – this category includes rival suppliers and TPIs – the remedies serve to enhance these parties’ ability to engage domestic customers, while seeking to ensure that customers are fully able to understand and choose between the range of options available to them. The remedies seek to achieve this through:
- (a) creating an Ofgem-controlled database of ‘disengaged customers’ who have been on the default tariff for three years or more, to allow rival suppliers to prompt them to engage in the retail energy markets;
 - (b) enhancing PCWs’ ability to improve engagement by:
 - (i) lifting regulatory restrictions that dull PCWs’ incentives to compete to engage customers (amending provisions of the PCW confidence code that undermine incentives for them to be active in the retail energy markets); and
 - (ii) giving PCWs (and other TPIs offering similar services) access to the ECOES and SCOGES databases¹¹ and bolstering the Midata

¹¹ The Electricity Central Online Enquiry Service (ECOES) database includes certain data to assist electricity suppliers in the transfer of customers, while the Single Centralised On-Line Gas Enquiry Service (SCOGES) database comprises similar data for gas.

programme to allow TPIs to make more effective use of customer data; and

- (c) the use of principles rather than prescriptive rules to ensure that customers are able to compare tariffs easily.

Ofgem-controlled database of 'disengaged customers'

232. Around 70% of the customers of the Six Large Energy Firms are on the standard variable default tariff and up to 55%¹² of these customers have been on the standard variable tariff with the same supplier for more than three years, up to 10 million customers.
233. In order to enable suppliers to prompt the domestic customers of rival suppliers on default tariffs, our remedy requires energy suppliers to disclose certain details of their domestic customers (on any meter type) who have been on their standard variable tariff (or any other default tariff) for three or more years (the 'Disengaged Domestic Customers') to Ofgem, and comprises a recommendation that Ofgem retains, uses, and discloses this data (via a centrally managed database) to rival suppliers. The Disengaged Domestic Customers would have the option to opt out of the disclosure process at any point in time.¹³
234. We consider that an Ofgem-controlled database of the most disengaged customers will be a highly valuable tool for harnessing the incentives of rival suppliers to prompt disengaged customers to engage in the retail energy markets. Ofgem will also be able to use the tool to engage directly with disengaged customers and in monitoring the impact of the remedies on engagement.
235. We recognise that there is a trade-off between the benefits of liberalising channels of engagement and the need to protect consumers from excessive and/or misleading marketing. Customers will have the right to opt out beforehand to avoid receiving communications by post, and will only be contacted electronically if they explicitly opt in to such communications. Operation of the database will have to comply with Data Protection Requirements and Ofgem will be required to put strict safeguards in place to protect against the misuse of data. Ofgem will also be responsible for

¹² We note that this is an upper bound estimate as for three suppliers the data provided was based on the length of the relationship with the supplier rather than the length of time on that supplier's SVT.

¹³ In the design of this remedy, we have drawn on discussions with the Information Commissioner's Office concerning the implications of the Data Protection Act 1998 and the Privacy and Electronic Communications Regulations 2003.

ongoing monitoring of the impact of the database with a view to maximising its effectiveness.

Enhancing the ability and incentives of third party intermediaries to promote customer engagement

236. We consider that TPIs such as PCWs are an important means by which effective competition can develop in the domestic retail markets. PCWs have a strong commercial incentive to engage with domestic customers and provide access to their services both online and by telephone. PCWs are also well-placed to: raise awareness among customers of their ability to switch and the potential benefits from doing so; reduce search costs for customers; and exert competitive pressure on energy suppliers by enhancing price transparency and facilitating the purchasing process for customers.
237. Our aim in our remedies relating to TPIs in the domestic retail markets is to help ensure that this potential for PCWs to promote competition to the benefit of customers can be realised by removing regulatory burdens that inhibit this role.
238. To strengthen PCWs' role (and the role of other TPIs offering similar services) in facilitating switching our remedies take the form of: orders on the code administrator or governing body with authority to grant access to the ECOES database and gas transporters to give PCWs (and other TPIs providing similar services) access upon request to the ECOES and SCOGES databases respectively on reasonable terms and subject to satisfaction of reasonable access conditions.
239. To strengthen PCWs' incentives to engage customers, we are proposing to recommend to Ofgem that it removes the Whole of the Market Requirement in the Confidence Code and introduces a requirement for PCWs accredited under the Confidence Code to be transparent over the market coverage they provide to energy customers. Further, we are proposing to recommend to DECC several changes to the Midata programme that (subject to customer consent) would give PCWs and TPIs increased access to more customer data and, in so doing, enable them to monitor the market on behalf of their customers and advise them of savings.
240. We are aware of the concerns around trust that led to the Confidence Code requirement that PCWs list all tariffs on the market rather than just those for which they earn a commission. We believe that such concerns around trust can be addressed – without undermining TPIs' incentives to engage customers – in two ways. First, there should be greater clarity around the

role of PCWs – effectively acting as brokers offering their customers good deals and facilitating switches rather than repositories of all available tariffs – and our remedies require greater transparency from PCWs about market coverage. Second, Citizens Advice is now operating a non-transactional PCW that lists all tariffs through a web-based service, which we believe will meet the needs of those customers who wish to see the whole of the market.

Use of principles rather than rules to avoid customer confusion

241. Our remedies also place a greater emphasis on the use of principles rather than detailed rules in seeking to address potential adverse supplier behaviour, reflecting our concern that prescriptive rules can never be fully exhaustive and risk encouraging gaming behaviour on the part of suppliers. In particular, we are recommending that Ofgem introduce an additional ‘standard of conduct’ into Standard Licence Condition 25C that would require suppliers to have regard in the design of their tariffs to the ease with which customers can compare ‘value for money’ with other tariffs they offer.

Remedies for customers on restricted meters

242. We believe that the above remedies will help customers on any meter type engage effectively in retail energy markets. Further, to address the specific problems faced by customers on restricted meters in shopping around for better deals and in switching, we have decided on a set of additional remedies that: require all suppliers to make all their single-rate tariffs available to any domestic customer on any type of restricted meter, without making switching conditional on a restricted meter being replaced; and ensure that domestic customers on restricted meters have access to information on the options available to them.

Transitional price cap for prepayment customers

243. We believe that competitive retail energy markets, in which energy suppliers operate free of inefficient technical and regulatory restrictions, and customers make informed decisions about the range of choices available to them, represent the best long-term approach to delivering positive outcomes for energy customers. We have identified substantial problems on both the supply and the demand side of the retail energy markets, and we believe that our remedies package will provide a long-term solution to them, by putting downwards pressure on prices towards the competitive benchmark level.
244. However, our remedies will take time to implement before they start to address the features that we have identified and, in turn, reduce the

detriment to domestic customers arising from them, in particular for prepayment customers. Also, we believe that the roll-out of smart meters is a necessary element for fully addressing certain features of the Prepayment AEC and of the Domestic Weak Customer Response AEC with respect to prepayment customers. As a result, we expect that the detriment arising from the domestic retail AECs we have identified will persist in substantial form for the next few years. Given the size of the detriment we have observed, of around £1.4 billion a year over the last three and a half years, we have therefore considered very closely the need to intervene to address domestic customer detriment directly in this transitional period, through a price cap.

245. We have concluded that a price cap should apply to domestic customers on prepayment meters for a transitional period (2017 to the end of 2020). In reaching this decision, we have given consideration to a number of factors. In particular, prepayment customers have not been able to benefit from competitive prices in the same way as other customers due to the various competition constraints we have identified on the demand side and on the supply side, and the level of detriment suffered by prepayment customers is particularly high. Over the period 2012 to Q2 2015, detriment expressed as a proportion of the bill for prepayment customers was substantially higher than that for direct debit and standard credit customers. Further, we note that, unlike other customers, where prepayment customers pay too high a price, part of the detriment may be felt in abruptly curtailed consumption.
246. We have decided to implement a 'reference price and cost index approach' to set the cap for prepayment customers, which will involve setting an initial level of the prepayment cap based on our competitive benchmark analysis and then allowing the cap to change over time according to movements in exogenous cost indices, including wholesale costs, network costs, policy costs and inflation. This design – unlike alternatives we considered – does not lead to a risk of perverse incentives on the part of suppliers. Further, the fact that the cap is time-limited and will be implemented according to an objective formula, will help minimise the risk of regulatory gaming behaviour.
247. In considering the stringency and design of the cap, we have been particularly mindful of the need to reduce customer detriment while avoiding distortions to competition. We anticipate that the cap will materially reduce detriment for prepayment customers. Had it applied in Q2 2015, it would have reduced prepayment customer detriment – and, equivalently, the revenues of the Six Large Energy Firms – by about a total of around £300 million per year, equivalent to a reduction in the average bills paid by prepayment customers of about £75. We note that the price cap would also

apply to Mid-tier Suppliers and smaller suppliers and will therefore result in revenue reductions outside of the Six Large Energy Firms.

248. In determining the overall level of the cap, we have included a level of headroom that will help ensure that competition in the prepayment segments can coexist with the cap. Indeed, the proposed level of the cap as of Q2 2015 is generally in line with the cheapest prepayment tariff prices in many regions and we believe that it will be possible for suppliers to compete beneath the level of the cap while still earning a normal rate of return. Further, the cap will not apply to fully interoperable (SMETS 2) smart meters when these are rolled out to prepayment customers – as we believe that customers with such meters will have access to a wide range of tariffs. This should increase the incentives of suppliers to roll out such meters to the benefit of prepayment customers.
249. We anticipate that, as our remedies to address supply-side constraints and improve customer engagement begin to take hold towards the end of the cap, and as SMETS 2 smart meter roll-out increases, competition rather than the cap will be determining the prices paid by most customers. There will therefore be a graduated glide path to the termination of the cap at the end of 2020.
250. While the detriment suffered by prepayment customers is particularly high, we note that other domestic customers will also suffer detriment during the transitional period before full implementation of our remedies, and have therefore given close consideration to the application of a price cap to all customers on the standard variable tariff.
251. Our decision on whether to introduce a cap for all standard variable tariff customers was balanced. The majority of us concluded that the disadvantages of attempting to address the detriment of all customers on the standard variable tariff through a price cap would likely be disproportionate. The majority of us believe that attempting to control outcomes for the substantial majority of customers would – even during a transitional period – run excessive risks of undermining the competitive process, likely resulting in worse outcomes for customers in the long run. This risk might occur through a combination of reducing the incentives of suppliers to compete, reducing the incentives of customers to engage and an increase in regulatory risk.
252. Since, as noted above, a large part of the detriment we have observed in the form of high prices is likely due to inefficiency rather than excess profits, we believe the best, most sustainable approach to reducing this detriment in the long term is through fully competitive markets, in which more efficient

suppliers gradually replace less efficient suppliers. We also note that for most domestic customers on standard variable tariffs detriment will be reduced as soon as they engage effectively, in contrast to the situation for prepayment customers, who do not have access to cheap tariffs. Having considered very closely both the short-term benefits to customers and the longer-term risks that a broader cap may create, set against the features of the Domestic Weak Customer Response AEC, the majority of us have therefore decided not to control prices across all customers on standard variable tariffs. Martin Cave dissented from this view, considering that a broader cap was required to address the scale of detriment identified in the short term.

Expected costs and benefits from our retail remedies package

253. We have assessed the likely costs and benefits of our remedies package, distinguishing between those measures that will have an effect solely during the transitional period of the smart meter roll-out and those that will have an enduring effect, particularly from around 2019/20 onwards.

Remedies that will have an effect solely during the transitional period

254. Some of our proposed remedies will apply only during the transitional period before the completion of the roll-out of smart meters (expected by the end of 2020) or earlier. Notable among these is the transitional price cap for prepayment customers.
255. The benefits accruing from the price cap will take the form of reduced prices for prepayment customers. We would expect around £300 million of detriment a year to be reduced through the application of the cap in the initial years of this transitional period. We would expect the impact of the cap to reduce over time, but the overall detriment reduced through the package to increase, as competition picks up through our remedies and in particular through the roll-out of SMETS 2 meters that are not covered by the cap.
256. There would be some administrative costs for both Ofgem and suppliers from implementing the cap, but we have chosen a design that minimises these to the extent possible (eg updating through readily available exogenous indices, and ex ante compliance assessed by suppliers) and, overall, we expect such costs to be very low compared to the benefits of the cap in terms of reduced prices. Potentially more significant are the distortions to competition that could arise from the application of the cap, but we have again chosen aspects of the design to minimise these – notably, by building in headroom to allow competition below the level of the cap, in the exclusion of interoperable SMETS 2 smart meters from coverage by the cap,

and by time-limiting the price cap to the end of 2020 with a mid-term review in 2019.

257. The other remedies that will apply only during the transitional period are: the remedies relating to the allocation of gas tariff pages; the remedies giving PCWs (and TPIs providing similar services) access to the SCOGES and ECOES databases; and the remedies designed to improve engagement for customers on restricted meters. We consider that the implementation costs of these remedies are very low. In relation to the first two, there would be a minimal administrative cost for Ofgem, the code administrator or governing body with authority to grant access to the ECOES database and gas transporters respectively. In relation to the third, there would be a small additional cost for suppliers arising from the need to aggregate consumption volumes in different registers for the purposes of single rate billing.
258. We recognise that the short space of time over which these latter remedies will be relevant and the inevitable lag between implementing the remedy, effectively addressing the relevant aspect of the feature and reducing detriment, will limit the scope for substantially reducing customer detriment through these transitional remedies. However, given the scale of the total customer detriment that we have identified for prepayment customers of almost £400 million in 2015, and customers on restricted meters of around £40 million in Q2 2015, even very small reductions in prices during the transitional period would lead to benefits that would far exceed any implementation costs.

Remedies that will have an enduring effect

259. The other remedies that we decided upon – concerning settlement reform, the withdrawal of aspects of the simpler choices component of the RMR rules and the engagement remedies other than the transitional measures discussed above – will work together on an enduring basis as a package. We have accordingly considered their benefits jointly, while noting their relative contribution to the package and identifying their costs, where material, on an individual basis.
260. We first assess costs and benefits for electricity settlement reform separately, as this reform has benefits in terms of load shifting that are additional to those of the package as whole (although we consider that they would also make a contribution to improving customer engagement).

Electricity settlement reform

261. There are potentially substantial savings from domestic peak load shifting, arising primarily from reductions in the cost of generation and distribution. One recent study estimated savings from the introduction of time-of-use tariffs within the domestic retail markets of between roughly £50 million and £100 million in 2020 and between roughly £100 million and £350 million a year by 2025.¹⁴ Expected savings increase with the roll-out of automated and dynamic time-of-use tariffs (for which settlement reform is necessary) and with increased penetration of low carbon technologies. We note in relation to this latter factor that the demand and supply of heat pumps, smart appliances and electric vehicles will be driven in large part by the availability of opportunities to exploit within-day price differentials. Therefore we would argue that a move to half-hourly settlement will be a necessary step in achieving the higher end of potential benefits from demand-side response.
262. In terms of implementation costs, we consider that these will be very low or nil for distribution network operators and that half-hourly settlement will overall result in a reduction in costs for Elexon. Suppliers indicated to us that the reform would involve substantial upfront and ongoing costs, although we did not receive sufficient information from enough firms to build a consistent, robust picture of the likely costs.
263. Our recommendation is that Ofgem conduct a full cost-benefit analysis of the move to mandatory half-hourly settlement, but overall, and based on the evidence we have seen, there are good reasons to expect the benefits from half-hourly settlement to outweigh the costs of its implementation by a substantial degree.

Effect of the package on engagement

264. In relation to the rest of the package, we consider that the main enduring benefit will accrue from improving customer engagement and therefore overcoming the Domestic Weak Customer Response AEC. We note that, almost 15 years after full price liberalisation, around 70% of the customers of the Six Large Energy Firms are on the default tariff, despite very large and growing potential gains from switching. Nevertheless, we believe that our reforms will succeed in improving engagement where other interventions have failed.

¹⁴ Baringa and Element Energy (August 2012), *Electricity System Analysis – future system benefits from selected DSR scenario*.

265. First, past interventions have been based largely on a priori reasoning, with little attempt systematically to test hypotheses through rigorous trials or other forms of testing before the intervention is implemented. A priori reasoning can provide useful insights into the sorts of interventions that may help, but rigorous evidence is needed to ensure that those interventions that are most likely to make a difference for given customers at a given point in time are implemented. The Ofgem-led programme that we are recommending is therefore essential to ensure that future interventions are based on what works in practice. Further, the Ofgem-led database will provide Ofgem with an extremely powerful tool for assessing the impact of different interventions and forms of communication with disengaged customers.
266. Second, our remedies will serve to intensify competition between suppliers to access and engage disengaged customers, by: reducing the costs of identifying and communicating with such customers (the Database remedy); and by amending elements of the regulatory framework to increase the incentives of suppliers to engage these customers (the withdrawal of certain aspects of the simpler choices component of the RMR rules and settlement reform).
267. Third, our remedies seek to harness the incentives of TPIs to unlock customer engagement, by giving them greater access to the data they need to perform this role more effectively and at lower cost. TPIs have grown considerably as an acquisition channel over the past few years and we believe that through our remedies they can continue to grow in importance, lowering acquisition costs for suppliers and lowering search costs for customers. We believe that greater availability of much richer data sets, which can be accessed in a variety of ways, combined with the roll-out of smart meters, which will give greater visibility to customers of the relationship between what they consume and what they pay, have the potential to have a transformative effect on customer engagement.
268. Finally, we note that increasing customer activity is not an end in itself: our aim is to ensure that customers benefit from increased engagement – ie that it results in them being on better deals than they are at present. In this respect we recognise that there is a potential trade-off between the benefits of liberalising channels of engagement and the need to protect consumers from excessive and/or misleading marketing, and we have reflected this in our design of remedies.
269. For example, in relation to the Ofgem-controlled database of disengaged customers, Ofgem will have powers to exclude suppliers from accessing the database if misleading information is given to customers and it will be responsible for continual monitoring of the effectiveness of the database, to

establish which forms of communication from suppliers genuinely help engagement in the interests of customers. And in other areas of our remedies package, we have looked to improve customer understanding and avoid the risk of confusion without undermining competition in the way previous interventions have done. For example, we are recommending the replacement of the RMR rules that restrict competition and lead to gaming with a principle requiring tariffs to be readily comparable.

Costs and benefits of engagement remedies

270. In relation to the costs of implementing the remedies, these are generally very low compared with the size of the detriment. For example, in relation to the Database remedy, we have estimated that the costs of setting up a secure cloud database in which to store details of the Disengaged Domestic Customers could be in the region of £200,000 to £300,000 with ongoing costs of £35,000 to £50,000 per year.
271. The largest cost would be imposed by the Ofgem-led programme, as it would require an ongoing system of testing and trialling interventions. We note that costs may vary substantially, depending on the size and complexity of the trial. In designing the programme and, in particular, the extent of any supplier participation that might be needed, we note that Ofgem will be required to assess the proportionality of the various stages involved in the programme.
272. We believe that the benefits of our remedies will be seen in part through a reduction in the average gains from switching that go unexploited by customers. However, crucially, this would not be achieved by a levelling up of prices (a potential risk of regulatory interventions that seek to constrain price differences) but by a gradual reduction in prices towards the competitive benchmark level, as more efficient suppliers gain customers from the less efficient.
273. We note that, in contrast to the situation for prepayment customers, who do not have access to cheap tariffs, for most domestic customers detriment will be reduced as soon as they engage effectively. We would therefore expect detriment to be reduced throughout the period 2017 to 2020, and in particular from 2018 as the Database remedy and Ofgem-led programme start to take effect. While it is not possible to quantify precisely the price reduction in the next few years, we note, for illustrative purposes, that a fall in average prices by 3% a year from 2017 to 2020 would be sufficient to eliminate the detriment by 2020.

274. We acknowledge the uncertainties in estimating the level of detriment that will be reduced by our remedies over the next few years, but our analysis of the history of liberalised retail markets in Great Britain suggests that appropriately targeted and designed remedies can have material, rapid effects in improving engagement and reducing detriment for the majority of customers.

Microbusiness AECs and detriment

275. 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.

Microbusiness AECs

276. In relation to customer engagement, despite positive signs of a recent increase in switching between suppliers, 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).
277. In relation to transparency, there is a general lack of price transparency concerning the tariffs that are available to microbusinesses, which results from many of them not being published, and a substantial proportion being individually negotiated between customer and supplier. In particular, the limited availability and low usage of PCWs makes it more difficult for microbusinesses to get a view of prices across each market.
278. 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 4% 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.
279. 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). 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 tariffs were 66 to 82% higher than retention tariffs for electricity, and 70 to 116% higher for gas.

280. 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).
281. Specifically in relation to auto-rollover contracts (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) some customers 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).
282. Overall, **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 (the Microbusiness Weak Customer Response AEC). 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.

Detriment suffered by microbusinesses

283. We estimate that the profits in excess of the cost of capital earned by the Six Large Energy Firms from the supply of gas and electricity to SME customers

amounted to approximately £220 million per year from 2007 to 2014,¹⁵ of which we estimate that approximately £180 million per year related to microbusiness customers.

284. We consider that this is a conservative estimate of detriment, as we have confined our estimate of detriment to a consideration of profits in excess of the cost of capital – that is, we have not included any estimate of inefficiency. We also note that we have not been able to conduct an analysis of supplier bills to produce an alternative, and more direct, estimate of detriment, as we have done for domestic customers.
285. Despite this conservative approach, we believe that the size of the detriment that we have identified is significant. The annual profits in excess of the cost of capital amounted to 5% of average annual microbusiness revenues for the Six Large Energy Firms from FY 2007 to FY 2014. This suggests that prices may have been on average 5% higher between FY 2007 to FY 2014 than would have been the case in a better-functioning market.

Microbusiness retail remedies

286. We have assessed remedies for microbusiness customers considering the same strategic themes as for domestic customers: creating a framework for effective competition; helping customers engage; and protecting customers who are less able to engage to exploit the benefits of competition.

Creating a framework for effective competition

287. Our remedies concerning the electricity and gas settlement systems, as discussed above, would also apply to microbusiness customers. In particular, the plan to move customers in profile classes 1 to 4 to mandatory half-hourly settlement in electricity would affect the majority of microbusiness customers (around 90% of which currently fall into profile classes 3 and 4). Similarly, the remedy to increase the accuracy of the gas settlement system will benefit microbusiness as well as domestic customers.
288. The other remedies that we are introducing with a view to improving the framework for competition for domestic customers either affect very few microbusiness customers or do not apply at all in the microbusiness segments.

¹⁵ The years referred to are financial years.

Helping microbusiness customers engage to exploit the benefits of competition

289. The main remedies we are introducing regarding microbusiness customers are those designed to help them engage to exploit the benefits of competition. These include remedies to:
- (a) increase price transparency;
 - (b) end auto-rollover contracts¹⁶ with certain restrictions (such as termination fees) that restrict microbusiness customers' ability to switch;
 - (c) establish a programme to provide microbusiness customers with information to prompt them to engage; and
 - (d) provide prompts to microbusiness customers on default contracts by enabling rival suppliers to contact them.
290. We believe that our engagement remedies will play a key role in addressing the features giving rise to the Microbusiness Weak Customer Response AEC, and the resulting customer detriment.

Price transparency remedy

291. The price transparency remedy will require suppliers to disclose the prices of all their available acquisition and retention contracts to a large proportion of their microbusiness customers. As an additional measure, it will also require suppliers to disclose their out-of-contract (OOC) and deemed contract prices on their websites. The measure in relation to acquisition and retention contracts will significantly increase microbusiness customers' abilities to access and assess price information. It will also facilitate the development of PCWs catering for microbusiness customers, which will further reduce the high search costs faced by microbusiness customers. As a result, the price transparency remedy will address barriers to accessing and assessing information experienced by microbusinesses.

Auto-rollover remedy

292. The auto-rollover remedy will address barriers to switching that microbusiness customers on auto-rollover contracts face by: (a) increasing the time window during which microbusiness customers would be able to give their termination notice to suppliers; and (b) prohibiting suppliers from

¹⁶ Auto-rollover contracts are fixed-term, fixed-price contracts that microbusiness customers can be moved onto if they fail to negotiate new terms when their existing contract comes to an end.

including certain restrictions (termination fees and the use of no-exit clauses). Our remedies will also prohibit termination fees in relation to evergreen and OOC contracts. These measures will ensure that suppliers will not be permitted to charge termination fees on default contracts with their microbusiness customers, thereby reducing the barriers to switching for such customers.

Programme to provide microbusiness customers with information to prompt them to engage/Database remedy

293. The remedies to establish a programme to identify additional (or new) information from suppliers to prompt microbusiness customers to engage, and to disclose the details of their most disengaged microbusiness customers to rival suppliers would increase the engagement of microbusiness customers on default contracts. By incentivising microbusiness customers to engage, we would expect the competitive constraint on energy suppliers to increase. This would incentivise suppliers to reduce the prices of their available acquisition and retention contracts for microbusiness customers.

Protecting customers who are less able to engage to exploit the benefits of competition

294. We have also considered the case for introducing a price cap for microbusiness customers on prepayment meters, but have decided not to do so, on the grounds that the costs associated with implementing a price cap for the microbusiness segments would be large relative to the potential benefits, which would accrue to a very small number of microbusiness customers (less than 1% of whom are on prepayment meters).

Costs and benefits of the remedies package

295. In developing our remedies, we have been mindful to ensure that they work together as a coherent package, which, as a whole, provides an effective and proportionate means of addressing the Microbusiness Weak Customer Response AEC, and the resulting customer detriment, and have assessed whether the benefits of the remedies package as a whole are likely to exceed the overall costs.
296. In relation to costs, we estimate that the price transparency remedy is likely to impose a one-off cost on the Six Large Energy Firms of approximately £750,000; and on all suppliers these costs could amount to approximately £4.5 million if they all adopted the more expensive online quotation tool option. We do not expect the auto-rollover remedy to impose substantial costs on suppliers, and we estimate that the costs of extending the remedy

that would enable prompts to microbusiness customers on default contracts to the microbusiness segments would be minimal for suppliers.

297. The costs of the Ofgem-led programme may be more substantial but we note that, in designing the programme and, in particular, the extent of any supplier participation that might be needed, Ofgem will be required to assess the proportionality of the various stages involved in the programme.
298. In relation to benefits, we consider that there is substantial scope for price reductions and that the remedies would still be proportionate if they led to only a small reduction in prices for microbusiness customers. On the basis of our profitability analysis, we consider that prices for the microbusiness customers of the Six Large Energy Firms could have been on average 5% lower between FY 2007 and FY 2014 in a better-functioning market, equivalent to £180 million a year – and we expect a material reduction in prices from the introduction of our remedies.
299. We have therefore concluded that the benefits of the remedies package for all microbusiness customers are likely to substantially exceed the costs that it would impose on all suppliers in the microbusiness segments.

Governance of the regulatory framework

300. The rules and regulations governing energy markets are set out in legislation, licence conditions and codes. These regulations have a profound effect on the nature and form of competition in both wholesale and retail markets, and we are therefore concerned that some key aspects of the structure and governance of the regulatory framework – including the roles and responsibilities of institutions and the design of decision-making processes – increase the risk of policies being developed in the future that are not in customers' interests and inhibit the development of policies that are in their interests. We also consider that 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.

Ofgem's duties and objectives

301. 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.

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

DECC / Ofgem relations

303. DECC and Ofgem have complementary and, in some cases, overlapping responsibilities in relation to regulatory and policy development in the energy sector. In some cases, the implementation of a particular energy policy requires a combination of measures taken by DECC (mainly through legislation), Ofgem (mainly through licence conditions) and indeed the industry (through the amendment of codes). We have two concerns regarding the relationship between DECC and Ofgem.
304. First, we note that two of Ofgem's most important decisions in recent years (neither of which we consider to have benefited customers)¹⁷ 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. We do not know how material this context was in influencing Ofgem, but the coincidence of DECC's and Ofgem's actions risked creating the perception of a lack of independence on the part of Ofgem.
305. 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 Ofgem's views are routinely and transparently expressed, so that stakeholders can understand why a particular decision is being made, leads to a lack of transparency in regulatory decision-making.
306. Second, we identified inefficiencies in the implementation of certain policy objectives (for example, the introduction of 17-day switching and half-hourly settlement for certain categories of customer) due to a lack of effective coordination.

¹⁷ The introduction of the simpler choices component of the RMR reforms in 2013 and of Standard Licence Condition 25A in 2009, prohibiting regional price discrimination.

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

307. 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.
308. 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.

Framework for financial reporting

309. 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.
310. 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 clear 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.
311. The absence of such trusted and transparent information is a potentially material problem, undermining regulatory stability. Parliamentary committees, customer 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.
312. 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 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.

313. Overall, **we have 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, we have found that:
- (a) Ofgem's statutory objectives and duties may constrain its ability to promote effective competition;
 - (b) there is a lack of a formal mechanism through which disagreements between DECC and Ofgem over policy decision-making and implementation can be addressed transparently;
 - (c) the impact of government and regulatory policies over energy prices and bills has not been effectively communicated; and
 - (d) there is a lack of a regulatory requirement for clear and relevant financial reporting concerning generation and retail profitability.

Industry codes

314. Industry codes are 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. Whereas, at the time of privatisation, there were two codes covering largely technical matters, there are now 11 codes, comprising over 10,000 pages of rules that cover a range of commercial and policy areas. Industry participants have a key role in the governance of these codes, and, under the current regime, proposed reforms that can have substantial impacts on competition and the delivery of policy objectives are implemented through code changes (the proposals to introduce half-hourly settlement and cash-out reforms are recent examples).
315. Current governance structures give industry participants a key role in decision-making even though their incentives are often not aligned with those of customers. Further, we note that incentives often differ between firms, leading to lengthy and costly regulatory processes and delays in decision-making. Examples of this include the long-running deliberations over whether to introduce locational charges for transmission losses over the past 25 years and Project Nexus, which is needed to address the deficiencies in the gas settlement system but has been continually delayed since being initiated seven years ago.

316. We are also surprised to note that some decisions that appear to us to be fundamental to ensuring effective competition and meeting the needs of customers appear to be loosely governed under the industry codes, and not to have involved any formal role for Ofgem. For example, in relation to competition for customers on prepayment meters, we understand, based on the relevant provisions set out in the Supply Point Administration Agreement, that there are no formal mechanisms in place to monitor the allocation of gas tariff pages and to govern the distribution of tariff pages between suppliers. This is of particular concern since the lack of access to gas tariff pages has been one of the factors inhibiting new entry into the prepayment segments, to the detriment of prepayment customers.
317. Our central concern is that Ofgem has insufficient ability to influence development and implementation processes for code changes, particularly where they affect competition or are needed to implement policy changes, increasing the risk of changes that are in customers' interest not being delivered in a timely and efficient way. Customer 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).
318. We have 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.

Detriment arising from problems in the regulatory framework

319. The problems we have identified relate to the processes, structures and institutions involved in regulatory decision-making in the energy sector. They are systemic in nature, having an impact across all of the energy markets that we have identified. While the detriment arising from these AECs is, by its nature, difficult to quantify, we consider that it is likely to be very substantial.
320. First, the costs of energy policies – the transfers and subsidies put in place to achieve government policy objectives such as reducing greenhouse gas

emissions – will comprise an increasing proportion of customers’ energy bills. On the basis of current announced plans, DECC estimates that climate and energy policies will add 37% to the retail price of electricity paid by households in 2020.¹⁸ Further, some policies – such as the roll-out of smart meters – are expected to improve energy efficiency and hence reduce energy bills. Given the central role that government policies are expected to play in determining energy bills in the future, we believe it is vital that policy decisions are robust, and informed by a transparent analysis of their impacts on customers.

321. Second, energy markets are highly regulated, and the nature of competition in these markets is shaped by the design of the regulatory regime to a much greater extent than in most other markets. This is particularly the case for wholesale markets, which currently comprise around 50% of the costs faced by electricity and gas customers, and where the nature and size of technological and regulatory changes expected over the next few years are substantial. We also note that many of the competition problems that we have identified in the retail energy markets – the settlement systems for gas and electricity, which fail to give suppliers the right incentives, the introduction of the RMR simpler choices reforms, which have stifled innovation – are regulatory in nature, reflecting specific provisions in legislation, licence conditions and industry codes.

Remedies relating to the governance of the regulatory framework

322. We have developed a package of remedies designed to improve the governance of the regulatory framework. The proposed remedies relate to five specific areas: Ofgem’s duties and objectives; the relationship between DECC and Ofgem; the analysis of the impacts of policy and regulation; the regime for financial reporting; and governance of the industry codes.
323. While the package is broad, affecting the full range of regulatory instruments and processes (legislation, licence conditions and industry codes), it is based on a simple set of principles, which recognise the importance of: well-defined powers and objectives aligned with the interests of customers; clear responsibilities and transparent, coordinated implementation; robust analysis underpinning decision-making and improving transparency; and an independent and authoritative regulator.

¹⁸ 2014 prices. Source: DECC (November 2014), [Estimated impact of energy and climate change policies on energy prices and bills](#).

Ofgem's duties and objectives

324. Our view is that Ofgem's statutory objectives and duties may, in certain circumstances, constrain its ability to promote effective competition. In particular, Ofgem told us that it considered that its duty to pursue its principal objective by 'wherever appropriate promoting effective competition' had been progressively downrated relative to other duties over the last ten years.
325. Our remedy is a recommendation to DECC to amend primary legislation in order to clarify Ofgem's statutory objectives and duties and thereby remove any constraint (actual or perceived) on Ofgem's ability to pursue its principal objective (protecting the interests of existing and future customers) by promoting effective competition where it considers this appropriate.

Relationship between DECC and Ofgem

326. We have decided on two remedies that are designed to recalibrate the relationship between DECC and Ofgem in a way that recognises Ofgem's independence while allowing for appropriate coordination of activities to deliver overarching policy goals:
- (a) First, we are recommending legislation to establish a clear process requiring Ofgem to publish opinions on all draft legislation and policy proposals that are relevant to its statutory objectives and that are likely to have a material impact on the GB energy markets.
 - (b) Second, we are recommending to DECC and Ofgem that they publish detailed joint statements setting out action plans for the implementation of proposed DECC policy objectives that are likely to necessitate Ofgem interventions, with clear responsibilities and timetables.

Transparent analysis of the impacts of policy and regulation

327. As noted above, government policies are having an increasing impact on energy bills and yet we have found that there is a lack of effective communication concerning the forecast and actual impact of government and regulatory policies on energy prices and bills. This has led to a lack of trust between stakeholders and is one of the features contributing to an overarching feature of a lack of robustness and transparency in regulatory decision-making.
328. To help address this, we recommend to Ofgem that it publishes annually a state of the market report which would provide analysis regarding issues such as the evolution of energy prices and bills over time; the profitability of

key players in the markets; the social costs of policies and distributional impacts arising from them; and the impact of initiatives relating to decarbonisation and security of supply. We are also recommending the creation of a team within Ofgem to take this work forward.

Regime for financial reporting

329. We have found that current regulatory requirements do not provide for clear and relevant financial reporting of generation and retail profitability. Our remedy seeks to address this, and in so doing to help ensure that Ofgem will be better placed in the future to make decisions using relevant financial information and to provide a clear and trusted assessment of the GB energy markets. This in turn should inform the public debate and support the development of appropriate policies.

330. Our remedy will require the Six Large Energy Firms to:

- (a) report their generation and retail supply activities on market rather than divisional lines;
- (b) report a balance sheet as well as a profit and loss account separately for their generation and retail supply activities;
- (c) disaggregate their wholesale energy costs for retail supply between a standardised purchase opportunity cost and a residual element; and
- (d) report prior year figures prepared on the same basis.

331. We are recommending that Ofgem introduces relevant changes in the licence conditions of the Six Large Energy Firms.

Governance of industry codes

332. We have found that the current system of industry code governance limits innovation and pro-competitive change and causes the energy markets to fail to keep pace with relevant policy objectives.

333. Our remedies package for codes will see Ofgem taking a more proactive role in code development, by setting a Strategic Direction and engaging actively in the code modification process through its influence over licensed code bodies. Further, we are recommending that Ofgem takes powers to initiate code modifications where these are necessary to deliver the Strategic Direction and be given powers to take substantive control of any ongoing strategically important modification proposals, as appropriate.

334. We are recommending to DECC that it seek to pass legislation: giving Ofgem the ability directly to modify industry codes in certain exceptional circumstances; and making the provision of code administration and delivery services activities that are licensed by Ofgem. This will give Ofgem a means of requiring code bodies to take on an expanded role to deliver code modifications consistent with the Strategic Direction.

Overview of the new regulatory framework

335. Our remedies are individually incremental but in combination represent a substantial reform package. They represent a ‘reset’ of the regulatory framework governing the energy sector, clarifying and recalibrating the roles and responsibilities of Ofgem, DECC and industry to help ensure that regulatory and policy decisions in the future are robust, efficient and timely, and driven by a concern for the interests of current and future customers.
336. Ofgem will be at the heart of this new regulatory framework, with a simpler and clearer focus on the interests of customers, an additional role to scrutinise and comment on government policies, greater access to relevant financial information from industry and greater powers to drive through changes to industry codes when these are needed to meet broader policy objectives and are in the interests of customers and competition.
337. We believe that the individual elements of our remedies package are mutually reinforcing. For example, the roles given to Ofgem to comment on and scrutinise the impacts of government policies on the one hand, and undertake greater scrutiny of companies’ financial returns on the other, will help both to:
- (a) improve the robustness of the decision-making process, the quality of regulatory decisions and transparency in public debates about energy; and
 - (b) bolster the perception of Ofgem as an authoritative, trusted and independent regulator, consistent with the greater responsibilities it will have in relation to code governance and reform.
338. We consider that our reforms are fully consistent with the government’s *Principles for Economic Regulation*¹⁹ and its *Better Regulation Framework Manual*.²⁰ In particular, our remedies should ensure that new policy proposals and existing policies and regulations are subject to robust scrutiny

¹⁹ BIS (April 2011), *Principles for Economic Regulation*.

²⁰ BIS (March 2015), *Better Regulation Framework Manual: Practical Guidance for UK Government Officials*.

in terms of their costs and benefits. Further, our proposed remedies relating to the code governance process and mechanisms to improve coordination between DECC and Ofgem should serve to streamline and rationalise the policymaking process, reducing overall regulatory burdens.

Dissenting view

339. One panel member, Martin Cave, felt that the retail remedy package was unlikely to succeed in reducing, in a timely way, the significant level of detriment identified. In his current view, a short-term price cap, covering a substantially larger number of customers, is required to reset the market.

Final decision on AECs and remedies

340. A comprehensive list of AECs and remedies is provided in Section 20 of this report.

Findings

1. Introduction

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Background on the reference and investigation

- 1.1 On 26 June 2014 the Gas and Electricity Markets Authority in exercise of its powers under sections 131 and 133 of the Enterprise Act 2002 (the 2002 Act) (as provided for by section 36A of the Gas Act 1986 (GA86) and section 43 of the Electricity Act 1989 (EA89)), made an ordinary reference to the Chair of the Competition and Markets Authority (CMA) for the constitution of a group under Schedule 4 to the Enterprise and Regulatory Reform Act 2013 for an investigation into the supply and acquisition of energy in Great Britain.¹
- 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. In our provisional findings report, a summary of which was published on 7 July 2015, and in the addendum to provisional findings (the Addendum), published on 16 December 2015, we provisionally found that there are a number of features of the markets for the supply of energy in Great Britain that, on their own or in combination, give rise to adverse effects on competition (AECs) within the meaning of section 134(2) of the 2002 Act. On 10 March 2016 we published our provisional decision on remedies, in which we set out the remedies that we proposed to implement to address the features that we had provisionally identified as giving rise to AECs.

¹ [Energy market investigation terms of reference.](#)

1.3 This document sets out our findings from our investigation, together with the remedies that we have decided to implement to address the AECs and/or detriment that we have identified.

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.²

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 Having identified a number of features of the markets for energy generation and supply in Great Britain that give rise to the AECs, we are required to decide the following additional questions:³

- whether action should be taken by the CMA for the purpose of remedying, mitigating or preventing the AEC concerned or any detrimental effect on customers so far as it has, or may be expected to result from, the AEC;
- whether the CMA should recommend the taking of action by others for the purpose outlined in paragraph 1.12 above; and
- in either case, if action should be taken, what action should be taken and what is to be remedied, mitigated or prevented.

1.7 A detrimental effect on customers includes such an effect on future customers and is defined as one taking the form of:⁴

² Section 134(2) of the 2002 Act.

³ Section 134(4) of the 2002 Act.

⁴ Section 134(5) of the 2002 Act.

- higher prices, lower quality, or less choice of goods or services in any market in the UK (whether or not in the market to which the feature or features concerned relate); or
- less innovation in relation to such goods and services.

- 1.8 In choosing appropriate remedial action, we have had regard to our statutory obligation to achieve as comprehensive a solution to the AECs we have identified and any resulting detrimental effect on customers as is reasonable and practicable.⁵ In light of this requirement, we have considered how comprehensively the remedies (and packages of remedies) set out in this document would address the AECs and the resulting detrimental effects on customers. Pursuant to our guidelines, we have sought to identify remedies that address the causes of the AEC directly. However, where this has not been possible, or as an interim solution, we have decided to introduce measures to mitigate the harm to customers created by the AEC.
- 1.9 In deciding what remedies would be appropriate, we have looked for remedies that would be effective and proportionate in achieving their aims. The CMA has made several general observations in its guidance about factors relevant to its consideration of effectiveness and proportionality.⁶
- 1.10 Some of the remedies we have decided to implement require a modification to certain licence conditions. Pursuant to section 168 of the 2002 Act, where relevant in proposing these remedies, we have had regard to Ofgem's statutory functions.
- 1.11 In reaching a judgement about whether to implement a particular remedy, we have also considered the potential effects on those persons most likely to be affected by it, generally customers and the businesses subject to the remedies. We have sought to assess the impact of our remedies in accordance with the relevant considerations set out in our guidelines.⁷ In particular, we have sought to quantify the costs and benefits associated with a remedy where it is reasonably practical to do so, taking into account any relevant customer benefits arising from the adverse feature or features of the market concerned.⁸ In practice, our remedies consist in several discrete actions to be taken by the CMA and several discrete recommendations to other public bodies.

⁵ Section 134(6) of the 2002 Act.

⁶ *Guidelines for market investigations: Their role, procedures, assessment and remedies (CC3)*, paragraphs 334–344.

⁷ *CC3*, paragraphs 348–353.

⁸ Section 134(7) and (8) of the 2002 Act.

- 1.12 Where we have made recommendations, we have had regard to the relevant considerations set out in our guidelines.⁹ We have noted that, while it will be for the person to whom the recommendation is addressed to decide whether to act on the recommendation, the government has made a commitment to give a public response to any recommendation made to it within 90 days of the publication of a CMA report. As per our guidelines, we have consulted with the relevant body prior to making the recommendation.¹⁰
- 1.13 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 our final report.

Background to the reference

- 1.14 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.
- 1.15 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 their less active customers. This suggested that competition was not working effectively for all customers.

⁹ CC3, paragraphs 379, 380, 390 & 391.

¹⁰ CC3, paragraph 380.

- 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.

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

Conduct of the investigation

1.17 Over the course of the investigation to date we have received over 250 submissions from energy suppliers, generators, government bodies, consumer groups, academics and other interested parties. These have been in response to the issues statement (IS), the updated issues statement (UIS), the provisional findings, an addendum to the provisional findings, two supplemental notices of possible remedies and the provisional decision on remedies. Submissions have also been produced as stand-alone submissions to the investigation or produced in relation to other market issues. Non-confidential versions of these submissions can be found on our website.

1.18 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, three smaller energy suppliers, bodies responsible for settlement in gas and electricity, PCWs, a collective switching website, a trader of wholesale energy and several academics. Non-confidential versions of the summaries of the hearings we have held are on our website.

1.19 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.

- 1.20 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, detriment 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.
- 1.21 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 disclosure rooms and confidentiality rings operated in March 2015, July 2015, September to October 2015, and March to April 2016. In particular, the confidential data disclosed included the data underlying the customer survey, and the data underlying our gains from switching, cost pass-through, descriptive statistics, retail profit margins, competitive benchmark, restricted meter, domestic bills benchmarking, indirect costs, costs by payment method, price cap and ROCE analyses.¹¹

Structure of our final report

- 1.22 This document, together with its appendices, constitutes our findings (or final report). 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 findings and our remedies.
- 1.23 The remainder of this report 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**, as well as the detriment arising from the AECs identified.
 - Section 6 sets out the **remedies** that we have decided to implement to address the features identified in the **wholesale electricity market**.

¹¹ Further details on the conduct of our investigation are set out in Appendix 1.1.

- Section 7 assesses the costs and benefits of **vertical integration** in the electricity sector.
- Section 8 sets out our assessment of the **nature of competition in domestic retail energy markets**.
- Section 9 provides our assessment of the **impact on retail market competition of weak customer engagement, supplier behaviour, barriers to entry and expansion in the supply of domestic prepayment customers and regulatory interventions**.
- Section 10 sets out our analysis of the **detriment suffered by domestic customers** as a result of the features identified in the retail energy markets.
- Section 11 provides an **overview of the package of remedies** that we have decided to implement in order to address the features identified in **domestic retail energy markets**.
- Section 12 describes the remedies that we have decided to implement in order to **create a framework for effective competition in domestic retail energy markets**.
- Section 13 sets out the remedies that we have decided to implement in order to **help domestic customers engage** to exploit the benefits of competition in retail energy markets.
- Section 14 provides our assessment of the **price cap remedy** that we have decided to implement in order to protect prepayment customers.
- Section 15 assesses the **effectiveness and proportionality of our package of remedies** for the domestic retail energy markets
- Section 16 sets out our analysis and assessment of **competition in the retail supply of energy to microbusinesses**, as well as the detriment arising from the AECs identified.
- Section 17 describes the remedies that we have decided to implement in order to address the AECs identified in the retail supply of energy to **microbusinesses**.
- Section 18 considers the impact of the **broader regulatory framework, including the current system of code governance**, on energy market competition and consumers.

- Section 19 sets out the **remedies** that we have decided to implement in order to address the AECs identified in the **broader regulatory framework for energy markets**, including the current system of code governance.
- Section 20 presents a summary of our **findings** in relation to the statutory questions that we are required to answer, and the remedies that we have decided to implement to address the AECs identified.

2. Overview of GB energy markets and outcomes

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Introduction

- 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 have framed 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 our findings.

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.

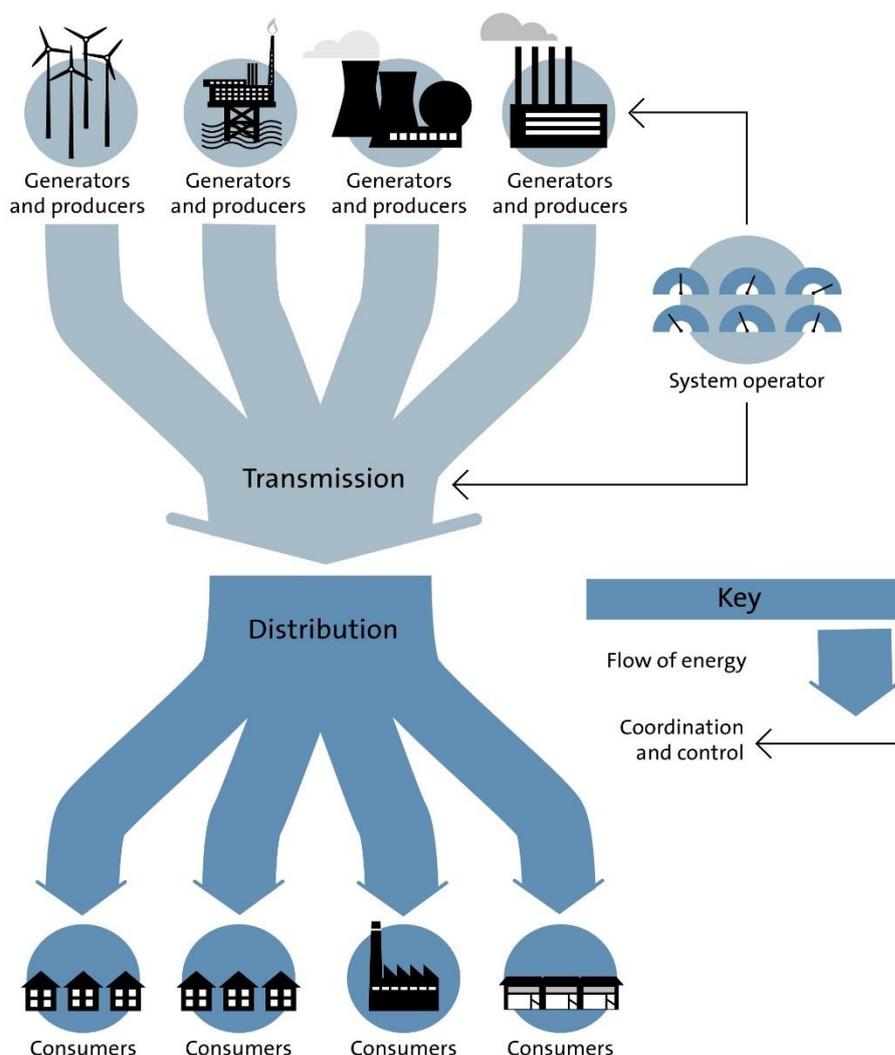
Physical supply chain in gas and electricity

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**, 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 system operator 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 system operator 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.

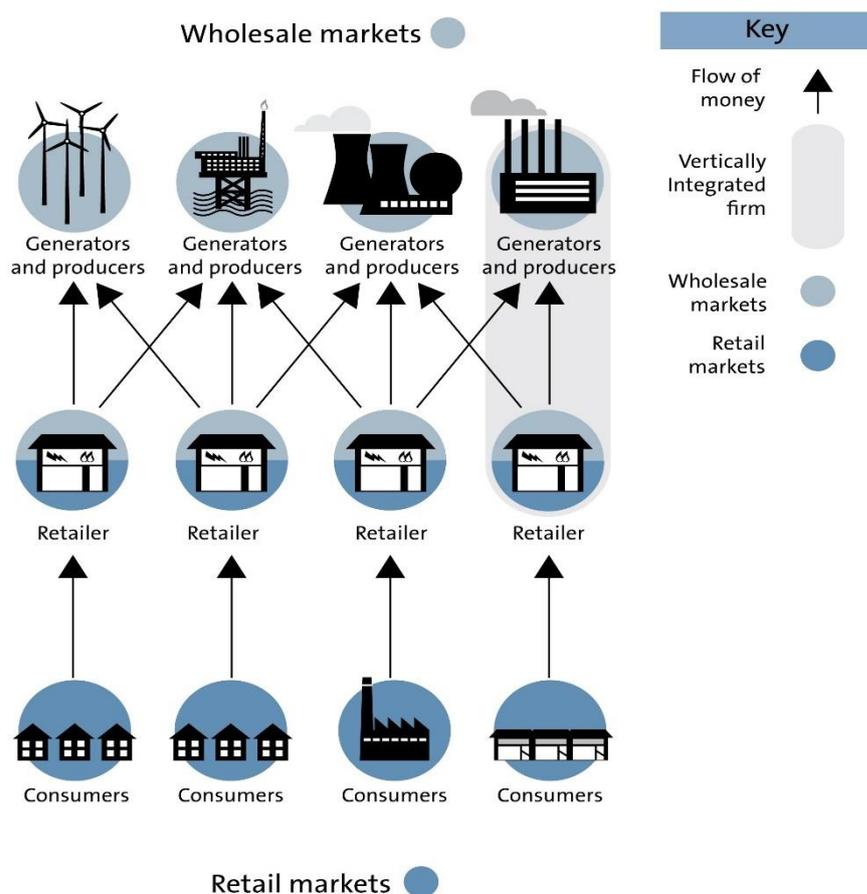
- 2.12 It is worth noting that retailers do not appear in the above diagram, as they have no role in the physical delivery of gas and electricity to final consumers. Their role is focused exclusively on commercial and financial transactions, as set out in the next section.

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.¹

¹ 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 7 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 system operator 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 Sections 8 and 9. 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.²
- 2.21 The nature of retail competition is discussed in more detail in Sections 8 and 9 of this report.

Current market participants

- 2.22 This section identifies some of the key participants in GB gas and energy markets.³

² We note that with the introduction of smart meters, some of these characteristics might change, as discussed in Sections 8 and 9.

³ A more detailed description of the companies operating in the GB gas and electricity sectors is provided in Appendix 2.2: Industry background.

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.⁴
- 2.24 Together, the Six Large Energy Firms currently supply energy to just under 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).⁵ Both SSE and Scottish Power also have interests in electricity transmission and gas and electricity distribution.
- 2.25 In relation to upstream gas supply, of the Six Large Energy Firms, only Centrica is a major player, with around 8% of GB supply in 2013/14. Statoil, the Norwegian state-owned producer is larger with 12% of production. Other gas producers on which the GB market depends include ExxonMobil, Total, Shell, and Gazprom with market shares ranging from 11 to 4%.⁶
- 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 April 2016 there were 34 suppliers selling both electricity and gas to households.⁷ The largest suppliers outside of the Six Large Energy Firms are: Utility Warehouse, First Utility, Ovo Energy (which, together with Co-operative Energy, we collectively call the '**Mid-tier Suppliers**' elsewhere in this report).

⁴ 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.

⁵ As noted in Section 4, E.ON has now demerged its conventional power stations (coal, gas and hydro) from its retail and renewables operation, which implies a large degree of vertical separation, and RWE has announced similar demerger plans

⁶ See Section 4: Nature of competition in wholesale energy markets, Figure 4.3.

⁷ Source: Cornwall. Cornwall advised that some of these suppliers were very new and likely to be going through controlled market entry. This figure of 34 does not include white-label suppliers or [Ovo communities](#). In 2014 there were 19 dual fuel domestic energy suppliers (see Cornwall Energy (October 2014), [Competition in British household energy supply markets: An independent assessment](#)).

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.

Institutions with policy and regulatory functions

2.31 The **Department of 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.⁸ 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.
- 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.

⁸ 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.

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).⁹

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.

- *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).

⁹ 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.

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)¹⁰ 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.¹¹ Three generation licences were initially awarded to 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

¹⁰ 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.

¹¹ 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 generators and suppliers were obliged to become party to the Pooling and Settlement Agreement under their respective licences, alongside National Grid.

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 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 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 transmission system operators; 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.¹²

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.¹³

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

¹² Including the Unfair Terms in Consumer Contracts Regulations 1999 and the Business Protection from Misleading Marketing Regulations 2008.

¹³ 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.

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.¹⁴

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.

- *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).

¹⁴ In Section 18, we consider whether Ofgem's duties and objectives impose a constraint on its ability in practice to promote competition.

- 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 8 and 9, 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 other 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 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 17, 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.¹⁵ 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.¹⁶ 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. The government is expected to propose draft legislation for the fifth budget in 2016. Under the current (second) carbon budget, which runs from 2013 to 2017, 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.¹⁷

¹⁵ In 2014, emissions from electricity generators and residential emissions (largely, consumption of gas) combined constituted just over 40% of total UK emissions. Source: [DECC, 2014 Greenhouse Gas Emissions, Final Figures](#).

¹⁶ These targets and policies are described in more detail in Appendix 2.1: Legal and regulatory framework.

¹⁷ 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.

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; increase to at least 27% the share of renewable energy consumed in the EU; and improve energy efficiency by at least 27%.¹⁸

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.¹⁹

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.

- *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

¹⁸ See [European Commission: Climate Action, 2030 climate & energy framework](#).

¹⁹ See, for example, [DECC, 2009, Low Carbon Transition Plan Analytical Annex](#).

scheme, the cap is 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 2020.²⁰ 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 2014.²¹ At the time of this report the EUA price was below €7.
- 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 The European Commission presented in July 2015 a legislative proposal to revise the EU ETS for the period after 2020, as a first step towards meeting the EU's target to reduce greenhouse gas emissions by at least 40% domestically by 2030 (see above). Under the proposal, the sectors covered by the ETS would have to reduce their emissions by 43% compared with 2005. To this end, the overall number of EUAs would decline at an annual rate of 2.2% from 2021 onwards, compared with 1.74% currently.²²
- 2.82 We 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 in substantial windfall transfers to the UK generators.²³ As of 2013 the sector is required to purchase all its allowances.
- *Climate change levy and the carbon price floor*
- 2.83 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

²⁰ Source: Policy paper: *2010 to 2015 government policy: greenhouse gas emissions*, [Appendix 2: EU Emissions Trading System \(EU ETS\)](#).

²¹ 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.

²² [EU Commission: Climate Action, Revision for phase 4 \(2021–2030\)](#).

²³ 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).

supplied to businesses. Rates vary across energy types but do not reflect differences in fuel carbon content.²⁴

- 2.84 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 CPSR and EUA is no lower than a trajectory announced in 2011 (£16/tCO₂ in 2013 rising to £30 in 2020). The CPSR is set two years in advance.
- 2.85 In the Finance Act 2014 the CPSR was capped at £18/t CO₂ from 2016/17 to 2019/20 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. In the 2016 Budget, the government announced it would uprate the cap in line with inflation in 2020/21. A decision on the long-term direction of the CPF is due to be announced in the 2016 Autumn Statement.

Policies that provide support to low carbon generation and heat

- 2.86 To comply with its targets for emissions reductions and renewables deployment, the UK government has progressively increased support for renewable and low carbon generation.
- *Contracts for Difference*
- 2.87 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.
- 2.88 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 5 and 6.

²⁴ 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.

- *Renewables Obligation*

2.89 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*

2.90 Feed-in tariffs 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 feed-in tariffs are passed through to consumers.

- *Renewable Heat Incentive*

2.91 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

2.92 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*

2.93 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.

2.94 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 9 we consider the potential competition implications of this exemption.²⁵

- *Smart meters*

2.95 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. We discuss the roll-out programme and the potential implications of smart meters for domestic retail competition in Sections 8 and 10.

2.96 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 Sections 9 and 11.

Security of supply

2.97 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.

2.98 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.

Capacity Market

2.99 The Capacity Market was introduced to address the concern that potential investors in generation and other forms of capacity might not be confident

²⁵ The exemption also applies to the delivery of feed-in tariffs and the Warm Home Discount, which is described below.

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.

- 2.100 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. Costs are passed through to electricity consumers. 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. The second auction (for delivery in 2019/20) was held in December 2015, and procured 46.4 GW of capacity at a price of £18/kW. This will result in capacity payments of approximately £830 million in the delivery year.
- 2.101 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

- 2.102 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.
- 2.103 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).²⁶ 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.

²⁶ 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

- 2.104 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%.
- 2.105 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.²⁷ 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.²⁸

Winter Fuel Payments

- 2.106 Winter Fuel Payments are a cash transfer, initially introduced in 1997, to households containing someone over the female state pension age. In 2016/17 the payment is £200, rising to £300 if someone is aged 80 or over. In 2014/15, nearly 9 million households were helped at a cost of more than £2.1 billion.

Cold Weather Payments

- 2.107 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 2014/15, 0.5 million payments were made at a cost of £10.4 million. By way of comparison, in 2012/13, 5.8 million payments were made at a cost of £146.1 million.

Warm Home Discount

- 2.108 The Warm Home Discount came into force in 2011. It puts an obligation on large energy suppliers to provide bill rebates, worth £140 in 2015/16, 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,

²⁷ IFS, Energy use policies and carbon pricing in the UK.

²⁸ See European Commission, [VAT rates applied in the Member States of the European Union: Situation at 1st January 2015](#).

typically those on means-tested benefits with young children or a disabled member.

Levy control framework

- 2.109 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, feed-in tariffs 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 2020/21.²⁹
- 2.110 The Office for Budget Responsibility (OBR) publish updated estimates of the cost of these schemes. The latest figures, published alongside the March 2016 budget, show that the total cost of the schemes covered by the Levy Control Framework is due to rise to £8.6bn for the period 2020/21.³⁰ DECC has announced a range of measures to address the projected over-allocation of renewable energy subsidies.³¹

Government Electricity Rebate

- 2.111 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

- 2.112 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

²⁹ National Audit Office (27 November 2013), [The Levy Control Framework](#).

³⁰ The figure shown in the OBR's Economic and Fiscal Outlook of March 2016 is £10.9 billion as this is in nominal terms. The figure of £8.6 billion is in 2011/12 prices, consistent with the £7.6 billion figure we previously published.

³¹ These include, for instance, new feed-in tariff rates, various amendments to the ROC regime and ending of the Green Deal funding (see DECC's press releases of [17 December 2015](#), [22 July 2015](#) and [23 July 2015](#)).

the competing goals of ensuring security of supply, improving affordability and reducing emissions.

- 2.113 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.³² We consider the policy trade-offs within the current system of energy taxation in more detail in Section 18.
- 2.114 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

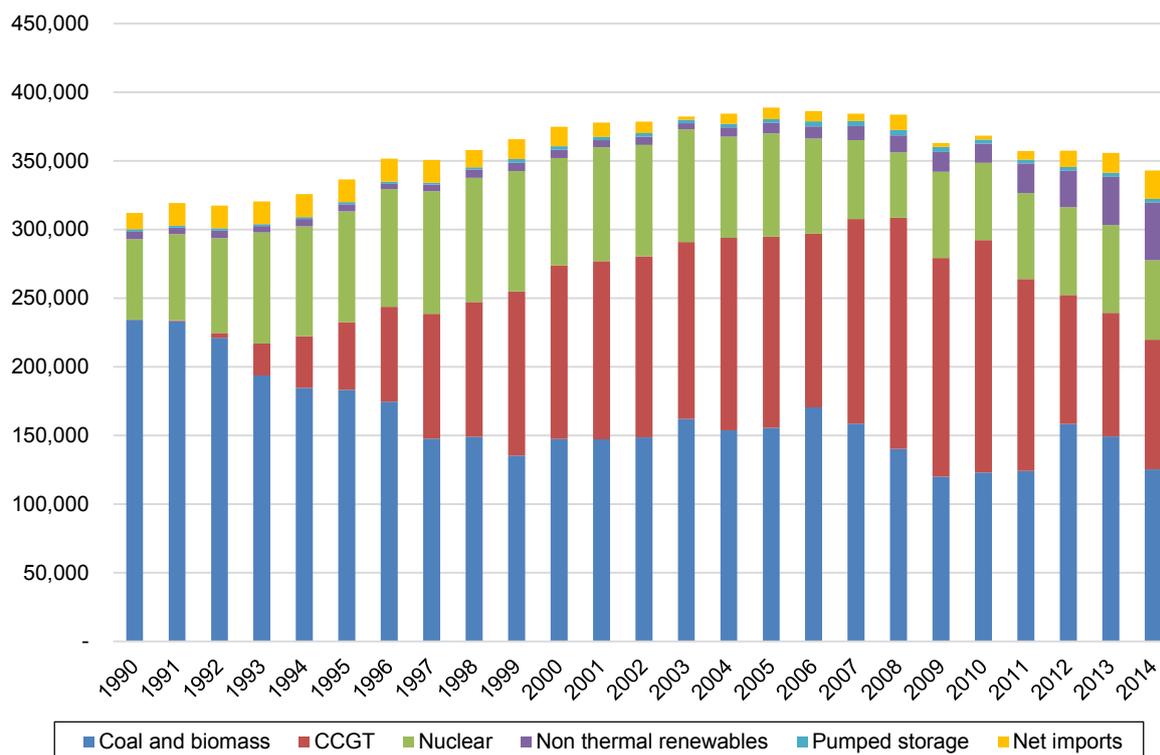
- 2.115 In this section we review some of the key changes that have taken place in the supply and demand of electricity and gas over the period since privatisation, with a particular focus on the decarbonisation and security of supply objectives discussed earlier.

Electricity supply and demand

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

³² Source: IFS, *Energy use policies and carbon pricing in the UK*.

Figure 2.3: Annual electricity generation by technology type, 1990 to 2014 (GWh)



Source: [Digest of UK energy statistics \(DUKES\) 2015](#), Table 5.1.3.

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

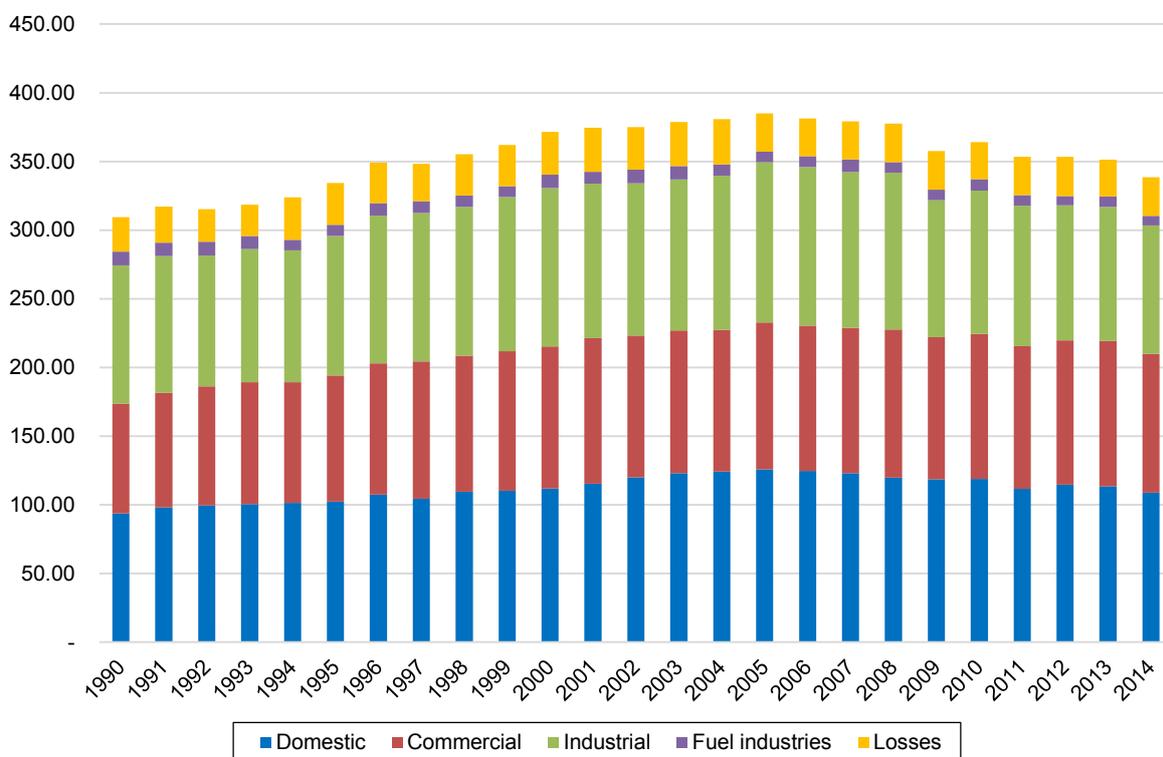
- the rapid expansion in the use of combined-cycle gas turbine (CCGT) plants in the 1990s, from no generation in 1990 to almost 50% of generation in 2010. In the period 2012 to 2014, there was a significant contraction in the use of CCGTs, caused both by the fall in coal prices relative to gas prices 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 2015 suggest that renewable generation was almost 25% of total generation over the year;³³
- generation from nuclear plant grew to 1998, then halved over the following ten years, before picking up from 2009 onwards; and

³³ DECC, [Energy Trends: March 2016](#), Section 6.

- while the level of net imports has fluctuated year on year, there have been consistently positive net imports in each year since 1990 and they reached their highest level in 2014.

2.118 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 consumption³⁴ 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%.

Figure 2.4: Annual electricity consumption by sector, 1990 to 2014 (TWh)

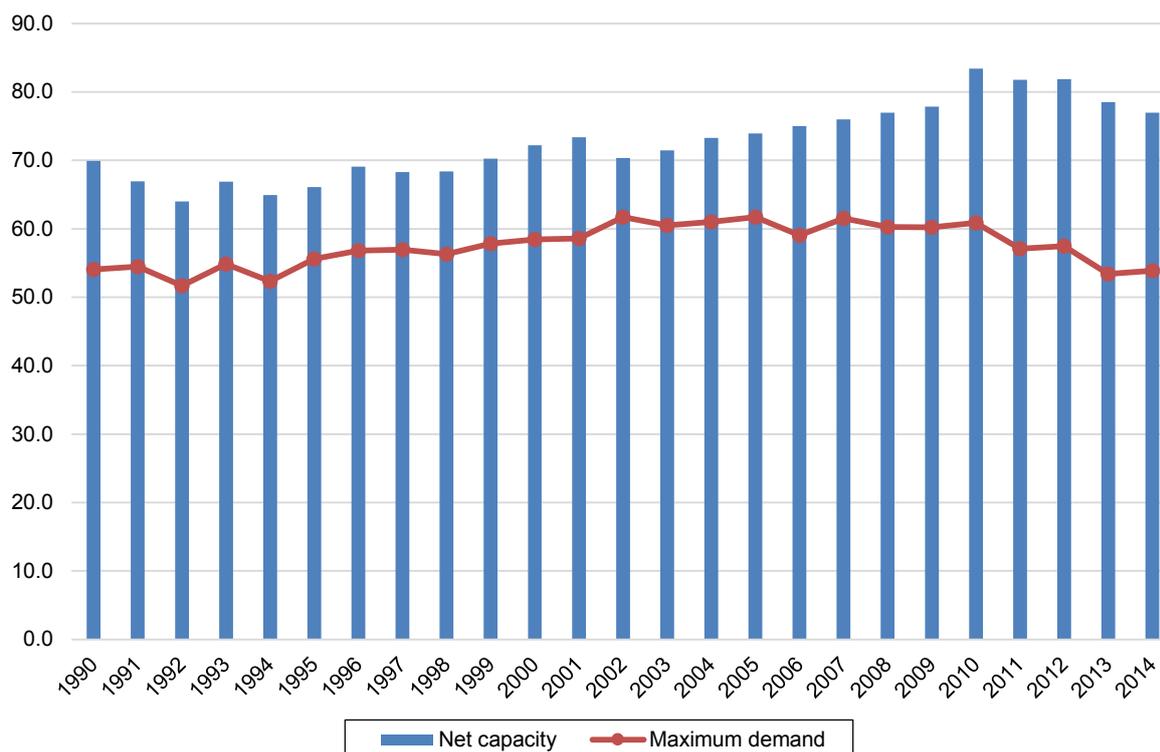


Source: DECC, [Historical electricity data, 1920 to 2013](#).

2.119 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.

³⁴ Microbusiness represents a subset of the ‘commercial’ sector shown here.

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



Source: DECC, [Historical electricity data, 1920 to 2014](#).

2.120 There has been only one loss of load event in the last four years.³⁵ 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.³⁶

2.121 Not all generating capacity is equally reliable. An increasing proportion of capacity is from renewable generation, much of it, such as wind, is 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.

2.122 While Figure 2.5 appears to show the capacity margin widening in recent years, Ofgem has stated that the outlook for winter 2016/17 is uncertain.³⁷

³⁵ 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).

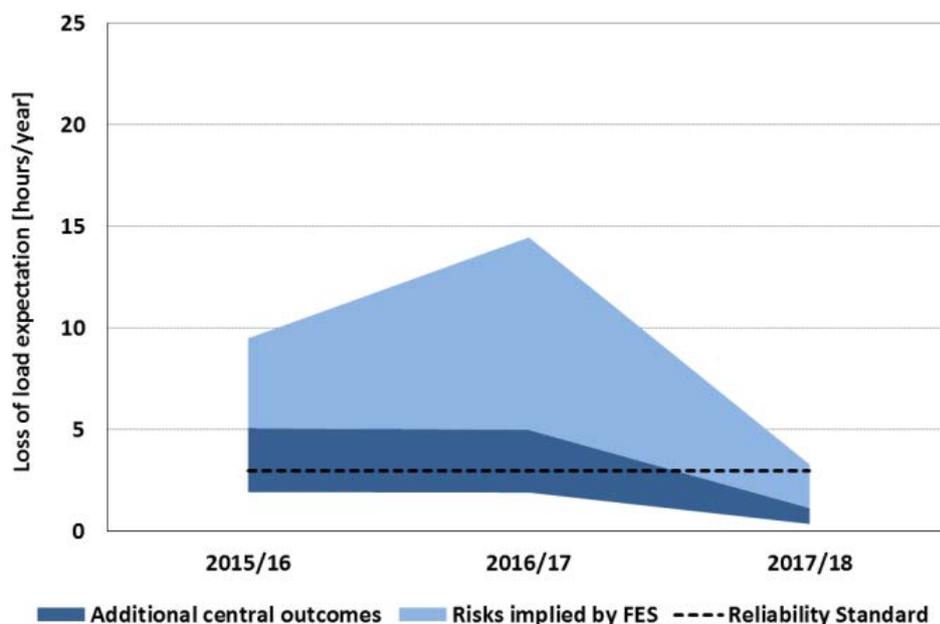
³⁶ National Grid (2012) [Saturday 11th February 2012](#), presentation to Electricity Operational Forum. This event illustrates that security of supply events do not necessarily occur at peak demand – this event occurred on a Saturday morning, rather than at the weekday peak.

³⁷ Ofgem (July 2015), [Electricity security of supply: A commentary on National Grid's Future Energy Scenarios for the next three winters](#), p6.

National Grid (with support from DECC and Ofgem) has developed two new balancing services (the Supplemental Balancing Reserve (SBR) and the Demand Side Balancing Reserve (DSBR)) to allow it to procure additional reserve from both demand-side participants and power stations.³⁸ On 4 November 2015, National Grid issued a Notice of Insufficient Margin as a result of low capacity margins, and made use of its DSBR to maintain security of supply.³⁹

2.123 Figures 2.6 and 2.7 show the range of loss of load expectation (LOLE)⁴⁰ and derated capacity margins to 2017/2018 respectively under National Grid’s Future Energy Scenarios (FES) and Ofgem’s central view. This shows LOLE increasing in 2016/17 under National Grid’s assumptions and falling in the following year.

Figure 2.6: Loss of load expectation to winter 2017/18, excluding SBR/DSBR



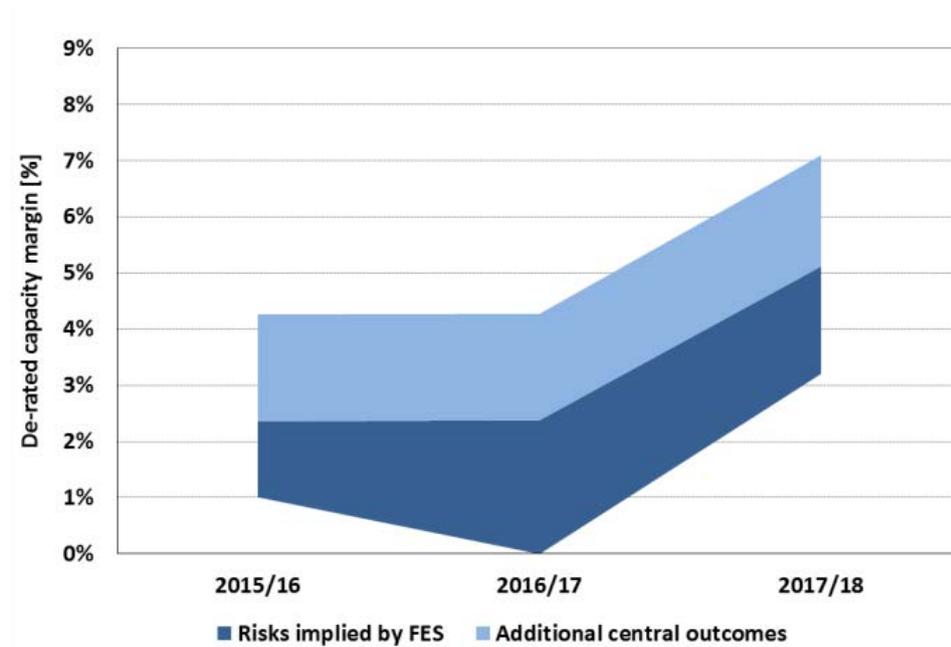
Source: Ofgem (July 2015), [Electricity security of supply: A commentary on National Grid’s Future Energy Scenarios for the next three winters](#).

³⁸ Supplemental Balancing Reserve and Demand Side Balancing Reserve.

³⁹ See [National Grid issues supply margin alert](#), November 2015

⁴⁰ LOLE is “the average number of hours in a year when we expect that there will be insufficient supply available in the market, and National Grid may need to take action that goes beyond the normal market operations to balance the system”. Ofgem (July 2015), [Electricity security of supply: A commentary on National Grid’s Future Energy Scenarios for the next three winters](#), p5

Figure 2.7: Derated capacity margins to 2017/18, excluding SBR/DSBR

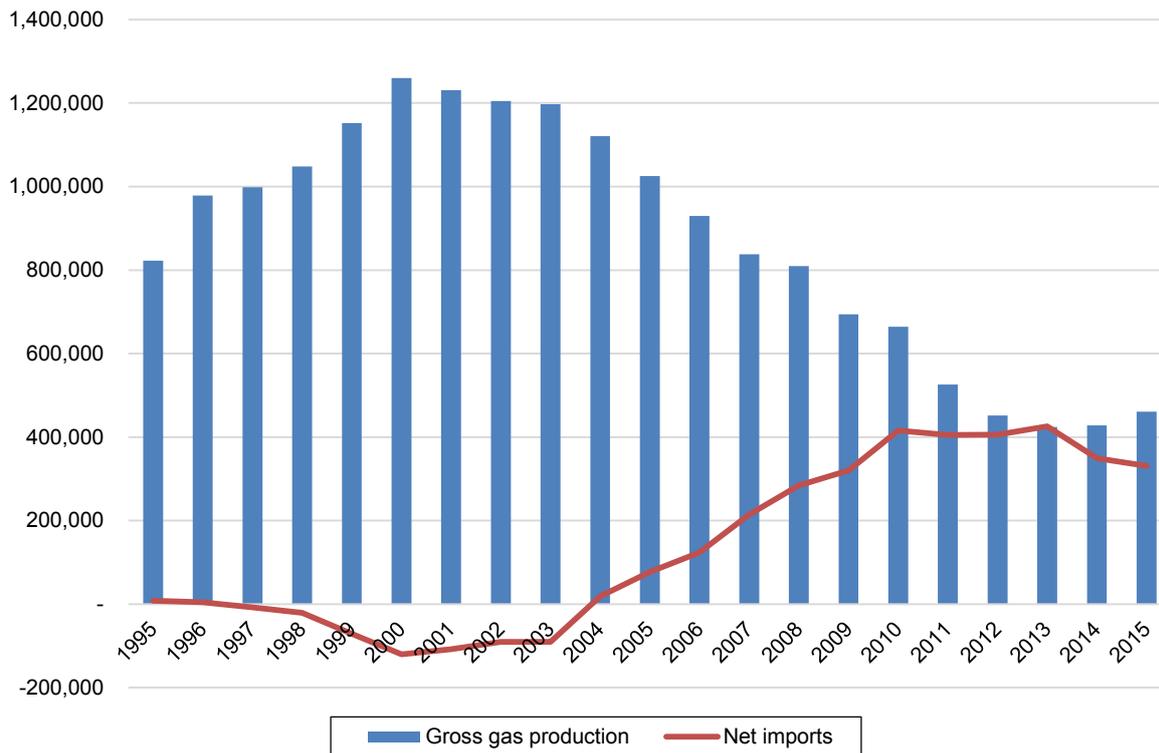


Source: Ofgem (July 2015), [Electricity security of supply: A commentary on National Grid's Future Energy Scenarios for the next three winters](#).

Gas supply and demand

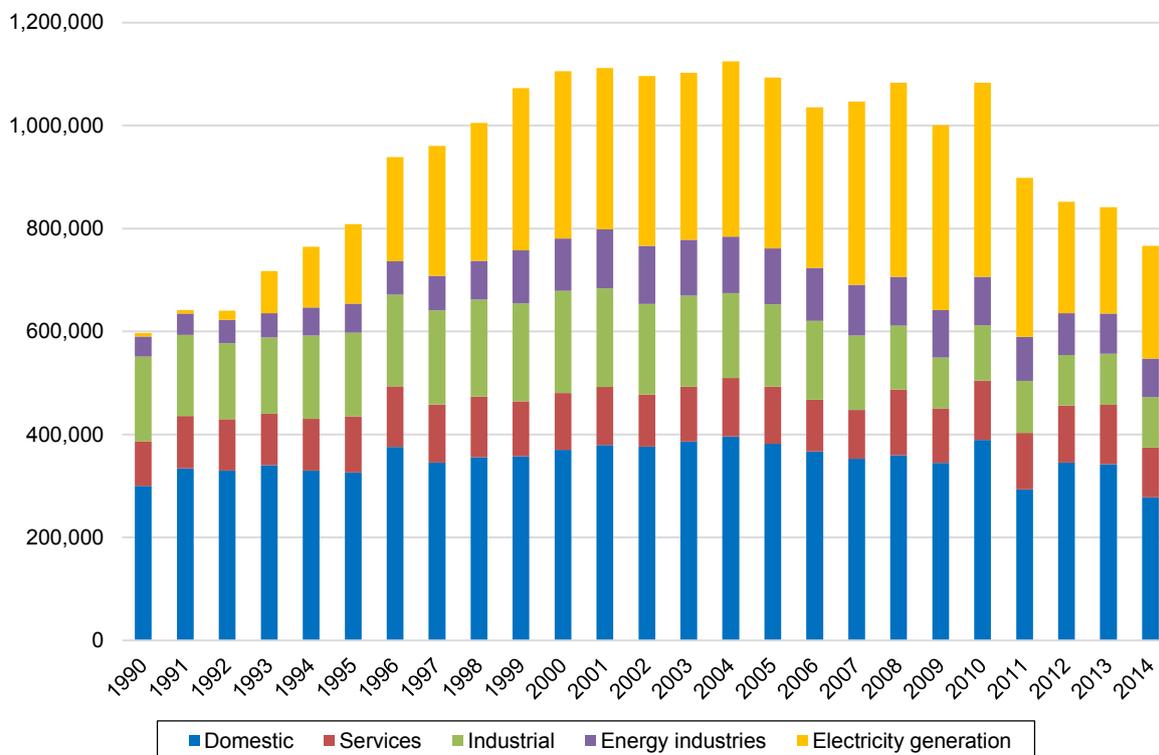
2.124 The figure below shows that gas production peaked in 2000 and that since 2004 the UK has been a net importer of gas. Import capacity has risen considerably over the past 15 years. The current main sources of gas imports into Great Britain are the gas interconnectors (linking to Belgium and the 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 (March 2016), Energy Trends Section 4: Gas.

Figure 2.9: Annual gas consumption by sector (GWh)



Source: DECC, Historical gas data: gas production and consumption 1882 to 2014.

- 2.125 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). In 2014, domestic consumption fell again and was at the lowest recorded level since 1990. 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.⁴¹
- 2.126 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.
- 2.127 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:
- 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;⁴² 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.⁴³
- 2.128 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).
- 2.129 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

⁴¹ 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](#).

⁴² LNG is transported in specialised container ships and then re-gasified prior to being input into the network.

⁴³ 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.

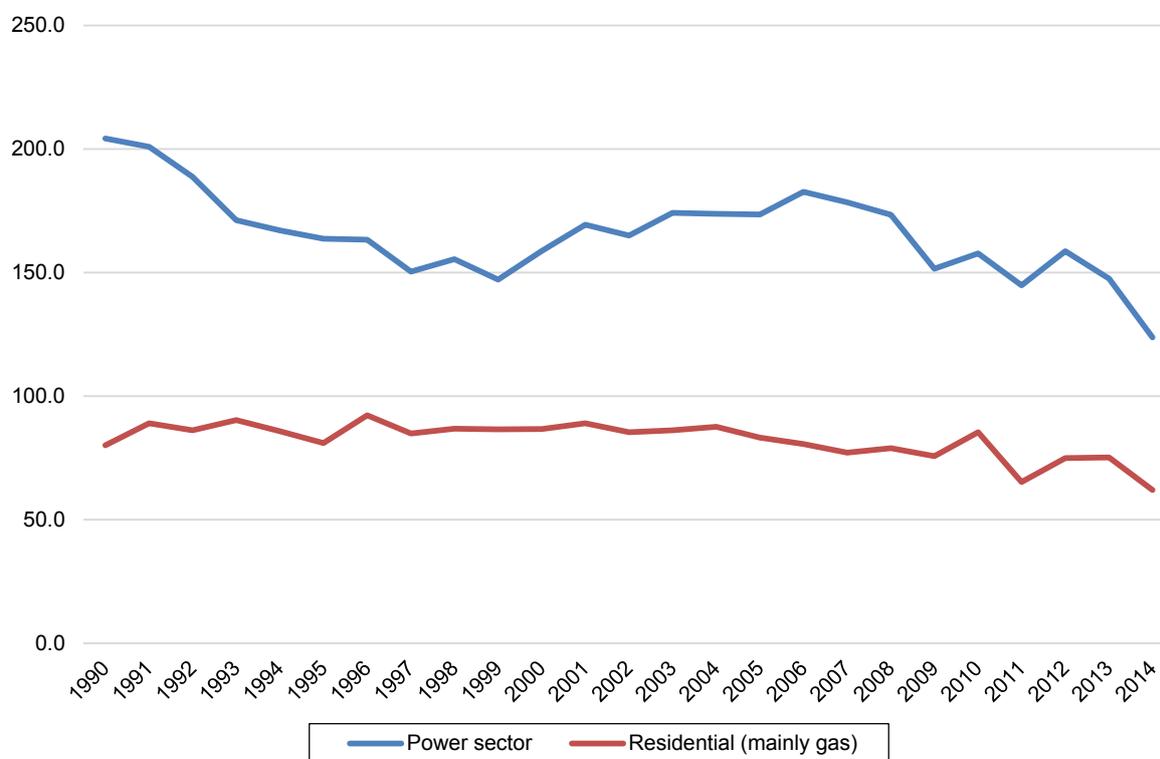
respectively. On this metric the UK was the ninth most resilient EU member state to gas supply infrastructure disruptions.⁴⁴

2.130 There has never been a network gas supply emergency in Great Britain.⁴⁵

Greenhouse gas emissions relating to electricity and gas

2.131 Overall UK emissions in 2012 were roughly 25% below 1990 levels, such that the first carbon budget (from 2008 to 2012) was met.⁴⁶ 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.

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



Source: DECC, 2014 Greenhouse Gas Emissions, Final Figures.

2.132 Residential emissions initially rose but have fallen since 2004, reaching their lowest level in 2014, 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

⁴⁴ DECC (2014), [Physical gas flows across the EU-28 and diversity of gas supply in 2013](#).

⁴⁵ National Grid, [Network Gas Supply Emergencies](#).

⁴⁶ 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.

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 were roughly 40% lower in 2014 compared with 1990, while residential emissions were roughly 23% lower.⁴⁷

Conclusion

- 2.133 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 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 2016/17, with higher associated loss of load expectations.
- 2.134 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.
- 2.135 Emissions from the power sector were roughly 40% lower in 2014 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. Residential emissions were just under 23% lower in 2014 compared with 1990, which likely reflects some improvement in energy efficiency relating to domestic gas consumption.

Prices, costs and profits

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

⁴⁷ 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.

- 2.137 Total revenues from the sale of gas and electricity by the Six Large Energy Firms exceeded £43 billion in 2014, of which revenues from sales to the domestic customers were just under £27 billion (62%), those to SMEs around £3.8 billion (9%) and sales to the Industrial and Commercial customers around £12.5 billion (29%).
- 2.138 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.
- 2.139 An analysis of prices and profitability in the wholesale energy markets is set out in Section 4 and Appendix 4.2.

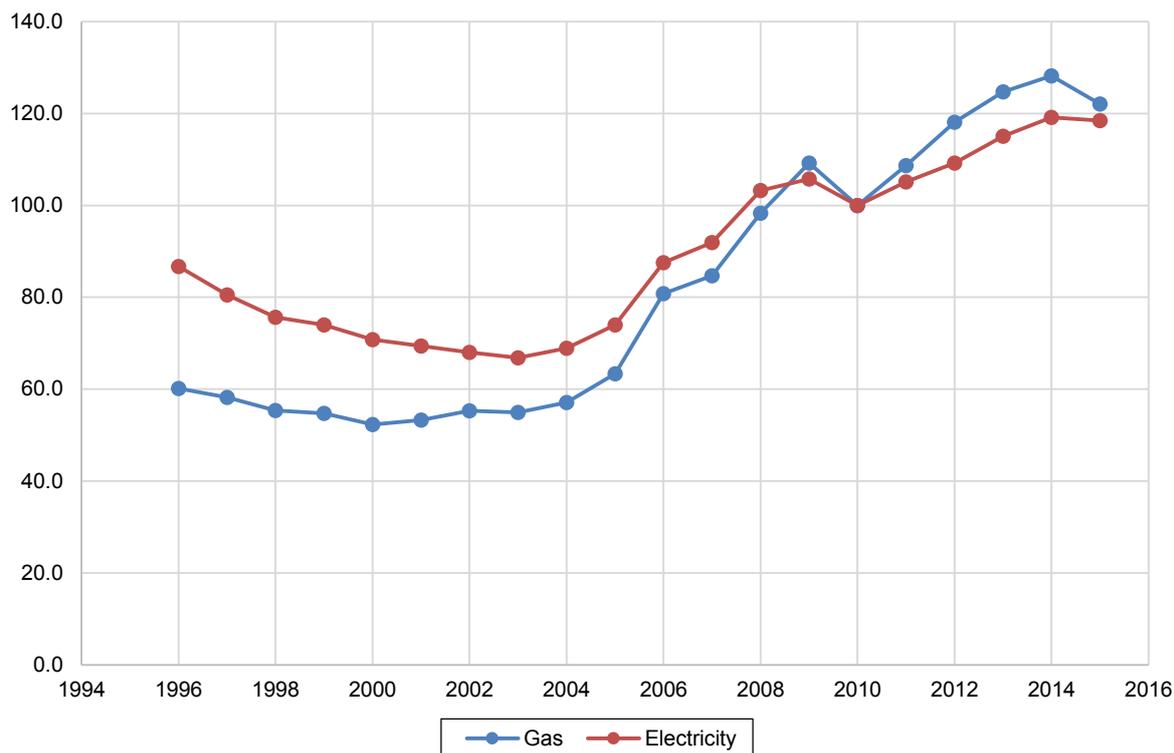
Domestic prices, costs and profits

- 2.140 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.
- 2.141 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 six 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

- 2.142 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 to 2015

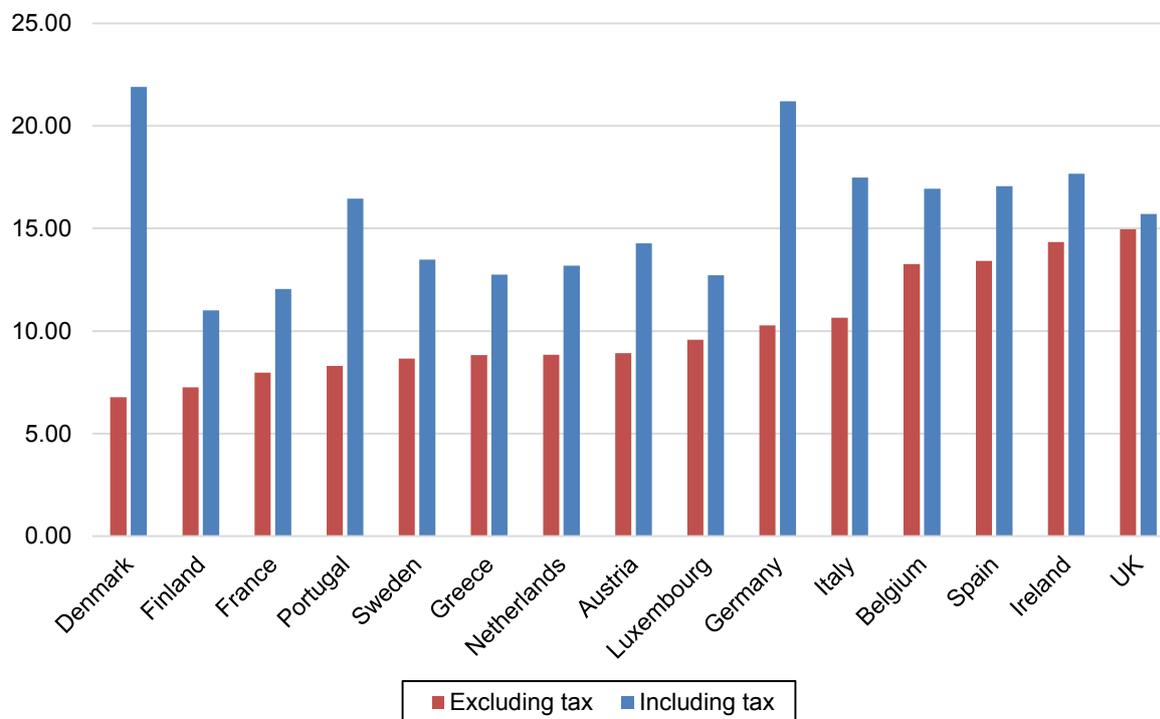


Source: ONS, Consumer prices index. Adjusted for inflation using the GDP (market prices) deflator.

- 2.143 The figure shows that both gas and electricity prices fell in real terms between 1996 and 2004, but increased substantially thereafter. 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. In 2015, the upwards trend halted, with electricity prices roughly flat and gas prices falling nearly 5% year on year in real terms.
- 2.144 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.
- 2.145 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 2015 was the EU 15⁴⁸ median price. The UK price **excluding** taxes was the highest in the EU 15 (and was 67% above the median price).

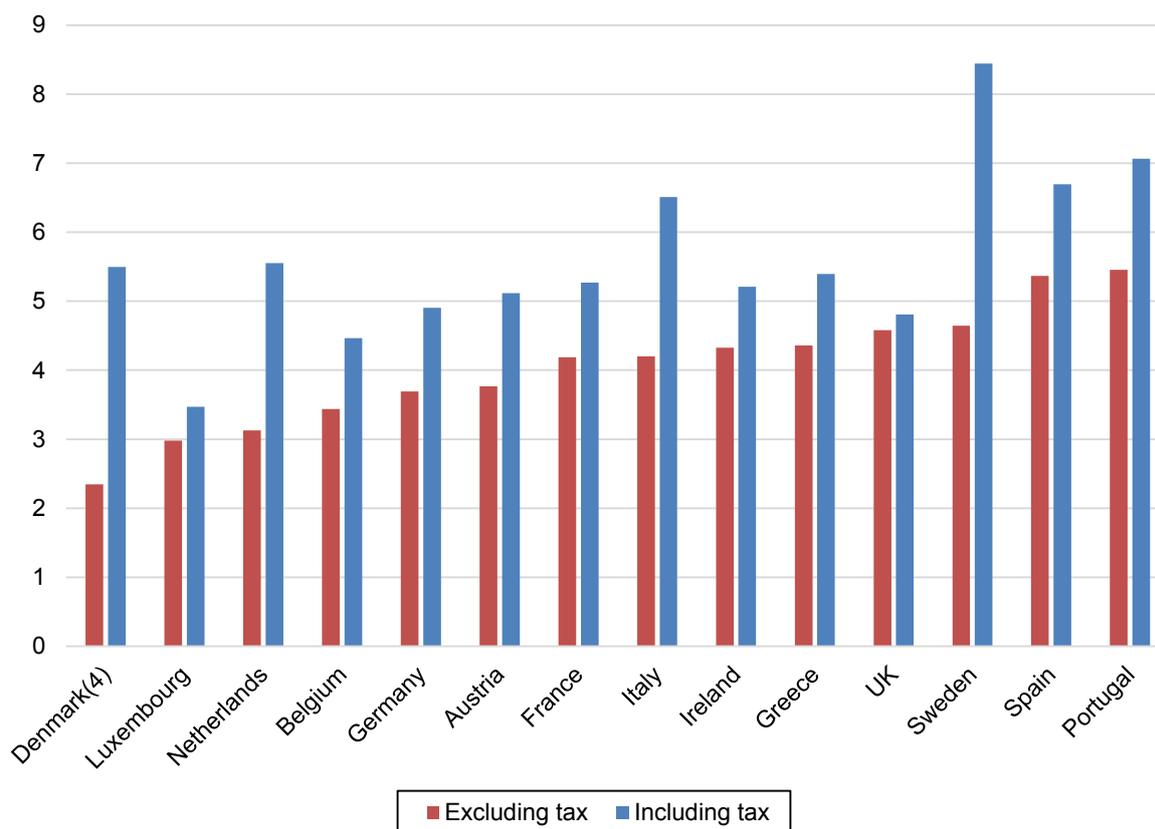
Figure 2.12: Electricity prices in the EU 15 for medium domestic customers from July to December 2015, including and excluding tax (p/kWh)



Source: DECC Domestic electricity prices in the EU, May 2016.

⁴⁸ The EU15 comprises the following 15 countries: Austria, Belgium, Denmark, Finland, France, Germany, Greece, Ireland, Italy, Luxembourg, Netherlands, Portugal, Spain, Sweden, United Kingdom. See the [OECD's Glossary of Statistical Terms](#).

Figure 2.13: Gas prices for medium domestic customers in the EU 15 from July to December 2015, including and excluding tax (p/kWh)*



Source: DECC Domestic gas prices in the EU, May 2016.
*Data for Finland not available.

2.146 For gas, over the period January to June 2015, UK prices for medium domestic customers were third cheapest including tax and eleventh cheapest excluding tax out of 14 of the EU 15 countries.

Changes in average domestic prices and costs

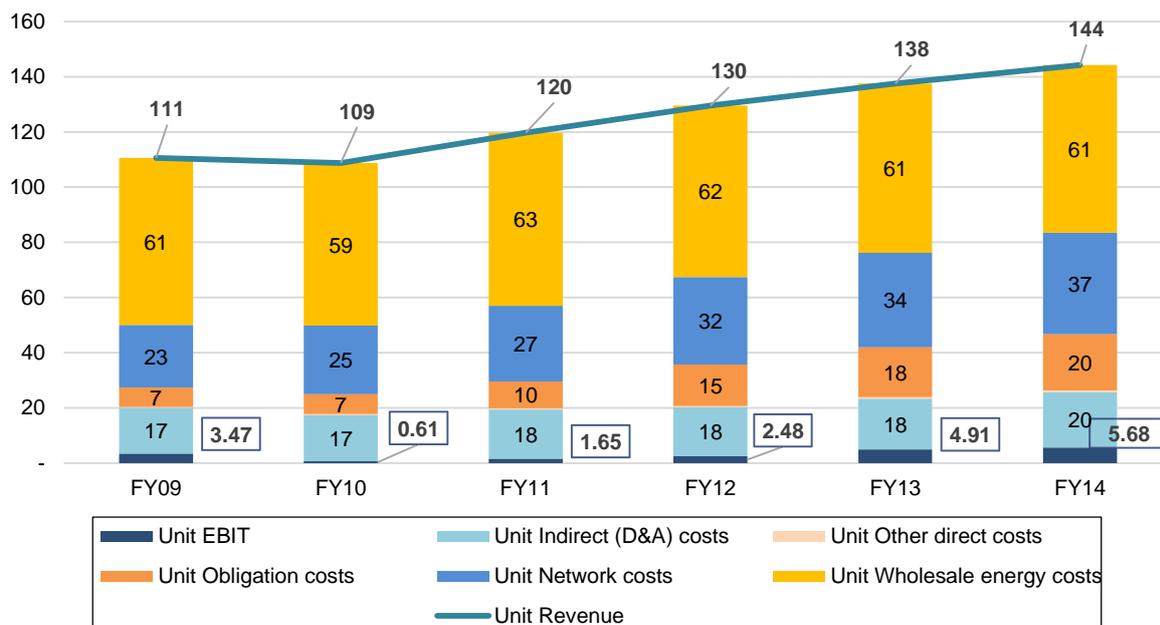
2.147 Figures 2.14 and 2.15 below show data on average electricity and gas prices⁴⁹ and costs as reported by the Six Large Energy Firms over the period 2009 to 2014.⁵⁰ As can be seen in the charts, from 2009 to 2014 average energy prices⁵¹ rose significantly over the period for the domestic customers of the Six Large Energy Firms. Average domestic electricity prices grew by 30% (in nominal terms) over the period, and average domestic gas prices grew by 34%.

⁴⁹ Calculated as revenues/kWh.

⁵⁰ The data is broadly reconcilable with the Consolidated Segmental Statements that Ofgem requires the Six Large Energy Firms to produce.

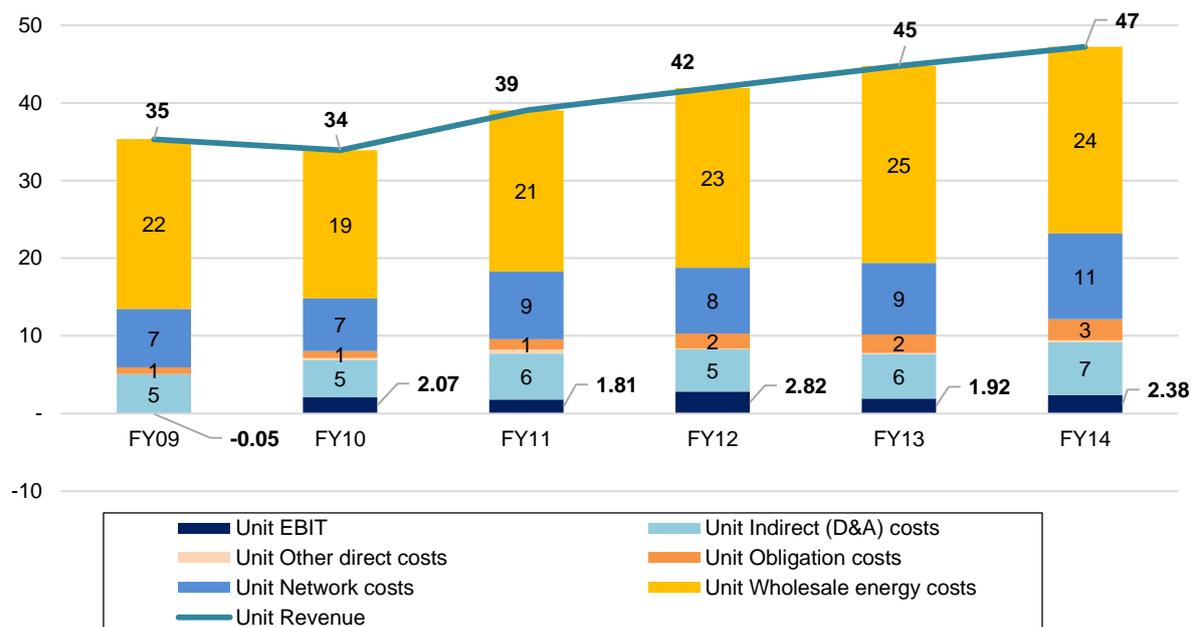
⁵¹ As measured by revenue/kWh.

Figure 2.14: Domestic electricity supply unit revenue breakdown, 2009 to 2014 (£/MWh)



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

Figure 2.15: Domestic gas supply unit revenue breakdown, 2009 to 2014 (£/MWh)



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

- 2.148 The data suggests that average profit (EBIT)⁵² margins earned on sales to domestic customers were 3.5% over the period. Average EBIT margins on sales of gas (4.5%) were higher than those on sales of electricity (2.5%).
- 2.149 For electricity, the main drivers of price increases were the costs of social and environmental obligations⁵³ and network costs. Reported wholesale costs remained flat while EBIT fell sharply in 2010 and rose steadily year on year thereafter. For gas, there was a more even increase in each cost component, with EBIT increasing significantly after 2009.
- 2.150 A significant component of this investigation has been to explore some of these cost elements in more detail. In Section 8 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 9.11, we review the indirect costs incurred by the Six Large Energy Firms and the Mid-tier Suppliers and examine the efficient level of such costs, by considering how they compare between firms and over time.
- 2.151 In relation to obligation costs, the data provided by the Six Large Energy Firms suggested that these represented around 14% of the domestic electricity price and around 6% of the domestic gas price in 2014.⁵⁴ 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 has had a major impact on prices and bills.
- 2.152 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.⁵⁵

Variability in the prices paid by domestic customers

- 2.153 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 mid-2015, average revenue

⁵² Earnings before interest and tax, or gross profit less indirect costs.

⁵³ 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.

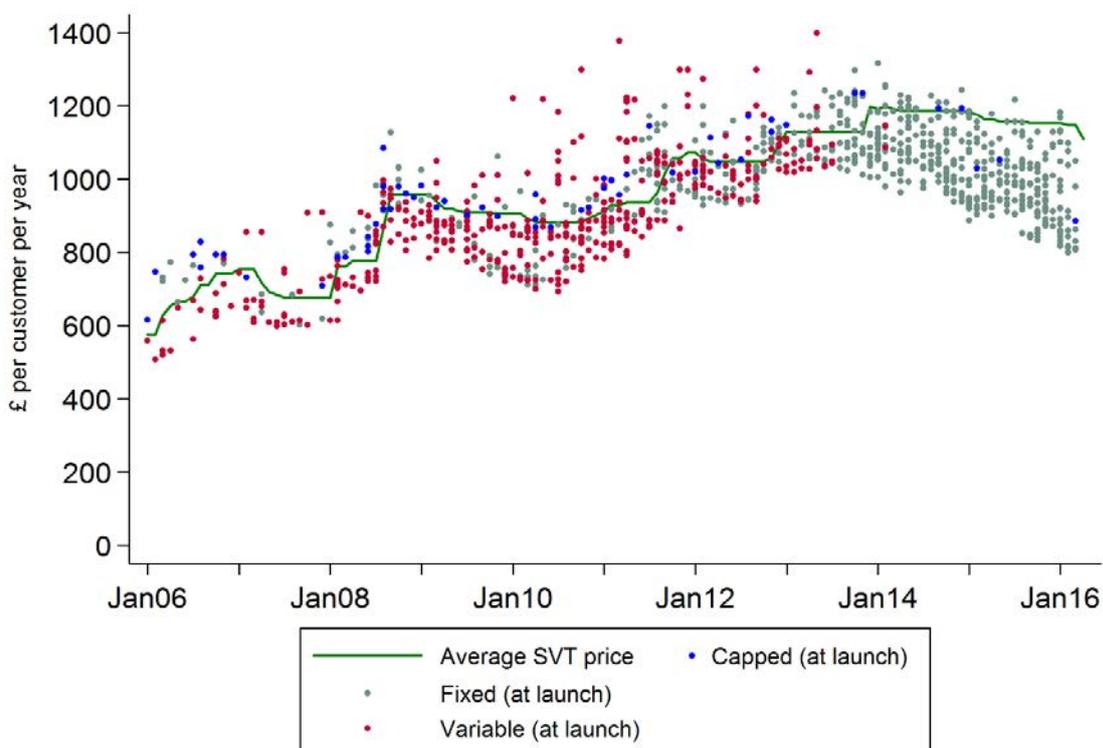
⁵⁴ These figures are broadly consistent with DECC's most recent estimates of the impact of these obligations on prices and bills. See DECC (November 2014), Estimated impact of energy and climate change policies on energy prices and bills.

⁵⁵ The CMA recently considered two appeals against Ofgem's RIIO-ED1 price control decision for electricity distribution companies.

per kWh from the SVT was around 11% and 15% higher than average revenue from non-standard tariffs for electricity and gas respectively across the Six Large Energy Firms.

2.154 The chart below shows all the tariffs that have been launched over the last ten 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 Firms⁵⁶ 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 two years.

Figure 2.16: Tariffs offered by the Six Large Energy Firms and Mid-tier Suppliers, 2006 to 2016 (based on the annual bill of dual fuel direct debit typical consumption customer)



Based on typical domestic consumption of 3200kwh/year for electricity and 13500kwh/year for gas.

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

2.155 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 2015, most customers could have made considerable savings from switching a combination of suppliers, tariffs and payment methods.

⁵⁶ The green line on the chart is a flat average of the SVTs offered by the Six Large Energy Firms.

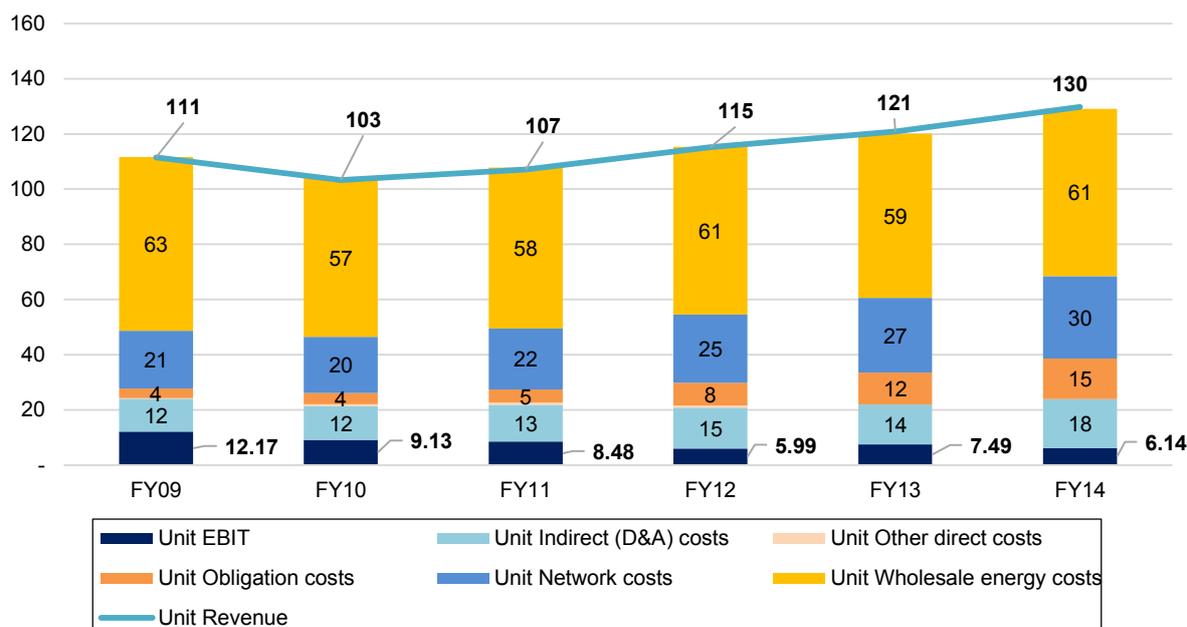
- 2.156 For all the dual customers of the Six Large Energy Firms, average potential gains from switching externally to any tariff offered were equivalent to 14% of the average bill (equivalent to just over £160 a year) over the period. As discussed in Sections 8 and 9, the gains available to specific customers depend considerably on the tariff and payment method that customers are currently on and the supplier they are currently with. For example, the dual fuel SVT customers of the Six Large Energy Firms who pay by standard credit could have saved an average of 23% of their bill (£245) by switching tariff and/or supplier and payment method, while the dual fuel customers of the Six Large Energy Firms who are on non-standard tariffs could have saved an average of 9% of their bill (£109) by switching over the period.⁵⁷
- 2.157 A key question that we consider in Sections 8 and 9 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

- 2.158 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. Between 2009 and 2014 average electricity prices grew by 16% and average gas prices grew by 15%, 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.
- 2.159 EBIT margins in the SME retail energy markets were on average 8.0% over the period – significantly higher than those on sales to domestic customers. Margins on sales of gas to SMEs (9.9%) were higher than those on sales of electricity (7.4%).

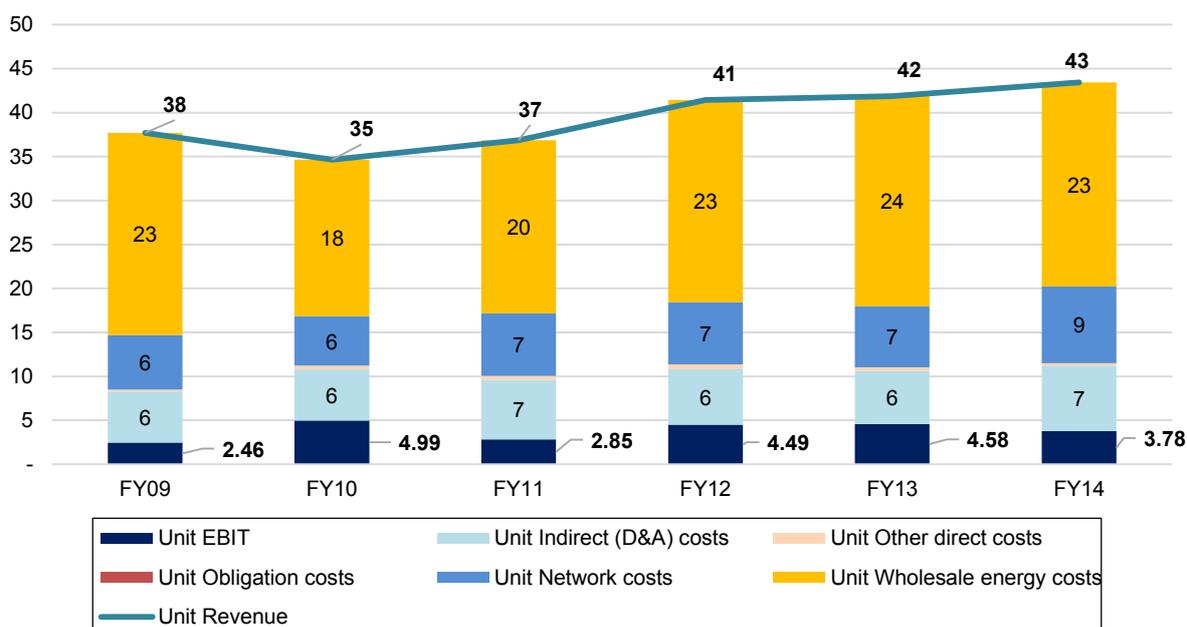
⁵⁷ As discussed further in Sections 8 and 9, these results deduct exit fees from the savings available to customers on non-standard tariffs, where these are applicable.

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

2.160 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).

- 2.161 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.
- 2.162 In Section 14, 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?

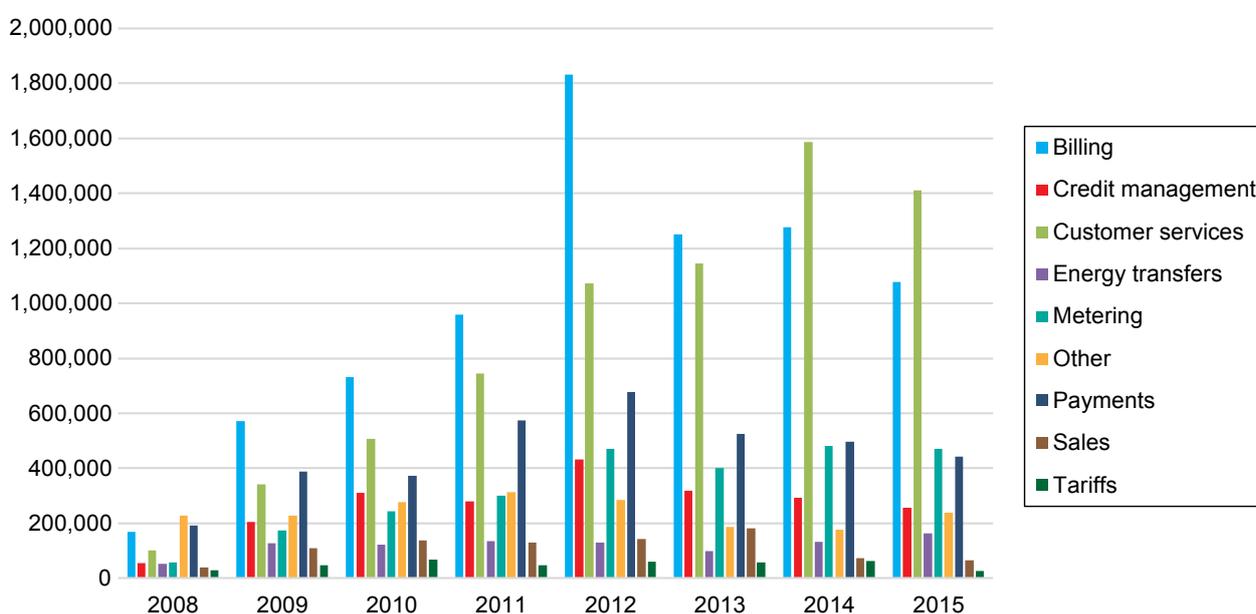
- 2.163 A key question we have considered in this investigation is whether the average prices paid by customers have been above the levels that we would expect to see in a well-functioning competitive market.
- 2.164 In Section 9 we set out our analysis on this issue in relation to domestic customers, employing two approaches to assessing the extent to which prices have been excessive:
- a 'direct' approach, which involves comparing the average prices charged by different suppliers, while controlling for those exogenous differences in each supplier's customer base that are likely to affect costs; and
 - an indirect approach, which involves assessing both:
 - (i) suppliers' levels of profitability (and in particular whether the return on capital employed (ROCE) by suppliers exceeds their cost of capital); and
 - (ii) the extent to which suppliers have incurred costs inefficiently (ie whether costs are higher than we estimate an efficient supplier would incur).
- 2.165 In Section 14, we set out similar analysis in relation to microbusinesses, focusing on the indirect approach (in the absence of sufficient data to employ the direct approach).

Quality of service

2.166 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 nearly sixfold from 2008 to 2014 and then fell by 20% in 2015; and
- problems related to billing, customer services and payments accounted for the majority of complaints, as shown in the chart below.

Figure 2.19: 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.

2.167 Complaints received by the Energy Ombudsman increased by more than fivefold between 2012/13 and 2014/15, driven primarily by complaints concerning billing, although problems relating to transfers have also been a factor.⁵⁸ 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.

2.168 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.

⁵⁸ [Energy Ombudsman 2014/15 Annual Report](#).

- 2.169 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.⁵⁹
- 2.170 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 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

- 2.171 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.
- 2.172 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

- 2.173 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

⁵⁹ A summary of results is available on the [Which? website](#).

‘competition for the market’, in which operators compete for long-term contracts through a centralised allocation process.

- 2.174 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.
- 2.175 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. Overall, on the basis of current announced plans, DECC estimates that climate and energy policies will comprise 37% of the retail price of electricity paid by households in 2020.⁶⁰
- 2.176 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 Sections 5 and 6, in relation to CfDs.

Increasing importance of renewable generation

- 2.177 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.
- 2.178 In 2015 the share of renewables in generation output was about 25% 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

- 2.179 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 Sections 8 and 11.

⁶⁰ 2014 prices. Source: DECC (November 2014), [Estimated impact of energy and climate change policies on energy prices and bills](#).

2.180 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 Sections 8 and 9 we consider changes to the regulatory framework that are required to achieve these outcomes.

Final observations

2.181 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.

2.182 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.

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

3. Market definition

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Introduction

- 3.1 In this section we set out our approach to market definition.¹ 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.²
- 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.³ 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.⁴
- 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

¹ 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).

² CC3, paragraphs 94 & 132.

³ CC3, paragraph 130.

⁴ CC3, footnote 74 (paragraph 132).

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.⁵

- 3.4 There are normally two dimensions to the definition of a market: a product dimension and a geographic dimension. Each of these aspects are considered below. In line with previous decisions taken by Ofgem and competition authorities, we assessed wholesale and retail markets separately.
- 3.5 Our starting point for assessing market definition was the terms of reference for this investigation, which concern the activities connected with wholesale and retail supply⁶ 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,⁷ 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.⁸
- 3.7 We considered first 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.

⁵ CC3, paragraph 133.

⁶ 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](#).

⁷ We include in these activities ancillary services associated with the wholesale supply of electricity and gas.

⁸ 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.

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 signals (in particular, domestic customers and microbusinesses).⁹ We also noted 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 conclusion is therefore that the upstream production and importation of gas and upstream generation and importation of electricity are distinct wholesale product markets.¹⁰

Further segmentation by types of products

- *Wholesale electricity*

- 3.9 We 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.¹¹ 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.

⁹ See further Section 4, the nature of wholesale competition and Section 8, the nature of retail competition. We note that the responsiveness of customers to short-term changes in price is likely to be greater following settlement reform facilitating the introduction of time-of-use tariffs, as discussed in Section 11.

¹⁰ 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.

¹¹ See further Section 4, the nature of wholesale competition and Section 8, the nature of retail competition.

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

3.12 However, within the context of our investigation, it was not necessary to distinguish between products by any of these characteristics (eg time, baseload/peakload, or source). Accordingly, we therefore 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*

3.13 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).

3.14 We note that in previous decisions, the European Commission found that gas storage, or gas flexibility, could constitute separate product markets.¹² However, within the context of our investigation, it was not necessary to adopt a similar approach. Accordingly, we therefore consider the wholesale gas market to be one market comprised of different segments including production (including imports through interconnectors) and trading.

Geographic definition

3.15 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

¹² 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.

compete closely because enough customers consider them to be substitutes.

- 3.16 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.
- 3.17 There can be times, especially as regards electricity generation and importation, when transmission constraints render competition on a GB-wide 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.
- 3.18 We noted 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 market¹³ or, more frequently, a GB market.¹⁴ For the purposes of our investigation, however, it was not necessary for us to take a definitive view on this.
- 3.19 Accordingly, our conclusion is therefore that the geographic wholesale markets for both gas and electricity are the whole of Great Britain.

Retail energy market(s)

Product definition

- 3.20 We considered whether the retail energy market(s) may be distinguished by types of fuel, by categories of customers or by tariff types.

Types of fuel

- 3.21 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

¹³ 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.

¹⁴ Storengy UK Ltd's application for a minor facilities exemption for Stublach phase 2.

short-run price signals (in particular, domestic customers and microbusinesses).¹⁵ Our conclusion is therefore that the retail supply of gas and electricity are in distinct product markets.¹⁶

- 3.22 We also considered whether it may be appropriate to segment the retail energy markets more narrowly by category of customer and/or by tariff types.

Categories of customers

- 3.23 Retail suppliers may provide gas and electricity to customers connected to the distribution grid. These include households, SMEs (including microbusinesses) and I&C¹⁷ (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. We first examined whether it was appropriate to distinguish separate markets between domestic customers and SMEs, and then within each of these two categories of customers.

- *Domestic customers vs SMEs*

- 3.24 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.

¹⁵ See further Section 7, the nature of retail competition.

¹⁶ We include in this definition of the product markets the services associated with the retail supply of gas and electricity including billing and metering.

¹⁷ 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.

- (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.¹⁸

3.25 In light of the material demand-side and supply-side differences, our conclusion is that domestic customers are in different markets from SME customers in relation to both gas and electricity.

- *Microbusinesses vs larger SMEs*

3.26 We also considered whether retail supply to microbusinesses should be distinguished from larger SME customers. SMEs are highly diverse in size, complexity, and their electricity and gas needs. We also found, as set out in Section 14, 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.

3.27 We noted that there are regulations specific to microbusinesses, and considered whether, on that basis, retail supply to microbusinesses might be considered as separate markets from the SME markets. However, we noted that, in practice, retail suppliers generally apply the same protections to all of the customers that they classify as SMEs, and therefore we did 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.

3.28 Accordingly, we consider that microbusinesses are a distinct segment of the markets for the supply of electricity and gas to SMEs in Great Britain, respectively.

¹⁸ See Section 8.

Length and type of contracts (domestic customers)

- 3.29 We also considered whether the domestic retail markets could be defined more narrowly based on the duration and/or type of supply contracts.
- 3.30 We note in Sections 8 and 9 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 noted that different domestic customers pay widely varying prices for their energy, with those who have not engaged generally paying more than those who have.
- 3.31 As set out in our Guidelines, we reflected 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.¹⁹
- 3.32 We 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 noted that all suppliers have consistently priced their SVTs at a premium to fixed-term tariffs. In Sections 7 and 8, we have found that suppliers are able to price discriminate between domestic customers on an SVT and those on a non-standard tariff.
- 3.33 However, as we considered in Sections 8 and 9, 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 did not think that customers subscribing to SVT and non-standard tariffs were sufficiently distinct to warrant defining separate markets for them.
- 3.34 Accordingly, our conclusion is that customers subscribing to an SVT and those subscribing to non-standard tariffs fall into different market segments

¹⁹ CC3, paragraph 150.

of the domestic retail markets, in the light of the different intensity of competition to which they are subject.

Types of payment method and meter (domestic customers)

- 3.35 Domestic customers may pay for their gas and electricity using one of three types of payment method: direct debit; standard credit; and prepayment. Domestic customers can also be distinguished according to the meter used to measure their consumption of gas and electricity. Meters can be categorised in a range of ways, notably:
- (a) 'smart' as opposed to 'dumb' meters; and
 - (b) within the category of dumb meters:
 - (i) credit as opposed to prepayment meters; and
 - (ii) single-rate as opposed to restricted meters.²⁰
- 3.36 Most domestic customers pay by direct debit and are on a credit single-rate 'dumb' meter, although we note that by 2020 all domestic customers are due to be transferred to smart meters.
- 3.37 Most customers have a choice as to whether to pay by standard credit or direct debit. Prepayment, in contrast, is not generally a choice on the part of the customer: all customers on (dumb) prepayment meters must pay by prepayment or switch meter. 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.
- 3.38 We note in Sections 8 and 9 below that the intensity of competition to attract customers differs considerably between customers on different payment methods. The cheapest deals are available to customers paying by direct debit, while customers who pay by prepayment have a much more limited range of tariffs to choose from, with the cheapest prepayment tariffs far in excess of those available to direct debit customers, and considerably higher than our estimate of the additional cost of serving prepayment customers.
- 3.39 We note that the restricted availability of tariffs is in part due to technical constraints affecting competition for customers on dumb prepayment meters. We also note that customers on prepayment meters have different characteristics from other domestic customers. For example, fewer prepayment customers use gas and prepayment customers are disproportionately

²⁰ Including Economy 7 meters.

represented within the socio-demographic groups that, in our survey, showed lower levels of engagement.

- 3.40 Accordingly, we consider customers paying by direct debit, standard credit and prepayment 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.
- 3.41 We also note in Sections 8 and 9 below that customers on non-Economy 7 restricted meters have access (unless they choose to switch meter) to a much more limited range of tariffs than customers on single-rate meters and that they face certain additional barriers to accessing information and switching suppliers compared with customers on single-rate and Economy 7 meters. We therefore consider that customers on non-Economy 7 restricted meters fall into a different market segment to customers on single-rate and Economy 7 meters.

Geographic definition

- 3.42 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.
- 3.43 We noted that:
- (a) the regulatory regime, which determines to a large extent the basic parameters of retail competition, applies equally across Great Britain; and
 - (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).
- 3.44 These considerations apply to both domestic and SMEs customers.
- 3.45 Accordingly, we 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.

Conclusion on the relevant markets

- 3.46 On the basis of the analysis set out in this section, we have concluded that the following are 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.
- 3.47 In this report, 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.
- 3.48 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 this report, 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

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Introduction

- 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. We identify specific areas of competition concern that have warranted more detailed investigation, which we provide in Section 5. 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.
- 4.2 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.
- 4.3 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.

- 4.4 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.
- 4.5 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.
- 4.6 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 to all consumers by 2020 (see Section 8 and Appendix 8.4) and some increase in demand responsiveness is an important part of the anticipated benefits.
- 4.7 There are unavoidable risks in the long-run and short-run decisions of market 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.
- 4.8 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 vertical integration 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.

4.9 This section: provides an overview and basic description of these complicating factors; assesses their impact on the nature of competition; and identifies specific areas of competition concern that we have investigated in more detail. 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.¹
- (b) We analyse the nature of competition in the **wholesale electricity market**, along the same dimensions.²

Wholesale gas market

Investment decisions

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

4.11 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

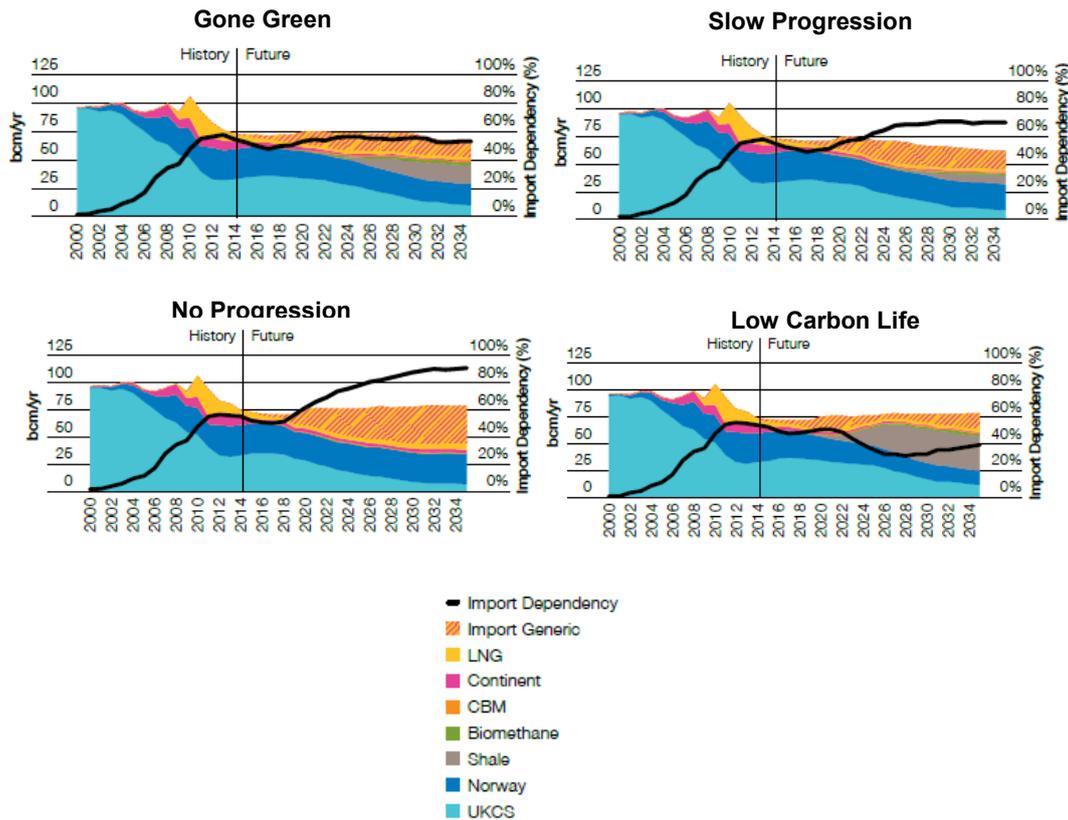
¹ This section draws on Appendix 8.6: Gas and electricity settlement and metering and our [working paper](#) on the Gas Wholesale Market, which set out our analysis in more detail.

² 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; 7.1: 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.

but increasing amount is shipped in on LNG ships, much of it originally extracted in Qatar.

- 4.12 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.³ 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.

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.

- 4.13 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.
- 4.14 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

³ For details, see our [working paper](#) on the Gas Wholesale Market, and specifically the section – ‘Barriers to entry’.

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.

- 4.15 An important factor in fossil fuel investment decisions worldwide is 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 carbon price support, which put an explicit price on carbon emissions, have led to a degree of coal to gas switching.

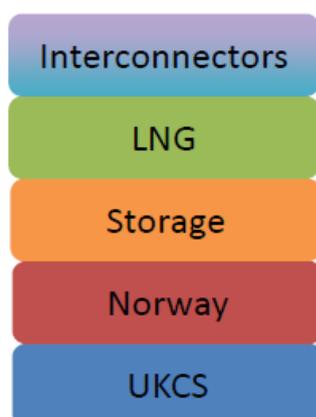
Short-run production decisions and the price-setting process

- 4.16 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

- 4.17 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.

- 4.18 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.

- 4.19 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

- 4.20 There is competition between providers of gas within and between sources. Ofgem provided us with analysis of market shares and HHIs⁴ for the gas wholesale market, covering both overall gas supply and 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 603. 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, 2013/14



Source: Ofgem based on shipper/industry data (confidential and commercially sensitive).
Note: HHI = 603.

- 4.21 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

⁴ Herfindahl-Hirschman Index.

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).⁵

4.22 [✂]

4.23 [✂]

4.24 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:⁶

(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 contract forwards. 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.

4.25 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

⁵ 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 updated 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](#).

⁶ See our [working paper](#) on the Gas Wholesale Market, and specifically the section – ‘Potential for unilateral market power’.

set by the opportunity cost of the last producer required to meet that demand.

- 4.26 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.

System operation and settlement

- 4.27 A gas supplier – a firm with a retail customer who has the ultimate demand for gas – must contract with a producer for a sufficient quantity of gas to meet its customers' demand. However, there are two aspects of the wholesale gas market which make this quite difficult to achieve.
- 4.28 The first complicating factor is that the gas that is bought and delivered by the producer is not 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 not the gas consumed. There therefore needs to be a central balancing organisation – the system operator, 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 system operator becomes the sole counterparty for trades on that day.⁷ Trades are conducted through the on-the-day commodity market where producers and consumers can offer balancing bids: the price at which they are prepared to increase or reduce supply or demand.
- 4.29 The second feature of the gas transportation system that complicates transactions is that most consumers are very approximately metered in their actual consumption of gas.⁸ Balancing is required day by day, but 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.

⁷ See our [working paper](#) on the Gas Wholesale Market, paragraph 2.

⁸ For details, see Sections 8 and 9 and Appendix 8.6: Gas and electricity settlement and metering.

4.30 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 existing physical infrastructure, these working approximations continued to be used, but their deficiencies have become increasingly apparent, particularly with the gradual introduction of smart meters and the possibility of increased demand responsiveness in the energy system. We discuss problems arising from the system of gas settlement in Sections 8 and 12, and the difficulties that have been experienced in attempts to reform gas settlement through the system of industry codes in Section 18.

Vertical integration

4.31 There is a small degree of vertical integration in the gas market.⁹ 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.

4.32 Figure 4.4 shows the degree to which, in 2013/14, 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 (2013/14)*

[✂]

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.

4.33 We do not believe that the harm that can sometimes arise from vertical integration – 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 of gas fields, remains a net

⁹ See our [working paper](#) on the Gas Wholesale Market and specifically the section – ‘Vertical integration’.

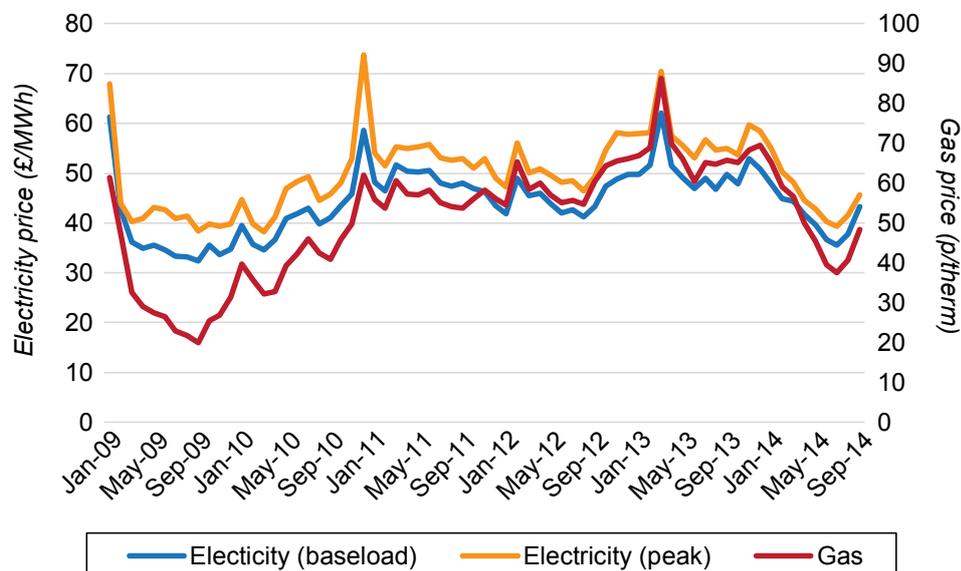
buyer of gas in the wholesale market. Higher wholesale prices would thus damage Centrica.

4.34 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 are therefore often the cause of 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

4.35 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, NBPGDAH.

4.36 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.¹⁰ 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 2008.¹¹

Figure 4.6: Traded volume and churn on GB gas markets

[✂]

Source: Ofgem (response on 6 May 2016).

Note: *Units used are billion cubic metres. 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.

4.37 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 judged¹² these issues 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.

Conclusion

4.38 Based on the analysis set out above, we have not found any features within the wholesale gas market that lead to an AEC.

Wholesale electricity market

Investment decisions and capacity

4.39 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

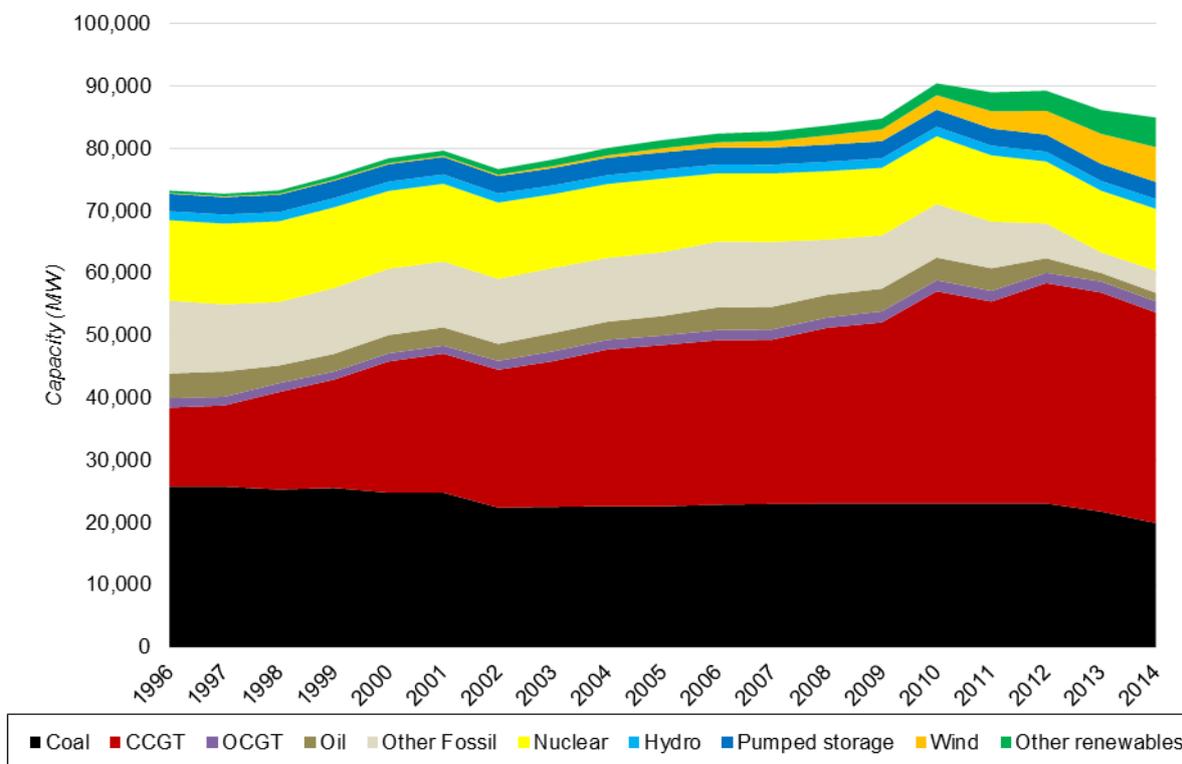
¹⁰ See our [working paper](#) on the Gas Wholesale Market, and specifically the section – ‘Liquidity’.

¹¹ See our [working paper](#) on the Gas Wholesale Market,, paragraphs 41–45.

¹² See our [working paper](#) on the Gas Wholesale Market,, 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.

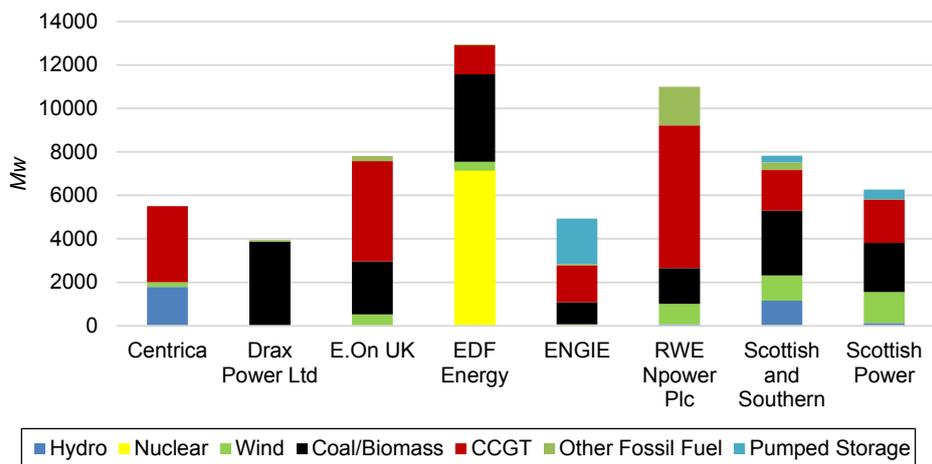
Figure 4.7: Generation capacity by technology (1996 to 2014)



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

4.40 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; at the time the data was compiled, E.ON was mostly a coal and gas owner, with a small wind portfolio (since then, the coal and gas plant has been separated out into a different and fully separate company, Uniper); 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 (2015)



Source: [DUKES](#) 2015, Table 5.10.

*Capacities shown are approximations. Shared ownership arrangements make precise capacities difficult to calculate.

4.41 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 capacity¹³), the two interconnectors to Northern Ireland and the Republic of Ireland generally export. Total net imports contributed 3.9% of electricity supply in 2013.¹⁴

¹³ [DUKES](#), Table 5B.

¹⁴ [DUKES](#), paragraph 5.6.

Figure 4.9: GB interconnectors

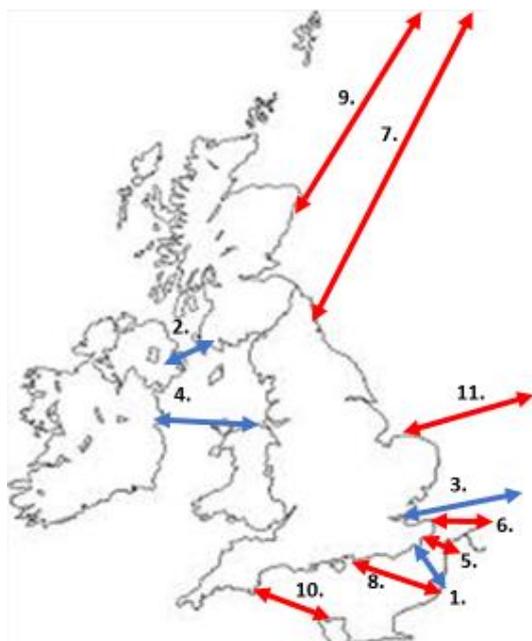


Number on map	Interconnector	Connects to	Capacity (MW)
<i>Operational interconnectors</i>			
1.	IFA	France	2,000
2.	Moyle	Northern Ireland	450
3.	BritNed	The Netherlands	1,200
4.	EWIC	The Republic of Ireland	500
Total			4,150

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

4.42 There is active interest in investment in greater interconnection capacity, as shown in Figure 4.10. Great Britain has among the lowest levels of interconnector 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)
<i>Operational interconnectors</i>				
1.	IFA	France	2,000	
2.	Moyle	Northern Ireland	450	
3.	BritNed	The Netherlands	1,200	
4.	EWIC	The Republic of Ireland	500	
<i>Proposed interconnectors</i>				
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

4.43 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.

4.44 In this sense, entering the traditional generation markets at scale has been equivalent to forming a long term judgement 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;¹⁵)
- (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;¹⁶
- (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

¹⁵ See Sections 2 and 5 and Appendix 5.3: Capacity.

¹⁶ 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.

4.45 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 electricity generation will be substantially decarbonised in the coming years,¹⁷ yet 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

4.46 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,¹⁸ with the first round of competitive allocations in 2015.
- (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) solutions¹⁹
- (c) 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.²⁰

¹⁷ See the discussion of the regulatory framework in Section 2 for a summary of current UK and EU decarbonisation goals.

¹⁸ Considered in detail in Section 5 and Appendix 5.3: Capacity.

¹⁹ Considered in detail in Section 5 and Appendices 5.3: Capacity; and 5.1: Wholesale electricity market rules.

²⁰ Considered in detail in Section 5 and Appendix 5.1: Wholesale electricity market rules.

- 4.47 We consider the competition impact of each of these policy changes in Section 5.
- 4.48 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.
- 4.49 In terms of the nature of competition, the CfD allocation can be thought of as providing for competition for the market for low carbon generation capacity through a public tender, whereas the RO mechanism attempted to create conditions of competition in a parallel market between renewable sources. Each mechanism raises many detailed competition questions, which we consider in Section 5.
- 4.50 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. Under the Capacity Mechanism, generators will no longer be so reliant on peak prices to recover their sunk costs and it therefore replaces to some degree competition **in** the market with competition **for** the market.
- 4.51 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.
- 4.52 An important aspect of generating capacity investment decisions is their location. The output of renewable generation capacity like wind, solar, wave and tidal is directly tied to its location. Further, electricity is transported over the grid, and the location of generation plant influences transmission 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 further transmission investment.

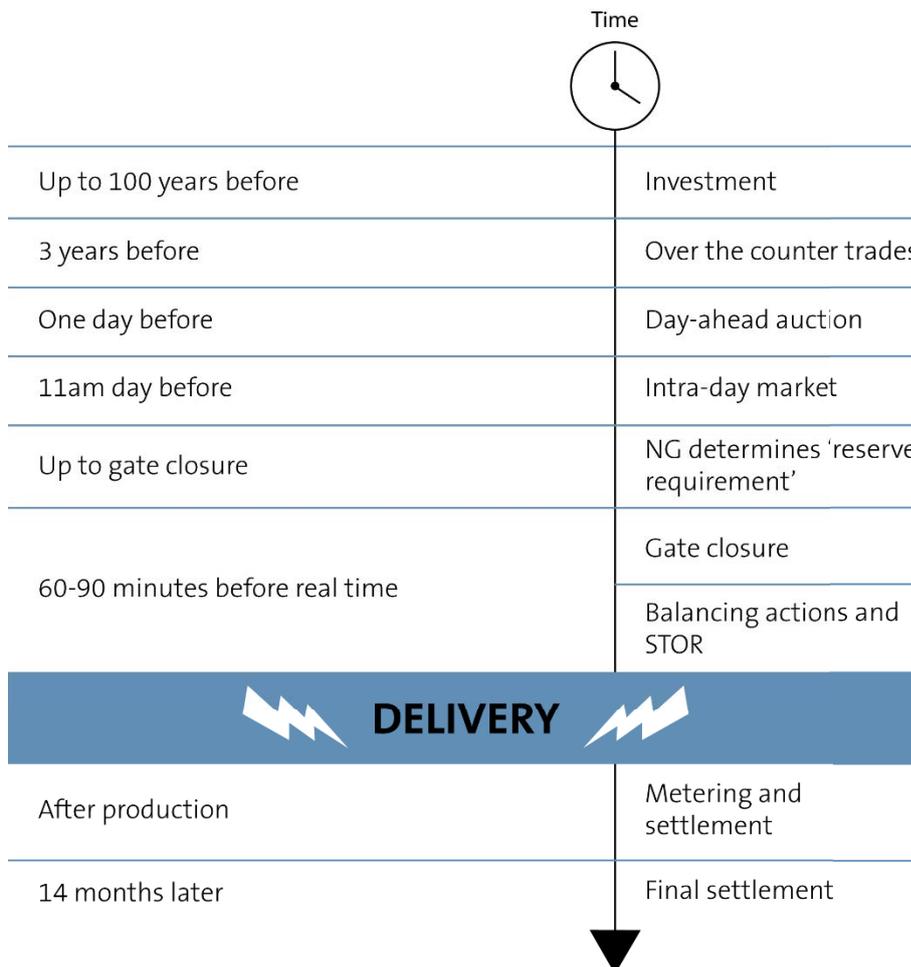
- (c) Transmission constraints arise when power cannot be transmitted to where it is needed, due to congestion at one or more points on the transmission network. Such congestion costs are driven by pattern of generation and consumption at any time.
- (d) Electricity is lost in transmission, and some elements of the losses are dependent on location.

4.53 We examine the impact of charging schemes for congestion and losses in Sections 5 and 6, and examine the code governance process as it applied to various attempts to introduce different schemes for charging for losses in Section 18.

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

4.54 The decisions that enable electricity demand to be satisfied in real time occur on a range of time-scales and in a number of markets. Figure 4.11 shows a timeline from investment through to the instant of production and to final financial settlement up to 14 months later.

Figure 4.11: Wholesale electricity market timeline



- 4.55 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 capacity 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 vertical integration.

Buying and selling close to real time

- 4.56 We briefly describe below the various ways in which buying and selling electricity occurs close to real time. The 'spot market' is not 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.
- 4.57 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 and anyone with electricity to buy can submit bids for the price and quantity they are willing to pay.
- 4.58 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.
- 4.59 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.

- 4.60 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.
- 4.61 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.²¹ The decision to participate in the day-ahead auctions will be based on a number of considerations, and notably:
- (a) Whether there is 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) Whether there could be cheaper ways of acquiring the electricity needed than producing it themselves.
 - (c) The trading and transactions costs on the platform - for example, the collateral costs needed to cover the risk that a party will not fulfil its contract.
- 4.62 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. However, 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 market²² which will have been used for longer-term hedging and at very small scales of operation, the OTC platforms may be thought to be a good enough substitute for the day-ahead auction.
 - (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

²¹ We describe the process in detail in Appendix 6.1.

²² The OTC market refers to a trading system in which bilateral trades are facilitated by a 'match-making' intermediary.

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.

- 4.63 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.
- 4.64 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 these trades (under 3%²³) are not visible to all parties in the market.
- 4.65 At gate closure, the electricity system becomes centrally operated. Competitive mechanisms nevertheless continue to be used in order to minimise costs. These include the balancing mechanism, where rapidly available incremental output from plant on the system can be purchased by the system operator and various other options, like short-term operating reserve (STOR) that the system operator can call on to balance supply and demand. The balancing mechanism is organised as a formal pay-as-bid auction and STOR purchases are made by competitive tender.
- 4.66 The system operator 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 relies to an extent on appropriate 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.
- 4.67 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

²³ See Appendix 5.1: Wholesale electricity market rules, paragraph 27.

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.

4.68 The goal of the cash-out (or 'imbalance') price-setting process is both to help with the natural monopoly regulation of the system operator²⁴ and 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.

4.69 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 Smartest Energy, 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: [✂].

4.70 The physical stability and integrity of the electricity system depends not only on actions in the balancing market aimed at maintaining system frequency but also on a number of other services to be provided, collectively known as 'ancillary services'. The system operator is charged with procuring these services. We have not, as part of this investigation, looked into the purchasing processes that the system operator has put in place to procure these services, which are part of the natural monopoly regulation of National Grid.

4.71 The electricity transmission and distribution system suffers from similar metering and settlement problems as were discussed with respect to gas in paragraphs 4.27 to 4.30. Almost all producers' injections on to the system are metered in real time;²⁵ most consumers' loads are not, pending smart meter roll-out.²⁶ The process of determining whether contracts were fulfilled is therefore relatively simple and quick for most generators. But for many

²⁴ As discussed in Section 5, Ofgem has had an objective to making sure that not too much balancing work is left to the system operator, by encouraging parties to contract ahead for their anticipated needs.

²⁵ This is not true of 'embedded' renewable generation.

²⁶ See Appendix 8.6: Gas and electricity settlement and metering.

customers – and almost all domestic and SME customers – it requires a lengthy process of successive approximations and reconciliations. It can take up to 14 months²⁷ for a supplier to know the final 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 competition concerns arising from the electricity settlement process in Sections 9 and 12.

Factors influencing the decision to generate

- 4.72 If a price-taking generator with a good forecast of what the price will be in a given period²⁸ has an incremental unit cost of operation smaller than the price for which it can sell its output, it will want to generate and therefore to have sold its output.
- 4.73 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, while 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 EUAs to cover its emissions and must top up that purchase by an amount equal to the carbon price floor. The price of EUAs 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, which can depend on whether it is operating at full capacity or not.
 - (d) **Maintenance costs and non-sunk fixed costs:** operating a plant will add to its wear and tear. Even planning to operate requires certain fixed

²⁷ See Appendix 5.1: Wholesale electricity market rules, paragraph 43.

²⁸ For spot-market purposes, the 'period' might be thought to be a half-hour – the administratively determined settlement period in the GB system; alternatively, it might be thought to be an hour, which is the period traded in the day-ahead auctions.

costs (like staff) to be incurred and maintenance costs as well as the economic life of a plant can depend on how 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 an imbalance price (see Section 5 and the Appendix 5.1). The difference between the contracted price and the imbalance price multiplied by 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 charges cover the costs relating to transmission congestion (see Section 5). 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 cash flow reallocation cash flow (RCRC)).

4.74 The first three factors are used to define 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: Ofgem.

4.75 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 the spread is, the greater the incentive. If it is negative, the owner would be disincentivised from producing electricity.

- 4.76 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 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

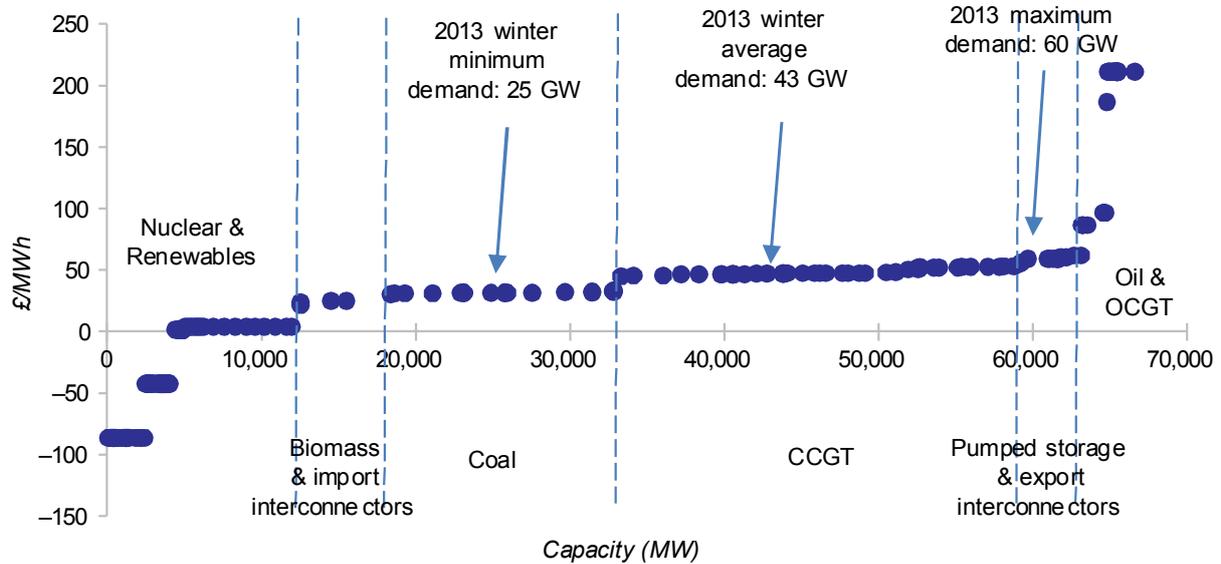
- 4.77 The calculation of the short-run break-even electricity price at which it is profitable to operate a plant can be represented for the whole system as a per-period supply curve, (also called a ‘merit order’ or a ‘stack’).²⁹ The industry uses these sorts of ‘fundamental’ models extensively in forecasting 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.
- 4.78 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,³⁰ which is next in the merit order.
- 4.79 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

²⁹ See Appendix 4.2: Generation return on capital employed, and specifically the section – ‘Basics of demand and supply of electricity.’

³⁰ 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)*



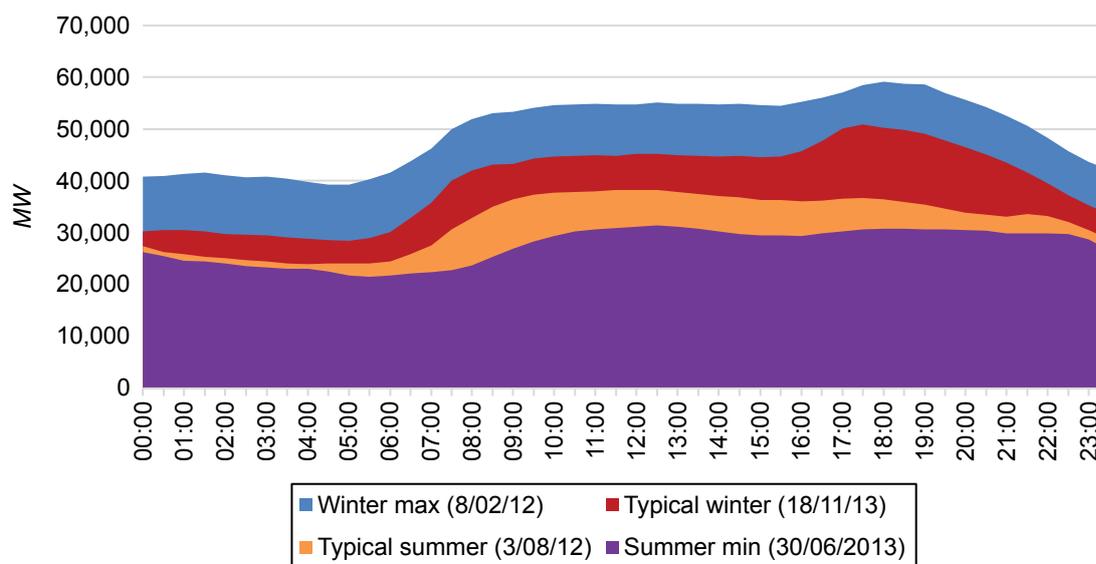
Source: CMA unilateral market power model.

*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.

4.80 The spot price is 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.

4.81 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

- 4.82 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.
- 4.83 If the price increases from the competitive strategy, this optimal price is achieved by a firm by withholding capacity.³¹ 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.

³¹ If the withholding strategy is inferior to the competitive strategy, the optimal strategy is the competitive strategy for that period.

Therefore, we believe that the strategies we have identified as optimal for each firm would also be stable for the market as a whole.

- 4.84 We analysed the ability and incentive for each of the Six Large Energy Firms and Drax to exploit unilateral market power, refining 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.
- 4.85 We found 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 and 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 would have forward-sold output in those periods, making it hard to exploit the profitable spot opportunity. We concluded that no single generator had the incentive to increase the wholesale price by a significant amount in a significant number of half-hour periods.
- 4.86 Our analysis of generation profitability adds strength to this 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.³²
- 4.87 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

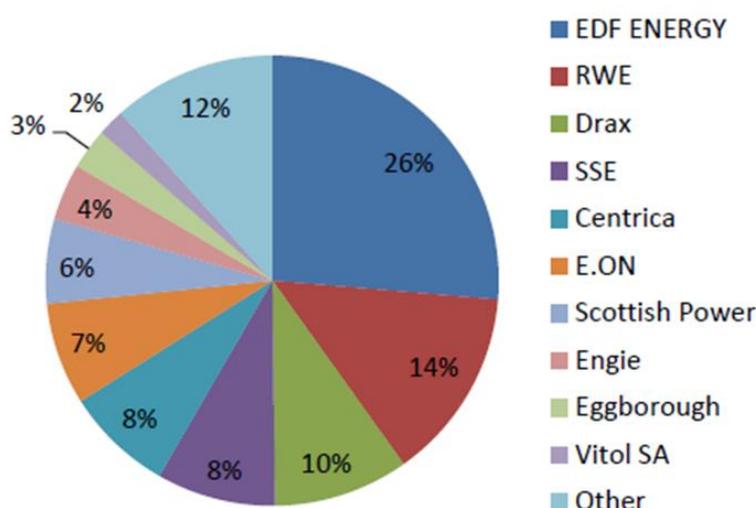
³² During this period (2007–2008), we understand that there were not significant impairments of assets. As a result, profits would not be affected by large one-off impairment expenses and capital employed would be estimated on the basis of depreciated replacement cost which tends to be higher than the carrying values actually used. This is particularly the case for coal-fired power stations.

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 and various environmental regulations that make new-build coal uneconomic.

Shares of generation output

- 4.88 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 (2014)



Source: Ofgem, National Report 2015.

Note: Market shares are calculated based on metered volumes associated with individual generation units (called balancing mechanism units). Assumptions have been made regarding which companies own each balancing mechanism unit. Volumes have been split based on equity stakes. Some degree of netting may have taken place for the underlying data. As such generation and demand from pumped storage and interconnectors may be underestimated.

Vertical integration

- 4.89 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.

Figure 4.17: Consumption, output and net electricity position by party (2013/14)

[✂]

Source: Ofgem (response on 6th May 2016).

4.90 Figure 4.17 shows a great deal of diversity in the nature and extent of vertical integration 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 vertical integration among the Six Large Energy Firms is in flux. E.ON has now demerged its conventional power stations (coal, gas and hydro) from its retail and renewables operation, which implies a large degree of vertical separation. RWE has also announced that its renewables, grids and retail activities are being transferred into a new subsidiary and it plans to list the shares in the new subsidiary on the stock market.³³ Centrica has announced substantial moves towards de-integration by closing and seeking buyers for some of its gas-powered plants.³⁴

4.91 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 vertical integration are stringent, and we examine whether they hold between the wholesale and retail electricity markets in Section 7. We also consider in Section 7 the impact of vertical integration on transparency in the market.

Financial markets

4.92 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.

Types of forward contract

4.93 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

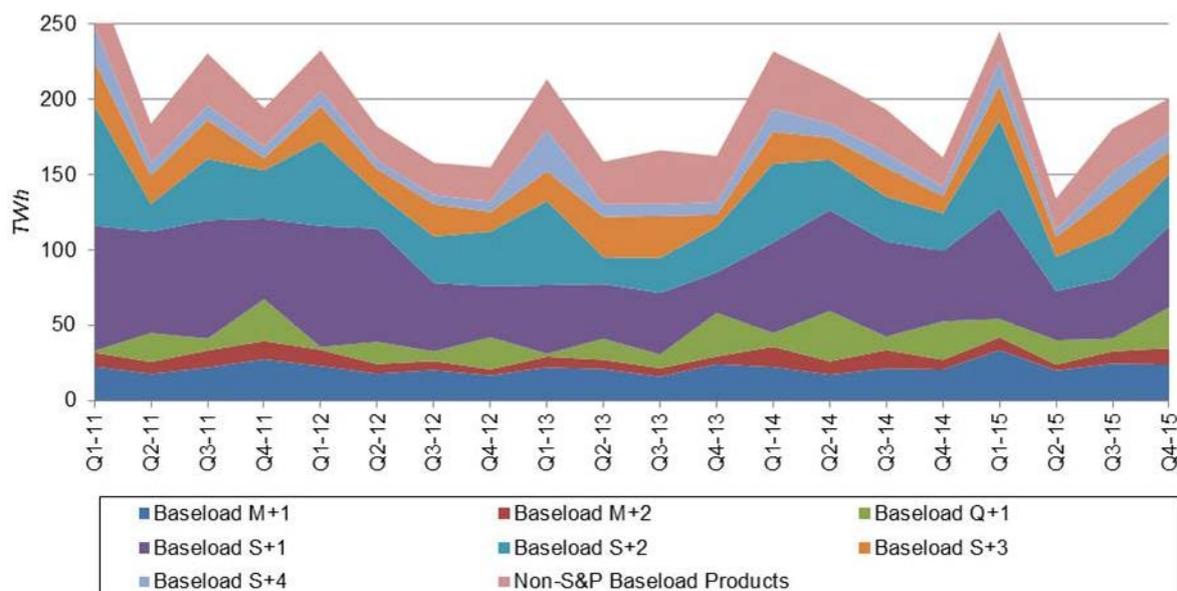
³³ See [RWE launches future-oriented business with new subsidiary](#), March 2016.

³⁴ Centrica subsequently made the decision to retain CCGT assets following a sales process, as bids received were significantly below its internal valuation.

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).

- 4.94 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.
 - (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 7.1: Liquidity). The standard forward contracts divide into different 'products' – baseload, off-peak and peak.
- 4.95 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

- 4.96 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.
- 4.97 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.
- 4.98 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.
- 4.99 We have assessed the extent of liquidity in the wholesale electricity market by gathering data from suppliers, generators and brokers.

- 4.100 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.³⁵
- 4.101 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.³⁶
- 4.102 In Section 7 we consider two questions relating to vertical integration and liquidity: to what extent vertical integration in electricity might reduce liquidity; and whether low levels of liquidity gives vertically integrated firms a competitive advantage.

Conclusions

- 4.103 We have not found any features in the wholesale gas market that lead to an AEC. Our analysis of the ability and incentive of generators to exercise unilateral market power indicates that there is currently no risk of an AEC.
- 4.104 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.
- 4.105 Section 7 examines in greater detail whether vertical integration might damage competition either via raising rivals' costs or by hampering transparency and good regulation.

³⁵ See Appendix 7.1: Liquidity.

³⁶ See Appendix 7.1: Liquidity.

5. Wholesale electricity market rules and regulations

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- 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 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 in 2001 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.

5.3 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.

5.4 Finally, we present our **conclusions** on whether any of the above areas give rise to an AEC.

5.5 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

5.6 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,¹ was designed as a self-dispatch wholesale electricity market. This

¹ See Section 2 and Appendix 2.1: Legal and regulatory framework.

contrasts with the system that it replaced, 'the Pool',² which was centrally dispatched.

Overview of centralised dispatch and self-dispatch

- 5.7 In a centralised dispatch system, generators and flexible demand³ tell the system operator 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 detailed technical information concerning constraints in plant operation. The system operator determines what it believes to be the least costly way of matching supply and demand and communicates a planned running order to each participant.
- 5.8 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 system operator 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)⁴ and in some form in most deregulated markets in the USA.
- 5.9 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 system operator. The system operator takes central control of balancing supply and demand close to real time, at a point known as 'gate closure'.
- 5.10 In Great Britain, gate closure is one hour prior to real time. It is at this point that the system operator⁵ 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 system operator. The system operator 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

² See Section 2 and Appendix 2.1: Legal and regulatory framework.

³ 'Flexible demand' refers to consumers who have the flexibility to reduce consumption at short notice in response to market signals.

⁴ In the Australian NEM, dispatch is determined 5 minutes ahead of time, rather than one day.

⁵ The exact definition and duties of a system operator vary from system to system. In the GB system, NGET carries out the system operator role.

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.

- 5.11 As the above description suggests, in practice there is not a binary distinction between self-dispatch and centralised dispatch. In all electricity markets, the system operator intervenes at some point to ensure the system is balanced. The key points of difference are when and how the system operator intervenes and how generators and suppliers interact prior to this intervention.
- 5.12 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:⁶
- (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

- 5.13 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 system operator and their close fit to actual prices.
- 5.14 We have reviewed these models in the context of our work on unilateral upstream 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 modelling⁷ suggests that day-ahead prices are well forecast by a cost-minimising assumption.
- 5.15 We asked National Grid to consider possible sources of savings that might be seen from reverting to centralised dispatch. It concluded that there would

⁶ Section 7 considers an additional hypothesis – whether self-dispatch increased incentives for vertical integration.

⁷ See Appendix 4.1: Market power in generation.

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 the system operator could under centralised dispatch rules, and that self-dispatch may in this sense be more technically efficient.

- 5.16 Professor Helm has argued,⁸ in response to the view that wholesale prices provide efficient signals, that they were not responding appropriately to falls in wholesale prices, and that the investigation ought to have examined the link between average input fuel price reductions and wholesale spot prices. We note, however, that where prices are determined by marginal cost – which provides the incentives for efficient dispatch – the wholesale price should follow the input costs of the marginal plant rather than average wholesale input cost. Appendix 4.1 shows a good fit between modelled prices based on marginal fuel input costs and out-turn prices. We also note that any rents accruing to inframarginal generators from changes in fuel input costs that are not reflected in prices would be reflected in outturn levels of generator profitability which, as set out in Section 4, we have not found to be excessive.

Impact on price transparency

- 5.17 We have found that for most purposes prices are transparent in the GB wholesale electricity market.⁹ The N2EX and APX exchanges publish day-ahead electricity auction prices. The equivalent of approximately 40% of total electricity generation goes through these auctions. The 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.
- 5.18 The N2EX and APX bids and offers are already used for the regulated purpose of determining EU-wide day-ahead prices and allocating inter-connection 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.

⁸ Helm submission in response to provisional findings, paragraph 14.

⁹ See Appendix 7.1: Liquidity.

- 5.19 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.
- 5.20 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 balancing mechanism bids that 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 (which has already been implemented and is discussed in paragraphs 5.151 to 5.155 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.¹⁰
- 5.21 For all these reasons, we do not believe that there would be a material advantage to competition from the point of view of increasing price transparency by reverting to centralised dispatch.
- 5.22 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 17 and in Appendix 17.2 (Codes and regulatory governance).

Impact on transactions costs

- 5.23 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

¹⁰ It is a price based on all bids and offers in the market since any operator that has notified to the system operator that it will be producing or consuming electricity is mandated to offer these bids to the system operator for any adjustments to their positions that need to be made in real time.

gross pool. In the case of a mandatory pool, the entire market participates, so the depth of the market is maximised.

- 5.24 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.¹¹ Therefore both self- and centralised dispatch systems typically require participants to have trading teams.
- 5.25 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.¹² Moreover, the reforms to the imbalance price regime (especially the elimination of ‘dual pricing’ discussed below) mean that reliance on the centrally cleared balancing mechanism for energy will no longer be unattractive by design. This will provide a further low-transaction cost option for buying or selling electricity.
- 5.26 In light of the above, our view is that there would not be significant transaction cost difference between the self-dispatch system in Great Britain and a centralised dispatch alternative.

Finding on self-dispatch

- 5.27 For the reasons set out above, and especially given the EBSCR reform that defines 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

- 5.28 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. Since the greater the distance travelled, the higher the losses, the costs of both losses and constraints vary considerably by geographical

¹¹ See Appendix 5.3: Capacity.

¹² 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.

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.

5.29 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.¹³

Locational elements in current network charges

5.30 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.

Table 5.1: Geographical variation in GB electricity network costs

<i>Cost category</i>	<i>Locational elements in current pricing arrangements</i>
Transmission congestion	No
Transmission losses	No
Transmission network investment	Yes
Transmission connection	Yes
Distribution network	Yes
Distribution losses	Yes

Source: CMA research.

5.31 As can be seen, there are several network cost categories charges which vary by geographical location under the current regulatory regime:¹⁴

(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.

¹³ This section draws on the analysis set out in Appendix 5.2.

¹⁴ All of these charges are regulated by Ofgem.

- (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.¹⁵
- 5.32 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 Section 8.
- 5.33 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.
- 5.34 **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.
- 5.35 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.
- 5.36 Congestion costs are currently incurred by National Grid through the balancing mechanism 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.

¹⁵ See National Grid: [Assistance for Areas with High Electricity Distribution Costs](#).

- 5.37 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%¹⁶ (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 to satisfy it from Scotland than from the Isle of Grain.
- 5.38 Transmission losses are currently recovered by adjustments to BSC parties' metered volumes for the purposes of balancing, 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.¹⁷
- 5.39 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.
- 5.40 In 2003 Ofgem approved P82¹⁸ but this was successfully challenged on judicial review on the basis of procedural flaws. In 2007 Ofgem indicated that it was minded to approve P203¹⁹ but, following a further judicial review, it ran out of time before it could make a final decision. In 2011 Ofgem rejected P229,²⁰ arguing that the proposals would have a large distributional impact and relatively modest expected benefits (see below our discussion of P229 and Ofgem's decision, paragraphs 5.51 to 5.56).

Impact on competition from lack of locational prices for transmission losses

- 5.41 In this section, we consider the impacts (and their scale) arising from the absence of locational prices for transmission losses on generation and

¹⁶ National Grid 2014, Transmission Losses Report: Reporting Period 1 April 2013 to 31 March 2014.

¹⁷ Under the current arrangements, transmission losses are allocated to parties uniformly, and independent of location, based on each party's metered energy. 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.

¹⁸ Ofgem (17 January 2003), [Modification to the Balancing and Settlement Code - Decision and Direction in relation to Modification Proposal P82](#).

¹⁹ Ofgem (26 June 2007), [Zonal transmission losses - the Authority's 'minded-to' decisions](#).

²⁰ Ofgem decision (28 September 2011), [Balancing and Settlement Code \(BSC\) P229: Introduction of a seasonal Zonal Transmission Losses scheme \(P229\)](#).

demand, in the short and long run. We do so by reviewing past modelling work and analysis, and also by conducting our own updated analysis. Within this context of our assessment we have considered the transitional costs and/or implementation difficulties that a move to locational pricing might create, and the views expressed by parties in response to our provisional findings and provisional decision on remedies.

- 5.42 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.²¹ 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 extension or closure of plant. There could also be inefficiency in the location of demand, particularly high-consumption industrial demand.
- 5.43 Pursuant to our guidelines, in order to assess whether this feature gives rise to an AEC, we have compared the current situation with a benchmark against which we could determine how the market is performing, in this case electricity markets where transmission costs are reflective of locational losses.²² As discussed below, based on existing analysis and our own modelling exercise, we have found that the current market, compared with such a benchmark, gives rise to a material consumer detriment (of the order of £150 million over the next ten years). In a well-functioning market, we would expect that technical solutions would be in place to remove such a feature (as set out in paragraph 5.42) and mitigate the detriment arising from it. We found, however, that attempts to introduce locational pricing for losses

²¹ 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.

²² As noted in our guidelines (CC3), ‘in identifying some features or combination of features of the market that may give rise to an AEC, the [CMA] has to find a benchmark against which to determine how the market may be judged to be performing. In the absence of a statutory benchmark, the [CMA] defines such a benchmark as “a well-functioning market” (see paragraph 30 [of CC3])—ie one that displays the beneficial aspects of competition (...) but not an idealized perfectly competitive market. The benchmark will generally be the market envisioned without the features.’

over the last 25 years have been systematically thwarted (see in particular paragraph 5.40 and paragraphs 5.51 to 5.56 for a discussion of Ofgem’s decision not to approve the latest attempt, ie modification proposal P229).²³ By their nature, the assessment of whether the absence of locational pricing for losses gives rise to an AEC in the electricity markets (and the detriment arising from it) is closely interlinked with the identification of an effective and proportionate remedy to such an AEC. In particular, our modelling exercise informs both assessments.²⁴ For reasons of narrative fluency, we described in this section all of our modelling work – both as it relates to the assessment of the existence of an AEC (and the detriment arising from it) and to remedy design options. However, some detailed elements of this modelling work which relate specifically to the identification of an effective and proportionate remedy are assessed separately in Section 6. Appendix 5.2 (and to the extent that they relate specifically to our assessment of remedies, Appendix 6.2) contain our responses to detailed comments relating to our modelling work, while Appendix 5.4 contains NERA’s detailed description of the model used and the results given by different scenarios chosen by the CMA.

Estimates of the size of detriment and distributional impacts

- 5.44 The principle that economic efficiency is improved when charges for transmission losses are more reflective of incremental costs has been validated on a number of occasions using detailed simulation modelling of the impact of the introduction of locational charging for transmission losses in the GB wholesale electricity market (see paragraphs 5.46 to 5.56 below).
- 5.45 We consider that this sort of modelling, while always open to debate in terms of specific assumptions and technical choices made, is valuable in providing indicative orders of magnitude of the likely detriment arising from the absence of locational charging for losses and the overall net benefit of introducing locational charges for losses. We have therefore critically reviewed previous simulation modelling work, especially that which was carried out for the purposes of P229. We have also engaged specialist consultants (NERA) to undertake simulation modelling under our guidance (with input from interested parties on our methodology and scenarios), with the aim of confirming the degree of confidence that we should have in the order of magnitude of any detriment, as well as helping us to test different design options.

²³ We also note that the features that give rise to the Codes AEC, discussed in Section 18, are likely to have also contributed to this situation. We address these features through the remedies set out in Section 19.

²⁴ Within the context of our modelling exercise, therefore, each scenario is an attempt to identify both a well-functioning benchmark and an effective and proportionate remedy.

- *Previous P229-related modelling*

- 5.46 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 locational pricing for transmission losses; there has been no attempt to quantify the long-run gains.²⁵
- 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),²⁶ arising from an average annual reduction in losses of 211 GWh (equivalent to about 5% of losses). 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 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 to the first effect, LE/Ventyx estimated that there would be a transfer of around £37 million a year (2011 prices) from consumers in the

²⁵ 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.

²⁶ 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.

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.²⁷

- 5.50 In relation to the third effect, LE/Ventrix 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.²⁸ 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.’²⁹ 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.’³⁰
- 5.51 In its assessment of modification proposal P229, Ofgem recognised that P229 would have led to more efficient dispatch decisions due to cost signals allowing variable losses to be taken into account. This in turn would have led to production cost savings, reduced losses and reduced emissions. Ofgem also stated that, in general, competition was likely to be more effective if the costs which parties imposed on the system were reflected in their charges and therefore their decision-making process. Ofgem found that, on balance, the improvements in cost reflectivity in the P229 proposals would help create a better level playing field for generators. It also noted that not all generators needed to be able and willing to respond to achieve the benefits of the proposal.
- 5.52 However, Ofgem concluded that it could not satisfy itself that the implementation of P229 was in the best interest of existing and future customers, and therefore would not be consistent with its principal objective and statutory duties. In its decision, Ofgem noted specifically that it was concerned by:

²⁷ Appendix 5.2: Locational pricing in the electricity market in GB notes that Brattle explains that the LE/Ventrix 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.

²⁸ 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.

²⁹ Both Redpoint and LE/Ventrix 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.

³⁰ Ofgem, Impact Assessment on RWE proposal 229, seasonal zonal transmission losses scheme, paragraph 4.28.

- (a) the large distributional impact both between individual generators and between suppliers/customers, although Ofgem acknowledged that these distributional impacts might be justified by the longer-term benefit from a more efficient, cost-reflective market (we discuss in more detail this point below); and
- (b) the uncertainty around long-term benefits of this intervention, due to the changing regulatory environment. It noted in particular:
 - (i) a debate at EU level for greater integration of electricity markets focused on market-splitting approaches that create multiple price areas within a national system which could have superseded P229 before the full benefits had been realised, possibly as soon as 2015; and
 - (ii) in the UK, changes to the incentives for the construction of new generating capacity in Great Britain that the government was considering at the time, which may have resulted in some change to the existing GB market arrangements in the medium term that would have undone the benefits of the P229 proposals before any long-term market efficiencies had been realised;
 - (iii) the modest benefits arising from P229 in the short term (ie two years from implementation).

5.53 We have found it difficult to reconcile Ofgem's decision with the evidence and analysis it commissioned and summarised in its impact assessment.

5.54 Specifically on distributional impacts (paragraph 5.52(a)), Ofgem's consultants did not suggest that significant redistribution from customers to generators was likely.

5.55 With respect to the long-term benefits of the proposed policy (paragraph 5.52(b)), we understand that Ofgem's concerns were linked to one of the EU network codes, ie the Capacity Allocation and Congestion Management regulation (which at the time of Ofgem's decision was in an early stage of development) as well as changes to the incentives for the construction of new generating capacity (ie the capacity market). However, this EU network code entered into force in August 2015 and does not contain provisions that in our view would prevent, or undermine, the mechanism set out in our proposed remedy. Further, we have not seen any evidence to suggest that P229 or our remedy would be incompatible with the capacity market currently being implemented by DECC. In discussions following the publication of our provisional decision on remedies, Ofgem has confirmed

our view that this concern is not material anymore in view of recent developments at EU level.

5.56 Therefore, in view of these developments, we believe that longer-term benefits are relevant to assessing the impact of the introduction of transmission charges for losses on existing and future GB customers. As discussed above, we have further investigated these impacts by carrying out a new modelling exercise, with a view to updating previous existing analysis set out above.

Our updated modelling

5.57 Following the publication of our provisional findings report, we decided to carry out an updated cost-benefit analysis for the introduction of locational charges for variable transmission losses, as set out in the Remedies Notice. The aim of this simulation modelling was to add to our evidence base, particularly about the orders of magnitude of the net impact of our scenarios due to the sensitivity to certain input parameters.³¹

5.58 In this section we set out some of the key principles informing our analysis of costs and benefits, describe the approach to modelling and the range of scenarios used, before assessing some of the criticisms of our approach, presenting the results and drawing overall conclusions from our analysis.

- *Process of consultation on methodology and scenarios*

5.59 In our consultation on the methodology for assessing the losses AEC and remedy,³² we encouraged parties to submit comments on both the methodology and scenarios proposed by our consultants, NERA, to assist us in deciding how much evidential weight to put on this work. We also invited parties wishing to conduct their own analyses to submit their results to the CMA.

5.60 We invited parties to a round-table workshop at which NERA presented its assumptions and its methodology. We published NERA's methodology and scenarios presentations, and invited parties to produce detailed input suggestions or to perform their own complementary analysis in order to add to the evidence base.

³¹ CMA (8 December 2015), [Notice regarding assessment methodology for losses proposed remedy – consultation on methodology and scenarios](#).

³² *ibid.*

- 5.61 We received responses from the Six Large Energy Firms (except for E.ON and Scottish Power), National Grid, Dong Energy and Ofgem. There were detailed comments on input assumptions, which we review in Appendices 5.2 (as far as they relate to the calculation of detriment) and 6.2 (as far as they relate specifically to the assessment of remedies). None of the parties submitted their own completed alternative simulation exercises to assess side by side with our own results.
- 5.62 Parties also commented on our modelling in their responses to the provisional decision on remedies. This included the correction of misinterpretations which have led us to re-run our simulation models with slightly modified input assumptions.
- *Principles guiding our approach to the modelling exercise (and the interpretation of results)*
- 5.63 Before describing the modelling, results and parties' views, we set out some important concepts and principles that have guided our overall assessment. In particular, we distinguish between, on the one hand, the social costs and benefits that might be expected to arise from the introduction of locational charges deriving from losses and, on the other, the transfers that it might lead to. We also distinguish between effects that we believe *a priori* are likely to hold for all or most plausible scenarios (ie that are systematically³³ related to the introduction of locational pricing for losses) and those that are likely to be more uncertain.
- *Social costs and benefits*
- 5.64 In terms of social costs and benefits (ie efficiency savings or costs that accrue to society as a whole), we would expect these to comprise:
- (a) short-run efficiency gains from the reduction in losses and hence reduction in generation costs (these are systematically associated with the introduction of locational pricing for losses);
 - (b) short-run costs from implementing the introduction of locational pricing for losses (these are systematically associated with the introduction of locational pricing for losses);

³³ By 'systematically' we mean that we would expect to see these in all cases in which the locational pricing for losses is introduced.

- (c) short-run costs or benefits from impacts on air quality (these are uncertain and not systematically associated with the introduction of locational pricing for losses);³⁴ and
- (d) dynamic benefits arising from more efficient investment in generation and energy-intensive demand (these are systematically associated with the introduction of locational pricing for losses).

5.65 We have attempted to quantify the first three elements in our cost-benefit assessment, but not the fourth. More efficient prices are likely to bring dynamic as well as static effects, but we considered that attempting to incorporate such investment benefits within the model would overcomplicate the modelling with no substantial benefit terms of greater accuracy.

5.66 Therefore our principal interest in modelling social costs and benefits was to establish whether the short-run efficiency gains from reduced losses are likely to exceed the costs of implementation under a range of scenarios. We also wished to establish whether air quality effects were generally positive or negative and whether their inclusion might affect the overall cost-benefit analysis.

- *Transfers*

5.67 The introduction of locational pricing for losses may also be expected to lead to various forms of transfers.³⁵ We have identified four distinct types of transfers. We noted the first three types of transfer in paragraph 5.48 when discussing previous analyses on the introduction of locational pricing:

- (a) Regional transfers within Great Britain from customers in areas of low generation relative to demand to customers in areas of high generation relative to demand;
- (b) Regional transfers within Great Britain from generators in areas of high generation relative to demand to areas of low generation relative to demand;
- (c) Transfers between generators and customers, as a result of the change in the wholesale price of electricity, with the direction of transfer

³⁴ If plants with relatively high emissions tend to have their generation reduced by the introduction of locational pricing for losses, this will have a net benefit in terms of air quality effects. If the opposite is true, the policy will entail a net cost.

³⁵ A transfer is simply a redistribution of money from one party to another, without entailing any social cost or benefit.

dependent on whether the price increases or falls (these transfers are not systematic *a priori* and highly uncertain).

(d) Transfers between Great Britain and the rest of the EU through the effect on import prices (these transfers are again not systematic).

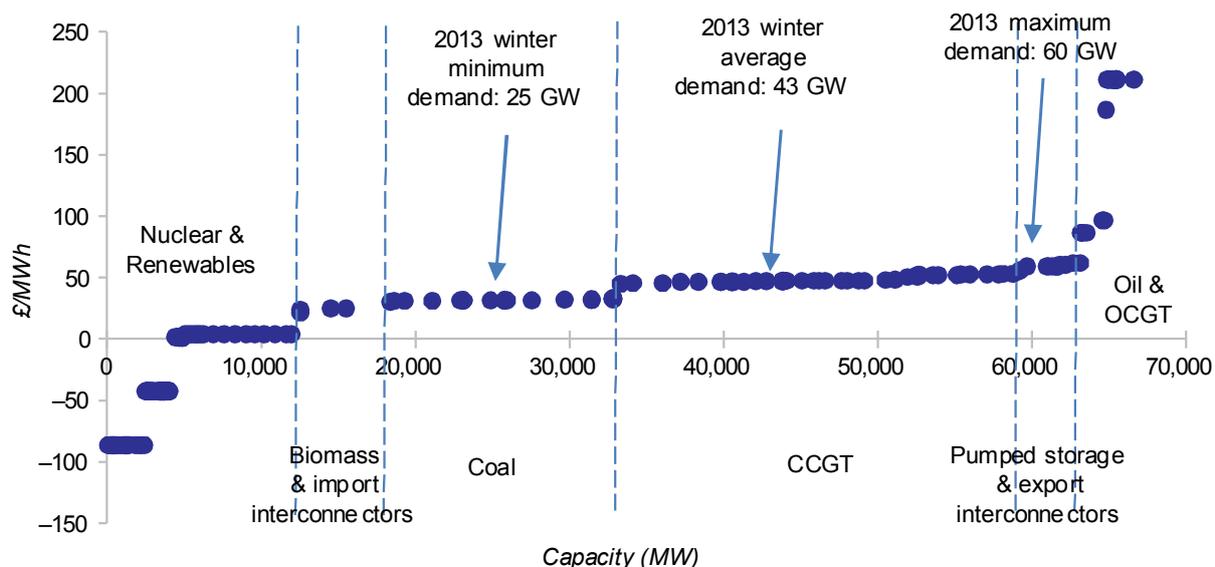
5.68 Of these transfers, only the first two are systematically associated with the introduction of locational pricing for transmission losses. The other two types of transfer are uncertain *a priori* – both in terms of direction and magnitude. Considering in particular transfers between generators and customers, these depend on whether the wholesale price increases or falls as a result of the change, which itself depends on whether marginal generators pay for a greater share of losses under the locational charging regime (in which case the price increases) or a lower share of losses under the locational regime (in which case the price falls).

5.69 The short-run effect on the wholesale price depends therefore on the location of the marginal plant. As shown in the diagram below, the GB merit order has been such in recent years that the marginal plant can change due to small changes in relative fuel costs or other factors. Therefore, the overall short-run impact of the introduction of locational pricing for losses on the wholesale price is likely to be uncertain (and indeed may vary from half hour to half hour, reducing the price in certain periods and increasing it in others).³⁶ The **total** effect on the cost – and in a well-functioning market, the price – of meeting energy service demand is unambiguously to reduce it,³⁷ but the short-run effect on the wholesale price component may be ambiguous.

³⁶ It should be noted that locational pricing will affect consumer bills through other avenues than the wholesale price effect. We expect that bids and payments in the Capacity Market will be affected, and that the quantity of energy billed to suppliers will fall because of reduced total losses. Therefore, the short-run effect on the wholesale price is not equivalent to the impact of the remedy on customers.

³⁷ Put briefly, reflecting a real-world cost (transmission losses) in wholesale prices (rather than these costs being 'smeared' across the industry) will, in aggregate, lead to the dispatch of generation plant which is more efficient/cheaper given the demand across Great Britain pertaining at the relevant time.

Figure 5.1: Representation of GB merit order, winter 2013



Source: CMA analysis.

5.70 Our modelling has attempted to estimate the short-run impacts of the introduction of locational pricing on customer bills and generator margins and hence has simulated both short-run wholesale price effects and transfers between Great Britain and the rest of the EU. Distributional issues, which require simulations of prices, can be important in our assessment, to the extent that they may affect the structure of the market and/or the scale of the detriment to consumers (hence of the net benefits to consumers arising from our remedy). We consider such arguments in Section 6 and Appendix 6.2. For the reasons discussed above, however, we note that the results of predictions of price impacts are likely to be particularly uncertain.

- *Scope and limitations of our modelling exercise*

5.71 When considering the results of our simulation modelling, we have been mindful of the limitations of such exercises and the evidential weight that can be attached to them. Simulation models of energy systems are relatively sophisticated but their results are uncertain and can be hard to interpret, particularly far into the future. It is not usually possible to ascribe exact probabilities to complex input scenarios, and therefore results should be taken as being indicative only. Sensitivity analysis is helpful in this context, but we note that even the most sophisticated simulation models of this sort are necessarily partial, so judgement has to be brought to an overall assessment of results.

5.72 We also note, as discussed above, that some elements of the modelling are likely to be more uncertain than others. In particular, while it should be possible to produce reasonable order of magnitude estimates of the social costs and benefits of the introduction of locational pricing, the short-run

transfers arising from wholesale price effects are likely to be uncertain in direction and magnitude, contingent on a number of factors and difficult to model precisely within a medium- to long-term modelling exercise.

5.73 Finally, while dynamic benefits have been excluded from the modelling for reasons of complexity,³⁸ the existence of such benefits (more efficient investment choices in generation) should, in a competitive market, result in lower long-run costs for customers, regardless of whether or not there is a short-term increase in the price.

- *Modelling methodology*

5.74 The modelling methodology adopted by our consultants (NERA) was shaped, reviewed and approved by us. It is described in detail in Appendix 6.2. Parties also had the opportunity to comment on it, as described in paragraphs 5.59 to 5.62 and Appendix 6.2.

5.75 At a high level, the method adopted can be described as involving the following steps:

- (a) Construct plausible sets of input assumptions (that is, scenarios) covering the major variables that will affect the electricity system over the next 20 years, including:
 - (i) environmental policy;
 - (ii) technological developments and their costs (including costs of sites, for example for new nuclear build);
 - (iii) fuel prices and renewable resource endowments (eg wind levels and profiles);
 - (iv) the level and location of customer demand; and
 - (v) regulatory behaviour with respect to transmission network charging.
- (b) For each scenario, determine what capital equipment will produce the electricity needed to meet demand and where plausibly it will be located (based, for example, on the existence of sites that have previously been used for generation), producing a view of the generation and demand aspects of the system.

³⁸ Modelling the dynamic benefits would have added another layer of complexity to the modelling and required another iteration. Further, it would have also required the treatment of Transmission Network use of the system charges as an endogenous variable.

- (c) For each such system, simulate the building of a consistent transmission grid.
- (d) Simulate generation to determine loss factors on that grid.
- (e) Examine the pattern of generation with and without losses to determine a consistent picture of the impact of the introduction of locational pricing for transmission losses.

5.76 There are many approximations and judgements involved in a modelling exercise of this sort. We met with parties in order to expose the methodology and allow others to propose alternative approaches and results. There was a technical discussion about the likely impact of some of the approximations made. Some of this is reflected in the scenarios we have developed, as explained in Appendix 6.1. However, given the purpose of the modelling – as described above – we did not conclude from this discussion that the methodology itself required changes.

- *Scenarios*

5.77 The input assumptions that we have collected into scenarios are described in detail in Appendix 6.1. Table 5.2 below provides a high-level description of two key inputs, fuel and carbon prices, under the three scenarios considered in the modelling exercise.

Table 5.2: Fuel and carbon prices under the scenario modelled

Reference case	Low case	High case
UK Carbon Price Support rate remains frozen at its current level of £18/tCO ₂ indefinitely.	Carbon Price Support is scrapped entirely from 2016/17 onwards, with the Carbon Price Support at zero £/tCO ₂ .	Carbon Price Support is £18/tCO ₂ until 2019/20 and then £30/tCO ₂ in 2020, rising to £70/tCO ₂ in 2030.
Merit order of coal and gas based on the International Energy Agency New Policies commodity prices scenario and assumptions on coal and CCGT plants' efficiencies.	Merit order is most advantageous to coal relative to gas; based on DECC Low case commodity prices scenario and assumptions on coal and CCGT plants' efficiencies.	Merit order is least advantageous to coal relative to gas; based on the International Energy Agency 450 scenario commodity prices scenario and assumptions on coal and CCGT plants' efficiencies.

Source: NERA (2015). Modelling the Impact of Zonal Transmission Loss Multipliers.
CCGT = combined cycle gas turbine.

5.78 The most direct mechanism through which charging for losses has an impact on generation costs arises when it is possible to substitute between different generating plant in different locations.

- 5.79 For each input scenario, we considered two options for introducing locational pricing for transmission losses: one in which a semi-marginal transmission loss factor is employed to recover variable transmission losses (option A), in line with the most recent modification proposal, P229; and another in which a fully marginal transmission loss factor is applied to variable transmission losses (option B).
- 5.80 Fully marginal loss factors are, in principle, preferable from the point of view of providing a signal to achieve technical efficiency because those causing losses should bear the cost of incremental changes to their positions. However, semi-marginal losses are envisaged in P229 because, given the electrical properties of losses, semi-marginal loss factors will approximately recover the costs of variable losses through the loss factor.^{39,40}

Results

- 5.81 In this subsection we discuss the modelling results. First we consider the relevant period for the results, before presenting the results according to the categorisation presented above, considering first the social benefits from the introduction of locational pricing for losses and then the transfers that it might lead to.

- *Relevant period for the results*

- 5.82 In reviewing the results, we have focused on those relating to the next ten years (2017 to 2026). We note that the model simulated the system until 2035, but we have put no evidential weight on the results from the years after 2026 because we cannot be confident that the results beyond 2026 are meaningful. Indeed, we believe that uncertainties beyond 2026 are very substantial and we are not confident that the scenarios can properly capture the range of policy tools that affect the location of investment and demand. Beyond 2026 in the modelled simulations, the geographic structure of the

³⁹ Variable losses – those that vary with output – are of an approximately quadratic form: $L = a Q^2$, where L is the amount of transmission losses on a particular part of the system, a is a constant and Q is the injection or withdrawal of energy at that node; therefore the marginal loss factor, $dL/dQ = 2aQ$. Therefore, the actual loss divided by the marginal loss is $aQ^2/2aQ$, which equals exactly $\frac{1}{2} Q$.

⁴⁰ In our provisional decision on remedies, we erroneously conflated the full-marginal versus semi-marginal question with that of the split of losses between generation and demand. P229 envisages that loss factors be semi-marginal, without any change to the BSC procedure by which fixed loss multipliers are further adjusted so that generators bear 45% of the cost of fixed losses. In the provisional decision on remedies, we reported scenario results in which generators are charged 45% of full marginal loss factors. To address our erroneous conflation, we have re-run the analysis with 50% loss factors, in line with P229. The results do not change materially compared to the 45% results reported in the provisional decision on remedies: the largest impact on total benefit is less than 2% of the total net benefit. We also present, for completeness, the results of scenarios in which generators are charged 100% of marginal loss factors.

GB energy system inverts, with the North on average becoming an importing region and the South an exporting region. Therefore from 2026 the results essentially model a system in which the physical flows are more or less the reverse of the system we see today.

5.83 This switch in the model is driven not by the losses charging regime itself, but by assumptions about the evolution in Transmission Network Use of System (TNUoS) charges, which are the main determinant of plant location decisions in the model. The assumed TNUoS charges are taken from NERA's and Imperial College's work during Project TransmiT.⁴¹ However, the TNUoS charges are not recomputed for each investment scenario. Thus, the incentive to locate a plant in the South does not abate as the amount of plants in the South increases in our scenarios. We consider that this is in large part the fact that we did not model this feedback which has led to the switch in energy flows and losses.

5.84 For these reasons, we do not consider the results based on the later years of the model to provide much useful information about the impact of locationally sensitive loss charging. In the next ten years, we would expect the non-modelled dynamic benefits to have only a modest impact, since there is less locationally incentivised investment on the system. Therefore, instead of engaging in speculative assessment in the years after 2026, we focus the benefit calculation on the relatively less uncertain early period. It should be noted, however, that the results show net benefits in the later period as well (2027 to 2035).

- *Technical efficiency benefits*

5.85 Table 5.3 summarises the total efficiency benefits over the medium term (ie next ten years) of the introduction of locational pricing for losses under our three sets of input assumptions and two scenarios. The measure shown is the reduction in the cost of meeting the electricity demand of GB customers due to the introduction of locational pricing. Total technical benefits vary between £131 million and £159 million for option A (semi-marginal) and £151 million and £190 million for option B (full marginal). Option B always yields greater benefits than option A.⁴²

⁴¹ [Project TransmiT](#) is Ofgem's review of electricity transmission charging and associated connection arrangements.

⁴² This approach to estimating cost savings values changes in net imports based on the change in generation costs in neighbouring jurisdictions. We believe that this is a more reliable estimate of the social benefits of the policy than the alternative approach, which values changes in net imports at prevailing market prices, and which produces a range of benefits of between £85 million and £204 million for option A and £122 million and £246 million for option B.

- 5.86 The order of magnitude of the results appear stable and robust, in that the estimated benefits are not very sensitive to our scenario input assumptions. This result of our modelling exercise should be interpreted as showing that, as modelled, the cost of meeting GB electricity demand would fall by this order of magnitude under our proposed remedy.
- 5.87 The additional efficiency gain of moving to fully marginal transmission loss factors from half-marginal loss factors (moving from option A to option B) is simulated to be worth between £15 million and £31 million. This effect is as expected, since fully marginal loss factors provide better economic signals that lead to more changes in the geographic pattern of generation.⁴³

Table 5.3: Total efficiency gain from introduction of locational pricing for losses, 2017 to 2026

	2015, £ million					
	Reference case		High case		Low case	
	A	B	A	B	A	B
Total efficiency gain	143	158	131	151	159	190
Change in generator fuel, CO2 and operating and maintenance costs	-10	-20	-11	-24	-9	-26
Change in cost of transmission losses	27	49	41	71	45	91
Change in cost of constraint management	126	128	102	103	123	126

Source: CMA scenarios with Imperial College and NERA calculations.

Notes:

1. All values are £ million NPV from 2017 to 2026 at a discount rate of 3.5%. Positive numbers are benefits from the introduction of locational pricing for losses (no intervention minus costs of the charging remedy shown). Case A refers to semi-marginal loss factors and Case B to full marginal loss factors.

2. Change in cost of constraint management refers to the cost of managing situations when power cannot be transmitted to where it is needed, due to congestion at one or more points on the electricity transmission network.

- 5.88 The model also estimates that there will be a moderate additional environmental benefit from the reduction in SO2 and NOX emissions from the introduction of locational pricing, (arising from a switch from coal to gas) valued at between £0.9 million and £14.4 million over the period.
- 5.89 As noted, we have not attempted to model the dynamic benefits from a move to locational pricing for losses, in terms of more efficient investment, due to the complications and uncertainties of such modelling.

⁴³ In our modelling for the provisional decision on remedies, we used 45% of loss factors rather than 50% loss factors (see footnote 151). Some of the benefits in some scenarios at 50% loss factor are marginally lower than they were at 45% loss factor – the largest difference is about 1.5% of net benefits. We believe that this non-monotonicity is very likely to be caused by the fact that P229 establishes average, season-ahead loss factors, while actual losses depend dynamically on conditions on the day. While the modelling suggests that 100% losses is clearly a better signal of price than 50%, very local moves towards full marginality, like the one between 45% and 50%, need not necessarily and in all scenarios improve actual technical efficiency.

- *Changes in customer bills and generator margins*

5.90 The tables below show the modelled impact of the introduction of locational pricing for losses on customer bills and generator margins under the six combinations of scenarios and options.

Table 5.4: Impact of introduction of locational pricing for losses on customer bills and generator margins, 2017 to 2026

	2015, £ million					
	Reference case		High		Low case	
	A	B	A	B	A	B
Total aggregate change in customer bills (+ve is a reduction in bill from policy)	1,466.63	1,637.78	-298.76	-214.53	-58.52	278.80
Change in generator margin (+ve is an increase in generator margin)	-796.69	-705.89	534.32	660.80	499.6	719.50

Source: CMA scenarios with Imperial College and NERA calculations.

Note: All values are £ million NPV from 2017 to 2026 at a discount rate of 3.5%. Positive numbers are benefits from the introduction of locational pricing for losses (no intervention minus costs of the charging remedy shown). Case A refers to semi-marginal loss factors and Case B to full marginal loss factors.

5.91 In relation to customer bills, the modelling results generate a reduction in bills in the reference scenarios and an increase in the high and low fossil fuel scenarios. Generator margins fall in the reference scenario and rise in the high and low scenarios. These results arise largely out of the impact of the introduction of locational pricing for losses on the wholesale price which, for the reasons discussed above, is highly uncertain. The magnitude of the effect on wholesale prices is also relatively small. The largest impact in any scenario in any year is £0.4/MWh, compared with a projected wholesale energy price of between £70/MWh and £90/MWh.⁴⁴

5.92 Overall, we do not believe that the short-run effect of the introduction of locational pricing on wholesale prices is systematic or stable, or likely to be very large.⁴⁵ In this sense, our view is similar to that expressed in Ofgem's impact assessment for the P229 code modification, which concluded that 'it is reasonable to conclude that the impact on wholesale prices is likely to be minimal'.⁴⁶

5.93 Further, as noted below, we have good reason to believe that the efficiency benefits we calculated above will, in a well-functioning GB electricity market and whichever the mechanism that allows this transfer, lead to lower bills for customers. We therefore do not consider that the risk of generators

⁴⁴ NERA report, section 4.4.2.

⁴⁵ Although the effect is not large relative to the price of electricity, the modelled effect is large because it multiplies a small price effect by a large quantity.

⁴⁶ Ofgem (2011), [Impact Assessment on RWE proposal P229 - seasonal zonal transmission losses scheme](#), paragraph 4.28.

capturing the efficiency gain through a transfer from customers as a result of locational pricing for losses to be a significant one.

- *Regional transfers*

5.94 Table 5.5 shows the simulated change in annual bills within different regions as a result of the introduction of locational pricing. In our reference case, average bills fall in all regions except in the North of England under semi-marginal factors. In the other cases, the picture is more varied. The North of Scotland shows falling bills in all scenarios. We note that the absolute magnitude of the effects are again small – of the order of 0.1% of annual bills.

Table 5.5: Changes in customer bills in different regions as a result of the introduction of locational pricing for losses (positive number shows reduction in bills), NPV average of £ per customer per year, 2017 to 2026

<i>Change in annual customer bill (+ve number is a fall due to the policy)</i>	£					
	<i>Reference case</i>		<i>High case</i>		<i>Low case</i>	
	<i>A</i>	<i>B</i>	<i>A</i>	<i>B</i>	<i>A</i>	<i>B</i>
National average	0.92	1.77	-0.19	-0.23	-0.04	0.30
North Scotland	2.17	2.66	1.15	0.75	1.36	1.34
South Scotland	0.92	1.77	-0.19	-0.23	-0.04	0.30
North England/Wales	-0.23	0.51	-1.12	-1.29	-1.09	-0.86
Midlands of England/Wales	0.32	1.10	-1.03	-0.53	-0.89	-0.13
South England/Wales	0.08	0.79	-0.75	-0.96	-0.73	-0.54

Source: CMA, with Imperial College and NERA calculations.

Notes:

1. Positive numbers are GB benefit from the introduction of locational pricing for losses (no intervention minus costs of the charging remedy shown).
2. Case A refers to semi-marginal loss factors and Case B to full marginal loss factors.

5.95 We note that these results are the combination of a systematic effect and an uncertain effect. The systematic effect, as discussed above, is that the introduction of locational pricing for losses will result in a transfer from customers in areas where consumption is high relative to generation to areas where consumption is low relative to generation. This pattern is borne out in the pattern of relative beneficiaries in the table above: customers in the North of Scotland tend to benefit to a greater extent than customers in the South of England, for example. However, the impact on customers in each region is also driven by wholesale price effects (for example, in the reference case all customers benefit in each region of Great Britain) which, as discussed above, is highly uncertain.

5.96 We note that distributional effects were one of the grounds for Ofgem’s rejection of P229. The main distributional impacts examined by Ofgem were from generators in the North to customers in the North and generators in the South. However, the main conclusion that we draw from an examination of regional transfers is that we do not believe that these are such as would

undermine the net benefits that would arise from the introduction of locational pricing (as described above).

- *Impact on GB/EU transfers*

5.97 Table 5.6 shows the details of modelled financial flows to and from continental Europe. Details of the calculations are contained in the NERA report.

5.98 The second line in the table below shows the change in the total cost of imports due to the introduction of locational pricing for transmission losses. This is composed of two effects: the increase in volumes of non-GB generation and the average price at which they are imported. In the reference case, GB average import prices fall and counteract the increase in generation costs, and in the other cases they rise. We do not believe that average price changes at times of import are linked to the introduction of locational pricing for losses in any systematic direction.

5.99 The first line shows the change in the cost of generation outside GB due to locational pricing. In all cases, the costs of generation outside GB increase. This is entirely due in the model to an increase in generation outside GB. Although we have not modelled the non-GB European market in great detail, we believe this is a plausible impact of the introduction of locational pricing for losses, since it will tend to reduce generation in distant locations and increase imports which are, under the current implementation of EU regulations, subject to a different mechanism for losses charging.

Table 5.6: Impact of introduction of locational pricing for losses on GB import costs

	<i>£ million, NPV</i>					
	<i>Reference case</i>		<i>High case</i>		<i>Low case</i>	
	<i>A</i>	<i>B</i>	<i>A</i>	<i>B</i>	<i>A</i>	<i>B</i>
Total change in generation costs outside GB (+ve implies higher costs under policy)	-34	-32	-23	-17	30	-224
Total change in net import cost valued at GB market prices (+ve implies a higher cost under policy)	10	56	13	-46	-3	-209

Source: CMA with Imperial College and NERA calculations.

Notes:

1. All values are £ million NPV from 2017 to 2026 at a discount rate of 3.5%. Positive numbers are GB benefit from the introduction of locational pricing for transmission losses (no intervention minus costs of the charging remedy shown).
2. Case A refers to semi-marginal loss factors and Case B to full marginal loss factors.

5.100 The modelling of import prices and EU production changes provides us with indications that benefits of the introduction of locational pricing on the GB economy do not flow primarily from reducing overall efficiency within connected electricity markets. If in some scenarios payments to EU generators increase, this is because supplying the GB market from imports

is sometimes a cheaper solution. In such cases, and given our confidence that the wholesale market is functioning properly, the net benefit to GB customers is positive.

- *Summary of our modelling results*

- 5.101 The simulation modelling was primarily intended to answer a question about the order of magnitude of the technical efficiencies that could be expected from the introduction of locational pricing for transmission losses. In view of the results of our modelling for the period 2017 to 2026, we believe that these technical efficiencies arising from short-term effects are likely to be of the order of £150 million (in view of the range provided by our modelling, between £131 million and £190 million), with a slight increase in expected benefits under Option B, where transmission losses factors are fully marginal.⁴⁷
- 5.102 We believe that the transfers arising from the introduction of locational pricing for transmission losses – particularly insofar as effects on the wholesale price and import price effects are concerned – are highly uncertain and not systematically correlated with the introduction of locational pricing for losses.
- 5.103 The simulation modelling results have therefore been useful in confirming the broad order of magnitude of quantitative results found in previous modelling exercises. They have also been useful in providing some evidence that the benefit derives essentially from real resource savings and is not driven to any large extent by reductions in transfers to continental Europe.⁴⁸ Similarly, any increase in payments to continental Europe that we see are the result of minimising the costs of meeting GB customer demand.

Views of parties

- 5.104 Parties made a number of comments in relation to the existence of an AEC and the additional analysis we undertook.⁴⁹ These are summarised below and presented in more detail in Appendices 5.2 and 6.2.

⁴⁷ See paragraph 5.85 for a definition of option B.

⁴⁸ This was not the case in the modelling and scenarios as part of the inquiry by [RWE](#).

⁴⁹ These were in response to provisional findings report and the provisional decision on remedies report.

- *Parties' views on the existence of an AEC*

5.105 Some of the commentary was supportive of the existence of an AEC:

- (a) Some of the Six Large Energy Firms,⁵⁰ some Mid-tier Suppliers,⁵¹ Ofgem,⁵² one smaller supplier⁵³ and one independent power generator⁵⁴ supported the principle of introducing locational pricing for variable transmission losses.
- (b) E.ON⁵⁵ and Scottish Power⁵⁶ agreed with the CMA's findings that the current system of allocating losses to market participants on a uniform basis creates a cross-subsidy that could distort competition in the market.
- (c) RWE⁵⁷ considered that the case for the economic efficiency and competitive benefits of zonal losses had been made on a number of occasions during the last few years. Further it submitted a new set of simulation scenario results showing that, under certain input and methodological assumptions, charging for losses would yield an NPV of net benefits in the hundreds of millions of pounds.⁵⁸
- (d) Intergen⁵⁹ agreed that locational adjustment to the Transmission Losses factor would help incentivise future investment decisions that would aid the balancing of the transmission system but it considered that in the short term these changes could be interpreted as a windfall gain/tax on existing generating assets with some winners and losers.
- (e) Ofgem⁶⁰ and EDF Energy⁶¹ argued before we had embarked on our own simulation modelling that the empirical evidence supporting locational pricing for transmission losses needed to be updated to reflect changes in market conditions (since P229) before a final conclusion was reached.

⁵⁰ Centrica response to provisional findings and Remedies Notice, p51; Centrica response to provisional decision on remedies, paragraph 451, p88. E.ON response to provisional findings, p3, paragraph 13; E.ON response to provisional decision on remedies, paragraphs 6 (pp1 & 2) and 43 (p8). EDF Energy response to provisional decision on remedies, paragraph 3.1, p17. RWE response to provisional findings, p2 paragraphs 50–54.

⁵¹ Co-operative Energy response to Remedies Notice, p1; Ovo Energy response to Remedies Notice, p10.

⁵² Ofgem response to Remedies Notice, p1.

⁵³ Good Energy response to Remedies Notice, p4.

⁵⁴ Intergen response to Remedies Notice, p4.

⁵⁵ E.ON response to provisional decision on remedies, paragraph 6, pp1 & 2.

⁵⁶ Scottish Power response to provisional decision on remedies, paragraph 3.1, p6.

⁵⁷ RWE response to provisional decision on remedies, paragraph 39.1, p12.

⁵⁸ RWE's [submission](#) to the CMA, 3 September 2015.

⁵⁹ Intergen response to provisional decision on remedies, p2.

⁶⁰ Ofgem response to Remedies Notice, p1.

⁶¹ EDF Energy response to provisional findings, paragraph 4.5, p10, provisional decision on remedies, p20.

It considered that a cost-benefit analysis should be conducted and that it should take into account distributional impacts.

(f) EDF Energy⁶² supported the principle of cost-reflectivity, and agreed that locational pricing for losses might theoretically result in lower costs for customers. However, it was not convinced that a locational losses scheme would bring customer benefits in practice, because of uncertainty about the exact method to be adopted; real future market scenarios; and the actual responses of participants to such a scheme. It also questioned the proportionality given the large distributional effects compared with net benefits.

5.106 Other parties, however, did not agree that we had established a sufficient evidence base to conclude that there was an adverse effect on competition. Some took the view before we had conducted our own simulation modelling, and some maintained the position afterwards. SSE⁶³ said that the CMA had not established the existence of an AEC to the required legal standard.

- *Parties' views on updated cost-benefit analysis and assumptions*

5.107 Some parties criticised the modelling approach followed by the CMA and NERA and some of the results obtained.

5.108 EDF Energy⁶⁴ considered that the additional modelling analysis undertaken by NERA did not meet the required standard of proof to conclude that there was a certain net benefit and to proceed directly to implementation. It also had some detailed points on modelling assumptions which we comment on in Appendix 5.2.

5.109 SSE⁶⁵ noted that engaging NERA to carry out the CMA's cost-benefit analysis entailed a very real risk of apparent bias or confirmation bias (or both) due to NERA's position as a long-standing adviser to RWE. It added that the measures put in place by the CMA to mitigate the potential risk of conflict of interest were insufficient and not followed in any case. In particular, SSE pointed out that the CMA did not adhere to the transparent and iterative process it had undertaken to follow by failing to publish a working paper with the details of NERA's model and its results.

⁶² EDF Energy response to provisional findings (August 2015), p3 and paragraphs 4.5–4.10, and EDF Energy response to Remedies Notice (August 2015), paragraph 1.7.

⁶³ SSE response to provisional decision on remedies, paragraph 8.2.2, p64.

⁶⁴ EDF Energy response to provisional decision on remedies, paragraphs 3.2 & 3.3, pp17 & 18.

⁶⁵ SSE response to provisional decision on remedies, paragraph 8.3.2, p64.

5.110 We provide detailed responses to these arguments in Appendix 5.2 (in relation to magnitude of AEC) and Appendix 6.2 (in relation to remedy design questions). In summary, we do not agree with SSE's comments and we do not consider that these comments and criticism detract from our conclusion on the order of magnitude of detriment from the absence of locational pricing for transmission losses, for the reasons set out in our assessment below.

Our assessment

5.111 In a well-functioning energy market, the regulatory structure should ensure that competition should put pressure on firms to avoid location-based losses by reducing variable transmission losses (and in a competitive market, these lower costs will be passed on to customers). This assumption has been tested through modelling, wide consultation, and consideration of all potential countervailing issues (costs, distributional impacts of change, and so on).

5.112 Our review of previously conducted simulation modelling and analysis of incentives all point to the existence of significant avoidable waste of electricity due to the absence of locational transmission loss charging. Our simulation modelling has strengthened our belief that the scale of inefficiencies arising from the absence of locational pricing for losses (and therefore the detriment to consumers) is substantial, of the order of £150 million over the next ten years.

5.113 As a result of the introduction of locational pricing for losses, we expect the following:

(a) Efficiency gains arising from short-run effects: costs will be higher for less efficient generation plants (ie subject to a higher level of losses) and lower for more efficient plants, leading to lower costs overall through a more efficient use of the overall generation capacity.

(b) Efficiency gains arising from long-run effects: investment decisions relating to generation plants (ie extension, closure or new plants) will take into consideration the costs of transmission losses and there could also be increased efficiency in the location of demand, particularly in investment decisions relating to the location of high-consumption industrial demand.

(c) Efficiency gains will be passed through to GB customers through lower total bills.

5.114 Our simulation modelling supports the existence of substantial costs arising from the absence of the efficiencies outlined above. Over the next ten years,

the model simulates total efficiency benefits of between £131 million and £159 million for option A and £158 million and £190 million for option B. Option B (in which full marginal transmission losses factors are implemented) always yields greater benefits than option A. While our model also simulates benefits for the period until 2035, for the reasons set out in the paragraphs above we do not believe the results for this later period are reliable. We note, however, that under all scenarios, benefits remain positive over this period. This is consistent with previous analysis described in paragraphs 5.46 to 5.56.

- 5.115 In our simulation modelling we have not tried to model the efficiency gains arising from long-run effects. However, we believe that in the long run, these efficiencies will eventually lead to lower prices for customers through a process of competition as a result of lower production costs in GB and/or lower GB wholesale prices. Consideration of long-run effects adds to our belief in the existence of substantial costs from the absence of locational transmission loss charging.
- 5.116 We note that our arguments relating to the transfer of benefits to customers rely on GB wholesale electricity markets being competitive. As described in Section 4, we have concluded that this is to a large extent the case. We have seen no evidence that any transfers would systematically disadvantage customers. We would therefore expect that, as a matter of principle, by virtue of competition in the wholesale and supply markets, increased technical efficiency will benefit GB customers. Against the identified efficiencies, the costs of implementation, as set out in Section 6, are small. The benefits of change are substantially greater than the status quo.

Conclusion on transmission losses AEC

- 5.117 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.⁶⁶ Similarly, cross-

⁶⁶ 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.

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.

5.118 We expect the detriment arising from the short-run effects to be of the order of £150 million over the next ten years. We have not quantified the detriment arising from the long-run effects, but consider that it is likely to be a small effect in the overall scheme of such investment decisions.

Impact on competition of lack of locational prices for constraints

5.119 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.⁶⁷
- (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.

⁶⁷ 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.

- 5.120 We do not think there would be a significant effect from impaired technical efficiency of electricity generation. The reason for this is that National Grid currently uses a competitive mechanism to buy balancing services through balancing mechanism bids and has an incentive to minimise congestion costs.
- 5.121 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 and be coordinated in the same way as France and Great Britain are currently coordinated.
- 5.122 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

- 5.123 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 limited quantification of splitting Scotland from England and Wales by Staffell and Green in 2014.⁶⁸ They found that on average domestic consumers in Scotland would benefit by an estimated £64 off their annual energy bills.⁶⁹ Generators in Scotland would have lower revenues.⁷⁰ 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),⁷¹ while generators there would enjoy higher revenues. While this

⁶⁸ I Staffell and R Green (2014), *Electricity markets in Great Britain: better together?*

⁶⁹ *ibid.*

⁷⁰ 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.

⁷¹ 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.

study looked at distributional effects it did not try to estimate a net benefit figure.

- 5.124 We note that transmission constraints are expected to abate following the implementation of existing plans for transmission capacity expansion between England and Scotland, which will tend to reduce any short-run (or indeed likely medium or longer term) benefits for introducing locational pricing to account for constraints.⁷²
- 5.125 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 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

- 5.126 Parties raised a number of concerns about reforms concerning increased locational pricing for transmission constraints:
- (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.

⁷² 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.

5.127 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

5.128 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).

5.129 We note, for instance, that there is now an EU process that requires 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.

5.130 Under the CACM regulation, the Agency for the Cooperation of Energy Regulators (ACER) is required to assess the efficiency of current bidding zone configuration every three years.⁷³ 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 Scottish Power Transmission) to launch a review of an existing bidding zone configuration.⁷⁴ The CACM includes a preferred European model for congestion charging, where needed, by zonal splitting.

5.131 In view of the above, and considering the above-mentioned reviews and potential changes to be implemented pursuant to the CACM regulation, including the possibility of a review of existing bidding zone configuration, we decided not to further investigate this issue within the context of this investigation.

⁷³ Article 33(1) of the CACM.

⁷⁴ Article 34.7 CACM.

Conclusion on locational pricing for transmission losses and constraints

- 5.132 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.
- 5.133 The current mechanism of averaging the cost of transmission losses irrespective of each generator's and customer's contribution to those losses results, over ten years in NPV terms, in an approximate cost to the system of the order of £150 million.
- 5.134 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, for the reasons further explained above, these concerns do not appear well-founded based on Ofgem's own quantitative work (and certain earlier concerns, relating for example to possible changes at EU level, are no longer maintained by Ofgem).
- 5.135 We have not reached a view 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

- 5.136 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 (already in force);
- (b) a move to making the imbalance price in all periods equal to the cost of the 1 MWh most costly action in the balancing mechanism (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;⁷⁵
- (c) a move to re-price STOR actions (typically periods of tight short-run margins due either to high demand or to supply disruptions)⁷⁶ to the probability of lost load multiplied by £6,000/MWh (the 'value of lost load' (VoLL)),⁷⁷ if this is greater than their utilisation price. This is known as 'reserve scarcity pricing', or **RSP**;⁷⁸ and
- (d) a move to price disconnection or voltage reduction actions equal to the **VoLL**.⁷⁹

5.137 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, which involved implementing only the first two elements of the reforms (ie no RSP and VoLL pricing).

5.138 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.

5.139 In this section we consider the likely effect of these reforms on competition in wholesale electricity markets. We first provide some background on the balancing mechanism and the proposed role of the reformed imbalance prices within it, before assessing the impact of each element of the reform.

⁷⁵ This was itself a narrowing from the original design, which was a simple average cost of all balancing actions).

⁷⁶ Periods of tight margins are periods when STOR is likely to be used. However, STOR is also used outside of very tight periods. The system operator has discretion to use a STOR plant over a balancing mechanism 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.

⁷⁷ 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.

⁷⁸ As noted above, the imbalance price calculation is applied to the stack of actions.

⁷⁹ There is a transitional period during which this will be set to £3,000/MWh.

Background on the balancing mechanism and imbalance prices⁸⁰

- 5.140 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.
- 5.141 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 balancing mechanism by accepting bids and offers submitted (**before** gate closure) by generators or suppliers, to increase or decrease the amount of energy they will produce (or consume).^{81,82} It can also take actions outside the balancing mechanism, such as the use of STOR.
- 5.142 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.⁸³
- 5.143 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.⁸⁴ 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).

⁸⁰ See Elexon's [initial written assessment](#) of P305 – EBSCR.

⁸¹ Bids are proposals to reduce generation or increase consumption. Offers are proposals to increase generation or reduce consumption.

⁸² 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.

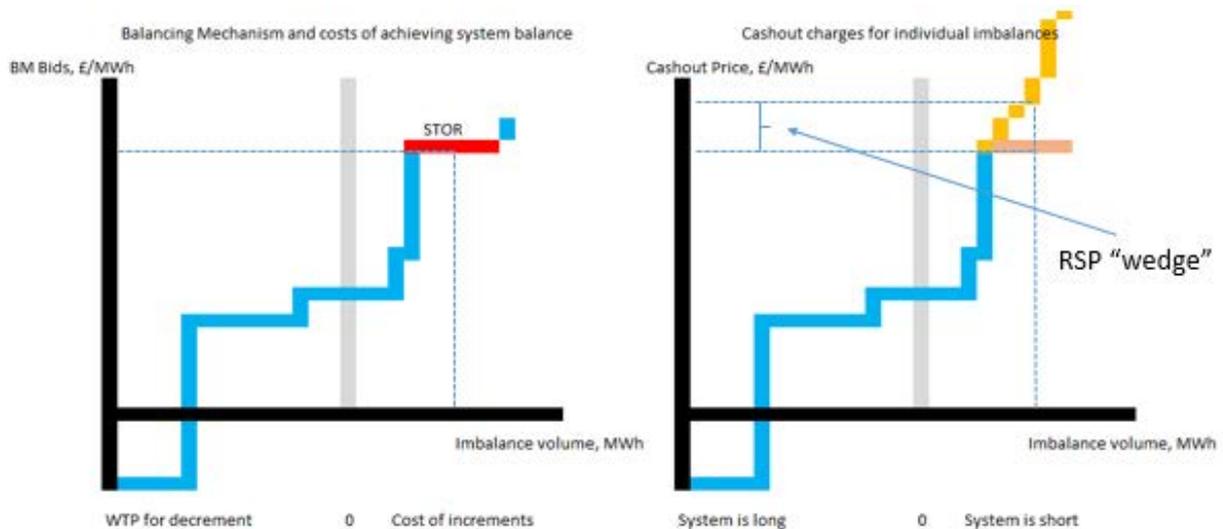
⁸³ National Grid, [STOR market information report: tender round 24](#).

⁸⁴ 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](#).

Balancing mechanism and imbalance prices post EBSCR

5.144 The relationship between pricing under the balancing mechanism and under the cash-out rules as reformed following the recent EBSCR (which is coming into force in a gradual way over the next two years) is shown schematically in Figure 5.2 below.⁸⁵

Figure 5.2: Balancing mechanism and imbalance ('cash-out') prices



Source: CMA analysis.

5.145 The left-hand diagram shows the cost of achieving system balance in the context of the balancing mechanism 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.

5.146 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 balancing mechanism. 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).

⁸⁵ This diagram abstracts from many detailed elements of the relationship between balancing mechanism 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 balancing mechanism, 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.

- 5.147 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.
- 5.148 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 balancing mechanism. This is shown in the right-hand diagram.⁸⁶
- 5.149 Following the EBSCR rule changes, the single imbalance price is set, as shown in the right-hand diagram, by the intersection of actual demand (ie overall system imbalance) and the supply curve.⁸⁷ This follows the supply curve for the balancing mechanism 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.
- 5.150 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

- 5.151 **Single imbalance price** is the 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 has replaced the previous dual imbalance price rule whereby actors who were long when the system was short or vice versa

⁸⁶ The cost of actions is not always reflected in cash-out prices and the system operator 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.

⁸⁷ This change will come into force by winter 2015/16.

(and were therefore contributing to the rebalancing of the system) were effectively penalised – or at least not rewarded – for doing so.⁸⁸

- 5.152 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 balancing mechanism 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).
- 5.153 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;⁸⁹ 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.⁹⁰
- 5.154 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 makes cash-out more attractive for these parties.⁹¹
- 5.155 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.

⁸⁸ 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 balancing mechanism.

⁸⁹ A small player’s own imbalance will not have a significant effect on system imbalance, hence the ‘fair bet’ involved in cash-out.

⁹⁰ 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.

⁹¹ This is confirmed in Ofgem (2014), *Further analysis to support Ofgem’s updated impact assessment*, Figure 3, which shows smaller suppliers benefiting from EBSCR.

PAR1

- 5.156 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'.
- 5.157 We have considered three concerns regarding the move to PAR1:
- (a) Stephen Littlechild has argued⁹² 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. 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, Ecotricity, 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.
- 5.158 In relation to first concern, Ofgem has argued to us that the system operator'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.
- 5.159 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

⁹² Professor Stephen Littlechild (January 2012), [Response to Ofgem's consultation on electricity cash-out issues](#).

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.

- 5.160 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 view is that PAR 1 in combination with the 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.
- 5.161 First Utility counter-argued⁹³ that while this was true, there were still particular disadvantages faced by smaller players with respect to finding adequate liquidity to address their own imbalance risk. While the larger suppliers had extensive insurance options – both from their own vertically integrated generation fleet and from the use of specialist brokerage products – not all of these options were available to smaller suppliers. In particular, ‘it is not necessarily open to all such market participants to contract for more flexible generation as lack of scale or ability to forecast likely demand may adversely affect the appetite of generators to enter such arrangements’.
- 5.162 We accept that there may be some economies of scale in supply. The ability to maintain a 24-hour trading desk or to find it profitable to outsource such trading is probably one advantage of scale. However, we do not consider that this advantage of scale amounts to a significant barrier to entry. We note a healthy level of entry from operators who have not contracted for such service.
- 5.163 In a similar vein, Cornwall Energy submitted analysis to us⁹⁴ that demonstrated, on the assumption that the existence of PAR1 would not lead to any behavioural changes, the extent to which the range of balancing mechanism prices will increase under the reform. It argued that the cost of this would be borne by those who were less good at balancing, which was the smaller and non-vertically integrated suppliers. It went on to argue that the parties affected would have little ability to modify their behaviour in response to these new costs. However, we do not agree with this view. There are companies that provide outsourced on-the-day trading services. Parties might find that the cost of these becomes more attractive than the risk of imbalance. As we note above in relation to First Utility’s argument,

⁹³ First Utility response to provisional findings, paragraphs 2.8 & 2.9.

⁹⁴ [REDACTED]

this does imply additional costs and it may be a cost item that demonstrates returns to scale. However, we do not believe that these constitute a significant barrier to entry.

- 5.164 Nevertheless, we recognise that the move to PAR1 will impose new costs on suppliers, including on smaller parties. 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

- 5.165 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

- 5.166 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.
- 5.167 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.

- 5.168 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 balancing mechanism because of difficulties it has in regulating National Grid's natural monopoly activity of centralised balancing.
- 5.169 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.'
- 5.170 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

- 5.171 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.
- 5.172 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 available concerning the likelihood of STOR being used and of loss-of-load probability (LOLP) being high.
- 5.173 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.

- 5.174 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.
- 5.175 Utilita and Ecotricity 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.
- 5.176 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 Sections 9 and 11.
- 5.177 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.
- 5.178 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 leads to an AEC.

Interaction with the Capacity Market

- 5.179 In our 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.⁹⁵ In this section, we examine the interactions between the two sets of reforms.⁹⁶

- 5.180 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 a lower clearing price and lower prices would then be passed through to consumers' bills.
- 5.181 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.
- 5.182 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 [redacted] 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 ([redacted]) said to us that, even if the reforms had been certain, they would probably have [redacted].
- 5.183 We note that several bidders appear to have made some adjustments to their bids that may take some account of the EBSCR reforms.⁹⁷ 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, with a similar clearing price in the second auction in 2015. These

⁹⁵ 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.

⁹⁶ 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).

⁹⁷ [redacted]

outcomes may reflect differences in view (between DECC and the participants in the auction) over any the variables affecting bids.

5.184 Overall, we have not found strong evidence that anticipation of EBSCR reforms resulted in lower bids in the Capacity Market auction in 2014 or 2015.

Conclusion on imbalance price reforms

5.185 Our concern has been to assess whether any aspects of Ofgem's EBSCR reforms lead to an AEC.

5.186 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.

5.187 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.

5.188 If, as argued by Utilita, Ecotricity, 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.

5.189 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.

5.190 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 or 2015.

5.191 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 Sections 18 and 19.

The Capacity Market

5.192 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.

5.193 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

5.194 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) over the lifetime of the generation, even if for (very specific peak plant) this is only at very occasional peak times – once every 20 years,⁹⁸ perhaps.

5.195 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.

5.196 In practice, investors in generation may be sceptical that such peak prices would ever be allowed to arise (indeed, there is some risk they may not arise either for a substantial period of time or during the lifetime of the generation plant). 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

⁹⁸ 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.

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.

- 5.197 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 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 (or such circumstances may not arise), investment will be deterred, with the risk of under-supply at peak periods.
- 5.198 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 (ie rare) events, and the system has never been tested in terms of extreme conditions (and therefore potential for extreme prices).
- 5.199 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 (most renewable generation is 'intermittent' – it may not therefore be relied upon to produce electricity at all times, and specifically at times of system stress). 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.
- 5.200 DECC's introduction of a Capacity Market is based on cogent arguments, not only in addressing the potential failure of the economic model in addressing the most extreme scenarios, but in terms of ensuring the 'security of supply' element of the energy trilemma is met. 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 recover fully the cost of past investments in these technologies.

Capacity Market design

- 5.201 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.⁹⁹ Winning bidders receive regular capacity payments in exchange for an obligation to provide a previously agreed level of capacity with 4 hours' notice from the system operator, National Grid.¹⁰⁰
- 5.202 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'.¹⁰¹ That is, DECC estimates the amount of capacity needed in any given year to meet its target level of reliability.¹⁰² The Delivery Body then holds auctions to procure this target level of capacity.
- 5.203 Capacity agreements are allocated via a multiple-round descending clock auction with a single clearing price.¹⁰³ Ahead of the auction, DECC announces the demand curve the auctioneer will use to determine the amount of capacity to procure.¹⁰⁴ 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.
- 5.204 Figure 5.3 illustrates DECC's demand curve for the first auction (completed in December 2014). It is important to note that the parameters of any future auction may be different; the second auction (completed in December 2015) had a slightly lower level of target capacity, for example.

⁹⁹ DECC (June 2014), [Implementing Electricity Market Reform \(EMR\): finalised policy positions for implementation of EMR](#).

¹⁰⁰ *ibid.*

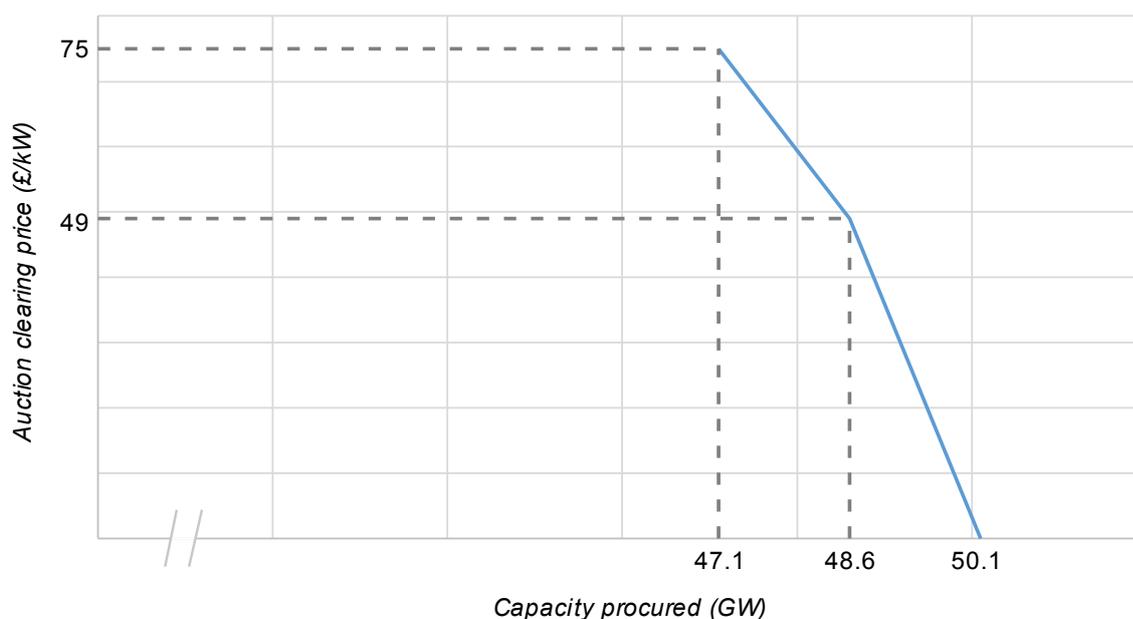
¹⁰¹ Expressed as loss of load expectation (LOLE): the number of hours during each year for which it is expected (statistically) that supply would not meet demand (absent further intervention from the system operator)

¹⁰² DECC (June 2014), [Implementing Electricity Market Reform \(EMR\): finalised policy positions for implementation of EMR](#).

¹⁰³ National Grid (July 2014), [Capacity Market user support guide: guidance document for Capacity Market participants](#).

¹⁰⁴ DECC (June 2014), [Implementing Electricity Market Reform \(EMR\): finalised policy positions for implementation of EMR](#).

Figure 5.3: DECC's demand curve for the 2018/19 T-4 auction



Source: CMA graph of [National Grid data](#).

5.205 The first T-4 Capacity 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.

5.206 The second T-4 Capacity Auction (for delivery in 2019/20) was held in December 2015, and procured 46.4 GW of capacity at a price of £18/kW. This will result in capacity payments of approximately £830 million in the delivery year.¹⁰⁵

Potential concerns

5.207 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.

5.208 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

¹⁰⁵ National Grid [Provisional Auction Results](#).

potential concerns that have been raised with us relating to the design of the Capacity Market.

Length of capacity agreements

- 5.209 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.¹⁰⁶ Also in December 2014, the CMA received a submission from Tempus Energy regarding the role of DSR in the Capacity Market.¹⁰⁷
- 5.210 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).
- 5.211 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.
- 5.212 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.
- 5.213 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).
- 5.214 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

¹⁰⁶ Case T-793/14, *Tempus Energy and Tempus Energy Technology v Commission*, lodged 4 December 2014.

¹⁰⁷ Tempus Energy [initial submission](#).

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 decided not to carry out further work in this area.

Recovery of Capacity Market costs

- 5.215 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.
- 5.216 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 a system based on triads (as originally proposed by DECC)¹⁰⁸ 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.
- 5.217 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.¹⁰⁹
- 5.218 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

¹⁰⁸ 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.

¹⁰⁹ 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.

option. If this is the case, it may result in an inefficient allocation of capacity agreements.

- 5.219 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.¹¹⁰ For the reasons set out above, we did not undertake further work in this area.

Penalty mechanisms

- 5.220 Capacity providers with capacity agreements face penalties if they fail to deliver their obligations.¹¹¹ These penalties are capped at 100% of the capacity provider's annual capacity market payments.¹¹² 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.
- 5.221 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).
- 5.222 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.
- 5.223 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.

¹¹⁰ DECC (October 2013), *Electricity Market Reform: Consultation on Proposals for Implementation*. While the consultation noted the potential for double payment between Capacity Market and triad avoidance, DECC has indicated that the final methodology put in place post-consultation should not have that effect.

¹¹¹ DECC (June 2014), *Implementing Electricity Market Reform (EMR): finalised policy positions for implementation of EMR*.

¹¹² The Electricity Capacity Regulations 2014, [Schedule 1](#).

5.224 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 so did not consider this issue further.

Conclusions on Capacity Market

5.225 Our conclusion is that the design of the Capacity Market appears broadly competitive. However, we cannot exclude the possibility that specific aspects of the Capacity Market's design could be improved.

5.226 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 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 decided not to carry out further work in this area.

Contracts for Difference

5.227 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.¹¹³

5.228 CfD payments are due to increase steadily, reaching about £2.5 billion a year by 2020/21.¹¹⁴ 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.

5.229 In this section, we set out our 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.

¹¹³ 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.

¹¹⁴ 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.

- (b) We analyse the ways in which CfDs are allocated and the impact on competition.
- (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 conclusions.

Comparison of Renewables Obligation Certificates and Contracts for Difference

- 5.230 In order to achieve its objective of decarbonising electricity generation, the government has supported renewable electricity generation since 2002 via the RO scheme.¹¹⁵
- 5.231 Under the current RO scheme, 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.¹¹⁶
- 5.232 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.
- 5.233 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.¹¹⁷

¹¹⁵ DECC (February 2015), *Increasing the use of low-carbon technologies*.

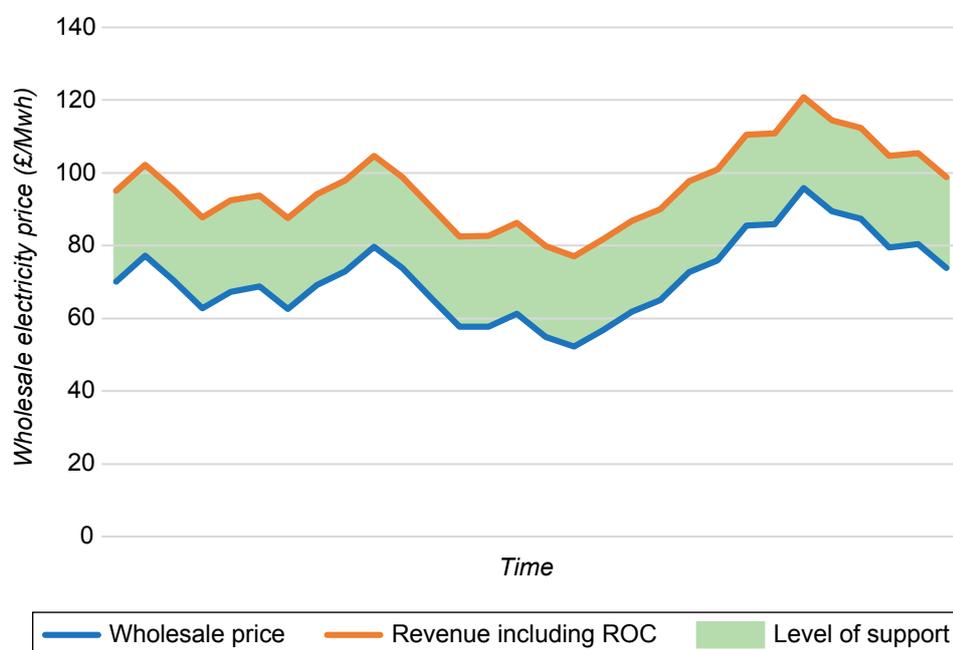
¹¹⁶ *ibid.*

¹¹⁷ DECC (June 2014), *Implementing Electricity Market Reform (EMR): finalised policy positions for implementation of EMR*.

5.234 A CfD is a private contract between the holder and the CfD counterparty¹¹⁸ in which the holder receives from (or pays to) the counterparty the difference between a previously agreed strike price and a CfD reference price.¹¹⁹ 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.¹²⁰ 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.^{121,122}

5.235 Figures 5.4 and 5.5 illustrate the payments under both ROCs and CfDs. Both figures are not based on actual data, and are provided for illustrative purposes only.

Figure 5.4: Renewables Obligation Certificates



Source: CMA (not actual price data).

¹¹⁸ 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](#).

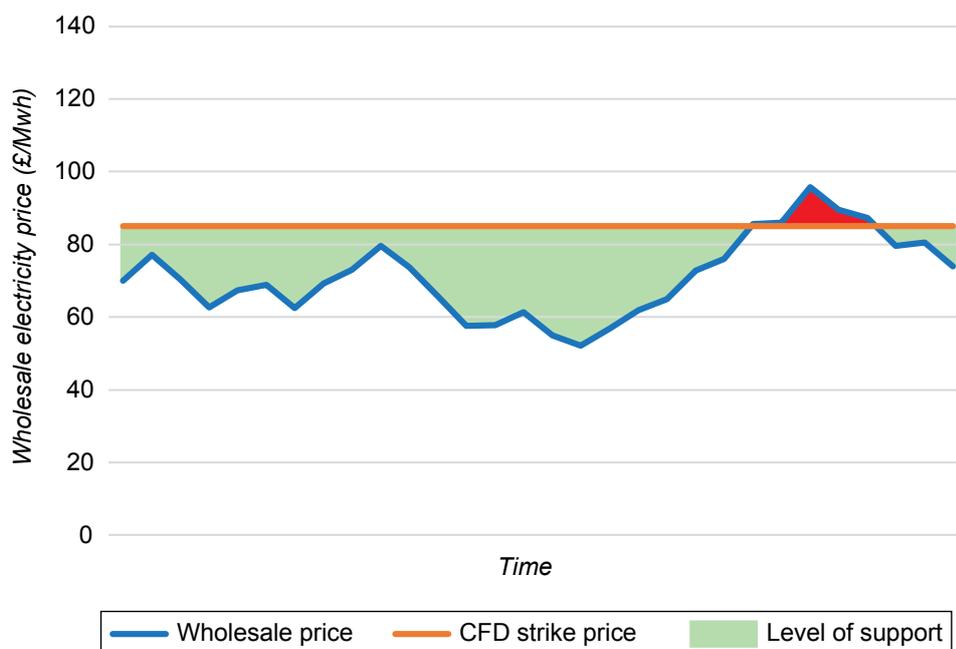
¹¹⁹ For baseload generation, the CfD reference price is the volume-weighted average of season-ahead baseload prices, based on data from the London Energy Brokers’ Association (LEBA) Baseload Index and the Nasdaq Baseload Index. For intermittent generation, the CfD reference price is the volume-weighted 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.

¹²⁰ DECC (August 2013), [Electricity Market Reform: Contract for Difference – allocation methodology for renewable generation](#).

¹²¹ [The Contracts for Difference \(electricity supplier obligations\) regulations 2014](#).

¹²² 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 5.5: Contracts for Difference



Source: CMA (not actual price data).

- 5.236 Figure 5.4 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.¹²³ In contrast, Figure 5.5 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.
- 5.237 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.¹²⁴ 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.¹²⁵
- 5.238 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 international political will to reduce the ETS cap to a sufficiently stringent level – and given the 2020

¹²³ The support to generators is driven by the price it receives for its ROCs, as explained above.

¹²⁴ DECC (October 2013), [CfD impact assessment](#).

¹²⁵ *ibid.*

(and ultimately 2050 target under the Climate Change Act 2008) 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.

- 5.239 As noted in Section 2, the RO has been successful in driving investment in renewable generation, which accounted for around 25% of all GB generation in 2015.¹²⁶ 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 2020/21,¹²⁷ and will make up around 8% of the domestic electricity bill in 2020.¹²⁸
- 5.240 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.
- 5.241 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

- 5.242 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 2020/21,¹²⁹ and will make up

¹²⁶ DECC, Energy Trends March 2016, Section 5.

¹²⁷ DECC (October 2014), [Annual energy statement 2014](#).

¹²⁸ 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.

¹²⁹ 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 2030.¹³⁰

- 5.243 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 (by way of competitive auction) can be used to set the strike price and hence the level of support provided to low carbon generators.
- 5.244 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’).
- 5.245 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.
- 5.246 Bidding for the first competitive allocation round took place in January and February 2015.¹³¹ 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 2020/21.¹³²
- 5.247 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.
- 5.248 We note that while, in general, a competitive allocation process will provide the best means of achieving an efficient outcome, this will not be the case in

¹³⁰ DECC (November 2014), *Estimated impacts of energy and climate change policies on energy prices and bills*.

¹³¹ Low Carbon Contracts Company (January 2015), *Electricity Market Reform Contracts for Difference: GB implementation plan*.

¹³² DECC (February 2015), *Contracts for Difference (CFD) Allocation Round One Outcome*.

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.

5.249 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

5.250 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.

5.251 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 2020/21.¹³³ The projects are expected to be completed by 2021, and will have a combined capacity in excess of 4.5 GW when completed.

¹³³ Based on DECC's assumptions of a wholesale electricity price of £53.43/MWh in 2020/21.

- 5.252 In our provisional findings report, 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.^{134,135,136} In 2013, DECC also agreed key commercial terms with EDF on a CfD for a new nuclear plant at Hinkley Point C.
- 5.253 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.^{137,138} 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’.¹³⁹ 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.¹⁴⁰ 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.’¹⁴¹
- 5.254 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

¹³⁴ NAO (June 2014), [Early contracts for renewable electricity](#).

¹³⁵ 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](#)), the Teesside biomass combined heat and power (European Commission (January 2015) [State aid SA.38796 \(2014/N\)](#) – [United Kingdom. Teesside Dedicated Biomass CHP Project](#)) and Lynemouth biomass conversion (European Commission (February 2015) [IP/15/6214](#) (press release) – decision not yet available)). The European Commission opened an in-depth investigation into support for the Drax biomass conversion in January 2015.

¹³⁶ 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 (p5) 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.’

¹³⁷ NAO (June 2014), [Early contracts for renewable electricity](#).

¹³⁸ 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.

¹³⁹ NAO (June 2014), [Early contracts for renewable electricity](#), paragraph 17.

¹⁴⁰ *ibid.*

¹⁴¹ *ibid.*, p8.

thorough explanation of the basis of its decision to use its powers to allocate CfDs outside a competitive process.¹⁴²

5.255 In our provisional findings report 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.¹⁴³ 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.¹⁴⁴

- *Scale of detriment of previous decisions under FIDeR*

5.256 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 the FIDeR projects displaced lower cost projects.

5.257 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 combined heat and power (CHP) plant, but they are not included in our analysis as biomass conversions were not eligible for CfDs in the first auction, and no dedicated biomass with CHP projects were awarded CfDs in the first auction. Our analysis may therefore understate the extent of overcompensation.¹⁴⁵

5.258 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

¹⁴² 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, neither [sic] is the level of support required to bring specific projects or technologies into existence' (p5).

¹⁴³ See [Energy Act 2013](#) and [Electricity: the Contracts for difference \(allocation\) regulations 2014](#).

¹⁴⁴ 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.

¹⁴⁵ 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 5.7: 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	1,200	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.

5.259 Table 5.7 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.¹⁴⁶ 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.

5.260 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 (or approximately £2.9–£3.5 billion NPV over the length of the contracts¹⁴⁷). This is equivalent to approximately a 1% increase on customers' average annual electricity bills for the 15-year length of these contracts.

5.261 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.

¹⁴⁶ 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*.

¹⁴⁷ Using a discount rate of 3.5% as recommended by the Treasury's Green Book. See HM Treasury, *The Green Book: Appraisal and Evaluation in Central Government*, p26.

- 5.262 The Crown Estate's Offshore Wind Cost Reduction Pathways report¹⁴⁸ estimated the levelised cost of electricity (LCOE)¹⁴⁹ for two different types of 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.¹⁵⁰ 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.
- 5.263 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,¹⁵¹ while the remaining two (Beatrice and Hornsea) would be Site B.¹⁵² By way of comparison, both projects awarded CfDs in the first auction (East Anglia 1 and Nearth Na Gaoithe) would be considered Site B projects.¹⁵³
- 5.264 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.¹⁵⁴
- 5.265 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.¹⁵⁵ 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 £[redacted]/MWh.
- 5.266 We therefore think it is reasonable to assume that, had the projects that were successful under FIDeR instead participated in the competitive CfD

¹⁴⁸ The Crown Estate (2012), *Offshore Wind Cost Reduction: Pathways Study*.

¹⁴⁹ An estimate of the lifetime cost of the project, per unit of electricity generated.

¹⁵⁰ 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.

¹⁵¹ 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.

¹⁵² Beatrice was awarded development rights in the Scottish Territorial Waters leasing round, and Hornsea is a round 3 site.

¹⁵³ East Anglia 1 and Nearth Na Gaoithe were awarded development rights under leasing round 3 and the Scottish Territorial Waters leasing round respectively.

¹⁵⁴ 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.

¹⁵⁵ 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.

allocation process, they would have had to bid below the level of support they were awarded under FIDeR in order to secure CfDs.

5.267 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 concerning their support considerably before those awarded CfDs in the first auction.^{156,157}

- *DECC's powers to award further CfDs outside the auction*

5.268 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.

5.269 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.¹⁵⁸

5.270 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) may have asset lives considerably longer

¹⁵⁶ 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.

¹⁵⁷ 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

¹⁵⁸ DECC (June 2014), [Consultation on directions to offer Contracts for Difference: government response](#).

than those competing in the CfD auctions, potentially making them unsuitable to compete in standard CfD auctions.

- 5.271 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.
- 5.272 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.¹⁵⁹ 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

- 5.273 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.
- 5.274 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 5.8 below), Pot 2 contains 'less established technologies' (see Table 5.8) and Pot 3 includes biomass conversion.¹⁶⁰ Projects applying for CfDs compete with other projects in the same pot to secure this limited budget.
- 5.275 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.

¹⁵⁹ 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.

¹⁶⁰ 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.

5.276 DECC set an ASP for each technology. This serves as a cap on the strike price that any project can receive. Table 5.8 shows the ASP for each technology.

Table 5.8: Administrative strike price per technology for the first CfD auction

Technology type	Pot	£/MWh			
		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*

5.277 In our provisional findings report 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.

5.278 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.¹⁶¹

5.279 Conversely, in relation to minimising rents for producers, it is possible that separating the budget into pots could result in different clearing prices for

¹⁶¹ 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.¹⁶² This could potentially decrease the rents accruing to producers, and minimise the impact on customer bills.¹⁶³

5.280 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*

5.281 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).

5.282 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.¹⁶⁴

5.283 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

¹⁶² 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.

¹⁶³ 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.

¹⁶⁴ DECC (January 2014), [Electricity Market Reform: allocation of Contracts for Difference, consultation on competitive allocation](#).

support,¹⁶⁵ and where such reductions are likely to outweigh any additional costs incurred in the short run.

- 5.284 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.
- 5.285 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.
- 5.286 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).
[✂]¹⁶⁶
- 5.287 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.
- 5.288 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.
- 5.289 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 generation capacity

¹⁶⁵ An analysis in relation to offshore wind is set out in Appendix 5.3, Annex A.

¹⁶⁶ [✂]

procured from Pot 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.

- 5.290 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.
- 5.291 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

- 5.292 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.^{167,168} 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.
- 5.293 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.
- 5.294 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

¹⁶⁷ DECC (June 2014), *Implementing Electricity Market Reform (EMR): finalised policy positions for implementation of EMR*.

¹⁶⁸ With the exception of solar above 5 MW for which the ROC scheme closed at the end of March 2015, and onshore wind for which the ROC scheme closed 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

- 5.295 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.¹⁶⁹
- 5.296 We noted in our provisional findings report 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 market¹⁷⁰ to make this profitable would need to constitute a larger proportion of trades in that market than we consider plausible.
- 5.297 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 therefore did not pursue this issue further. Annex C to Appendix 5.3 sets out our thinking on this issue in more detail.

Supplier Obligation

- 5.298 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.
- 5.299 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.
- 5.300 As set out in our provisional findings report, while we consider that there may be options available to hedge the Supplier Obligation,¹⁷¹ we also recognise that these risks may not be possible to hedge entirely. We encourage DECC to monitor and continue engaging with the sector around

¹⁶⁹ [Energy market investigation: statement of issues](#).

¹⁷⁰ The market from which the CfD reference price is calculated – discussed in more detail in Appendix 5.3, Annex C.

¹⁷¹ For example, entering into contracts with renewable generators that are likely to face offsetting risks.

the impact of the Supplier Obligation on suppliers' risks, and amend the arrangements if necessary in the future.

Conclusions on Contracts for Difference

- 5.301 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.
- 5.302 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.
- 5.303 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.
- 5.304 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.

- 5.305 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.
- 5.306 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.
- 5.307 Overall, we find 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.
- 5.308 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 give rise to an AEC.

Conclusions

- 5.309 This section has reviewed five key elements of the design principles and market rules and regulations that shape competition in GB wholesale electricity markets.
- 5.310 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.

- 5.311 The absence of **locational pricing for transmission losses** is a feature of the GB wholesale electricity market that we 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.
- 5.312 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 over ten years, in NPV terms, to an approximate cost to the system of the order of £150 million.
- 5.313 We have not reached a 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.
- 5.314 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.
- 5.315 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.
- 5.316 Our 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 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 decided not to carry out further work in this area.

- 5.317 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.
- 5.318 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.
- 5.319 Overall, we find 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.

5.320 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. Wholesale electricity market remedies

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6.1 The wholesale price of electricity represents just under half the total cost of supplying electricity to customers, and it is therefore vital, in the interests of ensuring that the overall prices paid by customers are competitive, to ensure that competition operates well in the wholesale market.

6.2 We have considered a range of aspects of electricity wholesale market design and operation. Generally we have found that the wholesale electricity market appears to be working well. In particular:

- (a) generating plant appears to be dispatched in merit order, minimising short-term generating costs; and
- (b) our view is that our analysis of profitability 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.

6.3 However, we have identified two aspects of the regulatory regime governing wholesale market operation that lead to AECs:

- (a) the mechanisms for allocating CfDs; and
- (b) the absence of locational charging for transmission losses.

6.4 In this section, we set out our remedies to each of the AECs we have identified. While the remedies are quite different, they have a similar high-level objective: to help ensure that competitive pressures are brought fully to bear on wholesale cost of electricity, helping to reduce the prices paid by electricity customers.

Allocation of Contracts for Difference

Introduction

6.5 As set out in Section 5, we have found 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.

6.6 In the provisional decision on remedies we considered the two following remedies:

(a) DECC to undertake and consult on a clear and thorough impact assessment before awarding any CfD outside the CfD auction mechanism ('non-competitive allocation proposed remedy').

(b) DECC to undertake and consult on a clear and thorough assessment before allocating technologies between pots and the CfD budget to the different pots ('pot design proposed remedy').

6.7 This section considers these two remedies in turn. It sets out the aim of each remedy, and parties' views on each remedy in response to the Remedies Notice and provisional decision on remedies, before setting out the main design considerations. The section then concludes by setting out (for both remedies together) why we consider these remedies to be effective and proportionate and our decision.

DECC to undertake and disclose a clear and thorough impact assessment before awarding any CfD outside the CfD auction mechanism

- 6.8 As set out in Section 5, we have concluded 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 on DECC to 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.
- 6.9 We estimate that DECC's decision to award CfDs outside the competitive auction process through Final Investment Decision enabling for Renewables (FIDeR) was likely to have resulted in considerable overcompensation of the generators securing these contracts. Had the strike prices for the offshore wind projects awarded under FIDeR in 2014 been in line with the strike prices for offshore wind projects under the first CfD competitive auction concluded in February 2015, the level of support to those projects would have been approximately £250–£310 million per year lower (or approximately £2.9–£3.5 billion NPV over the length of the contracts¹).
- 6.10 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.
- 6.11 We set out in Section 5 our view that without some further constraints on DECC's ability to award contracts outside the competitive process, further contracts may be awarded that result in excessive costs to energy customers.

Aim of the remedy

- 6.12 The aim of this remedy is to increase the likelihood that, in future, if DECC is considering allocating one or more CfDs outside the competitive auction process, it undertakes and discloses clear and rigorous analysis of the impact of doing so.

¹ Using a discount rate of 3.5% as recommended by the Treasury's Green Book. See HM Treasury, [The Green Book: Appraisal and Evaluation in Central Government](#), p26.

6.13 We consider that there are the following likely benefits of DECC undertaking and disclosing assessments of costs and benefits before allocating CfDs outside the competitive auction process:

- (a) **Improved decision-making:** The remedy aims to improve DECC's decision-making process by encouraging it to undertake a rigorous analysis before making decisions with potentially costly outcomes. By disclosing such analysis, this will give opportunity to third parties to comment on DECC's impact assessment and further ensure that DECC has undertaken a rigorous analysis. In doing so, this will increase the likelihood of DECC following the lowest cost path to achieving decarbonisation targets and minimising costs for energy customers.
- (b) **Increased transparency:** In addition to enabling stakeholders to provide feedback and challenge to DECC's proposals (which as noted above will reinforce the robustness of DECC's decision-making), increased transparency may increase stakeholders' trust in the energy markets. To the extent that this remedy gives stakeholders greater clarity around the budget available for future CfD auctions, it may also enable developers to make better-informed decisions regarding whether to develop future projects to the stage where they can bid in CfD auctions.

Parties' views

6.14 Below is a summary of parties' responses to our provisional findings and Remedies Notice,² and our provisional decision on remedies.

6.15 In response to our provisional findings and Remedies Notice, a large number of parties set out that they broadly supported our proposal for DECC to undertake and consult on a clear and thorough impact assessment before awarding any CfDs outside the CfD auction mechanism.³ However, two parties (Citizens Advice and Ecotricity) set out their concerns that the remedy might fail to change DECC's approach to awarding CfDs in practice. As set out below (paragraph 6.101), the extent to which our remedies will reduce the risk of suboptimal allocation of CfDs depends on the extent to which DECC complies with the broader spirit of our remedial action.

6.16 A number of parties set out their view that there might be circumstances under which it might be appropriate for DECC to award CfDs outside the

² See [Responses to provisional findings and notice of possible remedies](#).

³ This included Citizens Advice, Co-operative Energy, Drax, Ecotricity, EDF Energy, ENGIE, EON, Good Energy, Opus, RWE, Scottish Power, SSE and Which?

competitive auction.⁴ However, a number of these parties set out their view that this should be only in limited circumstances, with parties expressing a range of views around the specific circumstances under which this might be appropriate.

- 6.17 Regarding the degree of flexibility DECC should have in determining the types of project to which it may award a CfD outside the auction, Carbon Capture & Storage Association, EDF Energy, Scottish Power and Shell set out their views that DECC should retain a degree of flexibility.⁵ In contrast, Energy Action Scotland set out its concerns with DECC maintaining a high level of discretion in this area.
- 6.18 A number of parties set out their concerns that previous non-competitive allocation of CfDs might not have been in customers' best interests.⁶
- 6.19 A large number of parties had comments relating to the transparency of DECC's decision-making in this area. Co-operative Energy, E3G, the Highlands and Islands Housing Associations Affordable Warmth Group, [X], RWE and Scottish Power set out their views around the need for greater transparency. National Grid recognised the value of a transparent process for allocating CfDs. In addition, CCSA, Centrica, Citizens Advice, EDF Energy, ESB and RWE all set out their views that our remedy should result in increased transparency in this area.
- 6.20 In response to our provisional decision on remedies, all parties offering a view supported our remedy. A large number of parties set out their views that our remedy would increase the level of transparency around DECC's decisions in this area.⁷
- 6.21 A number of parties also set out their support for our recommendation that DECC should undertake and consult on two impact assessments; one before entering into negotiations and one following the conclusion of negotiations.⁸
- 6.22 As was the case with responses to provisional findings and the Remedies Notice, a significant number of parties set out their views that the default position should be that DECC should allocate CfDs through a competitive

⁴ This included CCSA, Centrica, EDF Energy, [X], ENGIE, EON, Good Energy, Renewable UK, [X], RWE, Scottish Power, Shell.

⁵ Shell considered that this should be for a transitory period of time.

⁶ See for example Energy Policy Group (Exeter University), EON, Ovo Energy, REG Group and Which?

⁷ This included E.ON, SSE, Smartest Energy, Energy UK, Renewable UK.

⁸ This included E.ON, RWE, Renewable Energy Association, Citizens Advice.

process,⁹ and that DECC should allocate CfDs outside this competitive auction process only in limited circumstances.¹⁰

- 6.23 Two parties raised concerns that even if DECC agrees to undertake impact assessments in line with our recommendations, it would not be obliged to act on the findings of its analysis.¹¹ As noted above and in paragraph 6.101, this remedy will be effective only if DECC adopts the broader spirit of our remedies.

Design considerations

- 6.24 In this section we set out our views on the circumstances under which it may be appropriate for DECC to award CfDs outside the competitive auction process. We then consider when DECC should undertake and consult on (or disclose) impact assessments before taking a decision to award CfDs outside the competitive process, and set out our thoughts on the sorts of analysis that DECC may want to include as part of these assessments.

- *DECC to set out why the project should not compete in the competitive auction process*

- 6.25 As noted in Section 5, awarding CfDs through a competitive auction process is likely to drive costs down, relative to awarding CfDs in a non-competitive (eg bilaterally negotiated) manner. As a result, we believe that DECC should allocate support to low carbon generators through the competitive auction process, unless there is objective and compelling justification for departing from this approach. If DECC considers it appropriate to award a CfD directly, it should set out in its impact assessment clearly why it considers a direct award to be preferable to making the project compete in the competitive auction process. However, the default should be to award CfDs through a competitive process.

- 6.26 As part of this remedy, we are not recommending absolute restrictions on the types of project to which DECC should award CfDs outside the competitive process, or the specific situations in which it should do so. As a general principle, we consider that DECC should allocate a CfD outside the competitive auction process only where it can demonstrate that the benefits to customers of doing so can be expected to exceed the costs.¹² We note

⁹ This included Centrica, E.ON, IREGG, Citizens Advice, Energy Intensive Users Group.

¹⁰ This included E.ON, RWE, Ecotricity, Citizens Advice.

¹¹ Renewable Energy Association, Chartered Institute of Procurement and Supply.

¹² While we consider it highly unlikely that it would be in consumers' best interests to award further CfDs outside the competitive auction process to technologies of the kind that were allocated CfDs under FIDeR (since they are

that there may be particular circumstances under which allocating CfDs directly (outside the competitive auction process) could potentially result in an efficient mix of generating technologies in the long run and/or minimise costs to customers, for instance:

- (a) There may be technologies and projects to which it would be efficient to allocate CfDs, but that might not be able to compete in the competitive auction process. For example, there may be potential projects with a lifespan and other operating characteristics that are so different to the characteristics of potentially competing projects that it is difficult to compare them on a like-for-like basis. If it would be efficient to award CfDs to such projects (ie they face lower costs than other low carbon technologies that would otherwise receive support), it may be in customers' interests to award CfDs directly to these projects outside the competitive auction process.
- (b) There may be positive externalities associated with supporting particular types of technology now. For example, some currently less developed (and higher cost) technologies may require support now in order to reduce the costs of similar projects in the future. If this is the case, even though these technologies may be part of the efficient energy mix over the long run, a technology neutral competitive auction (or one of similar levels of neutrality to the competitive auction process) may fail to award them CfDs. This may prevent them from successfully reducing their costs over time, and eventually becoming part of an efficient energy system. In such cases, there may be an argument for DECC to award CfDs directly to these projects outside the competitive auction process.¹³

6.27 An element of judgement will be required in making these assessments in any individual case (albeit based on a more rigorous analysis of costs and benefits) and we have therefore not considered it appropriate to recommend imposing absolute rules determining the situations in which non-competitive allocation would be allowed. We do consider, however, that before deciding to allocate support on a non-competitive basis, and entering into a negotiation for a specific project or technology, DECC should set out clearly in its impact assessment why it considers that it is not feasible (or appropriate) for the project to compete in the competitive auction process, and why the benefits of non-competitive allocation to a specific project or

allocated to auction pots and should therefore be able to compete in the competitive auction process), we are not minded to make a recommendation that DECC's powers to do so should be limited.

¹³ We note that DECC has designed the CfD auction process in such a way that it sets aside some of the available budget to support less developed technologies. We discuss this in more detail in paragraphs 6.55–6.94 below.

technology are likely to exceed the costs (compared to an allocation through an auction or, outside an auction, to another type of project or technology).

- *When should DECC undertake (and consult on) impact assessments?*

- 6.28 In order to achieve the aim of this remedy, we believe that DECC should undertake impact assessments seeking to establish whether it is appropriate for the government, in the light of the UK's long-term objectives of decarbonisation and security of supply, to support a specific type of project that, due to its particular characteristics, could not be allocated (or would not be appropriate to allocate) through the competitive auction process.
- 6.29 In our view, DECC should seek to address this question in two phases. DECC should first undertake and consult on a high-level impact assessment at an early stage (ie before entering into negotiations with prospective generators), in order to identify the possible costs and the benefits that may arise from supporting a specific technology. Within that context, it should explain why CfDs could not be allocated to that type of project through the competitive auction process (eg due to its size/and or technology), and why – based on its initial analysis – it considers awarding the CfD outside the competitive process is likely to benefit consumers. In the second phase, after the negotiations with the prospective generators and the provisional agreement of a strike price, DECC should carry out and disclose a detailed assessment of whether supporting the project in question is in customers' best interests.
- 6.30 At both phases, the expected costs and benefits of the proposal should be exposed transparently, and DECC should set out both the social costs and benefits of the proposal and expected distributional impacts with respect to both firms and customers (notably, the forecast impact on customers' bills).
- 6.31 In a hearing with the CMA, DECC raised concerns that the timing of the publication of a formal impact assessment ahead of entering into negotiations could jeopardise its ongoing negotiations. We have reflected on these concerns and consider that under the present formulation of this proposed remedy, there is minimal risk of this taking place. We consider that the initial impact assessment would be relatively high level, and may rely largely on already publicly available information (such as DECC's published estimates of the cost of the relevant technology, and potentially information provided by the developer),¹⁴ and that as a result it should not unduly affect DECC's

¹⁴ For example, DECC sets out its estimates of the costs of different generating technologies in DECC (2013), [Electricity Generation Costs](#). In the case of Swansea Bay Tidal Lagoon, the developer has set out that it would

negotiating position. We consider that the precise form of the impact assessment to be published should be left to DECC to determine, so it should be able to present the figures in such a way as to minimise the likelihood of undermining its negotiating position.

6.32 Likewise, undertaking an impact assessment following the conclusion of negotiations would not jeopardise DECC's negotiation position (although we accept that certain details of the terms of the agreement might need to be kept confidential) and need not delay the overall decision-making process. Any CfD agreed outside the competitive auction would need to be cleared by the European Commission under state aid rules. Within the context of this process, DECC could publish its impact assessment after reaching the initial agreement with the counterparty.¹⁵

6.33 DECC raised concerns that our initial proposal that it consult on an impact assessment after negotiations had been concluded, alongside the state aid notification process, would not be feasible. It noted that the state aid notification process could occur only once the commercial details of a CfD had been substantially agreed. It set out that consulting in parallel with the state aid process was not possible, so any consultation could occur only before the state aid notification had been submitted. There would therefore be a significant risk of delaying the project, and therefore increasing the total cost to consumers. For the purpose of our remedy, this second assessment should be disclosed to enhance transparency around the costs and benefits of awarding a CfD. However, on reflection, we consider that it would not be necessary for DECC to consult on the details of the agreement reached through negotiations, taking into account the state aid process that would follow and the delays that this would entail for the project (which in turn could have an adverse impact on the outcome of the negotiations).

- *Assessing the impacts of allocating CfDs outside the competitive auction process*

6.34 In this section, we give a brief overview of the various impacts that might result from allocating CfDs outside the competitive auction process, and how we believe DECC should assess them. Broadly, we consider that DECC should assess the impact on costs, the externalities that may result, and any

require a strike price of £168/MWh. See Pöyry (March 2014), [Levelised costs of power from tidal lagoons – A report to Tidal Lagoon Power plc](#).

¹⁵ We note that, in the case of Hinkley Point C, the initial agreement – including strike price – was publicly announced on 21 October 2013, the formal notification to the European Commission was filed on 22 October 2013, the decision to open an in-depth investigation was taken on 18 December 2013 and the positive decision was taken on 8 October 2014. See press release (21 October 2013), [Initial agreement reached on new nuclear power station at Hinkley](#) and the [case page](#) on the European Commission website.

other impacts that may be expected. To the extent possible, these impacts should be quantified.

- *Costs*

- 6.35 When setting out its estimates of costs, as well as presenting the overall cost of supporting a given project, DECC should present the costs of a given CfD compared with those that would have arisen under the counterfactual scenario under which it does not allocate a CfD outside the competitive auction process to the project in question. That is, DECC should set out its estimate of the incremental cost of awarding the CfD in question over and above the cost of supporting any other alternative projects that may otherwise have received support. By doing so, it would provide transparency to stakeholders around the additional cost (if any) of DECC's proposed policy.
- 6.36 By awarding a CfD outside the competitive auction process, the amount of low carbon generation required to meet decarbonisation targets will be reduced (along with the overall CfD budget available for other projects). As a result, another low carbon project (or projects) that would have been built had this particular CfD not been awarded outside the competitive auction process may be displaced. The incremental cost to customers of awarding the CfD in question outside the competitive auction process would be the cost of supporting the project under consideration relative to the cost of supporting any projects displaced. As part of the impact assessments, DECC should consider the suitable counterfactual in undertaking its assessment of costs.¹⁶
- 6.37 These incremental costs could be either positive or negative. If awarding a CfD outside the competitive auction process increases the costs relative to the counterfactual (eg if a tidal lagoon project displaces lower cost offshore wind projects or nuclear), doing so will result in a positive incremental cost. However, if awarding a CfD outside the competitive auction process results in lower costs than would have resulted under the counterfactual (eg if a nuclear power station displaces higher cost offshore wind projects), the incremental costs would be negative.

¹⁶ For example, if DECC opts to award a CfD to a tidal lagoon generator, the incremental cost would be the cost of supporting that project minus the cost of providing that volume of generation from the projects that are displaced as a result (eg offshore wind).

- 6.38 In order to ensure maximum transparency, we consider that DECC should set out the incremental costs in terms of total costs (NPV), total annual costs, and average impact on customer bills.
- *Externalities*
- 6.39 Where the case for supporting a high cost project is based on it resulting in lower costs for similar projects in future – ie it results in long-run externalities – DECC should set out the evidence informing its view that supporting the project will result in lower total costs to customers over the long run. In doing so, DECC should demonstrate that supporting a given technology will result in cost reductions that would not materialise absent support.¹⁷ Any impact of these externalities should be weighed against any incremental costs identified above.
- 6.40 Supporting a given technology could result in either positive or negative externalities. If awarding a CfD outside the competitive auction process decreases the costs of future projects of the same technology, this may reduce long-run costs (ie a positive externality). However, if the project displaces other projects, it is possible that this could increase the costs of projects involving that technology in the long run (ie a negative externality). DECC should take both these impacts into account.
- 6.41 It is important to note that demonstrating cost reductions alone does not necessarily indicate that there is a case for supporting a given technology. In order for there to be benefits to customers, the future costs would need to be low enough that this technology would form part of the future energy system (ie it would actually need to be deployed at this lower cost). If this were not the case, any future cost reductions would not deliver a lower cost energy system in future.¹⁸
- 6.42 Where it is not possible to quantify these impacts, DECC should nevertheless be transparent about the trade-offs it is making in reaching its decisions.

¹⁷ As noted above, there may also be projects where DECC is considering allocating a CfD outside the competitive auction process, without the expectation of significant future cost reductions. For example, DECC's main rationale for allocating a CfD to Hinkley Point C was not to reduce the cost of future nuclear plants. Rather it considered that securing reliable, long-term, low carbon baseload generation at the agreed strike price represented good value for consumers (without relying on future cost reductions). While its case for awarding a CfD outside the competitive auction process in such cases does not rely on future cost reductions for nuclear power stations, DECC should nevertheless consider the impact on the future costs of any technologies displaced by its decision to award a CfD directly (ie whether there are any negative externalities from supporting the project in question).

¹⁸ Take the example of a project that requires support of £200/MWh now, in order to reduce the required support of future projects to £150/MWh in the 2020s (instead of remaining at £200/MWh without support). While supporting this technology would clearly reduce the costs of future projects involving that technology, even following this reduction the cost may remain prohibitively high. As a result, such a technology may be unlikely to form part of an efficient future energy system, despite reducing its cost. As a result, despite support leading to a reduction in cost of the technology in the long run, it is unlikely to deliver benefits to consumers.

For example, if it has quantified the incremental cost of allocating a CfD outside the competitive auction process, but is unable to quantify the benefits (positive externalities), it should be able to articulate clearly why it considers that the benefits can be expected to exceed the costs.

- *Other impacts*

- 6.43 In addition to considering the impacts outlined above, DECC should also consider a range of broader impacts. As with the direct impact on costs and externalities set out above, these impacts should be considered relative to the counterfactual of not awarding that CfD outside the competitive auction process.
- 6.44 These broader benefits could be either positive or negative. For example, where a particular technology results in lower 'system-wide costs',¹⁹ or where supporting a given technology would result in a more diverse energy system,²⁰ these may result in positive impacts that DECC may want to take into account. Conversely, where DECC is considering awarding a CfD to a project that has certain, less desirable characteristics (eg risks around waste disposal for nuclear, or impacts on air quality for other types of plant), DECC should factor this into its assessment of the costs and benefits of awarding a CfD outside the competitive auction process.
- 6.45 This does not provide an exhaustive list of the other factors DECC may wish to consider in its impact assessment. As with the other impacts, it should aim to quantify these where possible. Where it is unable to do so, it should articulate clearly why it places value on them, the trade-offs it is making, and why it considers these to be in the best interests of customers.²¹
- 6.46 As set out above, we are recommending that DECC undertakes impact assessments at two stages when it is considering allocating CfDs outside the competitive auction process. We set out below the types of analysis we would expect DECC to undertake for each of these assessments.

¹⁹ For example, if DECC is considering supporting a given low carbon technology that is readily dispatchable or has a more predictable output than the technology that is displaced (i.e. the technology that would be deployed under the counterfactual), there may be benefits of supporting this technology that cannot be measured by comparing only the required levels of support (strike price).

²⁰ It is impossible to predict the precise characteristics of a future efficient energy system. As a result, there is likely to be some value in ensuring that GB low carbon generation consists of a diverse range of technologies. Ensuring this diverse mix may come at a cost (as it may require not always deploying the lowest cost technologies), but may deliver benefits through added resilience.

²¹ For example, it should set out the incremental costs of its proposed course of action (as set out above), and why it considers that the benefits of securing a source of dispatchable low carbon generation can be expected to outweigh these costs (even if it is unable to quantify the benefits).

- *Assessments before and after negotiations*

- *Before entering into negotiations with a party*

- 6.47 An impact assessment at this early stage would be strategic in nature, likely containing initial estimates. It would not, for example, be able to reflect detailed contractual provisions that would be negotiated at a later date.²² However, we consider that there is value in DECC setting out at a ‘high level’ why it considers that awarding a CfD directly to a specific type of project or technology may be in customers’ best interests at this stage, and why it considers that the project in question should not have to compete for a CfD in the competitive auction process (as discussed above). While DECC’s understanding of the underlying costs and benefits of awarding a CfD is likely to be limited at this stage, it should be in a position to articulate why it is planning to do so, and the range of potential impacts.²³
- 6.48 DECC undertakes assessments of the underlying costs of different generating technologies on a regular basis.²⁴ While it should undertake considerably more detailed assessments of costs before reaching a decision to award a CfD outside the competitive auction process (including an in-depth assessment of the specific project’s claimed costs), these broad estimates should enable DECC to set out the approximate costs of entering into a CfD with a given project. By making reasonable assumptions about the deployment of technologies under the counterfactual, DECC should be able to undertake an analysis of the incremental cost of awarding a CfD to a specific type of project or technology outside the competitive auction process.²⁵
- 6.49 With respect to externalities, DECC should have developed a good understanding of the nature of the technology ahead of entering into negotiations, and as a result should be able to set out at a high level its assessment of the potential for supporting a project to enable future cost reductions. As a result, where DECC’s case for allocating a CfD outside the

²² The level of detail with which DECC could set out the costs and benefits at this early stage is likely to vary with different types of project, based on its knowledge of different technology types.

²³ DECC did consult on its decision to enter into negotiations with Swansea Bay Tidal Lagoon, but did not publish an assessment of the likely costs and benefits of doing so.

²⁴ See for example DECC (2013) [Electricity Generation Costs](#).

²⁵ In addition to DECC’s own estimates of cost, potential developers may already set out the strike price they would require to invest (for example, in the case of Swansea Bay Tidal Lagoon, the developer has set out that it would require a strike price of £168/MWh – see Pöyry (March 2014), [Levelised costs of power from tidal lagoons – A report to Tidal Lagoon Power plc](#)). While DECC should not put too much weight on this figure, given the potential incentives for the developer to behave strategically in stating the level of subsidy it requires, it does provide a starting point (potentially an upper bound) for assessing the potential costs of supporting a project. Indeed, if developers thought that overstating these costs at an early stage could result in failing to get beyond this initial stage, they may face greater incentives to report their required level of support truthfully.

competitive auction process relies on these types of positive externality, it should be able to articulate why it considers that these benefits are likely to outweigh any costs identified.

6.50 Regarding its assessment of other impacts, DECC should be able to set out at this early stage its understanding of the characteristics (both positive and negative) of the generating technology it is considering supporting (eg predictability of output).

6.51 Overall, we consider that DECC should have sufficient information at this stage to set out its broad assessment of the likely costs and benefits of awarding a CfD to a specific project over and above the cost of supporting any other alternative projects that may otherwise have received support.²⁶

○ *Following negotiations with a party*

6.52 After concluding negotiations with a party, DECC should have a detailed understanding of the project's costs and the strike price it would require.²⁷ In addition, we would expect that by this point, DECC would have firmed up its view of the likely counterfactual (or set out a range of possible scenarios, if necessary). This should enable it to assess the likely incremental costs of supporting a given project in a more detailed and robust manner than it would have been able to do under the initial high-level impact assessment.²⁸

6.53 By this late stage of the process, DECC should have developed a good understanding of the extent to which there is scope for cost reductions in future (where applicable), and the extent to which these are dependent on supporting the technology now. As DECC's understanding of the project's costs would have improved over the course of the negotiations (through rigorous and independent assessment of its reported costs), so should DECC's understanding of the technology's cost structure more generally, and therefore the potential for cost savings in the future, and the extent to

²⁶ Where DECC has recently undertaken this analysis for another project of the same technology, it may be able to build on this for any subsequent assessments. However, it is important to note that the specific analysis is likely to be different for each potential project. For example, the costs of each technology can change rapidly, and DECC's impact assessments should reflect the most up-to-date information for the specific technology and for the technologies included in the counterfactual.

²⁷ We would expect DECC to undertake independent verification of the project's reported costs as part of its assessment.

²⁸ As noted above, we consider that DECC should set out its estimates of the incremental cost in terms of total amount (NPV) for the project, total annual costs, and average impact on consumer bills.

which any future cost savings are dependent on supporting the project in question.²⁹

- 6.54 By this late stage, DECC should have a more refined view of the value it places on any of the other impacts identified, and should therefore have more advanced thinking around the value of trading off the level of support (cost) for these other characteristics.³⁰

DECC to undertake and consult on a clear and thorough assessment before allocating technologies between pots and the CfD budget to the different pots

- 6.55 In Section 5, we set out that the mechanisms for allocating CfDs are a feature of the GB wholesale electricity market that give rise to an AEC due to the absence of an obligation for DECC to (among other things) 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 CfD auction.
- 6.56 We consider that a technology neutral competitive auction³¹ should be DECC's starting point when considering how to allocate CfDs, as it ensures that CfDs are allocated to the low-carbon generation projects with the lowest costs from the entire pool of potential bidders.³²
- 6.57 DECC's decision to separate technologies and budgets into different pots risks allocating CfDs to currently more costly (less efficient) projects, while excluding less costly (more efficient) ones. Given the large amounts of support being allocated to renewable generators, decisions in this area have the potential to have considerable impacts on customers' bills.

²⁹ Where DECC is unable to quantify the impact of these externalities, having identified its estimate of the costs of supporting a project, it should be able to set out the thresholds for future cost savings and levels of deployment beyond which it would expect the benefits of the externalities to outweigh any incremental costs identified. For example, DECC may conclude that given the costs of supporting a project, it would have to reduce the strike price required for future projects by £50/MWh and achieve deployment of 2 GW in order for the benefits of these externalities to outweigh the costs. DECC should be sufficiently well-informed by this point to be able to explain whether it considers this to be a likely scenario, and therefore whether the benefits of supporting a project are likely to outweigh the costs.

³⁰ We note that no such assessment was carried out in relation to the FIDeR projects. If any such assessment had been carried out, we do not believe that it would have led to the conclusion that it was in customers' interests to allocate the FIDeR projects outside of the competitive auction process. As noted in Section 5, we consider that the CfDs awarded to offshore wind projects under FIDeR resulted in consumers paying approximately £250–£310 million per year more than had these CfDs been awarded at the strike price received by the two offshore wind projects that were successful in the first competitive CfD auction. We noted that the cost characteristics of the FIDeR projects were very similar to the projects awarded CfDs through the competition auction process less than a year later.

³¹ Meaning a single auction with all low-carbon generating technologies competing with each other.

³² While we recognise that there may be cases for deviating from a technology neutral auction (discussed below), assessing the cost under a technology neutral auction will provide a benchmark cost to indicate the cost of any deviations. This should enable DECC to undertake rigorous analysis of whether such deviations are in consumers' interests.

- 6.58 We recognise that there may be cases where a technology neutral competitive auction could not be expected to result in an efficient outcome over the long term, for example if supporting less developed technologies enables them to lower their costs in future (ie positive externalities). Indeed, even where a technology neutral competitive auction may result in an efficient outcome, it may nevertheless not result in an outcome that minimises costs to customers now or in the longer run (eg if it results in successful projects receiving considerably more support than they require).
- 6.59 However, as set out in Section 5, we have not been made aware of any significant analysis undertaken by DECC on the rationale for its decision on how to allocate the technologies and budget between the pots for the first CfD auction in the manner it chose to do so.
- 6.60 In Section 5, we did not quantify customer detriment arising from DECC's initial decision to allocate budgets to pots for the first CfD auction, but we noted that the absence of robust analysis increases the risk of customer detriment in the future. Recent modelling work undertaken by NERA³³ (discussed in more detail below) estimates that for a potential CfD auction in 2017, holding a technology neutral competitive auction would result in a cost reduction of £50 million per year compared with keeping the same allocation of technologies and budgets to pots as in the 2015 CfD auction. This illustrates the significant impacts that DECC's decisions in this area can have on the costs faced by customers (who ultimately pay for the support to low carbon generators). It is essential, therefore, that DECC makes such decisions based on rigorous analysis, and communicates this in a clear and transparent manner.

Aim of the remedy

- 6.61 The aim of the remedy is to ensure that, in future, when making decisions about the technologies and budgets to allocate to different auction pots, DECC undertakes a rigorous and transparent analysis of the impacts of its decisions. As with the remedy discussed above concerning undertaking and consulting on impact assessments before allocating CfDs outside the competitive auction process, we consider that there are the following likely benefits of DECC undertaking and consulting on such an assessment concerning the allocation of pots:

- (a) **Improved decision-making:** The remedy aims to improve DECC's decision-making process by encouraging it to undertake a rigorous

³³ NERA (October 2015), [Modelling the GB Renewable Electricity CfD Auctions – the cost of excluding onshore wind and maintaining separate pots – A project for Citizens Advice – Final Report](#).

analysis before making decisions with potentially costly outcomes. By consulting on such analysis, this will further ensure that DECC has undertaken a rigorous analysis. In doing so, this will increase the likelihood of DECC following the lowest cost path to achieving decarbonisation targets and minimising costs for energy customers.

(b) **Increased transparency:** In addition to enabling stakeholders to provide feedback and challenge to DECC's proposals (which as noted above will reinforce the robustness of DECC's decision-making), increased transparency may increase stakeholders' trust in the energy markets. To the extent that this remedy gives stakeholders greater clarity around the budget available for future CfD auctions, it may also enable developers to make better-informed decisions regarding whether to develop future projects to the stage where they can bid in CfD auctions.

6.62 We note that the European Commission cleared the CfD regime under state aid rules.³⁴ It may, however, under Article 108 of the Treaty on the Functioning of the European Union (TFEU), review this regime. If the European Commission finds that the CfD regime is no longer compatible or is being misused, it may decide to require the UK government to abolish or alter such regime. In addition, parties are able to challenge decisions to allocate CfDs by judicial review.

6.63 In addition, we consider it unlikely that the European Commission will revisit the allocation of technologies and budgets on a regular basis. It is therefore important that DECC undertakes regular reviews in order to ensure that the allocation of technologies and budgets to pots remains in the interests of customers.

Parties' views

6.64 Below is a summary of parties' responses to our provisional findings and Remedies Notice,³⁵ and our provisional decision on remedies.

6.65 In response to our provisional findings and Remedies Notice, a number of parties set out their support for our remedy.³⁶ In addition, a number of parties (Drax, EDF Energy, Renewable UK, [X] and Scottish Power) all set out more general views around the need to move towards technology neutral competitive auctions. Citizens Advice and E.ON also set out that the process

³⁴ 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](#)).

³⁵ See [responses to provisional findings and notice of possible remedies](#).

³⁶ These included Co-operative Energy, Drax, E.ON, Good Energy, RWE, SSE, Which?

of reviewing the allocation of technologies to pots should enable DECC to establish which technologies had developed sufficiently to move into the 'more established' technologies pot (Pot 1). EDF Energy noted that less established technologies that failed to reduce costs should not be supported indefinitely and that those that did reduce costs should be moved into Pot 1 at the appropriate time.

- 6.66 A large number of parties agreed that the remedy would increase transparency around DECC's decision-making.³⁷ However, Ecotricity set out its view that despite increasing transparency, our remedy would not ensure that DECC was obliged to act on the findings of its analysis. National Grid recognised the value of a transparent process for allocating CfDs.
- 6.67 We received a range of responses regarding the regularity with which DECC should undertake analysis of the appropriate allocation of technologies to pots:
- (a) Citizens Advice, EDF Energy and E.ON set out that DECC should undertake this analysis ahead of each auction;
 - (b) Ecotricity and ENGIE set out that this should be done annually;
 - (c) Centrica set out that this should take place every two years as a default, if an earlier consultation had not been triggered by proposed changes in approach;
 - (d) Co-operative Energy set out that this should take place at a minimum of every two years; and
 - (e) Scottish Power considered that this should take place 'once every few years'.
- 6.68 Two parties (Renewable UK and Good Energy) also set out that it was important for DECC to make any announcement around the allocation of technologies to pots considerably ahead of the auction in order to ensure predictability for investors. Renewable UK suggested that there should be clarity around the allocation of technologies two auctions ahead, while Good Energy considered that changes should be signalled several auctions ahead of time. On a similar note, Citizens Advice and [X] both set out that it was hard to predict the amount of levy control framework budget remaining, and that it was important to have clarity on this to reduce risks to investors.

³⁷ These included Carbon Capture & Storage Association, Centrica, Ecotricity, EDF Energy, ENGIE, E.ON, SSE.

- 6.69 All parties offering an opinion (Centrica, EDF Energy, E.ON and ENGIE) set out that they did not consider that DECC should face absolute limits on the proportion of budget it was able to allocate to each of the pots.
- 6.70 In response to our provisional decision on remedies, a wide range of parties set out their support for our remedy. A number of parties set out their views that the default position should be a technology neutral auction, or that DECC should aim to move towards this outcome.³⁸ Related to this, a number of parties raised concerns with the government's stated policy of removing support for further onshore wind.³⁹
- 6.71 Some parties noted that our remedies should increase transparency and visibility for investors, and stressed the importance of this for investor confidence.⁴⁰
- 6.72 Parties offered a range of views regarding our proposal for DECC to confirm budgets one year ahead of each CfD auction round. Three parties (Renewable Energy Association, IREGG and Citizens Advice) agreed with our proposal, while two parties (Scottish Power and Renewable UK) set out their concerns that this would not leave DECC with sufficient flexibility to revise the auction budget as needed.
- 6.73 A number of parties suggested that our remedies should go further than those proposed. For example, one party (EDF Energy) considered that we should set out a more detailed list of factors that DECC should consider when deciding how its budget should be allocated between pots. Another party (E.ON) set out that DECC should publish milestones setting out the path to technology neutral auctions. Another party (IREGG) set out its views that DECC should commit to a set time frame for future auctions to give a greater level of certainty, and that DECC should be prevented from holding a Pot 2 auction without holding a Pot 1 auction alongside it.

Design considerations

- 6.74 In this section we set out our views on the sort of analysis DECC should undertake when deciding whether and how to allocate different technologies to different pots in the CfD auctions, and how to allocate the budget between the CfD pots.

³⁸ This included E.ON, Smartest Energy, Drax, IREGG.

³⁹ This included E.ON, RWE, Renewable Energy Association. In addition, the Energy Intensive Users Group set out that it recognised the case for removing support for further onshore wind, but that any decision by the government to do so should be based on a transparent impact assessment.

⁴⁰ This included Scottish Power, Smartest Energy, Energy UK, Renewable Energy Association.

6.75 As set out in paragraph 6.58 above, there may be objective and compelling justification for DECC to depart from allocating CfDs under a single, technology neutral competitive auction. As part of our remedy, we are not recommending absolute restrictions on the circumstances in which DECC can depart from allocating CfDs under a single, technology neutral competitive auction. However, we set out below two possible justifications for separating technologies and budgets into pots in the CfD auctions:

- (a) As noted above in the context of awarding CfDs outside the competitive auction process, there may be positive externalities associated with supporting particular types of currently less developed technology. In such cases, there may be an argument for DECC to support these technologies now, in order to reduce the costs of future projects of the same technology.
- (b) In addition, it is possible that customers may be better off if DECC allocates 'high cost' and 'low cost' technologies to separate pots, with separate auctions held for each, despite the risk of inefficient allocation. Under a single, technology neutral competitive auction, low cost bidders could be expected to receive a level of support considerably above the amount they require.⁴¹ By separating the auction into different pots, DECC may be able to price discriminate, to ensure that lower cost technologies receive only the low clearing price of the 'low cost' auction rather than receiving the higher clearing price of a single auction. We note, however, that this approach places a strong onus on DECC's ability to estimate the different costs of different projects accurately; if it is wrong in its estimations it may well increase the cost to customers. As a result, DECC should seek compelling evidence of the benefits to customers in order to justify departing from a technology neutral competitive allocation for this reason.

- *DECC to estimate increased costs of auction relative to technology neutral competitive auction*

6.76 We consider that a technology neutral competitive auction should be DECC's default approach to allocating CfDs, absent any objective and compelling reason for departing from this. As set out above, departing from this approach (by separating technologies and budget into pots) risks an

⁴¹ Under a single 'pay as clear' auction, all successful bidders would receive the clearing price set by the highest successful bid; under a 'pay as bid' auction, bidders would likely face incentives to bid close to the amount they expect the highest successful bidder to bid. That is, under either design, in a single auction we would expect low cost projects to secure strike prices above the level they require.

inefficient allocation of CfDs, and potentially increases the costs of supporting low carbon generation.

- 6.77 In the first CfD auction, DECC opted to divide the technologies and budget into three separate pots, in order to support less developed technologies, in the belief that it would decrease the costs of these technologies in the future – to the long-run benefit of customers.
- 6.78 We consider that, in order to demonstrate that separating technologies and budget into separate pots can be expected to be beneficial to customers, DECC should estimate the extent to which the short-run costs of supporting low carbon generation are affected by its decision. This can then be weighed against any long-run benefits (eg cost reductions of future projects), to arrive at the outcome that is best for customers.
- 6.79 We are also recommending that as part of its analysis DECC undertakes a modelling exercise to understand the likely impact of its decisions concerning the allocation of technologies and budgets to pots in the CfD auctions. We are aware that NERA has undertaken a similar exercise,⁴² which provides a useful example of the sort of work that can be done to estimate the additional short-run costs of supporting less developed technologies in the CfD auctions.
- 6.80 In its model, NERA constructed a supply curve of potential bidders based on information about the pipeline of potential renewable generation projects and assumptions around the strike prices that each project would require (and therefore the level at which each project could be expected to bid). Using this supply curve, it was able to compare the auction outcomes under a range of different scenarios, including a technology neutral competitive auction, and an auction that takes the same form as the completed 2015 auction (ie the same allocation of technologies and budgets to pots). As noted above, NERA's analysis suggests that the cost of support could be reduced by £50 million per year⁴³ by adopting a technology neutral competitive auction.⁴⁴
- 6.81 By undertaking (and consulting on) its own analysis of the likely auction outcomes under different design parameters, DECC would be able to estimate the impact on short-run costs of its decision to depart from a technology neutral competitive auction. We would expect that with its

⁴² NERA (October 2015), [Modelling the GB Renewable Electricity CfD Auctions – the cost of excluding onshore wind and maintaining separate pots – A project for Citizens Advice – Final Report](#).

⁴³ For each of the 15 years of the CfD.

⁴⁴ Compared to adopting the same split of technologies and allocation of budgets to pots as DECC did in the first CfD auction.

understanding of the sector, DECC should be in a good position to make sound assumptions about the pipeline of projects and their underlying costs with which to populate such a model. DECC expressed a concern that publishing such an analysis would risk introducing gaming opportunities for bidders. However, we consider that DECC should be able to publish the results of its modelling exercise in a way that minimises the risks of distorting the auction outcome.

6.82 As set out above, it is possible that separating the CfD auction into different pots could reduce the total costs to customers, if it reduces the extent to which projects are able to secure a level of support above that which they require. Undertaking a modelling exercise as outlined above should enable DECC to assess whether separating the auction into pots would be justified on these grounds.

6.83 It is worth noting that we consider it important to consider (a) the impact of the decision to allocate technologies into different pots, and (b) the decision concerning the allocation of budget to pots, together. In our view, it is not possible to assess the impact of allocating different technologies to different pots without reference to the level of budget that will be made available and how it is to be split between the different pots.

- *DECC to assess long-run benefits of supporting less developed technologies*

6.84 Where possible, DECC should aim to quantify the extent to which the future levels of cost for a given technology are likely to depend on the level of support the technology receives in GB. This will enable it to weigh the benefits of any long-run cost reductions against any increase in short-run costs identified. While we do not expect that DECC will be able to predict with certainty the precise impact of supporting a given technology on its future costs, we consider that DECC should be able to gain a sufficient understanding to make a well-reasoned argument for whether supporting a given technology is likely to result in cost savings that would not otherwise materialise.

6.85 We have noted in Section 5 that The Crown Estate's Offshore Wind Cost Reduction Pathways report set out the potential for a 39% decrease in the levelised cost of energy for offshore wind for projects reaching final investment decision in 2020 compared with those that reached final investment decision in 2011. Some of the possible future cost reductions highlighted in the study, such as deploying larger wind turbines as they are developed, may materialise without needing to support their deployment in GB. Conversely, some other potential cost reductions – such as those that

result from developing the GB supply chain for offshore wind components – may be dependent on levels of GB deployment.⁴⁵

- 6.86 We consider that DECC should, for instance, be able to make reasonable estimates of the extent to which these different categories of potential cost reduction may materialise both with and without GB support for offshore wind. In addition, we would encourage DECC to undertake similar analysis for other technologies it is considering supporting in this manner.
- 6.87 As noted above, cost reductions will benefit customers only where the technology in question can be expected to be deployed in a future efficient energy system. As a result, DECC should take this into account when considering whether supporting a given technology is likely to result in the long-run lowest cost path to meeting GB decarbonisation targets.⁴⁶ In addition, where supporting a given technology results in other projects being displaced (not receiving CfDs when they would have under a technology neutral competitive auction), DECC should consider the extent to which its decision affects the future cost of the displaced technologies.
- *When should DECC undertake (and consult on) these assessments?*

- 6.88 In considering when, and how frequently, DECC should undertake and consult on the analysis outlined above, there are two main factors to consider. Firstly, it is important that the allocation of technologies and budgets to pots takes place frequently enough that the CfD auctions result in an efficient outcome (and therefore minimise costs to customers).
- 6.89 Secondly, it is important that potential bidders have sufficient foresight of the auction parameters that they are able to make well-informed decisions about whether to bid. Progressing a project to the point where it can bid in a CfD auction can be costly, so ensuring that bidders are able to respond to changes that may affect their likelihood of securing a CfD may minimise the risks they face in developing projects. A number of respondents to our provisional findings noted that the uncertainty around the future budgets available to each technology may undermine the case for developing projects to the point where they can compete in auctions (given the high costs).

⁴⁵ See Appendix 5.3 for more information.

⁴⁶ As noted above in relation to the remedy on the allocation of CfDs outside the competitive auction, DECC may want to support currently less developed technologies in order to ensure a diverse mix of renewable technologies (see paragraph 6.44). As with the previous remedy, DECC should set consider the benefits of this as part of its assessment.

- 6.90 In our provisional decision on remedies, we set out a proposed recommendation that DECC should finalise its proposals for the allocation of technologies and budgets at least one year ahead of each CfD auction. DECC has since set out its concerns that this proposal places excessive constraints on its ability to manage the CfD allocation round auction. For example, given fluctuations in wholesale prices, finalising budgets that far ahead of allocation rounds reduces DECC's ability to ensure spending remains within agreed limits.
- 6.91 As noted in paragraph 6.72, two parties were similarly concerned that our proposed approach would not leave DECC with sufficient flexibility to revise the auction budget as needed. We agree with these concerns, and consider that DECC should identify an appropriate time frame for finalising and communicating to parties its proposals for the allocation of technologies and budgets to pots. Such a time frame should ensure that bidders have sufficient understanding of the budget available in order to make well-informed decisions around whether to progress a project. We also accept that these proposals will contain some flexibility allowing DECC to modify some parameters close to the auction, so as to reflect changes in the markets (eg change in wholesale prices).
- 6.92 While this approach gives DECC a greater degree of flexibility, we still consider it important that potential bidders are able to make well-informed decisions around whether to participate in each auction. If they are unable to do so, it could reduce the pool of willing bidders, potentially resulting in a less competitive auction and potentially higher costs to customers. DECC should therefore aim to provide certainty to investors around the timing and parameters of future auctions to the extent possible.
- 6.93 In addition, we consider it important that DECC sets out clearly the impact of any decisions it makes around removing support from certain technologies. In this regard, we note that DECC announced in June 2015 that it would be closing the ROCs scheme to onshore wind at the end of March 2016 (one year before the ROCs scheme closes for other technologies).⁴⁷
- 6.94 As noted above, a number of parties set out their concerns that support for onshore wind through CfDs would be removed; potentially at considerable cost to consumers (since higher cost technologies would be required to deliver GB decarbonisation targets). While DECC has not explicitly set out any plans to remove onshore wind from Pot 1 to date, the government has a

⁴⁷ DECC (June 2015), [Changes to onshore wind subsidies protect investment and get the best deal for bill payers](#).

stated policy to 'end new subsidies for onshore wind'.⁴⁸ Should DECC consider removing this (or other technologies) from the CfD regime, we would expect DECC to undertake a thorough impact assessment of the sort outlined above, setting out the impact of such a decision in a clear and transparent manner.

Assessment of effectiveness and proportionality of remedies package

6.95 For the reasons set out above, we have decided upon the following remedies package to address the CfDs AEC and/or associated detriment:

- (a) A recommendation to DECC to undertake, and disclose the outcome of, a clear and thorough impact assessment before awarding any CfD outside the CfD auction mechanism.
- (b) A recommendation to DECC to undertake and consult on a clear and thorough assessment of the appropriate allocation of technologies and CfD budgets between pots.

Assessment of effectiveness

6.96 In assessing the effectiveness of this remedy package, we believe it would be effective because it:

- (a) meets its aim;
- (b) is capable of effective implementation; and
- (c) will be implemented in a timely manner.

6.97 The remedies set out above seek to improve certain aspects of the process for the allocation of CfDs, with a view to bolstering DECC's ability to achieve its decarbonisation objectives efficiently, improve the robustness of DECC's decision-making, increase stakeholders' understanding of DECC's decisions (and therefore increase trust in the energy markets), and thereby to reduce the risk of detriment identified in the AEC we have provisionally found.

6.98 Our remedy relating to the non-competitive allocation of CfDs will encourage DECC to carry out the rigorous and clear analysis required to reach a decision that is cost-effective for customers, which will in our view reduce the

⁴⁸ DECC (June 2015), [Ending new subsidies for onshore wind](#).

risk of CfDs being allocated to projects outside a competitive auction process which may result in customer detriment.

- 6.99 Our remedy regarding the allocation of technologies between different pots will encourage DECC to monitor on an ongoing basis the evolution of low carbon technologies, and their relative costs and benefits. This will allow DECC to maintain a good understanding of the evolving costs and externalities associated with each low carbon technology, again minimising the risk of outcomes that are not in customers' interests.
- 6.100 As a result of the implementation of these two remedies, we believe that the CfD regime as a whole will be a more cost-effective mechanism for achieving the UK decarbonisation objectives.
- 6.101 We note that the responsibility of any future decision concerning the award of CfDs outside the competitive auction process, and the quality of such decisions, rests with DECC. While more robust processes as per our remedy package will reduce the risk of suboptimal interventions, it is important that DECC complies with the broader spirit of our remedial action (see, for example, our remedy package noted in Section 17 below).
- 6.102 As noted in our guidelines, before deciding to implement a remedy by way of a recommendation to another public body, the CMA will form a view as to the likelihood that the recommendation will be acted upon. In reaching this view, the CMA must have regard to the stated policy of the body to which the recommendation is to be directed. In this regard, we note the government's commitment to respond in writing to CMA recommendations within 90 days.⁴⁹ Further, we believe that our recommendations are consistent with the government's stated policy, as set out in its Green Book on policy appraisal,⁵⁰ which emphasises among other things the importance of robust cost-benefit analysis prior to decisions being made, and of reviewing policies to assess whether existing measures can be improved.
- 6.103 In the light of the above, we believe that DECC will be well placed to implement our recommendations, and that DECC can implement the recommendations promptly after our final report (ie as regards any subsequent CfD awards or auction processes). This is particularly the case given that the remedies do not require any legislative changes. As noted above, these recommendations are also consistent with the other aspects of our overall

⁴⁹ CC3, paragraph 327.

⁵⁰ HM Treasury, [The Green Book – Appraisal and Evaluation in Central Government](#).

proposed remedy package, including the remedies we have decided upon concerning the governance AEC as set out in Section 19.

Assessment of proportionality

- 6.104 Based on the design features above, we believe this remedy package would be proportionate because it:
- (a) is effective in achieving its legitimate aim;
 - (b) is no more onerous than needed to achieve its aim;
 - (c) is the least onerous if there is a choice between several effective measures; and
 - (d) does not produce disadvantages which are disproportionate to the aim.⁵¹
- 6.105 For the reasons noted in paragraphs 6.96 to 6.103 above, we believe the remedy package would be effective in achieving its legitimate aim.
- 6.106 As regards not producing disadvantages that are disproportionate to its aim, we set out above the scale of the potential cost to customers from departing from a technology neutral competitive auction. The scale of the support available to renewable generation projects is considerable, meaning that decisions around how to allocate CfDs can have enormous impacts on the costs faced by customers.
- 6.107 In the case of the ‘non-competitive allocation remedy’, we set out that in awarding CfDs outside the competitive process under FIDeR, customers are likely to face costs of approximately £250–£310 million higher than may have been the case had these CfDs been awarded at the strike price at which the first CfD auction cleared.
- 6.108 In the case of the ‘pot design remedy’, while we did not quantify the impact of DECC’s decision to allocate the majority of the CfD auction budget to less developed technologies, more detailed modelling from NERA suggests that the level of support to successful bidders was considerably higher than it would have been under a technology neutral competitive auction. NERA estimates that for a potential CfD auction in 2017, holding a technology neutral competitive auction would result in a cost reduction of £50 million per

⁵¹ CC3, paragraph 344, citing the principles established in the *Fedesa* case, Case C-331/88, *The Queen v Minister of Agriculture, Fisheries and Food and Secretary of State for Health, ex parte: Fedesa and others* [1990] ECR I-4023, paragraph 13.

year compared with keeping the same allocation of technologies and budgets to pots as in the 2015 auction.

- 6.109 We expect that the cost to DECC from implementing recommendations would be low, both in terms of the additional resource needed to produce and publish robust and clear impact assessments (as it already has substantial expertise in undertaking this sort of analysis) and in terms of the additional time it will take to hold the relevant consultations and consider stakeholders' responses (where such consultations are held at the points in DECC's timetable as noted above, we would expect DECC to factor this into its project plans).
- 6.110 Given the scale of the costs identified and therefore the scope for over-payment if these decisions are not efficient, we believe that the costs and timing implications of undertaking and consulting on the analysis outlined above would be more than offset and, therefore, both would be proportionate remedies. Even if undertaking this analysis improves the allocation of CfDs only fractionally, it could have a significant impact on the costs to customers; likely considerably in excess of the costs of undertaking such an analysis. As a result, we consider that these remedies are no more onerous than is needed to achieve their aims.
- 6.111 As set out above, we considered versions of these remedies that would have been more onerous. Regarding DECC's ability to allocate CfDs outside the competitive auction process, we considered whether it would be appropriate to recommend certain circumstances or types of project where DECC should not allocate CfDs outside the CfD auction. However, we considered that the version of the remedy set out above (without such restrictions) would be effective and less onerous. In addition, we considered whether it would be appropriate to recommend limits on how DECC should allocate budgets to pots in the CfD auction. However, we considered that the remedy set out above would be effective and less onerous.

Locational adjustments for transmission losses

- 6.112 As set out in Section 5, we have 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, and on an ongoing basis, 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. The price effect could also lead to inefficiency in the location of demand, particularly high-consumption industrial demand.

6.113 Our remedy will introduce locational charging for transmission losses in Great Britain. For the reasons discussed below, the design of the remedy will be identical in its technical aspects to the P229 code modification previously assessed in 2011, including notably the use of semi-marginal (rather than full marginal) transmission loss factors (for the avoidance of doubt, any reference to the P229 code modification proposal relates to the original proposal raised by RWE – referred to as the Proposed Solution in the P229 Assessment Report⁵² – and not to any alternative proposals considered within the context of the modification process).

Aim of the remedy

6.114 The aim of this remedy is to improve the accuracy with which the avoidable costs of variable transmission losses are borne by those who cause them, thus reducing waste of electricity, reducing the cost of electricity generation, and ultimately reducing total bills to end customers. Ultimately, then, the aim of this remedy is to address comprehensively the feature set out above and the detriment associated with it.

Parties' views on the remedy

6.115 We received a range of responses from parties on the remedy to the AEC proposed in our provisional decision on remedies,⁵³ including from the Six Large Energy Firms, the Mid-tier Suppliers,⁵⁴ independent power generators,⁵⁵ National Grid and consumer groups.⁵⁶

⁵² See Elexon's website, [Introduction of a seasonal Zonal Transmission Losses scheme](#).

⁵³ Many responses that touch on proportionality of the remedy but are also related to the establishment of the AEC are reported on and responded to in Appendix 5.2.

⁵⁴ In particular First Utility, Ovo Energy, Good Energy, Co-operative Energy and Ecotricity.

⁵⁵ Eggborough Power and Intergen.

⁵⁶ In particular Which? and Citizens Advice.

6.116 Some parties expressed support for the CMA's proposed remedy to introduce a requirement for variable losses to be priced by location.⁵⁷ In particular parties said the following:

- (a) E.ON said that it had long supported this proposal. It considered that much of the work had already been carried out and that P229 provided a solution with a net predicted benefit, which could be implemented relatively easily.⁵⁸
- (b) RWE strongly supported the CMA's proposals for the implementation of locational adjustments for transmission losses and considered that material benefits could be gained from a rapid implementation of a zonal loss scheme.⁵⁹
- (c) Intergen said that locational adjustments to the Transmission Loss Factor (TLF) would help to correctly incentivise future investment decisions that would aid the balancing of the transmission system.⁶⁰
- (d) Good Energy was supportive of the CMA's proposal provided it was implemented in a simple and efficient manner. It believed that the CMA should implement this remedy directly.⁶¹
- (e) ESB submitted that it believed that the proposed remedy could help promote more effective competition in the generation and supply of electricity and would operate in the interest of existing and future consumers.⁶²

6.117 Other parties supported the principle of cost-reflective charging to promote efficient investment/location decision and promoting efficient self-dispatch⁶³ but some questioned aspects of the remedy, including its proportionality,

⁵⁷ E.ON response to provisional findings and Remedies Notice, paragraph 45, p10. RWE response to Remedies Notice, paragraph 8, p2 and paragraph 1.1, p19. RWE response to provisional decision on remedies, paragraph 39.1, p12; Ovo Energy response to Remedies Notice, p14; Ecoctricity response to provisional decision on remedies, p3; Good Energy response to Remedies Notice, p4; ESB response to provisional findings and Remedies Notice, p2; Intergen response to provisional findings and Remedies Notice, p4; Intergen response to provisional decision on remedies, p2.

⁵⁸ E.ON response to provisional findings and Remedies Notice, paragraphs 45–47, p10.

⁵⁹ RWE response to provisional decision on remedies, p12.

⁶⁰ Intergen response to provisional findings and Remedies Notice, p4; Intergen response to provisional decision on remedies, p2.

⁶¹ Good Energy response to Remedies Notice, p4.

⁶² ESB response to provisional findings and Remedies Notice, p2.

⁶³ Centrica response to provisional findings and Remedies Notice, paragraphs 199–200, p44; Centrica response to provisional decision on remedies, paragraph 451, p88; Energy Policy Group, University of Exeter, response to provisional findings, p4. EDF Energy response to provisional findings, paragraph 2.1, p3 and paragraph 4.5, p9; EDF Energy response to provisional decision on remedies, paragraph 3.1, p17; Northern Powergrid response to provisional findings and Remedies Notice, paragraphs 1–5, Appendix 1, p3; Ofgem response to Remedies Notice, p8.

effectiveness, design and implementation and the underlying analysis.⁶⁴ We comment on these submissions below.

6.118 The critical responses to the remedy focused on the following areas:

- (a) The proposal to adopt a full marginal rather than semi-marginal pricing formula. For the reasons set out below in paragraphs 6.123 to 6.129, we have addressed these criticisms by deciding to implement a semi-marginal scheme based on the technical aspects of P229.
- (b) The allocation of the costs of losses between generation and demand. We have addressed these criticisms by first clarifying the confusion in the provisional decision on remedies which prompted the criticism, and second by adopting the policy described by P229 in conjunction with existing arrangement for the allocation of fixed losses.
- (c) The distributional impacts of the remedy. We have not accepted that these criticisms are valid, as discussed in Appendices 5.2 and 6.2.
- (d) The proportionality of the remedy. We have not accepted the criticisms that the remedy is disproportionate, for the reasons set out below in our assessment of the proportionality of the remedy.
- (e) Consideration, with respect to this remedy, of Ofgem's statutory functions, and of Ofgem's prior reasons for rejecting P229. We have not accepted the criticism that the remedy fails to pay due regard to all of Ofgem's duties and responsibilities, for the reasons set out below in paragraphs 6.188 to 6.197.
- (f) The timing of the remedy. We have accepted the criticism that October 2017 is too short a timetable for implementation, and have decided that implementation by 1 April 2018 would be more effective and proportionate (see paragraphs 6.151 to 6.160 below).
- (g) The method of implementation of the remedy. We do not agree with the proposals that the remedy ought to be implemented by way of recommendation to Ofgem. We have, however, modified our approach to implementation to address some concerns raised by parties (see paragraphs 6.139 to 6.150 below).

⁶⁴ Centrica response to provisional decision on remedies, paragraph 451, p88. EDF Energy response to provisional decision on remedies, paragraph 3.1, p17. EDF Energy response to provisional decision on remedies, paragraph 3.1, p17. The Energy Policy Group, University of Exeter, response to provisional findings, p4.

6.119 We elaborate in detail each of the categories of critical response and our response to them in Appendix 6.2. Some of the considerations and submissions, especially those around proportionality, are also framed as arguments against the AEC. These are therefore described and considered in Section 5 and Appendix 5.2.

Design considerations

6.120 Our remedy is to require that variable transmission losses are priced on the basis of location. As a result, the volumes of imbalance that are used to calculate imbalance charges under the balancing and settlement arrangements (as set out in the BSC) will reflect more accurately the transmission losses caused by generators and suppliers.

Scope of the remedy

6.121 As contemplated in previous modification proposals seeking to introduce locational pricing for losses (eg code modification P229⁶⁵), and consistently with our AEC finding, the remedy will apply to all generators and suppliers located within Great Britain.^{66,67}

Possible alternative design mechanisms

6.122 In the next subsection we discuss alternative possible remedies

- *Full marginal pricing of losses vs semi-marginal*

6.123 We have considered whether it would be better to charge full marginal prices on variable losses rather than P229's implementation of semi-marginal prices.

6.124 The modelling results described in Section 5 indicate that the additional technical benefits of full marginal over semi-marginal pricing is of the order of tens of millions of pounds in total over the next ten years (the estimated range is between £15 million and £31 million) compared with a semi-

⁶⁵ See Elexon, [Final Modification Report P229: Introduction of a seasonal Zonal Transmission Losses scheme](#), p6.

⁶⁶ Interconnectors are exempt from variable transmission losses in Great Britain. They are considered as 'a transmission line which crosses or spans a border between Member states and which connects the national transmission systems of Member States' Third Energy package. Electricity Regulation 714/2009, Article 2(1).

⁶⁷ Due to a misinterpretation of the mechanism of P229 which we describe more fully in paragraphs 5.71-5.73, our provisional decision on remedies proposed that locational pricing for losses should be imposed only on generators. Our remedy will apply to all GB generators and suppliers who contribute to transmission losses, as envisaged by P229.

marginal solution.⁶⁸ This is the direction of result that we would expect. As a matter of principle, we believe that full marginal losses would provide a better signal to generators and suppliers in their short-run decisions to generate and consume (eg DSR) electricity. As regards this particular aspect, it might be a more effective solution than P229 in addressing the full detriment arising from the AEC.

- 6.125 However, a move to full marginal pricing would lead to an over-recovery of losses costs, ie the pricing of losses would be higher than the actual costs of the losses caused by a generator. The reason for this is that variable losses increase non-linearly (ie following a quadratic curve) with output, while the locationally variable elements of the transmission loss factors are set as single marginal loss factors (ie a line). As a result, the over-recovery will arise when the actual level of generation or demand differs from the anticipated level of generation associated with the transmission loss factors. The non-linear increase of variable losses (which is determined by the laws of physics) is such that the over-recovery would, with full-marginal pricing, be almost twofold.⁶⁹
- 6.126 The over-recovery associated with full marginal pricing of losses risks leading to consequences which we believe may be material, and whose scale and overall impact on competition and consumers we have not had the opportunity to fully assess. It might be possible to develop a mechanism allowing a solution based on full marginal pricing (therefore delivering the full benefits of the introduction of locational pricing for losses), and we see merit in trying to do so. However, within the context of this investigation, we have not developed such a solution, and the industry has not consulted on one in the past. In order to develop a remedy that is capable of timely implementation, we have decided that a remedy based on modification P229 (ie semi-marginal), is more effective and proportionate than the full marginal alternative.
- 6.127 As noted in Section 5, the history of attempts to introduce transmission pricing for losses suggests that carrying out the analysis required to fully investigate the impacts of full marginal pricing would require time and resources, with an uncertain outcome. This in turn could potentially further delay implementation of this remedy. In contrast, a semi-marginal price based solution, such as P229, has already been assessed by the industry

⁶⁸ Section 5 provides details of the efficiency gain calculation and result.

⁶⁹ Variable losses – those that vary with output – are of an approximately quadratic form: $L = a Q^2$, where L is the amount of transmission losses on a particular part of the system, a is a constant and Q is the injection or withdrawal of energy at that node; therefore the marginal loss factor, $dL/dQ = 2aQ$. Therefore, the actual loss divided by the marginal loss is $aQ^2/2aQ$, which equals exactly $\frac{1}{2} Q$.

and developed, and can therefore be implemented within a more appropriate (effective) time frame.

6.128 It follows that, while a semi-marginal solution would somewhat dampen the signal given by the transmission loss factor, it is still capable of substantially and sufficiently addressing the detriment arising from the AEC (as suggested by our modelling exercise) and, contrary to full marginal pricing, it is capable of a timely implementation. We therefore believe that, on balance, a solution such as the one proposed in P229 is a more effective remedy. We nevertheless consider that the industry, as well as Ofgem (in particular in view of the new role and responsibilities that we are recommending for Ofgem within the context of codes governance – see Sections 18 and 19), should carry out additional work in order to develop and consider whether to implement a solution based on full marginal pricing.

6.129 The above is a relevant consideration for our approach to the implementation of the remedy, which is discussed in more detail below.

- *Other detailed design choices*

6.130 A number of comments, further discussed in Appendices 5.2 and 6.2, suggested that further detailed modelling was needed in order to bring into line the solution set out in P229 and NERA's simulations, so as to ensure that such simulations are a better representation of the remedy to be implemented. We accept that NERA's simulations are an approximation and that further work will need to be carried out in the implementation phase of the remedy. However, we do not believe that such additional work is needed to reach a conclusion on the effectiveness and proportionality of the remedy as set out in P229. This is the same approach taken by the industry within the context of the P229 process. There were a number of very detailed design choices that P229 left open – for example, how exactly to allocate individual supply and demand points to nodes, or how precisely to model the network to estimate losses. P229 envisaged that such work would be carried by specialists during the implementation phase of the modification.

- *Locational pricing for constraints and losses*

6.131 We also considered an alternative remedy design based on the introduction of locational pricing for both constraints and losses. National Grid⁷⁰ has provided a submission to the inquiry that sets out its early thinking on a

⁷⁰ National Grid response to Notice regarding assessment methodology for losses proposed remedy – consultation on methodology and scenarios.

possible direction of the GB mechanisms for locational pricing. Under the EU's Capacity Allocation and Congestion Management (CACM) framework, each EU system operator (National Grid in the case of the GB market) must submit, at least every three years, its thinking on whether or not to 'split' previously integrated markets to account for both losses and transmission constraints.⁷¹ National Grid's submission describes the way in which the GB balancing market mechanism could be used to accommodate market splitting compatible with the EU's preferred 'Target' model.

- 6.132 The Target Model envisages that where constraints and/or losses are large enough, it makes sense to have separate price-setting mechanisms. Trade between zones is facilitated by the creation of tradable transmission capacity permits and the simultaneous clearing of spot market auctions ('market coupling'). If all of the European markets were operated in this way and were competitive, an outcome close to technically efficient dispatch would be achieved, and the relevant 'borders' in the system would not be national but zonal.
- 6.133 The design relies on the idea of splitting the GB market into a number of zones – perhaps 4 – and having the system operator run a balancing mechanism in each of these zones. In the absence of contracts, a generator in one zone would have a positive imbalance in that zone, while a source of demand in another zone would have a negative imbalance there. The two parties could trade those exposures just as they do today in a single zone. Losses and constraints could be accommodated in various ways in such a mechanism: for example, if imbalance is defined at the level of the zone, a generator wanting to contract to satisfy the demand of a supplier in another zone will have to produce enough to cover the supplier's metered quantity in that zone and will receive a payment from balancing based on their supply to another zone. The price differences between zones can therefore reflect loss factors.
- 6.134 There are several potentially attractive features of this sort of design:
- (a) It can use measured quantities, property rights and trading to determine the level of pricing for losses and constraints simultaneously.
 - (b) In the absence of market power, this should lead to close to the marginal cost of losses and constraints.

⁷¹ Article 34 actually requires an evaluation of bidding zone configuration on market efficiency, with specific reference to congestion. National Grid suggested that losses could be addressed through this.

- (c) It is consistent with the market design that over time should apply in the rest of the EU, reducing the distortions that apply today to the treatment of losses across EU borders.
- (d) It is an evolution of the balancing-market-based mechanism that British Electricity Trading and Transmission Arrangements (BETTA) operates today and change should therefore be less costly and fit more easily with current industry practices than other potential solutions to the locational pricing problem.
- 6.135 In principle, there are therefore some reasons to believe that a mechanism such as the one described by National Grid might in theory be more efficient than the P229 mechanism. However, as noted in Section 5, 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.
- 6.136 We do not therefore intend to pursue this alternative remedy. National Grid's model is at a very early stage of development and might take several years to be implemented (or not be implemented at all, for instance because of inconclusive evidence or perceived risks of unintended consequences). Further, even if we did wish to implement such an approach, we would not be confident that an order or a recommendation to Ofgem could be sufficiently precise so as to ensure implementation of a remedy based on National Grid's design in a timely and effective manner. In contrast, we believe, for the reasons set out below, that our remedy is capable of timely and effective implementation by 1 April 2018.
- 6.137 For these reasons, we consider that our remedy will be more effective in the short and medium term (and quite possibly in the longer term given the uncertainties in development of the alternative). We also note that our remedy does not rule out a later move towards National Grid's proposed design, if this is considered appropriate.

Conclusion on the design mechanism

- 6.138 We have decided to take as a starting point the design that was chosen for P229 because it has the virtue of having already been thoroughly described and assessed. While we have noted above that alternative solutions may

potentially be more effective in addressing comprehensively the full detriment arising from the AEC (eg a solution based on full marginal pricing) or bring additional benefits (such as the solution proposed by National Grid), we are concerned that developing such solutions would require additional analysis and consideration of their impacts and, importantly, substantial delay. In contrast, while a semi-marginal solution would somewhat dampen the signal given by the transmission loss factor, such a solution is still capable of substantially addressing the detriment arising from the AEC (as suggested by our modelling exercise) and, contrary to full marginal pricing, also capable of a timely implementation. We therefore believe that, on balance, a semi-marginal solution such as the one proposed in P229 is a more effective remedy. We also recommend Ofgem (in particular in view of the new role and responsibilities that we are recommending for Ofgem within the context of codes governance – see Sections 18 and 19), as well as the industry, to carry out additional work in order to develop and implement a solution based on full marginal pricing.

Proposed implementation for the remedy

- 6.139 We have considered whether to implement this remedy by way of an order or a recommendation that Ofgem (or the industry) raise a code modification proposal.
- 6.140 SSE⁷² considered that the claimed benefits of the remedy remained highly uncertain and if the CMA considered that remedial action was justified, the only possible course of action that could be justified by the evidence would be to issue a recommendation to Ofgem to continue this work. Others, including EDF Energy,⁷³ Centrica⁷⁴ and DONG Energy⁷⁵ suggested that a recommendation would be a better way to implement this remedy, as it would give the opportunity to the industry to consider alternative design options with particular regard to distributional impacts.
- 6.141 We do not agree with these criticisms. We believe that there are two main reasons to reject this proposal:
- (a) Our work modelling P229, together with all the previous work on the same remedy, amounts to substantial evidence for the order of magnitude of the detriment linked to the AEC. We do not believe that

⁷² SSE response to provisional decision on remedies, paragraphs 8.8.1 & 8.8.2, p69.

⁷³ EDF response to provisional decision on remedies, paragraph 3.24, p21.

⁷⁴ Centrica response to provisional decision on remedies, paragraph 443, p84.

⁷⁵ DONG Energy response to provisional decision on remedies, p5.

additional simulation modelling will produce additional information relevant to the establishment of the order of magnitude of the detriment.

(b) Experience to date shows that it has been extremely difficult to introduce locational charging for transmission losses through code modification processes. We believe that much of that is due to the possible differential impact of the introduction of locational pricing for losses on some producers who have found it to be in their commercial interest to slow down the pace of change, and up until now to such an extent as to preclude it altogether.⁷⁶

6.142 We have therefore decided to implement this remedy through an order imposed on National Grid, as system operator, consisting of two parts. We will implement P229 in all its technical detail. This has been thoroughly reviewed and considered already through the normal BSC processes.

6.143 The first part of the order will require National Grid to ensure that, at all times, imbalance charges (and specifically the estimated volumes of an imbalance) are calculated such as to be locationally sensitive to transmission losses. In order to give effect to this requirement, the order will also provide for the modification of the Transmission Standard Licence Conditions, so as to include such duty.

6.144 The second part of the order will require National Grid to ensure that the imbalance charges are calculated, as of 1 April 2018, on the basis of the principles set out in the order. The order will therefore set out:

(a) the principles to be applied as of 1 April 2018 for the purpose of calculating the transmission loss factors (which will be identical, in all technical aspects, to P229);

(b) an obligation on National Grid to assume responsibility for the calculation of the transmission loss factors if the BSCCo and/or any other agent appointed for that purpose fails to perform its duties within this context; and

(c) an obligation on National Grid to raise a code modification proposal to modify the BSC in line with P229.

6.145 In order to give effect to these obligations (as set out in paragraph 6.144 above), the order will also provide for the modification of the Transmission Standard Licence Conditions.

⁷⁶ See [provisional findings report](#), paragraphs 5.42–5.43 and 5.48–5.50.

- 6.146 The second part of the order (as set out in paragraph 6.144 above) will cease to have effect once a BSC modification proposal identical in all technical aspects to P229 has been implemented. As a result, once such modification is implemented, the methodology to calculate transmission loss factors may be modified by BSC parties through the usual BSC modification process (to the extent that it complies with the principle set out in the first part of the order, ie that it maintains locationally sensitive transmission loss pricing).
- 6.147 Further, we have decided to make a recommendation to Ofgem to support National Grid by taking necessary steps that might facilitate the effective and timely implementation of the order. Ofgem will be under a duty to monitor compliance by National Grid with this order (as reflected in National Grid licence conditions).
- 6.148 We have also decided to make a recommendation to Ofgem and to the industry to assess alternative solutions to the remedy as implemented based on full marginal pricing and, if and when appropriate, consider whether to develop and implement a further code modification based on the most effective solution.
- 6.149 We believe that this approach to the implementation of the remedy, based on a technical solution (P229) which has already been through the usual industry process, is effective (and in particular capable of a timely implementation) and proportionate (see our assessment below). We are, however, aware of the need to maintain the possibility for Ofgem and the industry to amend the rules underpinning the locational pricing for losses in the years to come so as to improve (if appropriate, for instance in order to move to a full marginal solution) or adapt to future developments the technical details set out in P229. This is why the second part of our order, containing the technical details of P229, will cease to have effect once the BSC modification reflecting P229 will have been implemented. As from that moment, the industry (as well as Ofgem) will have the option to raise a new modification proposal so as to suggest further changes to the rules introduced by our remedy. Industry's ability to modify the BSC will, however, be constrained by the general duty on National Grid, pursuant to its licence conditions, to ensure, at all times, that imbalance charges (and specifically the estimated volumes of an imbalance) are calculated such as to be locationally sensitive to transmission losses. Ofgem will act as gatekeeper of the code modification process. Within this context, we also note the remedies relating to the Codes AEC, which will empower Ofgem to take actions if it considers that a change to these rules is needed.

6.150 In view of the above, we expect National Grid to raise a modification proposal, identical in all technical aspects to P229, as soon as practicable so as to reflect its obligation under the Transmission Licence into the BSC. This will facilitate the implementation of the remedy by 1 April 2018 and will also lead to the termination of the second part of the Order, therefore allowing Ofgem and the industry to implement our recommendation set out in paragraph 6.148 (and any further change that may be necessary from time to time).

Time frame for implementation

6.151 The P229 Assessment Report prepared by the BSC code panel indicated that most parties required six to nine months to implement P229 and that the relevant transmission loss factors needed to be made available to relevant parties at least three months before being used in calculating imbalance charges for the purpose of the settlement process. This would allow parties to take into account the effects of the remedy in their contracts.⁷⁷

6.152 Specifically, the following activities/steps will need to be undertaken before the remedy can become effective:

(a) National Grid to ensure that the steps referred to in paragraphs 6.144 (eg appoint third party agents, establish a load flow model, and calculate the relevant transmission loss factors) are carried out.

(b) Relevant transmission loss factors to be published at least three months before being used in settlement.

(c) Parties to amend their own systems, processes and documentation before the transmission losses factors are first published. We note that industry, throughout the BSC Panel, proposed an implementation date for P229 of either 1 April or 1 October due to existing contractual arrangements. We have followed this recommendation in designing our remedy.

6.153 Further, we consider that the implementation of the remedy shall not be phased in and that there should be no gradual introduction of non-zero transmission loss factors.⁷⁸

⁷⁷ See P229: [Introduction of a seasonal Zonal Transmission Losses scheme](#), Assessment report, p19.

⁷⁸ *ibid*, p19.

- 6.154 Based on the above, we initially proposed an implementation date of 1 October 2017.
- 6.155 In response to our provisional decision on remedies, some parties challenged this implementation date. Dong Energy⁷⁹ noted that the CMA had not finalised the details over how locational losses would be implemented and considered that there was still a significant amount of work that needed to be taken forward by industry parties as well as likely code modifications. Therefore it considered that 2020 would be a more appropriate implementation date and may still end up being too early. Further, it said that generators needed warning of any changes so that they could factor them into investment and operational decisions.
- 6.156 EDF Energy⁸⁰ said that the timescale that the CMA had proposed to implement this change (October 2017) was already well within the contracting horizon for generation and customers businesses. This meant that there would be a further impact due to already hedged and contracted positions, including the potential for windfall gains and losses for these businesses, and the likely need to reopen some contracts. It said that the CMA did not appear to have given consideration to this impact in setting the time frame or assessing customer impacts.
- 6.157 Further, Centrica⁸¹ said, given that the 2018/19 and 2019/20 Capacity Market auctions had already taken place, there would be no scope for generators to respond to the locational loss proposals within the duration of those Capacity Market contracts and it considered that there was a good case for transitional loss arrangements or a complete four-year deferral of their implementation once the detail allocation mechanism had been designed by National Grid.
- 6.158 As noted above, the approach taken in provisionally deciding on an implementation date as at 1 October 2017 was based on the industry's own analysis set out in the P229 Assessment Report, which suggested an implementation phase of 15 months (including a three-month notice period to generators and suppliers). While we accept that details over how locational losses will be implemented remain to be determined, the process to do so is identical to the one set out by the industry in the P229 Assessment Report. We believe that this approach is appropriate and does not have any material impact on the assessment of this remedy. We therefore disagree with DONG Energy that implementation should be delayed to 2020. We note, however,

⁷⁹ DONG Energy response to provisional decision on remedies, p4.

⁸⁰ EDF response to provisional decision on remedies, paragraph 3.19, p20.

⁸¹ Centrica response to provisional decision on remedies, paragraph 460, p89.

that in view of the time required for the CMA to make an order and/or for a modification proposal to the BSC to be approved by Ofgem, there is a material risk that the implementation date of 1 October 2017 is not achievable. In view of the above, and in particular of the industry's own implementation timetable set out in the P299 Assessment Report, we believe that an implementation of 1 April 2018 would be more effective and proportionate.

- 6.159 This date should mitigate some of the concerns raised by EDF Energy and Centrica (see paragraphs 6.156 and 6.157). As noted above, while we accept that this remedy will have distributional effects between generators, we believe that these concerns are overridden by the net benefits to consumers arising from the remedy. With respect to EDF Energy's point, we believe that generators will have the time to modify current investment and operational decisions within our timetable. While we accept that the Capacity Market auctions for 2018/19 and 2019/20 have already taken place, and that bidders have not explicitly taken into consideration the impact of our remedy, we believe that this impact will be small compared to the overall net benefits arising from the remedy.
- 6.160 In view of the above, we consider that the remedy should be implemented by 1 April 2018.

Costs of implementing the remedy

- 6.161 The costs of implementing the P229 proposal were estimated by LE/Ventrix as part of the modelling commissioned by Elexon. LE/Ventrix identified two categories of upfront (one-off) implementation costs: costs to BSC parties and central systems costs.⁸²
- 6.162 It estimated that the costs to BSC parties (ie the industry), which mostly relate to IT systems (billing and metered volumes), would range between £2.8 million and £4.1 million, with a midpoint estimate of £3.4 million. Central system costs consisting of changes to central BSC IT systems were estimated to be £0.4 million. Total upfront costs would therefore be £3.8 million when the midpoint estimate is considered.
- 6.163 In addition to these upfront costs, LE/Ventrix also estimated that there would be some ongoing costs for systems maintenance. These were estimated at approximately £0.2 million per year.

⁸² Ofgem (2011), [Impact assessment on RWE proposal P229 – seasonal zonal transmission losses scheme](#), pp37 & 38.

- 6.164 The costs estimated by LE/Ventrix were later reviewed by the Brattle Group, which considered them prudent when compared with implementation cost estimates from previous similar proposals.⁸³ We have not received any substantive challenge from parties on this.
- 6.165 We consider that parties will incur similar costs for implementing the remedy. Taking an NPV of these costs at 3.5% yields a present cost of well under £10 million for the remedy. We believe, therefore, that the cost is of the order of single millions of pounds.

Assessment of effectiveness

- 6.166 For the reasons set out above we believe that the implementation of the remedy would bring a net benefit over (at least) the next ten years due to an enhancement in technical efficiency. The evidence from our simulation model provides a robust indication of the order of magnitude of the overall efficiency benefits that will arise from short-run effects of this remedy. These will be (on an NPV basis) of the order of £150 million over the next ten years for a semi-marginal pricing of losses, substantially in excess of the costs of implementing the remedy. Positive benefits of a similar magnitude were estimated by previous models, as set out in Section 5. In addition, we have identified efficiency benefits arising from long-term effects that we have not sought to quantify (although we consider these unlikely to be material).
- 6.167 While it is not possible to give a precise quantification of the distribution of the overall efficiency benefits, we believe that it is more likely than not that, through the process of competition in wholesale markets, these benefits will be passed through to GB customers.
- 6.168 Additionally, we note that our remedy might have an impact on the costs of ancillary services provided by National Grid and the future development and location of renewable generation within Great Britain. However, we have not seen evidence that any such effects would systematically add to total system costs. Any such impacts can be mitigated through other existing market mechanisms or appropriate changes to policy. For instance, the auction price of CfDs can take into account pricing for variable transmission losses.
- 6.169 As noted above, the experience of the industry to date has been that it has been extremely difficult to move from a position of not charging for losses to one of imposing some charges. We believe, however, that our remedy, which sets out the key principles to calculate locational charges, and which

⁸³ *ibid*, p38.

clearly allocates responsibility for implementation, is capable of effective implementation and monitoring. This is because it follows the implementation design and timetable set out in P229. Having had bilateral and multilateral discussions with National Grid, Elexon and Ofgem, we are confident that:

- (a) National Grid, with adequate support from Elexon, has the expertise and ability to obtain the necessary information to implement this remedy and calculate locational charges;
- (b) pursuant to Section B, paragraph 1.2, of the BSC, the Panel must conduct its business in such a manner as to ensure the efficient discharge by National Grid, as Transmission Company, of the obligations imposed under the Transmission Licence (which we have decided to modify in order to implement the remedy);
- (c) any incentives that National Grid and the industry participants have to alter, undermine or delay implementation of our remedy will be constrained by our order and Ofgem's supervision; and
- (d) Ofgem has the duty to monitor compliance with the licence condition and the ability to further support timely implementation.

6.170 Implementation of our remedies will require National Grid to take a number of steps. Based on our review of the P229 Assessment report, and our bilateral and multilateral discussions with National Grid, Elexon and Ofgem, we believe that National Grid is in a position to appoint experts to calculate the relevant transmission loss factors and reflect them in its calculation of the imbalance charges for the purpose of the settlement process by 1 April 2018. In view of the potential impacts to GB generators and customers arising from the remedy, the inherent complexity of the transmission network and remedy, and the need to ensure that the transmission losses factor are calculated in a robust manner, we believe that this time frame is appropriate and timely.

6.171 As noted above in paragraphs 6.123 to 6.129, the decision to move to a semi-marginal pricing of losses implies the risk of a residual detriment (for the next ten years, our modelling exercise suggests a range of £15–£31 million). We believe, however, that our approach is necessary to ensure a timely implementation of our remedy. For the longer term, we have decided to recommend Ofgem, as well as the industry, to carry out additional work in order to develop and implement a solution based on full marginal pricing, which would be capable of addressing this residual detriment.

6.172 For these reasons, we believe that the remedy is effective in addressing the feature that gives rise to the AEC we have provisionally identified, as well as remedying the associated detriment, and that it is capable of effective and timely implementation.

Assessment of proportionality

6.173 For the reasons set out above, we consider that the remedy is effective in achieving its aim by addressing the feature giving rise to the AEC we have provisionally identified, and the associated detriment. We have then considered whether our remedy, implemented by way of an order, was no more onerous than necessary and the least onerous remedy of the options available.

6.174 As noted above, implementation of our remedy will require National Grid (with the support of Elexon) to take a number of steps. The remedy will also have implementation costs for parties. As noted above, estimated implementation costs are a small fraction (an NPV of under £10 million) of the overall likely net benefits arising from the remedy.

6.175 In our view, each of the implementation steps set out in our remedy is necessary to ensure that transmission loss factors are calculated in a robust manner. This in turn should increase the effectiveness of the remedy and avoid unintended consequences.

6.176 We have also considered alternative designs for implementing locational pricing for transmission losses.

6.177 We considered an alternative proposal raised by National Grid. However, for the reasons set out above in paragraphs 6.122 to 6.136, we do not believe that these alternative proposals are capable of effective and timely implementation.

6.178 We have also considered whether full marginal loss factors would be more efficient or less onerous. For the reasons set out above, we believe that pricing full marginal losses would require further analysis in order to avoid unintended consequence, which undermine the capability of this remedy to be implemented in a timely manner. We have therefore decided to order the implementation of a solution based on semi-marginal loss pricing, which has already been fully assessed by the industry and in our analysis. The benefits of implementing a semi-marginal loss pricing solution in a timely manner outweigh the residual detriment that is left unaddressed by this solution. In addition, to address this residual detriment, we have decided to recommend

Ofgem and the industry to carry out additional analysis to develop in the future a solution based on full marginal loss pricing.

- 6.179 We have also considered whether it would be more appropriate to take action by way of an order or a recommendation.
- 6.180 The latter could lead either to Ofgem modifying licence conditions, or to a modification proposal being raised for the industry to develop a modification proposal (similar to the process followed in the past, eg P229). In principle, this approach would give an additional opportunity to Ofgem and/or the industry to carry out further analysis and consult upon it (eg a more detailed simulation model).
- 6.181 Having compared the analysis performed by the CMA with the analysis carried out in the context of previous modification proposals, we do not see merit in recommending that Ofgem carry out further analysis concerning the merits of this remedy. The central purpose of modelling is to provide for an order of magnitude of technical benefits. Having consulted with third parties regarding the NERA analysis, we do not believe that other credible sets of input parameters or different types of model will alter the type or order of magnitude of effect that we have identified.
- 6.182 In addition, we are concerned that a recommendation to Ofgem or the industry would lead to unnecessary delays. As noted above, previous experience shows the difficulty in implementing this remedy. Ofgem's process to modify licence conditions would likely, within the context of a historically controversial measure such as this one, be longer than the CMA's process to impose an order (which is constrained by a statutory time frame). As noted in our provisional findings report, the code modification process, in particular when incentives are misaligned (as it is the case within this context), may lead to long delays. Moreover, a recommendation by the CMA, compared with an order, would increase the risk of the remedy not being implemented at all. We consider that an order by the CMA would lead to a simpler, less costly, implementation process.
- 6.183 We note, however, that our approach implies that the BSC be modified so as to reflect the order. Once this modification is implemented, the part of the order which contains the details of the transmission losses will cease to have effect. As discussed in paragraph 6.149 above, this effectively will allow Ofgem and the industry to take forward further changes to the remedy in order to implement our recommendation to explore options for moving to full marginal pricing of losses to make any other change required to keep pace with technical and commercial developments.

- 6.184 For these reasons, we believe that our remedy is no more onerous than necessary to achieve its aim and the least onerous of the alternative proposals that we have considered.
- 6.185 We have also considered whether this remedy may have disadvantages that are disproportionate to its aim. We noted that the remedy will have distributional effects, including transfers between generators in different regions, customers in different regions and between the GB market and generators (and possibly customers) in the rest of Europe. While we have not tried to assess the magnitude of these transfers with precision, we believe for the reasons set out above that it is more likely than not that the remedy will have a positive impact on GB customers' bills overall. Even if customers in certain regions of GB were to see their bills increase as a result of the remedy (to the benefit of other GB customers) we would expect this effect to be small (for individual domestic customers, under a few pounds per year).
- 6.186 We have also sought to examine whether the remedy may have unintended consequences on the environment, as a result of a shift of production from cleaner to more polluting plants (ie overall increase in CO₂), or a shift from generation in areas with low density population to high density population (ie SO₂ and NO_x emissions affecting a larger population). However, based on our modelling exercise (albeit acknowledging its limitations), and the absence of evidence pointing in the opposite direction, the reduction in overall generation of electricity to satisfy demand should overall have a beneficial environmental impact.
- 6.187 Further, we have discussed below the inefficiencies of the losses charging mechanism for interconnectors and noted that it does not provide signals allowing variable transmission losses to be taken into account in generation dispatch decisions. While we believe that Ofgem, ACER and other European regulators should consider how the charging mechanism should be reformed, we consider that this does not invalidate our case for having a more efficient allocation of transmission losses within Great Britain given that net benefits arise from it. It is possible that a reformed charging mechanism for interconnectors, which includes locational signals would bring even higher net technical efficiency benefits.

Assessment of the remedy against the relevant statutory functions of Ofgem

- 6.188 Where the CMA is considering whether to modify the licence conditions of entities involved in the transmission of electricity, it must 'have regard' to the

relevant statutory functions of Ofgem in deciding whether such action would be reasonable and practicable⁸⁴

- 6.189 Ofgem's statutory functions concerning the transmission of electricity are set out in Part 1 of the EA89, as amended by the Energy Act 2010 (EA10), and include (among other things) granting transmission licenses, promoting efficiency and economy on the part of persons authorised by licences or exemptions to transmit, distribute or supply electricity, and to secure a diverse and viable long-term energy supply. Ofgem, as the regulator, sets price controls for the companies that operate GB gas and electricity networks.⁸⁵
- 6.190 Ofgem's principal objective in carrying out such functions is to protect the interests of existing and future customers of gas and electricity supply.⁸⁶ The interests of such customers are taken as a whole, including their interests in (a) the reduction of greenhouse gases; (b) the security of supply; and (c) the fulfilment by Ofgem of the objectives set out in Article 36(a) to (h) of the Electricity Directive.⁸⁷
- 6.191 In reaching a decision to modify a licence condition, we must therefore assess the remedy against Ofgem's principal objective, as set out above. As part of our own application of the legal framework requiring us to decide upon proposed remedies that are effective and proportionate,⁸⁸ we have explicitly taken into account many of the above factors to which Ofgem must have regard when doing carrying out its functions. In particular, we have noted the expected net benefits of our remedy for GB electricity customers. We have therefore concentrated below on those considerations not explicitly taken into account elsewhere in this section.
- 6.192 We believe that the remedy is consistent with Ofgem's environmental objective of reducing greenhouses gases. The mechanisms for achieving this high level objective are not likely to be significantly influenced by the

⁸⁴ Section 168 of the 2002 Act and [CC3](#), paragraph 347.

⁸⁵ [Ofgem factsheet: Price Controls Explained](#).

⁸⁶ See, among others, section 3A and section 6B of the EA89.

⁸⁷ Directive 2009/72/EC of the European Parliament and of the Council of 13 July 2009 concerning common rules for the internal market in electricity and repealing Directive 2003/54/EC, OJ L211/55 (the Electricity Directive).

⁸⁸ [CC3](#), paragraph 327. These objectives include, among other things, a requirement on the national regulator to take all reasonable measures for a competitive, secure and environmentally sustainable internal market in electricity within the European Union, and ensuring appropriate conditions for (i) the effective and reliable operation of electricity networks, taking into account long-term objectives; (ii) developing competitive and properly functioning regional markets within the European Union; (iii) eliminating restrictions on trade in electricity between member states; (iv) eliminating restrictions on trade in electricity between member states; (v) facilitating access to the network for new generation capacity; (vi) ensuring that system operators and system users are granted appropriate incentives, in both the short and the long term, to increase efficiencies in system performance and foster market integration; (iv) ensuring that customers benefit through the efficient functioning of their national market; and (viii) helping to achieve high standards of universal and public service in electricity supply, contributing to the protection of vulnerable customers.

remedy. Any market-based mechanism is likely to function more efficiently in the context of price signals that are cost-reflective in other, related markets. As noted above, our modelling exercise estimates that there will be a moderate additional environmental benefit from the reduction in SO₂ and NO_x emissions from the remedy. The modelling also indicates a modest fall in CO₂ emissions due to the remedy, although we note that CO₂ emissions are subject to a binding cap at the European level.

- 6.193 While the remedy would have an impact on decisions relating to investment in, and dispatch of, capacity, we have seen no evidence that this would have any negative impact on the overall level of generation capacity in GB. On the contrary, increased efficiency in system performance is in our view consistent with the aim of achieving security of supply. The mechanisms that are in place for ensuring security of supply are, for the most part, the capacity mechanism, the CfD auctions, the balancing market pricing regime, and various direct procurement tools in the hands of the system operator. This remedy is not likely to have substantial effects on the operation of any single one of these mechanisms, and almost certainly not on the operation of all of them together. We therefore do not believe that the remedy will have a material impact on security of supply. Moreover, in general, we believe that market mechanisms (which all of the security of supply mechanisms are) function better if prices in related markets reflect incremental costs.
- 6.194 Our remedy will directly promote some of the objectives set out in the Electricity Directive, namely it will provide system operators and system users with the appropriate incentives, in both the short and the long term, to increase efficiencies in system performance. With locational pricing for losses, generators will have incentives to dispatch electricity more efficiently thus reducing the total amount of losses generated to meet demand. A more efficient pricing mechanism for losses will therefore promote the development of a competitive and properly functioning market in Great Britain and in turn may foster market integration with other regional markets. In this respect, we noted above that it is more likely that the GB system will evolve to an even better mechanism for locational pricing if it starts from a position of some locational pricing rather than none.
- 6.195 As discussed above and in Appendix 6.2, Ofgem concluded in September 2011, with respect to P229, that the proposed modification would not be consistent with its principal objective and statutory duties.⁸⁹ In its decision, Ofgem noted however that increased cost reflectivity as per P229 (as per

⁸⁹ Ofgem modification proposal decision (September 2011), [Balancing and Settlement Code \(BSC\) P229: Introduction of a seasonal Zonal Transmission Losses scheme \(P229\)](#).

our remedy) should result in more efficient dispatch due to cost signals allowing variable losses to be taken into account leading to production cost savings, reduced losses and reduced emissions. It also stated that, in general, competition is likely to be more effective if the costs which parties impose are reflected in their charges and therefore their decision-making process.

- 6.196 For the reasons set out above, and in Appendix 6.2, we have found it difficult to reconcile Ofgem's decision on P229 with the evidence and analysis Ofgem commissioned and summarised in its impact assessment. We also noted in paragraph 2.11(b) above that some of the concerns relating to the long-term benefits of the introduction of locational pricing for transmission losses were in our view unlikely to materialise in the light of recent development at EU level.
- 6.197 Therefore, for the reasons set out in this section, and in particular the expected net benefits for GB customers in the next ten years, we consider that the remedy is consistent with Ofgem's principal objective of promoting the best interests of existing and future customers.

7. Vertical integration

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Introduction

7.1 A range of parties have expressed concerns about vertical integration in the electricity sector, both in the context of this investigation and in the wider debate about competition in the energy sector.¹ 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.’²

7.2 In this section we consider a range of costs and benefits of vertical integration, before presenting our conclusions on whether vertical integration in electricity gives rise to an AEC. The section is set out as follows:

- **Introduction:** First, we give a brief introduction to vertical integration in the electricity sector, explaining what we mean by vertical integration in the context of electricity, a brief history of the evolution of vertical integration in Great Britain, some of the factors that may have led to

¹ The level of vertical integration 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 vertical integration in gas and it has not been a focus of our investigation. As a result, this section focuses only on vertical integration in electricity.

² Ofgem (June 2014), [Decision to make a market investigation reference in respect of the supply and acquisition of energy in Great Britain](#), p4.

vertical integration historically, and what forms it takes (paragraphs 7.3 to 7.23).

- **Potential competitive detriment resulting from vertical integration:** We then go on to consider whether there may be any detriment to competition as a result of the level or form of vertical integration, or the behaviour of vertically integrated firms. This includes an assessment of whether vertical integration is likely to lead to any issues around wholesale market liquidity, the likelihood of vertically integrated firms being able to foreclose their rivals, and the extent to which vertical integration could lead to issues around the transparency of financial reporting (paragraphs 7.24 to 7.56).
- **Benefits of vertical integration:** 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 vertical integration, and a range of other benefits. We then consider the extent to which any benefits are likely to be passed through to customers and whether there are alternatives to full vertical integration that may deliver the same benefits (paragraphs 7.57 to 7.128).
- **Conclusions on vertical integration:** Finally we set out our conclusions on the potential costs and benefits of vertical integration (paragraphs 7.129 to 7.137).

The meaning of vertical integration in electricity

7.3 A vertically integrated 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.

7.4 The Six Large Energy Firms are all vertically integrated, and some other energy firms also have a degree of vertical integration.³

³ Including Drax (which owns Haven Power), Ecotricity and ENGIE.

A brief history of vertical integration in electricity

- 7.5 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.
- 7.6 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.
- 7.7 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.
- 7.8 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:
- (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 2000.⁴
- 7.9 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.

⁴ NAO (February 2004), *Risk Management: The Nuclear Liabilities of British Energy plc*, paragraph 2.20.

- (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.
- 7.10 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.
- 7.11 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.
- 7.12 Some of this activity coincided with the introduction of NETA (later superseded by BETTA), the system of market arrangements under which electricity is traded, in March 2001.
- 7.13 Current trends may indicate that the level of vertical integration in the GB wholesale electricity market is decreasing:
- (a) A number of suppliers have announced substantial moves towards de-integration. E.ON has separated its operations (renewable energy generation, regional networks, supply businesses and German nuclear generation) from Uniper (conventional generation and trading activities).⁵ RWE has also announced that its renewables, grids and retail activities are being transferred into a new subsidiary and it plans to list the shares in the new subsidiary on the stock market.⁶ Centrica is closing some of its gas-powered plants and had tried to sell others.⁷ SSE also announced that it was reorganising its operations internally to increase legal separation.⁸

⁵ 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.](#)

⁶ See [RWE launches future-oriented business with new subsidiary](#), March 2016.

⁷ Centrica subsequently made the decision to retain CCGT assets following a sales process, as bids received were significantly below its internal valuation.

⁸ 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.

- (b) The first Capacity Market auction provided funding for 15 GW of capacity from firms other than the Six Large Energy Firms.^{9,10}
- (c) To date, CfDs have been allocated to 4.7 GW of renewable capacity from firms other than the Six Large Energy Firms.¹¹

Did self-dispatch increase incentives for vertical integration?

- 7.14 Under NETA, generators moved from central dispatch to self-dispatch.¹² Some have argued¹³ that self-dispatch created an incentive for parties to ‘contract with themselves’ – effectively, to vertically integrate – which in turn might lead to competition concerns.
- 7.15 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 system operator. 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.¹⁴ 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.
- 7.16 These arguments are plausible explanations for the attractions of vertical integration at the time of NETA’s introduction. However, these factors do not appear to apply in the current market conditions. We have found that:

⁹ EMR Delivery Body (June 2015), [2014 T-4 Auction Results](#).

¹⁰ As noted above, some other firms also have varying degrees of vertical integration, meaning this may overstate slightly the total amount of non-vertically integrated capacity.

¹¹ 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](#).

¹² 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 system operator. The system operator 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.

¹³ 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](#).

¹⁴ 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](#).

- (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;¹⁵
- (b) levels of self-supply, especially in near-term markets, are low, which suggests that vertical integration 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.

7.17 We therefore do not believe that a self-dispatch system in the current market conditions provides significant incentives for vertical integration.

Varying models of vertical integration

7.18 Models of vertical integration vary in practice, and vertically integrated firms organise their business units in a range of different ways. It is common for vertically integrated 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.

7.19 Within a vertically integrated 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.

7.20 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.

¹⁵ Appendix 7.1: Liquidity, paragraphs 35 and 36.

Current extent of vertical integration in electricity

- 7.21 The outcomes we observe suggest that current market conditions do not provide significant incentives for vertical integration. In relation to supply, we note that independent suppliers currently have just over 13% of domestic supply market share,¹⁶ and that their market share has grown considerably in recent years, which suggests that a stand-alone supply business is a viable business model that is able to compete effectively with vertically integrated firms.
- 7.22 In relation to generation, we note that many generators do have a supply business, although their degree of vertical integration varies considerably. For example, within the Six Large Energy Firms, [X] generates considerably more than it supplies to retail customers, while at the other extreme [X] supply volumes are considerably higher than its generation output.¹⁷ A number of other generators have some degree of vertical integration, although supply and generation volumes are not generally balanced. For example, [X] generates considerably more than its retail arm's supply volumes.¹⁸
- 7.23 Overall therefore, even where firms are vertically integrated, their supply and generation volumes are not generally balanced. This – and the recent move away from vertical integration from some of the Six Large Energy Firms discussed above – suggests that current market conditions do not create material barriers to firms that are either not vertically integrated, or that are only partially integrated.

Potential competitive detriment resulting from vertical integration

- 7.24 A range of parties have expressed concerns over the degree of vertical integration in the energy sector. In this section we consider three broad areas where it was argued that vertical integration could theoretically result in AECs.¹⁹ First we consider whether vertical integration is likely to have any significant impact on wholesale market liquidity. We then consider whether vertically integrated firms may be able to foreclose either the generation or supply markets. Finally we consider whether firms' vertical integration

¹⁶ See Section 8, Table 8.3.

¹⁷ See Section 4, Table 4.17.

¹⁸ See Section 4, Table 4.17.

¹⁹ In this context, we observe that the Six Large Energy Firms (which are the largest vertically integrated 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 vertical integration.

structures raise concerns relating to a lack of transparency around firms' levels of profitability.

Liquidity

- 7.25 In this section we consider the links between vertical integration and liquidity. 'Liquidity' can have a number of meanings, but we primarily use this term to mean good availability of products that market participants wish to trade.²⁰ 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.²¹ This disadvantage may in turn affect competition in retail markets or generation.
- 7.26 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 vertically integrated structure, it could be to the detriment of customers in the long run.
- 7.27 We consider two questions relating to vertical integration and liquidity. Firstly, we assess the extent to which the prevalence of vertical integration in electricity could reduce liquidity in the wholesale electricity market, and secondly we consider whether vertically integrated firms are better able to deal with low levels of liquidity.

Does vertical integration reduce the level of liquidity?

- 7.28 We consider in the section below on benefits arising from vertical integration whether vertically integrated 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 vertical integration was leading to a lower level of trading, it is possible that vertical integration could reduce wholesale market liquidity, potentially to the detriment of independent suppliers and generators.

²⁰ 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 7.1: Liquidity, paragraphs 8–10.

²¹ See Appendix 7.1: Liquidity, paragraph 101.

7.29 However, our conclusion is that vertical integration is unlikely to have a significant impact on the extent to which products are available to trade on the wholesale electricity market. That is, vertically integrated 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).²² We also saw similar patterns of trading behaviour between gas and electricity, even though there is a much lower degree of vertical integration, and liquidity is generally held to be better, in gas than in electricity.²³

7.30 As a result, we consider that vertical integration 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 vertically integrated firms have a competitive advantage relating to liquidity?

7.31 As noted in the Liquidity appendix, First Utility claimed that vertically integrated firms enjoyed a competitive advantage relative to independent suppliers because they could trade internally even when products were not available externally.²⁴

7.32 If this were the case, vertically integrated 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, vertically integrated firms would be at an effective cost advantage over independent suppliers. A similar theory could apply with regard to vertically integrated firms having advantages over independent generators.

7.33 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).²⁵

7.34 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

²² See Appendix 7.1: Liquidity, Table 2.

²³ See Appendix 7.1: Liquidity, paragraphs 145–149.

²⁴ See Appendix 7.1: Liquidity, paragraph 32.

²⁵ See Appendix 7.1: Liquidity, paragraph 108.

Energy Firms could reach their current hedged positions using their trades in externally available products.

- 7.35 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 vertically integrated firms. If so, that would suggest that liquidity does not distort competition, nor raise barriers to entry and expansion.
- 7.36 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 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.
- 7.37 We did not, however, find evidence that product availability was likely to be causing this.²⁶ 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.²⁷
- 7.38 In addition, Ofgem's Secure and Promote licence conditions also serve to further dampen concerns about the impact of vertical integration on liquidity, because they ensure the availability of the products that were most widely used for hedging by the Six Large Energy Firms.²⁸
- 7.39 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 vertical integration were distorting their hedging strategies in electricity, or if liquidity in electricity were a serious constraint on their trading.²⁹
- 7.40 As a result, we have reached the conclusion that vertically integrated firms do not experience a significant competitive advantage in relation to liquidity at present.

²⁶ See Appendix 7.1: Liquidity, paragraphs 119–139.

²⁷ See Appendix 7.1: Liquidity, paragraphs 40–52.

²⁸ See Appendix 7.1: Liquidity, paragraphs 90–98.

²⁹ See Appendix 7.1: Liquidity, paragraphs 145–147.

Is there sufficient liquidity for independent suppliers?

- 7.41 In its response to our provisional findings report, First Utility set out its concerns that there was insufficient liquidity in the wholesale electricity market, especially for bespoke products sold a long time ahead of delivery, which it required to hedge shape.³⁰ Tempus Energy made similar comments in its response to our provisional decision on remedies.³¹
- 7.42 While we recognise that additional liquidity would generally be beneficial to suppliers and generators (potentially both independent and vertically integrated),³² we do not consider that the current level of liquidity in the wholesale electricity market as a whole constitutes an AEC. The inability of a small number of suppliers to source products they would like to at prices they consider reasonable does not necessarily indicate that the market is failing to operate efficiently.
- 7.43 Any absence of a liquid market for these products suggests that there may not be prices at which both counterparties (eg supplier and generator) would be prepared to trade. As noted above, while a large number of generators have some degree of vertical integration, their generation output does not tend to be balanced with their supply volumes.³³ As a result, there is plenty of scope for independent suppliers to trade these products with generators if it would be mutually beneficial.
- 7.44 In its response to our questions on liquidity, Drax stated that selling bespoke products could impose risks on a generator, as it could leave it with unsold power. Generators may therefore require a premium to compensate them for the risks of selling bespoke products. If suppliers were not prepared to pay a sufficient premium for these products, it would not be surprising if they were traded infrequently and liquidity in such products was low.

Foreclosure

- 7.45 We considered whether vertically integrated 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

³⁰ [First Utility response to provisional findings](#).

³¹ [Tempus Energy response to provisional decision on remedies](#).

³² In addition, Shell set out in its [response to provisional findings](#) that greater liquidity in the market for 'long-dated shape power hedges' would be beneficial in its role as an intermediary.

³³ For example, [X] generates considerably more than its retail arm's supply volumes. See Section 4, Table 4.17.

work in this area – a more detailed assessment is contained in the Foreclosure appendix.³⁴

- 7.46 Foreclosure is the central competition concern that is commonly considered in the context of vertical integration.³⁵ It refers to the situation where a vertically integrated firm might sacrifice some profit in one part of its business (say, wholesale) in order to distort another market (say, retail) in such a way that independent firms are made worse off, to the overall benefit of the vertically integrated firm.
- 7.47 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:³⁶ The vertically integrated 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 customers.
- 7.48 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.³⁷ 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.
- 7.49 **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.
- 7.50 Our 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 vertically integrated 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.³⁸ We note that five of the Six Large Energy

³⁴ See Appendix 7.2: Foreclosure.

³⁵ CC3, p59.

³⁶ CC3, p58.

³⁷ [Energy market investigation updated issues statement](#).

³⁸ See Appendix 7.2: Foreclosure, paragraphs 47–59.

Firms are net buyers of electricity, and that independent suppliers have increased their market share in recent years, both of which offer a route to market for generators. In addition, we note that independent firms have continued to invest in new generating plants in recent years.³⁹ This indicates that widespread foreclosure is not currently occurring. Taken together, our current view is that customer foreclosure is unlikely to be an issue.

- 7.51 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 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 vertically integrated firms would have clear incentives or the ability to act in this way.⁴⁰
- 7.52 Secondly, we considered whether a vertically integrated firm might try to reduce liquidity (beyond the natural reduction that vertical integration 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 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.
- 7.53 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.⁴¹ Therefore we conclude that input foreclosure does not appear to be an issue in GB electricity.
- 7.54 We did not receive any comments on the provisional conclusions we set out in the provisional findings report. Our conclusion remains that the evidence does not indicate a problem arising from foreclosure.

Transparency of financial reporting

- 7.55 Finally, in considering the potentially harmful effects of vertical integration, we have considered whether there were any financial transparency issues arising from firms' vertically integrated structures, which might in turn lead to detriment to customers. We note that a number of stakeholders have raised concerns regarding financial transparency and summarise our consideration

³⁹ See Appendix 7.2: Foreclosure, paragraph 55.

⁴⁰ See Appendix 7.2: Foreclosure, paragraphs 66–82.

⁴¹ See Appendix 7.2: Foreclosure, paragraphs 83–93.

of this issue in Section 18 and in more detail in Appendix 18.1. In Section 19, we discuss remedies to improve financial transparency.

- 7.56 While not a result purely of firms' vertically integrated structures, we find in Section 18 that a lack of a 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.

Benefits of vertical integration

- 7.57 Vertical integration 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, vertical integration can create efficiencies leading to lower costs and potentially lower prices for customers.⁴²
- 7.58 Typically, potential efficiencies from vertical integration relate to the ability of the firm to take an integrated view when setting prices, so as to avoid the problem of double marginalisation.⁴³ We do not consider this to be a significant benefit of vertical integration 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 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.⁴⁴
- 7.59 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.
- 7.60 However, we note that there has been a recent move away from vertical integration between electricity supply and generation, which potentially calls into question the scale of any benefits from adopting this structure.

⁴² [Merger Assessment Guidelines \(CC2/OFT1254\)](#), especially paragraphs 5.6.4 and 5.7.10–5.7.12.

⁴³ Whereby both the upstream and downstream firms price above marginal cost, when the profit-maximising behaviour of a vertically integrated 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 vertically integrated firm and customers.

⁴⁴ However, to the extent that such benefits arise, we would expect these to increase efficiency, to the benefit of customers.

The natural hedge

- 7.61 It is often claimed that the ‘natural hedge’ is an important feature of vertical integration 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 vertically integrated firms are likely to benefit from a natural hedge.
- 7.62 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 vertical integration, 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
 - (b) volume risk: the risk that customer demand will change relative to expected levels.

Suppliers’ risks

- 7.63 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.
- 7.64 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.
- 7.65 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.⁴⁵

- 7.66 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.
- 7.67 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).
- 7.68 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 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).
- 7.69 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.
- 7.70 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.
- 7.71 The precise nature of the risks suppliers face is likely to depend on their customer base. For example, suppliers serving non-domestic customers

⁴⁵ This is an oversimplification of suppliers' hedging behaviour, but is sufficient to examine the benefits of the natural hedge.

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

- 7.72 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.
- 7.73 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).
- 7.74 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).
- 7.75 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.
- 7.76 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.
- 7.77 Most generators also face considerable volume risk.⁴⁶ 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

⁴⁶ 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.

(and therefore making money), and the wholesale price the generator receives.

- 7.78 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.⁴⁷

How does the natural hedge mitigate suppliers' and generators' risks

- 7.79 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 vertically integrated firm's overall risk, relative to stand-alone supply and generation businesses. This concept is referred to as the 'natural hedge'.
- 7.80 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 vertically integrated firm to hedge its exposure to the wholesale market actively (eg by trading electricity forward) compared with stand-alone suppliers and generators.
- 7.81 We consider below the extent to which vertical integration could reduce the risks identified above.
- *Price risk*
- 7.82 If changes to the wholesale price that reduce returns to a vertically integrated 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. Vertically integrated firms with a natural hedge have an in-built mechanism that reduces the firm's overall exposure to wholesale price, and may be less

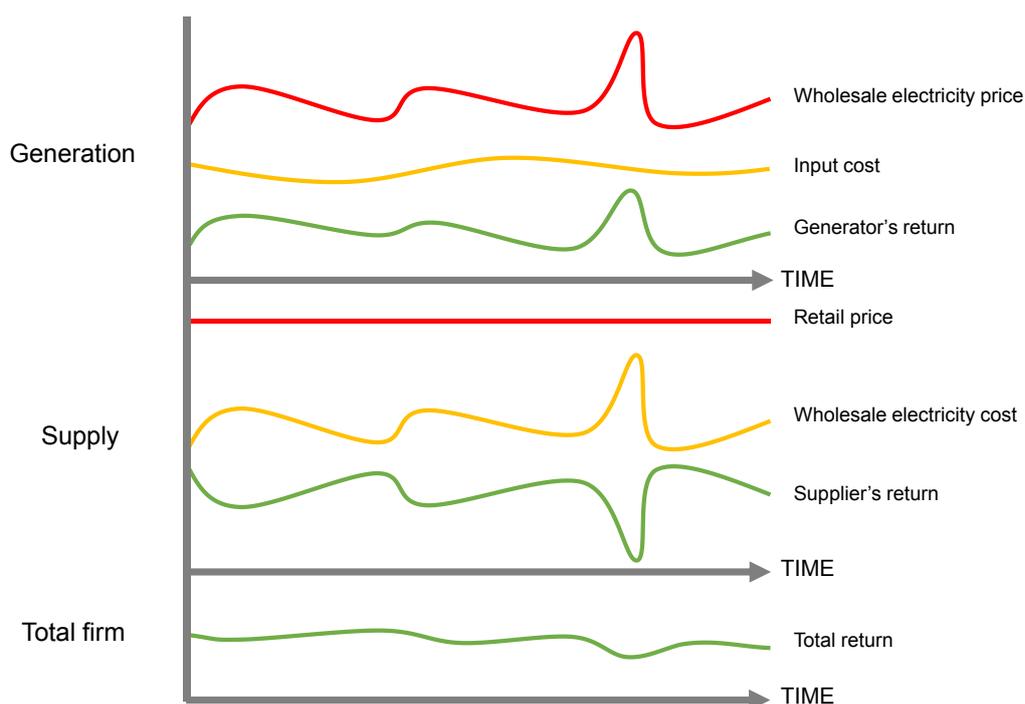
⁴⁷ For example, the investment in renewable technology in recent years has resulted in an increase in low marginal cost generation. Other things equal, this would be expected to reduce wholesale prices for all generators. As well as reducing wholesale prices, this will also have the effect of pushing 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.

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.

7.83 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 vertically integrated 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.

7.84 Figure 7.1 illustrates why the returns to a supply and generation business may be negatively correlated, and how this could reduce a vertically integrated firm's exposure to fluctuations in the wholesale price.

Figure 7.1: Example of negatively correlated supply and generation returns

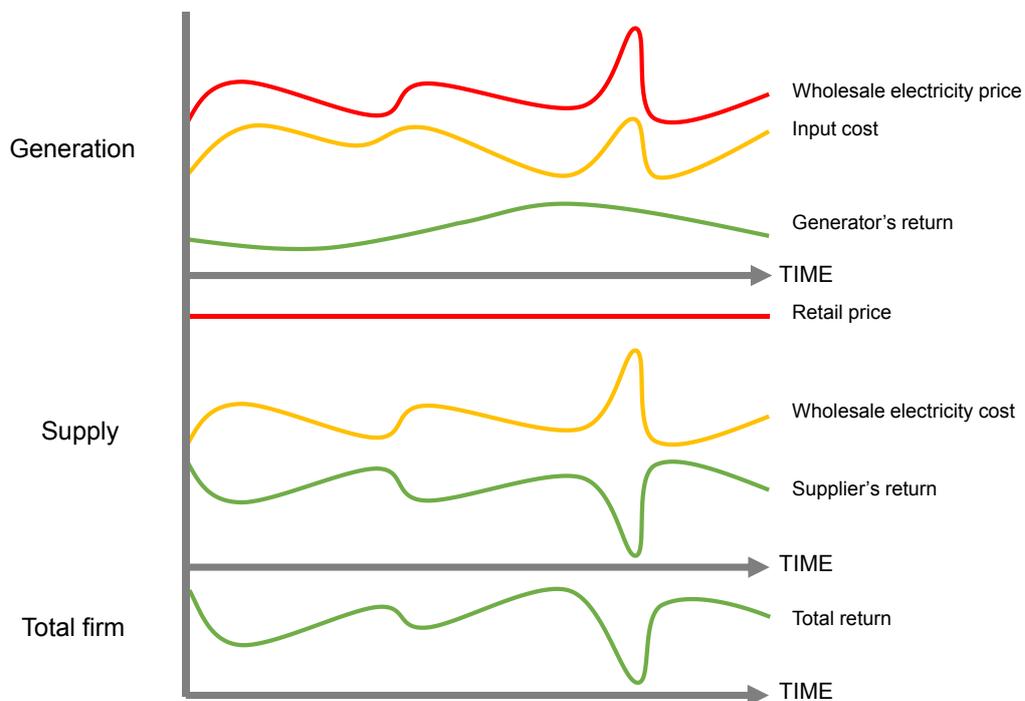


7.85 Figure 7.1 shows how the natural hedge can reduce a vertically integrated firm's exposure to price risk. A generator's revenue fluctuates with the wholesale market price, meaning that (in the example set out in Figure 7.1) the generator's returns also move in line with the wholesale market. Conversely, 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 vertically integrated firm is considerably less exposed to the wholesale market (as shown by the relatively stable total returns to the vertically integrated firm). This could potentially reduce the vertically integrated firm's need to trade in order to hedge its price risk.

- 7.86 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.
- 7.87 The type of generation technology a vertically integrated 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.
- 7.88 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 7.2 illustrates this point for a vertically integrated firm that owns gas-powered generation.

Figure 7.2: Example of supply and gas-powered generation returns



- 7.89 Unlike in the example shown above (in Figure 7.1), for a gas generator the wholesale electricity price tends to move broadly in line with the cost of gas.⁴⁸ As a result, the generator's returns do not move in line with the wholesale electricity price. The overall returns of the vertically integrated firm therefore remain exposed to the wholesale electricity price, and the firm does not enjoy a natural hedge.
- 7.90 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 vertically integrated firm with nuclear generation is likely to be more in line with Figure 7.1 than Figure 7.2 above. As a result, nuclear generation is likely to provide a stronger natural hedge against price risk than coal and gas generation.
- 7.91 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.
- 7.92 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 vertical integration between a supplier and a wind generator would be a substitute for hedging through trading.⁴⁹
- 7.93 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.⁵⁰ 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

⁴⁸ This is particularly the case in periods when gas is the marginal generator, as it often is at present (under normal demand conditions)

⁴⁹ 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.

⁵⁰ 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](#).

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.

7.94 Therefore, the main beneficiaries of the natural hedge against price risk are likely to be vertically integrated firms with predictable generation other than coal and gas (primarily nuclear), and potentially renewables. To the extent that this matches their expected demand, the vertically integrated 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 vertically integrated firm benefiting from this natural hedge could therefore potentially avoid some costly trading activity.

7.95 We consider it likely that for the majority of vertically integrated 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.⁵¹

7.96 Moreover, any benefits resulting from a natural hedge for price risk are likely to be limited. The Liquidity appendix finds that wholesale market liquidity is good in the key products used for volumetric hedging against price risk (discussed previously).⁵² As a result, if vertically integrated 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 vertically integrated firms' ability to reduce their level of trading in the wholesale electricity market.

- *Volume risk*

7.97 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

⁵¹ 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).

⁵² See Appendix 7.1: Liquidity, paragraph 99.

negatively correlated with the impact on a generator's returns, a vertically integrated firm may have a natural hedge against this risk.

- 7.98 As noted, there are two main sources of volume risk: system-wide (eg weather-related) volume risk, and risks resulting from volatile customer numbers.
- 7.99 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).⁵³
- 7.100 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 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.
- 7.101 This could be either pre- or post-gate closure. That is, it may be that a vertically integrated firm that enjoys a natural hedge in this area would be less exposed to balancing costs post-gate closure.
- 7.102 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 vertically integrated firm's risks.
- 7.103 The claimed advantage of vertical integration 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.

⁵³ As noted above, firms may be less exposed to weather-related risks in serving non-domestic customers.

- 7.104 As a result, it is unlikely that the supply arm of a vertically integrated 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.
- 7.105 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,⁵⁴ we consider it unlikely that suppliers are exposed to similar long-term risks. As a result, these risks faced by generators are not likely to be strongly correlated with the risks faced by suppliers. Therefore, vertical integration is likely to be a poor hedge for these types of risk.
- 7.106 For the reasons mentioned above, while it is possible that there may be a natural hedge for vertically integrated 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 vertically integrated firm.
- 7.107 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 vertical integration relating to volume risk may constitute a greater benefit than any natural hedge of price risk.
- *Broader benefits related to the natural hedge*
- 7.108 As set out above, if a vertically integrated 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.

⁵⁴ See paragraphs 7.63 & 7.64 above.

- *Transaction cost savings*

7.109 Any reduction in the amount of external trading is likely to reduce the transaction costs faced by a vertically integrated firm. Such costs may include brokerage and exchange fees.

7.110 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 vertically integrated 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*

7.111 Vertically integrated 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.

7.112 Some of the Six Large Energy Firms told us that historically there had been a benefit of improved security of supply from vertical integration, but with the evolution of a well-functioning wholesale market, this has ceased to be a material benefit.

- *Collateral*

7.113 If a vertically integrated 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 vertically integrated 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 vertically integrated 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*

- 7.114 We can see some potential benefits from vertical integration 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 vertically integrated firms that have some generating capacity at or near the margin at a given point in time.
- 7.115 Overall, while there may be a benefit to vertically integrated 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.
- 7.116 Any natural hedge against wholesale electricity price volatility could be expected to reduce vertically integrated 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.
- 7.117 It is important to note that any benefits associated with the natural hedge appear to result from increases in vertically integrated 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 customers.

Other benefits of vertical integration

- 7.118 In addition to the natural hedge and related benefits, we have identified a number of possible benefits that may arise from vertical integration 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 vertical integration. It may also be that the benefits have changed over time. For example, one of the Six Large Energy Firms ([redacted]) told us that the primary strategic reason for vertical integration in its case had changed from [redacted], to diversity of earnings during the 2000s, and was now cost synergies. In this section we summarise some of these other potential benefits of vertical integration.

Cost of capital and lower risk capital requirements

- 7.119 We did not see evidence that vertical integration 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.
- 7.120 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 vertical integration in itself.
- 7.121 In its response to our provisional findings report, Opus set out its view that ‘an investment-grade, vertically-integrated player has a significant financial advantage over a retail supplier who is not vertically-integrated or investment-grade’, suggesting that this gives vertically integrated firms a competitive advantage over non-vertically integrated firms.⁵⁵ However, when considering the impact of vertical integration on competition, we consider it important to distinguish between factors that relate to the vertically integrated firms’ overall creditworthiness (eg the Six Large Energy Firms’ strong balance sheets), and those that relate directly to vertical integration itself.

Sharing common resources

- 7.122 Vertically integrated 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 vertical integration between supply and generation.

Whether advantages are likely to be passed on to customers

- 7.123 We considered whether advantages of vertical integration are likely to be passed on to customers, both domestic and non-domestic. Our general view

⁵⁵ [Opus response to provisional findings](#).

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 vertical integration is likely to lead to marginal cost savings for a supply business.⁵⁶ We have found that competition in the retail energy markets is not working effectively for some customers (see Sections 8 and 9), which may limit the current extent of pass-through.⁵⁷

- 7.124 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.
- 7.125 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 customers.

Alternatives to common ownership

- 7.126 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 vertical integration (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 vertical integration through contracting with each other, it is likely to reduce the benefits of full vertical integration.
- 7.127 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.
- 7.128 Furthermore, dynamic trading of forward contracts may enable an independent supplier to replicate the cash flows of owning generation capacity. This goes beyond merely hedging expected output, and may enable independent suppliers to replicate the full benefits of vertical

⁵⁶ 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.

⁵⁷ However, failure to pass through cost reductions relating to vertical integration should not be seen as a problem with vertical integration; cost reductions that are only partially passed on to customers are likely to be preferable to a situation in which these cost reductions do not materialise at all.

integration. However, this is a very capital-intensive strategy, and it is not clear how feasible this would be for an independent supplier in practice.

Conclusion

- 7.129 In this section, we have considered the various means by which vertical integration could potentially harm competition and cause harm to customers.
- 7.130 We found that vertical integration 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 vertically integrated 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 vertically integrated firms.
- 7.131 We considered whether vertically integrated firms would have the ability and incentive to foreclose markets to rival independent firms and found that this is unlikely.
- 7.132 We also considered whether there were any financial transparency issues arising from firms' vertically integrated structures, which might in turn lead to detriment to customers. While not a result purely of firms' vertically integrated structures, we find in Section 18 that a lack of a 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, gives rise to an AEC.
- 7.133 Alongside this, we considered a range of potential benefits to firms of vertical integration. Our 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 vertically integrated firms resulting from the natural hedge, whereby certain outcomes that may be detrimental to the vertically integrated 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.
- 7.134 We also set out some other potential benefits from vertical integration 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.

- 7.135 We also note that some of the Six Large Energy Firms are moving away from a vertically integrated structure, giving further weight to the view that any benefits from vertical integration are likely to be reasonably limited.
- 7.136 Lastly, we recognise that benefits to a firm from vertical integration that result from genuine efficiencies have the potential to be passed on as benefits to customers. While it is not clear to what extent these benefits are likely to be passed through, customers are likely to be better off than they would be if these efficiencies were not present.
- 7.137 Overall therefore, our view is that vertical integration 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 vertical integration, that may be passed through to customers. As a result, our conclusion is that vertical integration does not give rise to an AEC.

8. Nature of competition in domestic retail energy markets

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8.1 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 9.

8.2 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, provide a brief history of regulatory interventions in the years since the gas and electricity sectors were liberalised and identify a key development currently in train – the mandatory roll-out of smart meters to all domestic customers by 2020.
- (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 some specific characteristics of the nature of competition for prepayment customers and customers on restricted meters, which suggest that competition for these segments is more limited than that for other types of domestic customer.
- (h) We identify any differences in outcomes that we observe between the **devolved nations and between regions**.
- (i) Finally, we present our **conclusions and implications for the issues** that we investigate in more detail in Section 9.

Demand and supply characteristics and the parameters of retail competition

8.3 This section sets out our understanding of the fundamental characteristics of domestic energy customers and retail energy suppliers, which has framed 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

- 8.4 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.

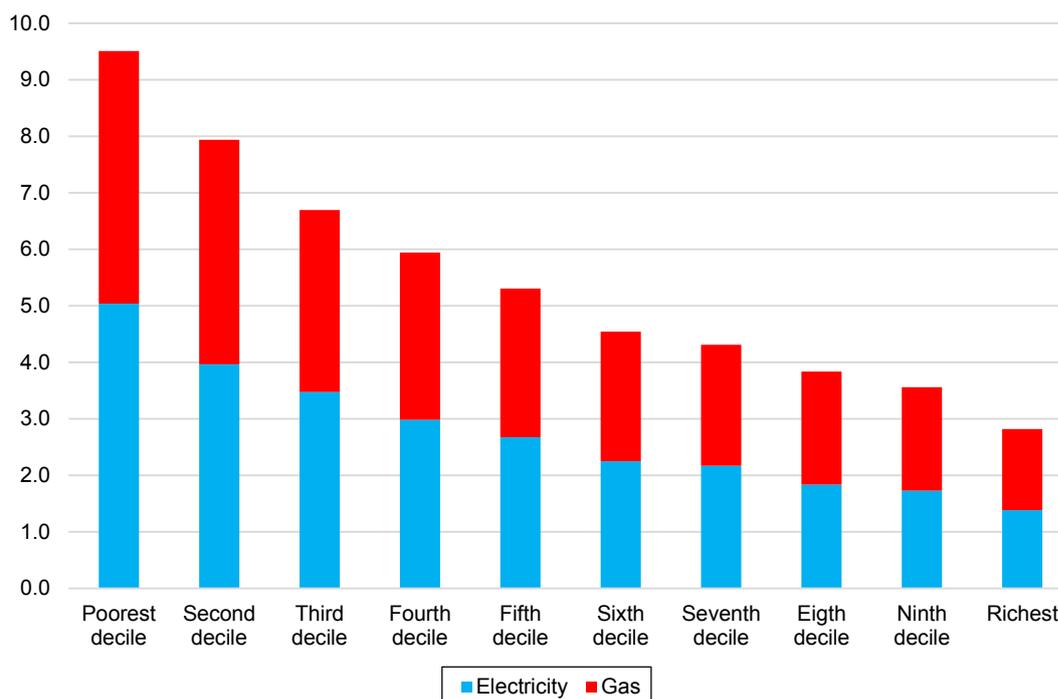
Energy is a necessity good

- 8.5 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.¹ As a result, the regulations governing energy supply ensure that 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.²
- 8.6 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. Figure 8.1 below shows the relationship between income and gas and electricity consumption.

¹ The value of lost load (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](#).

² 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 8.1: Household expenditure on gas and electricity (% of total expenditure) by disposable income decile



Source: ONS, Family Spending 2015.

8.7 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.³ This relationship between expenditure on energy and income explains part of the concern around energy price increases – they have a highly regressive impact.

8.8 Domestic price elasticity of demand for electricity and gas⁴ 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 for customers on non-smart meters, since they 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 limited substitutability, certainly for many uses of electricity. In the long run, as domestic customers are able to respond to increased prices through the installation of energy efficiency measures (and heating and cooking

³ ONS Family Spending 2014.

⁴ 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.

systems, for which there is a degree of substitutability between gas, electricity and other fuel sources) price elasticity is likely to be higher.

- 8.9 A survey of studies looking at residential energy provides some support for this characterisation. Espey and Espey (2004)⁵ found that, in the short run,⁶ 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.'⁷
- 8.10 Smart meters provide the opportunity for short-term customer response, through the use of static and dynamic time-of-use tariffs, as discussed further in Sections 9 and 12.

Homogeneity and the importance of price

- 8.11 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.
- 8.12 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'.⁸
- 8.13 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.
- 8.14 A further implication of homogeneity is that customers may be less interested in engaging in the markets for electricity and gas supply than in

⁵ 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).

⁶ This is a longer time period than the 'very short run' discussed above.

⁷ Gillingham, K, Newell, R and Palmer, K (2009), 'Energy efficiency economics and policy', [Resources for the Future Discussion Paper 09-13](#).

⁸ Appendix 9.1: Customer Survey.

other markets, where there is quality differentiation of products. This is discussed further in Section 9.

Non-price factors

- 8.15 Three types of non-price factor are likely to be of importance to certain customers.
- 8.16 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.
- 8.17 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 of bills), 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).⁹
- 8.18 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'.¹⁰ The scope for such advice and services is likely to grow with the full roll-out of smart meters.

Traditional meters

- 8.19 Traditional (ie non-smart) gas and electricity meters used in households do not record at what time energy is used¹¹ and are only read infrequently.¹²

⁹ Appendix 9.1: Customer Survey.

¹⁰ Appendix 9.1: Customer Survey.

¹¹ As noted in Section 3, there is a wide variety of such traditional meters, which can be categorised in a number of ways, including: credit or prepayment meters; and single rate or restricted meters. Restricted meters (which notably include Economy 7 meters) allow for some basic time-of-use information to be stored for billing and settlement purposes.

¹² 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](#).

8.20 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 domestic retail markets, as discussed in more detail in Section 9.¹³

Parties' views on demand characteristics

8.21 In response to our provisional findings report, most of the Six Large Energy Firms did not agree with the statement that 'gas and electricity are extreme examples of homogenous products in that the energy that customers consume is entirely unaffected by the choice of retailer' and therefore 'that customers are likely to attach a particular importance to the price of energy' (see paragraph 8.11 above). They submitted that non-price factors are also important to customers. In particular:

- (a) Centrica said¹⁴ that consumers had diverse needs and preferences and that it sought to differentiate itself from competitors through providing customers with a combination of products that manage price volatility while offering excellent customer service, a range of differentiated standard and innovative products, and competitive pricing across all its products. Centrica said that the CMA customer survey showed that consumers' choice of supplier was driven by a range of factors which were also considered essential or very important to customers, such as good customer service. In particular, 83% of customers considered good customer service to be essential or very important.
- (b) E.ON said¹⁵ that many elements associated with the retail supply of gas and electricity were not homogenous, and this influenced the decisions customers made on whether to act on potential savings. E.ON agreed that price was an important consideration for customers but that there were many other factors which a customer would take into account when considering switching.
- (c) RWE said¹⁶ that the CMA customer survey showed that, in addition to price, many consumers valued other product features when choosing their supplier (such as customer service, simplicity of tariff structures,

¹³ 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.

¹⁴ Centrica response to CMA's Provisional Findings, 15 August 2015, paragraphs 50 and 51

¹⁵ E.ON response to CMA's Provisional Findings, 15 August 2015, paragraphs 10 and 77

¹⁶ RWE response to CMA's provisional findings, 15 August 2015, paragraphs 9 & 10.

tailored tariffs, supplier brand, the range of other services available such as boiler maintenance and whether a supplier provided smart meters), and that suppliers competed to differentiate themselves and innovate in various ways. RWE¹⁷ said the CMA's stance that products were homogenous sat uncomfortably with the evidence available to it on the impact of the introduction of the RMR rules, which the CMA considered to have limited innovation. RWE also said¹⁸ that:

- (i) survey respondents identified factors relating to 'cost/tariff/price/rate' which potentially encompassed dimensions other than the price per kWh, and that the CMA had not explored what respondents meant by 'cost/tariff/price/rate' nor the importance customers might place on dimensions such as tariff structure;
 - (ii) in giving this response, survey respondents were answering a question about what factors they considered when choosing a supplier; they were not being asked to rank the importance of those factors; and
 - (iii) when asked about the importance of a range of factors, 'good customer service' (83%) was the most important factor followed by 'cheap tariff rate' (78%) and 'simple/easy to understand tariffs' (78%).
- (d) Scottish Power said¹⁹ that there were differences in the features and scope of the customer service offerings of different energy suppliers, and that the degree of homogeneity in energy supply was comparable to that of many other markets that displayed similar or greater levels of price differentiation.
- (e) SSE said²⁰ that the CMA's analysis of its customer survey to support its view that price was the most important driver of choice for survey respondents was highly selective. In particular, the CMA ignored the fact that, when prompted, more respondents (83%) indicated that good customer service was more important than a cheap tariff rate (78%) when choosing supplier. In addition, a significant proportion of customers (25%) also indicated that the other services offered by

¹⁷ RWE response to provisional findings, 15 August 2015, paragraph 59.

¹⁸ RWE response to provisional findings, 15 August 2015, paragraph 111.1.2.

¹⁹ Scottish Power response to provisional findings, 15 August 2015, paragraphs 1.11.

²⁰ SSE response to provisional findings, 15 August 2015, paragraphs 3.3.2 & 3.3.3.

suppliers (eg boiler maintenance) were also important in choosing a supplier.

- (f) SSE also said²¹ that the CMA ignored significant real-life evidence that products were not homogenous. In particular, consumer groups' energy supplier tables typically provided information across a broad range of competitive parameters, such as customer service, value for money, bills (accuracy and clarity), complaints handling, and helping to save money.

8.22 We do not agree with these comments for the reasons set out below.

8.23 First, we have observed that the gas and electricity that customers consume is a homogenous good. It is, indeed, unaffected by the choice of supplier. We also acknowledged that households are likely to place some value on factors other than price including the quality of customer service offered by suppliers (see the provisional findings, paragraphs 8.4 and 8.15 to 8.18).

8.24 Nevertheless, we said that we would expect price to be the product characteristic most important to a customer in choosing a supplier and/or tariff, and that the CMA customer survey found that price is the most important driver of choice of energy supplier. In particular, 81% of respondents identified cost/tariff/price/rate factors as important to them, followed by 50% of respondents identifying good quality service (see Appendix 9.1, Figure 23).

8.25 Further, paragraph 87 of GfK NOP's report of the CMA customer survey states that:

All households were asked what would be most important to them when choosing a supplier for mains gas or electricity, with responses captured spontaneously. Nearly three quarters (73%) of all households first response to this question was related to the cost or tariff. No other factor was mentioned to any great extent, the second most frequently given response being the quality and reliability of the service (14%). It is worth noting that the first top of mind response given by respondents is usually an indicator of what is the most important factor.

8.26 Second, it is correct that we also asked all respondents how important certain pre-selected factors are to their choice of energy supplier, and that 83% of respondents identified good customer service as essential or very important and 78% identified cheap tariff rate as essential or very important

²¹ SSE response to provisional findings, 15 August 2015, paragraph 3.3.4.

(see Appendix 9.1, Figure 24). However, for the purposes of assessing the importance of price to customers in choosing a supplier/tariff, we attach more weight to the results reported in paragraph 8.24. This is because this question was unprompted (in that customers were asked to state in their own words the factors they would take into account when choosing a supplier). Interviewers did not mention any possible factors.

- 8.27 Unprompted questions of this sort elicit from customers the factors that are most important in choosing between suppliers – ie those factors that most distinguish the offerings of the different suppliers. Respondents were asked ‘what would be the most important to you?’ and this was recorded as the first response. They were also allowed to mention more than one factor which allowed them to identify all aspects of their energy supply that mattered to them. Interviewers probed respondents ‘what else’. Respondents were therefore given the opportunity to mention as many factors as they wanted.
- 8.28 With the second question, respondents were asked to say how important each of a list of reasons for choosing a supplier were to them. Our judgement is that the unprompted question will generally be a more reliable way of identifying what is important to customers in choosing between suppliers. By contrast, we think that prompted questions are a useful means of identifying important requirements of suppliers’ offerings regardless of whether they are distinguishing features. So, for example, had we asked respondents how important continuity of supply was to them, we would have expected all, or nearly all, of them to have replied that it was essential. However, this did not figure in the responses to the unprompted question.
- 8.29 Third, we do not agree that responses to the unprompted question do not provide a basis for commenting on the relative importance of the factors mentioned. RWE submitted that respondents were not asked to rank the factors they mentioned. However, the question asked was ‘when choosing a supplier for mains gas or electricity people take all sorts of things into account. What would be most important to you?’ The fact that 73% of respondents identified price-related factors as their first response is, in our view, evidence of the relative importance of price in the market.
- 8.30 Overall, based on the results of the CMA survey, our judgement remains that price is the factor to which customers attach greatest weight in choosing a supplier and/or tariff, but not the only consideration. A minimum standard of customer service is also likely to be important. We also note that, in our gains from switching analysis, which focuses on price, we have also looked to take into account available evidence submitted to us on the quality of

service delivered by different suppliers, as proxied through their net promoter score.²²

Supply characteristics

8.31 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**.

8.32 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.

Wholesale purchases of gas and electricity

8.33 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

²² See Section 9.

below, the largest single cost item in the price of domestic electricity and gas.

- 8.34 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).
- 8.35 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. Overall, therefore, we would expect retailers to have 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.²³
- 8.36 The extent of pass-through of wholesale costs into retail prices has been an area of some controversy, with Ofgem, for example, suggesting in the reference decision 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.²⁴ 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 8.212 to 8.237 following) and consider the evidence on tacit coordination in Section 9.

Network access

- 8.37 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.²⁵

²³ We would expect this influence to increase with the full roll-out of smart meters and settlement reform 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 Sections 9 & 11.

²⁴ Ofgem (June 2014), [Decision to make a market investigation reference in respect of the supply and acquisition of energy in Great Britain](#).

²⁵ 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.

Sales and marketing

- 8.38 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 8.115 to 8.152 below.
- 8.39 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 8.160 to 8.164.
- 8.40 Retailers have a high degree of influence over sales and marketing costs.

Metering

- 8.41 Suppliers are responsible for installing and maintaining gas and electricity meters and for the roll-out of smart meters. Metering in Great Britain is a liberalised activity – in contrast to the situation in most EU member states where it is provided as a regulated activity by distribution network operators. Metering services are provided by three types of agents:
- (a) Meter asset providers (MAPs), who provide the capital for the meters and own them. We understand that suppliers typically have agreements with MAPs concerning the rental of the meter that is on their customer’s wall. Such costs are typically passed through to the consumer in the tariff price. All of the Six Large Energy Firms are MAPs, as are several of the Mid-tier Suppliers and some large independent companies.
 - (b) Meter asset managers (MAMs), who are accredited by Ofgem to provide metering services in gas – these services are installation, maintenance, certification. All of the Six Large Energy Firms are MAMs.
 - (c) Meter operators (MOps) provide metering services for the electricity market. All of the Six Large Energy Firms are also MOps.
- 8.42 When a supplier wins a new customer, they may not have a pre-existing agreement with the MAP whose meter that customer uses. If the new supplier has to negotiate a rental price for the meter, then the incumbent MAP could set a price that depends on the strength of its negotiating position – the new supplier can replace the meter with one of its own or alternatively come to a rental agreement with the incumbent MAP.

- 8.43 We consider that suppliers are likely to have a moderate degree of influence over the costs of metering, including the costs of meter installation and reading.²⁶
- 8.44 An important new development is the obligatory roll-out of smart meters to all domestic customers by 2020, which we consider in more detail in paragraphs 8.96 to 8.101 below and Section 11. We note that some suppliers have used the roll-out of smart meters as a point of competitive differentiation from their rivals.

Billing and customer service

- 8.45 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.
- 8.46 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

- 8.47 Retail suppliers also act on behalf of government in the delivery of environmental and social obligations and objectives, notably the RO, ECO, small-scale feed-in tariffs and the Warm Home Discount.
- 8.48 Appendix 8.1 discusses these obligations in more detail and paragraphs 8.85 to 8.94 sets out our assessment of the impact of the small supplier exemptions from some of these obligations. 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.²⁷

Value-added products and services and bundling

- 8.49 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

²⁶ As discussed in Appendix 9.8, suppliers report a relatively broad range of metering costs.

²⁷ We note that part of the rationale for ECO through suppliers was to create an incentive to bear down on the costs of delivery.

boiler and home maintenance services. Some suppliers are also engaged in the retail of other utility services (such as telecoms).

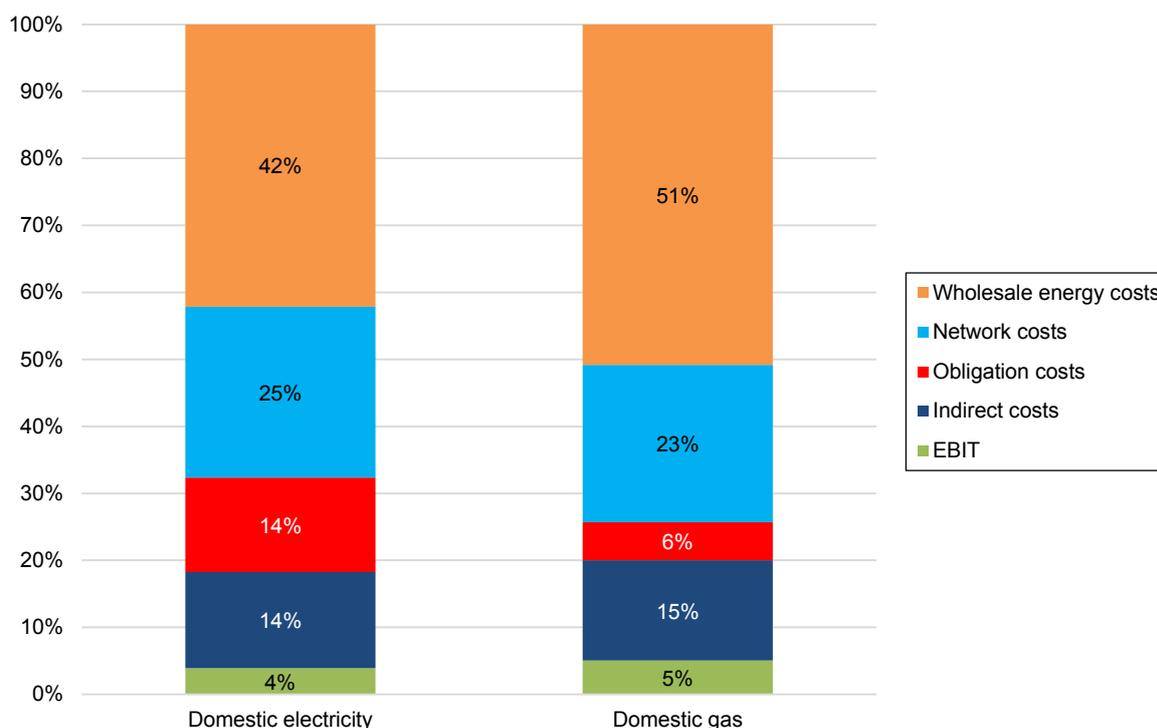
8.50 We consider that suppliers have a high degree of influence over such costs.

The cost structure of an energy supplier

8.51 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.

8.52 This is shown in Figure 8.2, which breaks down the average price of gas and electricity to domestic customers in 2014 into its constituent cost components (excluding VAT at 5%).

Figure 8.2: 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.

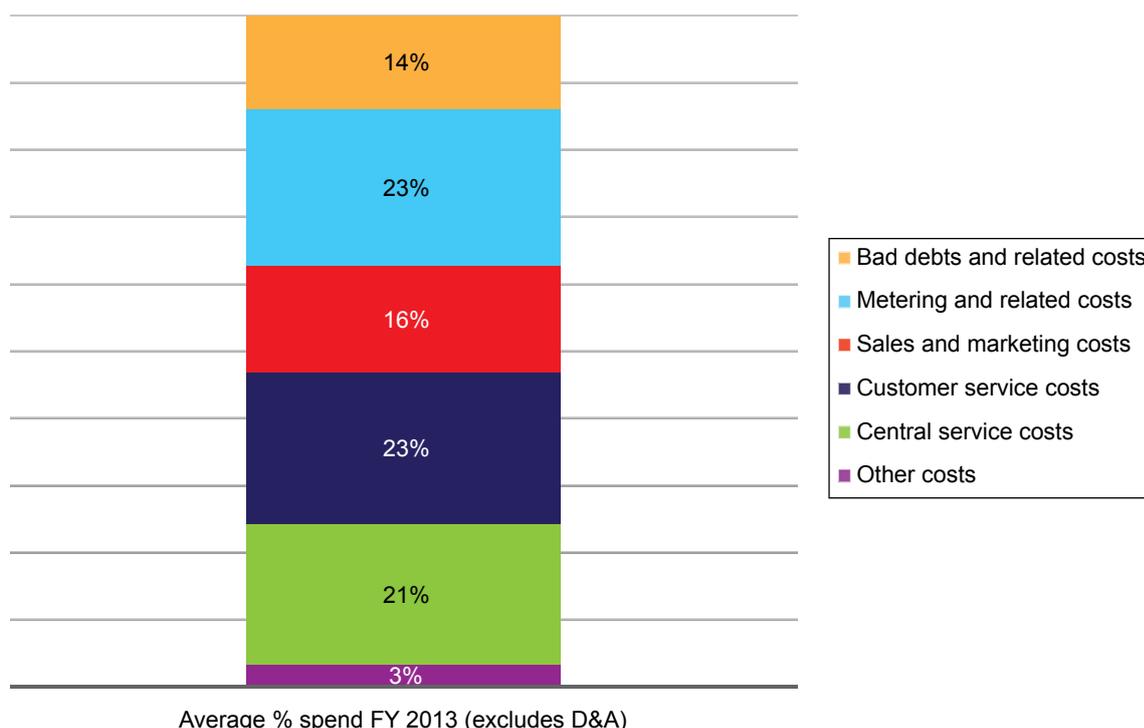
8.53 It can be seen that the single biggest cost item for both electricity and gas is the cost of wholesale energy, followed by network costs.

- 8.54 For electricity, obligation costs are a large (and growing) proportion of total costs.²⁸ 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.²⁹
- 8.55 Indirect costs and EBIT are the components of costs over which suppliers have greatest control. In 2014, the gross margin across the Six Large Energy Firms was 18% for domestic electricity and 19% for domestic gas.
- 8.56 The second figure, based on 2013 data, 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 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.

²⁸ 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.

²⁹ Source: DECC, [Price and Bill Impacts, 2014](#).

Figure 8.3: 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

- 8.57 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.
- 8.58 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 18% of the cost of electricity and 19% of the cost of gas.
- 8.59 We would also expect a (more limited) degree of competitive pressure on wholesale costs and obligation costs, which together comprise 56% of the costs of electricity and 57% of the costs of gas. After the smart meter roll-out we would expect suppliers to have a greater degree of influence over wholesale costs³⁰ and some limited influence over network costs.
- 8.60 We would expect competitive pressures to be such that customer service meets certain minimum required standards, notably accurate billing.

³⁰ Through encouraging load shifting through time-of-use tariffs.

8.61 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

8.62 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.³¹

8.63 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.

8.64 Over the last six years, three major interventions by Ofgem have changed the nature of retail competition significantly. We discuss these and other aspects of the regulatory regime that affect competition in retail energy markets in the following sections.

Prohibition on regional price discrimination

8.65 Following an investigation in 2008, Ofgem concluded that:³²

- (a) former incumbent electricity suppliers³³ were earning significantly higher margins in electricity than in gas, and on in-area domestic customers than out-of area;
- (b) proactive domestic customers were most likely to secure attractive deals, but suppliers' ability to differentiate their prices meant that these

³¹ This is described in more detail in Appendix 8.3: The pricing strategies of the large energy firms, Appendix 2.1: Legal and Regulatory framework and Appendix 11.1: Assessment of the impact of domestic retail remedies on detriment.

³² See Energy Supply Probe – Initial Findings, 2008, p52.

³³ Pre-liberalisation there were 14 regional retail electricity suppliers each with a monopoly in their respective region. We refer to these as the incumbent electricity supplier. We note for gas that British Gas was a monopoly supplier across Great Britain and is therefore the incumbent gas supplier.

customers did not act as a competitive constraint on prices in the rest of the retail market;

- (c) many inactive domestic customers were unlikely to ever switch;
- (d) electricity-only domestic customers 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 customers and improve the prospects of new entrants.

- 8.66 In response to these findings, in 2009 Ofgem implemented Standard Licence Condition (SLC) 25A, which prohibited regional price discrimination.³⁴ 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).³⁵
- 8.67 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 had the effect of restricting competition to the detriment of customers. We note also that some academic work has been conducted on this topic.³⁶ One independent supplier told us that the prohibition had reduced competition in incumbents' in-area regions and focused competition on the active customer, further segmenting the markets.
- 8.68 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

³⁴ It also introduced SLC 27.2A, which prohibited undue discrimination by payment methods.

³⁵ See Appendix 8.3: The pricing strategies of the large energy firms.

³⁶ 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.

wrote to suppliers to confirm that SLC 25A had lapsed and that suppliers were not bound by it in any way.

- 8.69 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 [redacted].

Doorstep selling

- 8.70 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. Between 2008 and 2010 Ofgem opened five investigations into the conduct of suppliers (covering four of the Six Large Energy Firms) that resulted in Ofgem imposing fines or financial penalties for breaches of the licence conditions governing face-to-face sales (including doorstep selling) and telephone sales.³⁷
- 8.71 In 2009 Ofgem³⁸ introduced a number of new licence requirements on suppliers designed to improve the quality and accessibility of the information available to domestic customers and small businesses 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

³⁷ Details of these investigations are provided in Appendix 8.3.

³⁸ Ofgem letter (19 October 2009): [Standards of conduct for suppliers in the retail market](#).

- (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.

8.72 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 channels³⁹. 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.⁴⁰ However, we note that there were real concerns that some switching decisions based on doorstep selling may have been of poor quality.⁴¹

Retail Market Review

8.73 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 market simpler, clearer and fairer to customers. These reforms are generally known as the Retail Market Review (RMR) reforms.

8.74 The three key components of the domestic RMR reforms package were:

- (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) fair treatment – to protect the interests of current and future customers in the retail energy markets and increase customers' trust in energy suppliers.

8.75 The 'simpler choices' component included a number of restrictions on suppliers, including restrictions on:

³⁹ See Appendix 9.3: Price comparison websites and collective switches.

⁴⁰ See Appendix 8.3: The pricing strategies of the large energy firms.

⁴¹ This is discussed in more detail in Appendix 11.1: Assessment of the impact of domestic retail remedies on detriment and Section 11.

- (a) the structure of tariffs: tariffs must have one structure – a unit rate (or unit rates for time-of-use tariffs) and standing charge, which can be zero;
 - (b) the number of tariffs offered to customers: suppliers must offer no more than four core tariffs per fuel type per metering arrangement in any region (the ‘four-tariff rule’);
 - (c) the offering of discounts: a prohibition against cash discounts, with exception for dual fuel (where a domestic customer takes gas and electricity from the same supplier) and for managing their account online and for dividend-type payments; and
 - (d) the offering of bundled products and reward point discounts.
- 8.76 The ‘clearer information’ component was designed to provide customers with relevant information, particularly in relation to their tariff and consumption. Ofgem introduced a number of requirements on suppliers which included: the provision of the tariff comparison rate (TCR), personal projections, the cheapest tariff messaging and a tariff information label (TIL). Ofgem also introduced new rules concerning routine communications with customers such as bills and annual statements.
- 8.77 The ‘fairer treatment’ component was designed to protect the interests of customers in the energy markets and increase customers’ trust in energy suppliers. Ofgem introduced the Standards of Conduct, which impose a number of requirements on suppliers to ensure that customers are treated fairly. Under the Standards of Conduct, suppliers must (among other things):
- (a) ensure that the information given to consumers is clear, easy to understand and written in jargon-free language;
 - (b) make it easy for consumers to contact them, act promptly and courteously to put things right; and
 - (c) publish statements each year clearly showing what actions they are taking to treat consumers fairly.
- 8.78 Suppliers can apply for a derogation from the RMR rules. Along with the RMR reforms, Ofgem implemented temporary arrangements for existing white labels. These arrangements exempted these white-labels from some of the RMR rules (in particular, the four-tariff rule and information rules) and expired at the end of December 2015. On 3 June 2015, Ofgem adopted a decision to implement, through the modification of SLC 31D, new arrangements for both existing and new white-label suppliers in the domestic retail energy markets.

- 8.79 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.
- 8.80 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.⁴² In addition to their evergreen tariffs, they can under the RMR rules 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 the RMR rules. Dual fuel customers may receive a dual fuel discount, which is not constrained to be cost-reflective.
 - (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.
- 8.81 We assess the impact of the RMR rules, particularly those relating to the simpler choices component, in Section 9.

PCW Confidence Code

- 8.82 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

⁴² SLC 22.

customers using accredited PCWs that the service they receive will meet these principles.

- 8.83 Ofgem's Confidence Code includes a requirement⁴³ on PCWs to use all reasonable endeavours to include price comparisons for all available domestic tariffs, where applicable for all available payment types, for licensed suppliers (including for any agents, affiliates, and brands operating under the licence of a supplier) (the 'Whole of the Market Requirement'). The Whole of the Market Requirement does not require PCWs to show:
- (a) social tariffs (ie tariffs where consumer eligibility is based upon social or financial circumstances, eg receipt of benefits);
 - (b) tariffs which the supplier has requested the Service Provider to remove from its Price Comparison Service; or
 - (c) tariffs which are available only to consumers in a specified region, to consumers that are not within that specified region.
- 8.84 Ofgem 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 fulfillable tariffs (a fulfillable tariff is one for which a PCW can facilitate the switch and is paid a commission for doing so). 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. Evidence on the impact of this amendment is considered in Section 13.

Small supplier exemptions

- 8.85 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.
- 8.86 The three main exemptions relate to:

⁴³ Requirement 2(A).

- (a) the ECO, a policy to improve domestic energy efficiency;
 - (b) feed-in tariffs, 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.
- 8.87 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.⁴⁴ The larger suppliers estimate the cost of the ECO obligation as around £50–£60 per dual fuel account. DECC estimated that the cost is lower, at £36 for a dual fuel customer.
- 8.88 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. 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 costs, a tapering effect is in place for suppliers passing through the threshold for the first time.
- 8.89 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 (see Appendix 8.1 for further details).
 - (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. [X] all mentioned delaying their expansion plans for a short time because of the threshold.
- 8.90 In relation to the argument that the exemption provides an unwarranted subsidy, we note that DECC's rationale for introducing the threshold was

⁴⁴ Appendix 8.1: Social and environmental obligations and policy cost, on which this section draws, assesses the regime for feed-in tariffs and the Warm Home Discount as well.

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,⁴⁵ 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 participants to grow. DECC introduced the threshold of 250,000 customer accounts based on evidence it received to the public consultation.

- 8.91 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 8.1) Further, any delays to expansion are not likely to have exceeded a few months at most.
- 8.92 In response to our provisional findings, Centrica said⁴⁶ that the CMA was wrong to conclude that the smaller supplier exception was not distorting competition and that the CMA's own analysis of the DECC impact assessment showed that the ECO resulted in a £36 cost advantage per customer for exempt suppliers. It added that, while it believed the DECC figures were too low, even if they were correct, the benefit conferred would far exceed the administration costs per account for ECO the CMA had estimated for small suppliers. Centrica said that the current exemption therefore overcompensated smaller suppliers.
- 8.93 E.ON said⁴⁷ that the current exemptions for small suppliers created a clear cost disparity between smaller and larger suppliers and allowed smaller suppliers to offer some of the lowest fixed-price contracts in the market. This distorted competition to the detriment of those customers choosing to be with a larger supplier who ended up picking up the ECO and Warm Home Discount costs for their more active fellow energy customers.
- 8.94 Overall, our view is that 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

⁴⁵ 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](#).

⁴⁶ Centrica response to provisional findings, paragraphs 105–107.

⁴⁷ E.ON response to provisional findings, paragraphs 7 & 8.

and experience in dealing with regulatory requirements, we do not believe that the impact of the current exemptions is likely to be market-distorting.

Competition in metering and smart meter roll-out

- 8.95 Metering is an essential part of well-functioning, competitive domestic retail energy markets. Because gas and electricity are consumed in real time, while billing and payment take place at periodic intervals, reliable and accurate meters play a vital role in determining exactly how much energy customers have consumed – and therefore how much they must pay suppliers.
- 8.96 Two aspects of the regulatory regime relating to metering have had, and are continuing to have, an important impact on retail market competition: the liberalised approach to metering installation and maintenance that has been adopted in Great Britain, which has given a central role to suppliers; and the obligation on suppliers to install smart meters for all their domestic customers by 2020.
- 8.97 From 2000 onwards, Ofgem gradually deregulated the metering market in both gas and electricity in order to ‘encourage innovation and competition within metering services’.⁴⁸ Price regulation of metering services was lifted in 2006 for electricity. There remains a regulated price for National Grid’s domestic gas metering assets, but others have the right to enter at unregulated prices. National Grid’s provision of non-domestic gas metering products and services are not subject to price controls although they are subject to various licence conditions. These were designed to counter adverse consequences of any market power that National Grid had as a result of its monopoly position when the market was opened to competition. Ofgem reviewed the performance of the deregulated metering market in 2010/11, and reported its Review of Metering Arrangements (ROMA) in December 2011.⁴⁹ Ofgem also undertook a review of the non-domestic gas metering market and published the report of this in March 2016.⁵⁰
- 8.98 Consistent with this liberalised framework for metering services, the obligation to roll out smart meters to domestic customers falls on domestic suppliers, each of which must ensure that all their domestic customers have a smart meter by the end of 2020.

⁴⁸ Ofgem, [ROMA final document](#), Appendix 2.

⁴⁹ The papers relating to Ofgem’s Review of Metering Arrangements can be found on Ofgem’s [website](#).

⁵⁰ Ofgem (March 2016), [Review of the non-domestic gas metering market in Great Britain - Final Report](#).

8.99 The timetable for the roll-out of smart meters is as follows:⁵¹

- (a) The Data Communications Company is due to go live on 17 August 2016. DECC considers that suppliers will be able to start installing SMETS 2 (fully interoperable) meters from this date.
- (b) SMETS 1 meters that are installed until 28 October 2017 (the ‘SMETS 1 end date’ – 12 months after the Data Communications Company provides the Release 1.3 functionality) will count towards suppliers’ smart meter roll-out targets; beyond this point they will not.⁵² As a result, it is unlikely that suppliers would install further SMETS 1 meters beyond this date. (Note that a customer with a SMETS1 meter may lose smart services when they switch supplier.)
- (c) We understand that suppliers will be able to ‘enrol’ some SMETS 1 meters into the Data Communications Company at some point in the future, but that this is unlikely to be possible before 2018.⁵³ Following this, customers with SMETS 1 meters that have been enrolled will no longer face the loss of smart functionality when switching supplier.
- (d) DECC estimates that the 2.4 GHz home area networks (already available) will enable suppliers to install smart meters in 70% of households. Where the home area network needs to extend over larger distances, either the 868MHz solution or an alternative home area network solution will be needed. The 868 MHz solution will be suitable for use in 96.5% of households, with the remaining households requiring ‘alternative home area network’ solutions.⁵⁴ DECC and industry stakeholders are working towards the availability of these solutions in late 2017 or early 2018.
- (e) DECC is proposing to require suppliers to fit smart meters for customers requiring a new or replacement meter: the New and Replacement Obligation. This is due to come into force in mid-2018.
- (f) The roll-out of smart meters to domestic customers⁵⁵ is due to be substantially completed by the end of 2020.

⁵¹ Appendix 8.4 gives further details of the roll-out programme and timescales.

⁵² DECC (2015), *Smart Metering Implementation Programme: Government response to the Smart Metering Rollout Strategy consultation*.

⁵³ The enrolment of SMETS 1 meters is subject to a feasibility study.

⁵⁴ DECC (2015), *Government Response on Home Area Network Solutions: Implementation of 868MHz*.

⁵⁵ Suppliers are under an obligation to take all reasonable steps to ensure that a smart metering system is installed on or before 31 December 2020 at each domestic premise and most microbusiness (profiles 3 and 4) it supplies.

8.100 As explained later in this section and in Sections 9 and 11, fully interoperable smart meters have the potential to bring significant benefits for domestic retail market competition, both in terms of alleviating supply-side constraints faced by prepayment customers and, potentially, through overcoming barriers to engagement for domestic customers more generally. We therefore believe it is vitally important that the prescribed timetable for their roll-out is adhered to and discuss the risks associated with this, and potential mitigating measures, in Section 11.

Customer activity and engagement

8.101 As of 31 January 2016, there were 28 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 – 20 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 million single fuel gas customers.

8.102 Before liberalisation, each customer would have been a single fuel customer of the monopoly gas and electricity supplier.⁵⁶ 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.

8.103 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.

⁵⁶ 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

- 8.104 Our customer survey provides material evidence of domestic customers' lack of understanding of, and engagement in, retail energy markets.⁵⁷ 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.⁵⁸
- 8.105 We regard this as evidence of a material degree of disengagement and in Section 9 we assess to what extent this can be explained by a range of barriers to engagement.

Parties' views

- 8.106 Several of the Six Large Energy Firms said the statement that '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' was incorrect or misleading.⁵⁹ For example, Scottish Power said that the wording 'one (or more)' is incorrect and that the survey showed that 36% of respondents did not know it was possible to change all three of these.⁶⁰ E.ON said that the data in the customer survey showed that it is actually at most 11% who do not think it is possible. E.ON also that many of those customers who were not aware of the ability to change all three (tariff, payment method and supplier) would be prepayment customers, where there was currently restricted choice.
- 8.107 We do not agree. The question asked in the CMA survey was 'which if any of the following do you think it is now possible for energy customers in general to do, subject to any exit fees that may be charged: change tariff

⁵⁷ Appendix 9.1: CMA domestic customer survey results provides a detailed description of the results of the survey.

⁵⁸ Appendix 9.1: CMA domestic customer survey results.

⁵⁹ E.ON response to provisional findings, paragraph 72; RWE response to provisional findings, paragraph 188; and Scottish Power response to provisional findings, paragraph 3.6

⁶⁰ Scottish Power response to the provisional findings, paragraph 3.6.

with their current supplier; change payment method; or switch to a different supplier'. The available codes for responses were 'possible'; 'not possible' and 'don't know'.

8.108 We found that 89% of respondents were aware that it is possible to switch supplier, 81% that it is possible to change payment method, 76% that it is possible to change tariff and 64% that it is possible to do all three.⁶¹ It follows that if 64% of respondents thought that it is possible to do all three, then the remaining 36% thought it was not possible to switch one, two or all three of these or did not know whether it was possible to do one, two or three of these. We also note that although the proportion of respondents falling into this latter category is significantly higher for prepayment customers (48%), the proportions for standard credit (37%) and direct debit (34%) respondents are not significantly different from the proportion of respondents that fall into the latter category overall (36%).⁶²

8.109 Scottish Power said that the following statements were also misleading:

- (a) '34% of respondents have never considered switching supplier.' Scottish Power said that if 11% of all respondents were unaware they could switch supplier, then 23% of the 34% cited above must be aware of their options, which could be consistent with these customers being engaged and satisfied with their provider.⁶³
- (b) '56% of respondents said they have never switched supplier, did not know it was possible or did not know if they had done so.' Scottish Power said that the CMA had confused actual switching behaviour with awareness of switching. There were many reasons why individuals might decide not to switch provider even when well aware of the possibility of switching. The focus in this disengagement measure should be on awareness, separate from an analysis of why individuals who were aware of the possibility and consider switching then chose not to do so.⁶⁴

⁶¹ 'Don't know' responses are included in the denominators for these percentages. This means, for example, that 11% of respondents thought that they could not switch supplier or did not know whether they could switch supplier.

⁶² Respondents are categorised based on their payment method. In particular, respondents are only included if they have the same payment method for all fuel types (that is, including those with only one fuel type). Bases differ for customer group and include those who responded 'Don't know'. Prepayment customer base = 646, direct debit customer base = 5,121 and standard credit customer base = 973 and overall customer base = 6,999. Based on question E01.

⁶³ Scottish Power response to the provisional findings, p9, Section 3.9.

⁶⁴ Scottish Power response to the provisional findings, p10, Section 3.11.

- (c) '72% of respondents 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.' Scottish Power said that this measure of disengagement focused on one aspect of switching which was not clearly correlated with engagement. Many customers that had never switched tariff might have recently switched supplier or considered switching tariff but had decided not to.⁶⁵

8.110 We do not agree with Scottish Power on these points as follows:

- (a) With regard to paragraph 8.109(a), Scottish Power appears to be asserting that customers who are aware that they could switch supplier but have not considered doing so could be engaged. We do not accept this. When we describe a customer as engaged we consider this to include those who are well-informed and act on the information available to them. It is implausible that customers who have never considered switching supplier will have shopped around which means that their reasons for not considering switching are unlikely to be well-informed.
- (b) With regard to paragraph 8.109(b), we consider that respondents' awareness of the options available to them and their behaviour are both of interest in assessing their level of engagement. We consider that it is uncontroversial that 'not knowing that it was possible to switch' or 'not knowing if they had switched' are indicators of a high level of disengagement. We recognise that, in the case of respondents who had never switched supplier, for some this could have been an informed choice (we found that 49% of those who had shopped around in the last three years had not switched in the last three years). Nevertheless, it is a measure of how active they have been in the market.
- (c) With regard to paragraph 8.109(c), we consider that whether a respondent had ever made an active decision to switch tariff with their existing supplier is another measure of how active they had been in the market. This is because switching tariffs with an existing supplier is very straightforward and non-prepayment customers on SVTs could have made substantial savings by switching to cheaper tariffs offered by their existing supplier.⁶⁶ As these cheaper tariffs have typically been short-term tariffs, respondents who had taken advantage of them would have made a decision to switch tariff at some time in the recent past. All this suggests to us that whether a respondent had ever switched tariff, was

⁶⁵ Scottish Power response to the provisional findings, p10, Section 3.12.

⁶⁶ We found that, over the period Q1 2012 to Q2 2015, on average, non-prepayment dual fuel SVT customers of the Six Large Energy Firms could have saved £67 on their annual bill by switching to short-term fixed-term tariffs with their existing supplier. See Appendix 9.2, Table 42.

aware that this is possible, or not aware if they had switched tariff is an indicator of their level of engagement.

- 8.111 For these reasons, we consider that the measures of engagement identified by Scottish Power are informative on the level of customer engagement in the energy market.
- 8.112 Several of the Six Large Energy Firms said that the CMA had been selective in the results reported and that the customer survey did not show that customers were disengaged.
- 8.113 E.ON,⁶⁷ RWE,⁶⁸ Scottish Power,⁶⁹ and SSE⁷⁰ said that the results indicated a high level of customer awareness. They are correct that 89% of respondents were aware that they can switch supplier. However, we note that 36% of respondents did not think it was possible or did not know if it was possible to change one or some of tariff, supplier or payment method. We consider this to be a large proportion of the customer base who is demonstrating no awareness of the ability to switch tariff or payment method or supplier.
- 8.114 Overall we consider that it remains the case that a substantial proportion of the respondents were, by various measures, disengaged (see paragraph 8.104).

Tariff type

- 8.115 The SVT⁷¹ 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’. 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 mid-2015, average revenue per kWh from the SVT was around 11% and 15% 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

⁶⁷ E.ON response to provisional findings, paragraph 72.

⁶⁸ RWE response to provisional findings, paragraph 11.

⁶⁹ Scottish Power response to provisional findings, p8, Section 3.8.

⁷⁰ SSE response to provisional findings, p4, Section 2.1.1.

⁷¹ Information presented below on SVTs includes dual and single fuel customers unless otherwise stated.

per kWh than non-standard tariffs over this period for each of the Six Large Energy Firms, for both gas and electricity.⁷²

8.116 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 2015.⁷³ 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 8.4: 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' responses to CMA Supply Questionnaire.

Note: [✂].

8.117 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: [✂].

8.118 Further, for both gas and electricity, the majority of all domestic customers are on one of the Six Large Energy Firms' SVTs. In particular, in 2015 63% of domestic electricity customers and 61% of domestic gas customers were on one of the Six Large Energy Firm's SVTs. In comparison, in 2011, the equivalent figures were 73% for electricity and 71% for gas.⁷⁴

8.119 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 8.5, this relationship holds for all of the historical electricity incumbent suppliers.

Figure 8.5: Share of SVT customers by incumbent/entrant region

[✂]

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

8.120 We note that it is 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.

⁷² 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 one year for its electricity SVT tariffs.

⁷³ This is based on customer number data submitted by the Six Large Energy Firms, in contrast to the data presented in Tables 8.2 and 8.3 below, which is based on CMA analysis of tariff data submitted by the Six Large Energy Firms for Q2 2015.

⁷⁴ Data from the Six Large Energy Firms is used to calculate the total number of customers on one of the Six Large Energy Firms' SVTs and data from Cornwall Energy on the total number of accounts.

Table 8.1: Average length of time on the SVT with existing supplier for the Six Large Energy Firms

Time on SVT with current supplier (in years)	%	
	Gas	Electricity
< 1	22.1	18.4
1 to 3	24.2	26.4
4 to 5	15.0	14.6
6 to 10	20.6	19.4
10+	18.1	21.0

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

Notes:

1. Tenure data is based on 'individual within a meterpoint'.

2. We note that for three suppliers the data provided was based on the length of the relationship with the supplier rather than the length of time on that supplier's SVT.

3. <1 relates to customers who have been with their current supplier for up to 12 months or 365 days (inclusive).

4. 1 - 3 relates to customers who have been with their current supplier for 12 months or 366 days to 36 months or 1095 days (inclusive).

5. 4 - 5 relates to customers who have been with their current supplier for up to 37 months or 1096 days to 60 months or 1825 days (inclusive).

6. 6 - 10 relates to customers who have been with their current supplier for up to 61 months or 1826 days to 120 months or 3650 days (inclusive).

7. >10 relates to customers who have been with their current supplier for 121 months or more or more than 3650 days (inclusive).

8.121 The table shows that at least 22% and 18% of the gas and electricity SVT customers of the Six Large Energy Firms have been on the SVT with the same supplier for less than one year.⁷⁵ 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.⁷⁶ Up to 55% have been on the SVT with the same supplier for more than three years and up to 40% have been on the SVT with the same supplier for more than five years.⁷⁷

8.122 RWE said⁷⁸ that the SVT should not be regarded as a default tariff as it was incorrect to assume that all SVT customers had defaulted onto the SVT and had not made an active choice of tariff. RWE noted that 25% of SVT customers (excluding prepayment customers) had been on the SVT with the same supplier for a year or less and that this figure rose to 37–39% when considering customers who had been on the SVT with the same supplier for two years or less.

8.123 We do not accept this proposition. In particular, we note that SLC 22C.7 mandates that a domestic customer on a fixed-term contract will be automatically moved to their existing supplier's cheapest evergreen tariff

⁷⁵ We note that this is a lower bound estimate as for three suppliers the data provided was based on the length of the relationship with the supplier rather than the length of time on that supplier's SVT.

⁷⁶ Paragraphs 8.160 to 8.164 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).

⁷⁷ We note that this is an upper bound estimate as for three suppliers the data provided was based on the length of the relationship with the supplier rather than the length of time on that supplier's SVT.

⁷⁸ RWE response to provisional findings, paragraph 169.

when the term of the contract expires unless they change supplier or expressly agree to move to another contract. In practice, the Six Large Energy Firms have recently had only one evergreen tariff (which they generally referred to as their Standard Variable Tariff) and so *de facto* this is the default (evergreen) tariff within the meaning of the SLC 22C.7. More generally a domestic customer who does not make an active choice of supplier/tariff will end up on an SVT.

8.124 The SVT plays an important role in the pricing strategy of the Six Large Energy Firms, as discussed in greater detail in paragraphs 8.168 to 8.185 below.

Payment type

8.125 Three types of payment regime exist for energy customers:

(a) standard credit;

(b) direct debit; and

(c) prepayment.

8.126 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.⁷⁹ We understand that the average standard credit premiums for a dual fuel SVT customer are currently £75–£80 per year, compared with our estimate of the additional cost of serving standard credit customers of £100.^{80,81} In addition, payment by direct debit offers convenience benefits over standard credit.

8.127 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

⁷⁹ 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.

⁸⁰ Source Ofgem based on dual fuel, typical consumption customer (applying the current definition).

⁸¹ 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.

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. This is discussed further in Sections 9 and 11.

- 8.128 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.^{82,83} We note that this is higher than our estimate of the additional cost of serving prepayment customers of £63.⁸⁴ 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 SVTs.⁸⁵ The specific constraints on prepayment customers are an important characteristic of the domestic markets that we consider in greater detail later in this section and in Section 9.
- 8.129 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 58% of customers choosing to pay by this method in 2015 and only 26% of customers paying by standard credit. The proportion of gas customers on prepayment meters doubled over the period, from 7% in 1996 to 15% in 2015.

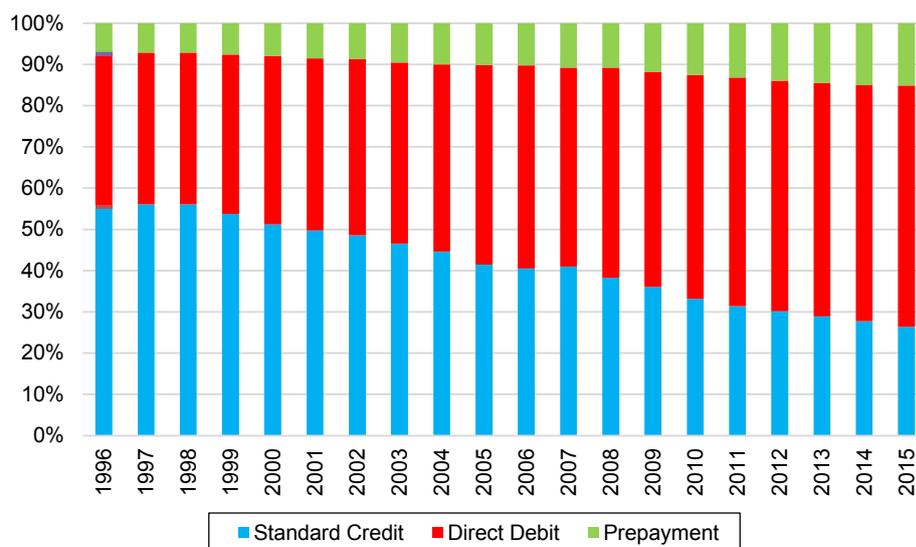
⁸² Source Ofgem based on dual fuel, typical consumption customer (applying the current definition)

⁸³ 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.

⁸⁴ See Appendix 9.8: Analysis of indirect costs by payment method.

⁸⁵ 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. See Section 9.

Figure 8.6: Change in percentage of gas customers in Great Britain using different payment methods, 1996 to 2015



Source: DECC Quarterly Energy Prices, March 2016.

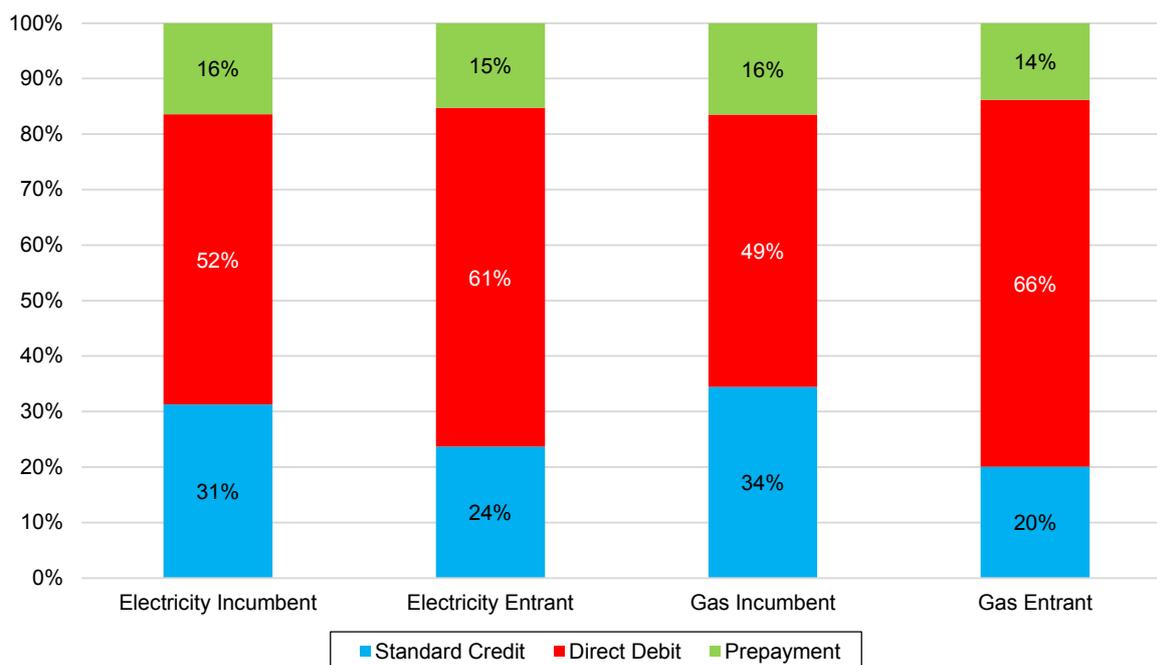
8.130 A very similar set of trends and final outcomes are observed in electricity. In December 2015, 27% of domestic electricity customers in Great Britain were on standard credit, 57% of customers on direct debit and 17% on prepayment.⁸⁶

8.131 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.

8.132 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 8.7 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 standard credit may have a greater propensity to be inactive than those who pay by direct debit.

⁸⁶ Source: DECC, Quarterly Energy Prices, March 2016.

Figure 8.7: Payment methods of domestic customers of gas and electricity incumbents and entrants, 2015



Source: CMA analysis of DECC Quarterly Energy Prices, March 2016.

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.

8.133 Further, we note from our survey that:

- (a) 7% of those on standard credit have switched in the last year (compared with 15% of those on direct debit);
- (b) 15% of those on standard credit have switched in the last three years (compared with 30% of those on direct debit);
- (c) 46% of those on standard credit are either not aware it is possible to switch or have never considered switching (compared with 26% of those on direct debit); and
- (d) 52% of those on standard credit are unlikely to consider switching in the next three years (compared with 36% of those on direct debit).

8.134 RWE said⁸⁷ that the CMA had not sought to investigate whether customers chose to pay by standard credit, despite noting that ‘the flexibility of timing of payment available to those who pay by standard credit may be of real

⁸⁷ RWE response to provisional findings, 15 August 2015, paragraphs 175–179.

benefit to the cash-constrained' and that the CMA was relying on other indicators of inactivity to evidence that paying by standard credit was a sign of inactivity, and then seemed to treat all customers who paid by standard credit as inactive.

8.135 However, we do not agree, as RWE suggests, that we have interpreted the evidence as supporting that all customers who pay by standard credit should be regarded as inactive. Rather, the results of the customer survey indicate that those who pay by standard credit are, as a group, relatively inactive (compared with those on direct debit). We consider this to be evidence that paying by standard credit may, for many, not be an active choice.

8.136 This issue is considered in greater detail in Section 9.

Choice of supplier

8.137 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

8.138 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 already supplied under a dual fuel tariff.

8.139 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 3% of the bill.⁸⁸

8.140 Unlike discounts for payment methods, the level of dual fuel discounts is not constrained by Ofgem, although the RMR rules requires dual fuel discounts to be available to all customers who purchase both fuels from the same

⁸⁸ See Appendix 8.3: The pricing strategies of the Six Large Energy Firms.

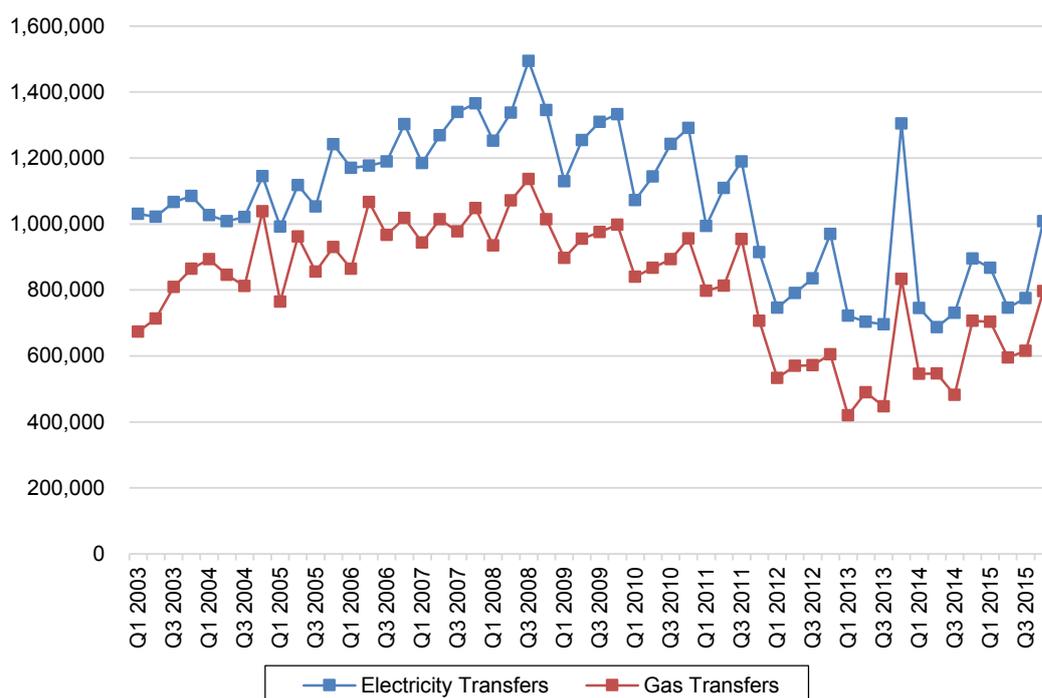
supplier regardless of payment type and whether these are invoiced together.

8.141 As at end January 2016, around 86% of gas customers and 71% of electricity customers were supplied under a dual fuel tariff.⁸⁹

Switching rates

8.142 Figure 8.8 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 surrounding energy prices. In 2015 there were around 3.4 million electricity transfers and 2.7 million gas transfers. This represents 12% of all electricity meters and 12% of all gas meters in 2015.

Figure 8.8: Quarterly domestic electricity and gas transfers in Great Britain



Source: DECC, Quarterly Energy Prices, March 2016.

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.

⁸⁹ Source: CMA analysis of Cornwall Energy data.

Length of tenure with current supplier

8.143 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 8.9 below.

8.144 Between about 21 and 29% 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 12% for [redacted] and 38% for [redacted].

Figure 8.9: Length of domestic customer relationship with the Six Large Energy Firms (as at June 2015)

[redacted]

8.145 Figure 8.9b provides the same information for SVT customers only. This shows that the proportion of SVT customers who have been with their current supplier for more than ten years is a little higher than the average.

Figure 8.9b: Length of domestic customer relationship with the Six Large Energy Firms, SVT customers only, as at June 2015

[redacted]

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

Notes:

1. Tenure data is based on 'individual within a meterpoint'.
2. <1 relates to customers who have been with their current supplier for up to 12 months or 365 days (inclusive).
3. 1 - 3 relates to customers who have been with their current supplier for 12 months or 366 days to 36 months or 1095 days (inclusive).
4. 4 - 5 relates to customers who have been with their current supplier for up to 37 months or 1096 days to 60 months or 1825 days (inclusive).
5. 6 - 10 relates to customers who have been with their current supplier for up to 61 months or 1826 days to 120 months or 3650 days (inclusive).
6. >10 relates to customers who have been with their current supplier for 121 months or more or more than 3650 days (inclusive).

8.146 It is interesting to note also that 20% of [redacted] electricity customers have been with them for over ten years. This would imply that [redacted] acquired substantial numbers of customers in the initial years after liberalisation, since when they have not switched supplier.

Customer characteristics and current levels of engagement

8.147 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.

8.148 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 8.2: GB domestic gas customers of the Six Large Energy Firms by tariff, fuel and payment type, Q2 2015

<i>Tariff type</i>	<i>Single or dual fuel</i>	<i>Payment type</i>	<i>Percentage of total domestic GB gas customers</i>	
Standard variable			71	
	Dual		55	
		Direct debit		30
		Standard credit		14
		Prepayment		11
		Other		0
	Single		16	
		Direct debit		5
		Standard credit		7
		Prepayment		4
		Other		0
Non-standard			29	
	Dual		27	
		Direct debit		23
		Standard credit		3
		Prepayment		1
		Other		0
	Single		2	
		Direct debit		1
		Standard credit		1
		Prepayment		0
		Other		0
Total			100	100

Source: CMA analysis of Six Large Energy Firm tariff data.

Base: customer accounts included in the analysis of potential gains from switching and (i) collective switching, (ii) accounts with less than three months remaining in the contract and (iii) time-of-use, social, green, DTS, bundle and winback tariffs.

Note: Numbers in columns may not add up to 100% due to rounding.

Table 8.3: GB domestic electricity customers of the Six Large Energy Firms by tariff, fuel and payment type, Q2 2015

Tariff type	Single or dual fuel	Payment type	Percentage of total domestic GB electricity customers		
Standard variable			72		
	Dual		47		
		Direct debit		25	
		Standard credit		11	
		Prepayment		10	
		Other		0	
	Single		26		
		Direct debit		10	
		Standard credit		10	
		Prepayment		6	
		Other		0	
Non-standard			28		
	Dual		22		
		Direct debit		19	
		Standard credit		2	
		Prepayment		1	
		Other		0	
	Single		5		
		Direct debit		4	
		Standard credit		1	
		Prepayment		0	
		Other		0	
Total			100	100	100

Source: CMA analysis of Six Large Energy Firm tariff data.

Base: customer accounts included in the analysis of potential gains from switching and (i) collective switching, (ii) accounts with less than three months remaining in the contract and (iii) time-of-use, social, green, DTS, bundle and winback tariffs.

Note: Numbers in columns may not add up to 100% due to rounding.

8.149 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.⁹⁰

8.150 While there are relatively few customers who pay a single fuel SVT by standard credit (10% of electricity customers and 7% 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.

8.151 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

⁹⁰ 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.

possible. We analyse the survey results in greater detail in Section 9, 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 potential barriers to engagement and switching, drawing on survey and other evidence.

- 8.152 In Section 9 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.

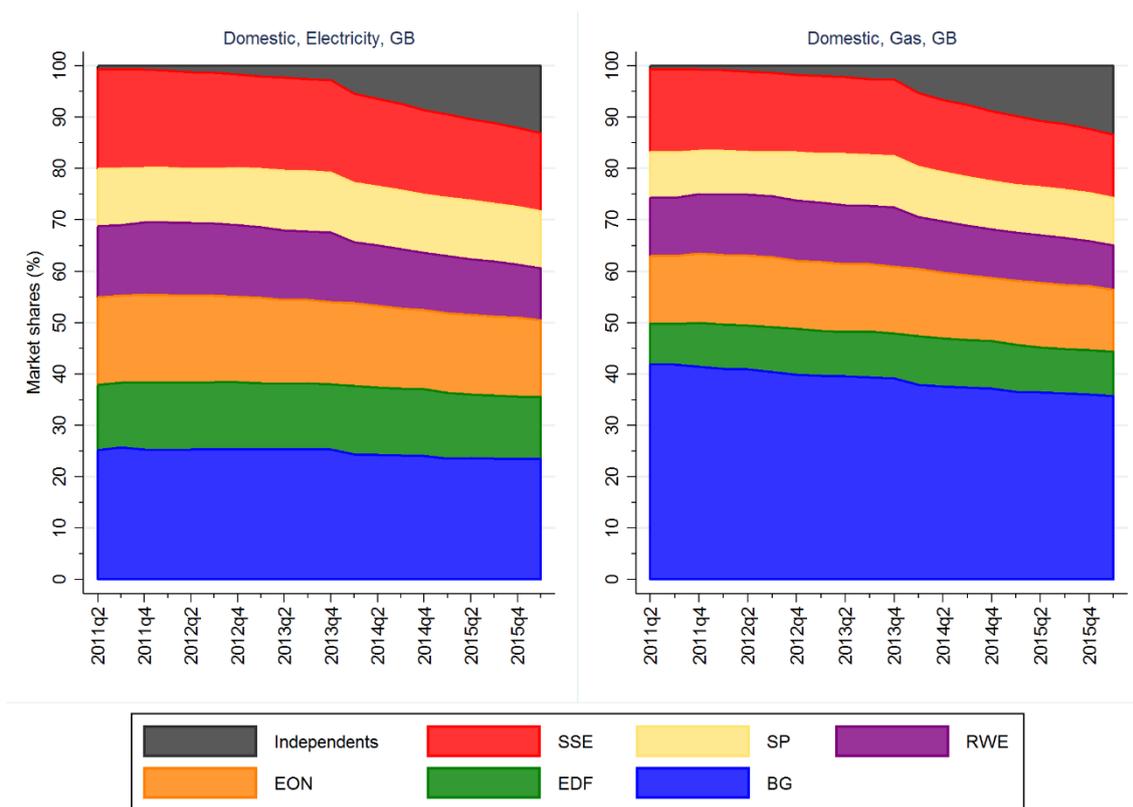
Market shares and acquisition channels

- 8.153 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

- 8.154 Figure 8.10 shows the evolution in the market shares of energy suppliers over the past five 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 13% in gas and electricity in the first quarter of 2016.

Figure 8.10: Quarterly market shares of domestic electricity and gas customers



Source: Cornwall Energy data submitted to the CMA.

8.155 This expansion has led to falling levels of concentration in retail supply, with the HHI⁹¹ in gas falling from around 2,450 at the beginning of the period to around 1,900 in 2015 and the HHI in electricity falling from around 1,800 to its current level of around 1,450.

8.156 The position as of Q1 2016 is shown in Table 8.4. 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.

⁹¹ 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.

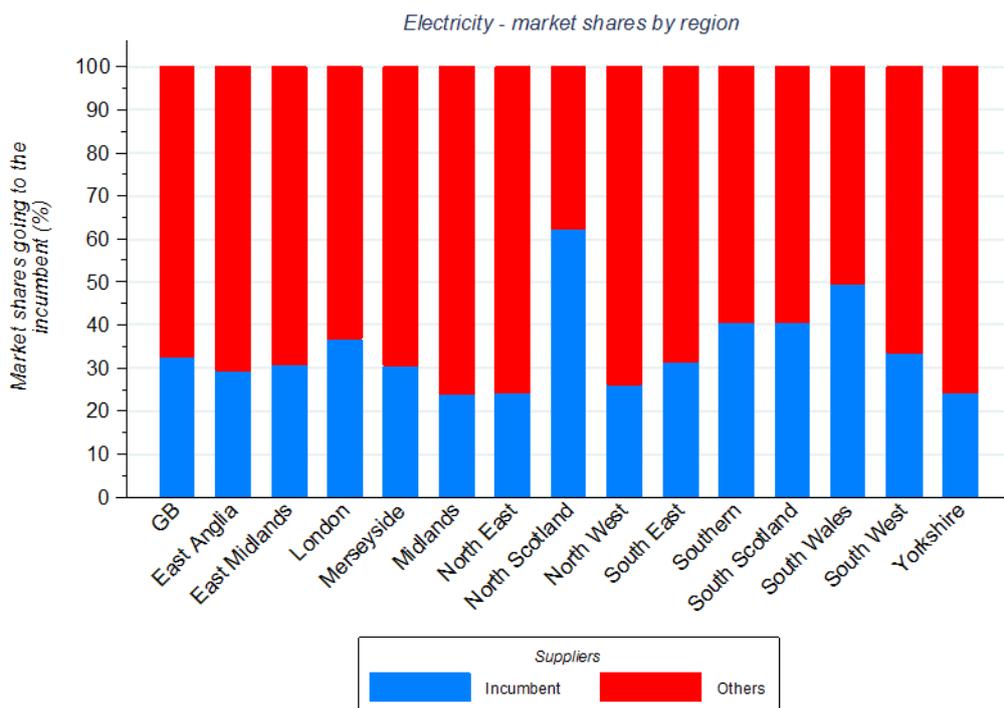
Table 8.4: Supplier market shares for Q1 2016 (% of GB total) – meter points

Supplier	%	
	Electricity	Gas
British Gas	23.4	35.8
EDF Energy	12.1	8.6
E.ON	15.0	12.1
RWE	10.1	8.6
Scottish Power	11.1	9.3
SSE	15.2	12.3
Independents	13.1	13.4
<i>of which:</i>		
Co-op Energy	0.83	0.90
First Utility	3.23	3.57
Ovo Energy	2.16	2.17
Utility Warehouse	1.92	1.88
Extra Energy	1.12	1.31
Utilita	1.07	1.18
Other suppliers	2.76	2.36

Source: Cornwall Energy data submitted to the CMA.

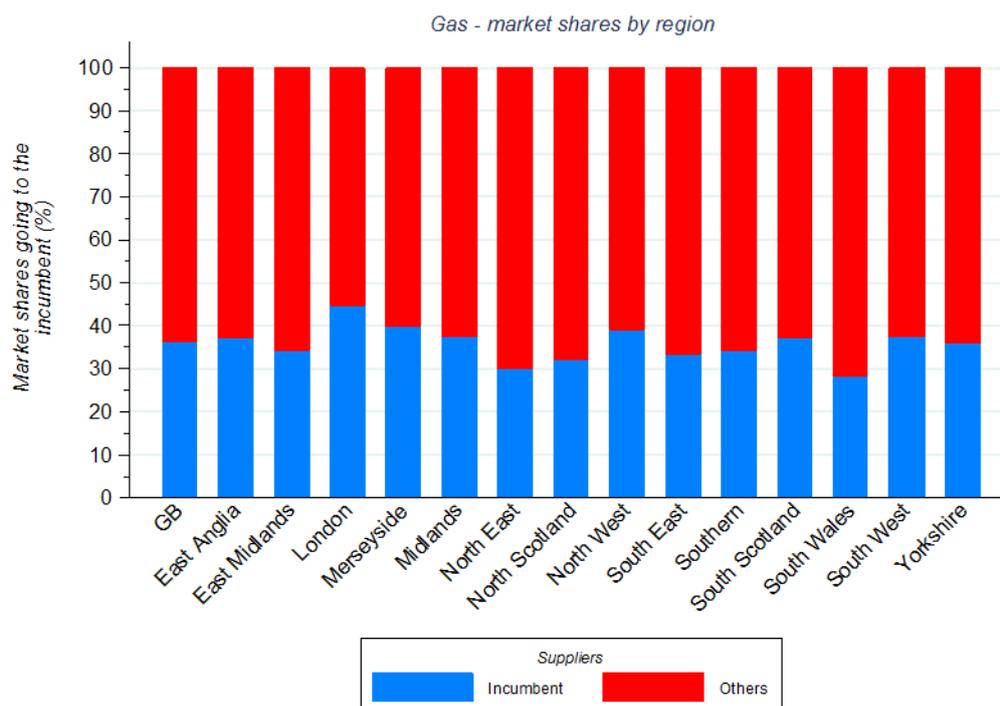
8.157 The figures below show the market shares of the electricity and gas incumbents in each of the GB regions.

Figure 8.11: Market share of electricity incumbents in 2015



Source: CMA analysis of Cornwall Energy data.

Figure 8.12: Market share of gas incumbent in 2015



Source: CMA analysis of Cornwall Energy data.

8.158 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 50% or more. 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.

8.159 We explore the evidence on differences in competitive pressures between the devolved nations and between regions in paragraphs 8.320 to 8.329. We have drawn on this analysis in setting out our views on market definition in Section 3.

Acquisition channels

8.160 Energy suppliers use a variety of sales channels to acquire domestic customers. Tables 8.5 and 8.6 show for each of the Six Large Energy Firms a breakdown of domestic customer acquisitions by channel for the period January 2014 to June 2015.

Table 8.5: Percentage of electricity acquisitions by acquisition channel, domestic, 2014/15

	%					
<i>Channel</i>	<i>British Gas</i>	<i>EDF Energy*</i>	<i>E.ON</i>	<i>RWE</i>	<i>Scottish Power</i>	<i>SSE</i>
Face to face	[X]	[X]	[X]	[X]	[X]	[X]
Telesales	[X]	[X]	[X]	[X]	[X]	[X]
Own website	[X]	[X]	[X]	[X]	[X]	[X]
Home movers	[X]	[X]	[X]	[X]	[X]	[X]
PCWs**	[X]	[X]	[X]	[X]	[X]	[X]
Cashback website (CBWs)	[X]	[X]	[X]	[X]	[X]	[X]
Collective switches	[X]	[X]	[X]	[X]	[X]	[X]
White-labels and partnerships	[X]	[X]	[X]	[X]	[X]	[X]
Win back/recovery	[X]	[X]	[X]	[X]	[X]	[X]
Other (including relationships with property industry)	[X]	[X]	[X]	[X]	[X]	[X]
Total number of acquisitions	[X]	[X]	[X]	[X]	[X]	[X]

Source: CMA analysis.

*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.

** Excluding white label and partnership tariffs.

Notes: [X]

Table 8.6: Percentage of gas acquisitions by acquisition channel, domestic, 2014/15

	%					
<i>Channel</i>	<i>British Gas</i>	<i>EDF Energy*</i>	<i>E.ON</i>	<i>RWE</i>	<i>Scottish Power</i>	<i>SSE</i>
Face to face	[X]	[X]	[X]	[X]	[X]	[X]
Telesales	[X]	[X]	[X]	[X]	[X]	[X]
Own website	[X]	[X]	[X]	[X]	[X]	[X]
Home movers	[X]	[X]	[X]	[X]	[X]	[X]
PCWs**	[X]	[X]	[X]	[X]	[X]	[X]
Cashback website (CBWs)	[X]	[X]	[X]	[X]	[X]	[X]
Collective switches	[X]	[X]	[X]	[X]	[X]	[X]
White-labels and partnerships	[X]	[X]	[X]	[X]	[X]	[X]
Win back/recovery	[X]	[X]	[X]	[X]	[X]	[X]
Other (including relationships with property industry)	[X]	[X]	[X]	[X]	[X]	[X]
Total number of acquisitions	[X]	[X]	[X]	[X]	[X]	[X]

Source: CMA analysis. See notes to Table 8.5.

** Excluding white label and partnership tariffs.

8.161 There are substantial differences between the acquisition channels of the Six Large Energy Firms. For example, for two of the Six Large Energy Firms (Centrica and SSE) their relationships with the property industry and white-label partnerships were important acquisition channels while PCWs accounted for [a small proportion] of acquisitions.⁹² In contrast, the remaining (four) Six Large Energy Firms (EDF, RWE, E.ON and Scottish Power) all used PCWs, and in some cases telesales channels, extensively

⁹² [X]

and did not use white-label partnerships or relationships with the property industry to the same extent.⁹³

- 8.162 An important new development is the expansion in the use of PCWs as a means of acquiring domestic customers over the past five years. Figures 8.13 and 8.14 show, for each of the Six Large Energy Firms and the Mid-tier Suppliers, the proportion of their total domestic customer acquisitions that was made via a PCW in each of the last six years.

Figure 8.13: Percentage of total domestic customer acquisitions made via PCWs (including PCW websites and call centres) for electricity, by supplier

[✂]

Source: CMA analysis.

Note: SSE data relates to financial years not calendar years (eg 2009 relates to 2009/10, etc). 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'.

Figure 8.14: Percentage of total domestic customer acquisitions made via PCWs (including PCW websites and call centres) for gas, by supplier

[✂]

Source: CMA analysis.

See note to Figure 8.13.

- 8.163 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.⁹⁴ In 2015, the proportion of total acquisitions to the Six Large Energy Firms facilitated by a PCW ranged from [close to zero to around 70% of gas and electricity acquisitions].
- 8.164 Of the ten major PCWs for which we received switching data, two PCWs – uSwitch and MoneySuperMarket⁹⁵ – 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.⁹⁶

⁹³ We note that E.ON acquisitions in its home-moves channel include acquisitions from its relationships with letting agents.

⁹⁴ 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 [✂].

⁹⁵ 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.

⁹⁶ 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.

- 8.165 As discussed above (see paragraph 8.83), Ofgem amended the PCW Confidence Code 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. PCWs were concerned about the impact of 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).
- 8.166 We consider the impact that Ofgem's RMR reforms, in Section 9, and reforms to the PCW Code, in Appendix 9.3 and Section 13, are likely to have on the ability of PCWs and other TPIs to compete effectively and improve customer engagement in domestic retail energy markets.

Nature and extent of price competition

- 8.167 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 SVT⁹⁷

- 8.168 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 paid the SVT in 2015, despite the fact that, over the last four and a half years average revenues from the SVT have been 11% higher for electricity and 15% higher for gas than average revenues from their non-standard tariffs.⁹⁸
- 8.169 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 3% of the bill).

Acquisitions onto the SVT

- 8.170 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:
- (a) EDF Energy told us that it did not price its SVT to win customers, as it does not actively win customers on SVTs,⁹⁹ and that in 2014 [redacted] of customer gains were on to a fixed-price tariff with the remaining [redacted] being on to the SVT ([redacted] prepayment customers and [redacted] 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 ([redacted]) 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;¹⁰⁰ and

⁹⁷ See generally Appendix 8.3: The pricing strategies of the Six Large Energy Firms.

⁹⁸ CMA analysis of profiled revenue data submitted by the Six Large Energy Firms.

⁹⁹ EDF Hearing transcript from CMA EDF Energy – Page 48.

¹⁰⁰ Appendix 8.3: The pricing strategies of the Six Large Energy Firms.

(d) Scottish Power said that since 2009 fixed-term tariffs had been its main acquisition tool, accounting for [redacted] of gains.

8.171 Tables 8.7 and 8.8 show for each of the Six Large Energy Firms the percentage of acquisitions that were on to the SVT over the period 2009 to 2015 (to end June) 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 (see paragraph 8.170), the proportion of SVT acquisitions has fallen over the period. In 2014 SVT acquisitions were less than [redacted] of total acquisitions for EDF Energy and [redacted]. For the first half of 2015, SVT acquisitions were [redacted] or less of total acquisitions for EDF Energy, E.ON, [redacted] and Scottish Power.

8.172 For British Gas, until 2013 [a substantial proportion] of acquisitions were on to the SVT, [redacted] in 2014 and around [redacted] in the first six months of 2015. [redacted] the percentage of acquisitions on to the SVT has over the period been [substantial] with the exception of 2013 (the year in which it offered discounted tariffs through PCWs).

Table 8.7: Percentage of acquisitions on to SVT by year and supplier – electricity

Year	%					
	British Gas	EDF Energy	E.ON	RWE	Scottish Power	SSE
2009	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
2010	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
2011	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
2012	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
2013	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
2014	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
2015 (to end June)	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]

Source: CMA analysis based on suppliers' responses to CMA Supply Questionnaire.

Table 8.8: Percentage of acquisitions onto SVT by year and supplier – gas

Year	%					
	British Gas	EDF Energy	E.ON	RWE	Scottish Power	SSE
2009	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
2010	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
2011	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
2012	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
2013	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
2014	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
2015 (to end June)	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]

Source: CMA analysis based on suppliers' response to CMA Supply Questionnaire.

Note: Acquisitions data is based on meter points or (site level for SSE – ie counts as an acquisition only if the site changes supplier.). For SSE these figures include customers paying the SVT on loyalty tariffs.

8.173 We note that a substantial proportion of SVT acquisitions in 2014/15 were for prepayment customers, for whom, as discussed above, there are very few non-standard tariffs available. This is shown, for the period January

8.177 RWE said¹⁰² that the [X], but added that the fact that in 2014, [X] and [X] of electricity and gas acquisitions respectively were onto RWE's SVT ([X] if excluding prepayment customers) indicated that for some customers, it was an active choice to be on an SVT. We note that Tables 8.9 and 8.10 show that in 2014/15 its relationships with the property industry accounted for over [X] of RWE's SVT acquisitions and telesales for a further [X], whereas PCWs accounted for less than [X]. This suggests to us that acquisitions onto RWE's SVT by active informed customers accounted for a very small proportion of RWE's total acquisitions.

Conclusions

8.178 Overall, our 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 SVT¹⁰³

8.179 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.¹⁰⁴ 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.¹⁰⁵

8.180 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

¹⁰² RWE response to provisional findings, 15 August 2015, paragraph 170.

¹⁰³ See Appendix 8.3: The pricing strategies of the Six Large Energy Firms.

¹⁰⁴ SLC 23 (formerly 44) of gas and electricity supply licences.

¹⁰⁵ 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.

(c) the costs to suppliers of changing tariffs (which are higher when prices are being increased due to regulatory requirements).

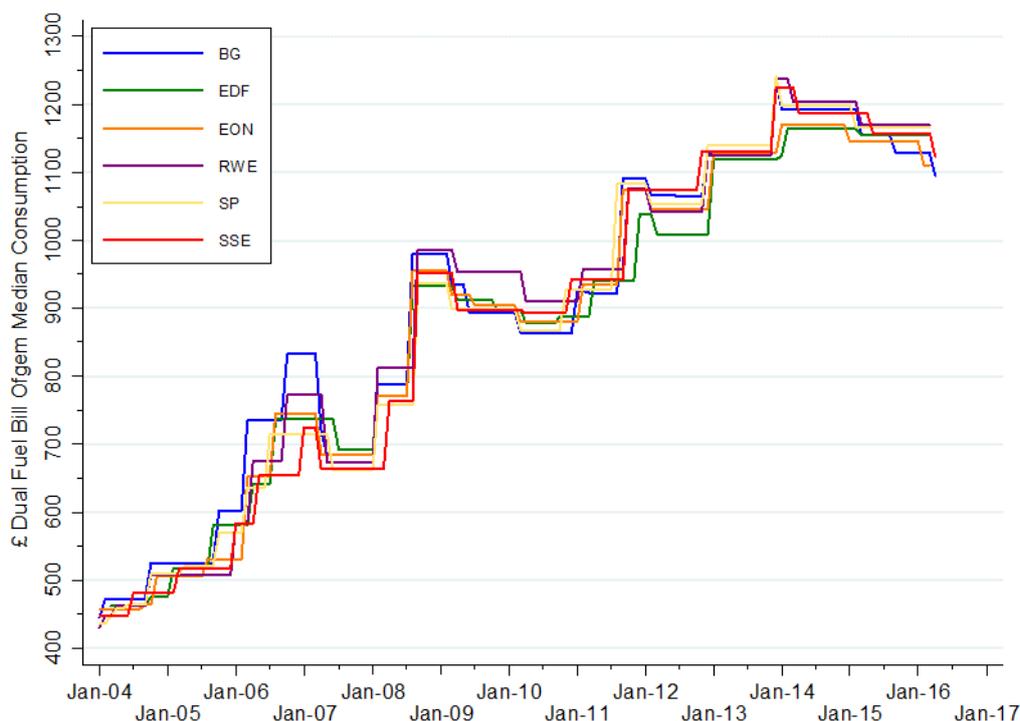
8.181 [✂]

8.182 In deciding on whether to change the price of the SVT, the Six Large Energy Firms [✂].¹⁰⁶ [✂]

8.183 As can be seen in Figure 8.16, 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 procurement strategies and hence similar wholesale costs; and they monitor their SVT price relative to that of their rivals.

8.184 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 9 and Appendix 9.4.

Figure 8.16: 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.

¹⁰⁶ These comparisons are often based on a dual fuel, direct debit, typical consumption customer.

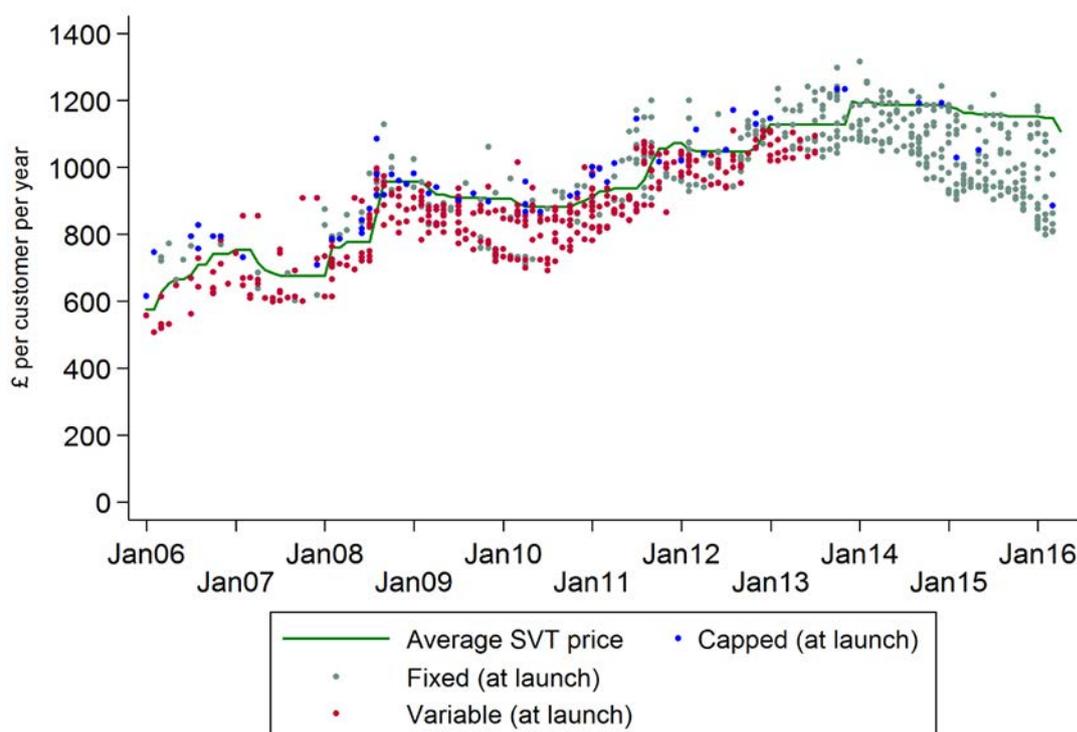
8.185 [✂]

Approach of the Six Large Energy Firms to setting non-standard tariffs

- 8.186 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. The Six Large Energy Firms have each offered broadly the same range of tariffs across the regions in terms of the both the number of tariffs offered and their characteristics.¹⁰⁷
- 8.187 In contrast to the SVT, non-standard tariffs are acquisition tariffs. Many 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 have historically, however, been some non-standard tariffs, such as longer-term price fixes, which are more expensive than the SVT.
- 8.188 The Six Large Energy Firms have different strategies for purchasing energy for non-standard tariffs. [✂]. The others would normally purchase (or commit) [✂].
- 8.189 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.

¹⁰⁷ Source: Energylinx tariff data set.

Figure 8.17: Non-standard tariffs at launch and average SVT price 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 and Ofgem.
 Note: Based on typical domestic consumption of 3,200 kwh/year for electricity and 13,500 kwh/year for gas.

- 8.190 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 the RMR rules, non-standard variable products were banned¹⁰⁸ and fixed products have taken their place as the cheap acquisition product.
- 8.191 Over the last two years, the disparity between the SVT and the cheapest non-standard products offered by the Six Large Energy Firms has increased, to more than £300 on the typical consumption customer bill in some cases, with falling commodity prices and as they have begun to compete more vigorously with the Mid-tier Suppliers in the non-standard space.
- 8.192 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 ([X]) told us that to attract customers it had to offer discounts on its SVT and that fixed-term

¹⁰⁸ 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.

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.¹⁰⁹ EDF Energy, E.ON and Scottish Power 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.¹¹⁰ [X]. EDF Energy 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.

8.193 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.¹¹¹

8.194 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 Firms¹¹² and participation in collective switching schemes.¹¹³ As shown in the figure below, tariffs sold through white-label 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 the RMR rules do not require partner suppliers to inform their customers of white-label tariffs.¹¹⁴ We note that white-label suppliers 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 have been required to include their white label tariffs in the cheapest tariff messaging.

¹⁰⁹ See Appendix 8.3: The pricing strategies of the Six Large Energy Firms.

¹¹⁰ See Appendix 8.3: The pricing strategies of the Six Large Energy Firms.

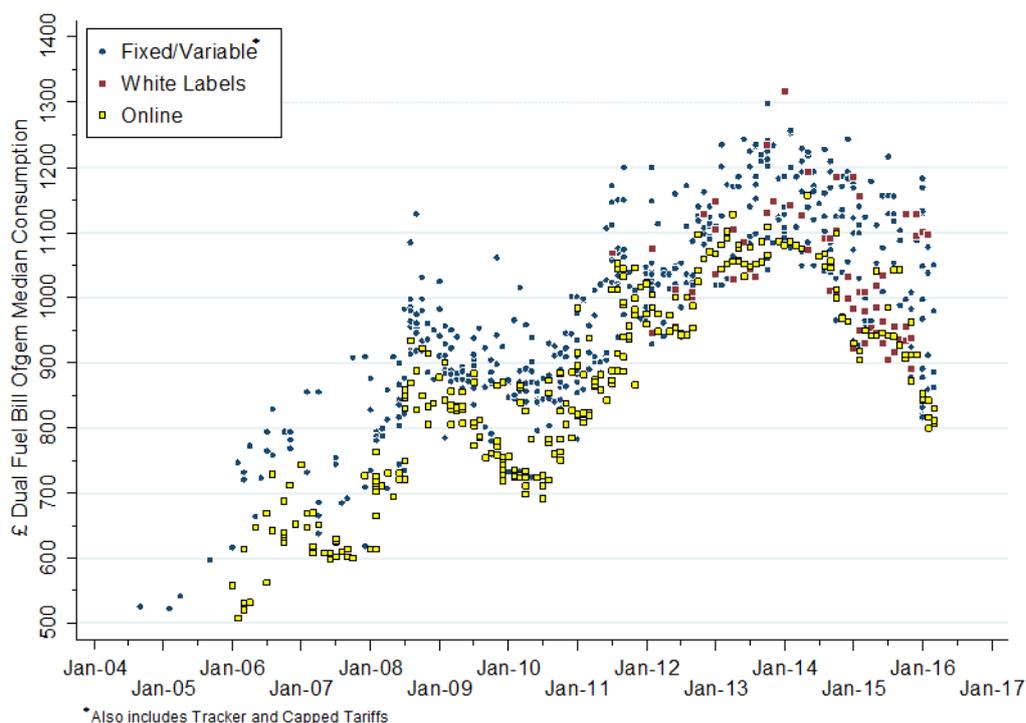
¹¹¹ In Section 9 we consider the potential effect these rules have on suppliers' incentives to discount to attract new customers.

¹¹² 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.

¹¹³ See Appendix 9.3 for further details.

¹¹⁴ This is the situation under the temporary arrangements included in SLC 31D but this is likely to change from July 2015.

Figure 8.18: 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 and Mid-tier Suppliers.
 Note: This does not include the following tariffs: (i) Economy 7 tariffs; (ii) collective switching tariffs; (iii) deemed tariffs; (iv) developer tariffs; and (v) tariffs available to specific sets of customers (eg special offers).

Average revenues

8.195 We observed earlier that over the period 2011 to mid-2015, average revenues from the SVT have been on average 11% and 15% 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.

8.196 We note that there is variation in the approach adopted by the Six Large Energy Firms. EDF Energy, E.ON, RWE and Scottish Power ([redacted]) 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.¹¹⁵ [redacted].

Figure 8.19: Average gas revenues of the Six Large Energy Firms

[redacted]

Source: CMA analysis of profiled revenue data submitted by the Six Large Energy Firms.

¹¹⁵ See Appendix 9.14: Price discrimination.

Figure 8.20: Average electricity revenues of the Six Large Energy Firms

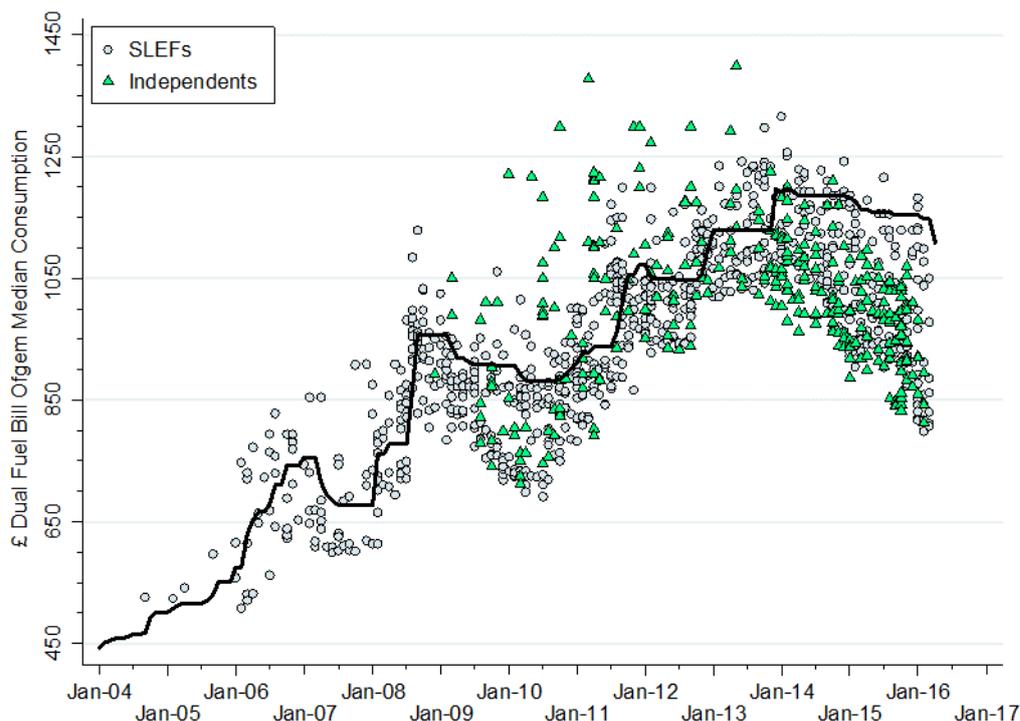
[✂]

Source: CMA analysis of profiled revenue data submitted by the Six Large Energy Firms.

Comparison of the Six Large Energy Firms and the Mid-Tier Suppliers

- 8.197 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.
- 8.198 We have focused on the two largest Mid-Tier Suppliers – First Utility, Ovo Energy.
- 8.199 There are important differences in business model between Utility Warehouse and the other two. First Utility and Ovo Energy are both fully independent of the Six Large Energy Firms, while 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. [✂]
- 8.200 There are also important differences in the business model of Co-operative Energy and First Utility and Ovo Energy. In particular, a large number of its customers have been acquired from the members of the Midcounties Co-operative. Those who were not acquired in this way have also been given the option of becoming members, entitling them to a share in the profits it generates from all business streams, not just from the energy business.
- 8.201 Figure 8.21 shows the tariffs offered by all four 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 [✂]) offered some expensive niche products at a premium to other available tariffs alongside cheaper tariffs.
- 8.202 In the last two years, 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 8.21: 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.

Notes:

1. This does not include the following tariffs: (i) Economy 7 tariffs; (ii) collective switching tariffs; (iii) deemed tariffs; (iv) developer tariffs; and (v) tariffs available to specific sets of customers (eg special offers).
2. The black line is the average of the SVTs of the Six Large Energy Firms.

8.203 Figure 8.22 shows the average domestic revenue earned by the First Utility and Ovo Energy compared with the Six Large Energy Firms. It can be seen that the average price offered by [redacted] has been below that offered by the Six Large Energy Firms since it commenced operations in 2009. In 2014, [redacted] domestic electricity and gas prices were 10% and 11% respectively below the average of the Six Large Energy Firms. To end June 2015, the corresponding figures are 8% and 12%.

8.204 For [redacted] average gas prices have been consistently lower than those of the Six Large Energy Firms and in 2014, the average price for gas was around [redacted]% below the average for the Six Large Energy Firms (at the end of June 2015 the corresponding figure was around [redacted]). [redacted] 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 [redacted] was [redacted]% below the average for the Six Large Energy Firms for electricity (at the end of June 2015 the corresponding figure was [redacted]).

Figure 8.22: Comparison of annual average revenue per kWh across suppliers: electricity and gas

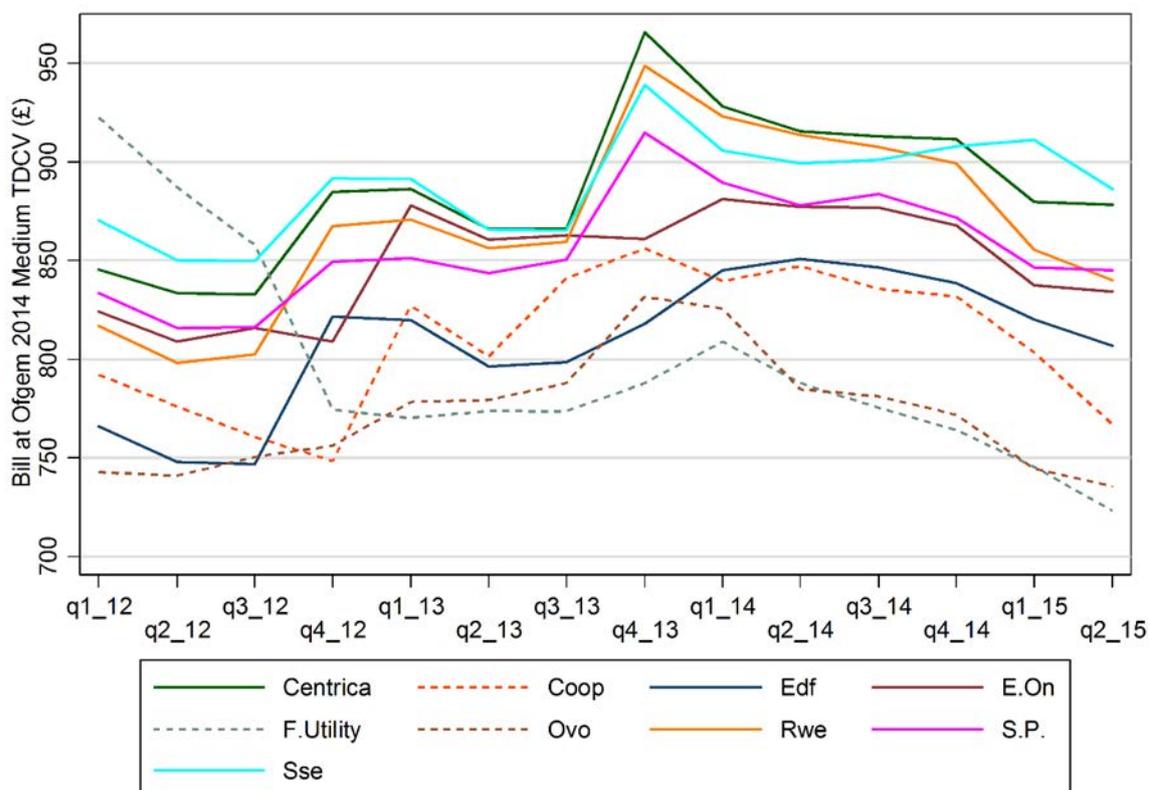
[redacted]

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.

- 8.205 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.
- 8.206 To address such effects, we have analysed how domestic customer bills differ between suppliers controlling for exogenous cost differences (network charges and the cost associated with different payment methods) and assuming a typical level of domestic consumption. The results are shown in the figure below, for the dual fuel customers of the Six Large Energy Firms and the Mid-tier Suppliers.

Figure 8.22b: Comparison of average dual fuel bills for medium TDCV domestic customers controlling for network and payment method costs



Source: CMA analysis of data provided by the Six Large Energy Firms and the Mid-tier Suppliers.

- 8.207 As can be seen in the figure, even after controlling for key exogenous costs, three of the Mid-tier Suppliers (Ovo Energy, First Utility and, to a less marked extent, Co-operative Energy) offered consistently lower average prices than the Six Large Energy Firms over the last 18 months of the period under review. EDF Energy offered consistently the lowest average prices

paid by customers of the Six Large Energy Firms, with the customers of SSE, Centrica and RWE generally paying the highest average prices over the period Q12012 to Q2 2015.

- 8.208 For the avoidance of doubt, when we say that a supplier has offered lower average prices we have calculated this taking into account all the standard variable and non-standard tariffs that their customers (with standard and E7 meters) were on at the end of each quarter (subject to some exclusions as set out in Appendix 10.2), and the number of customers on each of these tariffs. For each supplier, this includes the tariffs offered by white label partners (in particular, the analysis of Centrica tariffs includes British Gas and Sainsbury Energy tariffs, and the analysis of SSE tariffs includes SSE, M&S and Ebico tariffs).
- 8.209 We have excluded results for Utility Warehouse from the graph. This is because, for the purposes of the comparison of our bills analysis and the gains from switching analysis, we excluded all bundled tariffs (see Appendix 9.2). For Utility Warehouse this had the effect of excluding the majority of its fixed-term tariffs.
- 8.210 RWE said that the graph is misleading as it is based on Ofgem's medium typical consumption which is not representative of RWE's customers (who on average have lower levels of consumption). RWE considered that the graph is likely to make RWE's pricing appear less competitive than it would be if based on the typical consumption of RWE's customers.
- 8.211 In Appendix 10.2 (see Table 1) we provide results for the comparisons of bills applying Ofgem's high, medium and low typical consumption levels (averaged across quarters). This shows that at low typical consumption levels, the average prices offered by RWE were, on average, over the period, higher than those offered by EDF Energy, but lower than those offered by the other Six Large Energy Firms (in contrast to Figure 8.22(b), which indicates that RWE has been one of the Six Large Energy Firms with the highest average prices over the period). In other respects the ranking of the suppliers was largely unchanged, both within the Six Large Energy firms and between the Six Large Energy Firms and the Mid-tier suppliers. We draw on these results in assessing the level of detriment suffered by domestic customers in Section 10.

Cost pass-through

- 8.212 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.¹¹⁶ 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.¹¹⁷ We consider two measures of costs – forward-looking costs and historical costs (ie those actually incurred by firms) – and draw implications for the nature of price competition.

Forward-looking costs

- 8.213 In a competitive market we would generally expect prices to reflect marginal costs,¹¹⁸ 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).
- 8.214 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
 - (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.
- 8.215 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).
- 8.216 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,

¹¹⁶ A full description of the analysis we have carried out is set out in Appendix 8.2: Cost pass-through.

¹¹⁷ 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](#).

¹¹⁸ The change in total costs arising from a marginal increase in output.

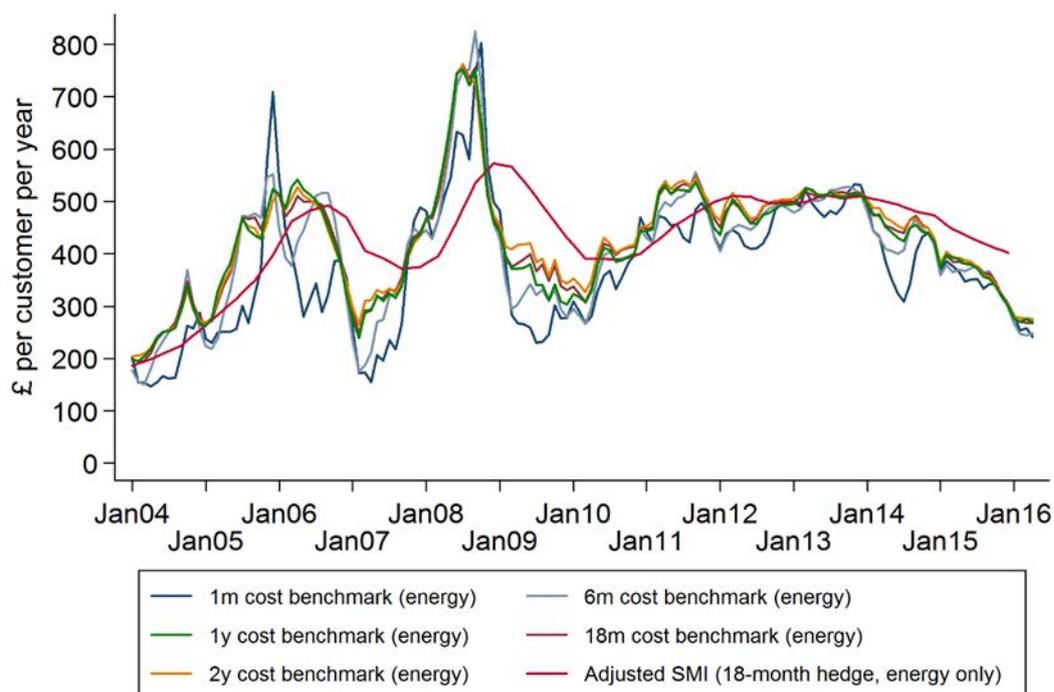
at a point in time, of the energy the supplier has already procured for future delivery.¹¹⁹

8.217 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).

8.218 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.

8.219 We also constructed one-month, six-month, one-year, 18-month and two-year forward-looking wholesale energy cost benchmarks. Figure 8.23 shows that the month benchmark is the most volatile, but that each of the others produced very similar results.

Figure 8.23: Forward-looking energy cost benchmarks for a dual fuel, typical consumption customer



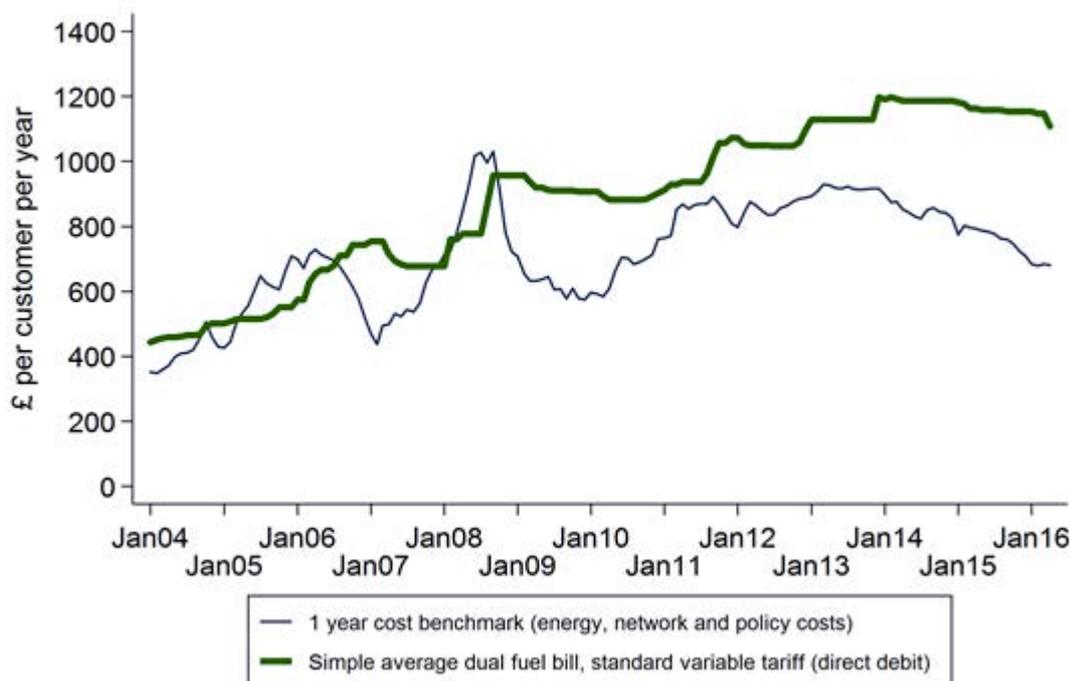
Source: CMA analysis of data collected from Ofgem and ICIS

Note: Based on typical domestic consumption of 3,200 kwh/year for electricity and 13,500 kwh/year for gas. Energy costs only.

¹¹⁹ 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.

8.220 Figure 8.24 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.

Figure 8.24: Average SVT price (based on the annual bill for a dual fuel direct debit typical consumption domestic customer) 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.
 Note: Bill is an average across regions and Six Large Energy Firms, for a typical consumer. Direct costs are not those actually incurred by firms, but forward-looking expectations. Indirect costs are not shown.

8.221 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 from 2014 as reductions in wholesale gas costs are not passed through into commensurate reductions in the SVT.

8.222 The evidence appears to be consistent with a potential weakening of competition concerning the SVT over time as the gap between the SVT and underlying costs appears to widen. This is particularly apparent from 2009 which broadly coincides with the introduction of the prohibition on undue regional price discrimination.¹²⁰ Following implementation of SLC 25A, the number of fixed-term tariffs launched by the Six Large Energy Firms increased,¹²¹ the effect of which 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.¹²² The withdrawal of the Six Large Energy Firms from doorstep selling in 2011 and 2012 may have also contributed to this pattern.

8.223 We looked at the extent to which prices have responded more quickly to increases in wholesale costs than reductions (the so-called ‘rockets and feathers’ hypothesis). Table 8.12 sets out the key summary statistics: the number of months when either costs or prices were rising or falling, and the average magnitude of these changes.

Table 8.12: Summary statistics of cost (one-year cost benchmark) and price (simple average SVT price across the Six Large Energy Firms) movements on a monthly frequency between January 2004 and March 2016

<i>Cost and price movements</i>	<i>Costs (one-year benchmark)</i>	<i>Prices (simple average SVT)</i>
Number of months when rising	75	42
Number of months when falling	73	26
Average increase in months when rising	£24.8	£22.7
Average decrease in months when falling	£20.7	£10.3
Average increase per month over the period 2004 to March 2016	£12.5	£6.3
Average decrease per month over the period 2004 to March 2016	£10.3	£1.8
Ratio of increases to decreases	1.2	3.5

Source: CMA analysis of data collected from Ofgem and ICIS.

8.224 We make the following observations based on Table 8.12:

- (a) Costs have risen and fallen at approximately the same speed (on average £25 and £21 per month respectively). In contrast, price increases have been approximately twice as large as price reductions (£23 and £10 per month respectively).

¹²⁰ See Energy Supply Probe – Initial Findings, 2008, p52.

¹²¹ 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.

¹²² 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 with which to compare domestic energy prices.

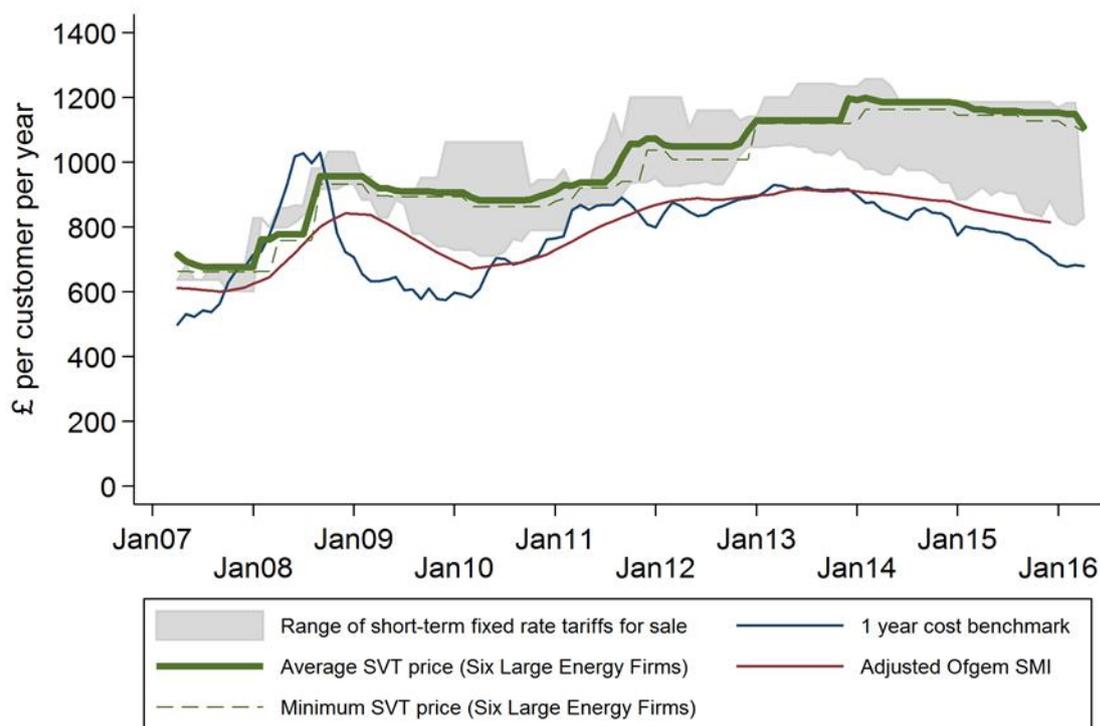
(b) Over the period of analysis, for every £1 of cost reductions there were £1.20 of cost increases; for every £1 of price reductions there were £3.50 of price increases.

8.225 We consider that the results in paragraph 8.224(a) and (b) suggest an amount of asymmetry, in that prices have adjusted upwards more than downwards, although overall we attach limited weight to them. Centrica has submitted that the results presented in Table 8.12 are highly sensitive to the volatility of prices versus cost movements. We acknowledge that the analysis cannot be used to identify the precise form and size of the asymmetry and the mechanism that may lead to this outcome. However, we believe that the results are indicative of the presence of a certain degree of asymmetric price response in the domestic retail energy markets, in that cost reductions have not been fully passed through to prices.¹²³

8.226 The chart below is based on the same data but also includes the range of short-term fixed-term tariffs (ie fixed-rate fixed-term tariffs with a term of two-years or less) 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.

¹²³ We considered conducting a robust assessment but we did not consider the data relating to prices and costs to be sufficiently rich to conduct.

Figure 8.25: The range of short-term fixed-rate tariffs* on sale, average and lowest SVT price and a forward-looking industry-level benchmark of direct costs (based on direct debit, typical consumption customer)



Based on typical domestic consumption of 3200kwh/year for electricity and 13500kwh/year for gas. Other costs include transmission, distribution, BSUoS and environmental and social obligations.

Source: CMA analysis of data collected from the Six Large Energy Firms, Mid-tier Suppliers, Ofgem and ICIS.

*Defined here as fixed-term, fixed-price tariffs with a contract (at the date of first launch) of up to 24 months.

Note: Based on typical domestic consumption of 3,200 kwh/year for electricity and 13,500 kwh/year for gas. Other costs include transmission, distribution, BSUoS and environmental and social obligations.

8.227 We observe that the cheapest short-term fixed-term 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 and 2015 while the SVT price remained flat.¹²⁴

8.228 However, there is still a relatively wide range of one-year fixed tariffs for sale, with some above the average SVT price. In Section 9, we consider the implications of these relatively expensive, non-standard tariffs.

8.229 The parties said that there was no widening of the gap between prices and costs over time, or the widening of the gap was likely to be overstated because the cost measures used are unrealistic. In particular, as:

¹²⁴ 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 8.16 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 costs, used in our analysis, have historically underestimated the actual cost of delivering the schemes at different stages in each programme.

8.230 We respond to these and other points in detail in Appendix 8.2.

8.231 Parties also said that any difference in the gap between the periods before and after 2009 reflected a period of unsustainably low profits before 2009. Our assessment of retail profitability is set out in Section 10.

8.232 Here we make two observations. 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 Appendix 8.2, Annex B, Figure 5). 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.

8.233 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.

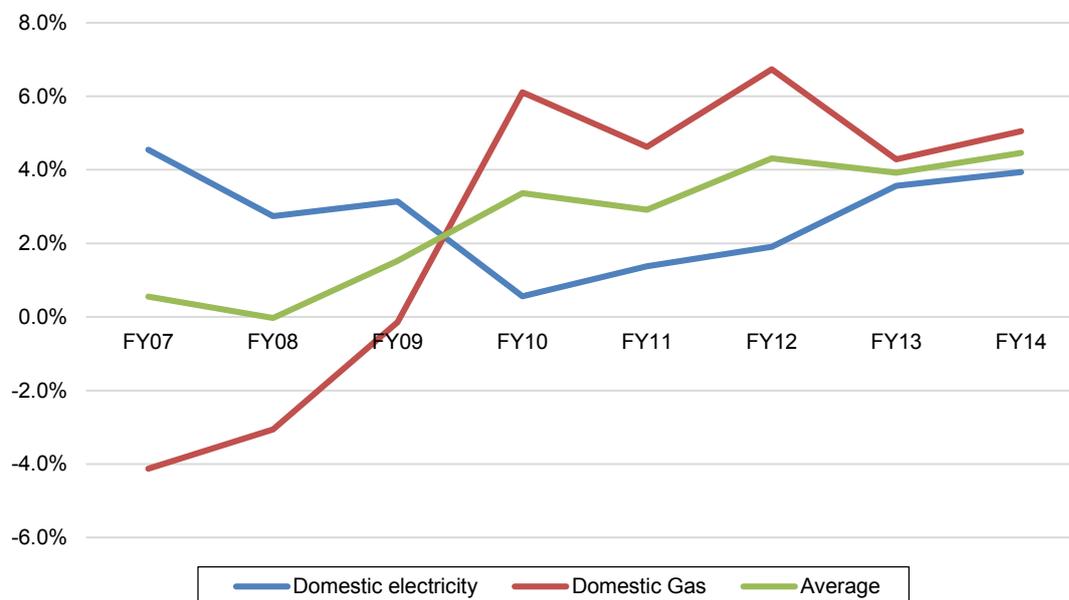
Historical costs and profits

8.234 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-through is not an analysis of the actual costs incurred by individual firms or the actual profit margins earned by firms.

8.235 Our analysis of the actual costs and profits earned by the Six Large Energy Firms is set out in Section 9 and Appendices 9.8 to 9.12. As shown in Figure

8.26, EBIT margins from the sale of gas to domestic customers were negative in 2007 and 2008 and have increased thereafter, although there is no obvious trend from 2010 to 2014. In contrast, EBIT margins from the sale of electricity to domestic customers were above 4% in 2007 and then declined in the period to 2010 before increasing back to around 4% by 2014.

Figure 8.26: Total domestic EBIT margins 2007 to 2014

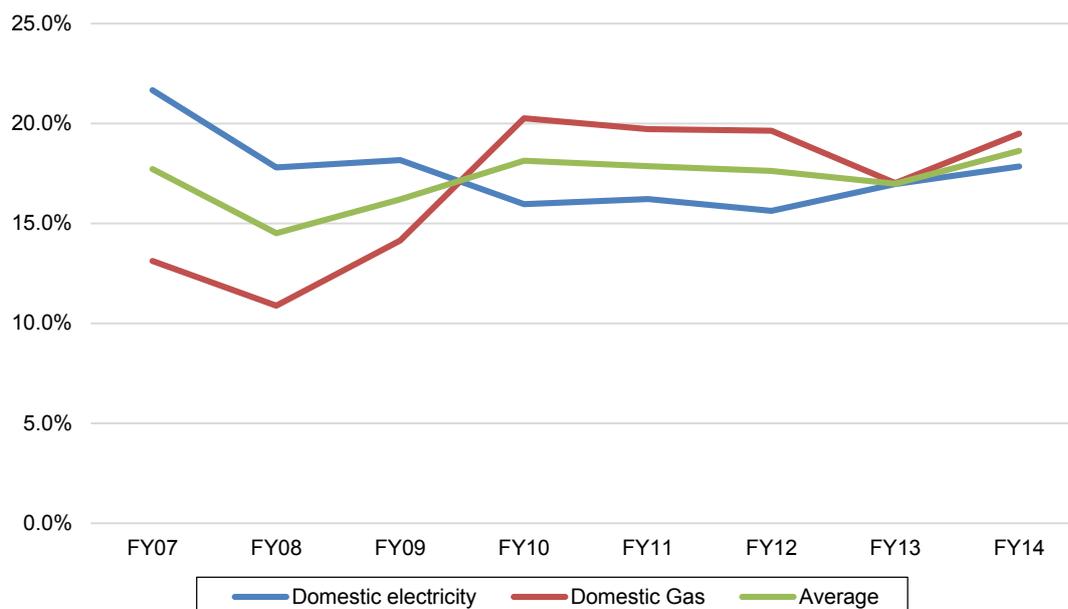


Source: CMA analysis of data submitted by the Six Large Energy Firms.

8.236 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 2014.¹²⁵ Figure 8.27 shows the gross margins earned by the Six Large Energy Firms on domestic electricity and gas

¹²⁵ Appendix 9.10: Retail profit margin analysis.

Figure 8.27: Total domestic gross margins 2007 to 2014



Source: CMA analysis of profiled revenue and cost data submitted by the Six Large Energy Firms.

8.237 As discussed in more detail in Section 10 and Appendix 9.10, over the period 2007 – 2009, the Six Large Energy Firms made an average annual economic loss (ie returns below the cost of capital) of £125 million, while over the period 2010 to 2014 they made an average annual economic profit (ie returns in excess of the cost of capital) of £560 million.

8.238 We note overall that there is not a simple, stable relationship between the gap identified in Figure 8.24 and realised profits, due largely to a number of factors including the impact of weather on levels of domestic consumption of gas and hence profits from sales of gas. As shown in Figure 2.9 in Section 2, domestic gas consumption was particularly low in 2011 and 2014, which would tend to reduce levels of profitability from gas sales in those years, while it was particularly high in 2010, which would tend to increase levels of profitability from domestic gas sales. Further, Figure 8.24 shows only the relationship between costs and the SVT, and so excludes around 30% of the customers of the Six Large Energy Firms.

8.239 Further, 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 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.

Conclusion on nature of price competition and implications for the investigation

- 8.240 We have observed that the SVT is a default tariff while non-standard tariffs are acquisition tariffs.¹²⁶ Further, we have noted that there are significant disparities in the prices between the SVT and non-standard tariffs. While some non-standard tariffs have historically been more expensive, a significant number are sold at substantial discounts to the SVT.
- 8.241 We have also noted that over the period 2014 to 2016 forward-looking measures of direct costs have been falling (the one-year benchmark has fallen by 24%), while, as of March 2016, the average SVT had fallen by only 4% since January 2014.¹²⁷ In contrast, the cheapest non-standard tariffs have tracked changes in expected direct costs more closely.
- 8.242 Several of the Six Large Energy Firms have submitted 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 at least 22% of their gas and 18% of their electricity SVT customers have been on the SVT for a year or less, which partly reflects the effect of such reversion.¹²⁸) 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-label suppliers or through online channels.
- 8.243 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 up to 39% of their gas and 40% of their electricity SVT customers of the Six Large Energy Firms have been with the same supplier and tariff for more than five years.¹²⁹)

¹²⁶ 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.

¹²⁷ The first supplier to cut SVT prices was E.ON in February 2016.

¹²⁸ We note that this is an upper bound estimate as for three suppliers the data provided was based on the length of the relationship with the supplier rather than the length of time on that supplier's SVT.

¹²⁹ We note that this is an upper bound estimate as for three suppliers the data provided was based on the length of the relationship with the supplier rather than the length of time on that supplier's SVT.

- 8.244 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 electricity offered by two of these suppliers – [✂] – Ovo Energy was about 15% and 8% lower than the average price of the Six Large Energy Firms and First Utility was around 18% and 6% lower than the average price of the Six Large Energy Firms in the first two quarters of 2015. In Appendix 10.1 we consider what implications we can draw from the tariffs of the Mid-tier Suppliers about the competitive retail benchmark price.
- 8.245 The Six Large Energy Firms have submitted 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 8.1.

Gains from switching

- 8.246 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 8.102:
- (a) Choice of tariff type¹³⁰ 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.
- 8.247 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:¹³¹
- (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 and payment method.

¹³⁰ 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.

¹³¹ See Appendix 9.2 – Analysis of the potential gains from switching, for a full description of the parameters that can be changed/held fixed when switching.

- (d) Scenario 3b Change supplier (to one of the Six Large Energy Firms or Mid-tier Suppliers) but keep tariff type 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 4c: Change supplier (to one of the Six Large Energy Firms) and tariff type but keep payment method.
- (h) Scenario 5: Change supplier, tariff type and payment method (except for prepayment customers).
- (i) Scenario 5x: Change supplier, tariff type and payment method (except for prepayment customers) but deduct exit fees where applicable.

8.248 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 barriers customers face in moving from a prepayment meter, as discussed in Section 9.¹³²

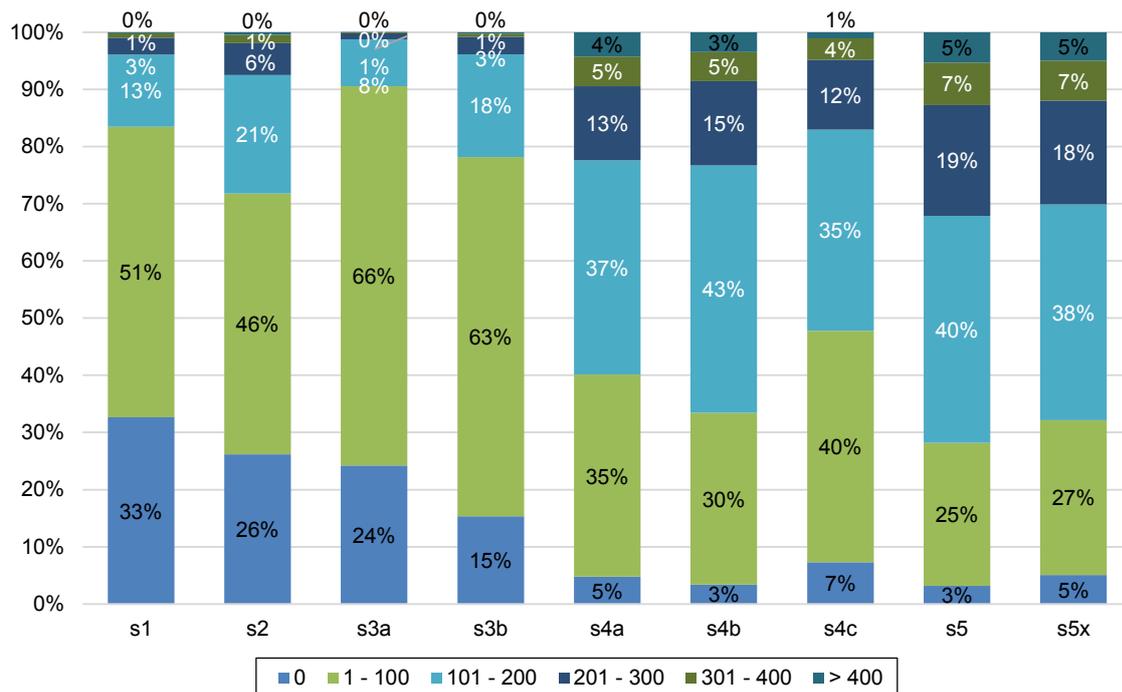
Results

8.249 We calculated potential savings on the above basis over the period Q1 2012 to Q2 2015. 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 8.28. On average, all these customers could have gained £164 over this period (equivalent to 14% of the bill) under scenario 5x and £65 (equivalent to 6% of the bill) under scenario 3b.¹³³

¹³² For further information setting out the data used and methodology applied, see Appendix 9.2: Analysis of the potential gains from switching.

¹³³ The reported average includes customers who could make no gains from switching.

Figure 8.28: Distribution of potential annual savings (in £) for dual fuel customers of the Six Large Energy Firms (average proportions across firms and quarters)

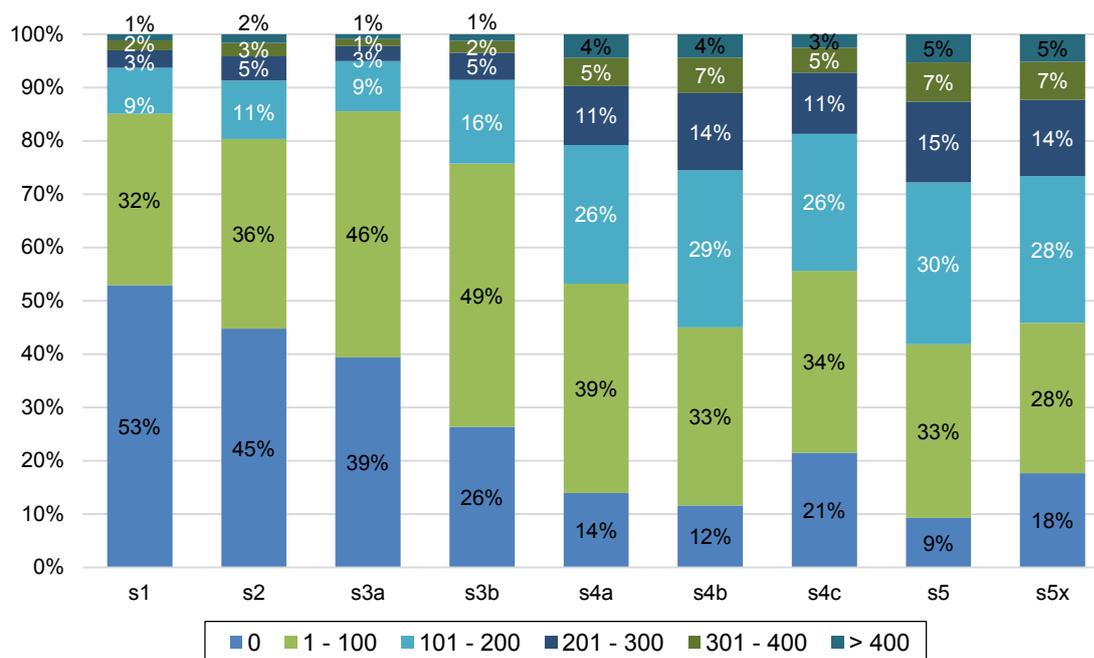


Source: CMA analysis.

8.250 The distribution of average annual savings for all of the dual fuel customers of the Mid-Tier Suppliers for each scenario is set out in Figure 8.29. On average, all these customers could have gained £143 (equivalent to 11% of the bill) under scenario 5x and £72 (equivalent to 5% of the bill) under scenario 3b.¹³⁴

¹³⁴ These results include Utility Warehouse. However, as noted above, we excluded all bundled tariffs for the purposes of the gains from switching analysis (see Appendix 9.2), which, for Utility Warehouse, had the effect of excluding the majority of its fixed-term tariffs.

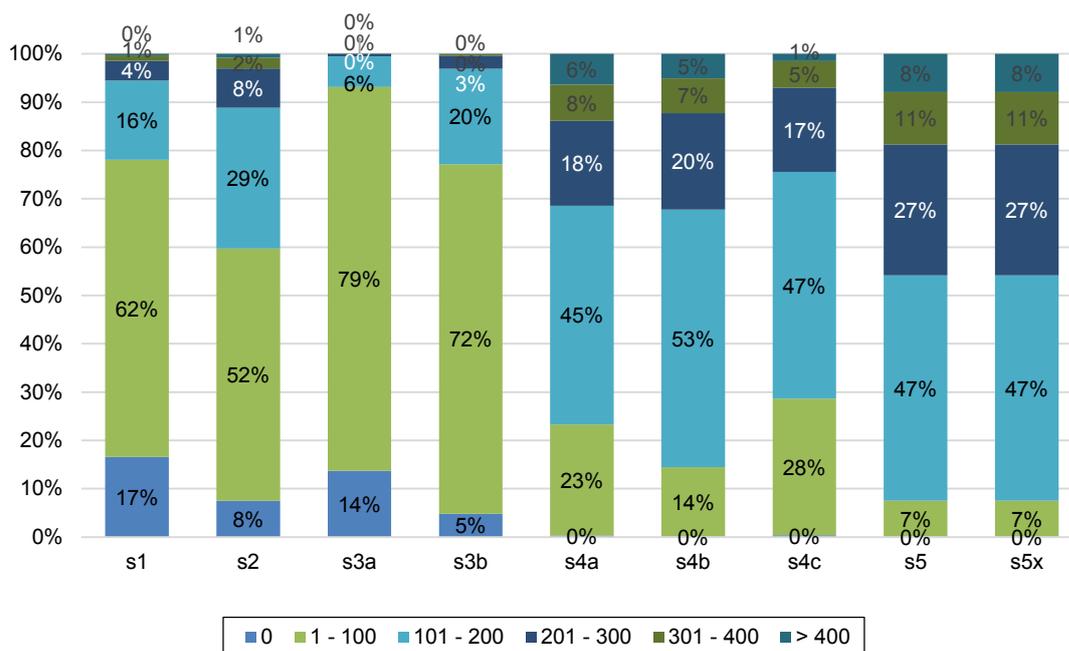
Figure 8.29: Distribution of potential annual savings (in £) for dual fuel customers of Mid-tier Suppliers (average proportions across firms and quarters)



Source: CMA analysis.

- 8.251 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.
- 8.252 The dual fuel SVT customers of the Six Large Energy Firms could have gained an average of £186 a year over this period (equivalent to 17% of the bill) under scenario 5x and £54 (equivalent to 5% of the bill) under scenario 1. Average savings are substantially higher than those for dual fuel customers on the non-SVT (savings equivalent to 9% of the bill under scenario 5x).
- 8.253 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 5x. In contrast, the non-prepayment dual fuel SVT customers of the Six Large Energy Firms could have gained an average of £219 over this period (equivalent to 19% of the bill) under scenario 5x and £67 (equivalent to 6% of the bill) under scenario 1. The distribution of these gains is shown in Figure 8.30.

Figure 8.30: Distribution of potential annual savings (in £) for dual fuel SVT customers (no pre-payment) of the Six Large Energy Firms



Source: CMA analysis.

8.254 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 £89 over this period (equivalent to 16% of the bill) under scenario 5x and £41 (equivalent to 7% of the bill) under scenario 3b. Gas customers could have saved an average of £115 over this period (equivalent to 19% of the bill) under scenario 5x and £47 (equivalent to 8% of the bill) under scenario 3b.

8.255 Bringing the above results together, Table 8.13 shows how gains from switching differ for customers on different tariff and payment types with the Six Large Energy Firms, under scenario 5x and scenario 4b.

Table 8.13: Average savings under scenario 5x and 4b for customers of the Six Large Energy Firms on different tariff and payment types Q1 2012 to Q2 2015

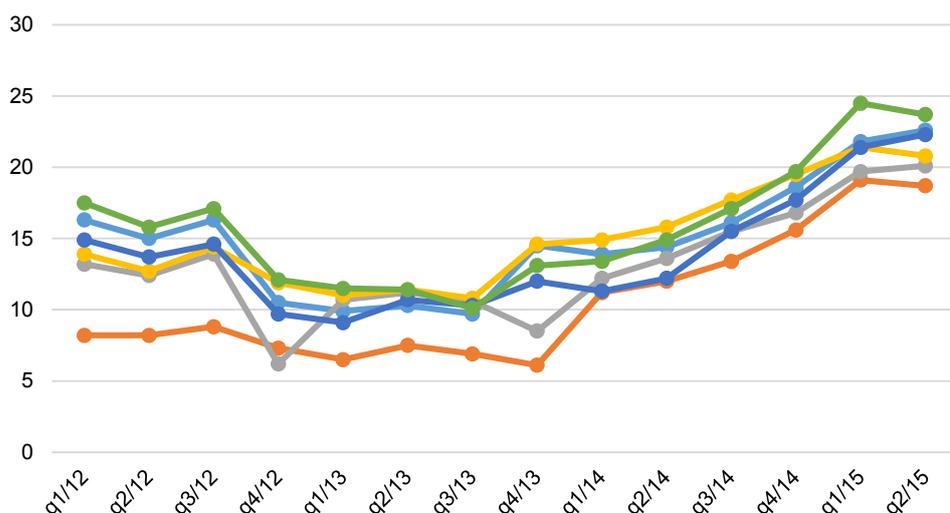
Fuel type	Tariff type	Payment type	% of total gas customers	% of total electricity customers	Average savings under S5x, £	Average savings under S5x, %	Average savings under S4b, £	Average savings under S4b, %
Dual	Non-standard	All	27	22	109	9	125	11
Dual	SVT	Direct debit	30	25	205	16	205	16
Dual	SVT	Standard credit	14	11	245	23	151	15
Dual	SVT	Prepayment	11	10	70	8	70	8
Single gas	All	All	18	0	115	19	100	17
Single electricity	All	All	0	31	89	16	74	13

Source: CMA analysis.

8.256 The table shows that – considering the most liberal scenario 5x 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.

8.257 Figure 8.31 shows that the available savings to customers of the Six Large Energy Firms have risen over the period.

Figure 8.31: Average potential savings (% of the bill) available to dual fuel customers of the Six Large Energy Firms under scenario 5x



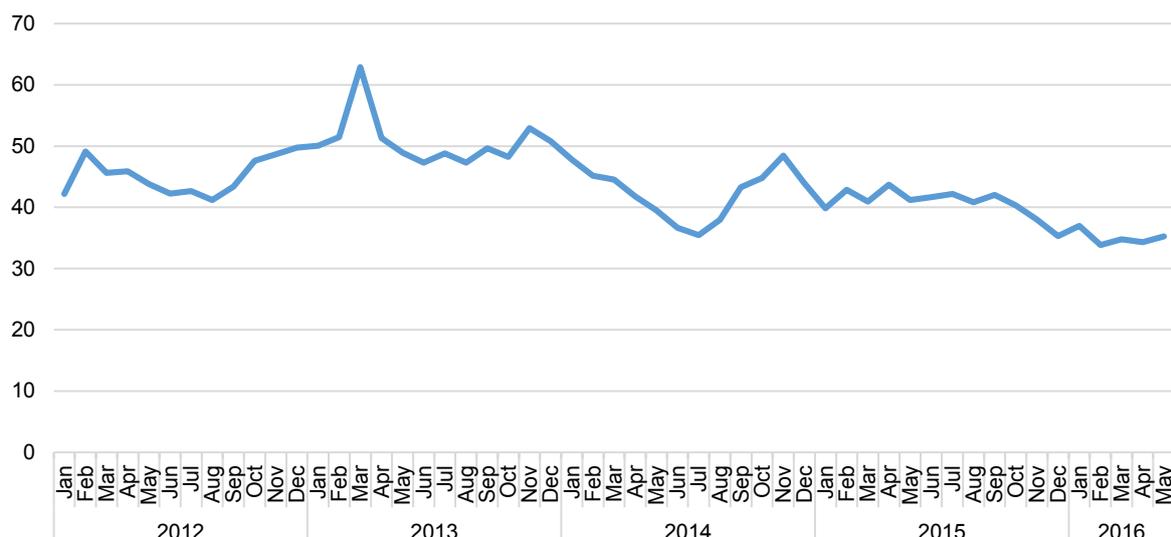
Source: CMA analysis

8.258 We note that in February 2016, the Six Large Energy Firms announced a reduction in price of their gas tariffs, ranging from 5 to 5.4%.¹³⁵ These announcements related mainly to their SVTs with effect from February to March 2016.

8.259 However, we do not believe this will materially change the pattern of results seen in the chart above. Indeed, gains may even have increased further, since we would expect the acquisition tariffs to follow more closely the reduction in wholesale gas and electricity prices, which comprise roughly 50% of the total costs incurred in supplying gas and electricity and have fallen around 31% and 15% since Q2 2015, respectively.

¹³⁵ EDF Energy announced a price cut of 5%; British Gas announced a price cut of 5.1% (British Gas also cut its gas prices by 5% in August 2015); E.ON announced a price cut of 5.1%; RWE npower announced a price cut of 5.2%; SSE announced a price cut of 5.3%; and Scottish Power announced a price cut of 5.4%.

Figure 8.33: Wholesale electricity day-ahead price – monthly average (GB)



Source: CMA analysis of data provided by ICIS Heren.
 Note: Data extracted on 23 May 2016.

8.261 Table 8.14 shows the savings available to customers of the Six Large Energy Firms with Economy 7 meters (compared with those with single-rate meters).

Table 8.14: Average savings available to customers of Six Large Energy Firms with Economy 7 and single-rate meters under scenario 5x Q1 2012 to Q2 2015

Fuel type	Tariff type	Payment type	Economy 7		Single-rate meter	
			Average savings under S5x (£)	Average savings under S5x (%)	Average savings under S5x (£)	Average savings under S5x (%)
Dual	Non-standard	All			106	9
Dual	SVT	Direct debit			200	16
Dual	SVT	Standard credit			240	23
Dual	SVT	Prepayment			66	8
Single gas	Non-standard	All			96	14
Single gas	SVT	Direct debit			132	19
Single gas	SVT	Standard credit			142	24
Single gas	SVT	Prepayment			48	13
Single electricity	Non-standard	All	88	11	43	8
Single electricity	SVT	DD	159	19	81	15
Single electricity	SVT	SC	181	24	106	23
Single electricity	SVT	Prepayment	69	10	39	8

Source: CMA analysis

8.262 The results show that under the most flexible scenario, S5x, the savings available to customers with Economy 7 meters were, on average, in percentage terms larger than those available to single-rate customers. This is the case across tariff and payment type. For example, the savings available to direct debit single fuel Economy 7 SVT customers could save £159 - that is 19% of their bill as compared to 15% for direct debit single fuel

single-rate SVT customers. As above, we also found that gains available to Economy 7 customers have increased over time.

Implications for the investigation

- 8.263 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).
- 8.264 Parties have commented on the interpretation of these results. Some of the Six Large Energy Firms said in response to the provisional findings and the provisional decision on remedies that we failed to take into account the non-price preferences of customers and, therefore, overstated the savings available to customers from switching tariff, payment method and/or supplier.
- 8.265 In Section 9 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.
- 8.266 Finally, we note that this analysis has focused purely on the implications of gains from switching for customer engagement.

Prepayment meters and restricted meters

- 8.267 In this section we consider the extent to which the nature of competition differs in relation to prepayment meters and restricted meters.

Competition in the prepayment segments

- 8.268 As outlined above, the proportion of customers on prepayment meters has increased steadily over the last 20 years, from 7% in 1996 to 16% currently.¹³⁸ Unlike the choice of whether to pay by direct debit or standard

¹³⁸ This is based on data from DECC Quarterly Energy Prices, March 2016, see Figure 8.6 and paragraphs 8.129 and 8.130. Consistent with this we note that as at Q4 2015 and based on data from the Six Large Energy Firms, Mid-tier Suppliers, Utilita and Economy Energy: for electricity roughly 17% of customers were on prepayment meters, roughly 23% of customers paid by standard credit and 60% paid by direct debit; and for gas roughly 15%

credit, prepayment is not generally a choice on the part of the customer. Prepayment meters are generally installed where a customer has had a poor payment history or in certain types of accommodation such as student accommodation.¹³⁹ Nearly all prepayment customers are on SVTs, reflecting the limited choice of non-standard tariffs they face.

8.269 In this section, we consider whether there are material differences in the outcomes in the prepayment segments of the domestic retail energy markets,¹⁴⁰ compared with the direct debit segments. In particular, we first investigated customer numbers and shares in the prepayment segments for both the independent suppliers and the Six Large Energy Firms. We then investigated outcomes in the prepayment segments relative to the direct debit segments.

Independent suppliers in the prepayment segments

8.270 We have looked at the account numbers in the prepayment segments and how they changed over time, for both the Six Large Energy Firms and the independent suppliers.¹⁴¹ This is shown in Figures 8.34 and 8.35 below.

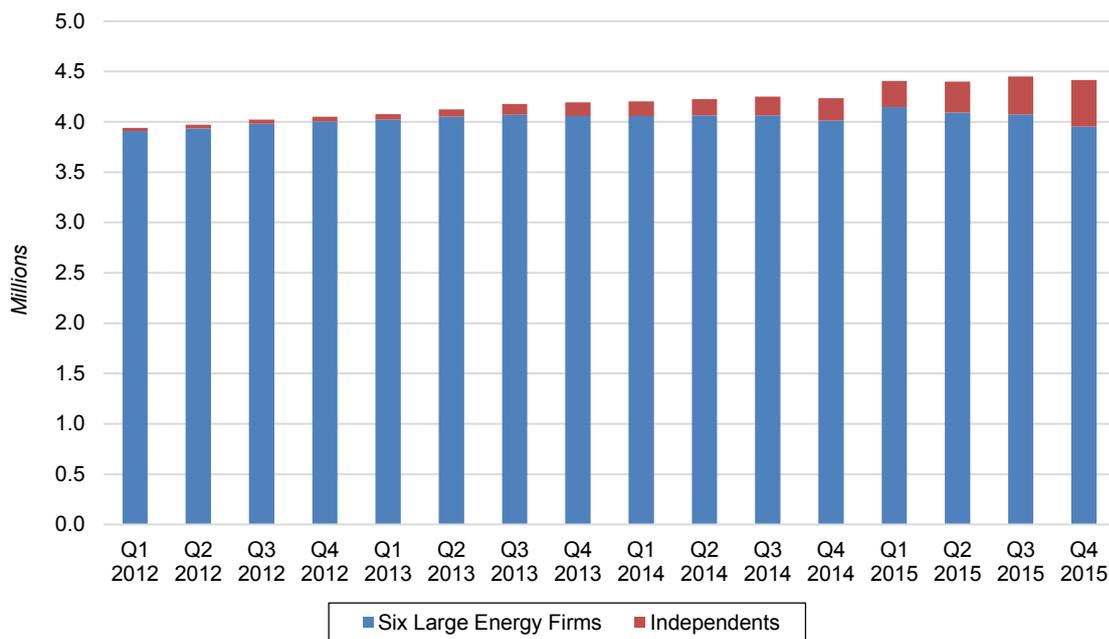
of customers were on prepayment meters, roughly 22% of customers paid by standard credit and 63% paid by direct debit. CMA analysis of data provided by the Six Large Energy Firms, Mid-tier Suppliers, Utilita and Economy Energy.

¹³⁹ For example, Ofgem reported that in 2014 more than 60% of prepayment meters were installed due to debt. Based on Ofgem Social Obligations reporting 2014. See Ofgem's [Prepayment review: understanding supplier charging practices and barriers to switching](#).

¹⁴⁰ For the purpose of this report, we distinguish the prepayment segments from the other segments of the domestic retail energy markets which also comprise the supply of energy to domestic customers that are not on a prepayment meter, ie that are on a credit meter (eg smart non-prepayment meters and dumb non-prepayment meters).

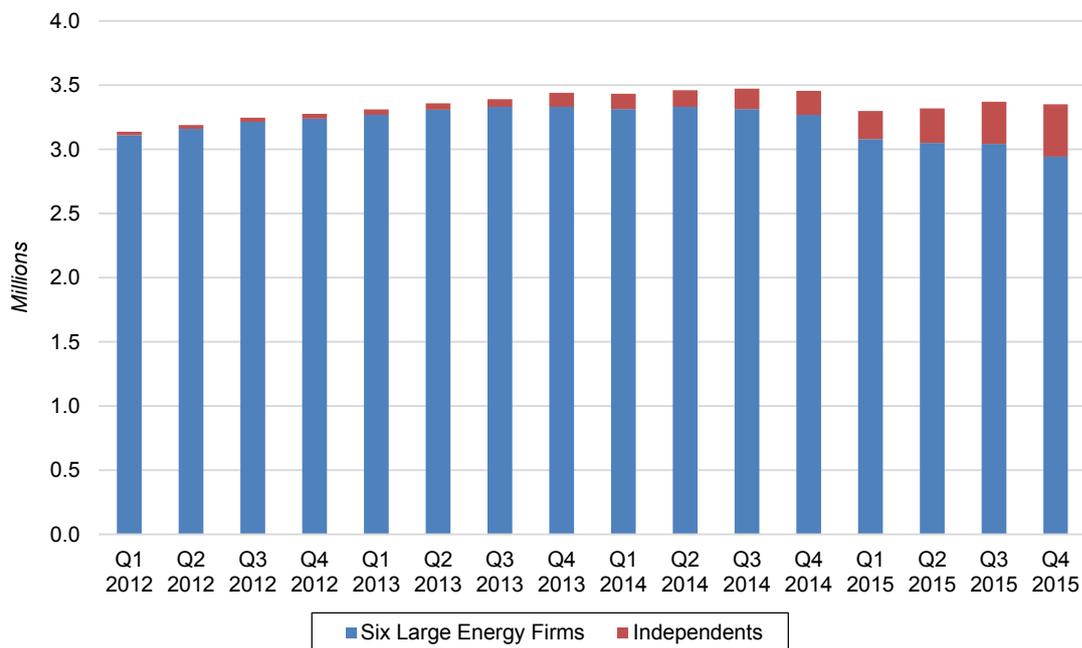
¹⁴¹ We note that respondents to the Addendum and Provisional Decision on Remedies said that the participation of smaller suppliers had grown much more quickly than we suggested. For example, Scottish Power told us that the number of prepayment customers that it had lost (based on de-registrations) to independent suppliers in each quarter had increased significantly from Q4 2013 to Q4 2015, such that by Q4 2015 the number of prepayment customers lost to independent suppliers was similar to the number of direct debit customers lost to independent suppliers. See Scottish Power's response to the Addendum, pp2 & 3. In addition, Utilita noted that the penetration of independent suppliers in the prepayment segments was roughly the same (12%) as the credit segments (13%). See Utilita's response to the provisional decision on remedies, p6. Also see Centrica's response to the Addendum p1, EDF Energy's response to the Addendum pp8–9 and SSE's response to the Addendum, pp9 & 10.

Figure 8.34: Electricity account numbers in the prepayment segments for the Six Large Energy Firms and independent suppliers



Source: CMA analysis based on data from the Six Large Energy Firms, the Mid-tier Suppliers, Economy Energy and Utilita.

Figure 8.35: Gas account numbers in the prepayment segments for the Six Large Energy Firms and independent suppliers



Source: CMA analysis based on data from the Six Large Energy Firms, the Mid-tier Suppliers, Economy Energy and Utilita.

8.271 The share of independent suppliers has been increasing over time, and we note that in Q4 2015, the share of the independent suppliers stood at 12.1% and 10.5% for gas and electricity, respectively. In comparison, in the direct

debit segments,¹⁴² the share of the (larger) independent suppliers stood at 12.4% and 11.9% for gas and electricity, respectively.

Outcomes in the prepayment segments

8.272 We have investigated certain outcomes in the prepayment segments relative to the direct debit segments. In particular, we have focused on:

- (a) the range of tariffs available in the prepayment segments;
- (b) the pricing of tariffs in the prepayment segments relative to the direct debit segments; and
- (c) the extent to which customers on prepayment meters switch to credit meters.

- *Tariff choices available to prepayment customers of the Six Large Energy Firms*

8.273 In relation to the availability of tariffs in the prepayment segments we have assessed the tariffs available as of October 2015. This analysis shows that the number of tariffs available in the prepayment segments is materially lower than the number of tariffs available in the direct debit segments.

8.274 In particular, all of the Six Large Energy Firms offer a prepayment version of their SVT as a default tariff, adjusted to reflect the cost-to-serve differential. In addition to this:

- (a) EDF Energy offers a prepayment-only fixed-term price tariff;
- (b) Scottish Power offers a charity support tariff, which is one of its relatively more expensive fixed-price offers though cheaper than SVT (which we take to be a retention tariff) with a prepayment add-on option;
- (c) Centrica offers a fixed tariff for prepayment customers under its British Gas brand;
- (d) E.ON has recently introduced Smart PAYG which allows customers access to all of E.ON's four core tariffs (and equivalent discounts) while using a prepayment method; and

¹⁴² The figures for the direct debit segments are based on data from the Six Large Energy Firms, all of the Mid-tier Suppliers, Economy Energy and Utilita. [§] In light of this all of Ovo Energy's credit meter customers have been treated as direct debit customers for the purpose of these shares and we do not believe that this materially affects the shares that have been estimated.

(e) RWE offers a fixed-price tariff to prepayment customers.

- 8.275 E.ON told us that after a recent pilot programme it would be rolling out SMART PAYG meters to customers in Q1 2016. These SMART PAYG meters will allow prepayment customers to access exactly the same E.ON tariffs as any other customer. Although this roll-out will eventually be nationwide we understand that currently it will only be available to existing E.ON prepayment customers who live in certain regions and that availability also depends on the customer's metering setup (for example, it is not available to all restricted meter customers or where a customer has more than one meter, either electricity or gas, and not all of these meters are prepayment meters).¹⁴³
- 8.276 In light of the above observations, we consider that the number of tariffs offered by the Six Large Energy Firms in the prepayment segments is significantly fewer than the number of tariffs they offer in the direct debit segments. For example, at Q2 2015 the Six Large Energy Firms, excluding white labels, offered 15 fixed-term tariffs to direct debit dual fuel customers with unrestricted meters in addition to a variable tariff each.¹⁴⁴ In contrast, based on the information above, as at October 2015 the Six Large Energy Firms, excluding white labels, offered four fixed-term tariffs to all prepayment customers in addition to a variable tariff each, while all E.ON's tariffs are also available to customers on E.ON's SMART PAYG meters.
- 8.277 In addition, through white labels, the Six Large Energy Firms, at Q2 2015 offered four fixed-term tariffs and three variable tariffs to direct debit dual fuel customers with unrestricted meters, but no fixed-term tariffs and one variable tariffs to prepayment dual fuel customers with unrestricted meters.¹⁴⁵
- 8.278 The number of tariffs offered by independent suppliers in the prepayment segments has increased over time. For example, at Q2 2015 independent suppliers offered ten prepayment tariffs (all variable) compared with four at Q1 2012.¹⁴⁶ However, the number of tariffs offered by independent suppliers is materially lower in the prepayment segments compared with the direct debit segments where, at Q2 2015, independent suppliers offered 50 tariffs.¹⁴⁷
- 8.279 Overall, as at Q2 2015, there were three fixed and 17 variable tariffs available to dual fuel prepayment customers whereas there were 43 fixed

¹⁴³ E.ON's website: 'Smart Pay As You Go is coming'.

¹⁴⁴ This is based on data from Energylink.

¹⁴⁵ This is based on data from Energylink.

¹⁴⁶ This is based on data from Energylink.

¹⁴⁷ This is based on data from Energylink.

and 35 variable tariffs available to dual fuel customers in the direct debit segments. We note that by October 2015 there was at least one additional fixed-term tariff available to prepayment customers, therefore we have checked the situation as at 17 May 2016 using the PCW uSwitch. In doing this we found that, although the exact number varied by region, there were at most six fixed-term tariffs and 20 variable tariffs available to dual fuel prepayment customers.

8.280 Therefore it can be seen that customers have a materially lower number of prepayment tariffs to choose from in comparison with the direct debit segments. Below we look at evidence on the extent to which the cheapest tariffs that are available in the prepayment segments are comparable (even when accounting for differentials in the costs to serve) to the cheapest tariffs in the direct debit segments.

- *Comparison of the tariffs offered in the prepayment segments compared with the cheapest tariffs offered in the direct debit segments*

8.281 In response to the Addendum some of the respondents, the Six Large Energy Firms in particular, submitted that the Addendum may have been more pessimistic about prospects of competition in the prepayment segments than the most recent evidence suggested. In relation to tariffs respondents noted that more recent data than the Q2 2014 data used showed keener pricing in the prepayment segments than suggested by the Addendum.¹⁴⁸

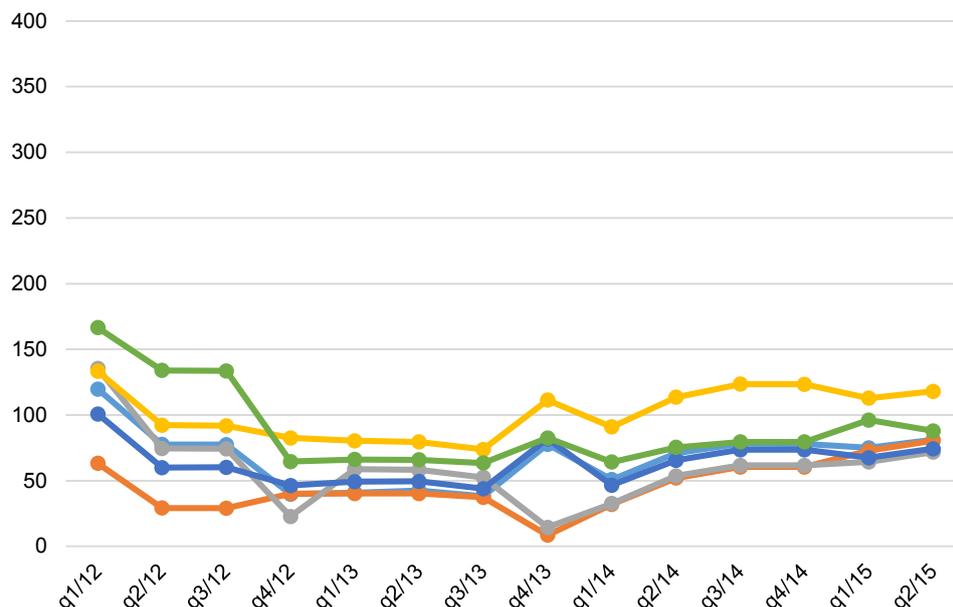
8.282 To assess this we have first looked at the gains from switching available to customers in the prepayment segments and how they changed over time. As set out in Appendix 9.2, we estimated annual potential savings in the gas and electricity bills for customers of the Six Large Energy Firms at each quarterly snapshot from Q1 2012 to Q2 2015.

8.283 Figure 8.36 shows the trend of the annual potential savings (in absolute terms and as a % of bill) that dual fuel prepayment customers of the Six Large Energy Firms could have potentially made if they had switched to another supplier while staying on a prepayment meter.

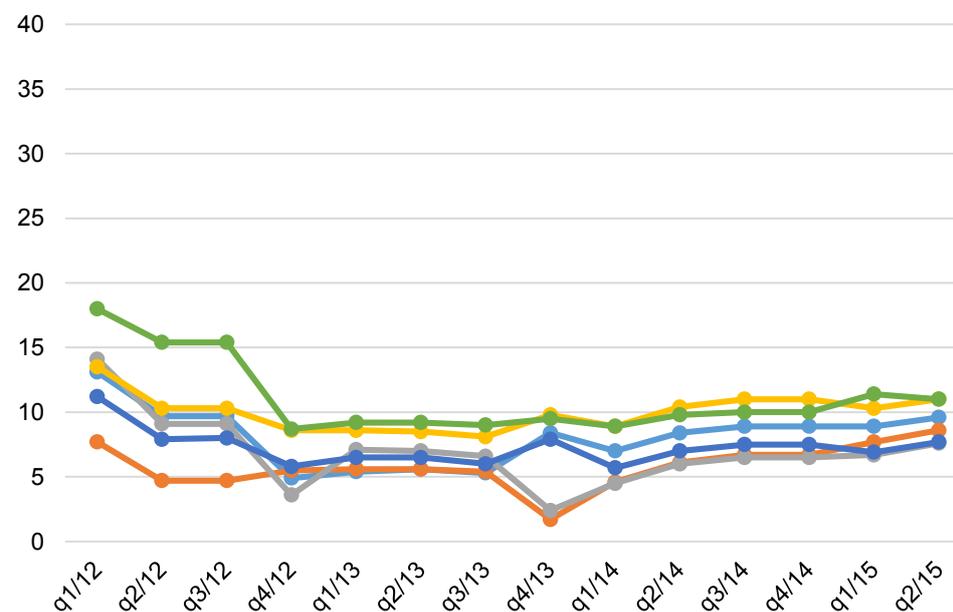
¹⁴⁸ For example, see SSE's response to the Addendum p11. Spark Energy also made similar comments in relation to the provisional decision on remedies, that is, the analysis included a period only up until Q2 2015, however, we note that our updated analysis on market shares is until Q4 2015 and our PCW analysis below is based on April 2016. See Spark Energy's response to the provisional decision on remedies, p2.

Figure 8.36: Weighted average potential savings (absolute and as a % of bill) available to prepayment meter dual fuel customers of the Six Large Energy Firms if they had switched to another supplier but to a prepayment meter tariff in each quarter Q1 2012 to Q2 2015

In £



As a percentage of the bill



Source: CMA analysis.

Notes:

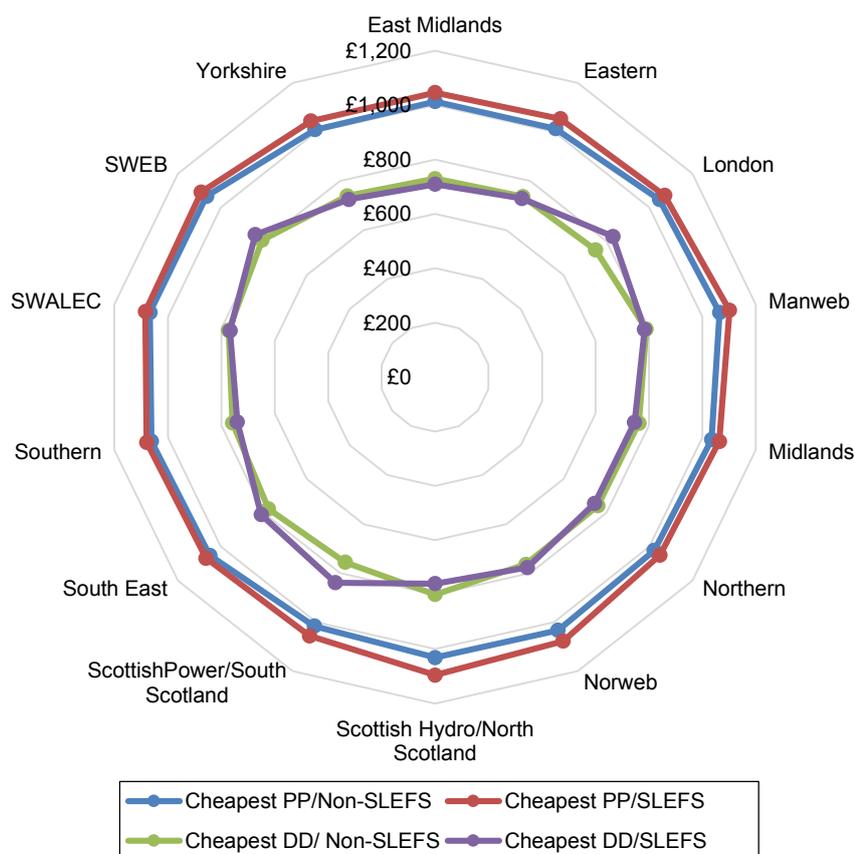
1. Within each quarter the weighted average has been calculated using data on the distribution of consumption and the weights reflect the number of accounts that belong to each tariff.
2. Base: all dual fuel prepayment customers.
3. Exit fees are not deducted from the annual potential savings where exit fees are charged by the current supplier.

8.284 For dual fuel customers the gains available from switching to the cheapest tariff in the prepayment segments appear fairly static over time, with a modest increase from the beginning of 2014. In Q2 2015, they ranged from

just over £70 (or 8% of the annual bill) for dual fuel customers of [X] and of [X] to roughly £120 (or 11% of the annual bill) for dual fuel customers of [X]. This is in contrast with a sharp increase in the gains available to dual fuel prepayment customers if they were able to switch to a credit meter, which roughly doubled between 2013 and 2015, reaching between £290 and £370 as of Q2 2015, depending on the supplier.

- 8.285 We have also looked at the more recent pricing data by conducting a search on a PCW on 28 April 2016. Figure 8.37 below shows for every GB region the cheapest tariff offered by the Six Large Energy Firms and independent suppliers for both prepayment meters and credit meters on the PCW uSwitch.

Figure 8.37: Comparison of cheapest dual fuel prepayment meter bills and direct debit bills as at 28 April 2016 based on Ofgem medium typical consumption values, by region and by supplier type



Source: CMA analysis.

Notes:

1. Cheapest bills identified on uSwitch on 28 April 2016 based on Ofgem medium typical consumption values (12,500 kWh of gas and 3,100 kWh of electricity).
2. Monthly direct debit was used for direct debit bills.
3. E.ON recently began rolling out SMART PAYG meters to customers in Q1 2016 and these customers will have access to all of E.ON's four core tariffs (and equivalent discounts) while using a prepayment method, however, these tariffs were not shown on the PCW.
4. Consistent with our approach taken elsewhere, Mid-tier Suppliers were used for non-Six Large Energy Firms in relation to direct debit. Scottish Power had the lowest bill in six regions (Online Fixed Price Energy May 2017), Co-operative Energy in three regions (Co-op Fix for Longer September 2017), EDF Energy in three regions (Blue+ Price Promise May 2017) and First Utility in two regions (First Fixed June 2017 v2).
5. For prepayment all non-Six Large Energy Firms on uSwitch were used. Robin Hood Energy had the lowest bills in nine regions (Robin Hood Energy Evergreen), Utilita in three regions (Smart Energy), Spark Energy in one region (Saver Fixed March 2018 – prepayment) and First Utility in one region (First Variable (Prepayment)).
6. The relevant postcodes used were: DE23 3XX for East Midlands, CB2 3ET for Eastern, WC1B 4AD for London, L1 5HA for Manweb, B4 7QD for Midlands, YO31 7EH for Northern, LA1 1RH for Norweb, PH15 2EH for Scottish Hydro/Northern Scotland, TD7 5JB for Scottish Power/Southern Scotland, BN2 1QB for South East, SO17 3RY for Southern, CF24 3FL for SWALEC, TR18 4SY for SWEB and DN1 2QE for Yorkshire.
7. Eastern is also known as East Anglia, Manweb is also known as Merseyside and North Wales, Northern is also known as North East, Norweb is also known as North West, South East is also known as Seeboard, Southern is also known as Southern Electric, SWALEC is also known as South Wales and SWEB is also known as South West.

8.286 In the majority of the regions the cheapest dual fuel prepayment tariff is offered by an independent supplier, though the difference from the cheapest of the Six Large Energy Firms' dual fuel prepayment tariffs is relatively small at roughly £17 to £64. The difference between the cheapest dual fuel prepayment and direct debit tariffs is very substantial, varying between £259 and £322, depending on the region. The difference between the cheapest

dual fuel prepayment and direct debit tariffs is therefore significantly larger than any cost to serve differential which we estimate to be £63 (see Appendix 9.8).

- 8.287 Therefore if the similar tariffs were offered in the prepayment segments (ie equivalent to the lowest priced direct debit tariff plus the cost-to-serve differential), prepayment customers would be able to make substantial gains from switching (by between £195 and £260, depending on the region) relative to the gains that are currently available in the prepayment segments.
- 8.288 Based on the above tariffs we consider that the Six Large Energy Firms do not offer tariffs in the prepayment segments that are comparable (even accounting for differentials in the costs to serve) to the cheapest in the direct debit segments.¹⁴⁹
- 8.289 Similarly, we do not consider that independent suppliers were offering tariffs comparable (even accounting for differentials in the costs to serve) to the cheapest in direct debit segments to prepayment customers. Therefore while we have observed that more recently independent suppliers have increased their tariff offerings and share in the prepayment segments, this has not materially reduced the substantial disparity in gains available to customers in the prepayment segments compared with customers in the direct debit segments.
- 8.290 Overall, therefore, while the independent suppliers continue to gain share, albeit from a low base, we have seen little evidence of price competition being intensified recently in the prepayment segments, certainly when compared with the direct debit segments.

Parties' responses

- 8.291 In response to the Addendum, RWE npower told us that our analysis used an inappropriate benchmark as using direct debit acquisition tariffs failed to take into account:¹⁵⁰
- (a) all relevant product characteristics; and
 - (b) the interrelated nature of acquisition tariffs and SVTs.

¹⁴⁹ As noted although E.ON offers all of its tariffs to customers on E.ON's SMART PAYG meters, but the roll-out of these SMART PAYG meters is currently limited to certain existing customers, see paragraph 8.275.

¹⁵⁰ See RWE npower response to the Addendum, p2.

- 8.292 We note that both these points have been raised in relation to our analysis more generally and are dealt with in Section 9.
- 8.293 In response to the Addendum SSE told us that:¹⁵¹
- (a) it was inappropriate to use direct debit acquisition tariffs as a basis for comparison without demonstrating that they were sustainable;
 - (b) the analysis was flawed as it ignored non-price factors and customer preferences; and
 - (c) the potential gains from switching within the prepayment segments were commensurate with those that would be expected in any competitive market.¹⁵²
- 8.294 In relation to (a) we note that our analysis as set out above is comparing the prices available in the prepayment segments and direct debit segments. As set out this shows that the cheapest prepayment tariffs are materially more expensive (even when taking into account differentials in the cost to serve) than the cheapest direct debit tariffs.
- 8.295 In relation to (b) and (c) we note that these points have been raised in relation to our analysis more generally and are dealt with in Section 9.
- 8.296 Centrica, EDF Energy and Robin Hood Energy told us that there were competitive acquisition tariffs. As examples Centrica and EDF Energy cited their fixed-term tariffs and Robin Hood Energy its standard prepayment tariff.¹⁵³ In particular, EDF Energy noted that the definition of whether a tariff was competitive in the prepayment segments should depend on whether it attracted customers from other tariffs and therefore provided a competitive constraint.
- 8.297 As noted above we do not believe that these tariffs offered by Centrica, EDF Energy and Robin Hood Energy are comparable to the cheapest direct debit tariffs (even when taking into account differentials in the cost to serve). Further, our view is not that there are no acquisition tariffs in the prepayment segments. Rather, our view is that the cheapest tariffs in the prepayment

¹⁵¹ See SSE's response to the Addendum.

¹⁵² SSE noted that based on its own data the potential prepayment meter gains from switching doubled during 2015 to over £110. See SSE response to the Addendum, p3.

¹⁵³ See Centrica's response to the provisional decision on remedies, p4, EDF Energy's response to the provisional decision on remedies, p10 and Robin Hood Energy's response to the Addendum, p1.

segments are materially more expensive (even when taking into account differentials in the cost to serve) when compared with direct debit tariffs.

- 8.298 E.ON noted that the cheapest direct debit acquisition tariff would vary between suppliers throughout the year based on various factors¹⁵⁴ and therefore it was not an appropriate benchmark against which to compare other tariffs.¹⁵⁵ However, E.ON did not provide any evidence in relation to why the points in time chosen for our analysis were not representative.
- 8.299 E.ON also told us that competition in the prepayment segments was strong, but based around the SVTs the suppliers could offer, given the technical constraints noted below. We agree that competition in the prepayment segments appears to be based around SVTs, and a limited number of fixed-term tariffs, however we do not agree, as outlined above that competition in the prepayment segments is strong.
- 8.300 Energy UK said that, as of 1 April 2016, there were a number of prepayment tariffs on offer and consumers could save up to £200 by switching to the cheapest prepayment deal.¹⁵⁶ Similarly Utilita told us that there was good competition in the prepayment segments and a number of suppliers were actively gaining prepayment customers at prices significantly below those being maintained by the incumbent suppliers.
- 8.301 We note that while the number of prepayment tariffs on offer has increased it is still materially lower than in the direct debit segments. In addition, although prepayment customers may be able to make material savings by switching to the cheapest prepayment tariff the cheapest prepayment tariffs are materially more expensive (even when taking into account the cost to serve) than the cheapest direct debit tariffs as outlined in paragraph 8.286.
- 8.302 BGL said that competition was weaker in the prepayment segments and that there was a gulf between the competitiveness of tariffs available to prepayment customers and customers with standard meters.¹⁵⁷

Conclusion on competition in the prepayment segments

- 8.303 Based on the above we therefore consider that the nature of competition in the prepayment segments is not the same as, and is less intense than, competition in the direct debit segments. In particular, while the independent

¹⁵⁴ E.ON noted a supplier's wholesale input costs, aspirations to grow or maintain its customer base and the quality of its product or service as factors that its prices would depend on. See E.ON's response to the Addendum p4.

¹⁵⁵ See E.ON response to the Addendum p4.

¹⁵⁶ See Energy UK response to the provisional decision on remedies, p3.

¹⁵⁷ See BGL response to the Addendum.

suppliers continue to gain market share, albeit from a low base, and the number of tariffs on offer increases we have seen little evidence of price competition being intensified recently in the prepayment segments, certainly when compared with the direct debit segments.

- 8.304 In Section 9 we consider to what extent this is due to material differences in the level of customer engagement in the prepayment segments when compared with the direct debit segments and the extent to which this is due to supply-side constraints on competition in the prepayment segments.

Competition for restricted meter customers

- 8.305 Restricted meters include any metering arrangement whereby a domestic customer's consumption at certain times and, in some cases, for certain purposes (for example, heating) is separately recorded.¹⁵⁸ These meters allow for customers to be charged lower rates for electricity used at times when demand is lower.
- 8.306 Where a restricted meter has more than one register the restricted meter has to be switched between recording usage on each register, similarly where a restricted meter only operates at certain times of the day the electricity supplied through that meter needs to be switched on and off. This switching process might be controlled remotely by radio signal (ie teleswitched) or locally (mechanically or electronically). Teleswitching can be either dynamic, static or semi-static. With dynamically teleswitched (DTS) meters the operational times might be changed – on the instructions of the host supplier¹⁵⁹ – in response to changes in market conditions.
- 8.307 There are currently around 4.4 million restricted meters (around 17% of all customer accounts) of which over 3.5 million are Economy 7 meters¹⁶⁰ (about 14% of customer accounts) and around 700,000 (about 2% of customer accounts) are non-Economy 7 restricted meters.¹⁶¹

¹⁵⁸ For example, a customer may have one meter covering all consumptions with two registers, a peak consumption register and an off-peak consumption register. Alternatively a customer may have two meters where one is for the space and water heating system and only operates at certain times of the day and the other is for all other electricity usage and operates at all times.

¹⁵⁹ DTS meters are switched using teleswitching codes where each code is controlled by a 'group code sponsor' or host where the incumbent supplier in a region is the host for DTS meters in that region. This means that in each region the incumbent supplier controls when DTS meters are switched. Ofgem (2013), [The state of the market for customers with dynamically teleswitched meters](#).

¹⁶⁰ For these purposes, White Meter 1 and White Meter 8 have not been included in Economy 7 meters. However, we note that Scottish Power told us that in Scotland these meters were equivalent to Economy 7 meters.

¹⁶¹ Note that this will be an overestimate. This is because this figure is the number of meters as a percentage of the total number of electricity accounts, but some customers will have two restricted meters.

- 8.308 The options available to customers with Economy 7 meters are broadly similar to those available to customers with single-rate meters. In particular, each of the Six Large Energy Firms and the Mid-tier Suppliers offers Economy 7 fixed-term tariffs which are advertised by suppliers and supported by PCWs and suppliers' own online search facilities. This is consistent with a recent Ofgem statement that most customers with restricted meters are on Economy 7 meters, for which the choice of tariffs and suppliers is similar to that for customers on single-rate meters (ie meters with a single register and through which energy is continuously provided).
- 8.309 Further, the factors that we have identified in Section 9 and set out in more detail in Appendix 9.5 in relation to restricted meters do not apply to Economy 7 meters. Accordingly, in the rest of this section we have focused solely on the position of customers on non-Economy 7 restricted meters (and, in the remainder of this report, refer to this group as 'customers on restricted meters' unless otherwise specified). However, we note that the gains from switching (see paragraph 8.262) and detriment (see Section 14) for customers with Economy 7 meters are larger as a percentage of their bill than for customers with single-rate meters. This suggests that competitive pressures are not as strong for customers with Economy 7 meters when compared with customers with single-rate meters.
- 8.310 In response to our provisional findings we received submissions in relation to restricted meters from several consumer bodies. These submissions stated that customers on certain meters often had little or no choice of supplier, that customers on these meters faced barriers to switching and that the specific tariffs offered for these meters did not compare favourably, in terms of price, to tariffs available to those with single-rate or Economy 7 meters (see Appendix 9.5).
- 8.311 We have found that the options available to customers differ based on the exact meter type as some meters are supported by more suppliers than others.
- 8.312 For Economy 10 meters most of the Six Large Energy Firms offer tariffs to support these meters and accept new customers on these meters,¹⁶² while some are also installing some new Economy 10 meters. However, as with other restricted meters, Economy 10 meters are not supported by PCWs nor do the Mid-tier Suppliers provide specific Economy 10 tariffs.

¹⁶² These were Centrica, EDF Energy, E.ON and SSE. For example, E.ON told us [REDACTED]. However, RWE npower said that, with the exception of Economy 7, [REDACTED].

- 8.313 For other restricted meters we have received little, if any, evidence that either the Six Large Energy Firms as a group or the Mid-tier Suppliers as a group are actively competing to attract customers with restricted meters. This is reflected in that many restricted meter customers do not have a choice of suppliers offering bespoke tariffs (ie tariffs designed to support their specific type of restricted meter). For example, we understand that only five of the Six Large Energy Firms have bespoke tariffs,¹⁶³ however, we note that of these RWE npower's meter-specific tariffs are all preserved tariffs and therefore not available to new customers and that the other four only offer bespoke tariffs to a limited range of restricted meters. In addition we note that Centrica offers its Economy 7 tariffs to these customers¹⁶⁴ and none of the Mid-tier Suppliers offers bespoke tariffs to customers on restricted meters (see Appendix 9.5).
- 8.314 In principle these customers can switch to a single-rate or an Economy 7 tariff offered by their supplier or rival suppliers, however, this involves certain costs which are discussed in more detail in Section 9 and Appendix 9.5.
- 8.315 Table 8.15 shows the incumbent share of supply by PES region for restricted meters as at September 2015¹⁶⁵ and separately for electricity (for all electricity meters including restricted meters) and gas as at July 2015. We note that the figures for restricted meters are only based on data for the Six Large Energy Firms while the figures for electricity and gas include all suppliers.¹⁶⁶
- 8.316 We have found that within each of the PES regions the incumbent electricity supplier, as at September 2015,¹⁶⁷ supplied between 40% and 91% of electricity customers with restricted meters,¹⁶⁸ with the incumbent share at over 70% in ten of the 14 regions.¹⁶⁹ Across GB the incumbent share of

¹⁶³ These are EDF Energy, E.ON, RWE npower, Scottish Power and SSE.

¹⁶⁴ [REDACTED]

¹⁶⁵ Note that information provided for SSE is as at June 2015.

¹⁶⁶ We note that the Mid-tier Suppliers have roughly 21,000 customers on restricted meters across Great Britain compared with a total of roughly 700,000 of all restricted meter customers. This equates to roughly 3% of all restricted meter customers.

¹⁶⁷ Note that information provided for SSE is as at June 2015.

¹⁶⁸ We note that the incumbency shares in the South East and South West regions are materially lower than in other PES regions. EDF Energy, the incumbent supplier in both of these regions, told us that, without access to the volumes of these meters from other suppliers and by region, it was not clear why the incumbency shares in these regions would be materially lower than in others. [REDACTED] We explored the extent to which these low incumbency shares may be due to the Six Large Energy Firms, other than EDF Energy, installing significant numbers of restricted meters in the South East and/or South West regions. However, we have not seen any evidence that these low incumbency shares are due to the installation of restricted meters by the other Six Large Energy Firms. Therefore it is not clear why the incumbency shares in these regions are materially lower.

¹⁶⁹ CMA analysis based on data from the Six Large Energy Firms.

supply in restricted meters is 79% which is significantly higher than the equivalent figure for all electricity (33%) and gas (37%) customers.¹⁷⁰

Table 8.15: Incumbent share of supply by PES region

Region	Non-Economy 7 restricted meters	Electricity (all)	Gas
Great Britain	[REDACTED]	[REDACTED]	[REDACTED]
East Anglia	[REDACTED]	[REDACTED]	[REDACTED]
East Midlands	[REDACTED]	[REDACTED]	[REDACTED]
London	[REDACTED]	[REDACTED]	[REDACTED]
Merseyside and North Wales	[REDACTED]	[REDACTED]	[REDACTED]
Midlands	[REDACTED]	[REDACTED]	[REDACTED]
North East	[REDACTED]	[REDACTED]	[REDACTED]
North Scotland	[REDACTED]	[REDACTED]	[REDACTED]
North West	[REDACTED]	[REDACTED]	[REDACTED]
South East	[REDACTED]	[REDACTED]	[REDACTED]
Southern	[REDACTED]	[REDACTED]	[REDACTED]
South Scotland	[REDACTED]	[REDACTED]	[REDACTED]
South Wales	[REDACTED]	[REDACTED]	[REDACTED]
South West	[REDACTED]	[REDACTED]	[REDACTED]
Yorkshire	[REDACTED]	[REDACTED]	[REDACTED]

Source: CMA analysis.

Notes:

1. Figures for non-Economy 7 restricted meters are based on data provided by the Six Large Energy Firms for September 2015, except for SSE which is as at June 2015.
2. Figures for electricity and gas are based on Cornwall Energy data covering Q1 and Q2 2015.
3. Figures for electricity cover all types of electricity meter and therefore include non-Economy 7 restricted meters.
4. The incumbent gas supplier is British Gas. The incumbent electricity supplier is E.ON for East Midlands, East Anglia, North West; EDF for London, South East, South West; RWE for Midlands, North East, Yorkshire; Scottish Power for South Scotland, Merseyside and North Wales; SSE for North Scotland, Southern, South Wales.

8.317 In addition, for certain types of restricted meters, we have been able to identify the percentage of customers who, as at September 2015,¹⁷¹ continued to receive electricity from the same incumbent supplier that installed their restricted meter. These customers have meter types, and are on supporting tariffs, that when installed were unique to an incumbent electricity supplier. In particular, we have investigated SSE’s THTC and SuperDeal meters, Scottish Power’s ComfortPlus meters, E.ON’s Heatwise meter,¹⁷² RWE’s SuperTariff meter¹⁷³ and EDF Energy’s WarmWise meter.

8.318 For customers on these types of restricted meter, the original incumbent supplier still supplies nearly [REDACTED]% of such customers. In particular, the lowest incumbent share was [REDACTED]% while for four of the seven meters the share was over [REDACTED]%.¹⁷⁴ For example, in relation to THTC meters in North Scotland and ComfortPlus meters in South Scotland the incumbent supplier

¹⁷⁰ Figures for electricity and gas are based on Cornwall Energy data covering Q1 and Q2 2015.

¹⁷¹ Note that information provided for SSE is as at June 2015.

¹⁷² E.ON told us that Heatwise meters were installed by E.ON specifically in the East Midlands region, however, it had no visibility in relation to whether other suppliers had installed Heatwise meters in any region.

¹⁷³ RWE npower told us that SuperTariff was a ‘brand’ tariff name used by Northern Electric, now part of the RWE group, in the North East. RWE npower noted that a [REDACTED] as incumbents in those regions offered their own tariffs with similar characteristics to SuperTariff.

¹⁷⁴ For WarmWise the incumbent share was [REDACTED]%, for Heatwise [REDACTED]%, for SuperTariff [REDACTED]%, for ComfortPlus Control [REDACTED]%, for ComfortPlus White Meter [REDACTED]%, for THTC [REDACTED]% and for SuperDeal [REDACTED]%. We noted that RWE npower told us [REDACTED] and this is discussed in more detail in Appendix 9.5.

in each region (SSE and Scottish Power respectively) appears to be the only supplier that offers bespoke tariffs for these meters and each has [REDACTED] of the share of supply.¹⁷⁵

Conclusion on restricted meters

8.319 Based on the above we consider that the nature of competition in relation to restricted meters is not the same as, and is less intense than, competition in relation to unrestricted and Economy 7 meters. In Section 9 we consider to what extent customers on restricted meters face additional barriers to accessing and assessing information and barriers to switching supplier and/or tariff.

Competition in the devolved nations and regional competition

8.320 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.

8.321 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

¹⁷⁵ We understand that E.ON has some customers ([REDACTED]) on these three meters with the majority on E.ON's single-rate SVT tariff as E.ON does not offer a bespoke tariff for all these meters. However, E.ON does offer a bespoke tariff to a subset of the ComfortPlus meters, referred to as 'Weathercall' meters, and has [REDACTED] customers with these meters on a tariff called 'Electrical Heating Comfort Extra Control'. SSE has [REDACTED] customer on ComfortPlus meters all on a bespoke SVT tariff, however, we understand that this tariff is not available to new customers. RWE npower also has some customers on these meters ([REDACTED]).

(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.

8.322 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).

8.323 A relatively high proportion of customers in both Scotland and Wales (29%) had been with their supplier for more than ten years (compared with 25% in England).¹⁷⁶ 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.

8.324 Market concentration is higher in Scotland and Wales compared with the GB average, and lower in England, as shown in Table 8.16.

Table 8.16: HHIs in Scotland, Wales and England for 2015

<i>Area</i>	<i>Electricity</i>	<i>Gas</i>
Great Britain	1,440	1,890
England	1,455	1,889
Wales	1,708	1,940
Scotland	2,194	2,207

Source: CMA analysis of data submitted by Cornwall Energy.

Note: HHI calculations are based on the market shares of the Six Large Energy Firms.

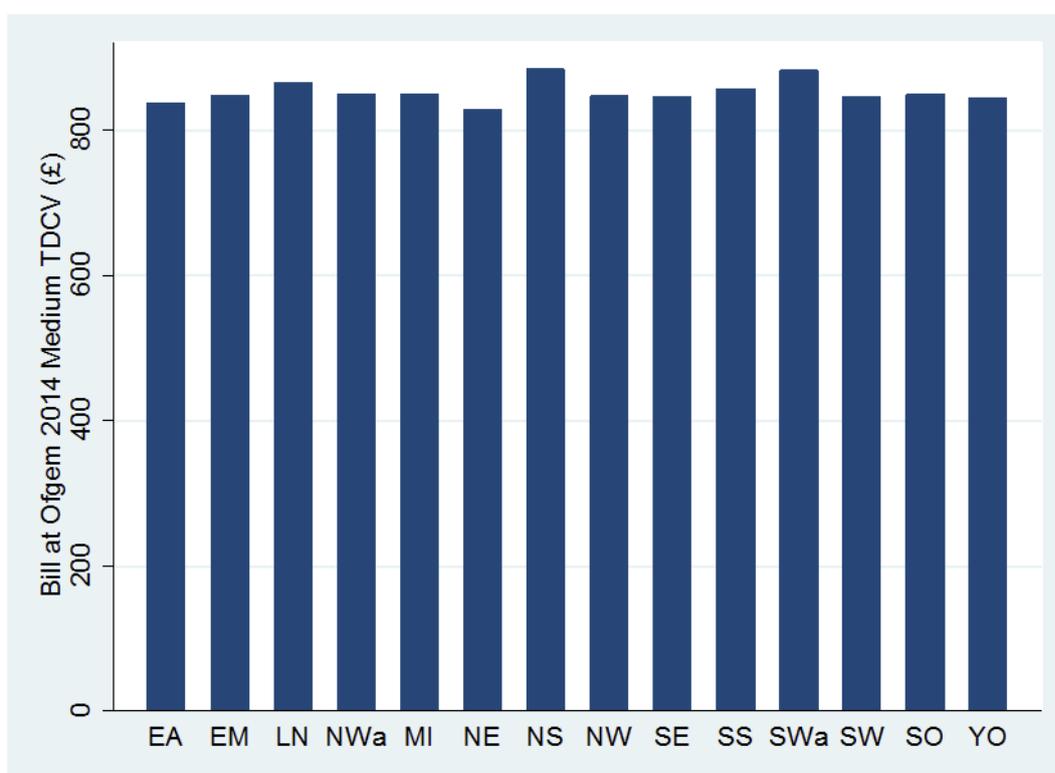
8.325 HHI calculations for Wales include Merseyside. We noted above that the two regions in Great Britain where the electricity incumbent has a market share of over 50% are North Scotland and South Wales, which, as of January 2015, had HHIs of 4,301 and 3,049 respectively, making them the two most concentrated regions in Great Britain.

¹⁷⁶ Figures relate to data submitted by the Six Large Energy Firms; data was extracted in mid-2014.

8.326 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.

8.327 The figure below shows how average dual fuel bills differ by PES region, controlling for network costs, payment method costs and assuming medium TDCV. As shown in the figure, some disparities in average prices persist even when controlling for these cost factors, with North Scotland and South Wales the most expensive regions.¹⁷⁷

Figure 8.38: Average dual fuel bill by region, Q2 2015



Source: CMA analysis

8.328 Overall, our view is that retail customers 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. However, in Section 9 we consider two specific constraints relating to meter type that are likely to affect customers in Scotland and Wales to a greater extent than customers in the rest of Great Britain: restricted meters, which are particularly prevalent

¹⁷⁷ Average prices in this analysis are defined as set out in paragraph 8.208.

in North and South Scotland; and prepayment meters, which are used by a higher proportion of customers in Wales and Scotland compared to England.

8.329 We have drawn on the preceding analysis in setting out our views on market definition in Section 3.

Conclusion

8.330 This section has analysed the nature of competition in domestic retail energy markets. We have identified four broad areas of concern.

8.331 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
- (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.

8.332 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**.

8.333 The second relates to **particular constraints affecting prepayment customers and customers on restricted meters**. We note that these customers face particular constraints on accessing the range of competitive prices available to customers in other segments.

8.334 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.

8.335 In the next section, we analyse these three areas in greater detail, and present our conclusions on whether they lead to an AEC.

9. Domestic retail AECs

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Introduction

9.1 This section provides our analysis and conclusions on whether any feature, or combination of features, of the domestic retail energy markets in Great Britain leads to an AEC. We consider the evidence on four areas where we expressed 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) **price discrimination and tacit coordination** in domestic retail energy markets;
- (c) **supply-side barriers to entry and expansion** in the supply of domestic prepayment customers; and

(d) the **regulatory framework** governing retail market competition, including notably the introduction of the **Retail Market Review** reforms and the regulations governing **gas and electricity settlement**.

9.2 We consider each of these areas in turn and then present our conclusions on whether any of these areas leads us to find one or more features that, alone or in combination, give rise to AECs.

Customer inactivity and lack of engagement

9.3 In Section 8, 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:

- (a) our survey suggests that around a third of domestic customers have never considered switching supplier;
- (b) we have observed that up to 55% of SVT customers have been on the default tariff with their supplier for over three years and up to 40% for over five years;¹ 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.

9.4 The objective of this section is to consider whether the lack of customer engagement is such that there is an 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 conclusions.

¹ We note that this is an upper bound estimate as for three suppliers the data provided was based on the length of the relationship with the supplier rather than the length of time on that supplier's SVT.

Breakdown of engagement and activity by customer characteristics

- 9.5 The analysis set out in Section 8 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.
- 9.6 The customer survey we conducted provides further evidence of the extent of customers' understanding of, and engagement in, domestic retail energy markets.² 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.
- 9.7 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.

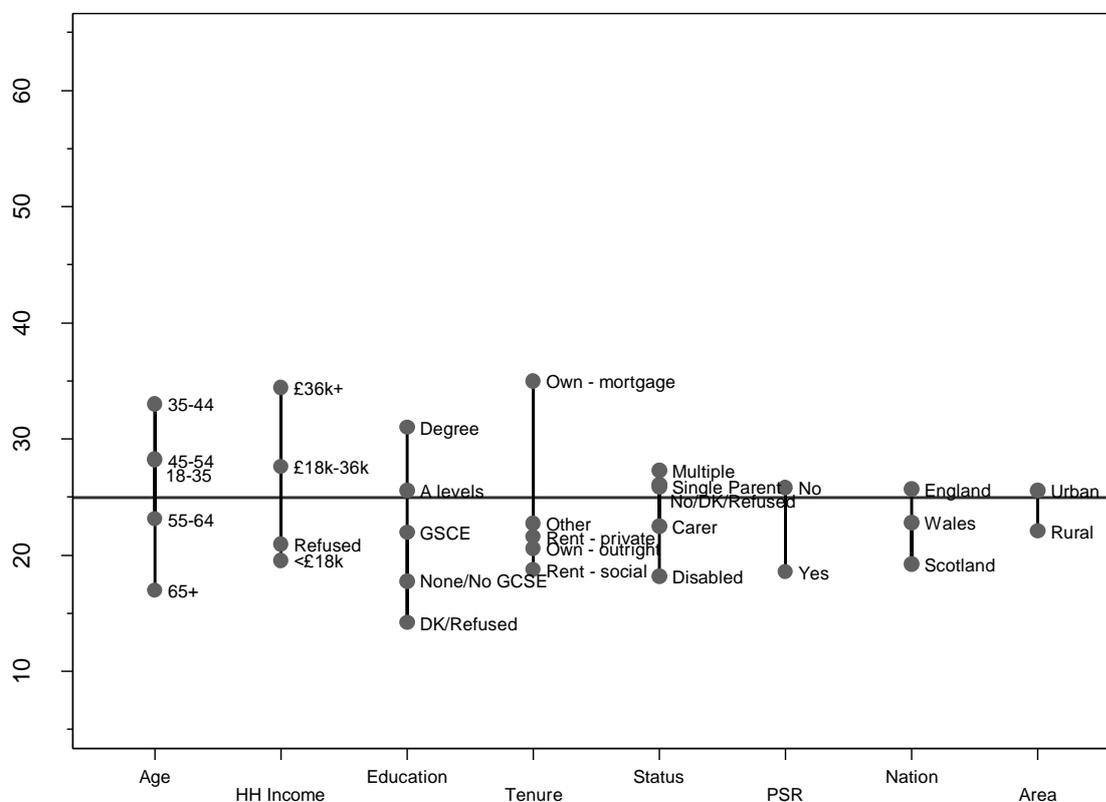
Summary of results

- 9.8 In Appendix 9.1 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.

² Appendix 9.1: CMA domestic customer survey results, provides a detailed description of the results of the survey.

9.9 Figure 9.1 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 9.1: 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 6,901, income 6,999, education 6,665, tenure 6,999, status 6,999, PSR 6,990, nation 6,999, area 6,976.

9.10 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.³

³ 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.

- 9.11 For age, income, education and tenure, the differences are both statistically significant⁴ 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.
- 9.12 Respondents with the characteristics described in paragraph 9.10 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 9.1.
- 9.13 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.
- 9.14 We also found that there is an association between the demographic characteristics described in paragraph 9.10 above and being on a dual fuel or single fuel SVT.⁵ 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.⁶
- 9.15 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 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

⁴ Our approach to statistical significance is discussed in Appendix 9.1: CMA domestic customer survey results, Annex C.

⁵ As set out in Appendix 9.1, this excludes those who are on the SVT for one fuel and non-standard tariffs for the other.

⁶ 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.

metrics are offset by suppliers proactively encouraging them to switch to a better tariff).

- 9.16 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 activities⁷, a higher proportion of its PSR customers were on fixed-term tariffs ([X]%) compared with non-PSR customers ([X]%). 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 alternative tariffs and promote the PSR.
- 9.17 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,⁸ promoted the PSR and the Warm Home 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).
- 9.18 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.⁹
- 9.19 The survey evidence also suggests that consumers living in social rented housing are less engaged. We conducted a separate survey in relation to those who rent, which covered both private and social tenants (the ‘Tenants Survey’), see Appendix 13.2. The Tenants Survey found that those who rent have low levels of engagement. In particular, over half (56%) of respondents had not considered switching supplier or tariff while living in their current home and nearly two-thirds (65%) said they had not switched supplier or tariff while living in their current home. We note that these results are not comparable to our main survey.
- 9.20 We also assessed to what extent gains from switching were associated with demographic characteristics. We noted in Section 8 that prepayment customers face a very restricted range of tariffs – and hence lower gains

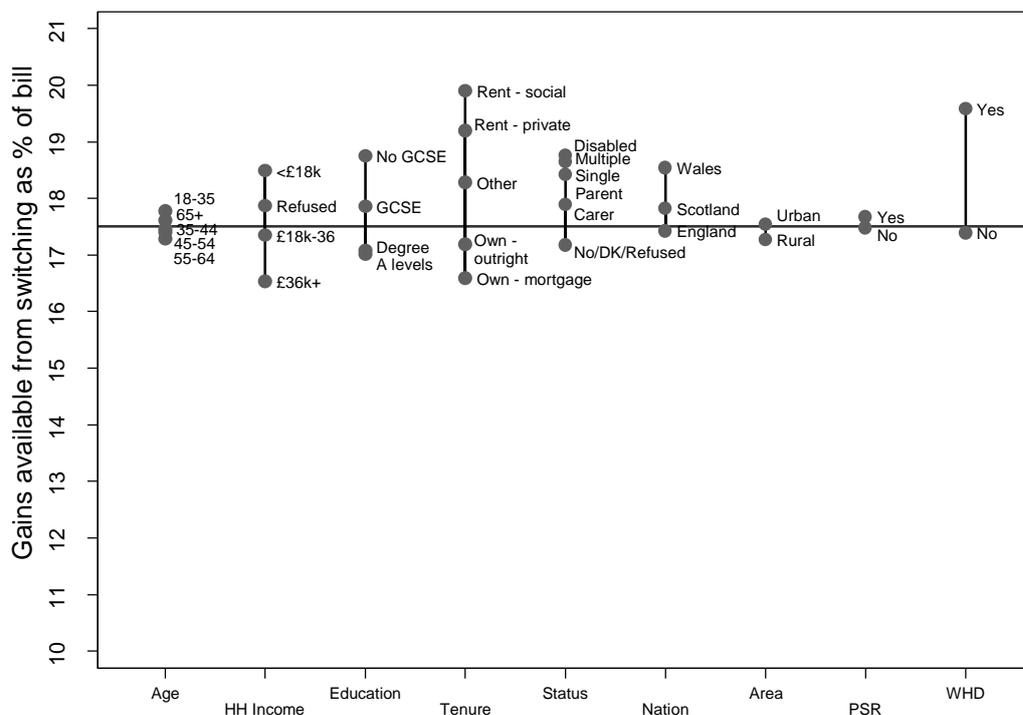
⁷ EDF Energy’s Personalised Support Service has been available to customers since the end of 2012.

⁸ Including StepChange, Debt Advice Charity, Shelter, MacMillan, Islington Council, Foundations and the Scottish Government

⁹ 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.

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 9.2: 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 9.1.
 Bases = 4,136 for all bars except age (4,078).

- 9.21 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 17% for those who own their homes outright and 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 (17% of the bill) and between the gains available to those who received the Warm Home Discount (20%) compared with those who do not (17%).
- 9.22 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 rebate¹⁰ 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.

Prepayment customers

9.23 In relation to payment method we have considered whether engagement is materially lower in the prepayment segments when compared with the other segments and the demographic characteristics of prepayment customers compared with other customers.^{11,12}

Summary of the results with respect to prepayment customers

9.24 In relation to switching behaviour, prepayment customers are not significantly more or less likely to have switched supplier in the last year (11%) compared with either direct debit (15%) or standard credit (7%) customers.¹³ However, there was a higher rate of switching in the last three years among direct debit customers (30%) compared with prepayment customers (22%), while prepayment customers were more likely to have switched supplier in the last three years compared with standard credit customers (15%).¹⁴ We note that our survey does not allow us to distinguish between those who actively switched and those who switched because, for example, they moved home, such that the length of time an individual has been at the same address may be one factor affecting results.¹⁵

9.25 We also note that switching rates are just one of a range of engagement statistics in our survey which capture different aspects of customer

¹⁰ 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.

¹¹ We note that customers on dumb prepayment meters can only pay by prepayment on their current meter whereas customers on dumb credit meters can either pay by direct debit or standard credit. Smart meters will allow prepayment customers to switch between all three payment methods without the need for a change of meter. See paragraph 9.217.

¹² In relation to the survey results set out below respondents are categorised based on their payment method. In particular, respondents are only included if they have the same payment method for all fuel types (that is, including those with only one fuel type).

¹³ We note that direct debit customers are more likely to switch in the last year than standard credit customers. Derived from question E30. Bases differ for customer group and include those who responded 'Don't know'. Prepayment customer base = 646, direct debit customer base = 5,121 and standard credit customer base = 973.

¹⁴ Derived from question E30. Bases differ for customer group and include those who responded 'Don't know'. Prepayment customer base = 646, direct debit customer base = 5,121 and standard credit customer base = 973.

¹⁵ For example, Good Energy said that prepayment meters were more prevalent in high transit rental accommodation where customers did not intend to stay for any period of time, see Good Energy response to the Addendum. We note that in England in 2014/15 the mean number of years in current home was 17.5 years for those who owned their home (24.1 for those who owned outright and 10.4 for those with a mortgage), four years for private renters and 11.4 years for social renters. See the Department for Communities and Local Government's [English housing survey headline report 2014 to 2015](#), Annex, Table 1.15. See paragraph 9.36 for a discussion of payment type and tenure type.

engagement, some of which are unrelated to the available gains from switching. In this respect, other results from the survey support an inference that levels of engagement are particularly low for prepayment customers when compared with direct debit customers, but not standard credit customers, as shown in the table below.

Table 9.1: Measures of engagement by payment method

	<i>Prepayment customers</i>	<i>Direct debit customers</i>	<i>Standard credit customers</i>
Shopped around in last 3 years	24*	43	26*
Never considered switching supplier	45*	26	47*
Switched supplier in last 3 years	22*	30	15*
Switched supplier in last year	11	15	7*
Likely to consider switching supplier in the next 3 years	29*	51	35*

Source: CMA analysis of survey data.

*These results are significantly different to those for direct debit customers based on 95% confidence intervals.

Notes:

1. Bases differ for customer group and include those who responded 'Don't know'. Prepayment customer base = 646, direct debit customer base = 5,121 and standard credit customer base = 973.
2. Derived from questions E1, E2, E13, E17, E30 and F1.
3. Respondents are categorised based on their payment method. In particular, respondents are only included if they have the same payment method for all fuel types (that is, including those with only one fuel type).

9.26 As set out below we have a particular concern about the material numbers of customers who appear to be fundamentally disengaged from the domestic retail energy markets in the sense that they have not considered exercising choice in the markets (see paragraph 9.128). In this respect, prepayment customers exhibit materially higher levels of fundamental disengagement compared with direct debit customers. As the table above shows:

- (a) a significantly higher proportion of prepayment customers said that they had never considered switching supplier (45%) compared with direct debit customers (26%);
- (b) a significantly lower proportion of prepayment customers said that they had shopped around in the last three years (24%) compared with direct debit customers (43%); and
- (c) a significantly lower proportion of prepayment customers said that they were likely to consider switching supplier in the next three years (29%) compared with direct debit customers (51%).

9.27 These results can be interpreted as evidence of disengagement irrespective of the size of potential gains – since a customer who has never considered switching is not likely to be aware of the potential gains available, and the same could be said for a customer who has not shopped around in the last three years.

- 9.28 Furthermore, prepayment customers are less likely than both direct debit and standard credit customers to believe that it is possible to: change tariff within their current supplier (66% vs 79% and 75%); and change payment method (72% vs 83% and 82%).¹⁶ Prepayment customers are also less likely than direct debit customers, but not standard credit customers, to believe that it is possible to change supplier (82% vs 92%).^{17,18} This is consistent with more recent evidence from Ofgem which shows that prepayment customers may not be as informed as direct debit customers concerning their right to switch supplier or tariffs.¹⁹
- 9.29 We also note that prepayment customers are less likely than direct debit customers, but not standard credit customers, to have ever switched tariff with their existing supplier (16% vs 34%).²⁰ Further, in relation to customers who had never switched tariff within the same supplier, prepayment customers were less likely than both direct debit and standard credit customers to have ever considered changing their energy tariff while staying with the same supplier (13% vs 36% and 33%).²¹
- 9.30 Therefore the overall weight of evidence, on balance, supports a finding that, despite similar levels of switching in the last year, a higher proportion of prepayment customers appear to be disengaged compared with direct debit customers. This evidence includes a range of disengagement statistics which are unrelated to the potential gains from switching, as well the evidence which shows that prepayment customers are less aware of their right to switch supplier or tariff than direct debit customers.
- 9.31 We also note that this evidence supports similar findings with respect to standard credit customers, although we have identified differences between prepayment and standard credit customers on certain measures of engagement. However, as discussed further below, prepayment segments are characterised, compared with the direct debit and standard credit segments, by higher barriers to engagement²² and specific supply-side constraints.

¹⁶ This might be explained by the fact that a change of payment method (excluding smart meters) requires a change of meter, which may be perceived as a barrier to switching. We explore this in more detail below.

¹⁷ This might be explained by confusion surrounding rights to switch when the customer has outstanding debt. We explore this in more detail below.

¹⁸ Derived from question E1. Bases differ for customer group and include those who responded 'Don't know'. Prepayment customer base = 646, direct debit customer base = 5,121 and standard credit customer base = 973.

¹⁹ The Ipsos MORI survey for Ofgem (Customer Engagement with the Energy Market: Tracking survey 2015) found that 63% of gas prepayment customers knew it was possible to switch to a different supplier, compared to 80% of monthly/quarterly direct debit customers.

²⁰ Derived from question E2. Bases differ for customer group and include those who responded 'Don't know'. Prepayment customer base = 646, direct debit customer base = 5,121 and standard credit customer base = 973.

²¹ Derived from question E3. Bases differ for customer group and include those who responded 'Don't know'. Prepayment customer base = 470, direct debit customer base = 2,954 and standard credit customer base = 668.

²² Subject to our discussion of barriers to engagement affecting customers on restricted meters.

Demographic characteristics of prepayment customers

- 9.32 We also considered the extent to which lower engagement of prepayment customers may be correlated to their demographic and household characteristics, and certain factors that may restrict the ability of prepayment customers to access and assess information about switching.
- 9.33 In relation to demographic characteristics, we noted that the groups of respondents who were less likely to have switched supplier in the last three years were those with any of the following characteristics: household incomes under £18,000 a year; living in rented social housing; without qualifications; aged 65 and over; with a disability or registered on the PSR (see paragraph 9.10). We have found that prepayment customers are disproportionately represented within the socio-demographic groups that, in our survey, showed lower levels of engagements (see Appendix 9.6 for more detail).²³
- 9.34 In relation to income, when compared with both direct debit and standard credit customers, prepayment customers are significantly: less likely to have an income of over £36,000 (6% vs 29% and 18%); and more likely to have an income below £18,000 (48% vs 16% and 25%).^{24,25} In relation to qualifications, when compared with both direct debit and standard credit customers, prepayment customers are significantly: less likely to have a degree as their highest qualification (17% vs 47% and 41%); and more likely to have a GCSE as their highest qualification (33% vs 19% and 19%).²⁶
- 9.35 We also found that, when compared with both direct debit and standard credit customers, prepayment customers are significantly more likely to: be disabled (23% vs 10% and 11%); be a single parent (18% vs 5% and 8%);

²³ For these purposes respondents are categorised based on their payment method. In particular, respondents are only included if they have the same payment method for all fuel types (that is, including those with only one fuel type).

²⁴ Bases differ for customer group. Prepayment customer base = 646, direct debit customer base = 5,121 and standard credit customer base = 973.

²⁵ BGL said that although not all prepayment customers were financially vulnerable and some might prefer to use a prepayment meter for their own budgeting purposes, research suggested that the number of customers on low incomes was disproportionately high. For example, in relation to gas, direct debit customers have the lowest fuel poverty rate (6%) and prepayment customers the highest rate (21%). See BGL response to the Addendum and [DECC: Annual Fuel Poverty Statistics Report 2015](#). We note that for electricity the fuel poverty rate is 7% for direct debit customers and 22% for prepayment customers, see [DECC: Annual Fuel Poverty Statistics Report 2015](#).

²⁶ Bases differ for customer group. Prepayment customer base = 605, direct debit customer base = 4,902 and standard credit customer base = 914.

or be more than one of disabled, single parent and carer (10% vs 3% and 4%).²⁷

- 9.36 We have also considered respondents' tenure type by payment type. We find that, when compared with direct debit customers, prepayment customers are significantly: less likely to live in a property they own; and more likely to live in rented housing, both social and private, and other. In addition when compared with standard credit customers, prepayment customers are significantly less likely to live in a property they own outright; and more likely to live in rented social housing and other.²⁸
- 9.37 Appendix 8.7 analyses the relationship between demographic characteristics and engagement in more detail, distinguishing between prepayment and non-prepayment customers. It finds that the differences between prepayment and non-prepayment customers in relation to several of the engagement metrics discussed above²⁹, are less marked after controlling for certain demographic and household characteristics such as income.³⁰ Further, we note that the Tenants Survey found that, based on some metrics, prepayment customers who rent may be as or more engaged than non-prepayment customers who rent (see Appendix 13.2).³¹
- 9.38 Therefore, when compared with the entire population, prepayment customers are disproportionately represented within the socio-demographic groups that, in our survey, showed lower levels of engagement. However, when compared with non-prepayment customers belonging to the same demographic group, prepayment customers may, on some metrics, be as or more engaged than non-prepayment customers.

²⁷ Bases differ for customer group. Prepayment customer base = 646, direct debit customer base = 5,121 and standard credit customer base = 973.

²⁸ Bases differ for customer group. Prepayment customer base = 646, direct debit customer base = 5,121 and standard credit customer base = 973.

²⁹ In particular, the proportion of respondents who: have never considered switching; not switched in the last three years; and not switched internally.

³⁰ Appendix 8.7, Table 1.

³¹ We note that for the purposes of the Tenants Survey results respondents were primarily classified as prepayment or non-prepayment, based on meter type rather than payment method. For the purpose of the Tenants Survey results reported here, prepayment customers are those who have a prepayment meter for at least one fuel, while non-prepayment customers are those without a prepayment meter or a smart meter for either fuel. Numbers of customers with a smart meter were low and not included in these comparisons. This results to whether respondents considered switching either supplier or tariff while living in their current home and whether respondents had switched either supplier or tariff while living in their current home. See Appendix 13.2 and Appendix 13.3

Parties' comments on analysis in the provisional findings and provisional decision on remedies

9.39 We received a number of comments from parties concerning the analysis of the relationship between engagement and demographic characteristics presented in our provisional findings report and our provisional decision on remedies (which largely focused on prepayment customers).

Provisional findings

9.40 RWE said³² that the CMA's analysis provided only limited insight as to which factors determined customer behaviour and potential gains from switching as the analysis looked at correlated demographic factors on a 'one-by-one' basis.

9.41 We agree with RWE that the demographic characteristics of respondents are likely to be correlated. We also agree that a more complex analysis of the relationship between the demographic and other characteristics of survey respondents and their levels of engagement would have been necessary had we wanted to establish causal relationships. We do not agree, however, that results on the association between respondents' demographic characteristics and their behaviour, experiences and attitudes are not informative on the possible reasons for inactivity and lack of engagement in the markets for the reasons given in paragraphs 9.60 to 9.63 below.

9.42 In response to our provisional findings RWE submitted results of a regression analysis it used in an attempt to understand the correlations between individual drivers of engagement. We discuss this analysis in detail in Appendix 8.7. We conclude that RWE's analysis has a number of weaknesses that make it unclear what the estimates are actually measuring and what interpretation should be given to the results.

9.43 RWE also said³³ that a limitation of the survey was the lack of collection of evidence on within-supplier tariff switching. We do not accept this. In particular, we asked:

- (a) all respondents whether they were aware that they could switch tariff with their existing supplier; and of those who were, whether they had been approached by their existing supplier;

³² RWE response to provisional findings, paragraph 227.

³³ RWE response to provisional findings, paragraph 228.1

- (a) respondents who had never switched tariff within same supplier, whether they had ever considered changing their energy tariff while staying with the same supplier and, if not, why not; and
- (b) respondents who had considered switching tariff with their existing supplier, whether they investigated tariffs offered by their supplier and, if not, why not.
- 9.44 In addition, we asked all respondents about their attitudes towards energy, use of PCWs, behaviour in other markets and demographics. All results are available in the published tables and the raw data was made available to advisers in the first data room.³⁴
- 9.45 SSE said³⁵ that the CMA's analysis did not support a conclusion that possessing any one of the six characteristics identified by the CMA (in particular, household incomes under £18,000 a year, living in rented social housing, no qualifications, aged 65 and over, having a disability, and being on the PSR) would, in itself, make a customer less likely to switch supplier.
- 9.46 SSE said³⁶ that these demographic characteristics were correlated with one another (and that the CMA's analysis did not attempt to disentangle the effect of each of these individual characteristics from one another), and correlated with other factors that appeared to have a more significant influence on switching behaviour (which meant that the socio-economic and demographic characteristics identified by the CMA were unlikely to be the real drivers of customer engagement, but merely correlated with the underlying causes of customer engagement).
- 9.47 SSE submitted further econometric analysis, the results of which were said to indicate that there were four statistically significant drivers of customer switching (internet access, contact by suppliers, receipt of Warm Home Discount and tenure type).³⁷
- 9.48 We discuss this analysis in detail in Appendix 8.7. We conclude that SSE's analysis does not, in our view, reliably isolate and measure the direct influence of these four explanatory variables. In particular, the SSE analysis by itself does not provide sufficiently strong evidence to establish that these are the main factors which directly influence the likelihood of switching and the ability to switch.

³⁴ Held after publication of the updated issues statement.

³⁵ SSE response to provisional findings, paragraph 5.2.1–5.2.4.

³⁶ SSE response to provisional findings, paragraph 5.2.4.

³⁷ SSE response to provisional findings, paragraphs 5.2.6 & 5.2.7.

Provisional decision on remedies (prepayment analysis)

- 9.49 Some parties have commented that weak customer engagement was as important a factor as – and potentially a more important factor than – technical constraints (which we discuss in paragraphs 9.383 to 9.421 below and Appendix 9.6) in negatively affecting outcomes for prepayment customers. For example, EDF Energy submitted³⁸ that the issues were largely complementary to the issue of weak customer engagement, noting that when weak customer engagement in switching and searching already exists, additional barriers or disincentives to switch, or otherwise engage, are problematic.^{39,40}
- 9.50 Further, Robin Hood Energy told us that its growth rate on prepayment was constrained by low levels of customer engagement. Co-operative Energy agreed that households using dumb prepayment meters tended to be less active in the market and were potentially more vulnerable.
- 9.51 In contrast, several suppliers said that weak customer engagement was not the issue in the prepayment segments.⁴¹ In particular, they said that customers on prepayment meters were no less engaged than those on credit meters and in some cases more engaged than standard credit customers or credit meter customers on SVTs.⁴²
- 9.52 For example, Scottish Power⁴³ noted that the switching rates for direct debit customers and prepayment customers were broadly similar (and significantly higher than for standard credit customers)⁴⁴ despite lower gains from switching being available to prepayment customers, and this suggested that

³⁸ EDF Energy response to the Addendum (13 January 2016), paragraphs 1.4 & 1.5.

³⁹ For example, in relation to acquisition costs EDF Energy said that prepayment customers were generally harder to access and less responsive to approaches by suppliers. See EDF Energy response to the Addendum, page 5.

⁴⁰ BGL said that while each of the supply-side features identified below (see paragraphs 9.375–9.476) may contribute to reducing competition in respect of the prepayment segments, the focus on supplier disincentives potentially underplayed the vulnerability and attendant inertia of prepayment customers.

⁴¹ See E.ON response to the provisional decision on remedies, p2, Scottish Power response to the provisional decision on remedies, p30, and SSE response to the provisional decision on remedies, p25.

⁴² See E.ON response to the provisional decision on remedies, p11, Scottish Power response to the Addendum, paragraph 22.3, p14 and Economy Energy response to the provisional decision on remedies, p2.

⁴³ Scottish Power response to the Addendum, p1. Similarly SSE noted that between April 2015 and its response to the Addendum, customers on prepayment meters had made up a [3%] proportion of its customer losses [3%] than its customer base overall [3%], that evidence from Ofgem showed that the monthly switching rate for prepayment customers was the same or slightly above the switching rates of non-prepayment customers and that evidence from DECC showed that prepayment customers were less likely, when compared with standard credit customers, to be with the incumbent supplier in their region. See SSE response to the Addendum, pp8 & 9.

⁴⁴ See Ipsos MORI survey for Ofgem (Customer Engagement with the Energy Market: Tracking survey 2015) and Scottish Power response to the provisional decision on remedies, p30.

the regular activity of card or key top-ups in advance of consumption may serve to improve engagement among prepayment customers.⁴⁵

- 9.53 SSE said that the churn rate of its own prepayment customers was higher than that for its customer base as a whole, and surveys showed that prepayment customers had higher levels of satisfaction than customers on direct debit and that 34% of its own prepayment customers actively chose to be on prepayment meters.⁴⁶
- 9.54 In relation to SSE's churn rate for prepayment customers, while it may be that for one supplier its churn rate for prepayment customers is higher than for other customers, this does not invalidate our survey result which relates to all suppliers. We also note that the results SSE quotes indicate that the majority of SSE's prepayment customers (ie 66%), do not make an active choice to be on prepayment meters.⁴⁷
- 9.55 RWE said that we placed too great an emphasis on prepayment customers switching supplier as an indicator of engagement. As noted in paragraph 9.43, in addition to indicators of external switching the survey includes several indicators of internal switching and engagement, and relevant indicators are explored at paragraph 9.29.
- 9.56 E.ON said that the underlying cause of any difference in engagement between prepayment and direct debit customers was likely to be the lack of tariffs available which was driven by the technical constraints specific to prepayment meters.⁴⁸ While RWE said that it would not be surprising if customers on prepayment meters were less engaged given the limited tariffs available to these customers resulting from the technical constraints and RMR rules. When it had recently offered discounted prepayment tariffs [✂].⁴⁹ See paragraphs 9.375 to 9.476 below for a discussion of supply-side barriers to entry and expansion in prepayment including technical constraints and RMR rules.
- 9.57 Similarly, EDF Energy said that prepayment customers had historically not had many options outside of SVTs and so might exhibit a different level of engagement to standard credit and direct debit customers on SVTs, more

⁴⁵ Ovo Energy told us that smartphone use was an important feature for its smart meter prepayment customers and that its customers interacted frequently with the Ovo Energy smartphone app, checking balances and credit several times a week on average.

⁴⁶ See SSE response to the Addendum.

⁴⁷ We also note that Ofgem reported that in 2014 more than 60% of prepayment meters were installed due to debt. Based on Ofgem, Social Obligations reporting 2014. See Ofgem (June 2015), [Prepayment review: understanding supplier charging practices and barriers to switching](#).

⁴⁸ See E.ON response to the provisional decision on remedies, p11.

⁴⁹ See RWE response to the provisional decision on remedies, p22.

particularly direct debit customers.⁵⁰ Energyhelpine said that it agreed that prepayment customers gained least from switching and probably remained disengaged for this reason.

9.58 We agree that to some extent the limited availability of non-standard tariffs may be a factor in explaining lower levels of switching among prepayment customers. However, we note that, first, several of the measures of engagement identified below, for example, having never considered switching supplier, are unrelated to gains from switching and tariff availability. Second, prepayment customers are generally on lower incomes than other customers (see paragraph 9.34 above) such that we would expect them to switch in response to lower gains than direct debit customers. Third, only a small proportion (3% in 2014) of prepayment customers switched to credit meters despite there being a larger number of tariffs on offer and that gains from switching from doing so are material for prepayment customers.⁵¹

9.59 Good Energy said that, while the level of switching in the prepayment segments was lower than for other payment methods, this was a poor measure of harm as there would be many customers who remained with a supplier, particularly an independent, because they were happy with the service they received. In relation to this we note that Good Energy did not provide evidence to suggest that customers in the prepayment segments were happier with the service they received than customers on other payment methods.

Conclusion on lack of engagement and demographic characteristics

9.60 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.

9.61 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:

⁵⁰ See EDF Energy response to the Addendum, p3.

⁵¹ See Section 8.

- (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.⁵²
- (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 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.⁵³
- 9.62 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.
- 9.63 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 8, expenditure on energy constitutes a high proportion of the total expenditure for the poorest households.
- 9.64 The evidence also suggests that prepayment customers overall are less engaged than direct debit customers (but not less engaged than standard credit customers), particularly in terms of whether they have ever considered switching or are likely to consider switching in the next three years, and their awareness of their ability to switch.
- 9.65 There are a number of factors that may explain this including that prepayment customers include higher proportions of individuals: with low levels of income; with low levels of education; living in social rented housing; and having a disability – demographic characteristics found to be associated with low levels of engagement. We also note that the need to top up prepayment cards regularly is likely to increase awareness of energy markets among prepayment customers, but that the lower gains from switching (see Section 8) and actual or perceived barriers to switching (see paragraphs 9.213 to 9.253 below) may have reduced the levels of engagement. While we have not established a causal relationship between these factors and the levels of disengagement we observe for prepayment

⁵² [EDF Energy response to the updated issues statement](#), paragraph 19.1.

⁵³ [E.ON response to the updated issues statement](#), paragraph 14.

customers, these results on the association between respondents' demographic characteristics and their behaviour, experiences and attitudes are informative for the reasons given in paragraphs 9.60 to 9.63 above.

Interpretation of the evidence on gains from switching

- 9.66 As set out in Section 8 and Appendix 9.2, we estimate that there were significant gains from switching that went unexploited by domestic energy customers over the period Q1 2012 to Q2 2015. We calculated the savings available from the key different dimensions of choice – choice of tariff type;⁵⁴ 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.⁵⁵
- 9.67 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 and payment method.
 - (d) Scenario 3b Change supplier (to one of the Six Large Energy Firms or Mid-tier Suppliers) but keep tariff type 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 4c: Change supplier (to one of the Six Large Energy Firms) and tariff type but keep payment method.
 - (h) Scenario 5: Change supplier, tariff type and payment method (except for prepayment customers).

⁵⁴ 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.

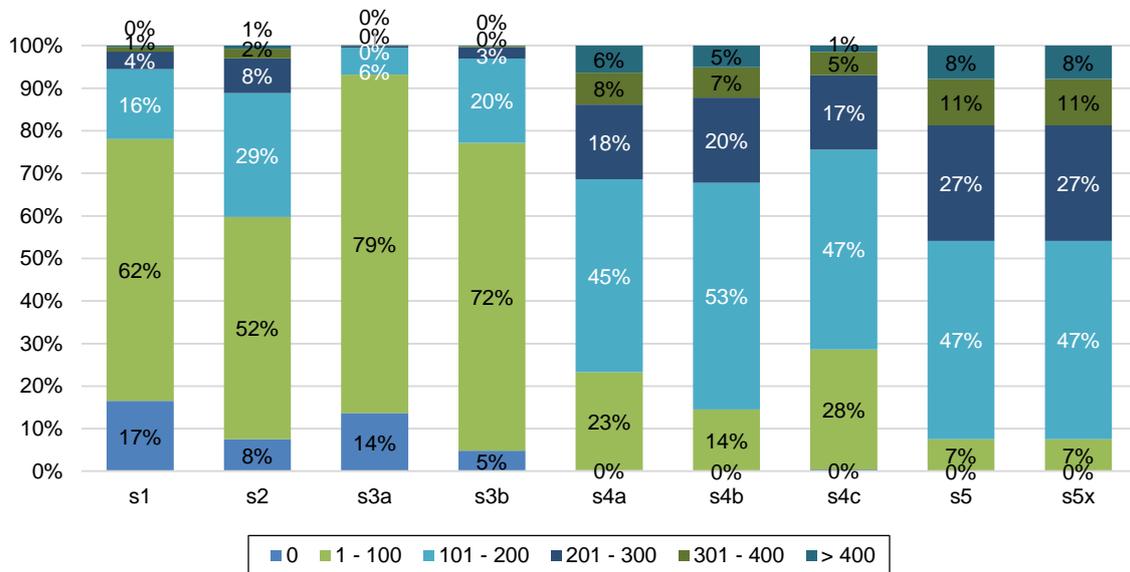
⁵⁵ See Appendix: 9.2: Analysis of the potential gains from switching, for a full description of the parameters that can be changed/held fixed when switching.

- (i) Scenario 5x: Change supplier, tariff type and payment method (except for prepayment customers) but deduct exit fees where applicable.

Summary of analysis

9.68 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. 46% of these customers could have gained over £200 under scenario 5x (in which they are allowed to change tariff type, payment type and supplier) while only 5% 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 9.3: Distribution of potential annual savings for dual fuel SVT customers (no prepayment) of the Six Large Energy Firms



Source: CMA analysis.

9.69 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 5x (the most liberal scenario for switching) and 4b (in which customers can switch tariff and supplier but not payment method).

Table 9.2: Average savings under scenario 5x and 4b for customers of Six Large Energy Firms on different tariff and payment types Q1 2012 to Q2 2015

<i>Dual or single fuel</i>	<i>Tariff type</i>	<i>Payment type</i>	<i>% of total gas customers</i>	<i>% of total electricity customers</i>	<i>Average savings under S5x, £</i>	<i>Average savings under S5x, %</i>	<i>Average savings under S4b, £</i>	<i>Average savings under S4b, %</i>
Dual	Non-standard	All	27	22	109	9	125	11
Dual	SVT	Direct debit	30	25	205	16	205	16
Dual	SVT	Standard credit	14	11	245	23	151	15
Dual	SVT	Prepayment	11	10	70	8	70	8
Single gas	All	All	18	0	115	19	100	17
Single electricity	All	All	0	31	89	16	74	13

Source: CMA analysis.

9.70 The table shows that – considering the most liberal scenario (scenario 5x) 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.

9.71 We also noted in Section 8 that:

- (a) the savings available to customers of the Six Large Energy Firms were on average higher than those for the customers of the Mid-tier Suppliers;
- (b) there were large differences between firms within each category;
- (c) for the SVT customers (excluding those on prepayment) of the Six Large Energy Firms, annual potential savings have risen substantially over the past two years, and reached their highest level in Q2 2015, reaching an equivalent of between £310 and £360.

Parties' views

9.72 We noted in Section 8 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.

9.73 Several of the Six Large Energy Firms submitted that there were competing explanations for gains from switching that went unexploited – namely that customers attached value to features of tariffs, suppliers and payment

methods that were not reflected in our analysis.⁵⁶ According to these submissions, a failure to switch to exploit financial gains was not necessarily an indication of a lack of engagement, but might be an active choice, taking into account non-price characteristics.

- 9.74 Parties have also submitted that our results overstated potential savings by, in effect, assuming that domestic customers should switch every quarter to whichever supplier was offering the best deal for them at the time.
- 9.75 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 2015 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.
- 9.76 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

- 9.77 As noted in Section 8, the most important tariff characteristic for customers is likely to be the price (in p/kWh).⁵⁷ 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.

⁵⁶ Centrica, EDF Energy, RWE, SSE and Scottish Power submitted that our scenarios, and in particular the most flexible scenario – S5 – did not sufficiently account for customers' preferences for a number of tariff characteristics, and therefore overstated the potential gains from switching.

⁵⁷ 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.

- *Non-standard tariffs*

9.78 As can be seen in Table 9.2 above, while the gains for those on non-standard tariffs are substantially below those on SVTs,⁵⁸ there were still appreciable gains to be made for those on non-standard tariffs – equivalent to an average 9% of the bill over the period we reviewed for scenario 5x.

9.79 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.⁵⁹ 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 2015, the product term at launch.⁶⁰

Table 9.3: Tenure of fixed rate gas tariffs in Q2 2015, by supplier and customer shares

Supplier	%	
	Customers in short term tariffs (24 months or less)	Customers in long-term tariffs (more than 24 months)
[X]	[X]	[X]

Source: CMA analysis.

Base: customer accounts included in the analysis of potential gains from switching and (i) collective switching, (ii) accounts with less than three months remaining in the contract and (iii) time-of-use, social, green, DTS, bundle and winback tariffs.

Table 9.4: Tenure of fixed rate electricity tariffs in Q2 2015, by supplier and customer shares

Supplier	%	
	Customers in short term tariffs (24 months or less)	Customers in long-term tariffs (more than 24 months)
[X]	[X]	[X]

Source: CMA analysis.

Base: customer accounts included in the analysis of potential gains from switching and (i) collective switching, (ii) accounts with less than three months remaining in the contract and (iii) time-of-use, social, green, DTS, bundle and winback tariffs.

⁵⁸ Excluding SVT prepayment customers, for whom the gains from switching are considerably lower, as discussed in more detail below.

⁵⁹ 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.

⁶⁰ 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.

- 9.80 The evidence shows that, while practice differs between the Six Large Energy Firms, overall about 80% of customers on fixed-term tariffs were on tariffs of between one and two years length, and the remainder on fixed-term tariffs of over two years length.
- 9.81 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 hard to identify from the current market. As discussed in Section 8, 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.
- 9.82 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 all of the gains from switching available to customers on non-standard tariffs – gains for non-standard customers on fixed-term fixed-rate tariffs of two years or less under scenario 3b (which reflects the gains from switching to a different supplier, but keeping the same tariff and payment type) are still £71 or 6% of the bill⁶¹. 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*
- 9.83 We noted in Section 8 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.⁶² 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.
- 9.84 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

⁶¹ Results for scenarios 5 and 5x suggest that these figures might be around £60 or 5% of the bill if we were to deduct exit fee from the gains available to customers on non-standard tariffs under Scenario 3b.

⁶² We noted that, while [redacted] still have [redacted] proportions of non-prepayment SVT acquisitions, [redacted].

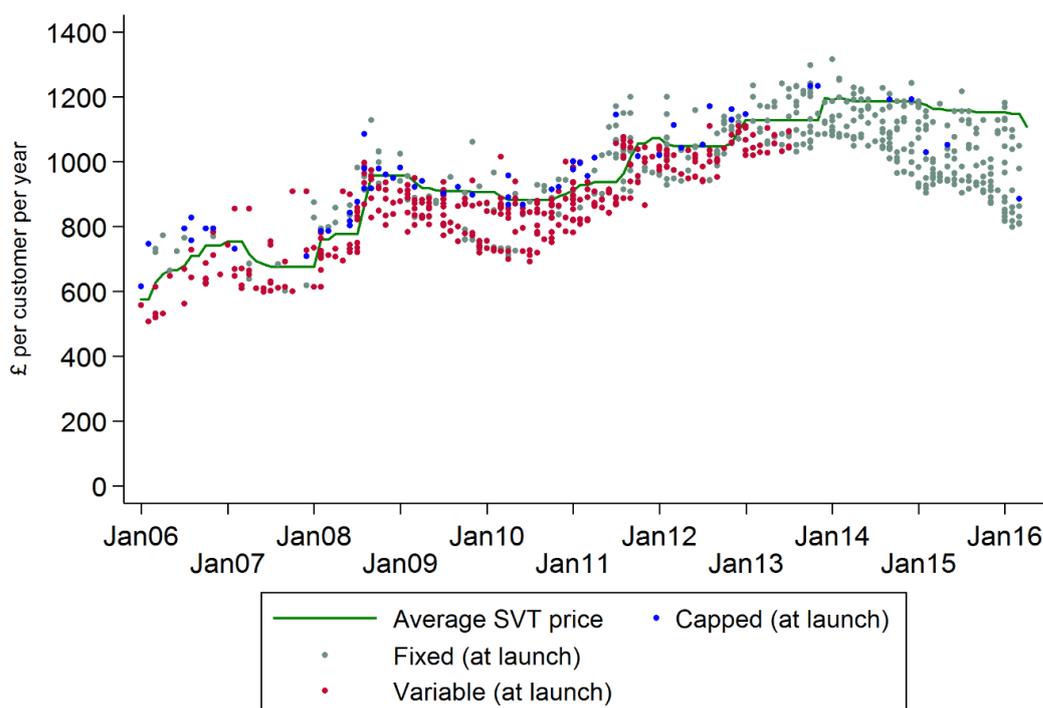
tariffs offer beneficial risk properties, as they fix the price for a fixed period, unlike the SVTs, which move on average once or twice a year.

- 9.85 Centrica also said⁶³ that the relative pricing of SVTs and non-standard tariffs naturally varied through the commodity cycle and that the SVT sometimes appeared cheaper and at other times more expensive than other products offered in the market. However, we find that the prices of SVTs over the commodity cycle have not, as Centrica suggest, sometimes been cheaper and at other time more expensive than prices of non-standard products.
- 9.86 In particular, we looked at how SVTs and non-standard tariffs offered by the Six Large Energy Firms compared over the period 2010 to 2015 (which we note was a period of both rising and then falling wholesale energy prices). Figure 9.4 shows that the relative prices of SVTs and non-standard prices have, as Centrica suggests, varied over the commodity cycle. For example, the gap between SVTs and discounted non-standard tariffs has widened in recent years with falling wholesale energy prices. However, at no time have SVTs been cheaper than the cheapest non-standard tariffs available in the market.
- 9.87 In fact, Figure 9.4 shows that the majority of non-standard tariffs offered by the Six Large Energy Firms have been offered at discounts to their SVT and that this has been the case over entire period (and therefore at times of both rising and falling wholesale energy prices).⁶⁴

⁶³ Centrica response to provisional findings, 15 August 2015, paragraph 13.

⁶⁴ Also see Appendix 8.3: The pricing strategies of the Six Large Energy Firms.

Figure 9.4: SVTs 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 provided by Six Large Energy Firms
 Note: Based on typical domestic consumption of 3,200 kwh/year for electricity and 13,500kwh/year for gas.

9.88 Results from the gains from switching analysis support these findings. In particular, results for scenario 1 show that throughout the period 2012 to mid-2015, SVT customers of each of the Six Large Energy Firms could have saved money by switching to non-standard tariffs with their existing supplier (see Appendix 9.2).

9.89 In relation to volatility, 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 above, even if this strategy does result in increased volatility, the customer in question would still save money in every period – since the SVTs are consistently and substantially more expensive than the cheapest fixed tariffs.

9.90 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.

9.91 We have found that for the Six Large Energy Firms, on average, over the period Q1 2012 to Q2 2015, around 50% of dual fuel 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 [redacted]⁶⁵ [redacted]⁶⁶ [redacted]. This suggests that substantial gains would still be available to customers on an SVT even if they wished to avoid exit fees.⁶⁷

Payment method

- 9.92 Payment method is a further potential dimension of choice to which customers may assign value. As noted in Section 8, paying by direct debit offers greater convenience to the customer than paying by standard credit.
- 9.93 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.
- 9.94 We noted in Section 8 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.
- 9.95 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 5x and 4b are both relevant as potential indicators of the lack of engagement implied by our gains from switching analysis.
- 9.96 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

⁶⁵ With the exception of RWE's In Control tariff, which provides a Nest Learning Thermostat.

⁶⁶ Paragraph 9.102 discusses what we mean by cheap in this context.

⁶⁷ 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 9.2: Analysis of the potential gains from switching.

poor payment history or in specific types of accommodation such as holiday homes and student accommodation.

9.97 The gains from switching are much smaller for prepayment customers than for other customers. We explore the barriers to engagement that prepayment customers are likely to face later in this section and paragraphs 9.163, 9.184, 9.189 and 9.212 to 9.253.

Quality of service offered by different suppliers

9.98 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.⁶⁸

9.99 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.

9.100 [✂]

Table 9.5: Suppliers offering the best deal to dual fuel customers (simple average across quarters)*

	%	
	<i>Scenario 4b</i>	<i>Scenario 5x</i>
[✂]	2	2
[✂]	14	18
[✂]	16	9
[✂]	5	5
[✂]	8	3
[✂]	3	2
[✂]	21	27
[✂]	4	4
[✂]	5	5
[✂]	5	9
[✂]	10	8
[✂]	7	8
[✂]	0	0

Source: CMA analysis.

*The average includes all quarters including those quarters where suppliers might have not offered the cheapest deal.

9.101 [✂]

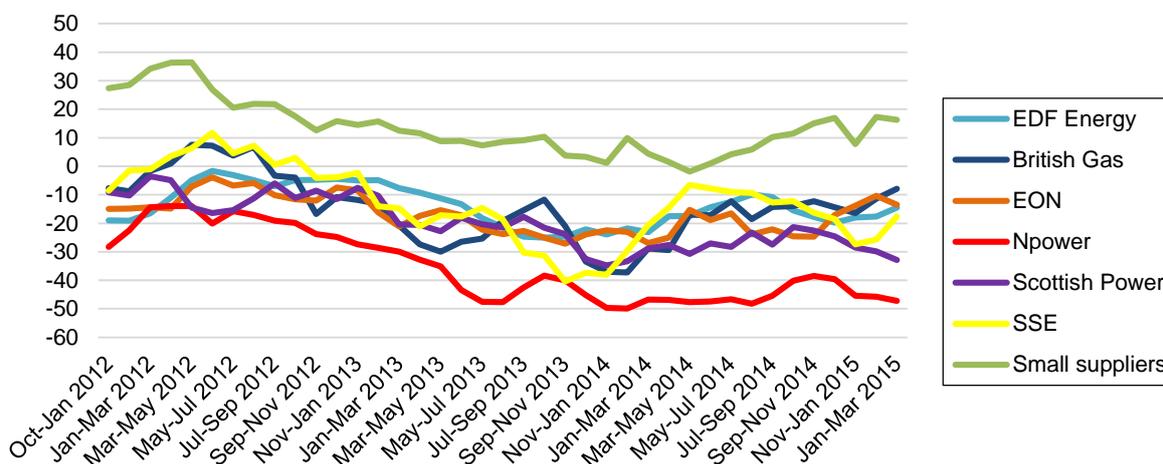
9.102 [✂]. Overall, against all measures, the Mid-tier Suppliers look relatively cheap, with the exception of Utility Warehouse.

⁶⁸ 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.

9.103 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.⁶⁹ 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.

9.104 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.

Figure 9.5: Net promoter scores of the Six Large Energy Firms and the small suppliers, 2011 to 2015



Source: [redacted].

9.105 Two trends are clear. First, the smaller suppliers⁷⁰ 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 [redacted].

9.106 We see no clear relationship between the cheapest supplier and customer service, as approximated by the NPS score, except that the smaller

⁶⁹ 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.

⁷⁰ For these purposes, ‘smaller suppliers’ means any suppliers other than the Six Large Energy Firms.

suppliers, which generally offer cheaper tariffs, receive consistently higher NPS scores.

- 9.107 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.

Parties' views

- 9.108 In summary, the Six Large Energy Firms (with the exception of EDF Energy) said that the analysis overstated the gains available from switching and did not provide evidence of weak customer engagement (see Appendix 9.2 for further detail). In particular, the following points were made by one or more of the Six Large Energy Firms:

- (a) The presence of gains from switching was consistent with a competitive market (particularly where there were different costs associated with different forms of supply, different products and different levels of service and other non-price forms of product differentiation) and that gains were required for competitive markets to function, as they provided an incentive for customers to engage.
- (b) The estimated gains from switching of around £137 for customers on non-standard tariffs (ie those that have actively engaged and switched within the last year) was evidence of this level of gain being a normal part of any market and consistent with the survey finding that customers required savings in order to incentivise them to switch (ie £120 median, £182 mean).
- (c) The dynamics of the competitive energy market meant that there would always be savings available, even when customers switched on a regular basis. If, for example, every domestic customer in the UK switched supplier once every year, quarterly changes in the cheapest tariff could mean that 80% of customers would still stand to save from switching in any given quarter over the ten-quarter period considered by the CMA.
- (d) The CMA had ignored evidence on non-price drivers of customer decision-making (for example, quality of services) from the customer survey. The scenarios assumed that price differences could be interpreted as 'gains' from switching, even in cases where the products being switched between were very different (eg switching from a

smoothed price product with cheque payment in arrears and call centre support available to a short fixed-term fixed-price product with advanced payment and online-only communication). The gains available from switching were only £76 to £117 for the median dual fuel customer, before other relevant factors that would influence customer engagement and switching levels, such as search costs, were taken into account.

- (e) The customer survey showed that 65 to 81% of consumers who were not likely to switch supplier in the next three years reported required savings that exceeded the gains available from switching. This showed that consumers were exercising rational choice in their search and purchasing decisions.
- (f) In some cases customers were switched to products which offered only a temporary discount from the SVT, or products which were quickly withdrawn from the market. Without understanding what happened to the prices paid by customers who switched to these products, the CMA could not assume that they would be better off on a sustained basis. Even for customers who simply switched to a rival SVT, different timings of SVT price changes between suppliers would mean that the 'snapshot' gains from switching at the time of the switch could not be assumed to be consistent over time.
- (g) The 'gains from switching' were almost as high for those on non-standard tariffs as for those on SVTs (differing by as little as £33), and the potential gains did not differ very much between those who had, and those who had not, switched recently. Such a finding was consistent with consumers valuing non-price attributes and inconsistent with the CMA's primary thesis that engaged customers were price sensitive and so benefited from low prices while disengaged customers paid high prices and so would gain enormously from switching tariff. In particular, the CMA did not explain why non-standard customers appeared to have similar 'unexploited gains', even though they were known to have engaged recently in energy markets and had generally reported that search and switching had been easy.
- (h) Estimates of gains for various groups of customers defined by measures of engagement, tariff type and payment method were under scenario 5 no lower than 11 to 12% of their bill. This provided a benchmark for gains in a competitive market as these applied to the most active customers, for example those that had switched in the past year or were on a non-standard tariff. Similarly, customers who were on a non-standard tariff paying by standard credit had potential gains from switching of 20%. However, the fact that these customers were on a

non-standard tariff indicated they made an active choice, including to pay by standard credit.

- 9.109 We respond to these comments in turn below.
- 9.110 With regard to a), we agree that a finding that customers could have gained from switching tariff/supplier is not, in itself, evidence of a retail energy market that is not working well for customers. However, in considering the findings of this analysis we have also noted the scale and persistence of the available savings (see paragraph 9.125) alongside other findings on weak customer engagement (see paragraphs 9.120 to 9.125). We also note that the gains have been consistently higher for customers on SVT tariffs (£219 under scenario 5x excluding prepayment customers) (see paragraph 9.78).
- 9.111 With regard to b), we do not agree that the estimates of savings available to customers on non-standard tariffs is evidence that savings of this level are a normal part of the market. Our view is that this assumes that all customers on non-standard tariffs are fully engaged. In particular, that they had all shopped around to find the best tariff in the market for them and switched to this tariff. In Section 8 we said 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. This is supported by our survey results. In particular only 34% of respondents on a non-standard tariff had ever shopped around, 21% had shopped around in the last year and 38% had ever switched supplier (although these percentages are higher than those for customers on an SVT).
- 9.112 With regard to c), we agree that in a competitive domestic retail energy market we would typically expect there to be some customers who could benefit from switching, even when customers switch on a regular basis, although the size of gains would be dependent on a number of factors including changes in prices since the customer switched.
- 9.113 With regard to d), the CMA has not ignored evidence on non-price drivers of customer choice. In Section 8 we concluded that we would expect price to be the most important product characteristic to a customer in choosing an energy supplier and/or tariff, but we also identified three non-price factors that are likely to be important to certain customers, namely, convenience, quality of service and provision of value-added and bundled products.
- 9.114 We also looked at a number of different scenarios in the gains from switching analysis so that we could assess the potential savings along different dimensions of choice available to domestic customers (see Section

8). We then considered the evidence for the observed gains from switching being consistent with customers actively choosing more expensive tariffs with certain non-price characteristics that they value (see paragraphs 9.76 to 9.107). We concluded that the evidence did not support this proposition.

9.115 With regard to e), we do not agree that the survey responses on the savings customers would need in order to consider switching are evidence that the observed gains from switching are consistent with rational customer behaviour, for the following reasons:

- (a) First, we consider that the responses to this survey question are unreliable. Respondents were asked what would be the minimum amount of money they would have to save to encourage them to switch supplier. A quarter said that they were unable to answer the question. This suggests to us that this was a question that respondents struggled with and that the results should therefore be treated with some caution.
- (b) Second, 66% of those who had not shopped around or switched in the last three years agreed that 'switching is a hassle, I do not have time' and 57% agreed 'I worry things will go wrong'. By contrast, of those who had switched supplier in the last three years 83% said it was easy. These findings suggest to us that respondents who had not recently shopped around or switched supplier believe finding the right deal and switching supplier to be more difficult than it is.
- (c) Finally, if customers perceive searching and switching to be more difficult than it actually is, while their behaviour (given these perceptions) might be considered rational, the outcomes for them would be worse than if they were to engage in the market. That is, we do not believe that a high perceived cost of switching can credibly be adduced as evidence of a well-functioning market.

9.116 With regard to f), we discuss Centrica's comments on the 'snapshot' approach in Appendix 9.2. In particular, it submitted that without looking at how the prices of tariffs evolved over time we could not assume that customers would be better off on a sustained basis. We did not have the data available to track customer bills over time and assess how these would have compared with bills had they made different choices. However, we do not agree that such an analysis would be necessary to support our conclusion.

9.117 Centrica identified two circumstances that could be problematic: (a) where a fixed-term tariff offered a temporary discount from the SVT; and (b) where products are withdrawn from the market. We consider that (a) could result in

us overstating the gains available to customers where the discount on the SVT at launch reduced during the term of the contract (as compared with the customer reverting to the SVT at the end of a contract period). This could be a reason for attaching greater weight to results for the later years when variable-rate fixed-term tariffs were prohibited by the RMR rules (results presented in Section 8 show that the estimated gains from switching have been increasing since Q4 2013). We do not agree that (b) would be a problem as a fixed-term tariff withdrawn from the market would continue to be available to customers on the tariff prior to it being withdrawn from the market.

9.118 With regard g) and h), suppliers have said that the gains from switching available to customers on non-standard tariffs are almost as high as those available to those on SVTs, and that this is not consistent with the hypothesis that engaged customers are paying lower prices. We make a number of observations which, in our view, undermine this observation:

(a) Under scenario 5x the gains available to non-prepayment SVT customers of the Six Large Energy Firms were, on average, £219 as compared with £109 for customers of the Six Large Energy Firms on non-standard tariffs and £89 for customers of the Mid-tier Suppliers on non-standard tariffs.

(b) The customers on non-standard tariffs include customers on long-term fixed-rate tariffs which have typically been priced at a premium to the SVT. If we exclude these customers, the gains for customers of the Six Large Energy Firms on non-standard tariffs amount to £100 and £81 for customers of the Mid-tier Suppliers under scenario 5x.⁷¹

9.119 In addition, as explained above, we do not accept the implicit assumption that all customers on non-standard tariffs are fully engaged (see paragraph 9.111). We do not therefore agree that the levels of gains observed in certain groups of customers should necessarily be regarded as a benchmark for gains that we might have expected to see in a well-functioning energy market. However, within each of the broadly defined groups of customers on non-standard tariffs identified above (see paragraph 9.108(g) and 9.108(h), our view is that we can reasonably expect variation in terms of their level of

⁷¹ We think that it is appropriate to compare the gains available to customers on SVTs with those available to customers on short-term non-standard tariffs (ie excluding those customers on long-term fixed-rate tariffs). This is because long-term tariffs have typically been priced at a premium to the SVT. The gains included in our analysis are therefore relatively high for these customers as they will be 'switched' under scenarios 2 to 5 to cheaper short-term tariffs. Given that these products have been priced at a premium we think it likely that the customers on these tariffs chose these products because they attach value to the certainty these have provided for 3 or longer. We therefore agree that for these customers the analysis is likely to overstate the gains available to them.

engagement. Evidence on this point is provided by the CMA customer survey. In addition to the results reported in paragraph 9.111, we note that 39% of respondents who had switched supplier in the last one to three years were not confident that they were on the right deal. This suggests to us that even within groups of customers on non-standard tariffs, some customers are likely to be on better deals than others.

Conclusion on our gains from switching analysis

- 9.120 Overall we have not seen evidence that we have overstated the gains from switching in our analysis.
- 9.121 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 considered all the options available to them, including of switching supplier.
- 9.122 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 gain from switching for these customers is considerably higher. We have not seen any characteristics of an SVT to which customers might attach substantial value.
- 9.123 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.
- 9.124 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 5x are both relevant as potential indicators of the extent of lack of engagement implied by our gains from switching analysis.
- 9.125 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

9.126 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 schematic representation 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.⁷²

Figure 9.6: Stages of engagement and barriers to engagement in domestic retail energy markets

	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 Complexity	Non-use of PCWs / TPIs Non-use of PCWs / TPIs
3	Act on information ↓	Actual barriers to switching	Perceived barriers to switching
4	Fully engaged		

⁷² 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.

- 9.127 Figure 9.6 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.
- 9.128 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;⁷³ 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.
- 9.129 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.
- 9.130 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 18% of their bill for those who have not considered switching or never switched compared with average gains of 14% for those who have switched in the last three years and 12% for those

⁷³ As explained in Appendix 9.1: CMA domestic customer survey results, 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 20% for those who have never considered switching and 17% for those who have considered switching supplier.

9.131 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.

9.132 The rest of this section is structured as follows:

- (a) First, we deal with parties' high level views on customer engagement;
- (b) Second, 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.
- (c) Third, 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, and the additional barriers to accessing and assessing information faced by customers on restricted meters.
- (d) Fourth, we consider **actual and/or perceived barriers to switching suppliers**, including the time taken to switch and the possibility of switching going wrong and the additional barriers to switching experienced by **prepayment customers and customers on restricted meters**.
- (e) Fifth, we consider the **impact of domestic customers' perceptions** of the difficulties of switching.
- (f) Finally, we present our 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.

Parties' views

9.133 RWE said⁷⁴ that barriers to engagement were very low and that this was evidenced by the high levels of engagement actually seen in the market. In particular:

- (a) that [redacted] of its domestic customer accounts joined RWE within the last three years; and over the period 2008 to 2015, each year [redacted], on average, of its customer accounts switched to another supplier or a different RWE tariff;
- (b) that [redacted] of RWE domestic customer accounts now had online billing, up from around [redacted] in 2013, and compared with around [redacted] in 2009; and
- (c) high levels of engagement could also be seen from the customer survey despite the fact that the survey presented only a partial picture as it focused overly on measures of engagement related to switching between suppliers.

9.134 However, in this regard, we note the following:

- (a) [redacted];
- (b) we do not accept that the survey overly focuses on measures of engagement related to switching between suppliers (see paragraph 9.43). However, the gains from switching show that the savings available to customers are substantially higher if customers switch supplier, as compared with switching tariff with their existing supplier (see Appendix 9.2).

9.135 Centrica,⁷⁵ E.ON,⁷⁶ RWE, Scottish Power and SSE all disputed that a material proportion of customers were fundamentally disengaged. Centrica⁷⁷ stated that the customer survey supported a finding that the level of engagement in the energy market is relatively high compared with how other relevant markets work in practice. They referred to the following results:

- (a) 89% of respondents know it is possible to switch energy suppliers

⁷⁴ RWE response to provisional findings, paragraphs 160.1–160.4.

⁷⁵ Centrica response to the provisional findings and Remedies Notice, paragraph 55.

⁷⁶ E.ON response to provisional findings, paragraph 74.

⁷⁷ Centrica's Response to the CMA's Provisional Findings and Notice of Possible Remedies, paragraph 55.

- (b) nearly half of respondents in the survey had either switched or considered switching in the past three years⁷⁸ and over 65% of respondents have considered switching or have switched;⁷⁹
- (c) 66% of respondents had either switched supplier, shopped around to compare suppliers or considered switching suppliers;⁸⁰
- (d) 79% of respondents had either considered switching, or were likely to consider switching in the next three years or both.⁸¹
- (e) switching levels are commensurate with other markets; and⁸²
- (f) 73% of customers are satisfied with their current supplier,⁸³ 84 and 41% of customers are satisfied with their existing tariff or supplier.⁸⁵

9.136 With regard to a) to e), we noted these statistics but consider that it remains the case that a substantial proportion of the respondents were, by various measures, disengaged (see paragraph 9.128). Looking at all these statistics in the round, we believe that these findings contribute, albeit to different extent, to our finding that a substantial proportion of customers are disengaged.

9.137 With regard to f), we discuss in paragraph 9.129 and in Appendix 9.1 the responses to survey questions on customer satisfaction. We conclude, however, that for customers who have not engaged in the market any such expressions of satisfaction with their current suppliers and/or existing tariffs are unlikely to be based on an understanding of the alternatives available to them.

9.138 Several of the Six Large Energy Firms also noted findings relating to the experiences of those respondents who had shopped around and switched supplier. We consider these parties' views below.

Limited awareness of, and interest in, customers' ability to switch supplier

9.139 We believe that the key measures of disengagement identified in paragraph 9.6, combined with the fundamental characteristics of energy consumption

⁷⁸ Centrica response to provisional findings and Remedies Notice, paragraph 57.

⁷⁹ SSE response to provisional findings, paragraph 3.2.3 b).

⁸⁰ E.ON response to provisional findings, paragraph 73.

⁸¹ E.ON response to provisional findings, paragraph 73.

⁸² SSE response to provisional findings, p19, Section 3.2.25.

⁸³ Centrica response to provisional findings and Remedies Notice, paragraph 56.

⁸⁴ SSE response to provisional findings, p4, Section 2.1.1.

⁸⁵ RWE response to provisional findings, paragraph 189.

discussed below, demonstrate that customers have limited awareness of, and interest in, their ability to switch energy supplier.

- 9.140 In this section we consider 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 9.6 above. The two fundamental characteristics that we discuss further below are: the homogenous nature of gas and electricity; and the role of traditional meters and bills.
- 9.141 In addition, as noted in Section 8, the regulations governing energy supply ensure that 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. An important implication of this is that there is no natural trigger point for engagement, which may depress levels of engagement relative to other sectors.
- *Homogenous nature of gas and electricity*
- 9.142 As noted in Section 8, gas and electricity are extreme examples of homogenous goods in that the quality of the product is entirely unaffected by the choice of supplier.
- 9.143 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 8, 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.
- 9.144 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 8, 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.

9.145 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*

9.146 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.

9.147 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.

9.148 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.⁸⁶ In addition, traditional meters do not report the same unit of usage as bills.

- 9.149 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. This may be deterring such customers from engaging in the market and searching for better deals.⁸⁷
- 9.150 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.⁸⁸
 - (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.
- 9.151 Overall, our 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

⁸⁶ 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.

⁸⁷ 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.

⁸⁸ 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.

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, as discussed in more detail in Sections 11 and 15.

- *Parties' views*

- 9.152 SSE said that the CMA's assessment was incorrect and incomplete. In particular, SSE said that we had failed to take into account survey results showing that 76%, 81% and 89% of consumers knew they could switch tariff, payment method, or supplier, respectively. The customer survey also indicates that 68% of customers take an active interest in their energy use and expenditure. Similarly, 66% of respondents had actively engaged with the market either by considering their options, shopping around or switching.⁸⁹
- 9.153 SSE is wrong to say that we did not take into account the survey results. We considered carefully the responses to all the survey questions. This is demonstrated by the analysis of results reported in Appendix 9.1. However, the survey found that a substantial proportion of customers were disengaged on various measures (see Section 8). We consider this to be a key finding. It is also consistent with other findings on the nature of competition in the market and the gains from switching available to customers. A result of particular importance was that 34% of respondents had never considered switching.
- 9.154 SSE also said⁹⁰ that the CMA's view that traditional meters and bills 'are likely to have a harmful impact on engagement' failed to give proper weight to the imminent roll-out of smart meters. We do not agree that the impact of smart meters should be given material weight in identifying any existing adverse effects on competition. In contrast, as explained in Sections 11 and 15, in developing our remedies package, we have given close attention to the potential that smart meters have to address some of the problems we have identified, and the likely timescale for roll-out.
- 9.155 RWE said⁹¹ that the CMA offered no credible evidence that the complexity introduced by the use of traditional meters created a barrier to engagement.

⁸⁹ SSE response to provisional findings, paragraph 3.3.8.

⁹⁰ SSE response to provisional findings, paragraphs 3.3.5 & 3.3.6.

⁹¹ RWE response to provisional findings, paragraph 160.2.

Customers did not need to interact with their meters other than to collect occasional meter readings and they could find all the information required to switch tariff or supplier on their bill. Evidence from the customer survey was that customers who had switched recently had found it easy to find information about their existing tariff and usage.

9.156 We do not accept this view. Traditional meters are typically read infrequently by the customer or the supplier, which means that bills (and the information contained within them) are often based on estimates of the amount of energy used over the period of the bill, or the pattern of usage where prices changed during the period of the bill. Estimating usage and bills is complex, involving several variables (see paragraph 9.148 for details of the input variables). Bills based on estimated usage are therefore unlikely to be accurate. In addition, traditional meters do not report the same unit of usage as bills. All this makes it difficult for customers to be able to understand their bills. That this is the case was confirmed by suppliers (see paragraph 9.150). RWE told us that much more accurate billing with the roll-out of smart meters would promote a better understanding of consumption and engagement.

- *Conclusion on fundamental characteristics of energy consumption*

9.157 In light of the above, we have found that customers have limited awareness of, and interest in, their ability to switch energy supplier (see paragraph 9.139 above), which arises, in particular, from the following fundamental characteristics of the domestic retail gas and electricity supply markets:

(a) 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

(b) 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.

9.158 For the reasons set out in paragraphs 9.8 to 9.22, 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. In addition, the fact that the regulations governing energy supply ensure that domestic customers generally receive continuous supply of gas and electricity implies that there is no natural

trigger point for engagement, which may depress levels of engagement relative to other sectors.

Barriers to accessing and assessing information

9.159 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; the role of TPIs in overcoming or adding to the actual or perceived barriers to engagement; and the extent to which customers on restricted meters face additional barriers to accessing and assessing information.

- *Barriers to accessing information*

9.160 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).⁹²

9.161 Figure 9.7 shows the proportion of respondents with no internet access by different measures of customer engagement in the energy sector.⁹³ 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

⁹² CMA Customer Survey.

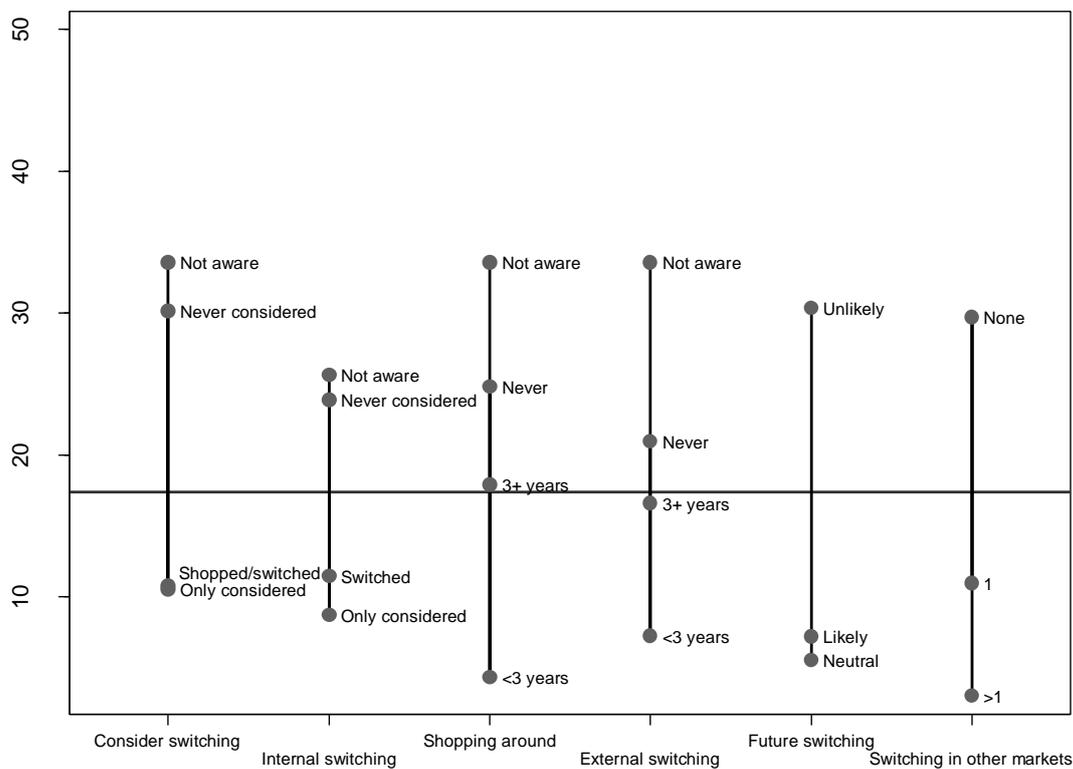
⁹³ Appendix 9.1: CMA domestic customer survey results, paragraph 156.

three years and are likely to consider switching supplier in the next three years are more likely to have access to the internet.⁹⁴

9.162 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 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.

9.163 In relation to payment method we note that the percentage of prepayment customers who have no access to the internet (25%) was significantly higher than the percentage of direct debit customers with no access to the internet (12%), but not standard credit customers (26%).⁹⁵

Figure 9.7: Relationship between internet access and customer engagement



Source: CMA customer survey.

Notes:

1. Derived from questions E1, E2, E3, E13, E17, E30, F1 and I1.

2. Bases = consider switching 6,986, internal switching 6,852, shopping around 6,912, external switching 6,859, future switching 6,744, switching in other markets 6,999.

⁹⁴ Appendix 9.1: CMA domestic customer survey results, paragraph 157.

⁹⁵ Derived from questions H1 and H3. Bases differ for customer group and include those who responded 'Don't know'. Bases differ for customer group. Prepayment customer base = 646, direct debit customer base = 5,121 and standard credit customer base = 973.

- *Complexity*

- 9.164 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 9.7 and paragraphs 9.478 to 9.513 of this section.
- 9.165 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. This concern is heightened by the complexity of bills (as set out in paragraph 9.151).
- 9.166 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.⁹⁶ 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 uncertain⁹⁷ 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.⁹⁸
- 9.167 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:⁹⁹
- (a) 85% found it difficult to make comparisons between suppliers;

⁹⁶ [EDF Energy response to the updated issues statement](#), paragraph 17.6.

⁹⁷ *ibid*, paragraphs 1.6 & 19.8.

⁹⁸ *ibid*, paragraph 19.9.

⁹⁹ Appendix 9.1: CMA domestic customer survey results, paragraph 136.

- (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.

9.168 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,¹⁰⁰ 53% said they did not understand or found it difficult to compare the tariff options and 33% said it is difficult to find information.

9.169 Ofgem's baseline customer survey,¹⁰¹ which was carried out in February and March 2014,¹⁰² 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 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*

9.170 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.

9.171 As discussed in Section 8 and Appendix 9.3: Price comparison websites and collective switches, the use of PCWs as a means of switching supplier has increased over the past five years. In the first six months of 2015, they accounted for around 30% of the domestic customer acquisitions of three of the Six Large Energy Firms, and around 63% of the domestic customer acquisitions of three 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.

¹⁰⁰ Appendix 9.1: CMA domestic customer survey results, paragraph 138.

¹⁰¹ TNS BMRB (2014), *Retail Market Review Baseline Survey: Report Prepared for Ofgem*.

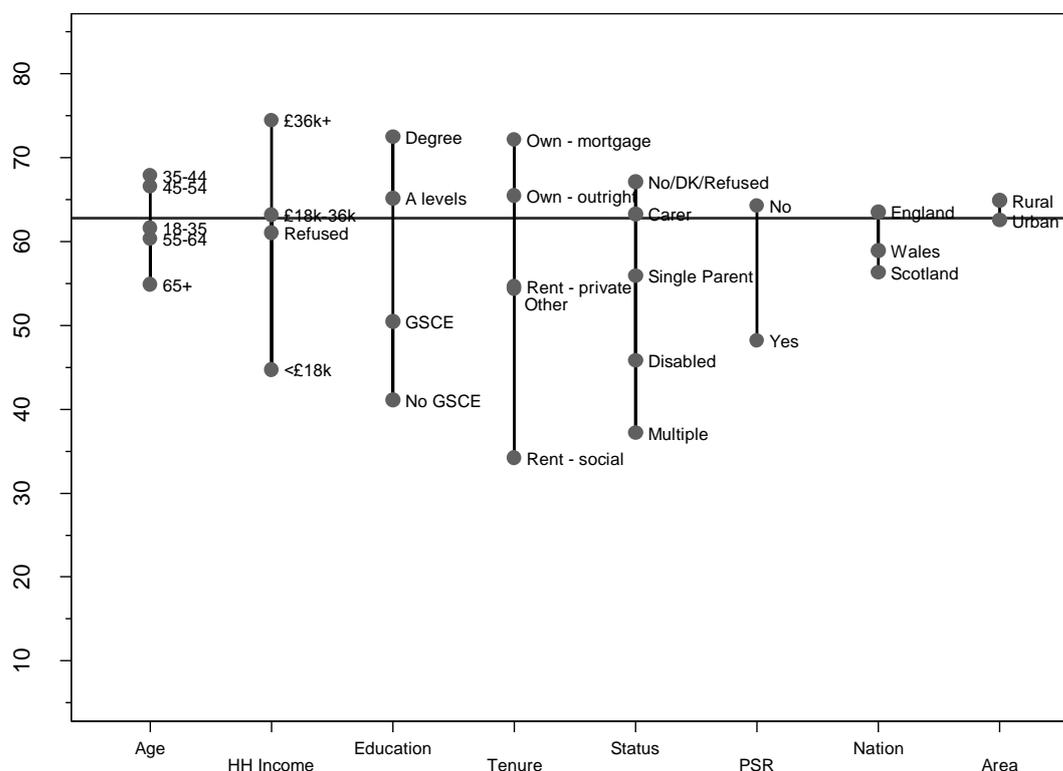
¹⁰² The RMR rules came into force in phases from August 2013 through June 2014. Some individual RMR remedies were therefore introduced in the months before the baseline survey fieldwork.

9.172 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.

9.173 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 two years 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 PCW Confidence Code in Section 13.

9.174 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 9.8: Proportion of PCW use by demographic and household characteristics



Source: CMA analysis of survey and supplier data.
 Base: Age 2,158, HH income 2,187, education 2,105, tenure 2,187, status 2,187, PSR 2,178, nation 2,187, area 2,184.

9.175 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 time-of-use tariffs as PCWs (and other TPIs) cannot offer these tariffs unless they have access to half-hourly 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.

- 9.176 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.¹⁰³
- 9.177 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 the RMR rules appear to be providing an environment that promotes the organisation of collective switch schemes, as we discuss in paragraph 9.505 below.

- *Parties' views*

- 9.178 Centrica, RWE, Scottish Power and RWE all disputed that the process of shopping around to find a better deal is difficult for customers.

(a) 76% of respondents found no difficulty when shopping around;¹⁰⁴

(b) 83% of those who switched in the last year and shopped around in the last three years found the overall task of shopping around to be very/fairly easy;¹⁰⁵

¹⁰³ Ofgem (2014), *Protecting consumers in collective switching schemes*.

¹⁰⁴ Centrica response to provisional findings and Remedies Notice, p4, section 11.

¹⁰⁵ RWE response to provisional findings, paragraph 160.2.2.

- (c) two-thirds of respondents who have shopped around in the last three years did not have a problem and found the process to be 'very' or 'fairly' easy;^{106,107}
- (d) three-quarters of respondents found finding out about their own energy usage and finding out about other energy supplier easy;¹⁰⁸
- (e) 70% of customers were confident that they would make the correct decision when switching;¹⁰⁹

9.179 In response to these observations, we recognise above that for the majority of respondents who had shopped around, they found the process relatively easy (see paragraph 9.167). However, as discussed above, nearly a quarter of such respondents said that they had found the process to be either fairly or very difficult. While only a minority of respondents, this figure appears to us to be sufficiently high to raise material concerns.

9.180 SSE said that the CMA's assessment was incorrect and incomplete. In particular, SSE said that we had failed to take into account the following survey results:

- (a) The customer survey found that: only 17% of respondents found it difficult to locate information and only 28% of respondents found it difficult to understand or compare tariffs; 67% of respondents who shopped around in the last three years found the process either very or fairly easy; and only 24% of respondents found the process either fairly or very difficult.¹¹⁰
- (b) The suggestion that consumers lack confidence in and access to PCWs ignores the fact that PCWs are very widely used today, and that their use is growing. Nearly three in four (71%) survey respondents who had shopped around for energy in the last three years used PCWs as an information source. Concerns around trust in PCWs are being addressed by Ofgem's PCW Confidence Code, which was strengthened in January 2015.¹¹¹

9.181 With regard to a), we agree that findings on the attitudes and experiences of those respondents who had recently shopped around or switched in the last

¹⁰⁶ Scottish Power response to provisional findings, paragraph 1.15.

¹⁰⁷ SSE response to provisional findings, page 13, Section 3.2.3.

¹⁰⁸ RWE response to provisional findings, paragraph 111.2.

¹⁰⁹ Centrica response to provisional findings and Remedies Notice, paragraph 56.

¹¹⁰ SSE response to provisional findings, paragraph 3.3.10.

¹¹¹ SSE response to provisional findings, paragraph 3.3.12.

three years shed some light on the extent of barriers (actual and perceived) to accessing and assessing information. As SSE notes, nearly a quarter of such respondents said that they had found the process to be either fairly or very difficult. While this is only a minority of respondents, this figure appears to us to be sufficiently high to raise material concerns, particularly if there is reason to believe that those who have engaged were more likely, given their experience and capabilities,¹¹² to have found the process easier to navigate. The experiences of those who have engaged are likely to contribute to wider perceptions on how easy or difficult it is to find and switch to a good deal.

9.182 In addition, SSE cites the finding that only 17% of respondents found it difficult to locate information and only 28% of respondents found it difficult to understand or compare tariffs. These are responses to a question on what respondents who had shopped around in the last three years had disliked about the experience. That over a quarter said that they did not understand or found it difficult to compare tariffs seems to us to be a substantial percentage which can contribute to the perception of barriers to switching. Further results on the experiences of those who shopped around and switched supplier are set out in Appendix 9.1. Of those who had shopped around in the last 3 years, we found that more respondents found it difficult to make comparisons between suppliers and understand the options available to them than found it difficult to find out about their own energy usage or other suppliers.

9.183 With regard to b), we agree that use of PCWs has been increasing. Nevertheless, we also found that the respondents who are less engaged in the energy markets are more likely to be among those who have no access to the internet or lack confidence in using the internet (21% of respondents who have never switched supplier do not have internet access compared with just 8% who switched in the last one to three years).

- *Barriers to accessing and assessing information for prepayment customers*

9.184 We have found that prepayment customers face higher actual and perceived barriers to accessing and assessing information (when compared with direct debit customers). In this regard, our customer survey shows that:

- (a) of those respondents who had switched supplier in the last three years, prepayment customers, when compared with both direct debit and

¹¹² See Appendix 9.1: CMA domestic customer survey results, section on 'Capabilities, confidence and experience'.

standard credit customers, were significantly less likely to have used a PCW for searching the last time they switched (34% vs 67% and 55%) if they had switched in the last three years.¹¹³

- (b) the percentage of prepayment customers who were confident that they would be able to find the right energy deal using a PCW (49%) was lower than the percentage for direct debit customers (59%), but not standard credit customers (46%).¹¹⁴
 - (c) As noted above, the percentage of prepayment customers who have no access to the internet (25%) was significantly higher than the percentage of direct debit customers with no access to the internet (12%), but not standard credit customers (26%).¹¹⁵
- *Barriers to accessing and assessing information for customers on restricted meters*

9.185 The customer survey that we conducted does not have sufficiently granular data to allow us to identify which of the respondents were customers on restricted meters. However, we have reviewed research by Ofgem, which found that customers on restricted meters have a low awareness and understanding of their DTS arrangements and tariffs, and face higher actual and perceived barriers to accessing and assessing information than customers on single-rate meters and Economy 7 meters.¹¹⁶ As regards the barriers to accessing and accessing information faced by customers on restricted meters, Ofgem's research found that:

- (a) people find the inherently complex heating system difficult to understand fully and operate efficiently;
- (b) there is a perceived lack of interest by suppliers in providing information on metering arrangements to customers on restricted meters and offering them alternatives; and

¹¹³ Derived from question E32. Bases differ for customer group. Bases differ for customer group. Prepayment customer base = 141, direct debit customer base = 1,864 and standard credit customer base = 161.

¹¹⁴ Derived from questions H1 and H3. Bases differ for customer group and include those who responded 'Don't know'. Bases differ for customer group. Prepayment customer base = 646, direct debit customer base = 5,121 and standard credit customer base = 973.

¹¹⁵ Derived from questions H1 and H3. Bases differ for customer group and include those who responded 'Don't know'. Bases differ for customer group. Prepayment customer base = 646, direct debit customer base = 5,121 and standard credit customer base = 973.

¹¹⁶ In November 2014 Ofgem published the results of research on the experience of consumers who use DTS meters and tariffs. Ofgem (2014), [Dynamically Teleswitched meters and tariffs – Ofgem's views on the way forward](#).

(c) the consumer base is often vulnerable and many find it difficult to access information and exercise supplier or tariff choice, even when this is available.

9.186 We have found that restricted meter tariffs (other than Economy 7 - in the remainder of this report, we refer to these tariffs group as 'restricted meter tariffs' unless otherwise specified) are not supported by PCWs or suppliers' online search tools.¹¹⁷ Further, if customers on restricted meters wished to switch to another restricted meter tariff or an Economy 7 tariff, they would need to understand not only their current tariff and the alternative tariffs available but also their usage patterns and consumption profile (including whether and how these might change over time), which can be difficult based on the information provided by traditional meters, see paragraph 9.151.

9.187 This means that, for customers on restricted meters, understanding the options available to them is substantially more difficult than it is for customers on other meter types.

- *Conclusion on barriers to accessing and assessing information*

9.188 Overall, our view is that 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. We note that alternative forms of TPIs, such as collective switching schemes, may be increasingly important for such customers.

9.189 In addition, we have identified aspects of the prepayment segments and restricted meters segments that strengthen the features that customers face actual and perceived barriers to accessing and assessing information. In particular, we have found that:

¹¹⁷ For example, see Citizens Advice response to the provisional decision on remedies, p47.

- (a) prepayment customers, when compared with direct debit customers, face higher actual and perceived barriers to accessing and assessing information about switching, arising, in particular, from relatively low access to the internet and confidence in using PCWs; and
- (b) customers on restricted meters face higher actual and perceived barriers to accessing and assessing information arising, in particular, from a general lack of price transparency concerning the tariffs that are available to them, which results from restricted meter tariffs not being supported by PCWs or suppliers' online search tools.

Barriers to switching

9.190 In this section, we consider the evidence on actual and perceived barriers to switching, focusing on the time it takes to switch supplier and the possibility that things will go wrong (erroneous transfers).

9.191 The discussion is structured as follows:

- (a) We set out parties' general views.
- (b) We review the evidence on the time it takes to switch supplier.
- (c) We review the evidence on erroneous transfers.

- *Parties' views*

9.192 SSE said that the customer survey found that the vast majority of respondents (83%) who had switched supplier in the last three years had found it very or fairly easy. Of the small number of respondents who had encountered difficulties in switching, approximately half had encountered problems with delays. These problems have, however, largely been addressed by recent developments to improve the switching process. Further developments are in train such as measures to facilitate reliable faster switching and the roll-out of smart meters.¹¹⁸

9.193 SSE's observations are concerned with recent and expected developments that should make the switching process faster and more reliable. Our view is that such developments will not address the actual and perceived barriers to switching faced by customers, such as where they experience erroneous transfers.

¹¹⁸ SSE response to provisional findings, paragraph 3.3.14.

- *Time taken to switch*

- 9.194 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.¹¹⁹ 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).¹²⁰
- 9.195 Ofgem has recognised the problems in its recent decision on fast and reliable switching.¹²¹ 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.
- 9.196 Changes introduced at the end of 2014 have reduced switching timescales from five weeks to 17 days.¹²² This means that a customer will be switched three days after their cooling-off period ends.
- 9.197 Ofgem is in the process of implementing its decision to introduce reliable next-day switching by 2019. This will build on the new arrangements introduced to support smart metering.¹²³ Ofgem recently published its decision to modify the Data Communications Company (DCC) licence to provide a central registration service which will facilitate the change of supplier process for all gas and electricity supply points.¹²⁴ 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.
- 9.198 DECC recently consulted on proposed powers – for the purposes of pre-legislative scrutiny – to be given to Ofgem to allow it to implement switching and settlement reforms in a timelier and more cost-effective manner.¹²⁵

¹¹⁹ 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.

¹²⁰ Ofgem (2013), [Enforcing three week switching](#) (letter to interested parties, 3 December).

¹²¹ Ofgem (2015), [Moving to reliable next-day switching](#).

¹²² This consists of a 14-day cooling-off period followed by three weeks for the switching process.

¹²³ Ofgem (2015), [Moving to reliable next-day switching](#).

¹²⁴ Ofgem (2016), [Decision: DCC's role in developing a Centralised Registration Service](#).

¹²⁵ DECC (2015), [Draft Measures: Fast and reliable switching and Half-hourly settlement power\(s\)](#), paragraph 42, p10.

9.199 The proposed powers will enable industry codes to be modified directly for the purposes of enabling switching and settlement reforms by Ofgem rather than industry so as to facilitate expeditious and coordinated changes to industry codes. This is because DECC considers that the current significant code review process (see discussion of this process in Appendix 8.6) will not deliver the policy objectives (enhanced competition and increased consumer engagement) of the switching and settlement reforms in a timely and cost-effective manner that ensures the best outcomes to consumers.¹²⁶

- *Erroneous transfers*

9.200 Erroneous transfers occur when a customer has their supplier switched without their consent, which can cause confusion and distress, and damage customers' perception of the retail energy markets.¹²⁷ Resolving erroneous transfers and returning the customer to their previous supplier is also costly for both suppliers.

9.201 Ofgem 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.

9.202 SSE said¹²⁸ that concerns regarding erroneous transfers are immaterial as they only affected around 1% of completed domestic gas and electricity transfers between January and September 2014 and recent Ofgem measures are intended to reduce erroneous transfers. Smart meter data should also reduce further the number of erroneous transfers. We agree that the proportion of erroneous transfers is small. We also acknowledged that the recent Ofgem measures and the roll-out of smart meters could reduce the numbers further. However, we consider that even a small number of erroneous transfers could have a wider adverse effect on customer engagement given the impact it might have on customer perceptions on the risks of switching going wrong.

¹²⁶ *ibid*, paragraph 47, p10.

¹²⁷ Ofgem (2013), *Preventing erroneous transfers* (letter to interested parties, 3 December).

¹²⁸ SSE response to provisional findings, paragraph 3.3.15.

- 9.203 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, which include the error and resolution arrangements in the BSC, could usefully be considered for other industry codes to assist with reducing the number of erroneous transfers.
- 9.204 We also note in Appendix 9.3 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.
- 9.205 On 9 April 2014, Ofgem also published a statutory consultation to prevent erroneous transfers.¹²⁹ 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.
- 9.206 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 to set up billing records and by the old supplier to send an accurate final bill to the customer.
- 9.207 Ofgem's September 2014 reforms appear to have improved suppliers' incentives, although no full set of data is available yet to assess their effectiveness.¹³⁰ 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.

¹²⁹ Ofgem (2014), [Statutory consultation on licence modifications to enforce three week switching and prevent erroneous transfers](#) (letter to interested parties, 9 April).

¹³⁰ Before the licence modification that came into effect on 1 September 2014, the market erroneous transfer rate was around 1% (55,000 switches per year). Based on data received by Ofgem from seven suppliers for the period October 2014 to July 2015, there has been some improvement in the market performance, however, suppliers' performance varies. Average erroneous transfer rates for those seven suppliers for this period ranged from 0.445% to 1.21% (electricity); and 0.421% to 1.127% (gas).

9.208 Overall, we 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.

- *Domestic customers' perception of the searching/switching process*

9.209 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%).

9.210 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.

9.211 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.

- *Barriers to switching for prepayment customers*

9.212 In this section, we consider the evidence on actual and perceived barriers to switching specific to prepayment customers, focusing on switching to credit meters and the process of switching for prepayment customers in debt.

- *Switching to a credit meter*
- 9.213 Customers on dumb prepayment meters can only access prepayment tariffs with their current meter, and would need to change to a credit meter to access direct debit or standard credit tariffs.¹³¹
- 9.214 As outlined in Section 8, the potential gains from switching show that switching to a credit meter to access direct debit tariffs is a choice which is likely to lead to material savings for prepayment customers. Therefore we have considered evidence on whether prepayment customers commonly switch to credit meters to enjoy the benefits of competition in the direct debit segments, as this could indicate that tariffs available in the direct debit segments may act as a constraint on suppliers' pricing strategies in the prepayment segments.
- 9.215 Ofgem data shows that about 130,000 electricity and 103,000 gas prepayment customers switched to credit meters in 2014, ie around 3% of all electricity and 3% of all gas prepayment customers.¹³² Ofgem also noted that 17,000 customers (in both gas and electricity) without debt who attempted to switch to a credit meter were refused in 2014.
- 9.216 In its prepayment review published in June 2015,¹³³ Ofgem indicated that likely reasons for suppliers refusing these switches were their request to prepayment customers to pay a security deposit, or pass a credit check before being able to switch to a credit meter. It also noted that prepayment meter removal charges (including cost of the meter, travel time, and the time for an engineer to exchange the meter for another meter type), which range between £46.84 and £160 per customer, were another factor that could explain the low switching rate from prepayment meter to credit meters, despite gains available of up to £300.¹³⁴
- 9.217 However, Ofgem's findings in this area highlighted that 13 out of 18 suppliers (including four of the Six Large Energy Firms) do not require security deposits when a prepayment customer wishes to switch to a credit meter. Similarly, 8 out of 18 suppliers (including five of the Six Large Energy Firms) do not charge for the removal of prepayment meters (95% of such meters that were removed in 2014 were removed for free). Also, smart meters will enable remote switching between prepay and credit modes (and

¹³¹ We note that customers on dumb prepayment meters can also access direct debit and standard credit tariffs by switching to smart meters, see paragraphs 9.217 and 9.220.

¹³² Ofgem, [Domestic Suppliers Social Obligations: 2014 annual report](#), p37.

¹³³ Ofgem (June 2015), [Prepayment review: understanding supplier charging practices and barriers to switching](#).

¹³⁴ This gains figure is as estimated by Ofgem. Figure 8.37 shows that the difference between the cheapest prepayment and the cheapest direct debit tariff is, dependent on the region, between £259 and £322.

vice versa) without needing an operator to physically exchange the meter. Ten out of 18 suppliers told Ofgem that they did not intend to charge for a switch between smart credit and prepay modes in any circumstances due to the cost saving to the supplier that would result from remote switching.¹³⁵

- 9.218 The Six Large Energy Firms and others told us that there were many reasons why certain categories of prepayment customers might not switch to credit meters beyond those identified above. For example, Scottish Power told us that while prepayment meter removal costs and security deposits might be a barrier to switching in some cases, its figures did not suggest that these were large-scale issues.¹³⁶ Suggestions on alternative reasons for why prepayment customers might not switch to credit meters included customer preferences,¹³⁷ perceptions of the complexity of the switching process,¹³⁸ the need to set up an appointment/be at home for a meter exchange,¹³⁹ landlord preferences for prepayment meters,¹⁴⁰ misalignment of monthly direct debit payments and benefit payments for some customers¹⁴¹ and awareness of options.¹⁴²
- 9.219 Evidence from EDF Energy and Scottish Power suggests that most of their customers are not in debt ([redacted] and [redacted] respectively)¹⁴³ and therefore should be able to switch to a credit meter, subject to creditworthiness. Similarly, Ofgem reported that in 2014 around 7% of electricity prepayment customers and 10% of gas prepayment customers were in debt to their energy supplier.¹⁴⁴
- 9.220 This indicates that switching to a credit meter is a choice available, which would lead to material savings (in that the benefits materially outweigh the costs of doing so), to a significant number of prepayment customers, which would give them access to the benefits of competition. This option will be more widely available with the roll-out of smart meters. At the moment,

¹³⁵ ie a switch that does not require an engineer to physically intervene on the meter.

¹³⁶ Scottish Power response to the Addendum, p2.

¹³⁷ For example, Centrica told us that customers might prefer prepayment meters as a way of budgeting, to avoid indebtedness or to repay debt at a manageable rate. Centrica response to Addendum, p13. SSE noted that a quantitative survey of its customers showed that 34% of respondents on prepayment meters actively chose prepayment as the most suitable payment method for them. See SSE response to the Addendum, p14. Also see Scottish Power response to the Addendum, p5 who said a possible reasons was because customer used prepayment meters as an aid to budgeting.

¹³⁸ Scottish Power response to the Addendum, p2.

¹³⁹ See EDF Energy response to the Addendum, p10.

¹⁴⁰ E.ON response to Addendum, p6, Centrica response to the Addendum, p13 and Good Energy response to the Addendum, p5. For a discussion of prepayment meters in rented accommodation see Appendix 12.2.

¹⁴¹ Scottish Power response to the Addendum, p6.

¹⁴² SSE response to Addendum, p5.

¹⁴³ See EDF Energy response to the Addendum, p3 and Scottish Power response to the Addendum, p6.

¹⁴⁴ Based on Ofgem Social Obligations report 2014, see Ofgem's [Prepayment review](#).

however, we note that only a small number of prepayment customers make that choice (3% in 2014, as noted above).

- 9.221 While some prepayment customers may not switch to a credit meter due to preferences, we consider that the lack of switching by customers on dumb prepayment meters to credit meters supports a finding that there are aspects of the prepayment segments that strengthen the feature that customers face actual and perceived barriers to switching for prepayment customers.
- 9.222 In particular, we consider that the need to replace a dumb prepayment meter with a credit meter (or smart meter) to be able to switch to a wider range of tariffs (and the obstacles associated with this requirement such as for instance perceptions of the complexity of the meter replacement process) is an aspect of the prepayment segments that strengthens the barriers to switching for prepayment customers.
- 9.223 Taken with the barriers to accessing and assessing information these customers face (see paragraph 9.184) this means that, for customers on prepayment meters, understanding the options available to them and switching supplier is substantially more difficult than it is for customers on other meter types.
- 9.224 The lack of switching to credit meters suggests that prepayment customers are not engaging with the wider market and therefore tariffs available to customers on credit meters do not represent a significant competitive constraint on the pricing strategy in the prepayment segments.
- *Parties' views*
- 9.225 RWE said that the CMA had put too great an emphasis on switching from prepayment to credit meters. In particular, RWE said that the CMA had no evidential base for its speculation that switching to a credit meter might make financial sense to a significant number of prepayment customers.
- 9.226 EDF Energy said that the CMA had not assessed whether 3% as a proportion of prepayment customers that switched to credit meters in 2014 was suboptimal from a consumer perspective. EDF Energy also said that certain categories of customer, such as those in debt or with a poor credit history, would face particular difficulties switching to the credit sector.¹⁴⁵
- 9.227 SSE said that the CMA had ignored alternative explanations for the low rates of switching to credit meters and that there was no evidence that

¹⁴⁵ See EDF Energy response to the Addendum, paragraph 4.5

prepayment customers faced barriers to switching to credit meters. In particular, SSE said that the CMA had ignored non-price factors and customer preferences that influenced customer choice: for example, it noted that 34% of its customers actively chose prepayment as the most suitable payment method for them.¹⁴⁶ SSE also said that the CMA provided no evidence to support its suggestion that impediments such as security deposits or charges for the removal of prepayment meters were directly linked to the number of switches attempted, and completed, by indebted customers.^{147,148}

- 9.228 We note that the evidential base is that the gains from switching from prepayment meters to direct debit are very high, as set out in Section 8. The evidence from Scottish Power, EDF Energy and Ofgem¹⁴⁹ shows that the vast majority of customers could switch to credit meters. In light of this we would expect an engaged prepayment customer who was basing a decision on price to switch from a prepayment meter to a credit meter.
- 9.229 Further, we note that our view is not that all prepayment customers would switch to credit meters even if there were no barriers to do so, as some customers may have a preference for prepayment. Rather our view is that a materially higher number of prepayment customers would switch to credit meters absent actual or perceived barriers to switching. Further, we note that [§] quantitative survey results indicate that the majority of [§] prepayment customers (ie 66%) do not make an active choice to be on prepayment meters.
- 9.230 E.ON said that the CMA had not properly explored the segment in depth, in particular, how many prepayment customers could benefit from a low cost switching to a credit meter¹⁵⁰ in relation to which E.ON noted that in its experience a number of customers preferred prepayment meters even when they were aware that they could switch to credit meters.¹⁵¹ E.ON also said that based on its experience around 60 to 70% of those prepayment customers who were in debt engaged with E.ON to manage their debt and had agreed voluntarily to have a prepayment meter installed leaving a very small proportion of customers who were required to have a prepayment meter fitted as a condition of supply.¹⁵² Further, E.ON also said that it was

¹⁴⁶ See SSE response to the Addendum.

¹⁴⁷ See SSE response to the Addendum, paragraphs 1.12 & 2.33.

¹⁴⁸ See paragraphs 9.216 to 9.218.

¹⁴⁹ See paragraph 9.219 and EDF Energy response to the Addendum, p3; Scottish Power response to the Addendum, p6 and Ofgem's [Prepayment review](#).

¹⁵⁰ See E.ON response to the provisional decision on remedies.

¹⁵¹ See E.ON response to the Addendum.

¹⁵² See E.ON response to the Addendum.

important to see how this related to the proportion of prepayment customers who were in fuel poverty which was higher both for gas and electricity when compared with direct debit customers and standard credit customers (21% vs 6% and 16% for gas and 22% vs 7% and 15% for electricity).¹⁵³

9.231 We set out our understanding of the options available to prepayment customers in Section 8 and the demographic characteristics of prepayment customers in paragraphs 9.32 to 9.38 above. As noted above, our view is not that all prepayment customers would switch to credit meters even if there were no barriers to do so, as some customers may have a preference for prepayment, but that in view of the potential gains we would expect materially higher number of prepayment customers to switch to credit meters. Although we do not know the exact number of customers who would benefit from switching to a credit meter, evidence from EDF Energy and Scottish Power suggests that the vast majority of prepayment customers have the option to do so and therefore would benefit from material savings by doing so. In addition, E.ON's response suggests that 30 to 40% of its indebted prepayment customers had a prepayment meter installed without their agreement. We agree that the incidence of fuel poverty is higher among prepayment customers compared to both direct debit and standard credit customers. However, in view of the availability of lower tariffs on credit meters, we note that the choice of prepayment tariffs raises a material risk of higher bills.

- *Our assessment*

9.232 Overall, we consider that certain features which contribute to the Domestic Weak Customer Response AEC are heightened for prepayment customers. In particular, we consider that the additional actual and perceived barriers to switching are heightened as regards prepayment customer (excluding prepayment customers with a smart meter) by the need to change meter in order to switch to a wider range of tariffs (and the obstacles associated with this requirement such as perceptions of the complexity of the meter replacement process). We note that meter removal costs and security deposits may be a barrier to switching, although in some cases customers can already choose from a range of tariff options offered by suppliers that do not charge the costs of replacing the meter upfront (if at all) or require a security deposit.

¹⁵³ See E.ON response to the provisional decision on remedies and E.ON response to the Addendum.

9.233 We note that the roll-out of smart meters will address in part these issues as prepayment customers will be able to access non-prepayment tariffs without having to change meter.

- *Customers in debt*

9.234 In 2014 approximately 7% of electricity prepayment customers and 10% of gas prepayment customers were in debt to their energy supplier.¹⁵⁴ The prepayment infrastructure is used to collect the payments that eventually pay-off that debt. Very often, customers are moved onto prepayment meters when they are in debt precisely in order to facilitate debt collection.

9.235 The DAP is the industry process used to assign debt when indebted prepayment customers try to switch supplier. It is based on SLC 14 for the supply of gas and electricity, on Schedule 9 of the Supply Point Administration Agreement (for gas) and section 30 of the Master Registration Agreement (for electricity).¹⁵⁵

9.236 If a customer is in debt and tries to switch then the DAP allows their current supplier to raise an objection to the switch on the grounds of the debt owed. When this is done the outcome depends on the level of debt that customer has:

(a) If the debt is less than £500 per fuel, the customer is informed of this objection by mail, and if the customer responds to the objection by mail and appeals under the DAP, then the customer's debt is automatically (and entirely) assigned to the acquiring supplier (which must pay within 28 days 90% of the debt to the incumbent supplier as full settlement)¹⁵⁶ and the switch completes.¹⁵⁷ The customer is also informed that they need to give the incumbent supplier permission under the Data Protection Act 1998 to share debt details with the acquiring supplier.¹⁵⁸

(b) If the debt is over £500 per fuel the incumbent supplier has the right to refuse the transfer.

¹⁵⁴ Based on Ofgem Social Obligations report 2014, see Ofgem's [Prepayment review](#).

¹⁵⁵ Including [MAP13 v1.8 - Procedure for the Assignment of Debt in Relation to Prepayment Meters](#).

¹⁵⁶ Note that the level of indebtedness of the customer is not adjusted downwards by 10%.

¹⁵⁷ We are not clear why there needs to be a pre-agreed level of debt reduction for switching to occur; it is not clear what is the impact of this requirement, combined with parties' obligations set out in SLC 14, on (incumbent and new) suppliers' incentives within the context of the switching process. EDF Energy said that while the reduction might be an incentive for incumbent suppliers to retain customers – see paragraph 9.446 below – it could also act as an incentive for suppliers to acquire customers, see paragraph 9.444 below. See EDF Energy response to the Addendum, paragraph 3.1(d).

¹⁵⁸ Ofgem has noted that it does not believe that this is actually mandated by the Data Protection Act 1998 and asked the industry to waive this requirement in September 2014. Ofgem open letter (22 September 2014), [Reforming the switching process for indebted prepayment meter customers – the Debt Assignment Protocol](#).

- 9.237 Therefore the DAP makes it particularly burdensome for a customer to switch. In particular, they need to assert their rights in the correct way, some period of time after they have had contact with the acquiring supplier, and in the context of the incumbent supplier having stated that they are objecting to the switch.
- 9.238 In 2014 Ofgem found that despite improvements over time in the DAP indebted prepayment customers still face unnecessary barriers to switching and complexity in the switching process, which could explain the small number of indebted prepayment customers completing a switch.
- 9.239 Ofgem has already taken some steps to address the barriers to switching it identified including amending SLC 14.6¹⁵⁹ to reflect the threshold of £500 under which suppliers have the obligation to facilitate a customer's switch. In an open letter published on 22 September 2014¹⁶⁰ it also identified issues around 'objection letters', 'complex debt' and multiple registrations as areas for improvement that required actions by Ofgem and the industry.¹⁶¹ Subsequently Ofgem has continued to work in this area to reduce barriers to switching for indebted prepayment customers (see Appendix 9.6 for more detail).
- 9.240 In April 2015 ten suppliers, including all of the Six Large Energy Firms, adopted a Point of Acquisition (POA) model with an additional supplier adopting the POA model in July 2015.¹⁶² This model is aimed at simplifying the switching process for customers by building the provision of information about the DAP and customer agreement to debt assignment in the event of a debt objection into suppliers' sales channels for all prepayment customers.
- 9.241 In addition those suppliers who signed up to the POA model also updated their debt 'objection letters' such that the letter sets out:
- (a) For those who have not previously agreed to the DAP the steps necessary to complete their switch through the DAP.

¹⁵⁹ Ofgem (12 May 2015), [Decision to make modifications to the gas and electricity supply licences to reform the switching process for indebted prepayment meter customers – the Debt Assignment Protocol](#).

¹⁶⁰ Ofgem open letter (22 September 2014), [Reforming the switching process for indebted prepayment meter customers – the Debt Assignment Protocol](#).

¹⁶¹ Ofgem asked the industry to revisit its procedures in 2014 and to have a new DAP by April 2015. Ofgem noted that suppliers were largely in agreement with Ofgem's proposal but raised concerns that amending the DAP in this respect would require significant system and processing changes. We understand that the industry has not approved the changes suggested by Ofgem yet.

¹⁶² For example, see Energy UK response to the Addendum.

- (b) For those who have previously agreed to the DAP that their switch will continue and that debt information will be shared with, and debt assigned to, the acquiring supplier to facilitate the DAP.
- 9.242 Initial evidence suggests that the POA model has increased the number of successful switches. In particular, Ofgem said that in Q3 2015 the proportion of attempted switches by prepayment customers being completed through the DAP was 3.4% for electricity and 4.2% for gas compared with figures of 0.3% for electricity and 0.4% for gas at Q3 2014.¹⁶³
- 9.243 Energy UK said that around a third¹⁶⁴ of switches attempted by prepayment customers with less than £500 of debt were successful by the end of the quarter where an objection was raised.¹⁶⁵ Ofgem told us that it understood that the differences between these numbers could be explained by different methodologies and coverage. For example, Energy UK included switches where an objection had been raised, but the switch occurred outside the DAP because the customer cleared their debt with their existing supplier and Energy UK's figures were only based on eight electricity and seven gas suppliers operating the POA model.
- 9.244 We note that although initial evidence suggests that successful switching has increased, the figures above still mean that the majority of switches attempted by prepayment customers with a debt under £500 failed.
- 9.245 Further, Ofgem said that although the POA model addressed one significant process issue, the industry believed that a number of other technical issues were causing attempted switches to fail partway through the switching process. Ofgem said that suppliers told it that a large proportion of attempted switches failed because the two suppliers involved in the switch held differing records of the name of the customer, which led to uncertainty and confusion as to whom the debt should be assigned.
- *Parties' views*
- 9.246 EDF Energy agreed that the DAP, as currently implemented by some suppliers, was a barrier to switching for some indebted prepayment customers.¹⁶⁶ In particular, EDF Energy said that the fact that certain

¹⁶³ This is based to information provided by suppliers to Ofgem as part of Social Obligations reporting. See Ofgem response to the Addendum.

¹⁶⁴ We note that this is based on only eight electricity and seven gas suppliers operating the POA model. See Energy UK response to the Addendum and SSE response to the Addendum, p27. SSE also said that its total customer gains and losses through the DAP had more than doubled in 2015 from 2014 levels.

¹⁶⁵ These switches were completed either through the DAP or because the customer cleared their debt with their existing supplier removing the objection.

¹⁶⁶ See EDF Energy response to the Addendum and RWE response to the provisional decision on remedies.

suppliers had not adopted the POA model was problematic in that a number of switch refusals under the DAP may be unjustified.

- 9.247 RWE said that changes to the DAP will have the benefit of reducing some of the perceived barriers to switching for indebted prepayment customers
- 9.248 SSE said that our analysis of the switching process was outdated given recent developments made under the POA and the increase in the percentage of prepayment customers with debts of less than £500 who successfully switched. SSE also noted that prepayment customers were at a relative 'advantage' compared with credit customers who may be prevented from switching where there were outstanding charges, under electricity SLC 14.
- 9.249 In relation to the issues identified by Ofgem in paragraph 9.239, SSE said that:
- (a) 'objection letters' were not complex or confusing and would be streamlined by the POA model; and
 - (b) complex debt was not a material issue as accounts with complex debt only account for around 5% of DAP processes.
- 9.250 E.ON said that evidence did not support a finding that disengagement and weak customer response created an AEC specific to prepayment meter overall as a group. Rather E.ON said that any AEC could only apply in respect of prepayment customers who either could not access other tariffs in the market (eg because they are in debt) or were discouraged from doing so through charges or security deposits.
- 9.251 E.ON said that the DAP ensured that many of those customers who were in debt were able to benefit from competition. Further, in relation to the issues identified by Ofgem in paragraph 9.239, E.ON said that:
- (a) 'objection letters' should not confuse customer as to their right to switch and the POA model improved these 'objection letters';
 - (b) while in practice the number of complex debt objections raised were very low, it agreed that some of the allowable complex debt reasons should be removed; and
 - (c) issues relating to multiple registrations could cause customer confusion through the receipt of multiple 'objection letters' and that issue generally arose in relation to suppliers who had not adopted the POA model.

9.252 In relation to these points we note that although the level of successful switching has increased materially for suppliers who have adopted the POA model the majority of switches (roughly two-thirds) are not successful for prepayment customers with debts of less than £500.

- *Our assessment*

9.253 Overall we consider that, although there has been some recent improvement with the adoption by some suppliers of the POA model, there are still actual or perceived barriers to indebted prepayment customers switching between different suppliers prepayment tariffs arising from the DAP. In particular, the majority of switches (at least two-thirds) are not successful for prepayment customers with debts of less than £500 even under the POA model. We understand that, in addition to the restrictions arising from the DAP, there may be technical issues which cause these switches to fail partway through.

- *Barriers to switching for customers on restricted meters*

9.254 As set out below we have found that customers on restricted meters face particularly strong barriers to switching supplier and/or tariff.

9.255 We have been told that many restricted meter customers (ie excluding customers with Economy 7 meters) do not have a choice of supplier offering bespoke tariffs (ie tariffs designed to support their specific type of restricted meter (see Appendix 9.5)). They can in principle switch to a single-rate or an Economy 7 tariff offered by their supplier or rival suppliers, but some suppliers would require their existing meter to be replaced with an single-rate or Economy 7 meter at a cost to the customer. Changing meters might also involve some rewiring in the home.

9.256 Further, a change of meter (particularly to an unrestricted meter) may entail a loss of functionality to the customer, and possibly higher tariffs in the future, with no option of reverting back to their old meter. As a consequence, customers face uncertainty in determining whether switching supplier is a good thing for them given the difficulties they face in both comparing the options available to them and taking into account the possible irreversible loss of the functionality of their installed space and water heating systems. In our view, this therefore demonstrates an additional perception of a barrier to switching for customers on restricted meters.

9.257 Taken with the barriers to accessing and assessing information these customers face (see paragraphs 9.185 to 9.187) this means that, for customers on restricted meters, understanding the options available to them

and switching supplier is substantially more difficult than it is for customers on other meter types.

- 9.258 The information we have received from suppliers also shows that incumbent shares of supply are much higher for customers on restricted meters compared to customers on other meters. One of the Six Large Energy Firms submitted that existing customers on restricted meters outside their incumbent regions were largely acquired through doorstep selling. We have received limited, if any, further evidence that either the Six Large Energy Firms or the Mid-tier Suppliers actively compete to acquire customers with restricted meters.
- 9.259 As set out in Section 8 we have found low levels of switching as shown by high incumbent supplier shares in relation to both PES regions and specific types of restricted meters. One potential explanation for the low levels of switching observed in these segments – which several suppliers submitted to us – is that restricted meter customers are generally already on the best deals available and so would not gain from switching. We note that customers on restricted meters are generally cheaper for suppliers to serve because their meters are designed to support space and water heating systems that operate in off-peak hours when wholesale costs of electricity are lower, and the electricity settlement system allows suppliers to benefit from such lower costs.¹⁶⁷ Therefore it is possible – if suppliers choose to pass such benefits on to their customers – those customers on restricted meters may indeed be on very favourable deals, such that there would be limited benefit from switching.
- 9.260 We have tested this hypothesis by comparing the bills paid by customers on restricted meters, roughly 93% of whom are on an SVT tariff bespoke to their specific type of restricted meter,¹⁶⁸ with those that they would have paid had they been on the cheapest single-rate electricity tariff in the markets.¹⁶⁹
- 9.261 In particular, for these purposes we have estimated the gains from switching for both direct debit and standard credit customers on restricted meters based on those customers switching to the cheapest single-rate direct debit tariffs, not taking into account one-off switching costs such as the cost of

¹⁶⁷ Appendix 9.5 provides further evidence on this question.

¹⁶⁸ This is as at Q2 2015 and based on the consumption data, before exclusions, collected as part of our restricted meter bills analysis, for more details see Annex B of Appendix 9.5. We note that: Centrica offers its Economy 7 tariffs to all restricted meter customers and therefore for Centrica when we refer to a meter-specific tariff we are referring to an Economy 7 tariff; and at E.ON restricted meter customers may also be on the single-rate SVT, in particular, where the customer has a restricted meter type for which E.ON does offer a bespoke tariff.

¹⁶⁹ In particular, our tariff information covered the Six Large Energy Firms, Sainsbury's Energy, Ebico, M&S Energy, Co-operative Energy, First Utility and Ovo Energy.

changing meter or rewiring. This is equivalent to scenario 5 from the main gains from switching analysis, see Appendix 9.2. The analysis is conducted at two points of time, end Q2 2015 and end Q2 2014, based on tariffs in the market and estimated annual consumption by meter.

- 9.262 We have found that, for Q2 2015, 67% of customers on restricted meters would have gained from switching to the cheapest single-rate tariffs from across the Six Large Energy Firms and the Mid-tier Suppliers and that those customers could have saved, on average, an amount equivalent to around 17% of their bill or £154.¹⁷⁰ Similarly for Q2 2014 we found that 50% of customers on restricted meters would have gained from switching to the cheapest single-rate tariffs from across the Six Large Energy Firms and the Mid-tier Suppliers and that those customers could have saved, on average an amount equivalent to around 14% of their bill or £120.¹⁷¹
- 9.263 Therefore we note that in both periods a material proportion of customers – at least half – could gain from switching to the cheapest single-rate tariff. Further, the increase over time reflects wider trends seen in the market where the gains from switching have increased over time (as shown in Appendix 9.2).
- 9.264 However, it should be noted that the results differ significantly depending on the supplier in question. For example, while for [redacted] customers the majority of customers on restricted meters would have been better off on the cheapest single-rate tariff in both periods ([redacted]), for [redacted] were better off on their current meter-specific tariffs in both periods (see Appendix 9.5).

o *Parties' views*

- 9.265 In response to the provisional decision on remedies we note that Centrica, EDF Energy, E.ON and RWE generally agreed with our assessment of the barriers to accessing and assessing information and switching facing customers on restricted meters¹⁷² although E.ON said that these barriers can be addressed.¹⁷³ Further, Scottish Power noted that it did not disagree that we had identified an issue in relation to what Scottish Power defined as

¹⁷⁰ Note that bills were calculated exclusive of VAT. In addition there were some observations where customers could have made extremely large savings and these results were skewing the mean savings. Therefore when calculating the mean saving we excluded observations where the savings were over £500.

¹⁷¹ Note that bills were calculated exclusive of VAT. In addition there were some observations where customers could have made extremely large savings and these results were skewing the mean savings. Therefore when calculating the mean saving we excluded observations where the savings were over £500.

¹⁷² See Centrica response to the provisional decision on remedies, p74; EDF Energy response to the provisional decision on remedies, p44; E.ON response to the provisional decision on remedies, pp4 & 12 and RWE response to the provisional decision on remedies, p67.

¹⁷³ See E.ON response to the provisional decision on remedies, pp4 & 12.

'low heating users' (these are those users for whom off-peak usage was less than 50%).¹⁷⁴

- 9.266 SSE said that we had not adduced sufficient evidence of an AEC in relation to customers with restricted meter. In particular, SSE submitted that the CMA's measure of detriment for customers on restricted meters is wholly inadequate, fundamentally flawed and does not support the case for the proposed remedies set out in Section 13. The points raised by SSE in relation to our restricted meter bills analysis are set out in more detail and addressed in Appendix 9.5.
- 9.267 Some suppliers also commented on our restricted meter bills analysis and these comments are addressed in Appendix 9.5.
- 9.268 We note that the roll-out of smart meters will in part address the issues identified in relation to customers on restricted meters. However, three of the Six Large Energy Firms¹⁷⁵ told us that smart meter equivalents were not currently available for all restricted meter types such that the roll-out of smart meters for customers who wanted or needed to keep the capability of those restricted meters was therefore delayed until smart meter equivalents could be developed.¹⁷⁶

- *Dynamically teleswitched meters*

- 9.269 Where a restricted meter has more than one register the restricted meter has to be switched between recording usage on each register. Similarly where a restricted meter only operates at certain times of the day the electricity supplied through that meter needs to be switched on and off. This switching process might be controlled remotely by radio signal (ie teleswitched) or locally (mechanically or electronically). Teleswitching can be either dynamic, static or semi-static. With dynamically teleswitched (DTS) meters the operational times might be changed – on the instructions of the host supplier¹⁷⁷ – in response to changes in market conditions. With static-teleswitching operational times will change infrequently, eg winter and summer. With local switching the operational times are programmed into the meter.

¹⁷⁴ See Scottish Power response to the provisional decision on remedies, p25.

¹⁷⁵ These were Centrica, EDF Energy and E.ON.

¹⁷⁶ Centrica and EDF Energy told us that this would be at least until 2017.

¹⁷⁷ DTS meters are switched, on and off or between registers, using teleswitching codes where each code is controlled by a 'group code sponsor' or host where the incumbent supplier in a region is the host for DTS meters in that region. This means that in each region the incumbent supplier controls when DTS meters are switched on and off or between registers. Ofgem (2013), [The state of the market for customers with dynamically teleswitched meters](#).

- 9.270 As set out in Appendix 9.5 we have considered whether, for meters operated in DTS mode, suppliers may be reluctant to offer tariffs for customers for whom certain operating parameters are controlled by another supplier.
- 9.271 In particular, we have received submissions that DTS technology constitutes a supply-side constraint on competition. In its 2013 'State of the market for customers with DTS' report, Ofgem said that when DTS meters were switched dynamically by the host supplier (ie the incumbent supplier), non-incumbent suppliers may face a DTS-specific barrier to entry due to the risk of imbalance between their supply and demand positions. This risk arises because non-incumbent suppliers may not know in advance the timing and duration of supply to heating circuits for these DTS customers. Therefore if a non-incumbent supplier has DTS customers then it may face unexpected periods of high or low demand.¹⁷⁸ However, we note that Ofgem also said that the great majority of teleswitched meters are currently programmed following a static or semi-static regime and where this is the case, to the extent that potential competitors are aware of the static usage of a teleswitched meter and this usage is maintained over time, they will be able to anticipate at what time and for how long load will be switched, and thus face minimal or no risk of imbalance.¹⁷⁹
- 9.272 Particular concerns have been raised in relation to DTS meters in Scotland, specifically those on the Total Heating Total Control (THTC) meter in North Scotland and the ComfortPlus meters in South Scotland where the incumbent supplier in each region (SSE and Scottish Power respectively) appears to be the only supplier offering bespoke tariffs for these meters and has [redacted] of the share of supply.¹⁸⁰
- 9.273 However, while some suppliers told us that there may be difficulties in offering tariffs in relation to DTS meters, the Six Large Energy Firms¹⁸¹ generally told us that the mechanism by which a restricted meter was controlled did not determine/limit the tariff choices available to customers.¹⁸² For example, Scottish Power told us that not all customers on its ComfortPlus White Meter tariff used DTS meters. Further, there are other

¹⁷⁸ Ofgem (2013), *The state of the market for customers with dynamically teleswitched meters*.

¹⁷⁹ Ofgem (2013), *The state of the market for customers with dynamically teleswitched meters*.

¹⁸⁰ We understand that E.ON has some customers ([redacted]) on these three meters with the majority on E.ON's single-rate SVT tariff as E.ON does not offer a bespoke tariff for all these meters. However, E.ON does offer a bespoke tariff to a subset of the ComfortPlus meters, referred to as 'Weathercall' meters, and has [redacted] customers with these meters on a tariff called 'Electrical Heating Comfort Extra Control'. SSE has [redacted] customer on ComfortPlus meters all on a bespoke SVT tariff, however, we understand that this tariff is not available to new customers. RWE npower also has some customers on these meters ([redacted]).

¹⁸¹ These were EDF Energy, E.ON and RWE npower.

¹⁸² For example, EDF Energy told us [redacted].

non-Economy 7 restricted meters that are not DTS meters where the incumbent suppliers have similar shares.¹⁸³ Further, many Economy 7 meters are classed as DTS meters¹⁸⁴ – although we note in this regard that they do not appear to currently be operated dynamically – and this does not appear to be an impediment to competition.

9.274 Finally we note that, based on the analysis set out below, the gains from switching for those customers with DTS meters who would have had lower bills on the cheapest single-rate tariff were not systematically higher than those for other restricted meters. For example, at Q2 2015 while the average gains for those on [X] meters, £[X] per customer, were higher in absolute terms than the average gains for all on restricted meters, £154 per customer, the average gains were lower for those customers on [X] meters, £[X] per customer, and [X] meters, £[X] per customer. Further, relative to their average bill the gains were lower for customers on [X] meters ([X]%), [X] meters ([X]%) and [X] meters ([X]%) than those for all on restricted meters (17%).

9.275 Therefore, based on the assessment above, our concerns regarding customers on restricted meters relate to the demand side, and in particular derive from the existence of enhanced barriers to accessing and assessing information, and barriers to switching when compared with those faced by customers on single-rate and Economy 7.

- *Conclusion on barriers to switching*

9.276 Overall, we 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, in particular when facing an erroneous transfer. While such issues may have only affected a limited number of customers, 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.

9.277 In view of the above, we have found that customers face actual and perceived barriers to switching, such as where they experience erroneous transfers which have the potential to cause material detriment to those who

¹⁸³ For example, for the Heatwise meter the incumbent share was [X], for the SuperTariff meter the incumbent share was [X] and for the SuperDeal meter the incumbent share was [X].CMA analysis of data from the Six Large Energy Firms.

¹⁸⁴ Based on information provided by the Six Large Energy Firms, excluding E.ON, and the Mid-tier Suppliers we estimate that roughly 424,571 Economy 7 meters can be operated dynamically.

suffer from them. Erroneous transfers may thereby impact customers' ability to switch as well as their perception of switching.

- 9.278 In addition, we have identified aspects of the prepayment and restricted meter segments that strengthen the feature that customers face actual and perceived barriers to switching for prepayment customers and customers on restricted meters.
- 9.279 We have found that prepayment customers face higher actual and perceived barriers to switching arising, in particular, from:
- (a) the need to change meter to switch to a wider range of tariffs (and the obstacles associated with this requirement such as perceptions of the complexity of the meter replacement process); and
 - (b) restrictions arising from the DAP hindering indebted prepayment customers' ability to switch supplier.
- 9.280 We have found that customers on restricted meters face higher actual and perceived barriers to switching arising, in particular, from:
- (a) the requirement imposed by suppliers on certain restricted meter customers to replace their restricted meter with an single-rate or Economy 7 meter, which may be at a cost to the customer, to be able to switch to a wider range of tariffs;
 - (b) the fact that a restricted meter replacement might involve some rewiring in the home; and
 - (c) the fact that a restricted meter replacement (particularly to a single-rate meter) may entail a loss of functionality to the customer, and possibly higher tariffs in the future, with no option of reverting back to their old meter.

Conclusion on barriers to engagement

- 9.281 We have noted that there are material numbers of customers who appear to be fundamentally disengaged in the sense that they either do not consider exercising choice in the markets or do not 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. Barriers to engagement may apply to different customers with different levels of strength, depending on their particular capabilities, attitudes and experience. While we acknowledge that some of these barriers may only affect a minority

of customers, all these barriers, taken in the round, contribute to the levels of disengagement we have identified.

- 9.282 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 finding of the features that lead to an AEC in the domestic retail energy supply markets.
- 9.283 Our 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**¹⁸⁵ 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. We note that these features differ in intensity across different meter types.
- 9.284 More particularly, in relation to domestic customers on all meter types 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.

¹⁸⁵ We refer to weak customer response as an overarching feature as synonymous with it being a source for an AEC ([CC3](#), paragraph 170).

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. In addition, the fact that the regulations governing energy supply ensure that domestic customers generally receive continuous supply of gas and electricity implies that there is no natural trigger point for engagement, which may depress levels of engagement relative to other sectors.

- (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) **Customers face actual and perceived barriers to switching**, such as where they 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.

9.285 We have found that prepayment customers and standard credit customers overall are less engaged than direct debit customers, particularly in terms of whether they have ever considered switching or are likely to consider switching in the next three years, and, for prepayment customers, their awareness of their ability to switch.

9.286 In relation to **prepayment customers** we have identified additional aspects that contribute to these features and support a finding that disengagement and weak customer response is a more significant problem among prepayment customers compared with domestic customers on direct debit. We have found that:

- (a) prepayment customers face higher actual and perceived barriers to accessing and assessing information about switching arising, in

particular, from relatively low access to the internet and confidence in using PCWs;

- (b) prepayment customers face higher actual and perceived barriers to switching arising, in particular, from:
 - (i) the need to change meter to switch to a wider range of tariffs (and the obstacles associated with this requirement such as perceptions of the complexity of the meter replacement process); and
 - (ii) restrictions arising from the DAP hindering indebted prepayment customers' ability to switch supplier.

9.287 We also note that prepayment customers include, compared to the entire population, higher proportions of individuals: with low levels of income; with low levels of education; living in social rented housing; and having a disability – demographic characteristics that we have found to be associated with low levels of engagement in retail energy markets.

9.288 In relation to customers on **restricted meters**, we have also found that disengagement is a more significant problem among customers on restricted meters compared with domestic customers, with single-rate or Economy 7 meters. In particular, we have identified aspects of the restricted meter segments that strengthen the features that customers face actual and perceived barriers to accessing and assessing information, and that customers face actual and perceived barriers to switching.

9.289 We have found that customers on restricted meters face:

- (a) higher actual and perceived barriers to accessing and assessing information arising, in particular, from a general lack of price transparency concerning the tariffs that are available to them, which results from restricted meter tariffs not being supported by PCWs or suppliers' online search tools.
- (b) higher actual and perceived barriers to switching arising from:
 - (i) the requirement imposed by suppliers on certain restricted meter customers to replace their restricted meter with an single-rate or Economy 7 meter, which may be at a cost to the customer, to be able to switch to a wider range of tariffs;
 - (ii) the fact that a restricted meter replacement might involve some rewiring in the home; and

- (iii) the fact that a restricted meter replacement (particularly to a single rate meter) may entail a loss of functionality to the customer, and possibly higher tariffs in the future, with no option of reverting back to their old meter.

9.290 These are the central contributory features to the Domestic Weak Customer Response AEC that we have identified. In terms of our approach to assessing potential remedies, however, we note two points. First, that some aspects 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 that are directly targeted on reducing the detriment observed.

Price discrimination and tacit coordination

9.291 In this section we consider to what extent supplier behaviour may be leading to a separate AEC or contributing to the AEC we have 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

9.292 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.

9.293 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.¹⁸⁶ 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.

9.294 For the avoidance of doubt, for the purposes of this market investigation, we consider suppliers to be price discriminating if we observe that SVT prices are higher than those for fixed-term products and these price differences do not reflect differences in the actual or expected costs of supplying customers over the term of the fixed-term tariffs. The relevant costs would include direct costs, indirect costs and acquisition costs.

Past and current pricing strategies of the Six Large Energy Firms

9.295 Price discrimination appears to have been a consistent feature of retail domestic energy supply in Great Britain. In particular, as explained in Section 8, 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 (see Section 8). In 2009 Ofgem prohibited undue price discrimination which appears to have had the effect of focusing competition on discounted fixed-term tariffs.

9.296 We asked the Six Large Energy Firms to explain the approach taken to setting prices for their SVTs and non-standard tariffs.¹⁸⁷

(a) One of the Six Large Energy Firms ([REDACTED]) 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 SVT 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.

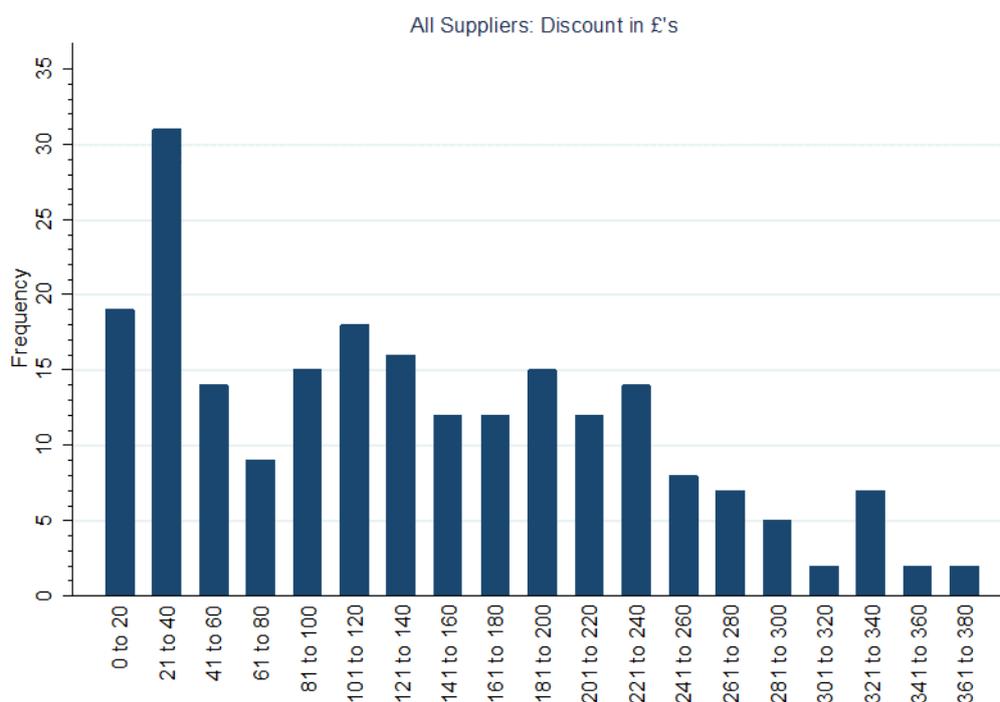
¹⁸⁶ This section summarises the analysis contained in Appendix: 9.14 Price discrimination.

¹⁸⁷ The full findings are set out in Appendix 8.3: The pricing strategies of the Six Large Energy Firms.

Evidence on price differentials

- 9.297 Figure 9.9 provides results on the size of discounts, at time of launch, for discounted fixed-term tariffs launched between mid-2013 and March 2016 (this analysis does not therefore include tariffs priced at a premium to the SVT¹⁸⁸). 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 £361 to £380 on an annual bill. We estimate that over 60% of discounted fixed-rate tariffs (including white-label tariffs) were priced at a discount of more than £100 on an annual bill.
- 9.298 With the exception of a small number of tariffs that were excluded from the analysis, all discounted fixed-term tariffs launched since mid-2013 have been fixed-rate or capped products (following the RMR reforms Section 12). This means that the discounts offered over the term of tariffs might have changed with changes in SVT prices. For fixed-rate tariffs launched earlier in the period discounts at time of launch are likely to have been lower than those offered over the life of the fixed-term tariffs and for others the reverse could be the case.

Figure 9.9: Distribution of fixed-term tariffs offered by Six Large Energy Firms at a discount, at launch, to the SVTs, mid-2013 to March 2016, £ discount



Source: CMA. Based on annual bill for dual fuel, direct debit typical consumption customer.

¹⁸⁸ 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.

- 9.299 We calculate that just over 50% 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) 15 out of 19 of the SSE fixed-term tariffs offered a discount at launch of 10% or less;
 - (b) 11 out of 25 of the E.ON fixed-term tariffs offered discounts of 4% or less;
 - (c) 45% of the British Gas fixed-term tariffs offered discounts of more than 10%;
 - (d) around 60% of EDF Energy, RWE and Scottish Power fixed-term tariffs offered discounts of more than 10%;and
 - (e) many of the British Gas and SSE discounted tariffs in this period are white-label tariffs.

Evidence on gains from switching

- 9.300 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 2015. 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, excluding prepayment customers these gains are, on average, largest for [redacted] (£129) followed by [redacted] (at £111), [redacted] (£83), [redacted] (£60), [redacted] (£54) and then [redacted] (£44). We note that these results do not include gains to be had from customers switching to white labels products offered by their existing supplier.

Cost differentials

- 9.301 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.
- 9.302 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 8, direct costs account for around 85% of total costs and indirect costs the remaining 15%.

- *Direct costs*

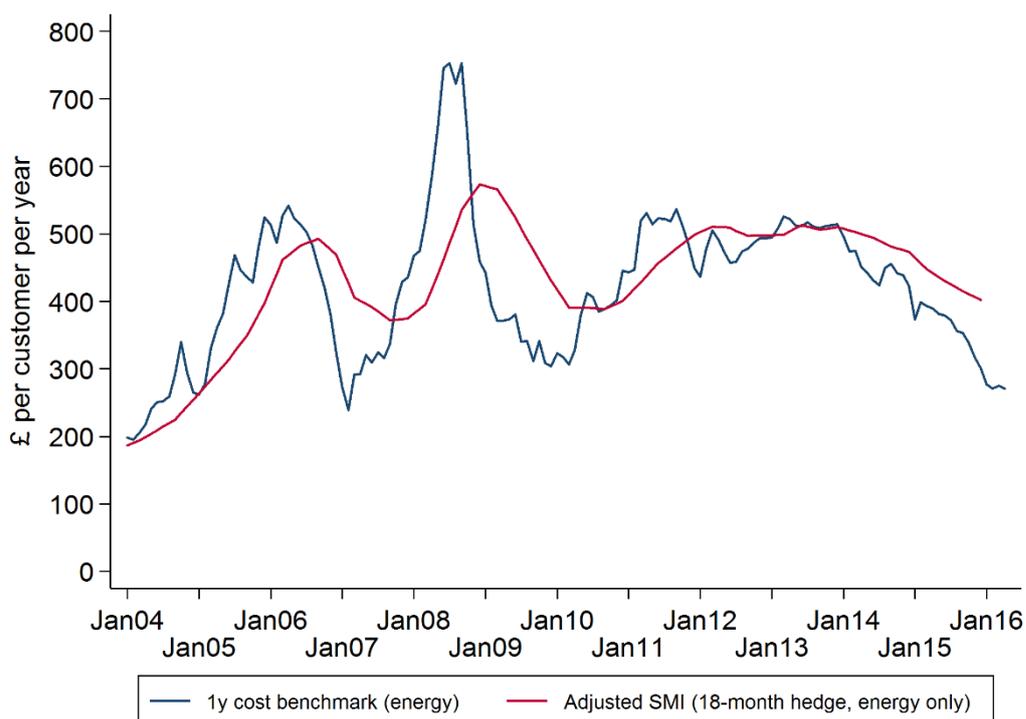
- 9.303 In relation to direct costs, we have seen no evidence to suggest that transmission and distribution charges and costs of meeting social and environmental obligations differ between customers subscribing to the SVTs and fixed-term tariffs.
- 9.304 [redacted]¹⁸⁹ Centrica said that price movements may still occur as a result of increase in other costs such as network costs and environmental and social obligation costs.
- 9.305 For their fixed-term tariffs the Six Large Energy Firms have adopted a range of different strategies. [redacted] The others normally purchase [redacted].¹⁹⁰
- 9.306 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.
- 9.307 However, our comparison of various forward-looking energy cost benchmarks and a stylised 18 months hedging strategy shows that no cost indicator has resulted in systematically higher or lower expectation of wholesale costs. The chart below compares the one-year forward-looking cost benchmark that we have calculated¹⁹¹ with the SMI (the 18-month hedge that Ofgem uses to approximate the average hedging strategy of the Six Large Energy Firms).
- 9.308 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).

¹⁸⁹ See Annex A of Appendix 9.14: Price discrimination, for a summary of energy purchasing strategies.

¹⁹⁰ See Appendix 9.14: Price discrimination, for a summary of energy purchasing strategies.

¹⁹¹ The two-year benchmark is very similar to the one-year benchmark.

Figure 9.10: Comparison of wholesale costs implied by SMI and one-year forward-looking benchmark



Source: CMA analysis.

Note: Based on typical domestic consumption of 3,200kwh/year for electricity and 13,500kwh/year for gas. One-year cost benchmark is a weighted average of baseload and peak electricity prices.

9.309 Further, we have considered the intrinsic risks associated with the SVTs and non-standard tariffs. We consider that the key risk for retail energy suppliers in the supply of domestic customers will be their exposure to movements in wholesale energy prices. We recognise that this risk will be different for different tariff types. 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).

9.310 It has been put to us that the risks faced by suppliers are higher for SVTs. For example, Centrica said that volume risk is higher for SVT (and other tariffs without exit fees) as customers can switch to another supplier at any time. On this basis, we consider that the risks to suppliers associated with movements in wholesale energy costs are likely to be greatest for fixed-rate tariffs with no exit fees. Like customers on SVTs, these customers can change tariff or supplier at any time without penalty. However, as customers on fixed-term tariffs are more engaged than those on SVTs, we consider that they are more likely than SVT customers to switch to another tariff or supplier to take advantage of cheaper tariffs if they become available.

- 9.311 We have found that for the Six Large Energy Firms, on average, over the period Q1 2012 to Q2 2015, around 50% of dual fuel customers on fixed-term tariffs were on tariffs with exit fees (see paragraph 9.91). RWE told us that it expected about [redacted] of customers on fixed-term tariffs to switch to another tariff or supplier in-term.¹⁹² E.ON and EDF Energy told us that with falling energy prices they had experienced customers on fixed-term tariffs switching in-term to cheaper tariffs.
- 9.312 [redacted] (see paragraphs 9.84 and 9.304). We consider that this approach to purchasing energy for SVT customers and the pricing of the SVT is only sustainable because a sufficiently large proportion of customers on these tariffs have not and are not expected to switch away from the SVT at times of falling energy prices.
- 9.313 Our view is that, taking into account both features of the SVT and fixed-term tariffs and the behaviour of people subscribing to them, we see no reason to expect that the downside risks associated with movements in wholesale energy costs are inherently and systematically higher in the provision of SVTs as compared with fixed-term, fixed-rate tariffs.
- *Indirect costs*
- 9.314 Centrica said that it would expect average indirect costs to be higher for customers subscribing to the SVT 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).
- 9.315 The other Six Large Energy Firms confirmed that they would expect both cost to serve¹⁹³ 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.
- 9.316 The Six Large Energy Firms confirmed that the key drivers of cost differences were payment methods. Our assessment of the average additional costs associated with serving customers who pay by standard credit is £100, and our assessment of the additional costs associated with

¹⁹² See Appendix 8.3: Pricing Strategies.

¹⁹³ 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.

serving customers who prepay is £63.¹⁹⁴ Since our analysis in this section is based exclusively on direct debit tariffs, this does not affect our analysis of the size of discounts, at time of launch, for discounted fixed-term tariffs launched since mid-2013.

Parties' views

9.317 We received the following submissions from the Six Large Energy Firms:

- (a) SSE said that it did not price its SVT above the price justified by costs (see paragraph 9.319);
- (b) Scottish Power and RWE said that we had taken insufficient account of the constraint imposed on SVT pricing by the availability of non-standard tariffs (see paragraphs 9.321 and 9.322);
- (c) RWE said that we had not taken sufficient account of what it called the 'see-saw' pricing model adopted in the industry (see paragraph 9.325);
- (d) Centrica said that our analysis was based on an unrepresentative period and that non-standard products were not always priced below SVTs (see paragraphs 9.331 and 9.333);
- (e) Centrica and RWE said that the commodity risks faced by suppliers were higher with SVTs (see paragraphs 9.336 and 9.337);
- (f) Centrica said that competitive market prices would not necessarily reflect only forward-looking costs (see paragraph 9.339); and
- (g) RWE said that indirect costs were higher with SVT tariffs as compared with non-standard tariffs (see paragraph 9.341).

9.318 We respond to these comments in turn below.

- *SSE does not price discriminate*

9.319 SSE said¹⁹⁵ that it did not price discriminate between SVTs and non-standard tariffs, and that there could be significant variation in the wholesale costs associated with SVTs and non-standard tariffs.

¹⁹⁴ See Appendix 9.8.

¹⁹⁵ SSE response to provisional findings, paragraphs 2.1.1 d) & 3.4.2.

9.320 We have found that SSE has offered non-standard tariffs at a discount to its SVT and, for the reasons given above (see paragraphs 9.303 to 9.316), we consider that such discounts have not been justified by differences in costs. We also note that SSE said¹⁹⁶ that suppliers had offered fixed tariffs at close to or under cost as ‘introductory’ offers to attract new customers, which suggests to us that SSE believes that rival suppliers have offered heavily discounted fixed-term products. Nevertheless, we observe that SSE has been less active than the other Six Large Energy Firms in offering discounted products, and that many of SSE’s discounted products were white-label tariffs (see paragraph 9.299).

- *Constraint imposed on the SVT by discounted products*

9.321 RWE said¹⁹⁷ that the CMA did not take proper account of the constraint imposed on the SVT by non-standard pricing. RWE said that it must price its SVT at a level which was competitive and which would enable it to retain customers given that competitors were competing for these customer with their discounted products. If the differential was too great, insufficient numbers of customers would revert to (or remain on, for a sufficient period) the SVT after the end of their fixed-term tariff.

9.322 Scottish Power said that¹⁹⁸ price discrimination was inherently limited by customer switching and that the CMA had not taken into account the fact that a large proportion of customers moved between the SVT and non-standard tariffs. That [redacted] of customers had been on their current SVT for two years or less, meant that they had recently defaulted onto the SVT from a non-standard tariff or switched to the SVT of their current supplier.

9.323 We do not dispute that the availability of discounted non-standard products will have imposed some constraint on suppliers in pricing their SVTs. However, our findings demonstrate that this has not been sufficient constraint. In particular we have found that for each of the Six Large Energy Firms their tariffs have, on average, exceeded competitive levels (see Section 10).

9.324 We also note that [redacted] told us that, excluding prepayment customers, up to [redacted] and [redacted] of its SVT gas and electricity customers, respectively, had been

¹⁹⁶ SSE response to provisional findings, paragraph 3.4.3.

¹⁹⁷ RWE response to provisional findings, paragraph 281.

¹⁹⁸ Scottish Power response to provisional findings, paragraphs 3.31 & 3.32.

on its SVT for less than three years. The percentage of those who had been on the SVT for two years or less would be lower.

- *See-saw pricing model*

- 9.325 RWE said¹⁹⁹ that it did not dispute that there was an element of price discrimination in the market, in particular that the differences between its SVT and non-standard tariffs were fully explained by differences in unit costs. RWE said²⁰⁰ that its non-standard tariffs were normally priced at a discount to its SVT and that this was a pricing model adopted across the industry. RWE said²⁰¹ that its non-standard tariffs were priced based on (and the financial viability of its cheapest non-standard products depends upon) a certain proportion of customers reverting to its non-discounted SVT at the end of their fixed term, for a certain period.
- 9.326 RWE also said that the CMA had failed to demonstrate why this raised any competition concern. Price variation and price discrimination were features of many competitive markets and from an economic point of view were often considered to be efficient/pro-competitive.²⁰²
- 9.327 We recognise that suppliers compete to acquire and retain customers through products priced at a discount to their SVTs (see Section 8).
- 9.328 We agree that the incentives suppliers have to offer discounted tariffs will be driven by the profits they expect to earn from the customers acquired or retained by such tariffs. Indeed, several of Six Large Energy Firms told us that they calculate the net present value of customers acquired by discounted products over a period of between three and five years²⁰³ and, in making these calculations, they will expect some of those acquired to revert to the SVT and others to switch to another discounted product or supplier.
- 9.329 We also agree that competition for customers with discounted introductory offers is commonplace in other markets.
- 9.330 According to RWE the viability of its cheapest non-standard products depends upon some customers reverting to the SVT prices. However, suppliers cannot be certain what proportion of the customers acquired will revert to the SVT or how long they will remain on the SVT and we would expect this uncertainty to limit their incentives to discount tariffs. This means

¹⁹⁹ RWE response to provisional findings, paragraph 279 and 291.

²⁰⁰ RWE response to provisional findings, paragraph 257.

²⁰¹ RWE response to provisional findings, paragraph 291.

²⁰² RWE response to provisional findings, paragraph 279.

²⁰³ See Appendix 8.3: Pricing Strategies.

that the competition to acquire customers through introductory offers is unlikely to have the effect of ‘fully competing away’ the profits generated by those customers who later revert to the SVT. More importantly, the incentives to discount will be limited to the profits earned on those customers acquired through discounted tariffs, and those customers who do not engage in the market and stay on SVTs will always be paying the higher SVT prices. However, our findings demonstrate that in the domestic retail energy markets the price discrimination we have observed is not a result of a well-functioning market. In particular, on average, customers have been paying prices that are above the competitive level (see Section 10).

- *Analysis based on unrepresentative period*

- 9.331 Centrica said²⁰⁴ that the CMA had based its analysis on a period in which commodity costs were relatively benign and generally falling (from July 2013 to March 2015), resulting in an incomplete view. Centrica considered it likely that a different conclusion would have been drawn had we considered pricing outcomes across the entire commodity cycle, including periods of higher volatility and increasing commodity prices.
- 9.332 Our analysis of discounted tariffs as set out in Figure 9.9 covers tariffs launched mid-2013 to March 2016. We selected this period as discounted tariffs launched in this period were largely fixed-rate. The purpose of this analysis was to illustrate the extent of discounting by each of the Six Large Energy Firms. However, suppliers have offered discounted tariffs over the period 2009 to 2016 (see Section 8), a period which has seen rising and falling wholesale energy prices. In addition, we have found that electricity revenues per kWh from the SVT are consistently higher than average revenues from non-standard tariffs. Over the period 2011 to mid-2015, average revenue per kWh from the SVT was around 11% and 15% higher than average revenue from non-standard tariffs for electricity and gas respectively across the Six Large Energy Firms.
- 9.333 Centrica said²⁰⁵ that non-standard tariffs were not always priced below the SVTs; a substantial number were priced above (around two-thirds were priced below and one-third above). Moreover, the proportion changed significantly over time, and appeared to be strongly driven by the relative costs of different hedging strategies (with fewer non-standard tariffs sold at a

²⁰⁴ Centrica response to provisional findings, paragraphs 71 & 72.

²⁰⁵ Centrica response to provisional findings, paragraph 76.

discount to the SVT at times when the SVT procurement strategy generated lower costs than the one-year forward curve).

- 9.334 We acknowledge that not all non-standard tariffs have been offered at a discount to the SVT. Figure 8.17 in Section 8 clearly shows some non-standard tariffs offered at prices, at launch, that are higher than SVTs in the market. However, we have calculated that over the period January 2010 to March 2016, over 70% of non-standard tariffs were launched at a discount. The majority of non-standard tariffs have therefore been launched at a discount to the SVT.
- 9.335 We looked at how the proportion of tariffs launched at discount over the period 2010 to end 2013 (a period of rising commodity prices) compared with the period January 2014 to March 2016 (a period of falling commodity prices). We found that while the proportion of non-standard tariffs launched at a discount was smaller in the earlier period, over 60% of fixed-term tariffs were launched at a discount. Contrary to Centrica's suggestion, the availability of discounted tariffs does not therefore appear to be driven by the movements in commodity prices.
- *Higher commodity risks with the SVT*
- 9.336 Centrica said that movements in wholesale energy markets materially affect the changes in the relative prices of SVT and fixed-term products over time as there were different costs and risks associated with the ways energy was bought for different products. In particular:
- (a) fixed-term products typically had a different weighted average cost of fuel to the SVT; and
 - (b) for the SVT and other tariffs without exit fees, customers could leave at any time, which meant that the supplier bore significant volume risk in terms of customer numbers as well as in demand per customer.
- 9.337 RWE said²⁰⁶ that [REDACTED].
- 9.338 We respond to these arguments in paragraphs 9.310 to 9.313.

²⁰⁶ RWE response to provisional findings, paragraph 288.

- *Forward looking costs*

9.339 Centrica said²⁰⁷ that it could not accept a proposition that only forward-looking costs should be reflected in prices in a competitive market. It said that such a proposition would fail to recognise that if prices were always driven by the current forward market view this would result in significantly more volatile pricing outcomes, which would not be in consumers' best interests. Centrica also said that with fixed-term contracts, at any point in time, most customers were midway through a contract, so the average price paid at any point in time would reflect past as well as current costs.

9.340 For the reasons set out above (see Section 8) we consider that in a well-functioning market we would expect prices, at the time they are set, to reflect forward-looking costs. We also note (see paragraph 9.312) that the approach the Six Large Energy Firms have adopted to purchasing energy for their customers on SVTs and then pricing these tariffs, has only been sustainable because a sufficient proportion of these customers have not taken advantage, at times of falling energy prices, of the opportunity to cut their energy bills by switching to cheaper tariffs with their existing or another supplier.

- *Higher indirect costs with the SVT*

9.341 RWE also considered that there were likely to be differences in the indirect costs associated with SVT and non-standard customers. For example, if comparing direct debit dual fuel tariffs, RWE said²⁰⁸ that costs associated with the SVT were likely to be higher than costs associated with non-standard tariffs, as a result of social tariff costs and complex metering costs which were more likely to be associated with SVTs, and the fact that non-standard customers were more likely to manage their accounts online which resulted in lower costs for RWE.

9.342 However, RWE also told us that while the [✂].

Conclusion

9.343 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.

²⁰⁷ Centrica response to provisional findings, paragraph 73.

²⁰⁸ RWE response to provisional findings, paragraph 290.

- 9.344 Specifically in relation to discounts on the SVTs, we have found that, over the period July 2013 to March 2016 just over 50% of discounted fixed-term 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 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.
- 9.345 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 2015; and information on average revenues by suppliers, tariff type and payment type for the period 2010 to 2014.
- 9.346 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 [redacted]. 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,²⁰⁹ at time of launch, but swiftly concluded that [redacted].
- 9.347 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.
- 9.348 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 view is that there is no evidence that energy costs are inherently and systematically higher for SVTs as compared with fixed-term, fixed rate tariffs (see paragraphs 9.309 to 9.313).

²⁰⁹ Based on typical consumption customer.

- 9.349 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.
- 9.350 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.
- 9.351 Our 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 evidence on how the average prices offered by the Six Large Energy firms have compared with those we would expect to prevail in a well-functioning competitive market.
- 9.352 Overall, our 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 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

- 9.353 In Section 8 we set out evidence consistent with weakening competition between the Six Large Energy Firms in the supply of customers on SVTs. In particular we found that from 2009 the gap between the SVT and underlying costs appears to have been widening. This broadly coincides with the introduction of the prohibition on undue regional price discrimination (which had the effect of focusing competition on fixed-term tariffs) in 2009 and then the withdrawal of the Six Large Energy Firms from doorstep selling in 2011 and 2012.

- 9.354 The State of the Market Assessment²¹⁰ 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.
- 9.355 In this subsection we have set 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 on the SVT.²¹¹
- 9.356 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 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.
- 9.357 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 conclusions.

Conditions for coordination

- 9.358 The Guidelines state that three conditions need to be satisfied for coordination to be sustainable:²¹²
- (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

²¹⁰ [Ofgem State of the Market Assessment](#).

²¹¹ Appendix 9.4: Coordination the retail market facilitated by price announcements, provides greater detail on the analysis we conducted.

²¹² [CC3](#), paragraph 250.

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.
- 9.359 Our 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.²¹³ In particular: the degree of transparency on the prices offered by suppliers and other terms and conditions; the degree of transparency on the suppliers to whom and from whom domestic customers are lost and gained; and the degree of similarity in the cost structures and business models offered by suppliers.
- 9.360 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.
- 9.361 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 markets, which is another significant factor that reduces the likelihood of coordination in the retail markets.

Evidence of tacit coordination through public price announcements

- 9.362 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

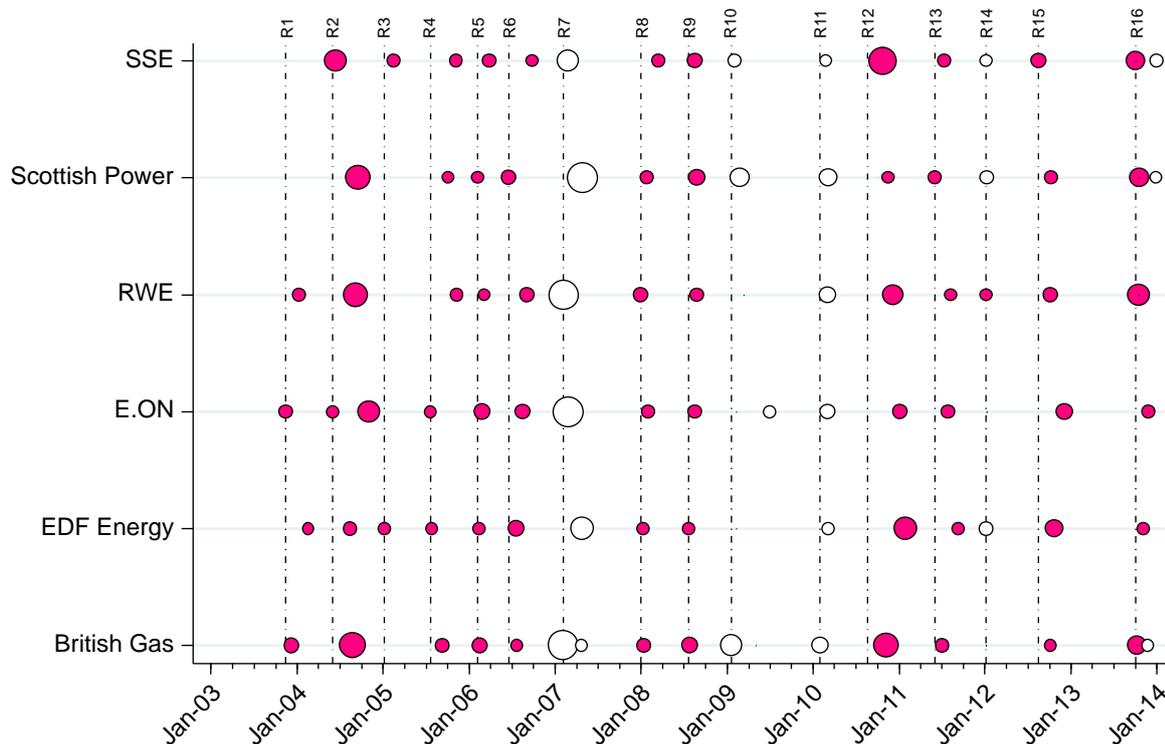
²¹³ Appendix 9.4 gives the views of the Six Large Energy Firms on whether market characteristics are conducive to tacit coordination.

across regions and based on the change in bill for a dual fuel domestic customer, paying by monthly direct debit with 'typical' consumption.

9.363 Figures 9.11 and 9.12 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).

9.364 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.

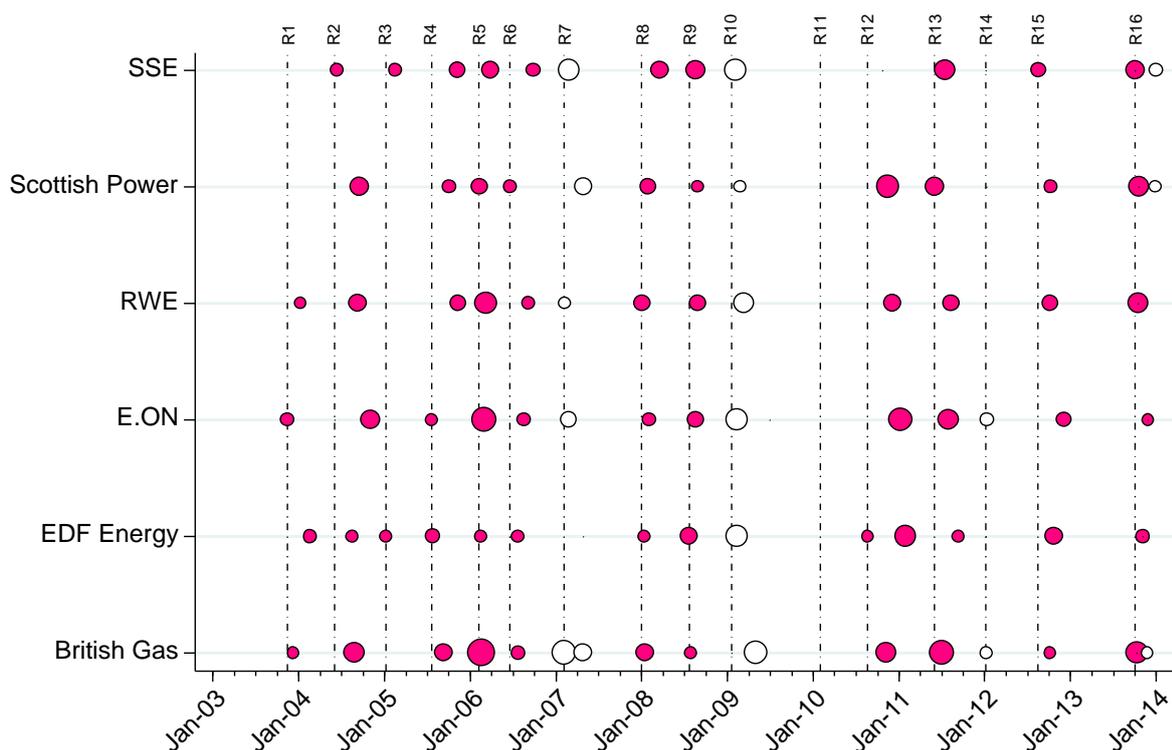
Figure 9.11: The timing, direction and size of announced changes in SVT gas prices, 2004 to 2014



Source: CMA analysis.

Note: Pink circles denote positive gas price changes and white circles denote negative gas price changes.

Figure 9.12: 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.

9.365 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.

9.366 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.²¹⁴

9.367 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

²¹⁴ Appendix 9.4: Coordination the retail market facilitated by price announcements.

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.

- 9.368 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.
- 9.369 We also assessed whether there was any evidence of announced pricing plans changing in response to subsequent announcements made by rivals to be significant.
- 9.370 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 not identified any occasions when its plans in relation to a change in price changed materially following the public announcement.
- 9.371 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.²¹⁵ Our view is that these explanations appear consistent with the documentary evidence we have received.
- 9.372 Our 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 8 that SVTs do move together. While we do not see a consistent convergence of tariffs over time, it appears that

²¹⁵ Appendix 9.4: Coordination in the retail market facilitated by price announcements.

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 8 that EBIT margins of the Six Large Energy Firms increased after 2009 and we consider the evidence on whether current levels of profitability are excessive.

9.373 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).

Conclusions on tacit coordination

9.374 Based on the evidence set out above, our 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.
- (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.

Supply-side barriers to entry and expansion in prepayment

9.375 Our analysis of the prepayment segments, as set out in Section 8, suggests that competition is significantly weaker than in the wider GB domestic retail energy markets. In particular, although we have seen some recent increase in activity by the independent suppliers concerning prepayment meters we have found that the outcomes for prepayment customers are significantly worse than those for customers in the credit meter segments. In particular, the range of tariffs available to prepayment customers is significantly more

limited than those available in the credit meter segments, and the cheapest tariffs that are offered by suppliers to prepayment customers are significantly higher (even accounting for differentials in the costs to serve) than the cheapest direct debit tariffs.

- 9.376 As outlined above the overall weight of evidence supports a finding that disengagement and weak customer response is a more significant problem among prepayment customers compared with domestic customers on direct debit. We have a particular concern about the material numbers of customers who appear to be fundamentally disengaged from the domestic retail energy markets in the sense that they have not considered exercising choice in the market (see paragraph 9.26). Our survey found that, based on several metrics, prepayment customers appear less engaged compared with customers on direct debit (see paragraphs 9.64 and 9.65).
- 9.377 In addition, we have found that prepayment customers face greater barriers to engaging and switching than other consumers. For instance, our survey results show that prepayment customers, compared with other customers, are less likely to use PCWs (see paragraph 9.184). We also found that prepayment customers face heightened features of the Domestic Weak Customer Response AEC. In particular, we have found certain heightened features:
- (a) the need for a meter exchange and an additional lack of awareness and understanding of their option to be able to change meter (see paragraphs 9.213 to 9.233); and
 - (b) indebted prepayment customers who face actual and perceived barriers to switching between different suppliers prepayment tariffs arising from the DAP (see paragraphs 9.234 to 9.253).
- 9.378 However, we do not consider that these demand-side constraints fully explain the absence of the cheapest tariffs (and limited range of tariffs) in the prepayment segments when compared with the direct debit segment (even accounting for differentials in the costs to serve).
- 9.379 Therefore we consider below whether there may be supply-side constraints on competition in the prepayment segments which might explain this absence of the cheapest tariffs in the prepayment segments compared with those offered in the direct debit segments (even accounting for differentials in the costs to serve).
- 9.380 In particular, we have considered in detail a number of features of the prepayment segments that may contribute to explaining the outcomes we have found, including:

- (a) technical constraints in the prepayment segments, in particular, in relation to dumb meters that limit prepayment tariff offerings.
- (b) softer incentives on suppliers to compete to acquire prepayment customers such as:
 - (i) higher costs of acquiring customers in the prepayment segments, and especially so for new entrants; and
 - (ii) the complexities involved in the assignment of customer debt in some prepayment meter switches.

9.381 In addition, we have considered whether certain aspects of the ‘simpler choices’ component of the RMR rules exacerbate the supply-side constraints affecting the prepayment segments, and the extent to which smart meters have the potential to mitigate or eliminate these constraints.

9.382 Our assessment of each is set out below in turn.

Technical constraints and dumb prepayment meters

9.383 The prepayment infrastructure for both gas and electricity was built and designed in the 1990s. Its vintage, combined with the fact that it was not designed to accommodate the proliferation of suppliers and tariffs now in the market, means that it imposes limitations on the total number of tariff offerings that can be made by suppliers, a point generally agreed upon by respondents to the Addendum and provisional decision on remedies (see below). We set out the nature of these constraints below.

9.384 While there are differences between the gas and electricity infrastructure, below we give a brief overview of the general system employed for both fuel types, highlighting any relevant differences where necessary.

9.385 Each prepayment customer is issued with a prepayment key (in the case of electricity) or card (in the case of gas). Customers top up at local shops and post offices that offer one of three types of payment terminal (Payzone, Paypoint and Post Office).²¹⁶ The customer puts their key/card in a prepayment terminal, which is then credited with the amount of the top up.

²¹⁶ Smart prepayment solutions, such as the one offered by Utilita, can also accept cash payments at shops but they are not limited to the shop having the physical infrastructure of a card or key reader connected to the Payzone, Paypoint and Post Office systems. With smart prepayment, a supplier could in theory have an agreement with any retail outlet to offer energy credit in exchange for cash payment.

- 9.386 When the customer returns home and inserts their key/card into the meter, the balance on the meter is increased to reflect the additional credit the customer has added. If a customer's balance runs out, and they have exhausted their emergency credit,²¹⁷ their supply will be temporarily disconnected until they have topped up again and have a positive balance.²¹⁸
- 9.387 However, the dumb infrastructure used by suppliers to communicate with customers' meters has a number of technical limitations that affect its functionality.
- 9.388 In order for a prepayment meter to draw down (or 'decrement') the customer's balance correctly,²¹⁹ the meter needs to be programmed with the customer's tariff details (standing charge and unit rate(s)). There is a mechanism through which suppliers can update the correct tariff for each customer's meter via the prepayment infrastructure.^{220,221}
- 9.389 The details of all tariffs offered by each supplier are stored on the prepayment infrastructure, with each tariff allocated a 'tariff code', setting out the details of the tariff (eg standing charge and unit rate(s)). Each customer's meter is then assigned the correct tariff code for their tariff, meaning that it is able to decrement the customer's balance at the correct rate, based on their usage. The key/card transports information to the meter that includes the level of credit available (and how much debt can be extended in an emergency) and the rate at which it should be decremented (the tariff).
- 9.390 The technological vintage of the system and the commercial context in which it was launched means it was not designed with the capacity to hold a very large number of tariffs. The current infrastructure has a finite capacity of tariff codes, meaning that there is a limited number of prepayment tariffs that can be on offer in the market at any given time.
- 9.391 While the broad description of tariff codes set out above applies to both the gas and electricity prepayment systems, there are some differences in the details – particularly around the number of tariffs that can be supported on

²¹⁷ Each customer is allowed to have a small negative balance on their meter before their supply is cut off.

²¹⁸ Smart prepayment meters will either be credited by wireless communication, or, in the case of some SMETS 1 meters, they can be credited by the customer keying a code into the meter.

²¹⁹ ie using the correct standing charge and unit rate(s) for their tariff.

²²⁰ Since a customer's tariff may change on a regular basis (eg when their supplier changes its SVT, when the customer switches tariffs, or when the customer switches supplier), it would likely not be efficient for suppliers to visit the customer's home each time the details of their tariff changed to change to tariff details on the meter manually.

²²¹ Siemens suggested that the easiest way to conceptualise the communications between supplier and meter was as 'pedestrian communications' where the card or key was carried between the shop and the meter by the customer. The communication could be thought of as a secure, specific, yet very slow and periodic communication channel.

each system. Below we set out more details on the gas and electricity tariff codes, and the extent to which their limited availability is likely to affect suppliers' ability to offer a range of tariffs.

Gas tariff codes

- 9.392 On the gas prepayment system (managed by Siemens), tariff codes are grouped into pages, each containing 11 codes.²²² We understand that there are a total of 103 tariff pages that can be allocated to suppliers. At the time of publishing our provisional findings, all of these tariff pages were allocated to suppliers, with no further gas tariff pages available. Since setting out our proposed remedies, suppliers have released a number of tariff pages, leaving four gas tariff pages currently available to suppliers. Overall, there is a total of 1,133 tariff codes, and therefore an absolute maximum of 1,133 tariffs that can be offered across the industry today (excluding smart prepayment meters).²²³
- 9.393 For a supplier to launch a new gas prepayment tariff nationally, with different prices in each of the 14 regions, it would require 14 tariff codes. Therefore, if suppliers offer a different price in each region, there would be an absolute constraint across the industry of approximately 80 gas prepayment tariffs (excluding smart prepayment meters).
- 9.394 While 80 gas prepayment tariffs across the industry may not seem overly restrictive (given that there are approximately 30 suppliers currently active), there are two reasons why the availability of gas tariff codes may put a particularly strong constraint on suppliers' ability to offer a range of prepayment tariffs. First, fixed tariffs (currently a popular format for acquisition tariffs) require a large number of slots, since suppliers require tariff codes for each tariff that currently has customers, even when they are no longer available to new customers. Secondly, 80% of available tariff pages are held by the Six Large Energy Firms, potentially restricting the ability of other suppliers to enter and offer a range of prepayment tariffs. We discuss both these issues in more detail below.
- *Tariff code requirement for fixed tariffs*
- 9.395 Suppliers need a tariff code for each tariff that still has customers on it, regardless of whether it is still available in the market. As a result, a fixed

²²² Tariff codes on the same page all have to share some characteristics, such as the amount of emergency credit available to customers.

²²³ Although Siemens has set out that technical solutions are being pursued to expand this to the theoretical maximum of 2,750 tariff codes.

tariff that is removed from sale will still require a tariff code for its entire duration (ie until the end of its fixed term).

- 9.396 Given the impact of fluctuating wholesale prices, suppliers tend to make their fixed tariffs available only for a short period of time, before withdrawing them and replacing them with new fixed tariffs. For a supplier to offer a fixed prepayment tariff that is removed and replaced by a new offer on a regular basis, it would require considerably more tariff codes than it would to offer a variable tariff. If, for example, a supplier removes its old fixed tariff and replaces it with a new one every two months, it could have customers on up to six different tariffs at any point in time.
- 9.397 In contrast, on a supplier's SVT, all customers within a region pay the same price regardless of when they joined, meaning that there is only ever one SVT (and therefore only one tariff code required).²²⁴ As a result, in order to offer a fixed tariff that renews every two months, a supplier would require at least six times the number of tariff codes it would require in offering an SVT. This means that the restricted availability of tariff codes makes it particularly difficult to offer fixed tariffs. Nevertheless, some of the large suppliers do offer some fixed tariffs to prepayment customers.
- 9.398 As set out above, there are sufficient tariff codes available for suppliers to offer a total of 80 gas prepayment tariffs across the segment (and more if they do not charge different prices in each of the 14 PES regions). If 30 suppliers offer a prepayment SVT (leaving sufficient tariff codes for 50 further tariffs), this could allow for a maximum of eight fixed tariffs that vary every two months (in the manner described above) across the whole segment.
- *Current allocation of tariff pages*
- 9.399 One reason why independent suppliers may be unable to offer a range of prepayment tariffs is that the limited number of tariff pages that are available are concentrated in the hands of the Six Large Energy Firms. As of May 2016, of the 103 tariff pages that are available to suppliers, a total of 82 (80%) are currently controlled by the Six Large Energy Firms.
- 9.400 Table 9.6 below sets out the allocation of the gas tariff pages by supplier. While each of the Six Large Energy Firms has at least seven tariff pages (with Centrica [3]), none of the Mid-tier Suppliers has more than [3]. Since, as noted above, each tariff page allows for 11 tariffs, suppliers need

²²⁴ Unless a supplier chooses to offer two or more SVTs (for instance with different standing charges and unit rates)

just over one page to launch a single tariff if they wish to vary prices in each of the 14 PES regions.

Table 9.6: Allocation of tariff pages by supplier as at 20 May 2016

	<i>Supplier</i>	<i>Tariff pages</i>
Six Large Energy Firms	[REDACTED]	[REDACTED]
	[REDACTED]	[REDACTED]
Mid-tier	[REDACTED]	[REDACTED]
	[REDACTED]	[REDACTED]
	[REDACTED]	[REDACTED]
Other suppliers	[REDACTED]	[REDACTED]
Unallocated		[REDACTED]
Total		103

Source: [REDACTED]

9.401 As set out above, fixed tariffs that are renewed regularly require considerably more tariff pages than variable tariffs. In the example set out above, where a supplier removes and replaces its fixed tariff every two months, it would require a total of 84 tariff codes, or eight gas tariff pages. It is clear from Table 9.6 that, given the current allocation of gas tariff pages, only the Six Large Energy Firms would have sufficient gas tariff pages to make such an offering.

9.402 In addition, Table 9.7 below sets out that most of the Six Large Energy Firms have a considerable number of unused tariff pages. For example, [REDACTED] and [REDACTED] have 10 and 12 tariff pages respectively, but each uses less than one full page; [REDACTED] uses some codes on 15 of its pages, but also has the equivalent of 19 unused pages.

Table 9.7: Number of unused tariff pages for each of the Six Large Energy Firms (in order of most gas tariff pages currently held)

<i>Supplier</i>	<i>Pages</i>	<i>Unused pages</i>
[REDACTED]	29	Currently using 7 slots on 14 of its pages and 1 further whole page (a total of 109 codes, or 10 pages)
[REDACTED]	14	Currently using 2 slots on 3 of its pages and 1 slot on each of its remaining 11 pages (a total of 17 tariff codes, or 2 pages)
[REDACTED]	12	11 pages unused (and uses 4 codes on the one page it uses)
[REDACTED]	10	9 pages unused (and uses 2 codes on the one page it uses)
[REDACTED]	10	6 pages currently unused; plans to use a further 4 of these pages (leaving 2 unused)
[REDACTED]	7	16 tariff codes currently unused

Source: [REDACTED].

- *Mechanism for allocating gas tariff codes*

- 9.403 We asked suppliers if there was an effective mechanism for monitoring the allocation of tariff codes and reallocating them where appropriate. Suppliers set out that tariff pages could be bought and sold via Siemens, but were not aware that a formal process existed for reallocating unused tariff codes.
- 9.404 Several independent suppliers gave us examples of the difficulties that they had encountered when they tried to secure a gas tariff page in order to enter or expand their offering in the prepayment segments. More detail of these suppliers' experiences of acquiring tariff pages can be found in Appendix 9.6.
- 9.405 We are aware that at least one of the Six Large Energy Firms has returned gas tariff pages to Siemens, and that some independent suppliers have successfully acquired gas tariff pages, suggesting that there is a mechanism for reallocating tariff pages.²²⁵ However, it is not clear that this is transparent and visible to all suppliers that may wish to acquire further tariff codes.
- 9.406 Overall, it is clear that it is not possible for suppliers to offer to customers on dumb prepayment meters the same range of gas tariffs on prepayment meters that they do on standard credit and direct debit (where there are no technical restrictions on the number of tariffs suppliers can offer). It is also clear that the Six Large Energy Firms control considerably more gas tariff pages than the independent suppliers, and that – were the Six Large Energy Firms' unused tariff pages to be used more efficiently – the infrastructure would allow for considerably more tariffs than are currently on offer.

Electricity tariff codes

- 9.407 In the electricity prepayment system (managed by Itron), each supplier is issued with a 'supplier ID', which is capable of supporting a total of 249 tariffs.²²⁶ There is a maximum of 99 supplier IDs available on the system, of which we understand just over half are currently assigned to suppliers (though some of these are assigned to defunct suppliers that have been taken over). Compared with gas prepayment tariff codes, where the number of tariff codes varies considerably by supplier, in the electricity prepayment system, each supplier receives the same number of codes.

²²⁵ We are aware that E.ON has returned four unused gas tariff pages to Siemens, and that Ovo Energy recently [redacted].

²²⁶ More accurately, each supplier has 255 tariff codes with six reserved for 'industry tariffs'.

- 9.408 Unlike in gas, where suppliers typically require 14 codes for each tariff they offer, in electricity suppliers tend to require more codes per tariff. The majority of suppliers offer Economy 7 tariffs in addition to single-rate tariffs. Since Economy 7 tariffs include a different structure (and different level) of prices compared with single-rate tariffs, suppliers require separate tariff codes for these variants.
- 9.409 A supplier that offers both Economy 7 and single-rate tariffs would require 28 tariff codes for each different tariff (14 regions, each with a single rate and Economy 7 version of the tariff). We understand that some suppliers have other types of prepayment meter (eg restricted meters used to offer time-of-use tariffs), which would require additional tariff codes.²²⁷
- 9.410 If each supplier served customers with both single-rate and Economy 7 meters, their 249 tariff codes would enable them to offer eight different tariffs (with different prices in each of the 14 PES regions, with both a single-rate and Economy 7 variant).

Our assessment

- 9.411 As noted above in relation to gas prepayment tariffs, offering fixed-term tariffs requires a greater number of tariff codes (as suppliers need to allocate tariff codes to all tariffs that currently have customers, even if they are no longer available to new customers). As a result, in practice a supplier could use its available electricity tariff codes to offer one SVT, and up to seven fixed-term tariffs throughout the year (eg introducing a new fixed-term tariff and removing the old one approximately every two months).
- 9.412 This suggests that the Six Large Energy Firms (with the exception of [REDACTED]) are likely to be more constrained by the availability of electricity tariff codes than they are by gas tariff codes. As noted, on the electricity prepayment system, each supplier could offer a maximum of eight tariffs (with different prices for each region, and separate codes for single rate and Economy 7 meters);²²⁸ most of the Six Large Energy Firms have sufficient gas tariff codes to offer more than this number of gas tariffs.
- 9.413 In contrast, suppliers other than the Six Large Energy Firms, which do not have a significant number of gas tariff pages, are likely to be considerably

²²⁷ A number of suppliers have set out that they also offer electricity prepayment tariffs for customers with restricted meters. In such cases, suppliers will require more than 28 tariff codes for each different tariff. For example, [REDACTED]. [REDACTED]. [REDACTED].

²²⁸ As noted above, some suppliers have stated that they require more than 28 tariff codes per electricity tariff, meaning that their 249 tariff codes may enable them to offer fewer than eight tariffs because of additional meter types that need to be catered for.

more constrained by the availability of gas tariff codes than by the comparatively less scarce electricity tariff codes.

- 9.414 We understand that when introducing a new tariff, suppliers tend to introduce both a new gas and electricity tariff together (with the same branding and tenor), to enable them to attract dual fuel customers. As a result, it is likely that a constraint on a supplier's ability to offer tariffs on one fuel type (eg gas) will affect its willingness to offer tariffs on the other (eg electricity). That is, suppliers that have very limited access to gas tariff pages (and are therefore restricted in the number of gas tariffs they can offer) are unlikely to make full use of their (comparatively less scarce) electricity tariff codes.
- 9.415 The above analysis of technical constraints makes it clear that it is not possible for any supplier, including the Six Large Energy Firms, to reproduce the current structure and type of acquisition tariffs available in the direct debit segments in the prepayment segments on dumb meters (this is reflected in the more limited offerings in the prepayment segments as identified in Section 8). In particular, the shortage of available gas tariff pages restricts the ability of independent suppliers to compete effectively to supply customers on dumb prepayment meters using fixed tariffs, more so than is currently the case with the Six Large Energy Firms, which between them have a significant number of unused tariff pages.

Parties' responses

- 9.416 The Six Large Energy Firms generally agreed that there were technical constraints in relation to the prepayment segments and that these constraints were such that the range of tariffs present in the credit segments could not be replicated in the prepayment segments for customers on dumb meters. In particular:
- (a) Centrica said that the technical constraints prevented suppliers offering more prepayment tariffs, in particular, it provided a constraint in offering dual fuel tariffs. Centrica said that the constraint was particularly acute in relation to electricity and in combination with the four-tariff rule these constraints prevent suppliers from operating at the technical limits of the gas system. Centrica also said that these technical constraints prevented suppliers engaging in prepayment collective switching events.
 - (b) EDF Energy said that a supplier that attempted to offer the same fixed-term tariffs as in the credit meter segments, which were updated monthly and varied by region, would quickly run out of tariff slots. In addition, EDF Energy said that although the current infrastructure might not be

operating at capacity per se, a supplier ran the risk of restricting future tariff options if it used all of its slots. [✂]

- (c) RWE said that we had understated the extent to which technical constraints, and the RMR rules on simpler choices, accounted for differences in the level of competition between the prepayment segments and the credit meter segments.
- (d) Scottish Power said that, together with the RMR rules, technical constraints were sufficient to explain the lack of aggressively priced fixed-price prepayment tariffs (see paragraphs 9.458 to 9.468 below for a discussion of the interaction of technical constraints and the simpler choices component of the RMR rules). Scottish Power also said it was effectively operating at the technical limits when launching dual fuel offers.²²⁹

9.417 However, SSE said that this did not preclude a well-functioning market and evidence showed that suppliers were competing effectively with both dumb and smart prepayment meters. In particular, SSE said that: all 19 prepayment suppliers competed in the dumb prepayment subsegments and new suppliers continued to enter (eg Economy Energy had entered and expanded rapidly); the cheapest prepayment tariff was a dumb tariff; and as recognised by Ofgem there were an increasing number of innovative prepayment tariffs available on dumb meters, such as collective switching tariffs, and half of the ten exemptions Ofgem granted from the simpler choices component of the RMR rules between January 2014 and May 2015 concerned tariffs that were open to prepayment customers and not based on smart technology but other factors such as environmental or social benefits.

9.418 As noted in Section 8 we agree that there has been some recent increase in activity by independent suppliers and their share in the prepayment segments has materially increased. However, as outlined in Section 8, the number of tariffs on offer in the prepayment segments is still materially lower than is the case in the direct debit segments, the cheapest prepayment tariffs are substantially more expensive than the cheapest direct debit tariffs and we have seen little evidence of price competition being intensified recently in the prepayment segments certainly when compared with the direct debit segments.

9.419 Ovo Energy and Robin Hood Energy agreed that there were technical constraints within the prepayment segments. Robin Hood Energy also

²²⁹ Scottish Power response to addendum to provisional findings, paragraph 6.2, page 7

agreed that the infrastructure allowed for more choice than was currently on offer.

- 9.420 First Utility agreed that the lack of gas tariff pages might have inhibited small suppliers from entering the prepayment segments.
- 9.421 Good Energy said that until recently the prepayment offerings from independent suppliers were not competitive because the prepayment infrastructure controlled by the incumbents had never really worked for a competitive market, nor moved with technology changes. Good Energy also said it was notable that recent challenges in the prepayment market from independent suppliers had occurred outside the prepayment infrastructure using smart meters. For a discussion of smart meters in the prepayment segments see paragraphs 9.469 to 9.475 below and Appendix 9.6.

Conclusion on technical constraints affecting dumb prepayment meters

- 9.422 In our view the technical limitations we have identified above contribute to the paucity of tariff offerings, especially from the independent suppliers (see Section 8) and this is a point generally agreed upon as outlined above. In particular, these technical constraints mean it is not possible for any supplier, including the Six Large Energy Firms, to reproduce the current structure and type of acquisition tariffs available in the direct debit segments in the prepayment segments on dumb meters. Further, certain regulatory constraints may exacerbate these technical constraints due to the number of tariff slots needed for each tariff (see below).

Softer incentives to compete to acquire prepayment customers

- 9.423 It is in our view plausible that competition between suppliers is stronger in segments of a market where the cost of acquiring customers is lower. Such difference in costs may depend on the costs to serve a new customer, on the costs to carry out marketing and sales activity (compared with the prospects of success), and on the likelihood of successfully completing a switch.

Higher acquisition and costs to serve of prepayment customers and independent suppliers' constraints on growth rates

- 9.424 We have considered the extent to which higher costs of acquiring prepayment customers may reduce incentives to compete to acquire prepayment customers, and lead in particular new entrants and/or Mid-tier Suppliers – who are constrained in their growth rates by access to capital or organisational complexity – to focus their limited rate of customer-acquisition

growth towards the larger credit meter segments (despite the potential gains from the higher tariffs observed Section 8). This might then be a reason for the apparently low levels of competition in the prepayment segments.

- 9.425 In doing this we have found that independent suppliers may incur higher metering costs than the Six Large Energy Firms in relation to the current prepayment infrastructure for a number of reasons.
- 9.426 First, we understand that there are two options for a supplier when supplying customers with a dumb prepayment meter:
- (a) allow the customer to continue to use their previous supplier's prepayment card and collect the payments from the previous supplier; or
 - (b) issue a new prepayment card to the customer so that the customer can be directly billed by the new supplier.²³⁰
- 9.427 Good Energy told us that it used both options. First, prepayment customers that switched to Good Energy continued to use their previous supplier's prepayment card and Good Energy had to collect the payments from the previous supplier. Good Energy told us that it was not always possible to recoup all payments made by the customer and that there could be difficulties in changing tariff rates. Second, for Good Energy's existing customers who fell into debt it had agreements with prepayment infrastructure providers to install prepayment meters and issue prepayment cards for these customers. Good Energy also told us that the prepayment segments were not a priority for it and it was obliged to serve it as it recently passed the 50,000 customer threshold.²³¹ Therefore Good Energy told us that it had not devoted a great deal of corporate effort into optimising its processes or offering in the prepayment segments.
- 9.428 Ovo Energy entered the prepayment segments with a smart solution in May 2014 where a customer's dumb prepayment meter was changed to a smart meter on switching to Ovo Energy. Ovo Energy found that due to the difficulty in scheduling the change in supplier and meter for the same point in time there was an interim period where a customer would be supplied by Ovo Energy and still have a dumb meter. For this interim period Ovo Energy had [redacted]²³² for what was a short interim period before a smart prepayment meter was installed.

²³⁰ Economy Energy has told us that the costs of issuing new prepayment cards have decreased as it has attracted more customers, indicating that this cost is higher for new entrants.

²³¹ SLC 27.2.

²³² Ovo Energy told us that the [redacted].

9.429 Second, there may also be additional metering costs in relation to the electricity prepayment infrastructure, and for (c) the gas prepayment infrastructure as well, that we would expect to have a more significant impact on new entrants. In particular, these are:

- (a) Unallocated payments, which occur where a prepayment infrastructure provider cannot identify which supplier should receive a payment. Although we understand that industry initiatives have reduced the number of circumstances in which unallocated payments occur and reallocated some funds, we understand that the total amount of unallocated payments, based on industry data, was roughly £14 million as at January 2016, down from roughly £25 million in October 2015.
- (b) Misdirected payments, which are where a prepayment infrastructure provider sends a payment to the wrong supplier. We understand that this can happen for a variety of reasons and in some circumstances a supplier can reclaim a misdirected payment. However, we understand this is not always the case, for example, Utilita estimated missing revenue of around [£] on its legacy meters as at September 2014.
- (c) Existing credit on acquiring customers, which is where a customer with existing credit on their prepayment meter switches supplier and the new supplier has to supply the electricity to cover that existing credit, but does not get paid for that electricity as the existing credit is paid to the old supplier. Utilita estimated that typically the customers it acquired had [£] of existing credit per fuel.

9.430 In addition we have also found that there are costs to serve that are higher for the Six Large Energy Firms and the independent suppliers in the prepayment segments, relative to the equivalent cost to serve in the rest of the domestic retail energy markets. Again, we expect those costs to adversely affect the incentives of the independent suppliers somewhat more so than they do for the Six Large Energy Firms.

9.431 The examples of these are costs related, among other things, to the need to use more expensive external telesales and face to face marketing channels in order to reach prepayment customers (see Appendix 9.6 for more detail) and the process involved in administering the Debt Assignment Protocol (see paragraph 9.445). We would expect there to be economies of scale in relation to these costs (including, for example, a larger company can more easily hire dedicated sales staff or dedicated staff to deal with the Debt Assignment Protocol) such that these costs are less important to the Six Large Energy Firms when compared to new entrants or other independent suppliers.

- 9.432 These are factors that in our view reduce suppliers' current incentives to compete to acquire prepayment customers.
- 9.433 We have also been told by successful new suppliers that they are capital-constrained in their growth rates: each new customer requires capital, and that this is a major limitation to their growth rate. It is plausible that, in light of the higher costs in the prepayment segments (due to the fact that most prepayment customers have a dumb meter), entrants have mostly focused on the relatively easier and still profitable prospects in the direct debit segments (and in particular the online subsegments). We would expect that, over time, and especially with the full roll-out of smart meters²³³, independent suppliers will increase the number of competitive offerings in the prepayment segments. However, it might take some years for entrants to invest sufficient resources to challenge incumbents sufficiently to lead to the sorts of low prices that have been seen in the competitive portion of the direct debit segments (and in particular the online subsegments).

- *Parties' responses*

- 9.434 Centrica agreed that there were higher costs to acquire and serve customers on prepayment meters and that suppliers, and in particular small and Mid-tier Suppliers, had an incentive to focus acquisition efforts on those customers with a lower cost to acquire or serve. Therefore these higher costs acted as a barrier to some suppliers competing for prepayment customers. Centrica also noted that this was exacerbated due to the need to invest in the prepayment infrastructure, which would be redundant in the near future.
- 9.435 RWE agreed that there were higher costs to serve including costlier acquisition channels, but noted that these higher costs were not the key constraint in the prepayment segments. RWE also noted that, in its view, the higher acquisition costs were due to the lack of tariffs available in the prepayment segments which reduced the financial incentive of prepayment customers to use PCWs.²³⁴
- 9.436 First Utility noted that the prepayment segments were not considered to be [✂]. Good Energy also told us that the prepayment segments were not a

²³³ Indeed, smart meters address both technical constraints on the number of tariffs and higher metering costs (and other costs to serve). While suppliers can already pursue a strategy based on smart meters, this requires, in the vast majority of cases, the supplier to finance upfront the installation of a smart meter. Once the roll-out of interoperable smart meters is substantially completed, this will not be the case anymore, therefore making the costs to acquire and serve prepayment customers substantially similar to customers on direct debit.

²³⁴ See RWE response to the provisional decision on remedies, p22.

priority for it²³⁵ and it was obliged to serve it as it recently passed the 50,000 customer threshold.²³⁶

- 9.437 Both EDF Energy and Scottish Power agreed that there were higher acquisition and costs to serve, but did not agree that these softened incentives to compete. In particular:
- (a) EDF Energy noted that it had a clear ambition to grow its customer base and provide competitive tariffs both to attract and retain customers across all segments, including the prepayment segments as evidenced by its prepayment specific tariff.
 - (b) Scottish Power said that higher acquisition costs were a natural consequence of the demographics of prepayment customers and the sales channels which were most effective in engaging with them. Scottish Power said that these acquisition costs would be expected to be reflected in payment type differentials in tariffs and were nowhere near high enough to reduce suppliers' incentives to compete to acquire prepayment customers. Scottish Power said that this was shown by the relatively high churn rates for prepayment customers and the recent rapid growth of new entrants.²³⁷
- 9.438 However, Scottish Power also said that it was natural for most new entrants to focus on the credit meter segments initially, and then invest in developing the additional systems and processes required to support customers on prepayment meters.²³⁸ In relation to this we note that the number of suppliers that operate in the prepayment space is materially lower.
- 9.439 E.ON told us that the prepayment segments were an attractive opportunity that suppliers were actively pursuing. For example, it had focused its roll-out of smart meters on prepayment and the decision to do so was a strategic decision to competitively acquire customers in the segments.²³⁹
- 9.440 SSE said that there were not material barriers to entry or expansion for suppliers in the prepayment segments and that suppliers did not have softened incentives to compete as shown by the level of switching observed and the increased activity by independent suppliers in the prepayment segments.

²³⁵ We note that Good Energy recently launched a prepayment tariff offering to all customers.

²³⁶ SLC 27.2.

²³⁷ See Scottish Power response to the Addendum, pp8 & 9.

²³⁸ See Scottish Power response to the provisional decision on remedies, p30.

²³⁹ See E.ON response to the provisional decision on remedies, pp10–12.

- *Our assessment*

9.441 On balance we consider that that the higher acquisition and costs to serve identified above contribute to softer incentives for suppliers to compete for prepayment customers. In particular, we put weight on the evidence provided by independent suppliers, who have driven competition in the direct debit segments, two of whom have told us that the prepayment segments are not a commercial priority. Further, we note that although there has been some recent increase in activity in the prepayment segments the outcomes for prepayment customers are significantly worse than those for customers in the credit meter segments.

Additional barriers to acquiring customers in debt

9.442 As outlined above, in 2014 approximately 7% of electricity prepayment customers and 10% of gas prepayment customers were in debt to their energy supplier.²⁴⁰ The DAP, outlined in paragraphs 9.235 and 9.236 and Appendix 9.6, is the industry process used to assign debt when indebted prepayment customers try to switch supplier. In paragraphs 9.234 to 9.253 above we explored the extent to which the DAP is an actual or perceived barrier to switching of prepayment customers in debt.

9.443 Here we explore the extent to which the DAP may be a barrier to suppliers acquiring prepayment customers in debt. In particular, the intensity with which suppliers can be expected to compete to acquire new customers in these segments may be dependent on what happens when a competing supplier persuades an indebted customer to switch.

9.444 From the point of view of an **acquiring** prepayment supplier, the DAP does not appear to be excessively onerous. In particular:

- (a) there is no prohibition on charging interest on the acquired debt;
- (b) prepayment customers are dependable payers – they incur debt before they are on prepayment meters, not after (and start to pay back the debt in order to purchase energy²⁴¹); and

²⁴⁰ Based on Ofgem Social Obligations report 2014. See Ofgem's [Prepayment review](#).

²⁴¹ Each time a customer makes a payment to top up their prepayment meter electricity key or gas card, a percentage is used to repay the outstanding debt according to the existing repayment plan. The remainder is used to purchase energy.

- (c) the customer still owes the entirety of the sum, but it is purchased by the new supplier at a 10% discount, providing a positive incentive to acquire such customers.
- 9.445 However, some suppliers have said that the DAP process is manual, onerous and costly to administer²⁴² while some new entrants suggested that their growth rate in the prepayment segments may be constrained by capex (and its impact on cost of capital) required to take on customers with debt.²⁴³ Therefore the DAP is likely to contribute to the higher acquisition costs identified in paragraphs 9.430 to 9.432 above.
- 9.446 The DAP arguably makes it unattractive for the incumbent supplier to lose an indebted prepayment customer, since it can only assign 90% of the debt value to the acquiring supplier. Moreover, once on a prepayment meter, an indebted customer is likely to be good at paying off their debt (as noted above). However, the fact that it is unattractive to lose such customers should not reduce the attractiveness of gaining these customers, which is the motivation that ought to create competitive pressure in the prepayment segments in the first place.
- 9.447 The DAP may significantly contribute to the small number of switches attempted, and successfully completed, by indebted prepayment customers. However, the cost for suppliers is only the lost sales effort; it is not any additional cost relating to winning such customers. In light of this we believe that the DAP probably makes it unattractive to compete specifically for indebted customers because it makes the probability of sales completion very low. While customer debt should not significantly reduce the general attractiveness of competing in the prepayment segments because only 7% of electricity prepayment customers and 10% of gas prepayment customers have outstanding debt,²⁴⁴ it may nevertheless to some extent soften suppliers' incentives to compete to acquire prepayment customers.

- *Parties' responses*

- 9.448 Set out below are parties' responses to the Addendum and/or provisional decision on remedies, each of which we have taken into account in our considerations set out in paragraphs 9.442 to 9.447 above.

²⁴² Centrica said that there were a number of process and procedural issues which made it difficult and costly to administer, including that the DAP remained very manual, time-consuming and costly to administer. Similarly Utilita told us that the DAP was currently manually intensive and onerous for suppliers while Robin Hood Energy told us that there were a number of manual steps that acquiring suppliers must take.

²⁴³ These were Robin Hood Energy and Our Power Energy Supply.

²⁴⁴ Based on Ofgem Social Obligations report 2014, see Ofgem's [Prepayment review](#).

- 9.449 As noted above Centrica believed that changes were required to the DAP as there were a number of process and procedural issues which made it difficult and costly to administer, including that the DAP remained very manual, time-consuming, and costly to operate. Centrica also said that even after the implementation of the POA model (see paragraphs 9.240 and 9.241), there were some remaining issues as it was not mandatory and therefore some switches continued outside of the POA model and Centrica was concerned that some suppliers outside of the POA model might not comply with the existing requirements of the DAP.
- 9.450 RWE said that the key constraint arising from the DAP was not the protocol itself, but that suppliers did not follow the same process as some had not adopted the POA model which had improved the prospect of a successful switch.
- 9.451 We have noted Centrica's and RWE's views. These do not negate the central issue identified above, ie that the DAP (ie the current regulatory framework for assigning debt between suppliers) as it stands reduces the overall probability of a prepayment customer successfully switching supplier. We consider what changes are required in our discussion of remedies (see Section 12).
- 9.452 EDF Energy agreed that the DAP as currently implemented could operate as an obstacle to customers switching supplier and to suppliers specifically targeting indebted customers. EDF Energy also said it had not historically differentiated between indebted and non-indebted customers as part of its acquisition strategy, and so its incentive to compete for these customers had therefore not been affected by any potential relative attractiveness of indebted customers. Again, even if a supplier in its acquisition strategies does not differentiate between indebted and non-indebted customers, the central issue remains that the DAP, as it stands, reduces the overall probability of a prepayment customer successfully switching supplier. EDF Energy also said that suppliers might have an incentive to acquire indebted customers as the customer still owed the entirety of the sum, but it was purchased by the new supplier at a 10% discount. While we acknowledge this might be the case for some suppliers, it might not apply to others (in particular for smaller suppliers with limited ability to finance such an acquisition).
- 9.453 SSE said that a conclusion that a low prospect of completing the switch of indebted customers gave rise to softened incentives was not supported by the evidence. As outlined above SSE noted that our analysis of the switching process was outdated given recent developments made under the POA and the increase in the percentage of prepayment customers with debts of less

than £500 who successfully switched. Further, SSE said that no evidence had been put forward to support the conclusion that problems in relation to a small proportion of customers could have a material impact on suppliers' incentives to compete for prepayment customers as a whole.

9.454 We have noted the recent developments under the POA. However, parties' responses and the industry's ongoing work in this area suggest that these recent changes have not been sufficient to address this issue. We accept that only a small proportion of prepayment customers are in debt (7% - 10%). However, in view of the higher acquisition and costs to serve identified above, we believe that this issue is likely, to a limited extent, to further soften suppliers' incentives to compete to acquire prepayment customers when compared to the direct debit customers. In particular, as independent suppliers, who have driven competition in the direct debit segments, are capital-constrained in their growth rates, it is plausible that this may have contributed, in part, to their choice to focus on the relatively easier and still profitable prospects in the direct debit segments.

Conclusion on suppliers' incentives to compete to acquire prepayment customers

9.455 We consider that certain further features of the prepayment segments soften competition by softening incentives for customer acquisition. In particular, we have noted that some of the reluctance on the part of suppliers to compete aggressively for the prepayment segments may be explained by:

- (a) suppliers, and in particular new entrants, facing actual and/or perceived higher costs to engage with, and acquire prepayment customers compared with direct debit customers; and, to a more limited extent,
- (b) the limited prospect of successfully acquiring customers with existing debt (which, as identified by Ofgem,²⁴⁵ may be driven by barriers to switching and complexities faced by indebted prepayment customers and by suppliers).

9.456 Both these features may make sales efforts targeted to prepayment customers unattractive, in particular for new entrants whose growth may be constrained by capital or organisational constraints and which may have limited experience in the prepayment segments.

²⁴⁵ Ofgem open letter (22 September 2014), [Reforming the switching process for indebted prepayment meter customers – the Debt Assignment Protocol](#).

9.457 Further, we note that lower engagement by prepayment customers, as identified above, will contribute to the higher acquisition costs and the softened incentives for suppliers to compete to acquire prepayment customers. For example, in relation to acquisition costs EDF Energy said that prepayment customers were generally harder to access and less responsive to approaches by suppliers so cost more to acquire per account.²⁴⁶

Impact of certain aspects of the regulatory framework on the technical constraints

9.458 For the reasons identified below in paragraphs 9.478 to 9.513, we have identified an AEC in relation to certain aspects of the simpler choices component of the RMR rules, which impact customers regardless of their payment method. We consider below whether, in addition to this AEC, the simpler choices component of the RMR rules (in particular the four-tariff rule and SLC 22B.7(b), which relates to regional variations within a core tariff) exacerbates the adverse effects of the above-mentioned technical constraints and therefore has an adverse impact on competition for reasons that are specific to the prepayment segments.

Four-tariff rule

9.459 In relation to the four-tariff rule we have considered the degree to which it might impose an opportunity cost to the offering, in the prepayment segments, of competitively priced acquisition tariffs (compared with the direct debit segments). In particular, several suppliers²⁴⁷ said that the four-tariff rule acted as a constraint in the prepayment segments, although one said it did not,²⁴⁸ and two of those suppliers said that we underestimated the impact of the four-tariff rule.²⁴⁹

9.460 We believe that such an opportunity cost exists, which in turn contributes to a softening of suppliers' incentives to compete to acquire prepayment customers. We do not conclude, however, that this is an absolute constraint on competition in the prepayment segments, nor that it is specific to the prepayment segments. In this respect we note that none of the suppliers provided evidence on why the impact of the four-tariff rule alone on

²⁴⁶ See EDF Energy response to the Addendum, p5.

²⁴⁷ Centrica, EDF Energy, Ovo Energy, RWE and SSE. We note that while EDF Energy agreed that the simpler choices component of the RMR rules had reduced the incentives for suppliers to design more prepayment-specific tariffs, its view was that the main issues were the technical constraints arising from the prepayment infrastructure. See Appendix 9.6.

²⁴⁸ First Utility.

²⁴⁹ RWE and SSE.

prepayment went beyond the issues identified as giving rise to the RMR AEC set out below (see paragraphs 9.478 to 9.513).

SLC 22B.7(b)

- 9.461 In response to the Addendum, Scottish Power noted that an element of the RMR simpler choices rules, which we understand to be SLC 22B.7(b), in combination with the four-tariff rule, exacerbated the technical constraints identified above.²⁵⁰
- 9.462 SLC 22B.7(b) requires any difference in charges between payment methods (including costs uplifts) to be applied by a supplier in the same way to all domestic customers with the same payment method (eg across different regions). This means that if a supplier charges different prices by region for its direct debit SVT (for example), which most suppliers do, it would also need to charge different regional prices for its prepayment SVT (with the same payment method cost adjustment for each region). If the supplier took a different approach to this, the price paid by prepayment customers in a given region may not be the cost-adjusted equivalent of the supplier's SVT in that region, and the tariff could therefore breach SLC 22B.7(b).
- 9.463 As the core tariffs offered to direct debit (and standard credit) customers generally differ by region, suppliers that wish to offer the same core tariffs to their prepayment customers are under an obligation to apply the same regional price variations to these customers. The implication is that, if a supplier decides to offer such a core tariff (ie one that has regional variations) to prepayment customers, it must use different tariff codes for each different regional variation.
- 9.464 Above we set out that if all suppliers offer different prices in each of the 14 distribution regions,²⁵¹ the total number of gas tariffs that could be offered to customers with dumb prepayment meters, across the entirety of the prepayment segments, is approximately 80 tariffs, due to the constraints of the gas tariff codes system.²⁵² These 80 tariffs could comprise, for example, 30 suppliers each offering just one prepayment SVT and eight suppliers each offering a 12-month fixed tariff that is changed every two months (ie a

²⁵⁰ See Scottish Power response to the second supplemental notice of remedies, p21, paragraph 23.4.

²⁵¹ ie the 14 electricity distribution areas (PES regions). While we note that there are only 13 gas distribution zones, we understand that, in practice, suppliers set regional variations within a core tariff based on the 14 PES regions.

²⁵² This limits the total number of gas tariff codes to 1,133.

total of 48 tariffs) – considerably fewer than the tariffs available to customers with credit meters.²⁵³

- 9.465 In contrast, we identified that the 249 electricity tariff codes available to each supplier would allow each supplier to offer one SVT and one 12-month fixed tariff that changes approximately every two months (each with a single rate and Economy 7 variant in each of 14 regions).
- 9.466 As noted above the four-tariff rule restricts suppliers' ability to offer core tariffs specifically targeted at prepayment customers. As a result of the limited number of tariff codes available to parties, and of these regulatory constraints, the number of core tariffs offered to prepayment customers may be constrained by suppliers' pricing strategy for credit meter customers.
- 9.467 We note that fixed tariffs, which typically vary by the 14 PES regions, are the main acquisition tool in the rest of the domestic retail energy markets, and that an SVT or tracker tariff, which require fewer tariff codes, are not good substitutes that could be used as effectively as fixed tariffs to acquire new customers given the nature of competition in the markets, which is based around offering the most competitive rates to new customers.
- 9.468 For these reasons, we believe that SLC 22B.7(b) exacerbates the technical constraints identified above. This in turn creates an actual or perceived²⁵⁴ higher cost to acquire prepayment customers which contributes to the softening of suppliers' incentives to compete to acquire prepayment customers.

Prepayment customers on smart meters

- 9.469 We acknowledge that some aspects of the features that we have identified apply only to competition in supply to customers on dumb prepayment meters. In particular the technical constraints relative to tariff codes and higher metering costs do not apply to smart meters. It follows (see Appendix 9.6) that suppliers may circumvent these issues by installing smart meters to existing customers or customers they acquire. We also note that costs to serve prepayment customers are significantly lower for customers on smart meters, allowing suppliers to offer cheaper tariffs. However, at present, only

²⁵³ Our analysis of Energylinx data suggests that there were 35 variable and 43 fixed tariffs (of differing lengths) available to direct debit customers at the end of Q2 2015 (see Section 8).

²⁵⁴ Depending on the impact of the technical constraints on an individual supplier. This constraint is likely to have a greater impact on independent suppliers with no more than one or two gas tariff page.

two independent suppliers – Ovo Energy and Utilita – offer smart meters as an acquisition strategy on a nationwide basis.²⁵⁵

- 9.470 Further, even where an independent supplier has pursued a strategy based on smart prepayment meters, this strategy has not been underpinned by prepayment tariffs that are comparable with the cheapest tariffs in the direct debit segments (even accounting for differentials in the costs to serve), see Section 8.²⁵⁶
- 9.471 Over all suppliers, the penetration of smart meters is currently low, at around 8% for dual fuel customers in the prepayment segments.²⁵⁷ While we have seen some encouraging evidence in relation to the roll-out of smart meters in the prepayment segments – namely E.ON's rolling out of its smart PAYG to existing customers (which it is planning to make available eventually to all prepayment customers)²⁵⁸ – we have not seen evidence that demonstrates that the rate of smart meter penetration in the prepayment segments as a whole is likely to change significantly in the near future.
- 9.472 We consider that this may particularly be a problem for some of the independent suppliers, as they may not find it financially viable to accelerate materially the roll-out of smart meters to the prepayment segments. Moreover, all suppliers, including the Six Large Energy Firms may not currently be incentivised to do so as a matter of priority.²⁵⁹
- 9.473 As the proportion of customers (including in the prepayment segments) having a smart meter increases, we would expect that the actual and/or perceived higher costs for suppliers to acquire and engage with prepayment customers would decrease (as the need to engage with the dumb prepayment meter and/or install a smart prepayment meter will decrease and eventually disappear).
- 9.474 For example, First Utility, a Mid-tier Supplier, told us that the prepayment segments would remain an expensive area to target until there was a smart

²⁵⁵ Economy Energy is planning to make smart meters available to all prepayment customers during 2016. We understand that Robin Hood Energy is also planning to make smart meters available to its existing and new customers, however, we note that as at 28 February 2015 it had only been in the market for three months and had [redacted] prepayment customers on supply and therefore we do not expect this to have a significant impact on the market.

²⁵⁶ RWE said that given the constraints arising from the RMR four-tariff rule, in particular, the disincentive to target niche customer groups, and the low level of smart meter penetration, it was perhaps not surprising that smart metering had not led to significant reductions in price whilst it remained small scale. See RWE response to the provisional decision on remedies, p48.

²⁵⁷ This is based on dual fuel customers as at Q4 2015. CMA analysis based on data from the Six Large Energy Firms, the Mid-tier Suppliers, Economy Energy and Utilita.

²⁵⁸ See E.ON's website: 'Smart Pay As You Go is coming'.

²⁵⁹ We are minded not to proceed with this possible remedy. See Section 12.

prepayment solution that it was happy with (a mass-market solution able to challenge the domestic markets). At the current time it offered a Smart prepay solution on its SVT to prepayment customers (which is not an acquisition tariff).

- 9.475 Considering that, as of Q4 2015, the independent suppliers only have, collectively, some 460,000 electricity and 410,000 gas prepayment customers, most of whom (roughly 60%) have been acquired by just one new entrant,²⁶⁰ it seems likely that many of the independent suppliers that offer competitively priced tariffs in the direct debit segments may not actively compete in the prepayment segments until a sufficient number of smart prepayment meters have been rolled out.

Conclusion

- 9.476 Our finding is that a combination of features of the markets for domestic retail supply of gas and electricity in Great Britain, relating specifically to the prepayment segments, give rise to an AEC (the Prepayment AEC). These features, in combination, reduce retail suppliers' ability and/or incentives to compete to acquire prepayment customers and to innovate by offering tariff structure that meet customers' demand. This Prepayment AEC, in combination with other retail AECs (in particular the Weak Customer Response AEC and the RMR AEC) explain why the range of tariffs available in the prepayment segments is limited and not competitively priced compared with the direct debit segment. These features are as follows:

- (a) Technical constraints that limit the ability of all suppliers, and in particular new entrants, to compete to acquire prepayment customers, and to innovate by offering tariff structures that meet demand from prepayment customers who do not have a smart meter. These technical constraints are exacerbated by certain aspects of the simpler choices component of the RMR rules.
- (b) Softened incentives for all suppliers, and in particular new entrants, to compete to acquire prepayment customers due to:
 - (i) actual and perceived higher costs to engage with, and acquire, prepayment customers compared with other customers; and
 - (ii) a low prospect of successfully completing the switch of indebted customers, who represent about 7 to 10% of prepayment customers.

²⁶⁰ Based on data from the Six Large Energy Firms, Mid-tier Suppliers, Utilita and Economy Energy.

Regulations

9.477 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 settlement system for gas and electricity.

Retail Market Review reforms

9.478 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.²⁶¹

9.479 The RMR reforms package that took effect in 2014 (the RMR rules) includes three broad components:

- (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.

9.480 In this section we analyse the impact on competition of certain aspects 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.²⁶² In particular, in the rest of this section we assess available evidence on:

- (a) the impact of the RMR rules on customer engagement;

²⁶¹ Ofgem (27 March 2013), *The Retail Market Review – Final domestic proposals*.

²⁶² A more detailed analysis of RMR is provided in Appendix 9.7.

- (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 suppliers and TPIs to compete.

Impact of the RMR rules on customer engagement

- 9.481 We reviewed the results from Ofgem’s baseline survey, which was carried out in February and March 2014,²⁶³ 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.
- 9.482 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.²⁶⁴ 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.
- 9.483 We note that at the time Ofgem conducted the year one survey the RMR rules had only been recently introduced, and that it was therefore a relatively early stage to be considering their impact on engagement. However, we do have broader doubts about the long-term impact on engagement of the ‘simpler choices’ element of the reforms.
- 9.484 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 with a standard meter 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.

²⁶³ 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.

²⁶⁴ The results are given in Appendix 9.2

- 9.485 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,²⁶⁵ Professor Catherine Waddams and the University of Exeter Energy Policy Group.²⁶⁶
- 9.486 In relation to complexity, we recognise that the two-part structure prescribed by the RMR rules²⁶⁷ 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 the RMR rules on tariff offerings and discounts

- 9.487 As a result of the RMR rules, many tariffs were removed, including several that had large numbers of customers.²⁶⁸ British Gas said it removed two tariffs in order to comply with the RMR rules. Scottish Power said it removed three tariffs as a result of the RMR rules. EDF Energy said that one tariff was removed as a result of the RMR rules. British Gas, RWE, Scottish Power, EDF Energy and E.ON all removed green energy tariffs as a result of the RMR rules. SSE said that green tariffs had limited appeal and thus were no longer commercially viable under the tariff cap.
- 9.488 RWE removed variable discount tariffs which offered a percentage discount to the SVT – in 2013 there were over [X] 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.
- 9.489 Scottish Power, SSE, British Gas, EDF Energy and E.ON all said that they removed prompt payment discounts in order to comply with the RMR rules. Scottish Power said that its prompt payment discount was valued by many of its credit customers, including older customers. The alternative of a late

²⁶⁵ Stephen Littlechild (15 August 2014), *Promoting or restricting competition? Regulation of the UK retail residential energy market since 2008*.

²⁶⁶ Response to Statement of Issues, University of Exeter, Energy Policy Group, 14 August 2014.

²⁶⁷ 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.

²⁶⁸ A more comprehensive list of tariffs withdrawn is set out in Appendix 9.7.

payment surcharge, which is allowed under the RMR rules, was not considered to have customer appeal.

- 9.490 The Six Large Energy Firms have made several comments in relation to the impact of the RMR rules on their ability to attract different types of customers – particularly their offering to low-consumption and vulnerable customers – and their ability to innovate.
- 9.491 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.
- 9.492 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 the RMR rules 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 [✂].
- 9.493 Some Mid-tier Suppliers have also told us that the RMR rules had restricted their ability to innovate. Ovo Energy 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.
- 9.494 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.
- 9.495 Further details are provided in Appendix 9.7.

Derogation from the RMR rules

- 9.496 Suppliers can receive a derogation from the RMR rules on application to Ofgem, 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.
- 9.497 We understand that there have been 25 derogation requests,²⁶⁹ of which 16 requests have been granted: ten of which included a derogation from the four-tariff rule, eight included a derogation from the restriction on discounts, two included a derogation from the rule requiring that tariffs are available to new and existing customers and one included a derogation from the bundling rules. See Appendix 9.7 for further details.
- 9.498 Our view is that the number and nature of the derogations sought is further evidence that the simpler choices rules have been a constraint on the tariffs and discounts offered by retail energy suppliers to their domestic customers, but that the number of derogations sought and granted will understate the extent of the constraint imposed by the relevant rules. This is because Ofgem will grant derogations only where an applicant can demonstrate that compliance with one or more relevant standard licence conditions would have substantial unintended or unanticipated negative consequences for consumers.
- 9.499 Several suppliers also 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. RWE said that white-labelling was something that was not initially allowed under the RMR rules, then was allowed for some suppliers and might now be allowed. British Gas said that when the RMR rules were first proposed it believed the proposals would discourage suppliers from developing white-label offerings.

Impact on of the RMR rules on the ability and incentives of suppliers to compete

- 9.500 We consider that certain aspects of the 'simpler choices component' of the RMR rules have the effect of dampening price competition between suppliers by either (a) directly restricting their ability to compete to acquire or retain customers through the tariffs or discounts they offer or (b) adversely affecting the incentives suppliers have to compete by making it more costly

²⁶⁹ One derogation request for a specific tariff or scheme may require derogation from more than one SLC.

to offer customers cheaper prices or discounts (the effect of which is to reduce the competitive pressure suppliers exert on their rivals). We also consider that these rules restrict the ability of suppliers to compete through innovation.

- 9.501 We consider that the ban on complex tariffs and the four-tariff rule restricts suppliers' ability to compete by offering new tariffs or products to attract customers. The four-tariff rule is particularly restrictive in relation to the ability of suppliers to offer tariffs that are designed to attract specific groups of customers rather than being targeted at the mass market (eg tariffs aimed at low consumption users, tariffs aimed at certain social groups and tariffs with particular characteristics such as 'green tariffs' and tracker tariffs). Whilst the RMR rules do not prohibit suppliers from offering such tariffs, the four tariff rule means that this would be at the expense of mass market products.
- 9.502 The RMR rules also limit the type of discounts suppliers can offer, including the prohibition on discounts that fall outside the three permitted types of cash discount, ie dual fuel, online account management, and dividend payments. We consider that the effect of these rules has been to restrict competition by preventing suppliers from offering discounts aimed at encouraging customers to switch suppliers and discounts that allow suppliers to offer cheaper prices by encouraging customer behaviour that reduces suppliers' costs. Before the RMR rules came into force suppliers offered cashback and one-off introductory discounts, and prompt payment discounts (see Appendix 8.3).
- 9.503 We consider that the requirement on suppliers to make all tariffs available to both new and existing customers reduces their incentives to respond, by offering cheaper tariffs, to competition for either the acquisition or retention of customers (which, in turn, reduces the competitive pressure each supplier exerts on their rivals). More generally, we consider that certain aspects of the RMR rules have the effect of restricting competition by limiting the flexibility suppliers have in the tariffs and discounts they can offer to compete in the acquisition and retention of customers.

The impact of the RMR rules on the ability and incentives of TPIs to compete

- 9.504 We also consider that certain aspects of the simpler choices component of the RMR rules (in particular, the four-tariff rule) limits the scope for competition between PCWs for customers switching energy suppliers to exert downward pressure on energy prices. In particular, we consider that absent the four tariff rule PCWs would be well placed to negotiate exclusive

tariffs with suppliers,²⁷⁰ which would have the effect of putting competitive pressure on energy suppliers and the costs of acquiring customers²⁷¹. We consider further the effect of the RMR rules on the ability and incentive of suppliers and PCWs to negotiate tariffs exclusively available via a particular PCW in Section 12.

- 9.505 One significant aspect of the RMR rules 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, the RMR rules have 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. We also note that components of the RMR rules 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.²⁷² EDF Energy said collective switch schemes were being artificially encouraged by being exempt from the four-tariff rule²⁷³ and First Utility said they were concerned that collective switch schemes might be used as a way to circumvent the RMR requirements.²⁷⁴
- 9.506 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 the RMR rules. 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 the RMR rules. There therefore appears to be ongoing uncertainty over whether cashback offered via TPIs is permissible or not.

²⁷⁰ 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.

²⁷¹ Due to uncertainty over whether cashback was permitted under RMR, many suppliers stopped working with cashback websites.

²⁷² Appendix 9.7.

²⁷³ Appendix 9.3: Price comparison websites and collective switches.

²⁷⁴ Appendix 9.3: Price comparison websites and collective switches.

Conclusion

- 9.507 The stated purpose of the RMR rules was to promote customer engagement in the retail energy markets in order to improve the competitive constraint provided by customer switching. However, we consider that some of the RMR measures (both individually and in combination) restrict the behaviour of suppliers and PCWs, and constrain the choice set for consumers in a way that has an adverse impact on competition and consumer welfare. We discuss further how the RMR rules impact on the incentives and ability of suppliers and PCWs to compete in Section 12.
- 9.508 The available evidence on the impact of certain aspects of the simpler choices component of the RMR rules on customer engagement 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 rules appear to remain so. Further we have doubts that the four-tariff rule will have a benefit on engagement in the long term.
- 9.509 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 the 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 rules, except RWE.
 - (c) The RMR rules 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.

- 9.510 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 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 the RMR rules could potentially stifle innovation around smart meters.
- 9.511 With regard to the impact of the RMR rules on the intensity of price competition, while the suppliers no longer offer discounted variable-rate tariffs, price competition now primarily 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. In Section 12 we consider further the impact of the RMR rules on the both incentives and ability of suppliers and PCWs to compete on price in the acquisition and retention of customers.
- 9.512 One area where the impact of the RMR rules 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,²⁷⁵ or indirectly by securing exclusive tariffs from suppliers because of the four-tariff rule. In Section 12 we also discuss this point further.
- 9.513 Overall, our finding is that certain aspects of 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) are 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 compete and innovate in designing tariff and discounts to meet customer demand, in particular, and by softening competition between suppliers and PCWs.

Gas and electricity settlement and metering

- 9.514 Energy suppliers generally purchase in advance the bulk of the electricity and gas that they expect their customers to consume, to help them manage price and volume risks. But both gas and electricity demand are driven by a range of factors that are difficult to predict accurately, such that there will always be some disparity between the volumes of energy covered by

²⁷⁵ 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.

suppliers' contracts and the volumes their customers actually use in real time.²⁷⁶

- 9.515 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 for²⁷⁷. 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

- 9.516 Xoserve is responsible for ensuring that gas transportation charges invoiced to gas shippers and traders are accurate and in line with the 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.
- 9.517 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.
- 9.518 Total non-daily metered gas in each Local Distribution Zone (LDZ) is allocated to all non-daily metered 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).

²⁷⁶ For settlement purposes, 'real time' means half hour by half hour for electricity, while for gas settlement is defined on a daily basis.

²⁷⁷ Equally, the settlement system is used to identify, and assign a price to, any disparities between generators' contracted volumes and the volumes they produce in practice.

9.519 We note that Ofgem has approved UNC 473²⁷⁸ which reinstated the independent Allocation of Unidentified Gas Expert (AUGE) following concerns that Ofgem raised in the UNC432 decision. The AUGE will be required to consider the evidence of the scale and sources of unidentified gas and propose a methodology for its allocation among the different market segments. The allocation will be determined by class of settlement rather than whether the supply point is categorised as daily-metered, large supply point and small supplier point. However, it is unclear when these new arrangements will be fully implemented.

9.520 Our main concerns in relation to gas settlement are that:

- (a) the infrequent updating of the AQs²⁷⁹ can result in shippers being faced with charges for gas that are inaccurate; this in turn provides inaccurate price signals to suppliers, which distorts the incentives to introduce new products. This might disadvantage certain types of supplier – notably those that have been particularly effective in helping their customers reduce their gas consumption;
- (b) the possibility of gaming the AQ system, due to the absence of efficient mechanisms to reconcile estimated consumption with actual consumption, leads to errors in the settlement process that ultimately impact competition and final consumers; and
- (c) the presence of unidentified gas distorts competition between domestic/ SME and non-domestic suppliers and leads to the inefficient allocation of costs to parties.²⁸⁰

- *Parties' views*

9.521 Several responses to our provisional findings and provisional decision on remedies echoed these concerns. The main points that were put to us in relation to the gas settlement process were as follows:

- (a) Centrica²⁸¹ said that the CMA was correct to conclude that the current gas settlement system was likely to lead to inefficient cost allocation. The causes of this were both the infrequent nature of meter reading

²⁷⁸ See Ofgem (9 April 2015), [Uniform Network Code \(UNC\) 473 and 473A: Project Nexus – Allocation of Unidentified Gas \(UNC473/473A\)](#)

²⁷⁹ Each meter has an AQ assigned to it, which is the expected annual consumption of the meter point. This expectation is based on historical metered volumes and seasonal normal weather conditions.

²⁸⁰ Appendix 8.6: Gas and electricity settlement and metering, sets out some of these concerns in more detail.

²⁸¹ Centrica response to provisional findings and Remedies Notice, paragraph 91, p22.

collection, the infrequent updating of AQ values, and the allocation of unidentified gas.

- (b) Ovo Energy²⁸² said the infrequent update of Aqs could distort supplier incentives, for example by disincentivising suppliers from measures which may reduce their customers' gas consumption.
- (c) 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 up²⁸³. It added that the mechanism that allocated unidentified gas was inefficient and some industry parties had little incentive to reduce the unidentified gas root causes within their portfolio.²⁸⁴
- (d) 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.²⁸⁵
- (e) Scottish Power identified a risk of significant cross-subsidy between domestic SSPs and non-domestic large supply points (LSPs). The cross-subsidy arises because under RbD there was a presumption that the costs of unidentified gas should be allocated to SSPs unless there was evidence to the contrary.²⁸⁶
- (f) SSE submitted that the most significant distortions in the gas settlement process arose from the allocation of disproportionate levels of unallocated gas on domestic shippers as compared to large gas customers.²⁸⁷ It added that there was a bias against domestic shippers in the way RbD allocated imbalance, which resulted in domestic shippers being overcharged by Xoserve (compared with large gas customers (whose supply points were settled individually based on actual consumption)). As RbD/unallocated gas represented a cost that suppliers must recover in their prices, these costs were ultimately borne (disproportionately) by domestic consumers.²⁸⁸

²⁸² OVO Energy response to gas and electricity settlement and metering working paper.

²⁸³ First Utility response to gas and electricity settlement and metering working paper.

²⁸⁴ First Utility response to provisional decision on remedies, paragraph 2.2, p6.

²⁸⁵ EDF Energy response to provisional findings, paragraph 4.53, p16.

²⁸⁶ Scottish Power response to gas and electricity settlement and metering working paper.

²⁸⁷ SSE response to provisional findings, paragraph 6.1.1, p51.

²⁸⁸ SSE response to provisional findings, paragraph 6.2.7, p52.

(g) Centrica²⁸⁹ submitted that the scale of unidentified gas, and the implicit cost cross-subsidy that the small supply points provided the large supplier points, was a material distortion to completion between suppliers that operated in these sectors. It also indicated that the SSP segments might be being over-allocated approximately £90 million for the cost of unidentified gas each year, based on analysis of its own imbalance costs.²⁹⁰

- *Impact of Project Nexus in addressing existing inefficiencies in the gas settlement process*

9.522 We note that a significant upgrade of the gas settlement system (known as Project Nexus) is planned to become operational on 1 October 2016 in an attempt to address some of these concerns. When implemented, the changes to gas settlement system will include:

- (a) the replacement of RbD with reconciliation at all individual gas meter points;
- (b) the opportunity for monthly rather than annual updating of the AQ (also referred to as rolling AQ);
- (c) the possibility for independent gas transporters to use the same systems and processes as other gas transporters; and
- (d) the potential for automated retrospective adjustment following meter readings where previously submitted data is shown to have been incorrect.

9.523 We acknowledge that Project Nexus is likely to address most of the current inefficiencies in the gas settlement system, set out in paragraph 9.520 above, and note that a few parties agreed with this view, for example:

- (a) Centrica²⁹¹ said that Project Nexus was central to resolving many of the current issues with gas settlement.
- (b) RWE said²⁹² that it accepted that the gas settlement system might not be optimal, but it considered that the concerns identified by the CMA would be largely addressed by implementation of Project Nexus.

²⁸⁹ Centrica response to provisional decision on remedies, paragraph 298, pp58 & 59.

²⁹⁰ Centrica response to gas and electricity settlement and metering working paper.

²⁹¹ Centrica response to provisional decision on remedies, paragraph 294, p58.

²⁹² RWE response to provisional findings, paragraph 36.

- (c) EDF Energy²⁹³ considered that the issues it identified with the current gas settlement (see paragraph 9.521(d) above) were likely to be resolved by the proposals contained in Project Nexus.
 - (d) SSE submitted that the introduction of a revised settlement regime under Project Nexus in October 2016 would address some of these concerns.²⁹⁴
 - (e) Scottish Power agreed with the CMA's assessment that the implementation of Project Nexus's core functionality, as originally specified, would go some way to addressing the gas settlement AEC.²⁹⁵
 - (f) First Utility agreed with the CMA that Project Nexus would address most of the current issues in the gas settlement system but expressed some concern that the new Project Nexus AQ mechanism was still monthly and it would not provide full reconciliation similar to that within the electricity settlement system.²⁹⁶
- 9.524 Utilita,²⁹⁷ instead, disagreed with the CMA's assessment that Project Nexus would remove the risk of inaccurate settlement currently experienced by shippers (its concern is that if the initial profile is not accurate for prepayment customers, then the average price used will also not be accurate). It considered that Project Nexus as originally conceived would have delivered significantly more benefits than it was now the case. It added that the Project Nexus reform would continue to expose prepayment customers to inaccurate settlement as the prices used to charge shippers would not be accurate.²⁹⁸
- 9.525 However, we remain concerned that even after implementation of Project Nexus, the gas settlement process would still be characterised by the presence of a (residual) amount of unidentified gas, inefficiencies in the allocation of the cost of this residual unidentified gas, as well as incentives that shippers face to place a higher priority on adjusting AQs down (and delaying adjusting AQs up, so as to game the gas settlement system). Further, we note that the implementation of Project Nexus has been subject to numerous delays. We discuss each of these concerns in turn below.

²⁹³ EDF Energy response to provisional findings, paragraph 4.53, p16.

²⁹⁴ SSE response to provisional findings, paragraph 6.2.8, p52.

²⁹⁵ Scottish Power response to provisional decision on remedies, paragraph 5.2, p8.

²⁹⁶ First Utility response to provisional decision on remedies, paragraph 2.3, p6.

²⁹⁷ Utilita response to provisional decision on remedies, paragraphs 5.20 & 5.25, p24.

²⁹⁸ We understand that the prices used to charge shippers for settlement imbalances were never part of the original specification of Project Nexus. Utilita has raised the issue with Ofgem.

- *Unaddressed inefficiencies in the gas settlement process*

9.526 For the reasons set out below, we have concluded that the current inefficiencies in the gas settlement process are unlikely to be addressed entirely by Project Nexus.

- *Unidentified gas*

9.527 We consider that the main inefficiencies that will subsist after implementation of Project Nexus relate to the presence of unidentified gas and the allocation of its costs between suppliers and shippers.

9.528 Although Project Nexus will allow for a more frequent update of AOs and introduce reconciliation for all supply points, we consider that these two measures alone will have a limited impact on the incentives of shippers and suppliers to sufficiently increase the frequency of these updates to a point that would entirely reduce unidentified gas.

9.529 We note that a recent report from the Allocation of Unidentified Gas Expert puts the cost of unidentified gas at £119 million in 2015/16 and considers that the majority of this cost is due to undetected theft.²⁹⁹ Some shippers believe this figure is an underestimate and suggest that its costs might be nearer £300 million annually.³⁰⁰

9.530 In addition to theft, other factors are contributing to unidentified gas. An independent report commissioned by Ofgem identified 40 different issues contributing to unidentified gas. These included shipperless sites, unregistered sites and offtake meter errors.³⁰¹

9.531 As noted by some parties (see paragraphs 9.521(e), 9.521(f), 9.521(g)) and in paragraph 9.518, the costs of unidentified gas are borne disproportionately by domestic and microbusinesses customers. We consider that this distorts competition between domestic/SME suppliers and domestic-only suppliers and in turn reduces the competitiveness of domestic and microbusiness retail supply.

- *Update of AOs and potential for gaming*

9.532 In addition, we note that while under Project Nexus a shipper will have the opportunity for monthly rather than annual updates of the AOs, they will still have an incentive to place a higher priority on adjusting AOs down and

²⁹⁹ [2014 Allocation of Unidentified Gas Final Table for 2015/16](#).

³⁰⁰ Ofgem's additional submission to the CMA, 30 October 2015.

³⁰¹ Ofgem's additional submission to the CMA, 18 September 2015.

delaying adjusting AQs up. Shippers might, even after delivery of Project Nexus, still gain financially, in terms of reduced imbalance and settlement costs, from such form of gaming, particularly if this would lead to an upward revision of an AQ. Further, the incentive for a shipper to place a higher priority on adjusting AQs down reduces that particular shipper's settlement costs, but would increase the cost of settlement for all other parties due to the unidentified gas mechanism. As a result, incentives for suppliers to encourage demand-responsiveness in their customers are dampened.

9.533 Ofgem also told us that Project Nexus (specifically the introduction of an 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.³⁰²

- *Delays to implementation of Project Nexus*

9.534 As discussed in Appendix 8.6,³⁰³ Project Nexus has taken a long time to develop. The Project Nexus working group began meeting in 2009 and the deadline for Project Nexus has been postponed several times. Ofgem put to us that 'this is another example of where industry governance processes may not facilitate the timely implementation of reforms that will improve efficiency and benefit consumers.'

9.535 As discussed in more detail in Section 12, Ofgem has taken a number of steps to ensure delivery of Project Nexus in a timely manner. This includes taking on an overall sponsorship role for Project Nexus and establishing new governance arrangements.³⁰⁴ We noted in paragraph 9.522 that Project Nexus was expected to be operational by the new deadline of 1 October 2016. However, some parties, including Ofgem, have expressed doubts as to whether this new deadline of 1 October 2016 would be met.³⁰⁵

9.536 Ofgem has published a consultation document proposing to postpone the implementation Project Nexus to a new implementation date between 1 February 2017 and 1 April 2017. Ofgem found that there are significant risks of problems occurring during its implementation and considers that additional testing of IT upgrades should be carried out before delivery of Project Nexus.³⁰⁶ Ofgem is therefore minded to accept PwC's recommendation to "continue with programmed delay", which has a target

³⁰² Ofgem response to gas and electricity settlement working paper.

³⁰³ See Appendix 8.6, Annex A.

³⁰⁴ Ofgem 15 April 2016. [Open letter: Cooperation with revised Project Nexus Governance Arrangements.](#)

³⁰⁵ See Ofgem (14 March 2016), [Improving the end-to-end management and assurance of Project Nexus.](#)

³⁰⁶ See Ofgem (2 June 2016), [Project Nexus: consultation on options for a successful implementation.](#)

“go-live” date of 1 February 2017.³⁰⁷ Further, we have noted that one of Project Nexus’s core areas of functionality, which relates to elements of the retrospective adjustment arrangements, has been deferred to October 2017.³⁰⁸ We discuss this further in Section 12.

- *Conclusion*

9.537 Overall, our 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 identified, we are concerned that the gas settlement system would still be characterised by the presence of a (residual) amount of unidentified gas, inefficiencies in the allocation of the cost of this residual unidentified gas to parties, as well as incentives that shippers face to place a higher priority on adjusting AQs down and delaying adjusting AQs up.

9.538 We are also very concerned at the slow pace of the implementation. We understand that implementation date is to be postponed again (to a date between 1 February and April 2017), and that certain aspects of Project Nexus (ie the implementation of the elements of the retrospective adjustment) have been further deferred to 1 October 2017. This means that the clear deficiencies in the gas settlement system will persist beyond October 2016. We believe that some players might have already been adversely affected by the delays in implementation. We also believe that this supports our view that the current code governance arrangements are inadequate, and we reflect on the implications of this (and other examples) in our assessment of the industry codes framework in Sections 18 and 19.

9.539 The current system of gas settlement also applies to microbusiness gas customers. Accordingly, our conclusion concerning the market for domestic gas supply also applies to the market for SME retail gas supply in Great Britain (see Section 16).

³⁰⁷ See Ofgem, 2 June 2016. [Project Nexus: consultation on options for a successful implementation](#)

³⁰⁸ Ofgem approved UNC573 in February 2016. See Ofgem, [Uniform Network Code \(UNC\) 573: Project Nexus. Deferral of implementation of elements of retrospective adjustment arrangements.](#)

Electricity settlement

- 9.540 The electricity settlement process is set out in the BSC. Elexon administers the BSC and provides and procures the services needed to implement it.³⁰⁹
- 9.541 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.
- 9.542 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 means 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.³¹⁰
- 9.543 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.
- 9.544 In Section 12, we present an overview of the potential benefits of domestic load shifting that could be expected to arise from the introduction of half-hourly settlement. We believe the benefits are potentially very large, and based on the evidence we have seen, there are good reasons to expect the benefits from half-hourly settlement to outweigh the costs of its implementation by a substantial degree.
- 9.545 We note that the introduction of half-hourly settlement is a substantial reform that would take some time to plan and implement. As noted in Section 18, governance processes have failed several times to deliver certain policy objectives, in particular when requiring an industry code modification process, even in circumstances where benefits to customers were clear. In view of the nature of the changes, and the likely impact on stakeholders (eg the costs of implementation), implementation of half-hourly settlement will have some of the same characteristics as major projects such as Project

³⁰⁹ ELEXON is currently fully owned by National Grid.

³¹⁰ 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.

Nexus and P272 (implementation of half-hourly settlement for profiles 5 to 8).

9.546 We therefore consider that without sufficient planning and strong project management, the implementation of half-hourly settlement for profile classes 1 to 4 may suffer from the same problems we reported for Project Nexus and P272, including an unnecessarily long lead time and difficulties with implementation.

9.547 We note, however, that following the publication of our provisional findings report, both DECC and Ofgem have taken a number of steps to facilitate the introduction of half-hourly settlement. We discuss this further in Section 12.

- *Parties' views*

9.548 Most parties supported a move to half-hourly settlement and the AEC we identified.

(a) Centrica³¹¹ agreed that profile-based settlement led to a less accurate allocation of costs than settlement based on actual consumption and that it diluted the incentives on suppliers to encourage their customers to change consumption patterns through, for example, dynamic time-of-use tariffs.

(b) Flow Energy³¹² said that it supported the introduction of half-hourly settlement in electricity as this would allow customers to be rewarded for shifting or reducing power load at appropriate times. Good Energy³¹³ considered that half-hourly settlement would encourage innovation and allow suppliers to engage customers in their energy use.

(c) EDF Energy³¹⁴ agreed that the lack of a half-hourly settlement regime for domestic customers was a barrier to the development of innovative time-of-use tariffs. It added that the CMA was right to be concerned at the lack of concrete plans for a move to half-hourly settlement and the fact that no modification process had begun such that there was a feature giving rise to an AEC.³¹⁵

(d) RWE said that the use of half-hourly consumption data to settle electricity would be a prerequisite for the widespread introduction of

³¹¹ Centrica response to provisional decision on remedies, paragraphs 282 & 283, p56.

³¹² Flow Energy response to provisional decision on remedies, p2.

³¹³ Good Energy response to Remedies Notice, p10.

³¹⁴ EDF Energy response to provisional decision on remedies, paragraph 4.1, p22.

³¹⁵ EDF Energy response to provisional findings, paragraph 4.57, p17.

time-of-use tariffs, and that suppliers might not be able to encourage customers to change their consumption profile with the use of such data.³¹⁶

(e) Utilita³¹⁷ and First Utility³¹⁸ agreed with the AEC identified by the CMA (although First Utility noted specific areas for further consideration).

(f) In particular Utilita [✂].³¹⁹

9.549 SSE³²⁰ and E.ON,³²¹ instead, did not agree that half-hourly electricity settlement constituted an AEC. In particular:

(a) SSE³²² said that half-hourly settlement did not give rise to an AEC given that the industry was at a relatively early stage of smart-meter roll-out.

(b) E.ON³²³ disagreed with the AEC finding but supported the long-term ambition for all customers to be settled using half-hourly data. It considered that the use of half-hourly data in the settlement of domestic electricity meters was likely to facilitate tariff innovation.

9.550 Some parties identified a number of barriers to half-hourly settlement:

(a) Ovo Energy³²⁴ considered that the most immediate barrier to facilitating half-hourly settlement to be industry inertia as the existing code process enabled industry parties to stall and delay the progress of any change if they felt that the changes were not in their interests. It said that there was a role for a government or regulatory party to project-manage the industry codes process and enable the delivery of elective half-hourly settlement to ensure that certain industry parties did not continually delay and frustrate the process of delivering the changes necessary.

(b) Tempus submitted [✂].

³¹⁶ RWE response to provisional findings, paragraph 347, p73.

³¹⁷ Utilita response to provisional decision on remedies, paragraph 5.10, p23.

³¹⁸ First Utility response to provisional decision on remedies, paragraph 1.1, p5.

³¹⁹ Utilita response to gas and electricity settlement and metering working paper.

³²⁰ SSE response to provisional decision on remedies, Annex 1, paragraphs 3.1.1 & 3.1.2, p1 and SSE response to provisional findings, paragraph 7.1.1, p53.

³²¹ E.ON response to provisional decision on remedies, paragraph 155, p33.

³²² SSE response to provisional decision on remedies, Annex 1, paragraphs 3.1.1 & 3.1.2, p1.

³²³ E.ON response to provisional decision on remedies, paragraphs 155 & 156, p33.

³²⁴ Ovo Energy response to provisional decision on remedies, paragraph 4.6, p24.

- 9.551 Utilita put to us that [redacted].³²⁵ It added that the current approach unfairly favoured large supply points, which paid a minimal amount compared to their size for the benefits of half hourly metering.³²⁶
- 9.552 SSE,³²⁷ Centrica,³²⁸ Scottish Power³²⁹ and EDF Energy³³⁰ identified securing customers' agreement to collect half-hourly consumption data from a smart meter as a further barrier (ie privacy concerns).³³¹ SSE³³² also said that these concerns would need to be fully reviewed in the context of the Data Protection Act 1998, licence conditions and industry codes.
- 9.553 Ecotricity³³³ noted that the introduction of half-hourly settlement would generate a huge volume of data, roughly 1,500 times more data per customer than was currently processed. It said that it would require significant IT infrastructure investment at a high cost and that trading and forecasting systems and process would also require enhancement. These costs would inevitably be passed through to customers.
- 9.554 In relation to the timing of moving to half-hourly settlement for all domestic customers, two of the Six Large Energy Firms, SSE³³⁴ and Centrica,³³⁵ warned that an early implementation of half-hourly settlement might risk the costs outweighing benefits.
- (a) SSE³³⁶ said that once the smart meter roll-out was sufficiently advanced, a plan could be put in place to introduce half-hourly settlement.
- (b) Centrica³³⁷ submitted that while half-hourly settlement was ultimately desirable, it was premature to commit the industry to developing a binding plan in the short, to medium, term. It added that:

³²⁵ Utilita also considered that the strict regulatory standards DACs had to comply with and the significant uncertainty on the roll-out of smart meters (including implications for the future role of DACs) prevented competitors from entering this market and hence allowed the existing DACs 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.

³²⁶ Utilita response to provisional decision on remedies, paragraphs 5.12–5.14, p23.

³²⁷ SSE response to Remedies Notice, p95.

³²⁸ Centrica response to provisional findings and Remedies Notice, p96.

³²⁹ Scottish Power response to Remedies Notice, p47.

³³⁰ EDF Energy response to Remedies Notice, p48.

³³¹ The Data Access and Privacy Framework for smart metering developed by DECC currently prohibits energy suppliers from collecting data with greater granularity than daily unless the customer has opted in.

³³² SSE response to Remedies Notice, p95.

³³³ Ecotricity response to Remedies Notice, pp8 & 9.

³³⁴ SSE response to provisional findings, paragraph 7.2.2, p53.

³³⁵ Centrica response to provisional findings and Remedies Notice, paragraph 376, p100.

³³⁶ SSE response to provisional findings, paragraph 7.2.2, p53.

³³⁷ Centrica response to provisional findings and Remedies Notice, paragraph 376, p100.

- (i) a full cost-benefit analysis of half-hourly settlement was needed before any implementation plan could be agreed;
 - (ii) the incremental benefits half-hourly settlement brought were likely to be limited in the foreseeable future, meaning it was likely to be too early to consider implementing half-hourly settlement for profile class 1 to 4 sites; and
 - (iii) implementation of half-hourly settlement would take significant resources and therefore risk undermining other important projects occurring now and in the future.
- (c) E.ON³³⁸ considered that should the use of half-hourly data be mandated, this would be most effective if introduced from 2020 once the smart meter roll-out was complete.

9.555 We agree with parties that the timing of a shift to half-hourly settlement 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. We provide an overview of the available evidence on the benefits of electricity settlement reform, and a discussion of the timing for moving to half-hourly settlement, in Section 12.

9.556 We note that the experience set out in Section 18 and Appendix 18.2 suggests that progressing the required code modifications for the introduction of half-hourly settlement 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.

- *Conclusion*

9.557 Following the publication of our provisional findings report, the Secretary of State for Energy and Climate Change wrote to us in July 2015 stating that she shared our views about the importance of half-hourly settlement in facilitating greater innovation in time-of-use tariffs and would shortly be bringing forward proposals for pre-legislative scrutiny that would seek to give Ofgem greater powers in order to deliver settlement reform more quickly.

³³⁸ E.ON response to provisional findings and Remedies Notice, paragraph 359, p77.

These proposals have since been published and considered by the Energy and Climate Change Select Committee.³³⁹

- 9.558 While we welcome these and other positive developments, which we set out in more detail in Section 12, we consider that a number of steps still need to be taken by both Ofgem and DECC before a firm plan for the introduction of half-hourly settlement can be established. For instance we note that the additional powers to be given to Ofgem to allow it to implement switching and settlement reforms have not yet been approved by Parliament. Further, we note that Ofgem has identified, in a recent conclusion paper,³⁴⁰ a number of barriers to elective half-hourly settlement. It considered that the changes to address these needed to be progressed through the usual industry governance process and that this relied on industry parties and code administrators playing a full and constructive role, including by raising changes.
- 9.559 As discussed above and in Section 18, governance processes have failed several times to deliver certain policy objectives, in particular when requiring an industry code modification process.
- 9.560 Therefore, our conclusion 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.³⁴¹
- 9.561 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.³⁴² Accordingly, our finding concerning the market for domestic electricity supply also applies to the market for SME retail electricity supply in Great Britain (see Section 16).

³³⁹ See [Energy and Climate Change Committee: Pre-legislative scrutiny of the Government's draft legislation on energy inquiry](#).

³⁴⁰ Ofgem (2016), [Elective half-hourly settlement: conclusions paper](#).

³⁴¹ 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.

³⁴² The majority of microbusinesses are currently assigned to profile classes 3–4, ie Non-Domestic Unrestricted Customers and Non-Domestic Economy 7 Customers.

Conclusions

9.562 Our 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**³⁴³ 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. We note that these features vary based on meter type.

9.563 More particularly, in relation to domestic customers on all meter types 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.

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. In addition, the fact that the regulations governing energy supply ensure that domestic customers generally receive continuous supply of gas and

³⁴³ We refer to weak customer response as an overarching feature as synonymous with it being a source for an AEC ([CC3](#), paragraph 170).

electricity implies that there is no natural trigger point for engagement, which may depress levels of engagement relative to other sectors.

- (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 perceived barriers to switching**, such as where they 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.

9.564 We have found that prepayment customers and standard credit customers overall are less engaged than direct debit customers, particularly in terms of whether they have ever considered switching or are likely to consider switching in the next three years, and, for prepayment customers, their awareness of their ability to switch.

9.565 In relation to **prepayment customers** we have identified additional aspects that contribute to these features and support a finding that disengagement and weak customer response is a more significant problem among prepayment customers compared with domestic customers on direct debit. We have found that prepayment customers face :

- (a) higher actual and perceived barriers to accessing and assessing information about switching arising, in particular, from relatively low access to the internet and confidence in using PCWs;
- (b) higher actual and perceived barriers to switching arising in particular from:

- (i) the need to change meter to switch to a wider range of tariffs (and the obstacles associated with this requirement such as perceptions of the complexity of the meter replacement process); and
- (ii) restrictions arising from the DAP hindering indebted prepayment customers' ability to switch supplier.

9.566 We also note that prepayment customers include higher proportions of individuals: with low levels of income; with low levels of education; living in social rented housing; and having a disability – demographic characteristics that we have found to be associated with low levels of engagement in retail energy markets.

9.567 In relation to customers on **restricted meters**, we have also found that disengagement is a more significant problem among customers on restricted meters compared with domestic customers, with single-rate or Economy 7 meters. In particular, we have identified aspects of the restricted meter segments that strengthen the features that customers face actual and perceived barriers to accessing and assessing information, and that customers face actual and perceived barriers to switching.

9.568 We have found that customers on restricted meters face:

- (a) higher actual and perceived barriers to accessing and assessing information arising, in particular, from a general lack of price transparency concerning the tariffs that are available to them, which results from restricted meter tariffs not being supported by PCWs or suppliers' online search tools.
- (b) higher actual and perceived barriers to switching arising from:
 - (i) the requirement imposed by suppliers on certain restricted meter customers to replace their restricted meter with an single-rate or Economy 7 meter, which may be at a cost to the customer, to be able to switch to a wider range of tariffs;
 - (ii) the fact that a restricted meter replacement might involve some rewiring in the home; and
 - (iii) the fact that a restricted meter replacement (particularly to a single rate meter) may entail a loss of functionality to the customer, and possibly higher tariffs in the future, with no option of reverting back to their old meter.

- 9.569 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 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.
- 9.570 The above AEC is reinforced by our finding on the customer detriment identified in Section 10.
- 9.571 In relation to **tacit coordination**, our 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.
- 9.572 In relation to **supply-side barriers to entry and expansion** in the supply of domestic prepayment customers our view is that a combination of features of the markets for domestic retail supply of gas and electricity in Great Britain, relating specifically to the prepayment segments, give rise to an AEC. These features, in combination, reduce retail suppliers' ability and/or incentives to compete to acquire prepayment customers and to innovate by offering tariff structures that meet customers' demand. As a result, the tariffs available in the prepayment segments are not competitively priced compared with the direct debit segment. These features are as follows:
- (a) Technical constraints that limit the ability of all suppliers, and in particular new entrants, to innovate by offering tariff structures that meet demand from prepayment customers who do not have a smart meter. These technical constraints are exacerbated by certain aspects of the simpler choices component of the RMR rules.

- (b) Softened incentives for all suppliers, and in particular new entrants, to compete to acquire prepayment customers due to:
 - (i) actual and perceived higher costs to engage with, and acquire, prepayment customers compared with other customers; and
 - (ii) a low prospect of successfully completing the switch of indebted customers, who represent about 7 to 10% of prepayment customers.

9.573 In relation to the regulatory framework governing domestic retail energy markets, our view is that:

- (a) Certain aspects of 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) are 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 compete and innovate in designing tariffs and discounts to meet customer demand, and by softening competition between suppliers and 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 very concerned at the slow pace of the implementation, the repeated postponement of the implementation date 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.

9.574 The table below summarises our view of how different categories of domestic customers (by meter type) are affected by the AECs we have identified in domestic energy markets.

Table 9.8: Summary of provisional AECs concerning domestic retail energy markets

<i>Provisional AECs</i>	<i>Categories of domestic customer affected</i>
Domestic Weak Customer Response AEC	Domestic customers on all meter types but: <ul style="list-style-type: none"> - customers on restricted meters (other than Economy 7), face higher barriers to accessing and assessing information and higher barriers to switching when compared with customers on single-rate and Economy 7 meters. - prepayment customers face higher barriers to accessing and assessing information and higher barriers to switching when compared with direct debit customers.
Prepayment AEC	Customers on prepayment meters only.
Regulatory AECs <ul style="list-style-type: none"> - Simpler choices element of RMR - Electricity settlement - Gas settlement 	Domestic customers on all meter types.

10. Analysis of detriment

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10.1 We have assessed the nature and extent of detrimental effects on domestic energy customers resulting from the AECs that we have identified in the domestic retail energy markets. This section sets out the results of our analysis of customer detriment.

10.2 Our approach to assessing the scale of detriment has involved considering to what extent the outcomes that we have observed in the domestic retail energy markets are worse than we would expect to see in a well-functioning market, including the extent to which domestic energy customers are, on average, paying higher prices and receiving poorer quality of service. As set out in our Guidance, 'a well-functioning market' is one that displays the beneficial aspects of competition, notably rivalry between firms which seek to win customers' business through lower prices, improved quality or variety and/or introducing new or better products. It is not an idealised perfectly competitive market.¹

10.3 We have considered three potential sources of detriment to customers in the domestic retail energy markets:

- (a) that domestic energy customers are, on average, paying higher prices than they would do in well-functioning markets;

¹ CC3, paragraphs 10, 12 & 320.

- (b) that domestic energy customers receive a poorer quality of service than they would do in well-functioning markets; and
 - (c) that suppliers innovate less in products and services than they would do in well-functioning markets, resulting in a more restricted range of products and services for domestic customers.
- 10.4 Most of our analysis has focused on the first source of detriment – excessive prices – as we believe that this is likely to be the most significant form of detriment suffered by energy customers, given the homogenous nature of gas and electricity.² Further, it is easier to quantify robustly the extent to which prices are excessive than the extent to which quality of service is relatively poor or innovation relatively restricted. Nonetheless, we do give some consideration to these second two sources of detriment at the end of this section.
- 10.5 We have adopted two approaches to assessing the extent to which prices are excessive (ie have exceeded those we would expect in a well-functioning market):
 - (a) A ‘direct’ approach, which involves comparing the average prices charged by the Six Large Energy Firms with a competitive benchmark price which is based on the prices charged by the most competitive suppliers, adjusted to allow for a normal return on capital and where appropriate for differences in suppliers’ size, rate of growth and the cost elements that are outside of their control.
 - (b) An indirect approach, which involves assessing both:
 - (i) the Six Large Energy Firms’ levels of profitability (and in particular whether the return on capital employed by such suppliers exceeds their cost of capital); and
 - (ii) the extent to which the Six Large Energy Firms have incurred overhead costs inefficiently (ie whether costs are higher than we estimate an efficient supplier would incur).
- 10.6 The benefit of the direct approach is that it gives us a more direct measure of customer detriment which is related to actual market prices – and prices are ultimately what matter to a customer, rather than the level of profitability or cost efficiency of any of the Six Large Energy Firms. Further, the direct approach allows for a much more granular breakdown of detriment, not just

² See Section 8.

by supplier but by customer type, including type of tariff and payment method.

- 10.7 The indirect approach provides information on profitability and overhead cost efficiency which can be a useful proxy for customer detriment – indeed it is sometimes the only available means of quantifying customer detriment. In this case, we believe that it can provide a useful independent cross check on our direct analysis, as it is based on a separate data set and methodology.
- 10.8 Our analysis of detriment has focused on the Six Large Energy Firms for which we have comprehensive pricing and profitability data that allowed us to implement both direct and indirect approaches to assessing detriment. These suppliers account for almost 90% of customers in the domestic retail energy markets which suggests that our estimate of detriment from their pricing policies is a close approximation – albeit a conservative one – of the overall detriment suffered by GB customers.
- 10.9 As explained further below, as part of our direct approach to assessing detriment, we have constructed a competitive benchmark to provide us with an estimate of the level of prices that we would expect to see in a well-functioning market. In that sense, our benchmark is applicable to all suppliers, including the Mid-tier Suppliers, and we use it for the purpose of setting the level of the prepayment price cap remedy described in Section 14 (the PPM Price Cap Remedy). The impact of using this competitive benchmark in the context of the PPM Price Cap Remedy on the Six Large Energy Firms, as well as on the other suppliers, is discussed in Section 14.
- 10.10 Finally, we note that detriment is a measure of harmful outcomes arising from AECs. In this section, we estimate the detriment arising from the AECs we have identified in the domestic retail energy markets, and in particular:
- (a) for customers on credit (ie non-prepayment) meters, the detriment arising from the Domestic Weak Customer Response AEC (noting how the strength of features differs between different categories of customer); and
 - (b) for customers on prepayment meters, the detriment arising from the Domestic Weak Customer Response AEC and the Prepayment AEC.
- 10.11 The Regulatory AECs may also contribute in part to the detriment we identify in this section (eg through the dulling effect on competition arising from aspects of the ‘simpler choices’ component of the RMR rules). However, other aspects of the detriment arising from the Regulatory AECs are incremental to the detriment that we identify in this section. These are

identified separately, in Sections 11 and 12, where we consider the potential benefits arising from half-hourly settlement in electricity.

10.12 The next section sets out the results of our analysis. Further details of our analysis are provided in Appendices 9.8 to 9.13, 10.1 and 10.2.

Direct approach: analysis of average prices and bills

10.13 Our direct approach to assessing detriment has involved calculating the average prices offered by the Six Large Energy Firms to their customers and comparing these to a 'competitive benchmark price', which is constructed on the basis of the average prices offered by the most competitive suppliers adjusted to allow for a normal return on capital and where appropriate for differences in suppliers' size and rate of growth.

10.14 In order to ensure that the comparison between our competitive benchmark and the average prices offered by the Six Large Energy Firms is carried out on a like-for-like basis, we have also adjusted our data for cost differences which are largely outside suppliers' control (we refer to these as exogenous cost differences).

10.15 The data set that we have used covers the customers of the Six Large Energy Firms and two Mid-tier Suppliers – Ovo and First Utility – who are on single-rate or Economy 7 meters, for the period Q1 2012 to Q2 2015. For customers on non-Economy 7 restricted meters (about 2% of the total customer base), we have conducted a separate, higher level exercise for Q2 2014 and Q2 2015, the results of which we summarise in paragraphs 10.81 to 10.90 below.

10.16 A number of tariffs have been excluded from our analysis following the approach we adopted for our gains from switching analysis, including green tariffs, social tariffs, tariffs that are included as part of a bundle with other services, tariffs with a very low number of customers and tariffs for which suppliers provided us with incomplete or corrupt data (see Appendix 10.2 for more detail).

10.17 In the rest of this section we:

(a) describe our methodology in more detail, including an explanation of our choice of suppliers to construct the competitive benchmark and the approach that we have adopted to adjusting for exogenous cost differences and cost differences which are due to differences in supplier size and growth rate;

(b) present the results of the benchmark analysis and detriment calculation;

- (c) describe a robustness test of the benchmark analysis;
- (d) summarise parties' views on the analysis presented at provisional decision on remedies; and
- (e) present the results of the high-level analysis of detriment that we have conducted for customers on restricted meters.

Methodology

- 10.18 Our competitive benchmark is a hypothetical construct, a 'supplier' that is a combination of the suppliers that we have identified as being the most competitive in the markets. The benchmark includes all direct debit tariff types³ weighted by the respective number of accounts within each of those suppliers. The payment method is set to direct debit (as explained below, we make an adjustment for payment method cost differentials where relevant).
- 10.19 Our methodology consists of a number of steps (a more detailed description is given in Appendix 10.2):
- (a) First, we choose the suppliers that will provide the basis for our assessment of competitive benchmark prices.
 - (b) We then consider whether an uplift is needed to their prices in order to generate revenue that would allow an energy supplier which has reached an efficient scale and is in steady state to earn a normal rate of return.
 - (c) After that we adjust our data to account for exogenous cost differences between the suppliers arising from differences in their customer mix.
 - (d) We then compute the average bill for each supplier by payment type and the benchmark average bill, and use those to calculate the extent to which suppliers' bills are priced above the competitive level, as implied by the benchmark bills.
 - (e) After that, we calculate the overall detriment to domestic customers from the prices being set by the Six Large Energy Firms above the competitive level.

³ As explained in paragraph 10.16, we excluded certain tariffs from the analysis. For both Ovo and First Utility the excluded tariffs account for just 2% of their customer base over the period.

- (f) Finally, we consider the robustness of our findings by performing the analysis of bills at different consumption levels and by comparing detriment estimates between dual and single fuel benchmarks.

Choice of suppliers for the competitive benchmark

- 10.20 We have found that weak customer response is an overarching feature of the domestic retail energy markets which gives suppliers a position of unilateral market power concerning their inactive customer base which they are able to exploit through their pricing practices. Because of that, for the purpose of choosing our competitive benchmark we have focused on suppliers whose average price best reflects the prices paid by active customers as we expect those customers to be on competitively priced tariffs.
- 10.21 We have estimated customer detriment by comparing the average bills between the Six Large Energy Firms and two of the Mid-tier Suppliers, Ovo Energy and First Utility (our benchmark suppliers), adjusting the prices of these Mid-tier Suppliers to give our competitive benchmark. We believe that this approach is justified for the following reasons:
- (a) Both Ovo Energy and First Utility are competing primarily through acquisition tariffs where competition is focused on price, and where customers are acquired through PCWs, which is the main channel for the acquisition of active customers.
- (b) Therefore, both Ovo Energy and First Utility have relatively few inactive customers, which means that we would expect their average price (or the 'system' price) to be close to a competitive level. This may not be the case with the Six Large Energy Firms which all have a high ratio of inactive to active customers (for example, see Appendix 8.1).
- 10.22 We note that these suppliers have been growing rapidly in recent years but that they are still smaller than the Six Large Energy Firms. As of January 2016, First Utility and Ovo Energy combined had around [X] of the gas and electricity markets. In contrast, the smallest of the Six Large Energy Firms, RWE, had [X] customer accounts in January 2016.⁴ We have considered the implication of those differences for our bills comparison in more detail in paragraphs 10.26 to 10.32 below.

⁴ Source: Cornwall Energy.

- 10.23 We did not include in our competitive benchmark the other two Mid-tier Suppliers: Utility Warehouse and Co-operative Energy.
- 10.24 Utility Warehouse acquired the majority of its existing customers through a deal with RWE npower rather than acquiring them through competition like Ovo Energy and First Utility. We also note that Utility Warehouse does not advertise its tariffs through PCWs where customers can compare and identify the most competitively priced tariffs. Instead, it works in a partnership with independent (and part-time) distributors (known as 'Partners') who receive a small share of the revenues from each new customer they introduce. Another reason Utility Warehouse is not suitable for our competitive benchmark is because their business model is focused on providing bundled services (energy and telecoms). It would therefore be difficult for us to compare on a like-for-like basis their prices with those of the Six Large Energy Firms.
- 10.25 Although Co-operative Energy in principle uses multiple acquisition channels, including, at times, PCWs, a large number of its customers have been acquired from the members of the Midcounties Co-operative which means that its customer base is unlikely to be as active and engaged as that of Ovo Energy and First Utility. Furthermore, those who were not acquired in this way have also been given the option of becoming members, entitling them to a share in the profits it generates from all business streams, not just from the energy business. This would make it difficult to compare Co-operative Energy prices with that of the Six Large Energy Firms on an entirely like-for-like basis. Another reason for not including Co-operative Energy in our benchmark is that it is a considerably smaller supplier than First Utility [§] and Ovo Energy [§]⁵ with indirect costs on a per customer basis which were significantly higher than those of Ovo Energy and First Utility in 2013 and 2014 (see Annex A to Appendix 9.11). This suggests that it may not yet be operating at an efficient scale.

Assessment of need to adjust benchmark suppliers' prices

- 10.26 Ovo Energy and First Utility have been growing rapidly in recent years but they are still considerably smaller than the Six Large Energy Firms. In response to our Provisional Decision on Remedies, some of the Six Large Energy Firms argued that we would need to take account of several important differences – both relating to costs and profitability – between Ovo Energy and First Utility on the one hand and the Six Large Energy Firms on the other if we were to use the former as a benchmark for the prices charged

⁵ Source: Cornwall Energy.

by the latter. We have therefore analysed the costs and profits of First Utility and Ovo Energy in order to determine whether their prices should be adjusted to be consistent with what we would expect a large, efficient operator to have in a steady state.

10.27 We have based our assessment on the principle that a competitive benchmark price in the domestic retail energy markets should fulfil the following criteria: (a) it should be reflective of the prices charged to active/engaged customers; (b) it should be reflective of the costs of an energy supplier which has reached an efficient scale (ie a large supplier) and which is in a steady state (ie the supplier that is neither growing nor shrinking rapidly); and (c) it should generate revenue that is consistent with a normal return (equivalent to an average EBIT margin of 1.25%).

- *Adjustments to costs*

10.28 We identified three cost categories that we considered were likely to be materially different for a large, efficient firm with a steady customer base: social and environmental costs, customer acquisition costs and overhead costs. We have adjusted those costs in the following way (the rationale for those adjustments and a more detailed description is provided in Appendix 10.1):

- (a) We assumed that First Utility and Ovo Energy incurred social and environmental costs per customer equal to the Six Large Energy Firms' average in each year, ie we adjusted these costs to reflect a situation in which these suppliers did not benefit from a small supplier exemption and incurred these costs based on their average customer numbers in each year.
- (b) We capitalised First Utility's and Ovo Energy's customer acquisition costs and amortised them over the industry average customer lifetime (of six years) in order to match the costs of customer acquisition more closely to be the period in which the benefits are received.
- (c) We adjusted their overhead costs as a percentage of revenues to be in line with First Utility's actual overhead costs in 2014 and 2015 and with Ovo Energy's forecast overhead costs to reflect the level of overhead costs that we would expect to see in a large firm that was operating with a stable customer base (ie one which was neither growing, nor shrinking materially year on year).

- *Normal rate of return*

10.29 We have also adjusted Ovo’s and First Utility’s prices to give a competitive benchmark price that is consistent with a return of 1.25% EBIT margin. This represents the EBIT margin that we estimate a large stand-alone retail energy supplier should earn (on average) in order to make a ‘normal’ level of profits⁶ and is based on our ROCE analysis (see Appendix 9.10).⁷ In addition, this level of EBIT margin is consistent with our analysis of profit margins in other energy sectors that we consider should be given greatest weight when compared to the domestic retail energy markets, namely margins earned serving I&C customers and on previous GB regulatory determinations (recognising that regulated firms may face fewer risks)(see Appendix 9.13).

- *Uplift to benchmark suppliers’ bills*

10.30 Having made these adjustments to Ovo Energy’s and First Utility’s costs, we then calculated the uplift to their bills that is required to generate an EBIT margin of 1.25% for each of those two suppliers.⁸ This uplift is shown in Table 10.1 below for each year in our sample:

Table 10.1: Uplift to benchmark suppliers’ bills

	%			
<i>Supplier</i>	<i>FY12</i>	<i>FY13</i>	<i>FY14</i>	<i>FY15</i>
First Utility	[REDACTED]	[REDACTED]	[REDACTED]	[REDACTED]
Ovo Energy	[REDACTED]	[REDACTED]	[REDACTED]	[REDACTED]

Source: CMA analysis.

10.31 For 2015, for example, we applied an uplift of [REDACTED] and [REDACTED] to First Utility’s and Ovo Energy’s bills, respectively.

10.32 We note that there is uncertainty regarding the likely development of the Mid-tier Suppliers’ cost bases as they increase in scale and their rate of growth in customers slows. It has, therefore, been necessary to make a

⁶ ie ensuring a return on capital employed in line with the WACC.

⁷ This EBIT margin represents the level at which a business which operates on a relatively asset-light basis, ie using an intermediary trading arrangement for the procurement of its wholesale energy rather than holding capital, would make a return approximately equal to its weighted average cost of capital (WACC), ie 10%. As we explain in Appendices 9.10 and 9.13, a firm that chooses to hold capital rather than using a trading intermediary could expect to earn a higher margin (at the same price level), with the incremental margin serving to remunerate the additional capital employed. In Appendix 9.13 we explain that this EBIT margin is likely to be around 2%. However, we note that we are using the tariffs of First Utility and Ovo Energy as the competitive benchmark. As these firms use such trading arrangements, we concluded that the relevant EBIT margin is 1.25% rather than 2% (see further paragraphs 158 and 159 of Appendix 9.10).

⁸ As discussed above, given that First Utility and Ovo Energy use intermediary trading arrangements, we consider that the relevant EBIT margin is 1.25% (from our ROCE analysis), rather than 2% (as set out in our profit margin comparator analysis).

number of judgements in coming to a view on the appropriate adjustments. As we set out in Appendix 10.1, we have based our adjustments on evidence drawn largely from the historical financial performance of the Six Large Energy Firms and First Utility and Ovo Energy. As a result, we consider that the approach we have taken produces a reasonable estimate of the competitive benchmark tariff for a large, efficient energy supplier with a stable customer base.

Adjustment of data to reflect exogenous cost differences in customer mix

- 10.33 We recognise that suppliers' customer bases differ across a range of dimensions, including location, tariffs and payment method. This may give rise to cost differences between the suppliers over which they have little control (we call these 'exogenous' cost differences), and which we therefore needed to control for in our analysis in order to be able to compare bills on a like-for-like basis. We have identified two such cost categories: network charges and the costs associated with different payment methods.
- 10.34 Network charges comprise distribution and transmission charges that vary across regions and fuels. They affect suppliers' costs in different ways, depending on their regional presence. We have computed the value of those charges by combining them with actual consumption data. We have then subtracted them from each electricity, gas and dual fuel bill in our sample.
- 10.35 The proportion of customers on different payment methods varies between suppliers. We have considered evidence from a variety of sources to reach a decision on whether there are systematic differences in the costs of serving prepayment meter, standard credit and direct debit customers. Our analysis shows that prepayment meter and standard credit customers are more costly to serve than direct debit customers by approximately £63 and £100, respectively. Appendix 9.8 sets out the analysis we have conducted to inform this conclusion.
- 10.36 To account for these cost differences, we have subtracted the corresponding amounts from each prepayment bill and standard credit bill in our sample. This is equivalent to a reduction in the standing charges of the Six Large Energy Firms on their prepayment and standard credit tariffs.⁹ We consider the implications of this adjustment on the bills comparison and our detriment

⁹ Energy tariffs are comprised of a daily standing charge and a unit rate. A standing charge is a daily fixed charge that goes towards covering the fixed cost of providing gas and electricity. It is payable regardless of whether any energy is actually consumed by the customer. The unit rate is the price per kilowatt hour of gas or electricity consumed.

estimates below as part of our robustness tests (see paragraphs 10.51 to 10.57).

- 10.37 Finally, we note that there may be some differences in customer characteristics that have an impact on costs but that we have not explicitly controlled for in the above approach. For example, First Utility and Ovo Energy have had a higher proportion of engaged customers since they have been growing. Such customers are likely to be more costly to serve than those who have not switched either tariff or supplier for several years.¹⁰ On the other hand, the customers of the Six Large Energy Firms may be more likely to be on the Priority Services Register, which entails certain additional costs for the supplier.¹¹ Our view is that the exclusion of these factors from our quantitative analysis does not introduce a systematic bias into the results.
- 10.38 Overall, our view is that adjusting for network costs and the costs of different payment methods will allow for a comparison of suppliers' bills on a broadly comparable basis.

Bills comparison

- 10.39 We have estimated the degree to which the Six Large Energy Firms' bills are priced above the competitive level using the following steps:
- (a) Step 1: We first compute the average bill (adjusted for network cost and payment method differential as described above) for each supplier/payment type weighted by the number of accounts for each tariff.
 - (b) Step 2: We calculate the competitive benchmark as the average bill of Ovo Energy's and First Utility's direct debit tariffs uplifted to allow a supplier operating at an efficient scale and in steady state to achieve a 1.25% EBIT margin.
 - (c) Step 3: We calculate the difference between the average bill for each supplier/payment type and the competitive benchmark.

¹⁰ First Utility told us that the costs incurred by a supplier over the three-week period when a customer joined were [REDACTED].

¹¹ As explained in Section 9, under their licences, suppliers must maintain a Priority Services Register and put customers 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 and advice to these customers.

- 10.40 The comparison between the benchmark and suppliers' bills is made at Ofgem's Medium Typical Domestic Consumption Values (TDCV)¹² rather than at the consumption levels associated with tariff types. We have done this in order to strip out the volume effect and therefore allow for a like-for-like bills comparison between the suppliers and payment methods. The comparison presented is therefore equivalent to a difference in average price paid. We have also made this comparison at Ofgem's low and high TDCV to test the robustness of our findings (this is explained further below and in Appendix 10.2).
- 10.41 The tables below show our estimates of the extent to which suppliers' bills are priced above the competitive benchmark level, split by payment type for dual fuel and single fuel customers. The results are averaged across the period between 2012 and 2015 as explained in Appendix 10.2.
- 10.42 There is a considerable variation in the extent to which individual suppliers have priced above the benchmark level. For dual fuel customers (the substantial majority of customers), the prices are highest for [redacted] among the Six Large Energy Firms and lowest for [redacted]. We note that the gap between the benchmark and suppliers' prices for single fuel gas customers is considerably higher than for single fuel electricity customers.

¹² This is explained in Appendix 10.2.

Table 10.2: Comparison of dual, single fuel electricity and gas bills by supplier and payment method, calculated at Ofgem 2014 Medium TDCV

Ofgem Medium TDCV

Dual fuel

Supplier	Average bill			Benchmark		Average difference (£)				Average difference (%)			
	DD	SC	PP	All	All	DD	SC	PP	All	DD	SC	PP	All
Centrica	[X]	[X]	[X]	[X]	[X]	[X]	[X]	[X]	[X]	[X]	[X]	[X]	[X]
EDF Energy	[X]	[X]	[X]	[X]	[X]	[X]	[X]	[X]	[X]	[X]	[X]	[X]	[X]
E.ON	[X]	[X]	[X]	[X]	[X]	[X]	[X]	[X]	[X]	[X]	[X]	[X]	[X]
RWE	[X]	[X]	[X]	[X]	[X]	[X]	[X]	[X]	[X]	[X]	[X]	[X]	[X]
Scottish Power	[X]	[X]	[X]	[X]	[X]	[X]	[X]	[X]	[X]	[X]	[X]	[X]	[X]
SSE	[X]	[X]	[X]	[X]	[X]	[X]	[X]	[X]	[X]	[X]	[X]	[X]	[X]
SLEFs	808	805	848	814	744	64	60	103	69	8	7	12	9

Single fuel (elec)

Supplier	Average bill			Benchmark		Average difference (£)				Average difference (%)			
	DD	SC	PP	All	All	DD	SC	PP	All	DD	SC	PP	All
Centrica	[X]	[X]	[X]	[X]	[X]	[X]	[X]	[X]	[X]	[X]	[X]	[X]	[X]
EDF Energy	[X]	[X]	[X]	[X]	[X]	[X]	[X]	[X]	[X]	[X]	[X]	[X]	[X]
E.ON	[X]	[X]	[X]	[X]	[X]	[X]	[X]	[X]	[X]	[X]	[X]	[X]	[X]
RWE	[X]	[X]	[X]	[X]	[X]	[X]	[X]	[X]	[X]	[X]	[X]	[X]	[X]
Scottish Power	[X]	[X]	[X]	[X]	[X]	[X]	[X]	[X]	[X]	[X]	[X]	[X]	[X]
SSE	[X]	[X]	[X]	[X]	[X]	[X]	[X]	[X]	[X]	[X]	[X]	[X]	[X]
SLEFs	349	345	366	351	327	22	18	40	24	6	5	11	7

Single fuel (gas)

Supplier	Average bill			Benchmark		Average difference (£)				Average difference (%)			
	DD	SC	PP	All	All	DD	SC	PP	All	DD	SC	PP	All
Centrica	[X]	[X]	[X]	[X]	[X]	[X]	[X]	[X]	[X]	[X]	[X]	[X]	[X]
EDF Energy	[X]	[X]	[X]	[X]	[X]	[X]	[X]	[X]	[X]	[X]	[X]	[X]	[X]
E.ON	[X]	[X]	[X]	[X]	[X]	[X]	[X]	[X]	[X]	[X]	[X]	[X]	[X]
RWE	[X]	[X]	[X]	[X]	[X]	[X]	[X]	[X]	[X]	[X]	[X]	[X]	[X]
Scottish Power	[X]	[X]	[X]	[X]	[X]	[X]	[X]	[X]	[X]	[X]	[X]	[X]	[X]
SSE	[X]	[X]	[X]	[X]	[X]	[X]	[X]	[X]	[X]	[X]	[X]	[X]	[X]
SLEFs	511	496	497	502	432	80	64	66	70	16	13	13	14

Source: CMA analysis.

Note: SLEFS = Six Large Energy Firms, DD = direct debit, SC = standard credit, PP = prepayment.

10.43 Looking at differences by payment method, we note that for dual fuel and single fuel electricity, the difference between the competitive benchmark and what customers pay is biggest for customers on prepayment meters (12% for dual fuel and 11% for single fuel electricity), followed by direct debit customers (8% for dual fuel and 6% for single fuel electricity), and then standard credit customers (7% for dual fuel and 5% for single fuel electricity). For single fuel gas, this relationship does not hold (16% for direct debit; and 13% for both prepayment and standard credit) although we note, as discussed further below, that our benchmark for single fuel gas is based on far fewer accounts than the benchmark for dual fuel and single fuel electricity.

Detriment calculations

10.44 We have benchmarked the Six Large Energy Firms' bills in the previous step using Ofgem's Medium TDCV to control for the volume effect. However, this

approach risks overestimating or underestimating the overall detriment since it relies on a market-wide measure of consumption which may not be representative of the level of consumption of the customer base of any given representative of the Six Large Energy Firms.

- 10.45 To address this issue, we have adjusted our detriment figures using information on consumption levels provided by the Six Large Energy Firms. More specifically, we have used data on consumption levels by supplier, region, payment type and tariff type and quarter.
- 10.46 We have calculated the overall detriment figure using the following steps:
- (a) Step 1: We have computed both bills and the benchmark at actual median consumption level of the corresponding tariff family;
 - (b) Step 2: We have computed the difference between the actual bill and the benchmark for each tariff;
 - (c) Step 3: We have multiplied this difference by the number of accounts for each tariff; and
 - (d) Step 4: We have aggregated across supplier/payment type to obtain the overall detriment figures.
- 10.47 We believe that this approach will result in an underestimate of detriment because it does not take into account that consumption is likely to be depressed due to prices being set above the competitive level. We expect that this effect will be the strongest in the prepayment segments because of the nature of the prepayment product, whereby consumption is curtailed when a customer runs out of credit.
- 10.48 Further, we note that the approach we have taken to adjust for the costs associated with different payment methods adopts a supply-side perspective in assessing detriment. Essentially, we are assuming that the proportion of customers on different payment methods will remain unchanged in a more competitive market, and recognising that the exogenous costs associated with those payment methods will need to be reflected in competitive prices. However, while justified from a supply-side perspective, this approach does somewhat understate the detriment faced by prepayment customers relative to standard credit customers. This is because customers paying by prepayment suffer additional costs (including the inconvenience of having to top up a payment card) compared to those paying by standard credit (who benefit over flexibility of payment timing).

10.49 The table below shows how aggregate domestic customer detriment has evolved over the period 2012 to 2015.

Table 10.3: Detriment estimates

<i>Year</i>	<i>Fuel type</i>	<i>£m</i>
2012	Dual fuel	511
	Electricity (single fuel)	262
	Gas (single fuel)	82
	Overall	855
2013	Dual fuel	1,026
	Electricity (single fuel)	220
	Gas (single fuel)	130
	Overall	1,376
2014	Dual fuel	913
	Electricity (single fuel)	138
	Gas (single fuel)	209
	Overall	1,260
2015*	Dual fuel	1,444
	Electricity (single fuel)	300
	Gas (single fuel)	250
	Overall	1,994
All years	Dual fuel	3,894
	Electricity (single fuel)	920
	Gas (single fuel)	671
	Overall	5,485

Source: CMA analysis.

*Based on information for the first two quarters.

10.50 Average detriment is assessed at £1.4 billion a year over the period as a whole, with an upward trend, reaching almost £2 billion in 2015. Our view is that this may represent not simply a deterioration in competitive conditions over time but also an emerging revelation of the scale of detriment, as the larger Mid-tier Suppliers have begun to operate at scale and reposition their tariffs to be more competitive through the process of price discovery. Therefore we attach somewhat greater significance to the more recent results.

Robustness checks

10.51 In this section we present the results of analysis we have conducted to assess the robustness of our calculation of detriment to different levels of consumption and choice of benchmark. This analysis is relevant both to our overall calculation of detriment and to the design of the price cap that we have decided to introduce for prepayment customers¹³, which draws on the benchmark analysis we have conducted.

¹³ See Section 14.

Structure of benchmark bills and detriment at different levels of consumption

- 10.52 We have examined how our bills comparison, and consequently detriment, varies when evaluated at different levels of consumption. Different suppliers may have different average levels of consumption, depending on their respective customer bases, which may have an impact on how they structure their tariffs and therefore on bills comparison when assessed at different consumption levels.¹⁴
- 10.53 We have first compared the unit rates and standing charges between our benchmark suppliers and the Six Large Energy Firms. We have found, for example, that the benchmark suppliers' direct debit tariffs have on average both lower unit rates and lower standing charges than the standard credit and prepayment tariffs of the Six Large Energy Firms (see Table 2 of Annex A of Appendix 10.2), such that they will be cheaper, on average, than those tariffs over all levels of consumption. However, as noted at paragraph 10.36 above, we have adjusted bills for payment cost differentials by subtracting a fixed amount from the annual bill which is equivalent to a reduction in the standing charges of the Six Large Energy Firms. For example, in Q2 2015 the impact of this adjustment, on average across the Six Large Energy Firms, is to reduce their standing charges for gas (both single and dual fuel tariffs) by 41%, and for electricity in the range between 27% and 29%, depending on meter/fuel type (see Appendix 10.2 for more detail). This results in an adjusted standing charge, on average, for the Six Large Energy Firms at a level below the benchmark suppliers' standing charges for direct debit.
- 10.54 This implicit change in the standing charge for the Six Large Energy Firms as a result of the payment cost differential adjustment has a different impact on the bills comparison depending on the level of consumption considered. This is shown in Appendix 10.2 where we compare bills using Ofgem's Low and High TDCV. The results of this comparison are broadly similar to the results that we obtained using Ofgem's Medium TDCV reported in Tables 10.2 above. The exception is the single fuel electricity at low TDCV where standard credit bills for the Six Large Energy Firms are, on average, cheaper than the benchmark bill.
- 10.55 This effect will be more pronounced at lower levels of consumption (i.e. lower than Ofgem's Low TDCV). In particular, for very low levels of consumption, the competitive benchmark bills are higher than average

¹⁴ Tariffs comprise a standing charge and a unit rate, such that, in a comparison between two tariffs, one may be cheaper for a customer with low levels of consumption (typically those with a low standing charge) and the other cheaper for a customer with high levels of consumption (typically those with a low unit rate).

actual bills, adjusted for payment cost differentials. However, as far as detriment estimates are concerned, this simplified approach to adjusting for cost differentials does not have a significant effect on the computation of overall detriment in this section given that this analysis has been performed at actual median consumption. We note that it is relevant in our assessment of the impact of the PPM Price Cap Remedy, and in particular for the assessment of how much detriment will be reduced through the application of the price cap.

10.56 This is particularly the case for single fuel gas where the implicit reduction in the standing charge is greater than in the case of single fuel electricity (as illustrated at paragraph 10.53 above), and where the actual median consumption, which is used to calculate detriment, is materially lower than Ofgem's Medium TDCV, which is used in the calculation of the price cap.¹⁵

10.57 This is further discussed in Section 14.

Single fuel benchmarks

10.58 We have also considered whether our single fuel benchmarks are good proxies for the level of prices that we would expect to see for single fuel tariffs in a well-functioning market. This is because we have found that suppliers, including the Mid-tier Suppliers, primarily compete to acquire customers using their dual fuel tariffs. To a certain degree, whilst not as competitive a market segment as dual fuel tariffs, suppliers also compete for customers using single fuel electricity tariffs as there are sizeable numbers of households that are off the gas mains network (ie they only consume electricity). In contrast, there does not seem to be significant competition between suppliers to acquire customers using single fuel gas tariffs. For instance, we note that Ovo Energy, which is one of the two benchmark suppliers, does not actively sell single fuel gas tariffs, and any gas-only customers it has are those that initially signed up for dual fuel but then switched to another supplier for electricity while maintaining their gas account with Ovo Energy.

10.59 Table 10.4 below shows the number of direct debit accounts by fuel type for the benchmark suppliers (i.e. those that are used in the benchmarks) i.e. in Q2 2015.

¹⁵ For example, in Q2 2015 the actual median consumption for prepayment gas customers was, on average, around 65% of Ofgem's Medium TDCV, as compared to 96% for electricity customers on single rate electricity meters, and 84% for customers on E7 electricity meters.

Table 10.4: Number of direct debit accounts for the benchmark suppliers in Q2 2015

Fuel	First Utility		Ovo Energy	
	Number of accounts	as % of total	Number of accounts	as % of
Dual fuel	[redacted]	[redacted]	[redacted]	[redacted]
Electricity	[redacted]	[redacted]	[redacted]	[redacted]
Gas	[redacted]	[redacted]	[redacted]	[redacted]
Total	[redacted]	[redacted]	[redacted]	[redacted]

Source: CMA analysis.

10.60 Thus, [redacted] of First Utility’s and [redacted] of Ovo Energy’s direct debit accounts relate to single fuel gas accounts. Both suppliers have significantly more single fuel electricity than single fuel gas customers ([redacted] of Ovo Energy’s accounts and [redacted]% of First Utility’s accounts are single fuel electricity), which suggests that a material number of customers can be acquired using single fuel electricity tariffs, in contrast to single fuel gas.

10.61 We have assessed the extent to which our single fuel benchmarks may overstate the competitive price by comparing them with the gas and electricity components of our dual fuel benchmark.¹⁶ This analysis shows that our benchmark suppliers priced single fuel electricity fairly closely to how they price electricity in their dual fuel tariffs: for 2012–2015 the single fuel electricity benchmark was £5 more expensive than the electricity component of the dual fuel benchmark. This difference is more pronounced in the case of gas where the single fuel benchmark was £19 more expensive than the dual fuel equivalent over the period.¹⁷ This is consistent with our assessment above that single fuel tariffs, and gas in particular, are less competitive market segments than dual fuel.

10.62 This analysis suggests that our estimates of detriment for single fuels – and single fuel gas in particular - are conservative. We take this into account when assessing the impact of the price cap on prepayment customers in Section 14.

Conclusion

10.63 Overall, our detriment estimates appear to be fairly robust to changes in the standing charge of the Six Large Energy Firms on their prepayment and standard credit tariffs when assessed at different typical domestic consumption values (i.e. Low, Medium and High) which are industry

¹⁶ This comparison was conducted at Ofgem medium TDCV.

¹⁷ The difference in Q2 2015 was £18. As noted in Section 14, this value is of particular relevance for considering the appropriate level of stringency of the prepayment price cap.

standard values for the annual domestic gas and electricity used by a typical consumer.

- 10.64 However, we note that at very low levels of consumption, which are more prevalent in the single fuel gas segment, our simplified approach to adjusting for cost differentials results in competitive benchmark bills that are higher than average actual bills, adjusted for payment cost differentials.
- 10.65 We also note that our benchmark suppliers are not particularly active in marketing single fuel tariffs and have a relatively small number of customers on single fuel gas tariffs in particular. As a result, our single fuel gas benchmark provides a conservative estimate of detriment.
- 10.66 We consider both of those issues when setting the price cap in Section 14.

Parties' responses to the provisional decision on remedies

- 10.67 We consider here parties' high-level comments about the appropriateness of our approach while detailed points about data and methodology are addressed in Appendix 10.2.
- 10.68 Centrica submitted that our direct detriment methodology is closely related to the gains from switching analysis (relying on the same datasets and codes), which we have previously stated is not a valid measure of customer detriment because 'suppliers offering the cheapest tariffs may not find it sustainable to have a large proportion of customers switching to them ... because cheapest tariffs might be acquisition products or the cost to serve additional customers would be higher than that for the current customer base of the supplier.'¹⁸
- 10.69 We consider that this is a misinterpretation of our direct detriment methodology. As explained above, our benchmark includes all direct debit tariff types offered by Ovo and First Utility (and not only the cheapest tariffs in the market) weighted by the respective number of accounts within each of the benchmark suppliers. Therefore, our competitive benchmark reflects the benchmark suppliers' average prices rather than their cheapest tariffs adjusted appropriately to allow a 1.25% EBIT margin, ie a level of normal profits¹⁹ that we consider a large, efficient energy supplier in a steady state would generate in a well-functioning market.

¹⁸ Centrica response to provisional findings, A7.4 paragraph 3.

¹⁹ ie ensuring a return on capital employed in line with the WACC.

- 10.70 Centrica also submitted that our analysis suffered from a failure to compare 'like with like' in terms of products because customers are not indifferent about the characteristics of their tariff. In particular, it suggested that customers valued the lower volatility provided by an SVT and that SVT prices should not be benchmarked against products priced against different (shorter) hedging strategies that, with the benefit of hindsight, have been lower cost over the short period covered by the direct detriment analysis. A similar submission was made by SSE, which noted that the [CMA's] significant body of evidence demonstrated that, for many customers, quality of service also played an important role in determining the choice of supplier.
- 10.71 We do not find these to be plausible arguments. First, as noted in Section 9, we consider gas and electricity to be homogenous goods which means that the most important tariff characteristic for customers is likely to be the price. This view is supported by our customer survey, which suggests that price is, by far, the most important driver of choice of energy supplier. In relation to volatility, we note that 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.
- 10.72 A more comprehensive discussion as to why we do not believe that SVTs have beneficial non-price attributes is provided in Section 9.
- 10.73 As regards quality of service, the evidence set out in paragraphs 10.117 to 10.119 below suggests that the Six Large Energy Firms have been providing poor quality of service to their customers and that they feature unfavourably in various comparisons against small suppliers and Mid-tier Suppliers. Furthermore, we observe that energy suppliers which offer lower prices do not have lower Net Promoter Scores. This suggests that a quality adjusted price comparison would imply even higher overall detriment from the pricing of the Six Large Energy Firms than our approach.
- 10.74 SSE submitted that we have used an idealised perfectly competitive market as a standard against which to benchmark the market and that focusing on a genuinely realistic 'well-functioning' energy market as a benchmark, which was the appropriate legal standard, would substantially reduce the CMA's detriment estimate. We have based our benchmark on tariffs offered by two competitive Mid-tier Suppliers, Ovo Energy and First Utility, adjusted to allow a normal return on capital and to allow for exogenous cost differences. Unlike the Six Large Energy Firms, those two Mid-tier Suppliers have relatively few disengaged customers and we expect their pricing, together with the adjustments we have made, and their conduct more generally, to be in line with how firms behave in a well-functioning market.

- 10.75 Several parties²⁰ suggested that Ovo Energy and First Utility were currently focusing on rapidly growing their customer bases and were likely to be sacrificing profits in order to obtain a larger customer base on which they would be able to earn higher profits in the future, particularly as some of those customers would transfer onto the SVT. While we do not agree that the evidence supports this view of the Mid-tier Suppliers' strategy, we note that for the purpose of detriment analysis (and our prepayment price cap), we have made adjustments to our competitive benchmark prices to ensure that such prices would enable a large, efficient energy supplier in a steady state to earn an EBIT margin (of 1.25%), which would entail a return on capital employed in line with the cost of capital. We set out details of this analysis and the consequent adjustments to prices in Appendix 10.1.
- 10.76 Several suppliers challenged our choice of benchmark suppliers. Scottish Power argued that we should have included Co-operative Energy in our benchmark. The reasons for excluding Co-operative Energy from our benchmark suppliers are set out in paragraph 10.25 above. Scottish Power noted that, like Co-operative Energy, Ovo and First Utility were not fully subject to relevant environmental obligations for the duration of the benchmark period and hence that this is not a valid reason to exclude Co-op from our benchmark. On this specific point, we note that we have now adjusted Ovo's and First Utility's cost to reflect a situation in which these suppliers were fully obligated based on their average customer numbers in each year (see paragraph 10.28 above). Scottish Power also pointed out that the assertion that Co-operative Energy is not comparable due to dividends being paid to members is not valid because the amount of dividends payable is relatively small.²¹ We accept that in most cases the dividend effect is likely to be small, but it nonetheless introduces distortion into the comparison. Importantly, we note that there are other reasons for not including Co-operative Energy in our benchmark, namely that its customer base is unlikely to be as active and engaged as that of Ovo and First Utility, and that Co-operative Energy is considerably smaller than Ovo and First Utility and may not yet be operating at an efficient scale.
- 10.77 Utilita submitted that there are a large number of smaller suppliers and the Mid-tier Suppliers currently operating in the UK energy markets, many of which operate at, or close to, the 'efficiency frontier', and therefore ought to be included in our benchmark. We acknowledge that Utilita may be operating efficiently compared to the Six Large Energy Firms. However we note that Utilita operates almost exclusively in the prepayment segments

²⁰ See Appendix 10.1.

²¹ For somebody paying £80 per month on their dual fuel bill, annual dividend payment would amount to £4.32.

which renders it unsuitable to be included in our competitive benchmark. This is because the level of competition in the prepayment segments is significantly weaker than in the wider GB domestic retail markets, as shown by our analysis in Section 9. As a result there are no competitively priced tariffs in those segments (see our analysis of existing tariffs at paragraphs 8.283 to 8.292 in Section 8). This is the same reason as to why we did not include the prepayment tariffs of Ovo in our benchmark, which was also suggested by Utilita.

- 10.78 EDF carried out a sensitivity analysis of our benchmark tariffs by looking at alternative benchmarks, including one based on all four Mid-tier Suppliers, and one based on all suppliers. At paragraphs 10.13 and 10.20 to 10.27 above we set out the criteria which we used to identify suppliers to include in our calculation of the competitive benchmark tariffs, and we explain why those are met by Ovo and First Utility but not by any other supplier. In its submission, EDF did not provide any analysis suggesting that these criteria were wrong. It did not explain why the tariffs offered by the suppliers included in its alternative benchmarks (other than First Utility and Ovo) could be used for the identification of a competitive benchmark, and what adjustment would have been needed in that context. As a result, we have not given material weight to EDF's sensitivity analysis for the calculation of our competitive benchmark tariffs.
- 10.79 E.ON and Scottish Power submitted that, in constructing the competitive benchmark tariffs, we should have taken into consideration the difference in hedging strategies between Ovo and First Utility on the one hand, and the Six Large Energy Firms on the other. Scottish Power said that, because the Six Large Energy Firms typically hedge further ahead than Ovo and First Utility, the former face higher wholesale costs than the two Mid-tier Suppliers when wholesale costs are falling (as has been the case since 2013). We consider that any differences in energy costs arising from how any particular supplier has chosen to purchase energy does not provide a sound basis for adjusting a competitive benchmark. This is because in a well-functioning market, we would not expect those differences to influence retail prices materially.
- 10.80 RWE, E.ON and EDF submitted that our competitive benchmark should reflect a tariff type mix of the Six Large Energy Firms rather than Ovo and First Utility. We disagree. As explained above, one of the criteria for choosing our competitive benchmark is that it should be reflective of the prices charged to active/engaged customers. We have established that a large proportion of customers of the Six Large Energy Firms are on an SVT tariff, which is a default tariff (an average of 71% for electricity and 69% for gas in 2015), and that many of those customers (around 55%) have been on

that tariff with the same supplier for more than three years (see Section 8). If we were to adopt the tariff structure of the Six Large Energy Firms, our benchmark would cease to be a good proxy for a price that we would expect to see in a well-functioning market.

Analysis of detriment for customers on restricted meters

- 10.81 Customers on restricted meters are not included in our estimates of detriment above. In particular, the 'direct' analysis above is based on a data set that includes only customers with unrestricted and Economy 7 meters. The detriment suffered by customers on restricted meters is not therefore captured in the results reported above in Table 10.3 and paragraph 10.50.
- 10.82 We have estimated the detriment suffered by customers on restricted meters using a higher level approach, and based on snapshots at two points in time, end Q2 2015 and end Q2 2014. Our approach consists of comparing the bills paid by these customers with those that they would have paid had they been on the cheapest available single-rate direct debt tariff, adjusted for payment method.²² This analysis is based on tariffs in the market and estimated annual consumption by meter as at each point in time. For further details of the data we used and the methodology applied see Appendix 9.5.
- 10.83 Our approach to estimating detriment has, therefore, been to use competitively priced single-rate direct debit tariffs in the market as a proxy for competitive prices for customers on restricted meters. For customers paying by credit or prepayment this benchmark tariff is adjusted upwards to allow for higher indirect costs of serving these customers. The figures used are those set out in Appendix 9.8.
- 10.84 We note that a different competitive benchmark has been used to estimate detriment for customers on restricted meters when compared to the benchmark used to assess detriment for customers with single-rate and Economy 7 meters. In particular, the competitive benchmark used for customers on single-rate and Economy 7 meters is based on all direct debit tariffs offered by First Utility and Ovo Energy, adjusted as outlined above (see paragraph 3.170 and Appendix 10.2) whereas for customers on restricted meters we have used the cheapest single-rate meter tariff available in the markets.²³ We consider this to be a reasonable approach for customers on restricted meters as we would expect, for the reasons set out in Appendix 9.5, the wholesale energy cost per kWh incurred by suppliers in supplying customers on restricted meters to be materially lower than for

²² Note that bills were calculated exclusive of VAT.

²³ For more details see Appendix 9.5, Annex B.

customers on standard meters. In a well-functioning market we would expect these cost differences to be reflected in the prices of tariffs offered to customers on restricted meters. We would therefore expect tariffs available to customers on restricted meters to be cheaper than those available to single-rate meter customers (even if we would not expect bespoke tariffs for different meter types). For this reason, we consider the cheapest single-rate tariffs in the market provide a reasonable basis for estimating detriment.

- 10.85 For Q2 2015 the results of our analysis show that for around 68% of customers on restricted meters, their bills were higher than they would have been using the competitive single-rate tariff. On average the difference was around £158 per customer or 17% of their average annual bill.²⁴ This shows a detriment in the order of £42 million a year.
- 10.86 For Q2 2014 the results of our analysis show that for around 51% of customers on restricted meters, their bills were higher than they would have been using the competitive single-rate tariff. On average the difference was around £123 per customer or 14% of their average annual bill.²⁵ This shows a detriment in the order of £28 million a year.
- 10.87 We note that in both periods the level of detriment is material. Further, the increase in the total level of detriment over time reflects wider trends seen in the market where the estimated detriment has increased over time, see Table 10.3 above and Appendix 10.2.
- 10.88 Table 10.5 sets out these detriment results by supplier. We note that differences between suppliers in the aggregate level of detriment will, in part, reflect differences in the size of their customer base and the type of restricted meter they support. Our key results are as follows:

(a) [REDACTED]

(b) [REDACTED]

(c) [REDACTED]

(d) [REDACTED]

(e) [REDACTED]

²⁴ Note that bills were calculated exclusive of VAT.

²⁵ Note that bills were calculated exclusive of VAT.

Table 10.5: Mean difference between single-rate bill and the current bill for those where the single-rate bill is lower, difference between single-rate bill and current bill as a percentage of current bill for those where the single-rate bill is lower, by supplier

	Q2 2015			Q2 2014		
	<i>Percentage where single-rate bill is lower</i>	<i>Mean bill difference*</i>	<i>Bill difference as a percentage of restricted bill*</i>	<i>Percentage where single-rate bill is lower</i>	<i>Mean bill difference*</i>	<i>Bill difference as a percentage of restricted bill*</i>
Centrica	[X]	[X]	[X]	[X]	[X]	[X]
EDF Energy	[X]	[X]	[X]	[X]	[X]	[X]
E.ON	[X]	[X]	[X]	[X]	[X]	[X]
RWE npower	[X]	[X]	[X]	[X]	[X]	[X]
Scottish Power	[X]	[X]	[X]	[X]	[X]	[X]
SSE	[X]	[X]	[X]	[X]	[X]	[X]

Source: CMA analysis of the Six Large Energy Firms' data.

*There were some observations where customers could have made extremely large savings and these results were skewing the mean savings. Therefore when calculating the mean saving we excluded observations where the savings were over £500. In Q2 2015 this led to the exclusion of 4% of observations and the highest saving observed was £2,209. In Q2 2014 this led to the exclusion of 1% of the observations and the highest saving observed was £3,193.

Note: Bills were calculated exclusive of VAT.

10.89 Further details of our approach to estimating detriment and further results are set out in Appendix 9.5.

10.90 We note that several suppliers provided comments on the calculation of the detriment for restricted meters. We consider these points in detail in Appendix 9.5. We have concluded that none of these comments undermine our calculation of detriment.

Indirect approach

10.91 The indirect approach allows us to estimate from the financial results of the Six Large Energy Firms the approximate level of prices that we might expect in a well-functioning market and therefore the extent to which there has been (price) detriment to customers over the 2007 to 2014 period. We carried out two separate types of analysis in order to estimate the level of (price) detriment to domestic and SME customers under the indirect method.

10.92 The first analysis sought to identify the level of profits in excess of the cost of capital earned by the Six Large Energy Firms over the period 2007 to 2014 by customer and fuel type. In order to do this, we have estimated the level of capital employed by the Six Large Energy Firms (by customer and fuel type). As set out in Appendix 9.10, we have sought to take a reasonable approach to each of the various assumptions we have made in conducting our analysis.

10.93 The results of this analysis are set out in Table 10.6.

Table 10.6: Profits in excess of the cost of capital/losses for the Six Large Energy Firms by customer and fuel, 2007 to 2014

Profits in excess of the cost of capital/(losses)	[REDACTED]						£m	%	
	[REDACTED]	[REDACTED]	[REDACTED]	[REDACTED]	[REDACTED]	[REDACTED]	Total	Average per year	
Domestic electricity	[REDACTED]	[REDACTED]	[REDACTED]	[REDACTED]	[REDACTED]	[REDACTED]	1,286	161	28
Domestic gas	[REDACTED]	[REDACTED]	[REDACTED]	[REDACTED]	[REDACTED]	[REDACTED]	1,133	142	25
SME electricity	[REDACTED]	[REDACTED]	[REDACTED]	[REDACTED]	[REDACTED]	[REDACTED]	1,391	174	31
SME gas	[REDACTED]	[REDACTED]	[REDACTED]	[REDACTED]	[REDACTED]	[REDACTED]	366	46	8
Domestic & SME total	[REDACTED]	[REDACTED]	[REDACTED]	[REDACTED]	[REDACTED]	[REDACTED]	4175	522	92
I&C	[REDACTED]	[REDACTED]	[REDACTED]	[REDACTED]	[REDACTED]	[REDACTED]	351	44	8
Total	[REDACTED]	[REDACTED]	[REDACTED]	[REDACTED]	[REDACTED]	[REDACTED]	4,526	566	100

Source: CMA analysis.

- 10.94 This analysis shows that the large majority of the Six Large Energy Firms' profits in excess of the cost of capital are earned from domestic and SME customers, with less than 10% being earned on I&C customers. The average profits in excess of the cost of capital earned on domestic customers across the Six Large Energy Firms as a whole were around £300 million a year, compared with around £220 million a year on SMEs. However, there are significant differences in the level of profits in excess of the cost of capital earned by the Six Large Energy Firms, with Centrica [REDACTED] on its domestic and SME customers, while EDF Energy [REDACTED].
- 10.95 We note that the level of profits in excess of the cost of capital earned on domestic customers was significantly higher from 2009/10 onwards, than in 2007 and 2008, when the industry made economic losses overall (ie profits which were less than the firms' cost of capital). If we consider the period from 2010 to 2014, the average level of profits in excess of the cost of capital earned on domestic customers was £560 million per year. In the last three years of the relevant period, ie between 2012 and 2014, which corresponds more closely to the period over which we have estimated detriment using the direct approach, the profits in excess of the cost of capital earned on domestic customers increased to around £650 million per year. Full details of this analysis are set out in Appendix 9.10.
- 10.96 This variation in the level of profits in excess of the cost of capital could be due to differences in the prices charged by the Six Large Energy Firms, differences in the efficiency with which the firms operate (ie some may have higher costs and/or capital employed than others), and/or differences in the level of wholesale energy costs incurred.
- 10.97 The second piece of analysis we undertook was to compare the indirect cost bases of the Six Large Energy Firms in serving their domestic customers over the 2007 to 2014 period in order to control for potential differences in (overhead) cost efficiency. We estimated the level of costs per customer

account across the Six Large Energy Firms and then benchmarked these across the Six Large Energy Firms. Our base case benchmark used the lower quartile of the Six Large Energy Firms' indirect costs per customer account. As a sensitivity we also estimated the Six Large Energy Firms' cost bases using the lowest cost supplier, [REDACTED], as the benchmark.

10.98 We consider our analysis to be conservative for two main reasons:

- (a) First, we have only benchmarked the Six Large Energy Firms against one another, which assumes that one or more of them is operating efficiently. It is, however, possible that all of the Six Large Energy Firms have inefficient cost bases, in which case our estimates of inefficiency will be understated. For example, we observe that, as of 2014 Ovo Energy and First Utility had lower indirect costs per customer account than all of the Six Large Energy Firms except [REDACTED]. This was in spite of their (self-reported) inability to benefit fully from the economies of scale available to larger operators.
- (b) Second, we observe that, in spite of [REDACTED] indirect cost base is below the lower quartile level that we have used as our benchmark. This suggests that a benchmark that controlled for such 'legitimate' cost differences (ie those arising from customer mix) would be likely to be below our lower quartile benchmark.

10.99 The results of this analysis are set out in Table 10.7.

Table 10.7: Estimates of indirect cost inefficiencies by fuel for the Six Large Energy Firms, domestic customers

FY 2007–2014	<i>Domestic electricity</i>	<i>Domestic gas</i>	<i>Total</i>
Combined Six Large Energy Firms' outturn indirect costs	14,644	13,445	
Restated using lower quartile	13,060	12,682	
Variance	1,584	763	2,347
Restated using [REDACTED]	10,755	10,535	
Variance	3,889	2,910	6,799
Lower quartile variance by supplier:			
Centrica	[REDACTED]	[REDACTED]	[REDACTED]
RWE npower	[REDACTED]	[REDACTED]	[REDACTED]
EDF Energy	[REDACTED]	[REDACTED]	[REDACTED]
SSE	[REDACTED]	[REDACTED]	[REDACTED]
E.ON	[REDACTED]	[REDACTED]	[REDACTED]
Scottish Power	[REDACTED]	[REDACTED]	[REDACTED]
TOTAL	1,584	763	2,347
[REDACTED] Variance by supplier:			
Centrica	[REDACTED]	[REDACTED]	[REDACTED]
RWE npower	[REDACTED]	[REDACTED]	[REDACTED]
EDF Energy	[REDACTED]	[REDACTED]	[REDACTED]
SSE	[REDACTED]	[REDACTED]	[REDACTED]
E.ON	[REDACTED]	[REDACTED]	[REDACTED]
Scottish Power	[REDACTED]	[REDACTED]	[REDACTED]
Total	3,889	2,910	6,799

Source: CMA analysis.

10.100 The base case comparison shows that the Six Large Energy Firms' indirect cost bases (as a whole) were £2.3 billion above the benchmark over the period (or £290 million per year). If the results of [REDACTED] are excluded, this increases to £3.3 billion over the eight-year period, or approximately £420 million a year. As set out in Appendix 9.11, several parties stated that we should deduct the outperformance of [REDACTED] against the efficiency benchmark, from our estimate of total detriment, ie use the £290 million figure rather than the £420 million figure for inefficiency. However, as set out in paragraph 10.98(b), the evidence did not indicate that these firms [REDACTED] were particularly efficient when compared with the Mid-tier Suppliers. Therefore, we continue to exclude their outperformance in our base case estimates. However, we recognise that there is some uncertainty as to the overall efficient level of costs. Therefore, we have also considered a sensitivity under which this outperformance in terms of efficiency is included in the total figure, ie using a total inefficiency of £290 million.

10.101 If the benchmark were set at the level of [REDACTED] indirect costs, the level of estimated inefficiency would increase to £6.8 billion over the period (or

around £850 million a year).²⁶ This benchmark gives an estimated level of inefficiency for [redacted] (see Appendix 9.11).

10.102 In order to estimate the (price) detriment to domestic customers over the 2007 to 2014 period, we combined the results of these two pieces of analysis, as set out in Table 10.8. We increased the level of profits in excess of the cost of capital earned by our measure of the inefficiency of each firm. The table shows the results using zero 'inefficiency' for [redacted], ie total inefficiency of £420 million.

Table 10.8: Estimate of customer detriment for the Six Large Energy Firms by customer and fuel type, 2007 to 2014

Profits in excess of the cost of capital/(losses) plus domestic cost inefficiency							£m	
	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	Total	Average per year
Domestic electricity	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	3,409	426
Domestic gas	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	2,355	294
Total	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	5,764	721
SME electricity	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	1,391	174
SME gas	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	366	46
Total	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	1,757	220
Domestic & SME total	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	7,522	940

Source: CMA analysis.

10.103 This analysis gives a total estimate of domestic customer detriment of around £720 million a year over the 2007 to 2014 period using the lower quartile efficiency benchmark (which we consider to be conservative). The estimate of domestic customer detriment decreases to £590 million if [redacted] outperformance against the efficiency benchmark is deducted from overall detriment.

10.104 Over the last three years of the period, our detriment figure increases to £1.1 billion (adding together profits in excess of the cost of capital of £650 million and measured inefficiencies of £420 million). If we were to use the lowest cost firm as our benchmark, our measure of detriment would increase further to £1.5 billion.

10.105 Although this analysis seeks to control for differences in the indirect cost bases of the Six Large Energy Firms, it suggests that there are significant

²⁶ We have not used this lower benchmark as our base case as we note that there are differences in the mix of customers across the Six Large Energy Firms, with Centrica having a higher proportion of customers who are more expensive to serve (eg prepayment and standard credit customers). As a result, we might expect Centrica to have a higher cost base than SSE (and the other of the Six Large Energy Firms), without this indicating that Centrica has been inefficient.

differences across the firms in terms of the level of (price) detriment, with [redacted] continuing to account for a large proportion of total detriment and [redacted].

10.106 The evidence on wholesale energy costs indicates that this is an important source of differences in profitability across the Six Large Energy Firms. Table 10.9 sets out the average wholesale electricity costs incurred by the Six Large Energy Firms in each year over the period, while Table 10.10 sets out wholesale gas costs.

Table 10.9: Wholesale electricity costs for the Six Large Energy Firms (£/MWh)

<i>Six Large Energy Firms</i>	2007	2008	2009	2010	2011	2012	2013	2014	8YP Avg
Centrica	[redacted]								
E.ON	[redacted]								
EDF Energy	[redacted]								
RWE	[redacted]								
Scottish Power	[redacted]								
SSE	[redacted]								
Average	47	61	61	60	63	62	61	61	59

Source: CMA analysis.

Table 10.10: Wholesale gas costs for the Six Large Energy Firms (£/MWh)

<i>Six Large Energy Firms</i>	2007	2008	2009	2010	2011	2012	2013	2014	8YP Avg
Centrica	[redacted]								
E.ON	[redacted]								
EDF Energy	[redacted]								
RWE	[redacted]								
Scottish Power	[redacted]								
SSE	[redacted]								
Average	17	21	22	19	20	23	25	24	22

Source: CMA analysis.

10.107 These tables show significant differences, ie around 10%, in the period average electricity and gas wholesale costs incurred by the Six Large Energy Firms over the eight-year period of review. These differences will have a substantial impact on the relative profitability of the Six Large Energy Firms. For example, if [redacted] had incurred the same average wholesale cost of electricity as [redacted] over the period, its profits on domestic and SME customers (alone) would have been around £[redacted] a year higher. We have not included an estimate of the impact of differences in wholesale energy costs in our indirect estimate of detriment.

Overall conclusion on excessive prices for domestic customers

10.108 We observe that there are some differences in the level of domestic customer detriment that we have calculated under the direct and indirect approaches. In this section, we consider the potential reasons for the differences observed and draw overall conclusions.

10.109 While, in theory, the results generated from each approach should be the same – as they both seek to provide an estimate of customer detriment – in

practice, we observe differences between the estimates of price detriment generated under each. The direct approach indicates that domestic customers may have paid around £1.4 billion a year more than could have been expected in a well-functioning market over the period 2012 to 2015, compared with our base case estimate of around £720 million a year under the indirect approach over the period 2007 to 2014.

- 10.110 There are a number of potential reasons for the difference. First, the analyses have been carried out over different time periods, with the indirect approach providing an annual average over the eight-year period from 2007 to 2014, while the direct approach has used data from 2012 to 2015. The ROCE analysis shows that several of the Six Large Energy Firms made returns below the cost of capital in 2007 and 2008, and returns in excess of the cost of capital thereafter. As a result, the estimate of customer detriment from the indirect approach is higher if a shorter period of time is used. In particular, for the period 2012 to 2014, (which allows for a like-for-like comparison) the indirect approach yields an estimate of detriment of £1.1 billion a year under the base case compared with £1.2 billion a year for the direct approach for this same period. We note that these figures are of a similar scale.
- 10.111 Second, the indirect approach uses the historic cost of wholesale energy purchases incurred by the Six Large Energy Firms, rather than making adjustments to reflect the 'opportunity cost' of such purchases, ie the market price of energy at the point where prices are agreed. We note that, in well-functioning retail energy markets, we would expect prices to customers be set on the basis of the opportunity cost of supply rather than the historical incurred cost.
- 10.112 Therefore, we find that our direct and indirect approaches, when compared on a like-for-like basis, provide similar estimates of the level of detriment to domestic customers in GB energy retail markets arising from the AECs we have found in the domestic retail energy markets. The fact that these two approaches, which are based on different data sets and methodologies, provide similar estimates, gives us confidence that our overall conclusions on the level of detriment are robust.
- 10.113 While our two estimates of detriment are similar, we place greater weight on the results produced using the direct method. As noted above, it has several advantages over the indirect approach, the principal of which is that it gives us a direct measure of customer detriment – prices are ultimately what matter to a customer, rather than a supplier's level of profitability or cost efficiency. Further, the direct approach allows for a much more granular

breakdown of detriment, not just by supplier but by customer type, including type of tariff and payment method.

- 10.114 We note also that detriment calculated under the direct approach is similar to the net profits earned by the Six Large Energy Firms from their sales to domestic customers from 2012 to 2014, but significantly higher than our estimate of excess profits from domestic sales over this period. The implication is that there is a material degree of inefficiency in current prices.²⁷
- 10.115 Using this approach, the detriment we have calculated for domestic customers is substantial – around £1.4 billion a year over the period we assessed and more in 2015. We note that there is a marked variation in the level of detriment suffered by customers of each of the Six Large Energy Firms and that prepayment customers generally suffer more detriment than those who pay by direct debit or standard credit.
- 10.116 We have drawn on this analysis in developing our remedies and, in particular, in assessing the effectiveness and proportionality of the package of remedies as a whole.

Non-price sources of detriment

Poorer quality of service

- 10.117 In the provisional findings report we set out a range of evidence that showed that the quality of service offered to domestic energy customers has been relatively poor in recent years:
- (a) results of suppliers' own customer research on Net Promotor Scores (see Section 8);
 - (b) statistics on trends in the number of complaints and the reasons for the complaints; and
 - (c) Ofgem enforcement activity where suppliers have been found to be in breach of licence conditions in their dealings with domestic customers.
- 10.118 We also note that, according to a survey conducted in October 2015 by Which? into customer satisfaction across the energy sector, all of the Six Large Energy Firms were in the bottom half of the table and two of them

²⁷ ie, if prices were to decline to the competitive level, the Six Large Energy Firms would need to reduce their cost bases substantially in order to make profits in line with their cost of capital.

came last of the 22 energy companies included in the survey. We also note three of the Mid-tier Suppliers were in the top half including both Ovo Energy and First Utility.²⁸

10.119 We recognise that there are difficulties in interpreting this information as we do not have benchmarks for what we might expect in a well-functioning market. Nevertheless our view remains that there is evidence of the Six Large Energy Firms providing poor quality of service, albeit with some recent indication of an improvement. In particular:

- (a) We have found that the smaller suppliers have achieved consistently higher net promoter scores than the Six Large Energy Firms (see Section 8).
- (b) Across the Six Large Energy Firms the number of recorded complaints increased nearly sixfold from 2008 to 2014 and then fell by 20% in 2015 with problems related to billing, customer service and payment accounting for the majority of complaints (see paragraph 2.166 in Section 6).
- (c) Since 2010 Ofgem has taken enforcement action against at least one of the Six Large Energy Firms for breach of standard licence conditions in their dealings with customers on 16 occasions, resulting in fines and customer redress totalling £90 million. The most common breaches of supply licence conditions have historically related to mis-selling and complaints handling.

Innovation

10.120 As above, it is difficult to determine the scale of detriment arising from a lack of innovation as we do not have a benchmark against which to compare the recent performance of the Six Large Energy Firms.

10.121 We note that we have seen a limited degree of innovation in the retail domestic energy markets in recent years. Examples include:

- (a) The Six Large Energy Firms and smaller suppliers offering domestic customers lower prices to manage their energy supply in ways that reduce costs to serve. Some examples of such behaviour are paying by direct debit, signing up to tariffs online, and giving meter readings on line.

²⁸ A summary of results is available on the [Which? website](#).

(b) The Six Large Energy Firms and smaller suppliers offering products supported by smart meters. Some examples are British Gas's Hive product which allows heating and hot water to be controlled remotely; and the recently launched E.ON and Ovo Energy pay-as-you-go prepayment products.

10.122 We have found that some regulatory interventions have served to reduce innovation in recent years. For example, the recent RMR rules imposed by Ofgem have resulted in the withdrawal of innovative tariffs and discounts and have curtailed the ability of the Six Large Energy Firms to offer attractive tariffs to low volume users. Further, the absence of settlement systems that expose suppliers to the full costs of their customers' consumption has inhibited the development of time-of-use tariffs, which could bring substantial benefits in terms of reduced costs, as discussed in Sections 9 and 12.

10.123 We would expect our remedies to promote competition in the retention and acquisition of domestic customers and encourage retail energy suppliers to be more innovative in both the products and services they offer to their customers and in managing their retail activities so that they can offer cheaper prices and better quality of service.

Overall conclusion on detriment

10.124 In this section we set out the evidence on the extent of customer detriment arising from the AECs that we have identified in the domestic retail energy markets. We have considered three potential sources of detriment:

- (a) that domestic energy customers are, on average, paying higher prices than they would do in well-functioning markets;
- (b) that domestic energy customers receive a poorer quality of service than they would do in well-functioning markets; and
- (c) that suppliers innovate less in products and services than they would do in well-functioning markets, resulting in a more restricted range of products and services for domestic customers.

10.125 We have quantified the detriment from higher prices directly by comparing the average prices charged by the Six Large Energy Firms with the prices charged by two of the most competitive and readily comparable of the Mid-tier Suppliers – Ovo Energy and First Utility – while making adjustments for scale effects and profitability, and controlling for exogenous cost differences, to ensure the comparison is on a broad like-for-like basis. Using this approach, we have estimated the detriment from excessive prices to be

about £1.4 billion a year on average over 2012 to 2015 (the entire period for which we had data).

- 10.126 We consider that this figure is a conservative estimate of the total detriment suffered by GB customers because our data set does not include all customer accounts, and our benchmark for single fuel accounts – particularly single fuel gas – is conservative. Further, we have not been able to capture all of the detriment suffered by the customers in our dataset, including detriment from a reduction in consumption to due to prices being set above the competitive level (see paragraph 10.47 above).
- 10.127 We have also considered the extent to which the scale of excessive pricing by the Six Large Energy Firms varies between different payment methods. For dual fuel customers (the majority of all the customers of the Six Large Energy Firms) and single fuel electricity customers (31% of their electricity customers), we found that the difference between the average price across all of the Six Large Energy Firms and the benchmark is biggest for prepayment customers (12% for dual fuel and 11% for single fuel electricity) followed by direct debit customers (8% for dual fuel and 6% for single fuel electricity) and then standard credit customers (7% for dual fuel and 5% for single fuel electricity). For single fuel gas customers (19% of their gas customers), the difference between payment methods is somewhat smaller than in the case of dual fuel and single fuel electricity (16% for direct debit and 13% for both prepayment and standard credit).
- 10.128 The ‘direct’ analysis above is based on a data set that includes only customers with unrestricted or Economy 7 meters. We have estimated the detriment suffered by customers on restricted meters using a higher level approach, and based on snapshots at two points in time, end Q2 2015 and end Q2 2014. The results of our analysis show that for around 68% of customers on restricted meters in Q2 2015, and 51% in Q2 2014, their bills were higher than they would have been using the most competitive single-rate tariff. On average the difference was around £158 per customer in Q2 2015 (or 17% of their average annual bill), and around £123 per customer (or 14% of their average annual bill). This amounts to a detriment in the order of £43 million a year in Q2 2015 and £28 million in Q2 2014. This change in detriment between 2014 and 2015 is consistent with the observed trend of an increasing detriment over time for unrestricted and Economy 7 meters.
- 10.129 We have also estimated customer detriment from excessive prices indirectly from the financial results of the Six Large Energy Firms which involved assessing both suppliers’ levels of profitability and the extent to which suppliers have incurred costs inefficiently. For the reasons explained in

paragraph 10.113 above, we place greater weight on the results produced using the direct method, but consider the indirect approach as a useful independent cross check as it is based on a separate data set and methodology.

- 10.130 The analysis using the indirect approach yields a total estimate of customer detriment from excessive prices over the period between 2007 and 2014 of £720 million a year under the base case. Over the period between 2012 and 2014, which corresponds more closely to the period for which we have estimated detriment using the direct approach, the indirect approach yields an estimate of detriment of £1.1 billion a year. We note that this is similar to the detriment estimated under the direct approach.
- 10.131 In relation to quality of service, we have observed that there are various metrics which suggest that energy customers receive a poorer quality of service from the Six Large Energy Firms than they would do in well-functioning markets. Those include the data which shows that the smaller suppliers have achieved consistently higher net promoter scores than the Six Large Energy Firms, and that there was a marked increase in recorded customer complaints between 2008 and 2014 which resulted in a number of enforcement actions by Ofgem against the Six Large Energy Firms.
- 10.132 We have also found that some regulatory interventions, in particular the recent RMR rules, have served to reduce innovation in recent years, and that the current status of the electricity settlement system has inhibited the development of time-of-use tariffs which could bring substantial benefits in terms of reduced costs, as discussed in Sections 9 and 12.
- 10.133 Overall, we consider that our updated analysis supports our finding of material customer detriment arising from the AECs that we have identified in the domestic retail energy markets. We have estimated that the customer detriment associated with high prices was approximately £1.4 billion a year on average for the period 2012 to 2015 with an upwards trend. We have also found evidence that is indicative of harm to customers from poor quality of service and restrictions on innovation. However, we note that by its nature this type of harm is less readily quantifiable.

11. Domestic retail remedies: overview of remedies package

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11.1 As set out in Section 9, we have identified five AECs affecting the domestic retail energy markets – the Domestic Weak Customer Response AEC, the Prepayment AEC, and three AECs relating to the regulatory framework, namely, the systems of electricity and gas settlement (the Settlement AECs)¹ and aspects of the ‘simpler choices’ component of the RMR reforms (the RMR AEC). We estimate that the detriment arising from these AECs is very substantial – at around £1.4 billion per year over the last three and a half years for the Domestic AECs.²

11.2 In this section we set out a wide-ranging package of remedies to address the features contributing to these AECs, based on the principles of creating a framework for effective competition and helping customers to engage. We

¹ The Settlement AECs concern the SME retail energy markets as well as the domestic retail energy markets.

² The Domestic Weak Customer Response AEC, the Prepayment AEC and the RMR AEC.

believe that, as a whole, the package of remedies represents an effective and proportionate response to these AECs and will substantially reduce detriment in the long term.

11.3 However, we note that the remedies will take some time to implement and fully address the detriment in particular with respect to prepayment customers and, therefore, for the reasons set out below, we have concluded that there is a need for a remedy to reduce detriment directly during this transitional period, through the introduction of a price cap for customers on prepayment meters. Prepayment customers have suffered particularly high levels of detriment as a result of the Domestic AECs and would continue to do so in the short term in the absence of this intervention.

11.4 At a high level, then, our package of remedies for domestic customers comprises three strategic components:

(a) creating a framework for effective competition (see Section 12);

(b) helping customers to engage to exploit the benefits of competition (see Section 13); and

(c) protecting customers who are less able to engage to exploit the benefits of competition (see Section 14).

11.5 We believe that competition is at its most effective when companies are free to compete within an efficient regulatory framework and when customers are appropriately engaged – that is, informed about the choices available to them and free to exercise choice without undue restrictions. There is, therefore, a close synergy between the first two strategic components of our remedies package. We are also aware that there are potential tensions between the third component and the first two – controlling outcomes directly through regulatory interventions can be necessary where customer detriment is high, but runs the risk of undermining the positive customer outcomes to which effective competition can lead. In this section we set out the synergies between different elements of the remedies package and explain how we have managed potential tensions.

11.6 In the rest of this section we:

(a) highlight the key importance of the roll-out of smart meters and its implications for the AECs we have identified and the remedies we are adopting;

(b) summarise our remedies designed to help create a framework for effective competition;

- (c) summarise our remedies designed to help customers engage;
- (d) summarise our remedy to reduce detriment directly during the transitional period, by imposing a cap on the prices paid by prepayment customers;
- (e) assess the interrelationship between the different components of the package; set out the timescales over which we would expect our remedies package to have an impact on the AECs, the features we have identified and to reduce the associated customer detriment; and
- (f) set out the expected benefits of our remedies package, comparing them to the costs.

11.7 In Sections 12 to 14 we present a more detailed assessment of our individual remedies, before considering the overall effectiveness and proportionality of the package of remedies addressing the AECs and associated detriment in Section 15. A full, comprehensive list of all remedies is presented in Section 20.

The importance of metering arrangements and the smart meter roll-out

11.8 Metering is an essential part of well-functioning, competitive domestic retail energy markets. Because gas and electricity are consumed in real time, while billing and payment take place at periodic intervals, reliable and accurate meters play a vital role in determining exactly how much energy customers have consumed – and therefore how much they must pay suppliers.

11.9 We have found that current metering arrangements have contributed to several of the problems we have identified on both the supply side and the demand side of the domestic retail energy markets. We note that smart meters, which are currently being rolled out, have the potential to address some of these problems. In this section, we consider the potential impact of smart meters, present our views on the importance of current timescales for the roll-out of smart meters being adhered to, and explain how our remedies will help ensure that the full benefits of the smart meter programme are realised in practice.

The impact of metering arrangements on the AECs and features

11.10 Several of the problems that we have identified as affecting competition for domestic customers relate to the metering arrangements that customers have in place. Section 9 above highlights the particular technical constraints

affecting suppliers to prepayment meter customers and customers on restricted meters, for example.

11.11 Further, in Section 9 we identified traditional meters and bills as a fundamental characteristic of the energy markets underpinning one of the features contributing to the Domestic Weak Customer Response AEC, as they give rise to inaccurate and confusing information for customers which dissuades them from engaging. We considered that this at least partly explains why we see such a significant proportion of domestic customers who are not engaged:

- (a) First, 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.³
- (b) 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.⁴
- (c) Overall, we found that 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.

The impact of smart meters on competition and engagement

11.12 The introduction of smart meters will address the technical constraints arising from the dumb prepayment infrastructure. Notably, the problems arising from tariff slots, and their allocation between suppliers, will cease to exist.

11.13 We also consider that smart meters should address the specific barriers to engagement experienced by customers on restricted meters, although we note that smart meter equivalents are not currently available for all restricted meter types such that the roll-out of smart meters for customers on those restricted meters is likely to be delayed.

11.14 In relation to customer engagement more generally, in view of the fundamental characteristic identified above relating to traditional meters, we consider it likely that smart meters will help improve customer engagement

³ See Section 9.

⁴ See Section 9.

by making the relationship between prices and consumption more visible and improving the accuracy of bills, although the extent of this effect remains uncertain.

- 11.15 There is limited evidence on the impact of smart meters on engagement in the domestic retail energy markets – and our review of the international experience of smart meter roll-out (see Appendix 8.5) did not identify any studies that have specifically addressed this question.
- 11.16 However, we are aware of recent evidence concerning customers in Great Britain that suggests that smart meters may improve customer understanding of bills and confidence in choosing the right tariff and supplier. The ‘Smart energy outlook’ survey conducted in February 2016 found that, compared to those without a smart meter, customers with a smart meter were more likely to:
- (a) understand their energy bills (75% compared to 61%);
 - (b) think they have the information they need to choose the right energy supplier (77% as opposed to 59%); and
 - (c) think they have the information they need to choose the right tariff (72% as opposed to 57%).
- 11.17 In addition, the specification for fully interoperable (SMETS 2) smart meters has been designed such that the meters can communicate with any supplier via the data and communications company (the DCC). This enhanced interoperability will facilitate suppliers’ ability to acquire customers and customers’ ability to switch to alternative tariffs, including for prepayment customers looking to switch to a standard credit or direct debit tariff.
- 11.18 We therefore think that fully functional smart meters are likely to have a substantial, positive impact on both competition and engagement, although we note that the extent of impact on engagement is more uncertain.
- 11.19 However, we also note that the current generation of SMETS 1 smart meters have the considerable disadvantage of potentially losing smart functionality when the customer switches supplier, which may have the effect of discouraging switching. Further, we understand that some prepayment customers with SMETS 1 meters may be unable to use the prepayment setting on their meter if they switch supplier. As a result, such customers may have to change their meter in order to switch supplier.
- 11.20 While we note that some suppliers have established bilateral agreements by which degrees of functionality can be preserved if customers on smart

meters switch between them,⁵ the risk of loss of functionality emphasises the importance of a timely roll-out of the new generation of SMETS 2 smart meters, which will be fully interoperable between suppliers. We consider the timetable for this roll-out below.

The roll-out programme and timetable

11.21 The timetable for the roll-out of smart meters is as follows:⁶

- (a) The Data Communications Company is due to go live on 17 August 2016. DECC considers that suppliers will be able to start installing SMETS 2 (fully interoperable) meters from this date.
- (b) SMETS 1 meters that are installed until 28 October 2017 (the ‘SMETS 1 end date’ – 12 months after the Data Communications Company provides the Release 1.3 functionality) will count towards suppliers’ smart meter roll-out targets; beyond this point they will not.⁷ As a result, it is unlikely that suppliers would install further SMETS 1 meters beyond this date. As noted above, a customer with a SMETS1 meter may lose smart services when they switch supplier.
- (c) We understand that suppliers will be able to ‘enrol’ some SMETS 1 meters into the Data Communications Company at some point in the future, but that this is unlikely to be possible before 2018.⁸ Following this, customers with SMETS 1 meters that have been enrolled will no longer face the loss of smart functionality when switching supplier
- (d) DECC estimates that the 2.4 GHz home area networks (already available) will enable suppliers to install smart meters in 70% of households. Where the home area network needs to extend over larger distances, either the 868MHz solution or an alternative home area network solution will be needed. The 868 MHz solution will be suitable for use in 96.5% of households, with the remaining households requiring ‘alternative home area network’ solutions.⁹ DECC and industry stakeholders are working towards the availability of these solutions in late 2017 or early 2018.

⁵ See Appendix 8.4: Smart meter roll-out in Great Britain.

⁶ Appendix 8.4 gives further details of the roll-out programme and timescales.

⁷ DECC (2015), *Smart Metering Implementation Programme: Government response to the Smart Metering Rollout Strategy consultation*.

⁸ The enrolment of SMETS 1 meters is subject to a feasibility study.

⁹ DECC (2015), *Government Response on Home Area Network Solutions: Implementation of 868MHz*.

- (e) DECC is proposing to require suppliers to fit smart meters for customers requiring a new or replacement meter: the New and Replacement Obligation. This is due to come into force in mid-2018.
- (f) The roll-out of smart meters to domestic customers¹⁰ is due to be substantially completed by the end of 2020.

- 11.22 In view of the benefits of SMETS 2 smart meters for competition and engagement, and more specifically for helping to address some of the features we have identified, we believe it is vitally important that the prescribed timetable for their roll-out is adhered to.
- 11.23 We spoke to DECC and energy suppliers about the smart meter roll-out programme. We are aware that it is a complex logistical programme involving substantial levels of investment and therefore inevitably involves some delivery risk. We have also reviewed international experience of smart meter roll-out programmes¹¹ and note that Great Britain is unusual in having adopted a supplier-led model, and that some have argued that this has added to the complexity and cost of roll-out.¹²
- 11.24 Whatever the merits of the roll-out model that has been adopted, we believe that a key focus of DECC and Ofgem should be to ensure delivery to the agreed timetable. DECC expects near universal roll-out by 2020,¹³ although some suppliers believe that 100% roll-out may not be feasible. We have seen the roll-out plans of suppliers submitted to Ofgem in February 2016, which indicate that, while most suppliers plan to have between around 90 to 100% of smart meters rolled out to domestic customers by 2020, [✂].
- 11.25 We are therefore concerned at the risk of slippage and believe that measures should be taken to reduce this risk and mitigate any adverse consequences. We are aware that Ofgem has the power to impose penalties on suppliers in the event that the prescribed timetables are not met and, in view of the importance of SMETS2 smart meters in addressing the competition concerns we have identified, we would expect it to use these tools effectively to ensure that suppliers comply with their obligation to take all reasonable steps to complete the roll-out by 2020. Further, we have also

¹⁰ Suppliers are under an obligation to take all reasonable steps to ensure that a smart metering system is installed on or before 31 December 2020 at each domestic premise and most microbusiness (profiles 3 and 4) it supplies.

¹¹ See Appendix 8.5 on the international experience of smart meter roll-out.

¹² See Appendix 8.4.

¹³ Licence conditions require suppliers to take all reasonable steps to ensure that, by end-2020, smart meters are installed at their customers' premises.

designed our remedies to mitigate the adverse effects of any delay to the roll-out programme.

- 11.26 We believe it is equally important that DECC and Ofgem give adequate focus to ensuring that the potential benefits of the smart meter programme for competition and engagement are delivered in practice, including ensuring that the wider changes needed to realise the faster switching and time-of-use benefits are driven to fruition. Several of our remedies relate to these benefits, as set out in the next section.

The importance of our remedies in the context of the smart meter roll-out programme

- 11.27 In the context of the smart meter roll-out, our remedies aim to ensure both: that the broader benefits of the smart meter programme can be delivered in practice; and that any adverse effects arising from dumb meters can be managed during the period of roll-out.
- 11.28 In relation to the broader benefits of smart meter roll-out, a potentially significant benefit from smart meters comes from load shifting but this can only arise at scale through the introduction of half-hourly settlement and changes to the provisions of SLC 47 that currently require suppliers to gain consent to access consumption data with greater granularity than daily. Our remedies serve to address both of these issues, unlocking the considerable potential for load shifting from domestic customers. Further, in relation to gas settlement, our remedies will ensure that up-to-date information from gas smart meters is used to improve the accuracy of settlement.
- 11.29 In relation to the transitional period during the roll-out of smart meters, our remedies to use dumb prepayment meter tariff slots more efficiently and to require suppliers to offer customers on restricted meters access to their single-rate tariffs will serve to mitigate the problems experienced by customers on dumb prepayment and restricted meters respectively. Further, the cap we are imposing on the prices paid by prepayment customers is explicitly designed to address the detriment suffered by these customers until they have a SMETS 2 smart meter installed. The cap will not cover customers on SMETS 2 meters, as we think these meters will address (at least partially) the constraints to which prepayment suppliers are currently subject through the Prepayment AEC (both in terms of the technical

constraints and their reduced incentives to compete) and for customers will lower barriers to switching to other suppliers.¹⁴

Creating a framework for effective competition

- 11.30 If competition in retail energy markets is to serve customers' interests, it is vital that the regulatory and technical framework allows suppliers to compete effectively. Provided customers are sufficiently engaged, this will help drive down prices and improve quality of service.
- 11.31 We have identified a number of aspects of the regulatory framework that we believe undermine effective and efficient competition and are introducing three categories of remedy that we believe will help improve this framework:
- (a) Reform of the settlement systems for gas and electricity.
 - (b) Measures to address the technical and regulatory constraints impeding competition for prepayment meter customers.
 - (c) The withdrawal of aspects of the simpler choices component of the RMR rules.
- 11.32 Essentially, the remedies we are introducing aim, at a high level, to improve the framework for competition in one of two ways:
- (a) by ensuring that suppliers bear the full costs that they and their customers impose on the system, thereby strengthening incentives to compete to reduce these costs, to the ultimate benefit of customers through lower prices and higher quality of service (electricity and gas settlement reform); or
 - (b) by overcoming technical and regulatory constraints that restrict the extent of competition for domestic customers (prepayment tariff slots, debt assignment protocols for prepayment customers, and the withdrawal of aspects of the simpler choices component of the RMR rules).

¹⁴ As noted above, both SMETS 1 meters and SMETS 2 meters will address the technical constraints arising from the dumb prepayment meter infrastructure and help barriers to engagement experienced by customers. However, due to their interoperability, SMETS 2 meters will be more effective in helping addressing some of the barriers to switching to other suppliers experienced by customers and some of the barriers to expansion and acquisition in the prepayment segments experienced by suppliers.

Settlement reform

- 11.33 Energy suppliers generally attempt to purchase in advance the electricity and gas that they expect their customers to consume, to help them manage price and volume risks. But both gas and electricity demand are driven by a range of factors that are difficult to predict accurately, such that there will always be some disparity between the volumes of energy covered by suppliers' contracts and the volumes their customers actually use in real time. Settlement is the system by which such disparities are identified, reconciled and paid for.
- 11.34 Accurate and timely settlement is fundamental to well-functioning retail energy markets, since without this, suppliers will not have the right incentives to minimise the overall costs of energy – which are ultimately borne by customers. However, in Section 9 we expressed concerns that elements of the settlement systems of both gas and electricity lead to inaccuracies and delays that distort competition between energy suppliers concerning supply to domestic and microbusiness customers.

Electricity settlement reform

- 11.35 Electricity settlement takes place every half hour but the majority of domestic and microbusiness (profiles 1 to 4) 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 four¹⁵ profile classes, which are used to estimate a profile of consumption over time and allocate energy used to each half-hour period.
- 11.36 Our main concern in relation to electricity settlement is that such estimates fail to charge suppliers for the true cost of their customers' consumption. 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 their customers' profile regardless of their customers' actual consumption behaviour. This in turn distorts 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.
- 11.37 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 remain concerned that there are currently no

¹⁵ There are eight profiles in total, profiles 5 to 8 relate to I&C customers and a small number of SMEs.

concrete plans for using half-hourly consumption data in the settlement of domestic electricity customers, even after the full roll-out of smart meters.

- 11.38 Further, SLC 47 currently prohibits suppliers from collecting consumption data with greater than daily granularity unless a customer has given explicit consent to do so (opt-in). We believe that this opt-in clause effectively precludes mandatory half-hourly settlement (which by definition requires the use of all customer data for settlement, not just the data of those customers who have opted in) and is therefore a major barrier to the development of static and dynamic time-of-use tariffs.
- 11.39 Our remedies package in relation to electricity settlement comprises recommendations: to DECC to consider removing any potential barrier for suppliers to collect consumption data with greater granularity than daily in the context of the review of the Data Access and Privacy frameworks; to Ofgem to conduct a full cost benefit analysis of the move to half-hourly settlement, consider options for reducing the costs of elective half-hourly settlement and consult on a proposed modification to the provisions of SLC 47; and to DECC and Ofgem to publish and consult jointly on a plan setting out timescales and responsibilities relating to the introduction of half-hourly settlement.

Gas settlement reform

- 11.40 Our concern in relation to the current system of gas settlement is that it leads to an inefficient allocation of costs to parties and creates scope for gaming, which reduces the efficiency and, therefore, the competitiveness of domestic retail gas supply.
- 11.41 We note that a modification process currently underway – Project Nexus – is likely to address most of the current inefficiencies in the gas settlement system. However, even after the implementation of Project Nexus, the gas settlement process would still be characterised by the presence of a residual amount of unidentified gas, inefficiencies in the allocation of the cost of this residual unidentified gas, as well as incentives that shippers face to place a higher priority on adjusting annual quantities down. Further, we are very concerned that the delivery of Project Nexus has been delayed again – Ofgem is currently consulting on a new implementation date, between 1 February and 1 April 2017, in order to allow additional testing of relevant IT systems to be carried out – and this means that the clear deficiencies in the gas settlement system will persist beyond October 2016.
- 11.42 Our remedies in relation to gas settlement comprise: a recommendation to Ofgem to ensure implementation of Project Nexus by 1 February 2017 (or as

soon as possible after that date, once Ofgem is satisfied that IT systems are ready for effective implementation); an order on gas suppliers to submit valid meter readings (as defined in the Uniform Network Code) for non-daily metered supply points in GB to Xoserve as soon as they become available and at least once per year, save for non-daily metered supply points with a smart or advanced meter, which must be submitted monthly; and a recommendation to Ofgem to take appropriate steps to ensure that a performance assurance framework is established within a year of the CMA's final report.

Remedies to address constraints on competition for prepayment customers

- 11.43 For the reasons set out in Section 9 above, we believe that, in addition to the RMR AEC and the Domestic Weak Customer Response AEC, there are features of the domestic retail energy markets that give rise to a distinct, but related, AEC concerning prepayment meter customers, arising principally from supply side constraints (the Prepayment AEC).
- 11.44 In relation to the supply-side constraints imposed by the dumb prepayment infrastructure, we have decided on a range of remedies that will make better use of the available tariff slots, so as to reduce the impact of the dumb prepayment meter technical constraints on the ability of suppliers, and in particular new entrants, to innovate by offering tariff structures that meet demand from prepayment customers who do not have a smart meter.
- 11.45 The remedies include a recommendation to Ofgem that it take responsibility for the efficient allocation of gas tariff pages and (absent undertakings from the Six Large Energy Firms) change gas suppliers' standard licence conditions to impose a cap on the number of gas tariff pages that any supplier can hold and to introduce a condition that allows Ofgem to mandate the transfer of gas tariff codes to another supplier.
- 11.46 To further mitigate the impact of tariff codes on competition for customers on dumb prepayment meters, we recommend that Ofgem modify SLC 22B.7(b) to allow suppliers to set prices to prepayment customers on dumb meters without applying the regional cost variations that are applied to other payment methods within the same core tariff. As a result, suppliers would be able to make better and more efficient use of the tariff codes that have been allocated. We also recommend that Ofgem deprioritise potential enforcement action against suppliers in relation to this licence condition pending the change. This will allow suppliers to make better use of their limited tariff codes.

11.47 We have also decided on a remedy to enhance prepayment customers' ability and incentives to engage in the markets and to switch to other suppliers (including by switching to tariffs available on standard meters) which, in turn, will partly address suppliers' softened incentives to compete to acquire prepayment customers. This takes the form of a recommendation to Ofgem to take appropriate steps to ensure that changes to the Debt Assignment Protocol are implemented by the end of 2016, and in particular in areas relating to objection letters, complex debt and issues relating to multiple registrations.

Withdrawal of certain aspects of the simpler choices component of the RMR rules

11.48 In Section 9 we set out evidence on the impact that certain aspects of the 'simpler choices component' of the RMR rules have had on the ability and incentives of suppliers to compete on the range of tariffs and discounts offered to domestic customers. We also consider that certain aspects of the simpler choices component of the RMR rules (in particular, the four-tariff rule) limit the scope for competition between suppliers and PCWs for customers switching energy suppliers. This softens competitive pressures on energy prices.

11.49 We have decided on a remedy, the aim of which is to:

- (a) promote competition and innovation between retail energy suppliers in the retention and acquisition of domestic customers by allowing them to offer a wider range of tariffs than permitted by the simpler choices component of the RMR rules, including tariffs designed to appeal to certain customer groups; and
- (b) facilitate competition between PCWs by allowing them to negotiate exclusive tariffs with domestic energy suppliers and to offer discounts funded by the commissions they receive from suppliers.

11.50 The remedy takes the form of a recommendation to Ofgem to remove a number of standard licence conditions relating to the simpler choices component of the RMR rules. These include: the ban on complex tariff structures; the four-tariff rule; the restrictions on the offer of discounts; and the restrictions on the offer of bundled products.¹⁶

¹⁶ Our recommendation also provides for the removal of the Whole of the Market Requirement included in Ofgem's Confidence Code, and the introduction of a requirement for accredited PCWs to be transparent over the market coverage they provide to domestic customers. In order to mitigate any potential unintended consequences arising from a potentially significant increase in the number of tariffs on offer, we also recommend the introduction of an additional Standard of Conduct into retail suppliers' standard licence conditions that would require suppliers to have regard in the design of tariffs to the ease with which customers can compare 'value-for-money' with other tariffs they offer.

Helping customers engage to exploit the benefits of competition

- 11.51 Engaged customers are an essential component of well-functioning energy markets. If customers are not fully aware of the options available to them, unable to make an informed choice about the relative merits of those options or, having made a choice, are unable to switch, then competitive pressures on suppliers to reduce prices and improve quality of service will be substantially reduced.
- 11.52 In Section 9 we found that considerable numbers of customers were disengaged, leading to our provisional finding of a Domestic Weak Customer Response AEC. From our customer survey we found that 34% of respondents said they had never considered switching supplier, while 56% of respondents said they had never switched supplier, did not know if it was possible or did not know if they had done so.
- 11.53 We also note that currently around 70% of customers are on the relatively expensive default tariff – the SVT – and that there are material, persistent gains from switching supplier, tariff and/or payment method that go unexploited by many customers. As discussed in Sections 8 and 9, our gains from switching analysis shows that the gains available to customers have increased over time and, for the dual fuel SVT customers of the Six Large Energy Firms (excluding prepayment customers, who have a limited range of tariffs), average savings as of Q2 2015 were equivalent to about £330.
- 11.54 We have decided on a wide range of remedies that attempt to improve domestic customer engagement by addressing aspects of the features contributing to the Domestic Weak Customer Response AEC.¹⁷ We have adopted five broad categories of remedy, which focus on the role of different participants in the retail markets – namely, Ofgem, the customer’s own supplier, TPIs, and rival suppliers – in strengthening domestic customer engagement.
- 11.55 In particular, the remedies provide for:¹⁸
- (a) the establishment by Ofgem of a programme to provide customers – directly or through their own suppliers – with information to prompt them to engage;

¹⁷ Since the Domestic Weak Customer Response AEC affects all domestic customers, including prepayment customers, the remedies can be expected, once they become effective, to also enhance suppliers’ incentives to compete for prepayment customers. There will therefore be a strong interaction between the remedies concerning the Domestic Weak Customer Response AEC and the Prepayment AEC.

¹⁸ A complete list of our remedies is set out in Section 20.

- (b) creating an Ofgem-controlled database of ‘disengaged customers’ on default tariffs, to allow rival suppliers to prompt these customers to engage in the retail energy markets (the Database remedy);
- (c) enhancing the ability and incentives of TPIs to promote customer engagement in the retail energy markets;
- (d) Ofgem making greater use of principles rather than prescriptive rules in addressing potential adverse supplier behaviour concerning the comparability of their tariffs; and
- (e) requiring all suppliers to make all their single-rate tariffs available to domestic customers on any type of restricted meter, without making switching conditional on a restricted meter being replaced, and to provide additional information to customers on restricted meters.

11.56 The different market participants identified above differ substantially in terms of the incentives they have to engage customers and their ability to do so and our range of remedies reflects this.

Regulatory interventions to improve engagement

11.57 We consider that customers’ current suppliers have the ability to engage their customers – through the regular communications they send to them – but are likely to face limited incentives to do so in a way that encourages customers to engage in the markets. Indeed, as those customers that have not engaged in the markets recently are both less likely to switch and generally on higher tariffs than those who have recently engaged, their suppliers are likely to face a financial incentive to keep them as disengaged as possible.

11.58 In these circumstances, we recognise that there is an argument for Ofgem to intervene directly to facilitate customer engagement, through influencing the form, content and frequency of communication between suppliers and their existing customers. Ofgem has also recognised the importance of clear information in facilitating customer engagement and introduced the ‘clearer information’ component of the RMR rules in an attempt to ensure that suppliers’ routine communications to customers were clear, easy to understand and personalised to them.

11.59 However, our concern with these provisions is that they were not subject to adequate testing prior to (or after) their introduction. Without adequate testing it is not possible to know which approach will work best in practice. Further, even if testing is conducted ex ante, changes in technology and cultural practices are likely to mean that what works changes over time.

Ofgem-led programme

- 11.60 Our remedies therefore call for a more evidence-based approach to developing such interventions in the future, through the use of rigorous testing and trialling, where appropriate through randomised controlled trials, with a recommendation to focus such trials on a priority list of measures. If such trials are to provide relevant information that can provide a robust basis for regulatory changes, it is essential that suppliers be required to participate, where the trial design requires it, and our remedies therefore seek to ensure such participation.
- 11.61 In particular, the remedies comprise recommendations to Ofgem to: establish an ongoing programme of identifying, testing and implementing measures to promote engagement in the domestic retail energy markets; and introduce a licence condition requiring suppliers to participate in the programme.

Harnessing the incentives of rival suppliers and TPIs to engage customers

- 11.62 Where market participants have an active incentive to engage customers – this category includes rival suppliers and TPIs such as PCWs – the remedies serve to enhance these parties’ ability to engage domestic customers, while ensuring that customers are fully able to understand and choose between the range of options available to them. The remedies seek to achieve this through:
- (a) creating an Ofgem-controlled database of ‘disengaged customers’ who have been on the default tariff for three years or more, to allow rival suppliers to prompt them to engage in the retail energy markets;
 - (b) enhancing TPIs’ ability to improve engagement by:
 - (i) lifting certain regulatory restrictions that dull PCWs’ incentives to compete to engage customers (amending provisions of the PCW Confidence Code); and
 - (ii) giving PCWs (and other TPIs providing similar services) access to the ECOES and SCOGES databases¹⁹ and bolstering the Midata programme to allow TPIs to make more effective use of customer data; and

¹⁹ The Electricity Central Online Enquiry Service (ECOES) database includes certain data to assist electricity suppliers in the transfer of customers, while the Single Centralised On-Line Gas Enquiry Service (SCOGES) database comprises similar data for gas.

- (c) the use of principles rather than prescriptive rules to ensure customers are able to compare tariffs easily.

Ofgem-controlled database of 'disengaged customers'

- 11.63 Around 70% of the customers of the Six Large Energy Firms are on their supplier's default tariff (the SVT). Up to 55% of these customers have been on the SVT with the same supplier for more than three years and up to 40% have been on the SVT with the same supplier for more than five years.²⁰
- 11.64 In order to enable suppliers to prompt the domestic customers of rival suppliers on default tariffs, our remedy requires energy suppliers to disclose certain details of their domestic customers (on any meter type) who have been on their SVT (or any other default tariff) for three or more years (the 'Disengaged Domestic Customers') to Ofgem, and comprises a recommendation that Ofgem retains, uses, and discloses this data (via a centrally managed database) to rival suppliers. The Disengaged Domestic Customers would have the option to opt out of the disclosure process at any point in time.²¹
- 11.65 We consider that an Ofgem-controlled database of the most disengaged customers will be a highly valuable tool for harnessing the incentives of rival suppliers to prompt disengaged customers to engage in the retail energy markets. Ofgem will also be able to use the tool to engage directly with disengaged customers and in monitoring the impact of the remedies on engagement.
- 11.66 We recognise that there is a trade-off between the benefits of liberalising channels of engagement and the need to protect customers from excessive and/or misleading marketing. Customers will have the right to opt out beforehand to avoid receiving communications by post, and will only be contacted electronically if they explicitly opt in to such communications. We have carefully considered the implications of existing and currently foreseeable data protection legislation concerning this remedy, and Ofgem will be required to put measures in place to protect against the misuse of data. Ofgem will also be responsible for ongoing monitoring of the impact of the database with a view to maximising its effectiveness.

²⁰ The figures for gas are 54% and 39% respectively and for electricity 55% and 40% respectively. We note that these are upper bound estimates as for three suppliers the data provided was based on the length of the relationship with the supplier rather than the length of time on that supplier's SVT.

²¹ In the design of this remedy, we have drawn on discussions with the Information Commissioner's Office concerning the implications of the Data Protection Act 1998 and the Privacy and Electronic Communications Regulations 2003.

Enhancing the ability and incentives of TPIs to promote customer engagement

- 11.67 We consider that TPIs such as PCWs are an important means by which customer engagement can improve and effective competition can develop in the domestic retail markets. PCWs have a strong commercial incentive to engage with domestic customers and provide access to their services both online and by telephone. PCWs are also well placed to: raise awareness among customers of their ability to switch and the potential benefits from doing so; reduce search costs for customers; and exert competitive pressure on energy suppliers by enhancing price transparency and facilitating the purchasing process for customers.
- 11.68 Our remedies relating to TPIs in the domestic retail markets aim to help ensure that this potential for TPIs to promote competition to the benefit of customers can be realised by removing regulations that inhibit this role.
- 11.69 To strengthen the role of PCWs (and other TPIs providing similar services) in facilitating switching our remedies take the form of: orders on the code administrator or governing body with authority to grant access to the ECOES database and the gas transporters to give PCWs (and other TPIs providing similar services) access upon request to the ECOES and SCOGES databases respectively on reasonable terms and subject to satisfaction of reasonable access conditions. To strengthen PCWs' incentives to engage customers, we are recommending to Ofgem that it remove the Whole of the Market Requirement in the Confidence Code and introduce a requirement for PCWs accredited under the Confidence Code to be transparent over the market coverage they provide to energy customers. Further, we are recommending to DECC several changes to the Midata programme that (subject to customer consent) would give TPIs increased access to more customer data and, in so doing, enable TPIs to monitor the market on behalf of their customers and advise them of savings.
- 11.70 We are aware of the concerns around trust that led to the Confidence Code requirement that PCWs list all tariffs on the market rather than just those for which they earn a commission. We believe that such concerns around trust can be addressed – without undermining TPIs' incentives to engage customers – in two ways. First, there should be greater clarity around the role of PCWs – effectively acting as brokers offering their customers good deals and facilitating switches rather than repositories of all available tariffs. Second, Citizens Advice is now operating a non-transactional PCW that lists all tariffs through a web-based service, which we believe will meet the needs of those customers who wish to see the whole of the market.

Principles rather than rules to avoid customer confusion

- 11.71 Our remedies also place a greater emphasis on the use of principles rather than detailed rules in seeking to address potential adverse supplier behaviour concerning the comparability of tariffs. This reflects our concern that prescriptive rules seeking to ban confusing tariffs can never be fully exhaustive and risk encouraging gaming behaviour on the part of suppliers. In particular, we recommend that Ofgem introduce an additional standard of conduct into SLC 25C that would require suppliers to have regard in the design of tariffs to the ease with which customers can compare 'value for money' with other tariffs they offer.

Remedies for customers on restricted meters

- 11.72 We believe that the above remedies will help customers on any meter type engage effectively in the retail energy markets. Further, to address the specific problems faced by customers on restricted meters in shopping around for better deals and in switching, we have adopted a set of additional remedies that require all suppliers to make all their single-rate tariffs available to any domestic customers on any type of restricted meter, without making switching conditional on a restricted meter being replaced; and ensure that domestic customers on restricted meters have access to information on the options available to them.

Remedy to reduce detriment directly during the transitional period

- 11.73 We believe that competitive retail energy markets, in which energy suppliers operate free of inefficient technical and regulatory restrictions, and customers make informed decisions about the range of choices available to them, represent the best long-term approach to delivering positive outcomes for energy customers.
- 11.74 Notwithstanding the substantial problems that we have identified, there have been some positive developments in the domestic retail energy markets over the last few years, including the increasing market share of independent suppliers, several of which have been able to offer prices substantially below the average prices offered by the Six Large Energy Firms. Indeed, the average prices that such suppliers have been able to offer have given us valuable insights into the competitive benchmark tariff and hence the average prices that should be achievable.
- 11.75 We have identified substantial problems on both the supply and the demand side of the domestic retail energy markets, and we believe that our remedies package will provide a long-term solution to them, by putting downwards

pressure on prices towards the competitive benchmark level, as more efficient suppliers gain customers from the less efficient.

11.76 However, as noted in more detail below (see paragraphs 11.117 to 11.119 and Appendix 11.1), our remedies will take time to fully address the features that we have identified and, in turn, reduce the detriment to domestic customers arising from them. In particular, as discussed in more detail in Section 15, we believe that the roll-out of smart meters are a necessary element for fully addressing certain features of the Prepayment AEC and of the Domestic Weak Customer Response AEC with respect to prepayment customers²². Given the size of the detriment we have observed, of around £1.4 billion a year over the last three and a half years, we have therefore considered the need to intervene to address domestic customer detriment directly in this transitional period, through a price cap.

11.77 Given the interventionist nature of a price cap remedy, and the potential for adverse consequences²³, particularly risks for the emergence of a long-term competitive outcome, we have considered very carefully both the need for, and the appropriate scope of, a price cap. We have considered two broad options:

- (a) introducing a price cap focused on prepayment customers;
- (b) introducing a broader cap that would cover prepayment customers and:
 - (i) all customers on the SVT; or
 - (ii) a subset of customers who could be considered particularly disengaged according to our survey.

11.78 We have decided, on balance, to introduce a cap for domestic prepayment customers but not a broader cap. Our decision was not unanimous on the case for a broader cap – with one of us believing a broader cap across all SVT customers was also necessary.

Assessment of the case for a prepayment price cap

11.79 We have concluded that a price cap should apply to domestic customers on prepayment meters for a transitional period (2017 to the end of 2020) covering all domestic prepayment customers except those on SMETS 2

²² We have also noted that smart meters have the potential to improve customers' understanding of bills and confidence in choosing the right tariff or supplier. The roll-out of smart meters is particularly important for prepayment customers, who are affected by specific supply-side constraints (some of which can only be addressed by SMETS 2 meters) and face higher barriers to engagement.

²³ See below and our discussion of possible unintended consequences of a price cap in Section 14.

smart meters when these are rolled out to customers. In reaching this decision, we have given particular consideration to the following:

- (a) the Domestic AECs we have identified, the features giving rise to them and the relative strength of those features as they apply to different categories of customer;
- (b) the scale of the detriment that we have observed from the Domestic AECs, and the extent to which the detriment differs between different categories of customer;
- (c) the impact of our prepayment remedies²⁴ and engagement remedies²⁵ on the features giving rise to the Domestic AECs, and their interaction with the price cap (see also Section 15), including the need for an iterative process of greater supply- and demand-side pressures for more competitive prices to emerge;
- (d) the potential for adverse consequences from the introduction of a price cap, and how these might be expected to differ according to the scope, design and duration of the price cap remedy; and
- (e) the practicability of implementing a cap on a sufficiently timely basis to address the detriment during the period while our other remedies take effect.

11.80 In relation to the Domestic AECs, we have taken account of, in particular, the strength of the features contributing to the Prepayment AEC and the Domestic Weak Customer Response AEC as it applies to prepayment customers, as well as the impact on competition of our remedies and of the roll-out of smart meters (as discussed in more detail in Section 15).

11.81 Compared to other customers, prepayment customers have not been able to access the cheaper tariffs available to other customers and on average pay higher prices. We note that this has been due in part to the effect of supply side constraints arising from the dumb prepayment infrastructure, that smart meters (in particular SMETS 2 meters due to their interoperability) should not be subject to such restrictions and that recently there has been an increase in the share of independent suppliers offering smart tariffs. However, we have yet to see significantly lower prices or, most importantly, evidence of a substantial reduction in detriment. In relation to the Domestic Weak Customer Response AEC, we note that in our survey prepayment

²⁴ See Section 12.

²⁵ See Section 13.

customers were considerably less likely to have ever considered switching or to consider switching in the next three years than direct debit customers.

- 11.82 The level of detriment suffered by prepayment customers is particularly high. Over the period 2012 to Q2 2015, detriment expressed as a proportion of the bill for prepayment customers was higher than that for direct debit and standard credit customers for both dual fuel customers (12% for prepayment, 7% for standard credit, 8% for direct debit) and single fuel electricity customers (11% for prepayment customers, 5% for standard credit and 6% for direct debit). For single fuel gas customers, the levels of detriment are high for the three payment types (between 13% and 16%). Further, we note that, unlike other customers, where prepayment customers pay too high a price, part of the detriment is likely to be felt in abruptly curtailed consumption. The detriment we have calculated for prepayment customers is also increasing, reaching almost £400 million per year for all prepayment customers in 2015.
- 11.83 As noted below (see paragraph 11.113) we believe that the direct remedies and engagement measures that we are introducing will not fully address the levels of detriment that we have identified for prepayment customers in a sufficiently timely fashion, and in particular before the substantial completion of the roll-out of smart meters.
- 11.84 We assess the potential for adverse consequences arising from a price cap in Section 14, in the section on design considerations. However, we note that, in principle, a cap covering a relatively restricted proportion of customers, such as prepayment customers (about 16% of the total customer base) is likely to be less prone to adverse consequences than a cap covering a broader group.

Assessment of the case for a broader price cap

- 11.85 While the detriment suffered by prepayment customers is particularly high, we note that other domestic customers will also suffer from detriment during the transitional period, and have therefore given close consideration to the application of a price cap to broader categories of customers, notably:
- (a) all customers on the SVT; and
 - (b) a subset of customers who could be considered particularly disengaged according to our survey.

Assessment of the case for a price cap across all SVT customers

- 11.86 The majority of us concluded that the disadvantages of attempting to address the detriment of all SVT customers through a price cap would exceed the benefits, believing that attempting to control outcomes for the substantial majority of customers²⁶ would – even during a transitional period – undermine the competitive process, potentially resulting in worse outcomes for customers in the long run. This risk might occur through a combination of reducing the incentives of customers to engage, reducing the incentives of suppliers to compete, and an increase in regulatory risk. Martin Cave dissented from this view, considering that a broader cap was required to address the scale of detriment identified in the short term.
- 11.87 Substantial remedies will be taking effect to improve engagement from 2017, with major new remedies introduced in each year over the period 2017 to 2020.²⁷ We note that for most domestic customers on SVTs detriment will be reduced as soon as they engage effectively, in contrast to the situation for prepayment customers, who do not have access to cheap tariffs (see also paragraphs 11.80 to 11.82).
- 11.88 The majority of us considered that once the principle of such a highly interventionist remedy to deal with weak customer engagement is established, it inevitably increases the risk of further such interventions in the future, with ongoing harmful effects on engagement and supplier incentives. We consider that there is a clear distinction here with our price cap for prepayment customers, which addresses severe detriment arising from: a set of specific technical constraints that are impeding competition, arising from a technology which, once smart meters are fully rolled out, will become obsolete; enhanced features concerning the Domestic Weak Customer Response AEC for prepayment customers; and suppliers' reduced incentives to compete.
- 11.89 As discussed in more detail in Section 15, the roll-out of smart meters will be a key step in addressing these two AECs (by addressing directly the technical constraints, increasing suppliers' incentives to compete and increasing the effectiveness of our engagement remedies).
- 11.90 We were also mindful of the practical challenges involved in implementing a sufficiently robust cap in a short period of time for such a large proportion of the existing customer base. While these challenges exist for any price cap – including our cap for prepayment – they are amplified for an intervention

²⁶ 72% of the electricity customers and 69% of the gas customers of the Six Large Energy Firms as of June 2015.

²⁷ See Appendix 11.1, paragraph 57.

covering most of the market. Such challenges include: designing the approach to indexation and the impact that will have on supplier behaviour; ensuring compliance with relevant EU legislation and case law; and, most significantly, setting the cap at the right level. A large part of the detriment we have observed in the form of high prices is likely due to inefficiency rather than excess profits, such that if we were to eliminate the entirety of the detriment we have observed through a price cap it would create substantial losses for the sector as a whole. We note in this respect that our analysis of the impacts of our prepayment price cap suggests that substantial reductions in detriment can be achieved in the prepayment segments while retaining reasonable profits for suppliers, suggesting that there are currently particularly high levels of both detriment and profitability in these segments.

- 11.91 Given the large proportion of the total detriment in the broader domestic markets that we consider can be attributed to inefficiency, we consider that the best, most sustainable approach to addressing the features giving rise to the Domestic Weak Customer Response AEC and Prepayment AECs in the long term is through fully competitive markets, in which more efficient suppliers gradually replace less efficient suppliers. In this respect, the concern that the majority of us held in relation to the introduction of a price cap on all SVTs is that it would undermine this long- term outcome.
- 11.92 Overall, the decision on whether to introduce a cap for all SVT customers was balanced. We all agree that the prices currently paid by SVT customers are too high, but have had a difference of view on the best way of addressing this problem. Martin Cave thought that the size of the detriment was such that a price cap to reduce SVT prices was required now. The majority of us thought that the long -term costs to customers in terms of higher prices in the future would outweigh this short- term benefit.
- 11.93 This difference in view reflects therefore, in part, our respective judgements on the likelihood that better outcomes will be delivered through competitive markets with more engaged customers over the next few years. We set out a review of the available evidence on this in the discussion of the costs and benefits of the package below (see paragraphs 11.148 to 11.154, and Section 15) and in Appendix 11.1. We all acknowledge however, that, given the wide-ranging changes happening in the sector, future outcomes are uncertain. And we all agree that the wide-ranging package of remedies that we are putting in place represent the best chance for competition to work effectively in the domestic retail energy markets. Once our remedies are fully in place, and once smart meters are available for all customers, it will become possible to evaluate more fully the benefits that competition can

deliver and we note that Ofgem will continue to keep the market under review.

- 11.94 Therefore, having considered very closely both the short-term benefits to customers and the longer-term risks that a broader cap may create, set against the features of the Domestic Weak Customer Response AEC, we have decided, on balance, not to propose an intervention to control prices across all customers on SVTs.

Assessment of the case for a price cap across particularly disengaged customers

- 11.95 We noted in Sections 8 and 9 that our survey suggests that customers who have low incomes, have low qualifications, have a disability, 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. We therefore considered the case for a cap that, in addition to covering prepayment customers, would be extended to customers with different combinations of such characteristics.
- 11.96 Appendix 8.7 provides some analysis that shows the relationship between different metrics of engagement and demographic characteristics including household income, disability and age. We note that there is, as expected, a negative relationship between various measures of engagement: having household income below £18,000; having a disability; and being over 65, although there is no exact fit (ie there are significant numbers of customers who are disengaged who do not fall into these demographic categories and significant numbers of customers who do fall into these categories who are not disengaged). We also noted that in practice we would not be able to use these demographic characteristics directly to target a price cap, but would need to use proxies available through the benefits system.
- 11.97 We considered that any such price cap would, overall, not be sufficiently effective and/or would be disproportionate, and the practical difficulties of such an approach would outweigh the benefits. In particular, we noted that a potential price cap based on the use of data matching through the benefits system to try to target customers with particular demographic characteristics could not easily be implemented within a short period of time, partly because, unlike the prepayment and SVT options considered above, which have easily identifiable criteria for qualification, the process of identifying customers covered by the cap would be a time-consuming and inefficient one. Overall, we concluded that the practical difficulties of such an approach would outweigh the benefits.

Design of the prepayment price cap remedy

11.98 We have considered a range of options for the design of the PPM Price Cap Remedy, which we have evaluated against several key design criteria, notably:

- (a) practicability (whether the cap is easy to implement on a timely basis, easy to calculate in an objective way and easy to comply with and monitor);
- (b) impacts on supplier incentives (whether the design minimises the scope for perverse incentives and encourages competition);
- (c) accuracy (whether the cap accurately reflects changes in competitive market conditions over time, and any changes in the costs that an efficient supplier would be expected to bear); and
- (d) impact on customers and suppliers (whether the cap reduces prices for prepayment customers while allowing efficient suppliers a reasonable opportunity to recover their costs).

11.99 Sections 14 and 15 provide further details of this assessment. In summary, we have decided to implement a 'hybrid reference price and cost index approach', which would involve setting an initial level of the prepayment cap based on our competitive benchmark analysis and then allowing the cap to change over time according to movements in exogenous cost indices. We consider that this design has benefits, relative to alternatives, against our design criteria:

- (a) **Practicability:** our preferred approach is easier to implement than alternatives, and less burdensome for both Ofgem and suppliers. It is therefore capable of swift implementation – a key design criterion given the interim nature of the cap.
- (b) **Supplier incentives:** there appears to us to be minimal scope for perverse incentives under the preferred approach, unlike approaches based on reference prices, which create the potential for the cap to be manipulated and competition to be undermined. Further, the fact that the cap is time-limited and will be implemented according to an objective formula, will help minimise the risk of regulatory gaming behaviour.
- (c) **Accuracy:** our preferred approach will accommodate actual changes in wholesale and network costs relatively simply. In relation to policy costs, we have concluded that the best way to accommodate these within our

preferred approach is to use annual estimates of the costs arising from such policies produced by the Office for Budget Responsibility.

- 11.100 In considering the stringency and design of the cap, we have been particularly mindful of the need to reduce customer detriment while avoiding distortions to competition. At the current proposed level, the cap will materially reduce detriment for prepayment customers. Had it applied in Q2 2015, it would have reduced prepayment customer detriment – and, equivalently, the revenues of the Six Large Energy Firms – by about £300 million per year, equivalent to a reduction in the average bills paid by prepayment customers of about £75. We note that the proposed price cap would also apply to Mid-tier Suppliers and smaller suppliers and will therefore result in revenue reductions outside of the Six Large Energy Firms.
- 11.101 In determining the overall level of the cap, we have included a level of headroom that will help ensure that competition in the prepayment segments can coexist with the cap. Indeed, the proposed level of the cap as of Q2 2015 is generally in line with the cheapest prepayment tariff prices in many regions and we believe that it will be possible for suppliers to compete beneath the level of the cap while still earning a normal rate of return. Further, the cap will not apply to fully interoperable (SMETS 2) smart meters when these are rolled out to prepayment customers – as we believe that customers with such meters will no longer be materially disadvantaged compared with other customers. This is because SMETS 2 meters will provide the basis for effective competition by giving these customers access to a much wider range of tariffs than at present.
- 11.102 We anticipate that, as our remedies to address supply-side constraints and improve customer engagement begin to take hold towards the end of the cap and as SMETS 2 smart meter roll-out increases, competition rather than the cap will be determining the prices paid by most customers. There will therefore be a graduated glide path to the termination of the cap at the end of 2020.

Synergies and interactions between different elements of the remedies package

- 11.103 Each individual remedy we are introducing needs to be considered in the context of the overall package of remedies, as there are important synergies and interactions between individual components of the package. In this section, we set out some of the key interactions and synergies, as well as highlighting how potential tensions are resolved.

- 11.104 Most fundamentally, we consider that the overall aims, objectives and effects of the components of the package designed to create a framework for effective competition on the one hand and to improve customer engagement on the other, are mutually reinforcing. Even if suppliers are able to operate in a market free of inefficient regulatory and technical restrictions, if customers are not sufficiently engaged, outcomes will be suboptimal. Similarly, even if customers are fully aware of the options available to them and confident in their ability to switch, if the prices available to them are inefficiently high, outcomes again will be suboptimal, resulting in customer detriment.
- 11.105 Therefore, at a fundamental level, we consider that both of these strategic components of our remedies package are necessary if we are to see material, sustained reductions in detriment.
- 11.106 The mutually reinforcing nature of supply- and demand-side problems is perhaps seen most clearly in the prepayment segments of the domestic retail energy markets, where the features of the Domestic Weak Customer Response AEC also affect prepayment customers, and combine with and contribute to the features of the Prepayment AEC and the RMR AEC.²⁸ As discussed in Section 9, the technical constraints imposed by the dumb prepayment meter infrastructure are all the more important in conjunction with the particular engagement problems we have observed with prepayment customers. Similarly suppliers' incentives and abilities to compete to acquire prepayment customers are affected not just by the technical and regulatory problems we have identified, but also the degree of disengagement of some prepayment customers. Further, some aspects of the simpler choices component of the RMR rules and the Debt Assignment Protocol are likely to have exacerbated suppliers' softened incentives to compete in these segments. The levels of disengagement that we have observed among prepayment customers are in part due to the demographic characteristics that those customers have, but for some, they may also reflect the historical absence of competitive prices.
- 11.107 We therefore consider that addressing the problems faced by these customers is likely to require both measures to directly address the supply side features giving rise to the Prepayment AEC and engagement measures. By improving engagement among prepayment customers, suppliers could be expected to have enhanced incentives to compete for such customers. In this way, the domestic engagement remedies and exclusively supply-side remedies will mutually reinforce to address the

²⁸ See Section 15, where we discuss how each remedy addresses one or more features of the Prepayment AEC, the Domestic Weak Customer Response AEC and/or the RMR AEC.

detriment for prepayment customers that derives from the Prepayment AEC and the Domestic Weak Customer Response AEC.

- 11.108 We also consider that, given the mutually reinforcing nature of the problems we have identified, it would take some time for prices to fall for a substantial number of such customers even after application of our remedies, raising the need to address detriment directly over a transitional period through the prepayment price cap.
- 11.109 There are several elements of the reform package that will have beneficial effects on both the conditions for effective competition and customer engagement. Our recommendation to remove certain aspects of the simpler choices component of the RMR rules, for example, will help to reinvigorate competition, by allowing suppliers to introduce the sorts of incentives and discounts for new and existing customers that will allow them to try to increase engagement. And electricity settlement reform will have a supply-side effect in the first instance, by exposing suppliers to the true costs their customers impose on the system, improving the efficiency of price signals to suppliers. This change, in turn, will incentivise suppliers to offer a wider range of time-of-use tariffs to customers, who will have access to a greater range of potential savings, increasing engagement for those customers who wish to take up such tariffs.
- 11.110 Similarly, the remedies to improve the incentives and ability of TPIs to compete will also primarily benefit customer engagement (in particular, in light of the withdrawal of aspects of the simpler choices component of the RMR rules). But they will also, by increasing competitive pressures on suppliers and TPIs, serve to bear down on costs, notably the costs of acquiring customers.
- 11.111 There are broader synergies between the remedies we discuss here and those we consider in Section 19, on the governance of the regulatory framework. We have identified several aspects of the regulatory regime applying to the domestic (and SME) retail energy markets that have had an adverse effect on both the supply and demand side of these markets. These relate both to regulations introduced by Ofgem and regulations governed under the industry codes. While we believe our package of remedies will effectively address these regulations, the policy environment governing energy is a dynamic one, such that there is a risk that new regulations will be introduced in the future that do not serve customers' interests. It is for this reason that we consider our reforms to governance arrangements – which we believe will serve to increase the chances of decisions being adopted in the future that are in the long-term interests of customers – to be an essential part of the overall package of remedies for the energy sector.

- 11.112 We are also aware that there are some areas where there are potential tensions between aspects of our remedies and we have ensured, in the remedy design, that any such tensions can be managed. For example, as discussed earlier, we have decided that aspects of the simpler choices component of the RMR rules should be withdrawn, as they undermine effective competition between suppliers and between PCWs. We recognise that Ofgem introduced these particular rules in an attempt to make it easier for customers to make better choices by stripping away unnecessary complexity in tariff choices, but believe that any unintended adverse consequences from the withdrawal of the simpler choices component of the RMR rules can be addressed through the measures we are putting in place to improve customer engagement. In particular, one of our remedies introduces a new Standard of Conduct that places a greater emphasis on the use of principles rather than rules – which we believe can lead to gaming behaviour – in seeking to address potential adverse supplier behaviour. Further, our remedies call for a more evidence-based approach to developing interventions to facilitate customer engagement in the future, through the use of rigorous testing and trialling.
- 11.113 Potentially, the greatest tension could be between our engagement and competition remedies on the one hand, and measures to control prices on the other. As set out above and in Section 14, the direct remedies and engagement measures that we are introducing will not fully address the levels of detriment that we have identified for prepayment customers in a sufficiently timely fashion, and we believe that a remedy to address the detriment directly – through imposing a temporary cap on the prices paid by prepayment customers – is necessary until the roll-out of smart meters has been concluded. We note that the introduction of a price cap risks undermining competition and engagement, but we have been mindful, in designing the cap and setting its level, to allow for effective competition to coexist with the cap.
- 11.114 In particular, we have excluded SMETS 2 meters from coverage of the cap, which will increase the incentives of suppliers to accelerate the roll-out of such meters, and offer attractive deals to prepayment customers to encourage them to take them up. We therefore believe competition in these segments could be intensified as a result of the limited scope of the cap, once SMETS 2 meters become available. Further, once smart meters have been fully rolled out and our other remedies are fully in force, the cap will end.²⁹

²⁹ See Section 14.

11.115 The synergies and interactions noted above are further discussed in Section 12 (measures to create a framework for effective competition), Section 13 (measures to improve customer engagement), Section 14 (measures to protect customers who are unable to engage to exploit the benefits of competition) and Section 15 (our assessment of the effectiveness and proportionality of the package).

Timelines for the implementation of remedies

11.116 Given the scale of the detriment we have identified, we believe that it is vital to ensure that our remedies are implemented as rapidly as practicable. To assess the effectiveness of the remedies package in addressing the features we have identified – and the need for remedies to control outcomes while these features are being addressed – we have considered the timescales over which these remedies are likely to be implemented. We have also considered when they are likely to start to take effect in addressing the relevant features and, ultimately, reducing domestic customer detriment. These timelines are set out in detail in Section 15.

Summary of timeline

11.117 Drawing on the assessment set out in Section 15, we would expect the overall timescale for the implementation of remedies to be broadly as follows:

- (a) In 2017, a number of remedies would be implemented, and in particular:
 - (i) Regarding the framework for effective competition: gas prepayment tariff codes would be reallocated; SLC 22B.7(b) would be amended (we are also recommending to Ofgem to deprioritise enforcement pending consultation of this change); the Project Nexus performance assurance framework would be in place.
 - (ii) Regarding customer engagement: the relevant elements of the simpler choices component of the RMR rules would be formally withdrawn and the revised Standard of Conduct in place (we note that Ofgem has already published a letter announcing its intention to deprioritise enforcement of these aspects of the simpler choices component of the RMR rules); the reforms to increase the incentives and ability of TPIs to improve customer engagement would all be in place.
 - (iii) The cap on the prices paid by prepayment customers would be in place, commencing in April 2017.

- (b) In 2018, suppliers would be able to access the database of Disengaged Domestic Customers who had not opted out, which would be updated every month, and, towards the end of the year the first intervention from the Ofgem-led programme would be implemented.
- (c) In 2019, we would expect further interventions arising from the Ofgem-led programme to be progressively implemented.
- (d) In 2020, mandatory half-hourly settlement is likely to be in place for domestic customers. We also note that the national programme for the roll-out of smart meters is scheduled to be substantially completed.

11.118 Overall, for non-prepayment customers – for whom overcoming barriers to engagement is the main challenge – substantial remedies will be taking effect to improve engagement from 2017, with major new remedies introduced in each year over the period 2017 to 2020. Perhaps the two most significant engagement remedies – the Database remedy and the Ofgem-led programme – would start to take effect in 2018 and 2019.

11.119 For prepayment customers, in addition to the above remedies, a price cap will be in place in 2017, as well as a number of remedies relating to the specific constraints they face. For example, we expect that by 2017, gas prepayment tariff codes would be reallocated and SLC 22B.7(b) would be amended to help address supply-side constraints imposed by tariff codes.

Expected costs and benefits of our remedies package

11.120 In this section, we consider the likely costs and benefits of our remedies package. Drawing on the analysis of the preceding section, we have distinguished between those measures that will have an effect solely during the transitional period of the smart meter roll-out and those that will have an enduring effect, particularly from around 2019/20 onwards.³⁰

Remedies that will have an effect solely during the transitional period

11.121 Some of our remedies will apply only during the period before the substantial completion of the roll-out of smart meters (expected by the end of 2020) or earlier. Notable among these is the transitional price cap for prepayment customers.

11.122 The benefits accruing from the price cap will take the form of reduced prices for prepayment customers. Had it been in place in 2015, we estimate that

³⁰ A more detailed assessment of the costs of individual remedies is provided in Sections 12, 13, 14 and 15.

the cap would have generated customer benefits of around £300 million in that year. We estimate that savings will be of a similar order of magnitude in the early part of its operation, from April 2017, but would expect customer benefits to reduce over time as customers move onto interoperable SMETS 2 smart meters and as our other remedies take effect.

11.123 There would be some administrative costs for both Ofgem and suppliers from implementing the cap, but we have chosen a design that minimises these to the extent possible (eg updating through readily available exogenous indices, ex ante compliance except in the event of a derogation granted by Ofgem) and, overall, we expect such costs to be very low compared to the benefits of the cap in terms of reduced prices. Potentially more significant are the distortions to competition that could arise from the application of the cap, but we have again chosen aspects of the design to minimise these – notably, in the exclusion of interoperable SMETS 2 smart meters from coverage by the cap.

11.124 The other remedies that will apply only during the transitional period are:

- (a) the remedies relating to of the efficient use of tariff codes (since there will be no need for tariff codes once all prepayment customers have smart meters);
- (b) the remedies giving PCWs (and other TPIs providing similar services) access to the SCOGES and ECOES databases (since TPIs would ultimately have access to meter number information through phase 2 of Midata, when implemented, subject to implementation of our remedy); and
- (c) the remedies designed to improve engagement for customers on restricted meters (since we consider that the specific barriers faced by customers on such meters will disappear with the full roll-out of smart meters).

11.125 We consider that the costs of implementation of the above remedies are very low. In relation to the first two, there would a minimal administrative cost for Ofgem, the code administrator or governing body with authority to grant access to the ECOES database and the gas transporters respectively. In relation to the third, there would be a small additional cost for suppliers arising from the need to aggregate consumption volumes in different registers for the purposes of single rate billing. We are also calling for Citizens Advice to offer advice to customers in relation to their ability to switch, given this new regime, but this is a role it already has, so this involves no additional cost.

11.126 We recognise that the short space of time over which these latter remedies will be relevant and the inevitable lag between implementing the remedy, effectively addressing the relevant aspect of the feature and reducing detriment, will limit the scope for substantially reducing customer detriment through these transitional remedies. However, even very small reductions in prices during the transitional period would lead to benefits that would far exceed any implementation costs. Further, while we noted above that we consider it essential that the prescribed timescales for the roll-out of smart meters are adhered to, should there be any delay, the impacts and benefits accruing from these remedies would be expected to increase.

Remedies that will have an enduring effect

11.127 The other remedies that we are introducing – settlement reform, the withdrawal of aspects of the simpler choices component of the RMR rules and the engagement remedies other than the transitional measures discussed above – would work together on an enduring basis as a package. We have accordingly considered their benefits jointly, while noting their relative contribution to the package and identifying their costs, where material, on an individual basis.

11.128 We first assess costs and benefits for electricity settlement reform separately, as this reform has benefits in terms of load shifting that are additional to those of the package as a whole (although we consider that they would also make a contribution to improving customer engagement).

Electricity settlement reform

11.129 As set out in more detail in Section 12, there are potentially substantial savings from domestic peak load shifting, arising primarily from reductions in the cost of generation and distribution. One recent study estimated savings from the introduction of time-of-use tariffs within the domestic retail markets of between roughly £50 million and £100 million in 2020 and between roughly £100 million and £350 million a year by 2025.³¹ Expected savings increase with the roll-out of automated and dynamic time-of-use tariffs (for which settlement reform is necessary) and with increased penetration of low carbon technologies. We note in relation to this latter factor that the demand and supply of heat pumps, smart appliances and electric vehicles will be driven in large part by the availability of opportunities to exploit within-day price differentials. Therefore we would argue that a move to half-hourly

³¹ Baringa and Element Energy, Electricity System Analysis - future system benefits from selected DSR scenario (August 2012).

settlement will be a necessary step in achieving the higher end of potential benefits from demand-side response.

11.130 In terms of implementation costs, we consider that these will be very low for distribution network operators and Elexon (more specifically, [X]). Suppliers indicated to us that the reform would involve substantial upfront and ongoing costs, although we have not received sufficient information from enough firms to build a consistent, robust picture of the likely costs.

11.131 Our recommendation is that Ofgem conducts a full cost-benefit analysis of the move to mandatory half-hourly settlement, but overall, and based on the evidence we have seen, there are good reasons to expect the benefits from half-hourly settlement to outweigh the costs of its implementation by a substantial degree.

Remedies to improve customer engagement

11.132 In relation to the rest of the package, we consider that the main enduring benefit will accrue from improving customer engagement and therefore overcoming the Domestic Weak Customer Response AEC. Given the fact that, almost 15 years after full price liberalisation, around 70% of the domestic customers of the Six Large Energy Firms are on the default tariff, despite very large and growing potential gains from switching – equivalent to around £330 a year for non-prepayment dual fuel SVT customers as of Q2 2015 – we have considered very carefully whether our remedies are likely to succeed where other interventions have failed. We believe that they will, for a number of reasons, which we summarise below and are set out in more detail in Appendix 11.1.

- *Regulatory interventions informed by robust evidence*

11.133 First, our remedies will help ensure that **future regulatory interventions to improve engagement are based on robust evidence**. Past interventions have been based largely on *a priori* reasoning, with little attempt systematically to test hypotheses through rigorous trials or other forms of testing before the intervention is implemented. And yet the reasons customers have for not engaging in the presence of substantial gains from switching are likely to vary both between different types of customer and over time – in our survey over a third of respondents said that they had simply never considered switching supplier.³² The key to unlocking engagement from such customers may be relatively simple – the way in

³² See Sections 8 and 9.

which information is framed or the medium of communication, for example – but is likely to differ between types of customer and over time.

11.134 In this context, *a priori* reasoning can provide useful insights into the sorts of interventions that may help, but rigorous evidence is needed to ensure that only those interventions that are most likely to make a difference for given customers at a given point in time are implemented.³³ The Ofgem-led programme that we have recommended is therefore essential to ensure that future interventions are based on what works in practice.

11.135 Further, Ofgem will be able to use the database of disengaged customers to assess the effectiveness of different interventions. The database, which could contain the records of up to 10 million customers,³⁴ will provide Ofgem with an extremely powerful tool for assessing the impact of different interventions and forms of communication with disengaged customers.

- *Intensified competition between suppliers*

11.136 Second, our remedies will serve to **intensify competition between suppliers** to access and engage disengaged customers, by: reducing the costs of identifying and communicating with such customers (the Database remedy); and by amending elements of the regulatory framework to increase the incentives of suppliers to engage these customers (the withdrawal of certain aspects of the simpler choices component of the RMR rules and settlement reform).

11.137 In relation to the costs of communicating with disengaged customers, our survey evidence shows that of those SVT customers who have not switched in the last three years, over 50% either did not have access to the internet or were not confident in using PCWs, suggesting that a medium other than the internet – such as written correspondence – will need to be used to access them. Further, First Utility, the largest of the Mid-tier Suppliers, told us that it would like to try to [X]. Our Database remedy will provide a cost-effective way for all suppliers, including new entrants, to market their products to those customers.

³³ We have ourselves identified some proposals for increasing customer engagement, such as providing customers with information on the cheapest tariffs in the market, or changing the name of the default tariff, which we recommend should be subject to trials. If the evidence from such trials suggests that a particular initiative will not work, it should be rejected.

³⁴ To calculate this figure we used data as at Q2 2015 on the total number of electricity customers in Great Britain (27.4 million customers), the share of electricity customers of the Six Large Energy Firms (89.6%), the percentage of customers on an SVT at the Six Large Energy Firms (71.5%) and the percentage of customers who have been on an SVT with the same supplier from the Six Large Energy Firms for more than three years (55.1%). We note that this is an upper bound estimates as for three suppliers the data provided on the percentage of customers who have been on that supplier's SVT for more than three years was based on the length of the relationship with the supplier rather than the length of time on that supplier's SVT.

11.138 In relation to the regulatory regime, past experience suggests that engagement in the retail energy markets can be improved where suppliers have the incentives and ability to do so. For example, as noted in Section 8 and Appendix 11.1, switching rates in 2008 reached around 20% (compared to the current levels of 12%), through a combination of out-of-area discounts on SVTs and accessing otherwise-disengaged customers through doorstep selling. We also note that our evidence on cost pass-through suggests that there was a much lower margin between the SVT and forward-looking measures of direct costs during this period.

11.139 Since then, a variety of regulatory interventions have served to soften competition – including SLC 25A, enforcement action by Ofgem leading to the abandonment of doorstep selling by most suppliers, and, more recently, RMR – resulting in a fall in switching rates and an increase in the gap between the SVT and direct costs. Our recommendation to remove aspects of the simpler choices component of the RMR rules will help to reinvigorate competition, by giving suppliers the incentives and ability to introduce the sorts of discounts for new customers that will allow them to increase engagement.³⁵ Crucially, however, and as discussed further below, our remedies will also address the concerns about customer confusion and poor decision-making that led to the initial introduction of these regulations.

11.140 In the longer term, settlement reform will both expand the role of suppliers and change their relationship with their customers. Currently, suppliers have a financial incentive to keep their customers disengaged. However, with the introduction of this reform, they will no longer be charged according to their customers' actual consumption profile and will therefore have an incentive to encourage their customers to shift consumption to cheaper periods. As wholesale electricity prices are expected to be more volatile in the future, suppliers will face a strong price signal to do so.

- *Expanded role of TPIs and data*

11.141 Third, our remedies seek to **harness the incentives and enhance the ability of TPIs to unlock customer engagement**, by giving them greater access to the data they need to perform this role more effectively and at a lower cost, and by removing regulatory barriers to their expansion.

11.142 TPIs have grown considerably as an acquisition channel over the past few years, yet, as discussed in Appendix 11.1, we believe there is great potential for further growth. We note that, since the introduction of the whole of the

³⁵ See Section 12 and Appendix 11.1.

market requirement, fewer suppliers are paying commission rates, undermining PCWs' incentives to advertise and, therefore, engage customers who are currently disengaged. In Appendix 11.1 we observe that current levels of advertising by PCWs relating to energy are very low relative to other sectors, suggesting scope for much greater activity following our remedy to remove the whole of the market requirement.

11.143 Our remedies will also give TPIs much greater access to data, allowing them to continue to grow in importance, lowering acquisition costs for suppliers and lowering search costs for customers. While PCWs are the most common type of TPI currently, TPIs are taking a variety of forms that are likely to appeal to different demographic groups: some, such as Flipper, which offers an automated switching service, may radically reduce the hassle of switching for those who sign up while others, such as collective switching services advertised through a variety of media, may appeal more to customers who are less confident in using the internet.

- *Ensuring customers benefit from engagement*

11.144 Finally, we note that increasing customer activity is not an end in itself. Our aim is to **ensure that customers benefit from increased engagement** – ie that it results in them being on better deals than they are at present. In this respect we acknowledge that some of the regulatory interventions discussed above – notably enforcement action by Ofgem against the misuse of doorstep selling – were motivated by a legitimate concern that in the absence of intervention, customers may be persuaded to switch to deals that would leave them worse off.³⁶ We believe that the creation of an Ofgem-controlled database of disengaged customers will be far less prone to abuse than doorstep selling, because Ofgem will have powers to exclude suppliers from accessing the database if misleading information is given to customers and it will be responsible for continual monitoring of the effectiveness of the database, to establish which forms of communication from suppliers genuinely help engagement in the interests of customers.

11.145 The Ofgem-led programme would also be used to identify through robust testing the most appropriate form of information received by domestic customers from suppliers. This should reduce or minimise the complexity of those communications, and provide such customers with information that would prompt them to switch and help them to make an accurate decision in relation to the various options available to them. As part of this programme,

³⁶ The evidence we review in Appendix 11.1 suggests that material numbers of customers in the past may have switched to a worse tariff.

we are recommending that Ofgem tests the case for market-wide tariff messaging on bills, which could provide customers, particularly those who do not use PCWs, with a valuable source of information on the cheapest tariffs available in the market. We note that such an approach would avoid the disadvantages identified above relating to the current Cheapest Tariff Messaging requirements, which relate to the supplier's own tariffs, and hence dull incentives to offer cheap tariffs to new customers.

11.146 In other areas of our remedies package, we have looked to improve customer understanding and avoid the risk of confusion without undermining competition in the way previous interventions have done. For example, we are recommending the replacement of the RMR rules that restrict competition and lead to gaming with a simple principle requiring tariffs to be readily comparable. And in relation to TPIs, our remedies will see clarity over market coverage and the ability for customers to access all available tariffs through the Citizens Advice PCW rather than, as at present, requiring all PCWs to advertise all deals whether they receive a commission or not, undermining their incentives to operate in the sector.

11.147 Our overall approach, therefore, avoids both the laissez-faire approach of the early years of liberalisation and the overly constraining regulations that have dulled competition in more recent years by giving suppliers and intermediaries greater incentives to engage customers and by ensuring customers have the information they require to make an informed choice. Allied to the changes that will be brought about through the full roll-out of smart meters, the move to next day switching, and ever-easier access to information facilitated by improvements in IT, we believe that our remedies will bring about a significant improvement in customer engagement.

- *Costs of engagement remedies*

11.148 In relation to the costs of implementing the remedies, these are generally very low compared to the size of the detriment. For example, in relation to the Database remedy, Ofgem has estimated that the costs of setting up a secure cloud database in which to store details of the Disengaged Domestic Customers that have not opted out could be in the region of £200,000 to 300,000. We do not think it would be an expensive web-based application to maintain because it would not require significant, or complex, functionality.

11.149 The largest cost would be imposed by the Ofgem-led programme, as it would require an ongoing system of testing and trialling interventions. The Behavioural Insights Team said that the costs of the trials that it had conducted to date had been [£], although we note costs may vary substantially, depending on the size and complexity of the trial. In designing

the programme and, in particular, the extent of any supplier participation that might be needed, we recommend that Ofgem assess the proportionality of the various stages involved in the programme, including the testing involved in each specific proposed measure. In this regard, we would expect Ofgem to take into account issues such as the potential costs incurred by suppliers as part of its proportionality assessment.

- *Benefits of engagement remedies*

11.150 Our overall package of remedies to improve engagement will give suppliers and TPIs greater incentives to engage customers and ensure customers have the information they require to make an informed choice. Combined with the changes that will be brought about through the full roll-out of smart meters, the move to next day switching, and ever-easier access to information facilitated by improvements in IT, we believe that our remedies will bring about a major improvement in customer engagement.

11.151 We believe that the benefits of our remedies will be seen in part through a reduction in the gains from switching that go unexploited by customers. However, crucially, this would not be achieved by a levelling up of prices (a potential risk of regulatory interventions that seek to constrain price differences) but by a gradual reduction in prices towards the competitive benchmark level, as more efficient suppliers gain customers from the less efficient.

11.152 We note that, in contrast to the situation for prepayment customers, who do not have access to cheap tariffs, for most domestic customers detriment will be reduced as soon as they engage effectively. We would therefore expect detriment to be reduced throughout the period 2017 to 2020, and in particular from 2018 as the Database remedy and Ofgem-led programme start to take effect.

11.153 While it is not possible to quantify precisely the price reduction in the next few years, we note, for illustrative purposes, that a fall in average prices by 3% a year from 2017 to 2020 would be sufficient to eliminate the detriment by 2020.³⁷ If average prices could be reduced by 1% a year from 2017 to 2020, detriment as of 2020 would stand at around £1 billion, and if average

³⁷ As set out in Appendix 11.1, this is based on the assumption that detriment will remain constant at its 2015 level (the most recent year for which it was calculated) in 2016 – ie around £1.6 billion for non-prepayment domestic customers. In practice, reductions in average price and hence detriment could come about through a combination of: a reduction in the proportion of customers who are on expensive tariffs (and notably the SVT) as customers switch tariff or supplier; and a reduction in the price of expensive tariffs as suppliers respond to increased engagement.

prices could be reduced by 2% a year over the same period, detriment would be around £500 million in 2020.

11.154 We acknowledge the uncertainties in estimating the level of detriment that will be reduced by our remedies over the next few years, but our analysis of the history of liberalised retail markets in Great Britain suggests that appropriately targeted and designed remedies can have material, rapid effects in improving engagement and reducing detriment for the majority of customers (see Appendix 11.1).

Summary

11.155 Overall, we consider that our package of remedies represents an effective and proportionate response to the Domestic and Settlement AECs and associated detriment we have identified. For non-prepayment customers, our remedies to create a framework for effective competition and improve customer engagement will begin to address the features we have identified over the next few years and reduce detriment materially over the period.

11.156 In the transitional period between 2017 and 2020, we will introduce a cap on the prices paid by customers on prepayment meters, who have suffered particularly high levels of detriment, and have been subject to additional supply-side constraints that have restricted the choices available to them. We would expect around £300 million of detriment a year to be reduced through the application of the cap in the initial years of this transitional period. We would expect the impact of the cap to reduce over time, but the overall detriment reduced through the package to increase, as competition picks up through our remedies and in particular through the roll-out of SMETS 2 meters that are not covered by the cap.

11.157 In the following sections, we analyse our remedies in more detail:

- (a) In Section 12, we assess our remedies to create a framework for effective competition;
- (b) In Section 13, we assess our remedies to improve customer engagement;
- (c) In Section 14, we assess our remedy to introduce a price cap for customers on prepayment meters; and
- (d) In Section 15, we assess the effectiveness and proportionality of the overall package of remedies for domestic customers.

12. Domestic retail: creating a framework for effective competition

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- 12.1 If competition in retail energy markets is to serve customers' interests, it is vital that the regulatory and technical framework allows suppliers to compete effectively. Provided customers are sufficiently engaged (an issue we consider in Sections 9 and 13), this will help drive down prices and improve quality of service.
- 12.2 We have found that a number of features give rise to AECs by undermining the framework for effective competition in the supply of domestic and/or microbusiness gas and/or electricity customers. These are as follows:
- (a) 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, which 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 (the Electricity Settlement AEC).

- (b) The current system of gas settlement, which 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 (the Gas Settlement AEC).
- (c) A combination of technical constraints that limit the ability of all suppliers, and in particular new entrants, to innovate by offering tariff structures that meet demand from prepayment customers who do not have a smart meter; and softened incentives for all suppliers, and in particular new entrants, to compete to acquire prepayment customers (due to actual and perceived higher costs to engage with, and acquire, prepayment customers compared with other customers; and a low prospect of successfully completing the switch of indebted customers, who represent about 15% of prepayment customers) (the Prepayment AEC).
- (d) The 'simpler choices' component of the RMR rules, which 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 (the RMR AEC).

12.3 In this section, we set out our decision with respect to three categories of remedy that we believe will help address the features leading to these AECs and improve the framework for effective competition:

- (a) Reform of the settlement systems for gas and electricity.
- (b) Measures to address the technical and regulatory constraints impeding suppliers from competing for prepayment customers.
- (c) The withdrawal of aspects of the simpler choices component of the RMR rules.

12.4 In the rest of this section we provide a detailed assessment of each of these remedies. In terms of the interaction between these remedies and our remedies for domestic customers:

- (a) We set out in Section 11 our high level assessment of how we expect each of these remedies to interact with the other components of our remedies package, notably measures to help customers engage to exploit the benefits of competition and measures to protect customers are who are less able to engage to exploit the benefits of competition.

- (b) In Section 15, we present a more detailed assessment of the effectiveness and proportionality of the remedies package for domestic customers concerning, in particular, the Prepayment AEC, the RMR AEC and the Domestic Weak Customer Response AEC.

Reform of electricity and gas settlement

- 12.5 Accurate and timely settlement is fundamental to well-functioning retail energy markets since, without this, suppliers will not have the right incentives to minimise the overall costs of energy – which are ultimately borne by consumers. However, in Section 9 of this report we expressed concerns that elements of the settlement systems of both gas and electricity lead to inaccuracies and delays that distort competition between energy suppliers.
- 12.6 In the case of both electricity and gas settlement, we note that reforms are already in hand to address some of the concerns we have identified, and we reflect on these reforms in our consideration of remedies.

Electricity settlement reform

- 12.7 As set out in Section 9, our main concern in relation to electricity settlement is that the use of load profiling to estimate each supplier's demand fails to charge suppliers for the true cost of their customers' consumption. 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 its customers' profile regardless of their actual consumption behaviour. This in turn distorts 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.
- 12.8 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 remain concerned that there are currently no concrete proposals for using half-hourly consumption data in the settlement of domestic and small electricity customers (profile classes 1 to 4), even after the full roll-out of smart meters.
- 12.9 Accordingly, we have found that the absence of a firm plan for moving to half-hourly settlement for domestic and the majority of microbusiness electricity customers (ie profile classes 1 to 4) 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. This overall reduces the efficiency and, therefore, the competitiveness of domestic and microbusiness retail electricity supply.¹

12.10 In our provisional decision on remedies we proposed to address the Electricity Settlement AEC and/or associated detriment as follows:

- (a) A recommendation to DECC to consult on amending the provisions of the Smart Energy Code that prohibit suppliers from collecting consumption data with greater granularity than daily unless a customer has given explicit consent to do so.
- (b) A recommendation to Ofgem to:
 - (i) conduct a full cost-benefit analysis of the move to mandatory half-hourly settlement, including analysis of costs, benefits and distributional implications as well as mitigating measures;
 - (ii) start the process of gathering evidence for the analysis as soon as practicable;
 - (iii) consider the cost-effectiveness of alternative design options for half-hourly settlement such as a centralised entity responsible for data collection and aggregation; and
 - (iv) consider options for reducing the costs of elective half-hourly settlement, including (i) whether any of these options are likely to delay or accelerate the adoption of mandatory half-hourly settlement; and (ii) any challenges that may arise or benefits that may accrue from the existence of two settlement systems, including in particular the possibility of gaming/cherry picking behaviour.
- (c) A recommendation to both DECC and Ofgem that they publish and consult jointly on a plan setting out:
 - (i) the aim of the reform for half-hourly settlement;
 - (ii) a list of proposed regulatory interventions (including code changes), and the relevant entity in charge of designing and/or approving such interventions that are necessary in order to implement the half-hourly settlement reform;

¹ See Section 16.

- (iii) an estimated timetable for the completion of each necessary intervention; and
- (iv) where appropriate, a list of relevant considerations that will be taken into account in designing each regulatory intervention.

Aim of the remedy

- 12.11 The aim of this remedies package is to ensure that, within a reasonable timetable, half-hourly consumption data is used to settle electricity customers falling into profile classes 1 to 4.
- 12.12 Accordingly, the ultimate aim of the remedies package is to address the feature of the GB electricity retail markets relating to 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, as it gives rise to an AEC through the distortion of suppliers' incentives to encourage their customers to change their consumption pattern.

Estimates of the potential benefits and costs of half-hourly settlement

- 12.13 The introduction of half-hourly settlement would have a number of benefits, the most substantial of which arise from the incentives it provides to electricity suppliers to encourage demand-side responses from domestic and SME customers such as peak load shifting, thus helping to reduce the overall costs of supplying electricity.
- 12.14 In this section, by way of background, we set out some of the available evidence on the potential benefits of load shifting, other benefits that might be expected to arise from settlement reform and the costs of reform.

- *The link between settlement reform and load shifting*

- 12.15 The main mechanism by which suppliers can encourage load shifting and other forms of demand-side response is through the introduction of time-of-use tariffs. Time-of-use tariffs can take the form of:
- (a) Static time-of-use tariffs, which use prices that vary according to the time of day to incentivise consumers to shift their energy consumption from peak to off-peak times. The price structures of such tariffs are fixed ex ante – ie they do not vary according to real-time network conditions. Economy 7 tariffs are a simple form of static time-of-use tariff.

- (b) Dynamic time-of-use tariffs, which offer consumers variable prices depending on network conditions – for example, during a period of plentiful wind, consumers may receive an alert that electricity will be cheaper for the next few hours. This could include critical peak pricing, where alert of a higher price is given usually one day in advance, for a pre-established number of days per year.
 - (c) Automated time-of-use tariffs, which provide for an automated customer response, for example through remote control of appliances by a third party or programmable appliances. The response could be driven by price or non-price factors (such as network conditions). Automated time-of-use tariffs are likely to provide the largest potential for load shifting.
- 12.16 We note that suppliers can opt, for some meter systems, to introduce basic forms of static time-of-use tariffs within the current settlement system, through a process known as ‘chunking’.² However, Elexon told us that in the absence of significant changes to existing settlement processes to provide for dynamic feedback from suppliers, settlement did not facilitate dynamic time-of-use tariffs or critical peak pricing for non-teleswitched meters. These limitations precluded the use of non-static time of use tariffs. Further, since such an approach is optional, it does not ensure that suppliers take full account of the costs their customers impose on the system.
- 12.17 In contrast, half-hourly settlement would expose all suppliers to the full costs that their customers impose on the system (thus incentivising them to reduce these costs), and enable the provision of dynamic time-of-use tariffs which will more closely match the cost of procuring energy in the wholesale market and conditions on the transmission and distribution networks. For example, customers might be incentivised to use electricity when there is plenty of renewable generation available.
- 12.18 Dynamic time-of-use tariffs such as load control and critical peak pricing will play a more important role as the penetration of electric motor vehicles, heat pumps, other automation technologies (load control technologies) and generation from intermittent sources increases.

² Chunking allows the energy recorded on non-half-hourly electricity meters with at least two registers to be allocated to specific times of the day. Meter read data is then processed and aggregated for all suppliers’ customers on the new configuration and submitted to the settlement system. The settlement system processes will then be used to ‘allocate’ the number of units used between meter readings for all customers, on the new configuration to a load profile according to the times that each meter register is active.

12.19 In summary, we would expect a move to half-hourly settlement to be necessary for any form of dynamic or automated time-of-use tariffs and for the introduction of static time-of-use tariffs at scale.³

- *The savings from domestic peak load shifting*

12.20 The main potential cost savings from peak load shifting are:

- (a) Reductions in the short-run marginal costs of generation: if demand is shifted from peak to off-peak periods, savings will arise due to differentials between the marginal costs of generating electricity at peak and off-peak times.
- (b) Reductions in the costs of investing in new generating capacity: shifting demand from peak to off-periods will reduce the need for investing in certain types of new generation capacity in the future.
- (c) Reductions in the costs of investing in the distribution network: peak load shifting will also reduce the need to invest in new distribution network capacity.
- (d) Reductions in environmental costs: lower peak demand could also lead to reductions in greenhouse gas emissions and emissions having a harmful impact on air quality, since the generation mix during peak times tends to be more carbon-intensive (and have a worse impact on air quality) than off-peak generation.

12.21 The potential savings from these effects are substantial. In Section 8 we conducted an analysis of the costs incurred by the Six Large Energy Firms in supplying domestic electricity customers. This analysis showed that wholesale energy costs, which currently make up around 42% of the overall costs of supplying electricity, are the single biggest cost item, followed by network costs (25%).⁴

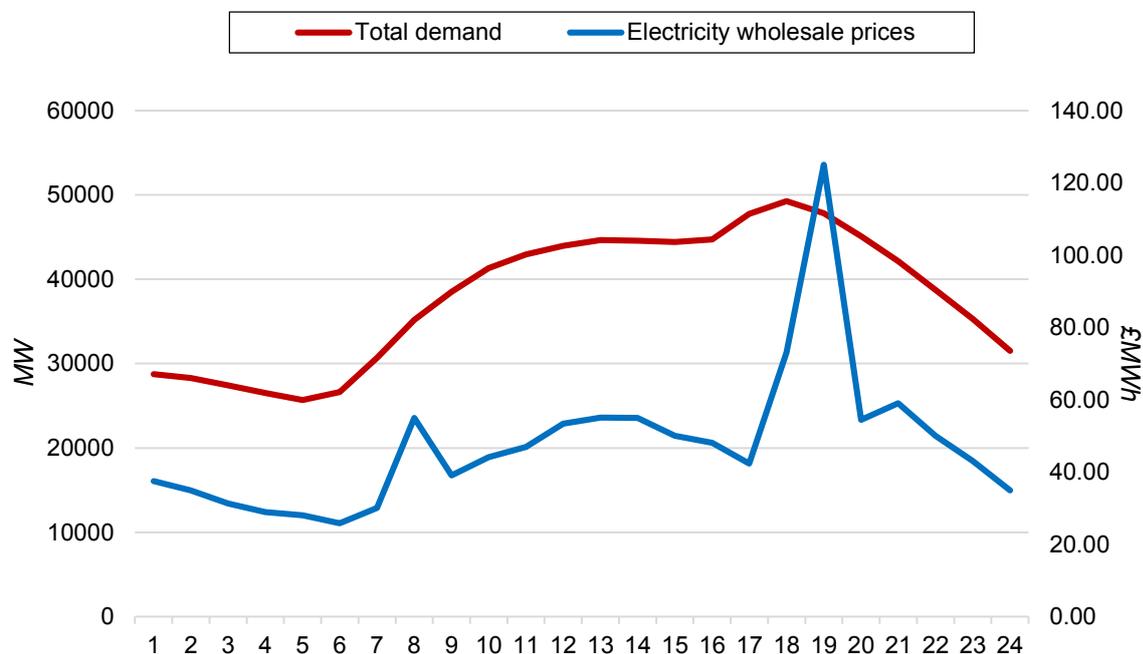
12.22 In relation specifically to potential savings in the wholesale costs of electricity, the chart below shows total electricity demand and wholesale prices by time of day for a typical weekday in winter in Great Britain. Electricity demand peaks between 5pm and 8pm. Over the peak period, the

³ We note that DECC's Impact Assessment concerning the introduction of smart meters assigns relatively modest benefits to load shifting – around £900 million in net present value terms. It has subsequently clarified to us that these estimates reflect the amount of load shifting that could be expected to occur in the absence of settlement reform. After the introduction of half-hourly settlement, they would expect the potential for load shifting to be much greater. See [DECC Impact Assessment, Smart meter roll-out for the domestic and small and medium non-domestic sectors \(GB\)](#).

⁴ See Section 8, Figure 8.2.

wholesale price increases from around £40/MWh to around £120/MWh, such that, if 2 GW of peak demand (less than 5% of total demand) were shifted to non-peak times, the savings would be of the order of £0.5 million a day.

Figure 12.1: Electricity demand and wholesale electricity prices for a typical weekday in winter (2 January 2013)



Source: National Grid (demand) and N2EX auction prices (electricity wholesale prices).

12.23 We would expect daily wholesale price differentials to increase in the future, due to the increasing deployment of intermittent and zero marginal cost plant and the use of subsidy regimes that will increase the likelihood of negative prices at certain times of day. The fact that more intermittent generation will be on the system will not only increase daily price differentials, but will tend to make price peaks and troughs more erratic and more difficult to predict far in advance. The implication is that dynamic and automatic time-of-use tariffs (as noted above, half-hourly settlement is a prerequisite for the introduction of such tariffs) will become increasingly important to allow such price differentials to be exploited.

12.24 Various studies have been conducted in an attempt to estimate both the potential for domestic load shifting in Great Britain in the future and the extent to which demand-side response might be expected to arise from domestic customers from the introduction of different types of time-of-use tariffs.

12.25 In terms of technical potential, Sustainability First and the Brattle Group have estimated the technical potential for load shifting in 2025 for domestic, industrial and commercial customers, using 2010/11 as a baseline. Their

results suggest that potentially 'shiftable' electricity demand may reach as high as 10GW in the domestic sector in 2025.⁵

- 12.26 Other studies have produced more conservative estimates. For example, Baringa (2013)⁶ estimated that by 2031, the peak load reduction from domestic customers would vary between 2.1 and 7.9 GW depending on the time-of-use scenario modelled. Frontier Economics (2015),⁷ in its recent review of the potential for demand-side response to 2035, suggested that the greatest potential for demand-side response will occur in the future, if and when technologies such as heat pumps, electric motor vehicles and electrical energy storage systems reach mainstream acceptance.
- 12.27 We are aware of one study that has attempted to value the amount of peak demand reduction expected to arise through different types of time-of-use tariffs. Baringa and Element Energy⁸ (2012) estimated the potential for demand-side responses from domestic and SME customers and attempted to monetise benefits from load shifting under a number of different scenarios, relating both to:
- (a) the uptake of different types of time-of-use tariffs (static, automated and dynamic including critical peak pricing); and
 - (b) the penetration of different types of low carbon technologies such as heat pumps, electric vehicles and smart appliances.
- 12.28 They estimated savings within the domestic sector of between roughly £50 million and £100 million a year by 2020 and between roughly £100 million and £350 million a year by 2025. Expected savings increase with the roll-out of automated and dynamic time-of-use tariffs (for which settlement reform is necessary if efficiencies are to be fully and accurately realised) and with increased penetration of low carbon technologies. We note in relation to this latter factor that the demand and supply of heat pumps, smart appliances and electric vehicles will be driven in large part by the availability of opportunities to exploit within-day price differentials. Therefore we would argue that a move to half-hourly settlement will be a necessary step in achieving the higher end of potential benefits from demand-side response.

⁵ Sustainability First and The Brattle Group (2014), [Impact of demand reduction and demand shifting on wholesale prices and carbon emissions](#).

⁶ Baringa (2013). Smart Metering Load Shifting Analysis, p7, Figure 7.

⁷ Frontier Economics, LCP (2015), [Future potential for DSR in GB](#). A report prepared for DECC by Frontier Economics with support from LCP and Sustainability First. See p3.

⁸ [Electricity System Analysis- future system benefits from selected DSR scenario \(August 2012\)](#).

- *Other benefits arising from settlement reform*

12.29 A number of additional benefits and cost savings might be expected to arise from the implementation of half-hourly settlement. These include the following:

- (a) Improved data quality and faster settlement – suppliers could face less financial uncertainty in the allocation of imbalance charges as meter readings would be more accurate and submitted to settlement sooner, and the costs that suppliers incur as a result of errors in consumption data could fall.
- (b) Lower administration charges – load profiles would no longer be necessary, so the costs currently incurred by suppliers and Elexon in supporting the current profiling system would be saved.⁹
- (c) Better forecasting of demand, which results in a lower cost of balancing the electricity system.

- *The costs of reforming the settlement system*

12.30 In relation to costs, we would expect that the implementation of half-hourly settlement for profile classes 1 to 4 will require changes to the systems employed by Elexon, distribution network operators and electricity suppliers. Therefore we asked Elexon, distribution network operators and electricity suppliers to estimate how much it would cost to implement half-hourly settlement.

12.31 In terms of implementation costs, we consider these to be low for distribution network operators and Elexon.

12.32 Elexon submitted that a move to half-hourly settlement for profile classes 1 to 4 would result in it incurring implementation costs ranging between £550,000 and £850,000. Elexon indicated an increase in its annual costs of approximately £260,000–£460,000 in years 1 and 2 following implementation with potential for net annual savings of up to £755,000 thereafter when compared to current costs (subject to the cessation of non-half hourly settlement).¹⁰

⁹ Elexon pointed out that some profiling and data estimation might still be needed to address circumstances where meter data is not available through a technical fault or a result of customers choosing not to have a smart meter (see Elexon response to provisional decision on remedies, p2). We believe the number of cases where this will occur to be small.

¹⁰ See Elexon [submission](#) to the CMA, 29 October 2015.

- 12.33 Four distribution network operators responded to our request. Their estimates of the costs of implementing half-hourly settlement, both upfront and ongoing [REDACTED]. This is based on the assumption that half-hourly settlement for profile classes 1 to 4 is introduced on an aggregated basis where all customers on the same distribution use of system tariffs are grouped together in the bill sent to the suppliers.¹¹ Electricity North West submitted that costs for implementing half-hourly settlement for profile classes 1 to 4 had already been incurred as part of two previous industry modification proposals.
- 12.34 In relation to electricity suppliers, only two of the Six Large Energy Firms ([REDACTED]) and one other supplier ([REDACTED]) were able to provide estimates of the upfront and ongoing costs from the implementation of half-hourly settlement within the required timescale. While the estimates of the upfront and ongoing costs that they provided were substantial – running into several millions of pounds – they were not provided with sufficient supporting detail (or from a sufficient number of firms) to allow us to build a consistent, robust picture of the likely costs.
- *Distributional implications*
- 12.35 There is limited evidence on the distributional implications arising from half-hourly settlement. While we accept the argument that some customers might not be able to shift their consumption from peak to off-peak periods, there is limited evidence to suggest that these are more likely to be vulnerable or low-income consumers. We note that in the Northern Ireland Powershift trial, consumers in the trial group, who mostly had low incomes, were found to benefit from the lower off-peak prices in the time-of-use tariff passively (that is, without having to change their behaviour), as a lot of their electricity use was already at off-peak times.
- *Our views regarding the potential costs and benefits of settlement reform*
- 12.36 Overall, and based on the evidence we have seen, there are good reasons to expect the benefits from half-hourly settlement to outweigh the costs of its implementation by a substantial degree. However, a full cost-benefit analysis has not been possible within the time available to us and, in particular, we have not conducted our own modelling of benefits or collected a comprehensive and robust set of data on costs.

¹¹ An alternative would be the introduction of site-specific settlement whereby energy suppliers will be billed separately for each specific customer that is connected to a distribution network. The cost of site-specific settlement would be significantly higher than aggregate settlement.

12.37 We believe Ofgem should conduct such an exercise as part of its plans to introduce elective and mandatory half-hourly settlement for profile classes 1 to 4 (for the reasons set out below), including with a view to determining when half-hourly settlement should become mandatory for all domestic and SME customers.

Parties' views

12.38 We received responses to our Remedies Notice and to the proposed remedies package set out in our provisional decision on remedies from various parties including the Six Large Energy Firms, two Mid-tier Suppliers,¹² other smaller suppliers,¹³ Elexon, ElectraLink, Ofgem and Citizens Advice.

12.39 Most parties expressed support for our proposed remedies package.

(a) EDF Energy,¹⁴ RWE,¹⁵ Northern Powergrid,¹⁶ and Ovo Energy¹⁷ considered that a plan for moving domestic and SME electricity customers to half-hourly settlement was needed.

(b) Centrica,¹⁸ Scottish Power,¹⁹ RWE,²⁰ Utilita,²¹ First Utility²² and Ofgem²³ broadly supported the CMA's proposed remedy in this area. First Utility²⁴ said this was subject to specific areas they highlighted for further consideration.

(c) Elexon²⁵ said that it supported the move to half-hourly settlement and the production of a plan that would provide clarity on the timing of any move to elective and/or mandatory arrangements. Haven Power²⁶ also supported a move to half-hourly settlement and said that it was encouraging to note that Ofgem was asked to conduct a full cost-benefit analysis of the proposals, including the assessment of the distributional

¹² Ovo Energy, Co-operative Energy and First Utility.

¹³ Flow Energy, Ecotricity, Gazprom, Good Energy, Haven Power, Opus, Smartest Energy, Labrador and Utilita.

¹⁴ EDF Energy response to Remedies Notice, p47.

¹⁵ RWE response to Remedies Notice, p120.

¹⁶ Northern Powergrid response to Remedies Notice, p3.

¹⁷ Ovo Energy response to Remedies Notice, p29.

¹⁸ Centrica response to provisional decision on remedies, paragraphs 282 & 283, p56.

¹⁹ Scottish Power response to provisional decision on remedies, paragraph 4.1, p7.

²⁰ RWE response to provisional decision on remedies, paragraphs 40.1; 41.2 & 42.1.

²¹ Utilita response to provisional decision on remedies, paragraph 5.1, p23.

²² First Utility response to provisional decision on remedies, paragraph 1.1, p5.

²³ Ofgem response to provisional decision on remedies, p1.

²⁴ First Utility response to provisional decision on remedies, paragraph 1.1, p5.

²⁵ Elexon response to provisional decision on remedies, p2.

²⁶ Haven Power response to provisional decision on remedies, p1.

implications for customers to ensure decisions are made on an informed basis.

- (d) Scottish Power²⁷ said that it was sensible for the CMA to consider whether any additional intervention was required to ensure that industry delivered half-hourly settlement in a well-planned and cost-effective manner. It added that in defining a plan for the introduction of half-hourly settlement two dates should be considered: (a) the earliest date at which the systems for half-hourly settlement were available and suppliers elected to settle individual customers based on half-hourly consumption; and (b) the date by which suppliers were obliged to settle all customers on a half-hourly basis.
- (e) EDF Energy²⁸ supported the CMA's recommendations to Ofgem and DECC.
- (f) E.ON²⁹ welcomed the proposals to adjust the Smart Energy Code and to conduct a broad and comprehensive piece of work to scope out details of how best to achieve a move to half-hourly settlement. It noted that an assessment for half-hourly settlement had been undertaken in the Irish market and that Ofgem could benefit from following a similar approach.
- (g) SSE,³⁰ despite disagreeing with the CMA's finding of an AEC for electricity settlement, welcomed the CMA's recognition that a full cost-benefit analysis of the move to mandatory half-hourly settlement was required and agreed that Ofgem was best placed to carry this out.

12.40 Gazprom,³¹ however, said it was not yet convinced whether the remedy was required. It said that as smart and advanced meters were rolled out to domestic and SME customers, then half-hourly settlement and tariff innovation might develop without the need for regulation.

12.41 Some parties commented on aspects of the remedies package that required further consideration. They identified potential risks, including potential unintended adverse consequences. In particular:

- (a) EDF Energy³² highlighted that the industry changes required to deliver half-hourly settlement were likely to be complex and costly at a time when the industry was already managing other initiatives such as next

²⁷ Scottish Power response to Remedies Notice, p46.

²⁸ EDF Energy response to provisional decision on remedies, paragraphs 4.1 & 4.3, pp22 & 23.

²⁹ E.ON response to provisional decision on remedies, paragraphs 156 & 160, pp33 & 34.

³⁰ SSE response to provisional decision on remedies, Annex 1, paragraphs 3.1.1 & 3.1.2, p1.

³¹ Gazprom response to Remedies Notice, p20.

³² EDF Energy response to provisional decision on remedies, paragraphs 4.4 & 4.5, p23.

day switching, Project Nexus and the roll-out of smart meters. It considered it essential that any plan for half-hourly settlement was correctly sequenced. It agreed that high quality project management and preparation was required if the problems reported by the CMA for P272 and Project Nexus were to be avoided for the remedy package concerning electricity settlement. In particular, it said that sufficient time should be taken to design, build and test any solution prior to implementation.³³ First Utility³⁴ expressed similar views and considered that the cumulative impact on industry participants of domestic half-hourly settlement and other (ongoing or in the process of being launched) industry programmes needed to be taken into account. RWE³⁵ also submitted that the interaction of any change for half-hourly settlement, both elective and mandatory with other major change programmes taking place at the same time should be carefully considered by Ofgem and DECC. Haven Power³⁶ added that the impact of concurrent regulatory changes on independent participants who did not necessarily have a high level of resources available to manage multiple IT projects needed to be considered.

- (b) RWE³⁷ and First Utility³⁸ noted that a move to elective half-hourly settlement could result in higher 'group correction factor' charges, which might mean that non half-hourly settled customers would attract a greater proportion of group correction factor charges. Both considered that this issue should be recommended for consideration by Ofgem.
- (c) Haven Power expressed some concerns about the costs of half-hourly settlement and the impact it would have on vulnerable customers, many of whom it expected to be significant users of electricity at times of peak prices.³⁹ Gazprom⁴⁰ expressed similar views and submitted that the cost and benefits of all electricity consumers moving to half-hourly settlement needed to be considered carefully as there would be winners and losers. The Behavioural Insights Team⁴¹ said that there would be a transition period before the benefits of time-of-use tariffs flowed to consumers and

³³ EDF Energy added that for mandatory half-hourly settlement to be most efficient and effective, it should take place after SMETS 1 enrolment and adoption. It expressed concerns that managing SMETS1 meters on a non-DCC system would create costly short-term IT changes. EDF Energy response to provisional decision on remedies, paragraph 4.5, p23.

³⁴ First Utility response to provisional decision on remedies, paragraphs 1.1–1.6, pp5 & 6.

³⁵ RWE response to provisional decision on remedies, paragraph 42.6, p16.

³⁶ Haven Power response to provisional findings, p21,

³⁷ RWE response to provisional decision on remedies, paragraph 41.3, p15.

³⁸ First Utility response to provisional decision on remedies, paragraphs 1.3–15, pp5 & 6.

³⁹ Haven Power response to provisional decision on remedies, p1.

⁴⁰ Gazprom response to Remedies Notice, p20.

⁴¹ Behavioural Insights Team response to provisional findings, p14.

it considered that vulnerable customers should be protected during this period.

- (d) SSE,⁴² RWE^{43,44} and Smartest Energy⁴⁵ considered that, as part of its cost-benefit assessment of half-hourly settlement, Ofgem should also consider the implication of a potential EU-wide harmonisation to adopt 15-minute imbalance settlement periods. We understand that Ofgem is aware of this process and in its recent conclusions letter⁴⁶ on elective half-hourly settlement it stated:

We note that the European process is ongoing, and has a range of potential outcomes. These would have wider impacts on the GB market, beyond elective half-hourly settlement. We will continue to pay attention to this process – but it should not be seen as a reason to pause work on elective HHS, because, as noted above, there is a range of potential outcomes.⁴⁷

- (e) Centrica⁴⁸ supported the principle of half-hourly settlement for all electricity meters but said it should not be implemented before the point at which a full impact assessment showed the benefits case was net positive for consumers. It⁴⁹ welcomed the CMA's recommendation that Ofgem completes a full cost-benefit analysis before proceeding with implementation and considered that the analysis must be carried out separately for domestic and microbusiness customers.⁵⁰

⁴² SSE response to provisional decision on remedies, Annex 1, paragraphs 3.1.1 & 3.1.2, p1.

⁴³ RWE response to provisional decision on remedies, paragraph 41.4, p15.

⁴⁴ RWE considered that the cost-benefit analysis must also include the financial impact of half-hourly settlement on customers. This should include the cost of industry-wide system change as well as the perceived financial gains and the financial impacts on those customers that continue to be settled on a non-half-hourly basis. It also suggested that the analysis should cover risks, issues, and unintended consequence; and the likelihood of customers electing half-hourly settlement.

⁴⁵ Smartest Energy response to provisional decision on remedies, p3.

⁴⁶ Ofgem (2016), *Elective half-hourly settlement: conclusions paper*, paragraph 5.30, p19.

⁴⁷ Ofgem considered that among the potential outcomes of this process there could be a different settlement period for wholesale and retail markets.

⁴⁸ Centrica response to provisional decision on remedies, paragraphs 286 & 288, pp56 & 57.

⁴⁹ Centrica response to provisional decision on remedies, paragraph 286, p56.

⁵⁰ Centrica also went into some length discussing other aspects of the cost-benefit analysis that Ofgem should consider. These included: the distributional impacts of half-hourly settlement on customers and the market; what benefits could already be realised today, for example through 'chunking'; what impact an initial move to elective half-hourly settlement would have, what controls may be needed to protect those vulnerable customers who may be penalised under such a regime, when the benefits case turned net positive; how long should a reasonable implementation programme take; a post-implementation review of the benefits of P272 and the opportunity cost of deploying resources to the half-hourly settlement project (eg on diverting industry resources from other programmes such as 'Faster and More Reliable Switching' or smart metering); quantifying the benefits to competition flowing from more accurate settlement, as well as considering how these impacts varied between the domestic and SME sectors, where the costs, benefits and distributional impacts were likely to be different. Centrica response to provisional decision on remedies, paragraph 287, p56.

- (f) RWE⁵¹ said that the move to half-hourly settlement would impact the entire market, including the customers that it served, and that a process of careful planning and development needed to be adopted before any large scale investment was made around half-hourly settlement. In particular it considered that careful consideration should be given to both the timing of a move to mandatory half-hourly settlement and the approach taken to get there. It urged Ofgem, DECC and the industry to learn from the experience of P272 and ensure that the path to half-hourly settlement was fully supported by industry processes before introducing a deadline.
- (g) Utilita⁵² argued that in addition to requiring Ofgem to do a full impact analysis prior to implementation of mandatory half-hourly settlement, the CMA should make an order to update the BSC to alter the charging arrangements to a £/MWh charge as this would facilitate elective half-hourly settlement.

12.42 We believe that these concerns should be addressed through the cost-benefit analysis that we are recommending below.

12.43 Some suppliers⁵³ agreed that the provisions of the Smart Energy Code that restrict suppliers' access to customers' half-hourly consumption data are a barrier to half-hourly settlement and hinder suppliers' ability to design tariffs which incentivise load shifting. Parties⁵⁴ also agreed with the CMA's proposed recommendation that DECC should consult on amending these provisions.

12.44 Some parties⁵⁵ noted that SLC 47 contained the same data access restrictions and that it was necessary to amend it to ensure DECC's consultation resulted in a relaxation of the data constraints on collecting half-hourly data. Utilita⁵⁶ added that the CMA's proposed recommendation to DECC would also need to apply to Ofgem through the licence condition change process.

⁵¹ RWE response to provisional decision on remedies, paragraphs 42.3, 42.4 & 42.8, p16.

⁵² Utilita response to provisional decision remedies, paragraph 5.13, p23.

⁵³ E.ON response to provisional decision on remedies, paragraphs 156 & 157, p33; Centrica response to provisional decision on remedies, paragraphs 291-293, p57; RWE response to provisional decision on remedies, paragraphs 40.1-40.6, p14.

⁵⁴ Utilita response to provisional decision on remedies, paragraphs 5.18 & 5.19, p23. RWE response to provisional decision on remedies, paragraphs 40.1-40.6, p14. E.ON response to provisional decision on remedies, paragraphs 156 & 157, p33. Centrica response to provisional decision on remedies, paragraphs 292 & 293, p57.

⁵⁵ Scottish Power response to provisional decision on remedies, paragraph 4.3, p8. RWE response to provisional decision on remedies, paragraphs 40.1-40.6, p14.

⁵⁶ Utilita response to provisional decision on remedies, paragraphs 5.18 & 5.19, p23.

- 12.45 Citizens Advice,⁵⁷ instead, disagreed with the CMA's proposed recommendation in relation to access to smart data. It considered that allowing suppliers default access to the most detailed smart meter data risked undermining the competitive market generated by different companies offering a wide range of services to consumers in exchange for that data. It added that DECC's planned review of the Data Access and Privacy frameworks was the appropriate opportunity to consider the need for any changes to data choices in detail.
- 12.46 The Information Commissioner's Office⁵⁸ advised that there was potential for intrusion into the private lives of individuals by organisations that process smart meter consumption data. It said that the more granular the consumption data was, the more could be inferred and so the higher the risk to individuals' privacy. It advised that under the current Smart Meter Data access and privacy framework⁵⁹, suppliers require customers' prior consent to be able to access half hourly consumption data (the most granular).
- 12.47 Some parties, whilst agreeing with the need for Ofgem to have more powers to implement half-hourly settlement, expressed some concerns with DECC's planned review. In particular:
- (a) Centrica⁶⁰ agreed that an Ofgem-led process for the assessment and delivery of half-hourly settlement was preferable to the normal code modification route. However it expressed some concerns over DECC's proposals to remove any right to appeal to the CMA over the implementation of half-hourly settlement. Similar concerns were expressed by Elexon.⁶¹ We understand however that there is currently no right to appeal to the CMA on the basis of this power and that DECC is currently considering the introduction of such a right.
 - (b) Scottish Power⁶² agreed that it may be helpful for Ofgem to have the power to modify industry codes-in relation to half-hourly settlement to ensure timely implementation. However, it considered that Ofgem needed to ensure that licensees were given adequate time for

⁵⁷ Citizens Advice response to provisional decision on remedies, p15.

⁵⁸ Information Commissioner's Office response to Remedies Notice, pp9 & 10.

⁵⁹ DECC (2012), *Smart Metering Implementation Programme Data access and privacy: Government response to consultation*.

⁶⁰ Centrica response to provisional decision on remedies, paragraph 291, p57.

⁶¹ Elexon also expressed concerns that proposed legislation did not include code administrators in the list of parties who Ofgem is required to consult in relation to proposed modifications. Elexon response to provisional decision on remedies, p9.

⁶² Scottish Power response to provisional decision on remedies, paragraph 4.7, p8.

implementation, especially as they were likely to be managing a number of other complex system and operational changes at the same time.

12.48 EDF Energy,⁶³ instead, did not believe that a case had been made for Ofgem to be provided with additional broad powers allowing it unilaterally to make modifications to industry codes in respect of the faster switching and settlement reforms. It considered that increasing Ofgem's powers to implement changes without due assessment by experts could lead to sub-optimal changes being developed and further damage to customer trust in the energy markets. In view of our findings in relation to codes governance and the remedies we are introducing in that context (see Sections 18 or 19), we consider that the additional powers that Ofgem will have will be appropriate within this context.

Design considerations

12.49 In Section 9, we observed that the introduction of half-hourly settlement was a substantial reform that would take some time to plan and implement. Our concern was that, despite the fact that the reform has the potential to deliver significant benefits, beyond those taken into consideration by DECC in its smart meters impact assessment,⁶⁴ there was no concrete plan in place to move to half-hourly settlement for domestic and SME customers.

12.50 We considered that without sufficient planning and strong project management, the implementation of half-hourly settlement for profile classes 1 to 4 may suffer from the same problems we reported for Project Nexus and P272, including an unnecessarily long lead time and difficulties with implementation (see also our remedies relating to codes governance in Section 19).

12.51 We have been encouraged to note that, since the publication of our provisional findings report, substantive progress has been made by both DECC and Ofgem towards developing a concrete plan for the introduction of half-hourly settlement. We summarise these developments in the next section, before setting out certain issues that we consider should inform the development of such a plan.

⁶³ EDF Energy response to provisional decision on remedies, paragraph 4.8, p23.

⁶⁴ DECC's impact assessment contains only modest estimates of the potentials from load shifting. See paragraph 12.19.

- *Recent developments*

- 12.52 Following the publication of our provisional findings report, the Secretary of State for Energy and Climate Change wrote to us stating that she shared our views about the importance of half-hourly settlement in facilitating greater innovation in time-of-use tariffs and would shortly be bringing forward proposals for pre-legislative scrutiny that would seek to give Ofgem greater powers in order to deliver settlement reform more quickly.⁶⁵
- 12.53 In January of this year, DECC consulted on proposed powers – for the purposes of pre-legislative scrutiny – to be given to Ofgem to allow it to implement switching and settlement reforms in a timelier and more cost-effective manner.⁶⁶ The proposed powers will enable industry codes to be modified directly by Ofgem rather than industry so as to facilitate expeditious and coordinated changes to industry codes. This is because DECC considers that the current significant code review process (see discussion of this process in Section 18 and Appendix 18.2) will not deliver the policy objectives (enhanced competition and increased consumer engagement) of the switching and settlement reforms in a timely and cost-effective manner that ensures the best outcomes for consumers.⁶⁷
- 12.54 Under the current draft legislation, the proposed power(s) will be time-limited to five years from commencement and scope-limited to the switching and settlement reform programmes only. In view of the concerns set out above, and the potential impact of half-hourly settlement on consumers' interests and/or competition, we believe that an Ofgem-led process could be more appropriate than the normal industry-led process to implement half-hourly settlement. To this extent, these proposed powers are consistent with our remedies relating to the Codes AEC set out in Section 19.⁶⁸ We consider, however, that once the half-hourly settlement reform is implemented, further modifications to the relevant codes should follow the normal code governance process (as amended pursuant to our remedies set out in Section 19).
- 12.55 The power(s) will also introduce the ability for Ofgem to reduce the 56-day period between the notice of a licence modification being published and the modification coming into effect. We consider that such a provision could be

⁶⁵ Letter of 31 July 2015, available on GOV.UK.

⁶⁶ DECC (2015), *Draft Measures: Fast and reliable switching and Half-hourly settlement power(s)*, p10, paragraph 42.

⁶⁷ *ibid*, p10, paragraph 47.

⁶⁸ See in particular our proposed remedy that Ofgem should have the power (call-in power) to take control of the development and implementation of strategically important modification proposals in certain exceptional circumstances.

useful to ensure that Ofgem is able to implement half-hourly settlement in a more timely manner.

- 12.56 Ofgem has agreed (in a letter published on 17 December 2015) to take forward a project to reform the electricity settlement arrangements in Great Britain.⁶⁹ The project's aim is initially to remove barriers to elective half-hourly settlement for domestic and microbusiness customers and then eventually mandate half-hourly settlement for all customers. It has recently published a conclusion paper⁷⁰ where it has identified three main barriers to elective half-hourly settlement. It considered that the changes to address these needed to be progressed through the usual industry governance process and that this relied on industry parties and code administrators playing a full and constructive role, including by raising changes.
- 12.57 Ofgem envisages that elective half-hourly settlement will be enabled by early 2017 and that it will issue a decision on mandatory half-hourly settlement, including timescales, by the first half of 2018. It has consulted on a plan to launch a Significant Code Review on mandatory half-hourly settlement. It has not yet indicated what the timescale might be for the introduction of mandatory half-hourly settlement. We comment on the respective merits of elective and mandatory half-hourly settlement in paragraphs 12.65 to 12.75 below.

- *Issues to consider*

- 12.58 We think that the steps that, since the publication of our provisional findings report, DECC and Ofgem have taken towards developing a concrete plan for the introduction of half-hourly settlement for domestic customers are positive, and we welcome them. We set out below some additional considerations that, in our view, should inform the development of a concrete plan for implementing half-hourly settlement.
- 12.59 We have identified several issues that would need to be taken into account when developing a plan for half-hourly settlement:
- (a) access to half-hourly consumption data by energy suppliers;
 - (b) the respective costs and benefits of mandatory and elective half-hourly settlement;
 - (c) alternative options for institutional design regarding settlement;

⁶⁹ See Ofgem (2015), [Half-hourly settlement: the way forward](#).

⁷⁰ Ofgem (2016), [Elective half-hourly settlement: conclusions paper](#).

- (d) the conduct of the cost-benefit analysis; and
- (e) the need for a formal, joint plan between DECC and Ofgem.

12.60 We discuss these in turn below.

- *Supplier access to half-hourly data*

12.61 One of the suppliers' licence conditions (SLC 47) prohibits suppliers from collecting consumption data with greater granularity than daily unless a customer has given explicit consent to do so (opt in).⁷¹

12.62 We believe that this opt-in clause effectively precludes mandatory half-hourly settlement (which by definition requires the use of all customers' half hourly data for settlement, not just the data of those customers who have opted in) and is therefore a major barrier to the development of static and dynamic time-of-use tariffs. We note the Information Commissioner's comments and acknowledge that data privacy is a controversial area. We think the government needs to explain clearly why access to half-hourly data is necessary if major demand-side response – with associated benefits for consumers – is to be achieved.

12.63 We have noted Citizens Advice's suggestion that DECC's planned review of the Data Access and Privacy Framework is the appropriate opportunity to consider the need for any changes to data choices in detail. DECC has told us it committed to explore the interactions between the provisions of the Data Access and Privacy Framework and the work being led by Ofgem to consider half-hourly settlement of domestic and smaller non-domestic consumers, and has confirmed that it may be necessary to propose amendments to the current Data Access and Privacy Framework to ensure that the benefits of settlement reform are delivered, whilst maintaining appropriate privacy safeguards.⁷² We recommend that DECC consider removing any potential barrier for suppliers to collect consumption data with greater granularity than daily in the context of this review.

12.64 DECC has told us that the Smart Energy Code does not prohibit suppliers from collecting consumption data with greater granularity than daily unless a customer has given explicit consent, but only does so through a reference to

⁷¹ See Appendix 8.4: Smart meter roll-out in Great Britain. We also note that, with respect to certain meters (including smart meters), the collection of data relating to periods of less than a day can be authorised by Ofgem for a trial period (SLC 47.7 to 47.9).

⁷² See: DECC (December 2015), [Smart Metering Implementation Programme: Government response to consultation on timing of the review of the Data Access and Privacy Framework](#).

suppliers' licence conditions. We agree with DECC that the thrust of this restriction is set out in SLC 47⁷³. Accordingly, for the purpose of implementing mandatory half-hourly settlement, we are recommending that Ofgem modifies SLC 47 so as to allow suppliers to collect consumption data with greater granularity than daily unless a customer has given explicit consent to do so. We consider that access to half-hourly data is necessary if major demand-side response – with associated benefits for consumers – is to be achieved.

- *Elective vs mandatory half-hourly settlement*

12.65 In relation to the merits of mandatory as opposed to elective half-hourly settlement, we note that the first stage of Ofgem's work will be focused on removing the barriers to elective half-hourly settlement and that it proposes to draw on the experience of elective half-hourly settlement in developing its views on mandatory half-hourly settlement.

12.66 We would express some caution about the sequencing implicit in this approach. In Section 9 of this report, we noted that there were barriers to elective half-hourly settlement – notably that it was prohibitively costly under the current system – and if a simple, cost-effective way can be found to reduce these costs, we would support this.

12.67 However, in our view, elective half-hourly settlement is unlikely to be an effective substitute for full, mandatory half-hourly settlement. This is because under mandatory settlement, all suppliers bear the full costs that their customers impose on the electricity system. This, in turn, will both reduce overall costs per head and give stronger financial incentives to suppliers to engage all of their customers, in an attempt to shift their consumption to cheaper periods. In contrast, under the status quo, suppliers have a financial incentive to keep their customers disengaged, since they are generally on higher tariffs and have a lower propensity to switch. Elective half-hourly settlement would not change this incentive as greatly as mandatory settlement.

12.68 We are also mindful of some of the comments made by parties in relation to the costs and risks associated with elective half-hourly settlement. SSE⁷⁴ has submitted that with elective half-hourly settlement the customer population as a whole would have paid for a system that would only be used by some. Also, RWE⁷⁵ was concerned that customers who did not

⁷³ Section 1.2(a) of the Smart Energy Code.

⁷⁴ SSE response to Remedies Notice, p96.

⁷⁵ RWE response to provisional decision on remedies, paragraph 41.2, p15.

participate in half-hourly settlement would be 'burdened' by the cost of enabling it.

- 12.69 EDF Energy⁷⁶ and SSE⁷⁷ said that mandatory half-hourly settlement would eliminate the need to maintain both non-half-hourly and half-hourly regimes (other than as an exception process) which would reduce costs compared with maintaining both regimes. EDF Energy stated that it did not believe it would be possible to implement a cost-effective industry solution for half-hourly settlement until the end of the smart metering roll-out. EDF Energy added that elective half-hourly settlement was unlikely to be an effective substitute for full, mandatory half-hourly settlement⁷⁸ and that maintaining both regimes could become a barrier to switching.⁷⁹
- 12.70 Further, Centrica⁸⁰ submitted that optional half-hourly settlement would create the risk of gaming whereby suppliers would settle half-hourly those customers whose difference from a profiled usage benefited the supplier's imbalance and trading position. Centrica,⁸¹ Citizens Advice,⁸² Good Energy⁸³ and Ofgem⁸⁴ all agreed that mandatory half-hourly settlement would reduce this risk.
- 12.71 We note that other suppliers – notably E.ON,⁸⁵ Ovo Energy,⁸⁶ First Utility⁸⁷ and Scottish Power⁸⁸ – supported a move to optional half-hourly settlement in the first instance.
- 12.72 In particular, Ovo Energy⁸⁹ believed that the case for elective half-hourly settlement was far more compelling than the CMA had been led to believe, especially as elective half-hourly settlement could greatly facilitate the delivery of mandatory half-hourly settlement. It said that elective half-hourly settlement ahead of mandatory would place competitive pressure on suppliers by any one supplier starting half-hourly settlement. Further it considered that there were also compelling operational benefits to proceeding with elective half-hourly settlement first as industry participants

⁷⁶ EDF Energy response to Remedies Notice, p48.

⁷⁷ SSE response to Remedies Notice, p96.

⁷⁸ EDF Energy response to provisional decision on remedies, paragraph 4.2, pp22 & 23.

⁷⁹ EDF Energy response to Remedies Notice, p48.

⁸⁰ Centrica response to provisional findings report and Remedies Notice, p97.

⁸¹ Centrica response to provisional findings report and Remedies Notice, p97.

⁸² Citizens Advice response to Remedies Notice, p59. Citizens Advice response to provisional decision on remedies, p17.

⁸³ Good Energy response to Remedies Notice, p10.

⁸⁴ Ofgem response to Remedies Notice, p97.

⁸⁵ E.ON, response to provisional findings report and Remedies Notice, p76.

⁸⁶ Ovo Energy response to provisional decision on remedies, paragraph 4.3, p23.

⁸⁷ First Utility response to provisional findings report and Remedies Notice, p50, paragraph 3.142.

⁸⁸ Scottish Power response to Remedies Notice, p48, paragraph 13.10.

⁸⁹ Ovo Energy response to provisional decision on remedies, paragraph 4.3, p23.

would have the opportunity to test and trial various aspects, ironing out issues along the way.^{90,91}

- 12.73 We believe that DECC and Ofgem should consider these points in developing a plan to move to mandatory half-hourly settlement.
- 12.74 In relation to costs, if, for example, Ofgem's further analysis of this issue suggested that substantial additional resources would be needed to develop and maintain a viable option of elective half-hourly settlement, this would suggest that such resources would be better used accelerating the implementation of mandatory half-hourly settlement.
- 12.75 In relation to the scope for gaming, we acknowledge that having a choice of settlement system may lead to a risk of cherry picking (ie simply opting for elective settlement for those customers whose consumption profile means they would be cheaper to serve). While this would result in a reduction in costs to the supplier, overall system costs would not fall and the potential efficiencies of half-hourly settlement would not be realised. We believe it is only through behavioural change that settlement reform will lead to expected benefits.
- *Alternative options for institutional design regarding settlement*
- 12.76 Some parties have submitted that a centralised system for data collection and aggregation would reduce the cost of half-hourly settlement by delivering economies of scale and overall efficiencies which would result in lower costs for customers.⁹² A few parties suggested that the DCC could perform the role of data collector/aggregator and could pass the aggregated data directly to the settlement administrator (Elexon). However, Citizens Advice⁹³ noted that the DCC might not be able to fulfil this function for all profile class 1 to 4 meters as many SME customers had an advanced meter which would not be enrolled under the DCC (DCC opt-out for smaller non-domestic customers).

⁹⁰ Ovo Energy response to provisional decision on remedies, paragraph 4.4, p24.

⁹¹ Ovo Energy also identified a number of issues to be resolved to enable elective half-hourly settlement. These included: change of measurement class, half-hourly data and system capacity, the effect of feed-in-tariff spill on group correction factors, TNUoS charging, balancing and settlement code cost recovery and the distributional effects associated with transitioning to half-hourly settlement. Ovo Energy submitted detailed information on these issues to Ofgem as part of its response to Ofgem's open letter on half-hourly settlement: the way forward, 29 January 2016.

⁹² Scottish Power response to provisional decision on remedies, paragraph 4.5, p8; EDF Energy response to provisional decision on remedies, paragraph 4.6, p23; E.ON response to provisional finding and Remedies Notice, paragraph 352, p76.

⁹³ Citizens Advice response to provisional decision on remedies, p16.

12.77 Utilita⁹⁴ strongly opposed the introduction of a monopoly data collection/data aggregator as it did not believe that introducing a further body to the industry, which was not subject to competitive pressure, would result in long-term efficient costs. Smartest Energy⁹⁵ submitted that it should also be borne in mind that customers appreciate the value added services that independent data collectors bring. Smartest Energy therefore was not convinced that a centralised solution would be sufficiently innovative to give the customer what they wanted.

12.78 While we have not reached any view on possible design options for half-hourly settlement, we believe that in theory a centralised system for half-hourly settlement could lower costs for customers and suggest that Ofgem should assess this in its development of a plan for mandatory half-hourly settlement.

12.79 In relation to the comments made by Citizens Advice regarding the role of the DCC, we understand that DECC is currently considering removing the DCC opt-out, subject to the results of a further consultation which concluded on 27 May 2016.⁹⁶

- *Cost-benefit assessment*

12.80 In relation to the cost-benefit assessment that Ofgem proposes to undertake, we consider that this should both draw on the available estimates of costs and benefits from studies already conducted – including those we have reviewed in this report – and involve original analysis. The original analysis should include:

- (a) modelling of benefits, considering technical potential, the likely variability of wholesale prices in the future and different scenarios regarding the roll out of time-of-use tariffs and low carbon technologies (noting that the latter two factors are likely to be strongly influenced by the timing of the move to mandatory half-hourly settlement);
- (b) more disaggregated and consistent information on the upfront costs of implementing half-hourly settlement and the costs and savings expected

⁹⁴ Utilita response to provisional decision on remedies, paragraph 5.17, p23.

⁹⁵ Smartest Energy response to provisional decision on remedies, p3.

⁹⁶ DECC's preliminary conclusion was that the DCC opt-out policy was no longer appropriate, particularly as it appeared that opted-out meters could not deliver the policy aims of interoperability and easier switching. Further, there was no firm evidence received of an alternative provider coming forward to deliver an equivalent service to the DCC. Government response to the March 2015 consultation on non-domestic smart metering: the DCC opt-out, 21 April 2016, paragraphs 12 & 13, p7.

to accrue on an ongoing basis from the introduction of half-hourly settlement; and

(c) an understanding of distributional impacts, noting potential mitigating measures.

12.81 As noted above, firming up estimates of costs, benefits and distributional impacts will take time. We have therefore decided to recommend that Ofgem start this analysis as soon as possible. The outcome of this work would be a firm date for the move to mandatory half-hourly settlement.

- *The adoption of a joint plan between DECC and Ofgem*

12.82 In this report, we identified a number of situations in which the implementation of policy goals had been delayed or suboptimal due to a lack of coordination between DECC, Ofgem and the industry. We noted, as an example, the difficulty in implementing modification proposal P272 (half-hourly settlement for certain categories of customer under profiles 5-8). Since 'load shifting' contributes to the case in favour of the roll-out of smart meters in DECC's impact assessment, we consider that DECC and Ofgem should have agreed on a set of concrete actions to ensure such benefits would be delivered, including clear responsibilities to take forward proposals for settlement reform (see Section 19).

12.83 We consider that half-hourly settlement reform for customer profiles 1-4 presents very similar potential benefits and challenges. We therefore believe that DECC and Ofgem should adopt a joint plan setting out the aim of the reform and the respective responsibilities of DECC (eg granting new powers to Ofgem through legislation), Ofgem (carrying out a cost-benefit analysis) and, as the case may be, the industry (eg with respect to consequential modifications to industry codes) in delivering the reform.

12.84 Beyond making responsibilities for delivery clear, publishing detailed joint statements should facilitate the engagement of and commentary from stakeholders. By giving more clarity about the actual implications of the proposed action plan, stakeholders will be in a better position to contribute their knowledge and expertise on the most legal and technical details. This process will also give more legal certainty to parties about the likely pace and technical implications of a given policy, allowing them to roll out the necessary internal changes (eg IT).

- *Implementation of the remedy*

12.85 For the reasons set out above in we support DECC's proposals:

- (a) to introduce the ability for Ofgem to reduce the 56-day period between the notice of a licence modification being published; and
 - (b) to give Ofgem powers to modify industry codes time-limited to five years from commencement and scope-limited to the switching and settlement reform programmes (we consider this proposal to be consistent with our remedies set out in Section 19).
- 12.86 Further to these proposals, for the purpose of addressing the features giving rise to the Electricity Settlement AEC, we have decided to make recommendations to both DECC and Ofgem.
- 12.87 First, we recommend that Ofgem:
- (a) conducts a full cost-benefit analysis of the move to mandatory half-hourly settlement, including analysis of costs, benefits and distributional implications as well as mitigating measures;
 - (b) starts the process of gathering evidence for the analysis as soon as practicable;
 - (c) considers the cost-effectiveness of alternative design options for half-hourly settlement such as a centralised entity responsible for data collection and aggregation;
 - (d) considers options for reducing the costs of elective half-hourly settlement, including:
 - (i) whether any of these options are likely to delay or accelerate the adoption of mandatory half-hourly settlement; and
 - (ii) any challenges that may arise or benefits that may accrue from the existence of two settlement systems, including in particular the possibility of gaming/cherry-picking behaviour; and
 - (e) consults, as part of the implementation of half-hourly settlement, on a proposed modification to the provisions of SLC 47 that prohibit suppliers from collecting consumption data with greater granularity than daily unless a customer has given explicit consent to do so. This is because access to half-hourly data is necessary if major demand-side response – with associated benefits for consumers – is to be achieved.
- 12.88 Second, we recommend that DECC considers, within the context of its planned review of the Data Access and Privacy frameworks, whether it is appropriate to remove any other potential barrier for suppliers to collecting

consumption data with greater granularity than daily for the purpose of implementing mandatory half-hourly settlement.

12.89 Third, we recommend that DECC and Ofgem publish and consult jointly on a plan setting out:

- (a) the aim of the reform for half-hourly settlement;
- (b) a list of proposed regulatory interventions (including code changes), and the relevant entity in charge of designing and/or approving such interventions, that are necessary in order to implement the half-hourly settlement reform;
- (c) an estimated timetable for the completion of each necessary intervention; and
- (d) where appropriate, a list of relevant considerations that will be taken into account in designing each regulatory intervention.

Assessment of effectiveness

12.90 In assessing the effectiveness of this remedy, we have considered:

- (a) the extent to which it meets its aim;
- (b) the extent to which the remedy is capable of effective implementation, monitoring and enforcement; and
- (c) the timescale over which the remedy is likely to have an effect.

12.91 Our view is that the remedy will be effective in achieving its aim of ensuring that, within a reasonable time frame, half-hourly consumption data is used to settle domestic and SME electricity customers falling into profile classes 1 to 4. Accordingly, our conclusion is that the proposed remedy will address, in part, the feature that an 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 gives rise to the Electricity Settlement AEC through the distortion of suppliers' incentives to encourage their customers to change their consumption profiles.

12.92 The evidence we have obtained does not allow us to determine what would be the most appropriate time frame for the implementation of half-hourly settlement reform. We believe that Ofgem, as sector regulator, is best placed to carry out a cost-benefit analysis that will allow it to reach a view on this matter, and to take overall responsibility for implementing the reform.

- 12.93 We also noted above that DECC has published draft legislation (see paragraphs 12.53 to 12.55) giving Ofgem additional powers to progress electricity settlement reform more quickly, and that Ofgem has published an initial plan to implement half-hourly settlement. In particular, we noted that Ofgem envisages that a final decision on mandatory half-hourly settlement will be taken by the first half of 2018. We welcome these recent developments (including Ofgem's time frame) and consider these consistent with the aims of our proposed remedial action.
- 12.94 While we have noted above concerns relating to the difficulty for Ofgem of implementing such a significant reform (see also Section 19 with respect to the regulatory framework and codes governance), we believe that the new powers that are intended to be granted to Ofgem under the draft legislation will greatly facilitate implementation of the reform. In the short term, however, we consider that (a) Ofgem needs to conduct cost-benefit analyses concerning mandatory half-hourly settlement reform; and (b) DECC and Ofgem need to publish a joint document (eg Memorandum of Understanding) setting out their respective roles and responsibility. Further, before making such decisions with respect to elective half-hourly settlement, Ofgem should consider the costs and benefits of doing so (compared to moving directly to mandatory half-hourly settlement).
- 12.95 In summary, we believe that DECC and Ofgem will act upon our remedy and that our remedy is capable of effective and timely implementation. As a result, we expect Ofgem to deliver the half-hourly settlement reform within an appropriate time frame in a way that maximises the benefits and mitigates the (transitional) costs.
- 12.96 Given both DECC's and Ofgem's recent progress concerning the implementation of half-hourly settlement reform, we are confident that both bodies will implement our recommendations. We will also expect Ofgem to be able to demonstrate developments concerning our recommendations promptly after our final report is published.

Assessment of proportionality

- 12.97 Our view is that the remedy will be effective in achieving its aim of ensuring that, within a reasonable time frame, half-hourly consumption data is used to settle domestic and SME electricity customers falling into profile classes 1 to 4. Accordingly, our conclusion is that the remedy will address, in part, the feature that an 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 gives rise to the

Electricity Settlement AEC through the distortion of suppliers incentives to encourage their customers to change their consumption profiles.

- 12.98 Considering the recent developments set out in Section 9, and the general direction of travel of DECC and Ofgem concerning the development of plans for half-hourly settlement reform, we believe that the incremental costs of this remedy will be low and, in any event, justified by its aim. No party provided evidence to the contrary in response to the provisional decision on remedies.

Duty to have regard to Ofgem's statutory duties

- 12.99 Where the CMA is considering whether to take action for the purpose of modifying one or more of the conditions of a retail gas or electricity supplier's licence, in deciding whether such action would be reasonable and practicable, the CMA must 'have regard' to the relevant statutory functions of Ofgem. Specifically in this context, we consider the recommendation that Ofgem amends SLC 47.
- 12.100 Ofgem's statutory functions concerning the transmission of electricity are set out in Part 1 of the GA86, as amended by the EA10, and include (among other things) granting transmission licences, promoting efficiency and economy on the part of persons authorised by licences or exemptions to transmit, distribute or supply gas, and to secure a diverse and viable long-term energy supply.
- 12.101 Ofgem's principal objective in carrying out such functions is to protect the interests of existing and future consumers of gas and electricity supply.⁹⁷ The interests of such consumers are taken as a whole, including their interests in (a) the reduction of greenhouse gases, (b) the security of supply, and (c) the fulfilment by Ofgem of the objectives set out in Article 40(a) to (h) of the Gas Directive.⁹⁸
- 12.102 As discussed above, we consider that these remedies should, by encouraging demand side response, have a positive impact on security of supply and sustainable development. Further, subject to the results of Ofgem's cost benefit analysis, the remedies should reduce overall costs, improving affordability for customers on average.

⁹⁷ See, among others, section 3A and section 6B of the EA89.

⁹⁸ Directive 2009/73/EC of the European Parliament and of the Council of 13 July 2009 concerning common rules for the internal market in gas and repealing Directive 2003/54/EC, OJ L211/55 (the Electricity Directive).

12.103 As noted above, we believe that this component of the remedies package is necessary to ensure that benefits from half-hourly settlement are achieved in a timely manner. As set out above in paragraph 12.62, SLC 47 is a major barrier to the development of static and dynamic time-of-use tariffs. While we have noted the concerns relating to the protection of personal data, we believe that these can be adequately addressed by putting appropriate safeguards in place.

12.104 In light of the above, we consider that our remedy is consistent with Ofgem's principal objective of promoting the interests of existing and future consumers.

Gas settlement reform

Introduction

12.105 As set out in Section 9, we have found that the current system of gas settlement is a feature of the GB domestic and SME retail gas markets that gives rise to an adverse effect on competition through the inefficient allocation of costs to parties (in particular of the costs arising from unidentified gas) and the scope it creates for gaming, which reduces the efficiency and, therefore, the competitiveness of domestic and microbusiness retail gas supply.

12.106 In reaching this view, we have considered in particular parties' submissions, which have suggested that:

(a) the infrequent updating of the annual quantities⁹⁹ (AQs) can result in shippers being faced with charges for gas that are inaccurate; this in turn provides inaccurate price signals to suppliers, which distorts the incentives to introduce new products;

(b) the possibility of gaming the AQ system, due to the absence of efficient mechanisms to reconcile estimated consumption with actual consumption, leads to errors in the settlement process that ultimately impact competition and final consumers; and

12.107 The presence of unidentified gas distorts competition between domestic/SME only suppliers and non-domestic suppliers and leads to the inefficient allocation of costs to parties. In Section 9 we noted that Ofgem has approved a modification proposal (known as Project Nexus) designed to

address some of these concerns. This included a modification to the Uniform Network Code that would lead to:

- (a) the replacement of Reconciliation by Difference with reconciliation at all individual gas meter points;
- (b) the opportunity for monthly rather than annual updating of the AQ (also referred to as rolling AQ);
- (c) the possibility for independent gas transporters to use the same systems and processes as other gas transporters; and
- (d) the potential for automated retrospective adjustment following meter reads where previously submitted data is shown to have been incorrect.

12.108 The new arrangements comprise the establishment of two new governance groups, chaired by Ofgem,¹⁰⁰ and a reconfiguration of the existing Project Nexus Steering Group, also chaired by Ofgem. The changes are designed to improve the governance of the programme to provide more efficient mechanisms to engage the right people, and facilitate quicker consultation and decision making.¹⁰¹

12.109 We acknowledged that Project Nexus was likely to address most of the current inefficiencies in the gas settlement system set out in Section 9. However, we were concerned that even after implementation of Project Nexus, the gas settlement process would still be characterised by the presence of a (residual) amount of unidentified gas, inefficiencies in the allocation of the cost of this residual unidentified gas, as well as incentives that shippers face to place a higher priority on adjusting AQs down (and delaying adjusting AQs up, so as to game the gas settlement system).

12.110 In addition, we noted our concerns relating to the delays in the implementation of Project Nexus, ie:

- (a) the slow pace of its implementation;
- (b) the lack of a binding time frame for its implementation (the deadline for implementation has been moved several times);

¹⁰⁰ These are Project Nexus Sponsors Forum and Project Nexus Delivery Group. See Ofgem (15 April 2016), Open letter: Cooperation with revised Project Nexus Governance Arrangements, p2.

¹⁰¹ See Ofgem (15 April 2016), Open letter: Cooperation with revised Project Nexus Governance Arrangements- Overview of new governance arrangements, p1.

- (c) the fact that some market participants may be adversely affected by these delays; and
- (d) the deferral of implementation of certain aspects of Project Nexus (ie elements of the retrospective adjustment arrangements) to 1 October 2017.¹⁰²

12.111 In our provisional decision on remedies, we proposed to address the Gas Settlement AEC and/or associated detriment as follows:

- (a) A recommendation to Ofgem to ensure implementation of Project Nexus by 1 October 2016 through monitoring closely the progress made by the industry in meeting intermediate milestones and to take (where appropriate) further measures to achieve this objective.
- (b) An order on gas suppliers (and amendments to gas suppliers' standard licence conditions) to submit all meter readings for non-daily metered supply points in GB to Xoserve as soon as they become available, and at least once per year, save for non-daily metered supply points with a smart or advanced meter, which must be submitted at least once per month.
- (c) A recommendation to Ofgem to:
 - (i) take responsibility for the development and delivery of a performance assurance framework to increase accuracy of the gas settlement process as soon as reasonably practicable, and at the latest within one year of our final report;
 - (ii) establish a project plan and allocate responsibility to Uniform Network Code parties to take actions for its implementation;
 - (iii) supervise its implementation; and
 - (iv) take appropriate steps to ensure that failure to meet targets under the performance assurance framework is sanctioned.

¹⁰² Ofgem approved on 26 February 2016 [UNC 573](#), which defers to 1 October 2017 some of Project Nexus' core functionality related to automated retrospective adjustments. The decision was taken on the grounds that this reduced specification was more likely to be delivered by 1 October 2016.

Recommendation to ensure Project Nexus is implemented in a timely manner

- *Aim of the remedy*

12.112 As discussed above, the implementation of Project Nexus would address most of the concerns that we identified in Section 9 of this report and, in turn, contribute to remedying the Gas Settlement AEC. This remedy would seek to ensure that, in addition to resolving the remaining issues, appropriate mechanisms are put in place in order to ensure that Project Nexus is implemented across the industry.

12.113 We note that the ultimate aim of any remedy is to address, in part, the detriment arising from the Gas Settlement AEC.

- *Parties' views*

12.114 We received responses to our provisional findings, Remedies Notice and to the proposed remedies package set out in our provisional decision on remedies from various parties including the Six Large Energy Firms, two Mid-tier Suppliers,¹⁰³ certain smaller suppliers,¹⁰⁴ Ofgem and Citizens Advice.

12.115 Many respondents¹⁰⁵ supported the implementation of Project Nexus by 1 October 2016 and some¹⁰⁶ welcomed the CMA's proposal that Ofgem take more control over the delivery of the programme. We note, however, that while the majority of respondents to our provisional findings considered that the new implementation date of 1 October 2016 was likely to be achieved, in response to our provisional decision on remedies, a number of parties expressed concern that this new implementation date might now be at risk.

(a) SSE¹⁰⁷ said it was aware of some risks to the current timetable.

(b) Scottish Power¹⁰⁸ said that there appeared to be a risk of further deferral of Project Nexus' functionality due to transporters' readiness. It noted

¹⁰³ Ovo Energy and First Utility.

¹⁰⁴ Flow Energy, Smartest Energy and Utilita.

¹⁰⁵ Centrica response to provisional decision on remedies, paragraph 294, p58; E.ON response to provisional decision on remedies, paragraph 163, p34; SSE response to provisional decision on remedies, paragraph 4.1.2, p2. Flow Energy response to provisional decision on remedies, p2; EDF Energy response to provisional decision on remedies, paragraph 5.1, p24; Co-operative Energy response to Remedies Notice, p22.

¹⁰⁶ RWE response to provisional decision on remedies, paragraph 43.1, p18; Centrica response to provisional decision on remedies, paragraph 294, p58.

¹⁰⁷ SSE response to provisional decision on remedies, Annex 1, paragraphs 4.1.1–4.1.3, p2.

¹⁰⁸ Scottish Power response to provisional decision on remedies, paragraph 5.2, p8.

that Ofgem had approved modification 573 to defer some of Project Nexus' core functionality on the grounds that this reduced specification was more likely to be delivered by the gas transporters by 1 October 2016. First Utility¹⁰⁹ also noted the de-scoping of the retrospective adjustment component of Project Nexus until October 2017 and said that, notwithstanding this de-scoping, significant risk to the implementation of Project Nexus remained.

- (c) RWE¹¹⁰ said that responsibility for the delays to the Project Nexus programme sat with Xoserve in its role as central delivery body. It noted recent delays to Xoserve's testing activities related to metering and processing and expressed concerns about its ability to deliver the programme by 1 October 2016. It added that Ofgem must ensure that speed of delivery is not prioritised over quality of delivery.¹¹¹
- (d) Utilita¹¹² said that Xoserve had not been able to deliver Project Nexus to the required timescales and that this had resulted in a reduced version of the system due to repeated de-scoping.
- (e) Ofgem¹¹³ submitted that whilst it remained committed to doing everything reasonable to achieve the 1 October 2016 implementation date, there were a number of issues affecting the industry's ability to be ready to go-live by this date with an acceptable level of risk to the consumer. It said that to increase the prospects of the programme being delivered successfully, it had recently taken over sponsorship of the programme, and extended the role of PricewaterhouseCoopers (PwC) to provide end-to-end programme assurance and project management support.

12.116 Some parties considered that the CMA should revise the recommendation to Ofgem and allow for more flexibility on the implementation of Project Nexus.

- (a) SSE¹¹⁴ considered that it would be preferable to have sufficient flexibility to address any identified issues than for Project Nexus to be pushed forward to meet a specific deadline with issues continuing following implementation. Due to the potential for unintended consequences, SSE did not consider a binding implementation date to be appropriate.

¹⁰⁹ First Utility response to provisional decision on remedies, paragraph 2.3, p6.

¹¹⁰ RWE response to provisional decision on remedies, paragraph 43.5, p19.

¹¹¹ RWE response to provisional decision on remedies, paragraph 43.4, p18.

¹¹² Utilita response to provisional decision on remedies, paragraph 5.22, p24.

¹¹³ Ofgem response to provisional decision on remedies, p5,

¹¹⁴ SSE response to provisional decision on remedies, paragraph 4.1.3, p2.

- (b) Utilita¹¹⁵ considered that the CMA must not insist on the delivery of Project Nexus for 1 October 2016 if in the view of Ofgem and industry this imposed unacceptable risks to consumers or shippers.
- (c) Scottish Power¹¹⁶ suggested that before finalising this remedy the CMA and Ofgem should carry out a further assessment regarding what was likely to be delivered by Xoserve. If there was a risk of further de-scoping, it suggested that the delivery date should be reassessed with the possibility of deferral to the earliest date that a full Project Nexus solution was possible.
- (d) Smartest Energy¹¹⁷ said that imposing an arbitrary deadline on Project Nexus did not help. It considered that it was much better to allow flexibility in the go-live date and to get the system changes right rather than to force it to be quickly available.
- (e) Centrica¹¹⁸ said that it would like any recommendation to Ofgem to also provide it with the flexibility to delay implementation further if it believed that it was absolutely necessary. It added that it would not support proceeding with implementation on 1 October 2016 if for example the changes to the new systems had not been fully tested.
- (f) Corona Energy said that there was little point in insisting on a timely implementation of Project Nexus unless the industry as a whole could be sure the implementation would be effective. The costs and damage to the industry of a 'timely' but ineffective implementation would far outweigh the costs associated with a delayed but effective implementation particularly when the implementation affected the whole industry.¹¹⁹
- (g) Ofgem suggested that the CMA's recommendation to it could be focused on outcomes rather than on any specific date. It said that it would welcome a recommendation that Ofgem ensured Project Nexus was implemented in a timely fashion, safeguarding the interests of consumers.¹²⁰

¹¹⁵ Utilita response to provisional decision on remedies, paragraph 5.24, p24.

¹¹⁶ Scottish Power response to provisional decision on remedies, paragraph 5.3, p9.

¹¹⁷ Smart Energy response to provisional decision on remedies, p8.

¹¹⁸ Centrica response to provisional decision on remedies, paragraphs 294–295, p58.

¹¹⁹ Corona Energy response to Remedies Notice, p13.

¹²⁰ Ofgem response to provisional decision on remedies, p5.

(h) Some parties¹²¹ proposed the imposition of financial penalties on Xoserve and/or gas transporters who caused Project Nexus to slip further. In particular, RWE raised a modification proposal (UNC 550) to introduce in the Uniform Network Code an incentive payments scheme pursuant to which, if one or more gas transporters are determined to be responsible for a specific failure, leading to a deferral of the implementation date beyond 1 October 2016, payments are to be made to shippers.¹²² We understand that Ofgem has now considered this modification proposal and decided to reject it¹²³ on the grounds that it does not meet the UNC objective (f) the promotion of efficiency in the implementation and administration of the Code.¹²⁴

- *Design considerations*

12.117 Earlier this year, Ofgem stepped in to take an overall sponsorship role for Project Nexus and established new governance arrangements to oversee the implementation of the project.¹²⁵ In spite of this intervention, we understand that the implementation of Project Nexus may be delayed again beyond 1 October 2016 and Ofgem is currently consulting on a new implementation date, between 1 February and 1 April 2017, in order to allow additional testing of relevant IT systems to be carried out before full implementation of Project Nexus. Ofgem considers that delivery of Project Nexus by 1 October 2016 is challenging,¹²⁶ in particular due to changes to suppliers' processes. This creates risks for the accuracy of customers' bills,¹²⁷ and therefore delivery by that date could lead to inefficient outcomes for consumers.¹²⁸

¹²¹ Scottish Power response to Remedies Notice, paragraph 12.3 p44; Utility Warehouse response to Remedies Notice, pp14 & 15; RWE response to Remedies Notice, pp117 & 118; RWE response to provisional decision on remedies, paragraph 43.2, p18.

¹²² We understand that UNC 550 is currently being considered by Ofgem, following the UNC's panel recommendation to implement it. See [Final Modification Report. 0550 Project Nexus – Incentivising Central Project Delivery](#).

¹²³ See Ofgem (27 May 2016), *Uniform Network Code (UNC) 550: Project Nexus -Incentivising Central Project Delivery*.

¹²⁴ See Ofgem (27 May 2016), *Uniform Network Code (UNC) 550: Project Nexus -Incentivising Central Project Delivery*, p2.

¹²⁵ Ofgem (15 April 2016), [Open letter: Cooperation with revised Project Nexus Governance Arrangements](#).

¹²⁶ See Ofgem (14 March 2016), [Improving the end-to-end management and assurance of Project Nexus](#).

¹²⁷ Ofgem said that customers might be unable to switch suppliers or face billing issues as shippers were unable to settle their gas volumes. See Ofgem (2 June 2016), *Project Nexus: consultation on options for a successful implementation*, p2; and Ofgem (14 March 2016), [Improving the end-to-end management and assurance of Project Nexus](#).

¹²⁸ Ofgem said that customers might be unable to switch suppliers or face billing issues as shippers were unable to settle their gas volumes. See Ofgem (14 March 2016), [Improving the end-to-end management and assurance of Project Nexus](#).

12.118 We are very concerned that the delivery of Project Nexus may be delayed yet again, as this means that the clear deficiencies in the gas settlement system will persist beyond 1 October 2016. We believe that this supports our view that the current systems for effecting major regulatory change through the code modification process are inadequate, and we reflect on the implications of this and other examples in our assessment of the regulatory framework in Sections 18 and 19.

12.119 Further, as described in Section 9 and in paragraph 12.110(d), we note that certain aspects of Project Nexus' core functionality have been deferred to October 2017.¹²⁹

12.120 In light of these developments, and having considered the concerns raised by Ofgem with respect to an implementation date on 1 October 2016, we have amended our remedy in relation to the implementation of Project Nexus. We recommend that Ofgem:

- (a) ensure implementation of Project Nexus by 1 February 2017 (or as soon as possible after that date, once Ofgem is satisfied that IT systems are ready for an effective implementation of Project Nexus and do not pose risks to customers) by monitoring closely the progress made by the industry through its role as a chair of the three governance groups;
- (b) if appropriate, in order to ensure the effective implementation of Project Nexus, amend the implementation process for Project Nexus (eg by requiring relevant parties to carry out further testing), and sets a new suitable implementation date for Project Nexus; and
- (c) take further measures where appropriate to achieve this objective (for instance if a party fails to meet agreed milestones or causes a further deferral of the implementation date).

- *Effectiveness of the proposed remedy*

12.121 We believe that Ofgem has the appropriate tools to monitor steps taken by the industry to implement Project Nexus, particularly in light of the new governance arrangements, and to take appropriate measures to ensure implementation in a timely manner, once it is satisfied that IT systems are ready for an effective implementation of Project Nexus).

¹²⁹ Ofgem approved UNC573 in February 2016. See Ofgem, [Uniform Network Code \(UNC\) 573: Project Nexus. Deferral of implementation of elements of retrospective adjustment arrangements.](#)

12.122 We believe that Ofgem has the powers and incentives to act upon our recommendation and we do not consider any direct intervention by the CMA would increase the likelihood of a timely and effective implementation of Project Nexus.

12.123 In view of the above, we consider that a recommendation to Ofgem to monitor implementation and, where appropriate, take appropriate measures to ensure implementation by 1 February 2016 (or as soon as possible after that date, once Ofgem is satisfied that IT systems are ready for an effective implementation of Project Nexus), would be effective to ensure implementation of Project Nexus. This in turn will contribute significantly to addressing the detriment arising from the Gas Settlement AEC.

- *Proportionality of the proposed remedy*

12.124 We consider that a recommendation to Ofgem to ensure implementation of Project Nexus by a date agreed with the industry or as soon as possible after that date, once Ofgem is satisfied that IT systems are ready for an effective implementation of Project Nexus through monitoring closely the progress by the industry and to take (where appropriate) further measures to achieve this objective, would not impose any additional costs on the industry. We understand Ofgem has already allocated some resources to monitoring Project Nexus. As a result, the incremental costs of this remedy are negligible, in particular, compared with the inefficiencies that are being addressed through the implementation of Project Nexus. For these reasons, we consider that the remedy is no more onerous than necessary and does not produce disadvantages that are disproportionate to its aim.

12.125 For the reasons set out above, we believe that a remedy imposed by way of an order by the CMA, as consulted upon in the Remedies Notice, would be more intrusive without being more effective in achieving its aim. Accordingly, we believe our remedy is the least intrusive of equally effective alternatives.

Remedies seeking to address inefficient allocation of costs between gas shippers arising from the gas settlement process

12.126 As noted above and in Section 9 we have found that the current system of gas settlement is a feature in the domestic and SME retail gas markets that gives rise to an adverse effect on competition through the inefficient allocation of costs of unidentified gas to parties and the scope it creates for gaming, which reduces the efficiency and, therefore, the competitiveness of domestic and microbusiness retail gas supply.

12.127 While we have noted that Project Nexus is likely to address most of the current inefficiencies in the gas settlement system identified, we believe that inefficiencies in the allocation of the costs of unidentified gas and 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, leading to inaccurate reporting of customers' consumption and therefore inefficiencies in the allocation of the cost of unidentified gas.

12.128 For the reasons set out below, we have decided to proceed with three remedies, which are complementary to each other, and, as a package, would increase suppliers' incentives to provide more accurate and frequent updates on individual supply points, reduce the amount of unidentified gas and improve the allocation of costs between suppliers. The revised remedies package consists of the following elements:

- (a) With respect to all non-daily metered supply points in Great Britain with a dumb meter, we will impose an order on gas suppliers to submit to Xoserve Valid Meter Readings¹³⁰ as soon as they become available and at least once per year.
- (b) With respect to all non-daily metered supply points with a smart or advanced meter, we will impose an order on gas suppliers to submit to Xoserve Valid Meter Readings at least once per month.
- (c) A recommendation to Ofgem to take appropriate steps to ensure that a performance assurance framework is established within a year of the publication of the CMA's final report.

12.129 These are described in more detail in paragraph 12.150.

- *Aim of the remedies package*

12.130 The purpose of this remedies package is to increase the accuracy of the gas settlement system with a view to reducing, to the extent possible, unidentified gas, and therefore addressing the inefficient allocation of costs between suppliers. It should also reduce the scope for gaming.

12.131 Accordingly, the ultimate aim of the remedies package is to address, in part, the detriment arising from the Gas Settlement AEC.

¹³⁰ As defined in section M3.1.4. of the Uniform Network Code - [Transportation Principal Document](#).

- *Parties' views*

12.132 We report below parties' views in response to our Remedies Notice and to the proposed remedies package set out in our provisional decision on remedies.

- *Order to submit meter readings*

12.133 In the Remedies Notice, we proposed imposing an obligation on suppliers to update their customers' AQs on a monthly basis. Most respondents¹³¹ to our Remedies Notice considered that implementation of this possible remedy would be impractical and costly until the majority of customers had a smart meter.¹³²

- (a) In our provisional decision on remedies, we revised our proposed remedies in light of those views (as set out in paragraph 12.120). Most parties supported the CMA's revised remedies on the submission of meter readings. In particular, parties said the following: EDF Energy¹³³ said that these requirements would reinforce existing requirements, which should in turn result in an increase in settlement accuracy.
- (b) E.ON¹³⁴ considered that the CMA's proposals for submitting all meter readings for non-daily metered supply points in GB to Xoserve as soon as they become available was a sensible approach.
- (c) Scottish Power¹³⁵ supported the revised remedy proposed by the CMA as it considered that it accommodated the practicalities governing the collection and submission of non-daily meter reads.
- (d) Centrica¹³⁶ considered the revised proposals for meter reads submission to be reasonable and said that they should be effective at achieving the CMA's aim of improving gas settlement accuracy.
- (e) First Utility¹³⁷ welcomed the measures proposed by the CMA in relation to meter reads and considered it as a significant step in addressing read submission issues, improving settlement accuracy and reducing the

¹³¹ Centrica response to Remedies Notice, pp98 & 99. Scottish Power response to Remedies Notice, paragraph 12.10, p45. EDF Energy response to Remedies Notice, p46. RWE response to Remedies Notice, pp119 & 120. First Utility response to provisional findings and Remedies Notice, paragraph 3.132, p48.

¹³² Suppliers would need to visit customers' premises to obtain monthly meter reads and this would be costly.

¹³³ EDF Energy response to provisional decision on remedies, paragraph 5.3, p24.

¹³⁴ E.ON response to provisional decision on remedies, paragraph 165, p34.

¹³⁵ Scottish Power response to provisional decision on remedies, paragraph 5.4, p9.

¹³⁶ Centrica response to provisional decision on remedies, paragraph 297, p58.

¹³⁷ First Utility response to provisional decision on remedies, paragraphs 2-6-2.8, p7.

volume of unidentified gas albeit that this would not on its own address issues around reads.

12.134 SSE,¹³⁸ instead, considered that this remedy would not be necessary in view of the implementation of Project Nexus. According to SSE, Project Nexus would ensure that all gas was reconciled back to actual meter readings and that therefore there would be an incentive on all shippers to ensure that AQ values were as accurate as possible to avoid imbalance costs at the moment of reconciliation.

12.135 A few respondents, whilst agreeing with the remedy proposed, said that remedy required further consideration.

(a) RWE¹³⁹ said that in order for this remedy to be effective Project Nexus needed to be designed so that it had the capacity to accept and process the number of meter readings suggested by the CMA and that it was not clear whether Project Nexus would be capable of this. RWE considered that a meter read frequency target should be set, monitored and maintained by a Gas Assurance Framework. Further, it considered that the CMA's proposed remedy should be amended so that suppliers were only compelled to submit Valid Meter Readings.

(b) First Utility¹⁴⁰ believed that the proposed remedy required a robust read validation/exception management capacity before it could be in place and urged the CMA to clarify the scope of the submission obligation. For the avoidance of doubt, the obligation will apply to Valid Meter Readings.

(c) Scottish Power¹⁴¹ noted that this remedy for smart/advanced meters was dependent on Project Nexus being in place to provide the capacity to accept monthly meter reads from shippers. It suggested that the requirements for monthly reads should take effect after an appropriate grace period to enable the Project Nexus solution to be sufficiently capable and operationally reliable.

(d) Centrica¹⁴² noted that in practice it was highly unlikely that any party would achieve 100% meter read collection over a given period of time as, for example, some customers might refuse entry to their property. It considered that any obligation in this area should allow suppliers to fulfil it by taking 'reasonable steps', as the Ofgem licence condition in this

¹³⁸ SSE response to provisional decision on remedies, Annex 1, paragraph 4.2.1, p2.

¹³⁹ RWE response to provisional decision on remedies, paragraphs 44.1–44.2, p19.

¹⁴⁰ First Utility response to provisional decision on remedies, paragraphs 2.6–2.8, p7.

¹⁴¹ Scottish Power response to provisional decision on remedies, paragraph 5.4, p9.

¹⁴² Centrica response to provisional decision on remedies, paragraph 297, p56.

area did. We acknowledge this point, which is relevant to the implementation of this remedy.

- *Performance assurance framework*

12.136 Our revised remedy, as set out in the provisional decision on remedies, included the establishment of a performance assurance framework. Below we report parties' views on this element of the remedies package.

12.137 Most parties supported the CMA's proposals in relation to a performance assurance framework.

(a) First Utility¹⁴³ and EDF Energy¹⁴⁴ supported the CMA's proposed remedy concerning the gas performance assurance framework. In particular, EDF Energy¹⁴⁵ believed that these were positive measures and should increase suppliers' incentives to provide more accurate and frequent updates on individual supply points, and should reduce the amount of unidentified gas and improve the allocation of its costs between suppliers.

(b) SSE¹⁴⁶ said that this remedy was in line with its efforts to implement a performance assurance framework with an overarching monitoring framework to identify, understand and address the causes of unidentified gas. However, it considered that this remedy should be accompanied by a review of the current shrinkage model as it considered that there was sufficient evidence to challenge the current working assumptions of the model.

(c) Citizens Advice¹⁴⁷ welcomed the CMA's proposals and considered that as Ofgem developed its plans for a performance assurance framework, it should study the effectiveness of the regime already in place for electricity.

12.138 Scottish Power¹⁴⁸ strongly supported the implementation of a performance assurance framework as an important means of reducing unidentified gas. It also made a number of comments regarding its implementation:

¹⁴³ First Utility also considered that a key element of a performance assurance framework, a performance assurance committee, was missing from the arrangements currently being considered by industry. It added that the lack of this element weakened the benefits that a performance assurance framework could have brought. First Utility response to provisional decision on remedies, paragraphs 2.9–2.10, pp7 & 8.

¹⁴⁴ EDF Energy response to provisional decision on remedies, paragraph 5.4, p25.

¹⁴⁵ EDF Energy response to provisional decision on remedies, paragraph 5.4, p25.

¹⁴⁶ SSE response to provisional decision on remedies, Annex 1, paragraphs 4.3.1 & 4.3.2, pp2 & 3.

¹⁴⁷ Citizens Advice response to provisional decision on remedies, p19.

¹⁴⁸ Scottish Power response to provisional decision on remedies, paragraph 5.5, pp9 & 10.

- (a) It expected that large gas transporters, independent gas transporters and Xoserve would be included with shippers as they could also be responsible for the accuracy of inputs that could significantly contribute to unidentified gas.
- (b) It questioned whether the performance assurance framework could be implemented within 12 months, as proposed by the CMA, if half of this time was given over to developing the project plan.
- (c) It considered that there would need to be broad tolerance on targets at the introduction of the regime as shippers/transporters became familiar with the new operating regime. However, it would then expect that these should be tightened over time to ensure that controls were put in place to address areas where parties had influence over accuracy and unidentified gas.

12.139 Centrica¹⁴⁹ welcomed the proposal to implement a performance assurance framework for gas settlement and agreed with the CMA that the main cause of inefficiency in the gas settlement process arose from the process of allocating unidentified gas between suppliers. It also agreed that Ofgem is best placed to oversee implementation of this new framework.

12.140 E.ON¹⁵⁰ welcomed the proposal for Ofgem to take responsibility for the development and delivery of a performance assurance framework. It believed that Ofgem should build on work already completed in this area and that a plan of when and how Ofgem would implement it would be helpful, together with a commitment to provide sufficient resources. RWE¹⁵¹ expressed a similar view and noted that the performance assurance workgroup under the Uniform Network Code had already completed a considerable amount of work in this area. It considered that Ofgem should be compelled as part of the remedy to utilise and build upon the existing work of the performance assurance working group. It also noted that the current performance assurance framework was anticipated to go-live with Project Nexus' implementation.

- *Design considerations*

12.141 Based on the submissions received from parties and our own analysis, we consider that the implementation of the remedy originally consulted upon in the Remedies Notice, ie a mandatory submission of monthly updates to

¹⁴⁹ Centrica response to provisional decision on remedies, paragraphs 296 & 298, pp58 & 59.

¹⁵⁰ E.ON response to provisional decision on remedies paragraph 166, p35.

¹⁵¹ RWE response to provisional decision on remedies paragraph 45.1, p19.

AQs, would be impractical and costly until the majority of customers have a smart/advanced meter installed. This is because, in the absence of smart/advanced meters, for the majority of domestic and microbusiness customers, meter readings can only be obtained through a site visit or directly from the customer. Once smart/advanced meters have been rolled out, meter readings can be obtained remotely.

- 12.142 Suppliers are already required under the SLC 21B to take all reasonable steps to read customers' meters at least once a year for billing purposes. However, the Uniform Network Code only requires that shippers submit meter reads for 70% of all non-daily metered supply points¹⁵² annually (ie suppliers may decide not to submit up to 30% of the meter reads they have collected in a year).¹⁵³
- 12.143 An Ofgem request for information on AQs, issued in January 2015, found that most suppliers read a high proportion of meters at least once every six months, and that these meter reads were largely being entered into Xoserve's central settlement systems. However, it also suggested that there was substantial scope for improvement.¹⁵⁴
- 12.144 More recently an interim report by National Grid Distribution, as part of a review of annual read meter reading requirements,¹⁵⁵ found that the industry as a whole was achieving a performance close to 95%¹⁵⁶ of annual reads submitted into settlement. However, this did not differentiate between reads from dumb and smart meters. The report considered that with the roll-out of smart meters the 70% target might no longer be appropriate. It also noted that each year a number of meters went unread despite shippers' efforts to access the meter to take a reading.¹⁵⁷
- 12.145 While we accept that collecting monthly meter reads for 'dumb' meters would significantly increase costs for shippers and suppliers (and may be burdensome for customers), we believe that the current option of not submitting the meter reads that have been collected (as is currently possible under the Uniform Network Code) is inefficient as it undermines the

¹⁵² These are customers whose consumption is not provided to gas transporters on a daily basis. These are divided into: Smaller Supply Points (SSPs), ie meter points that have an annual consumption of not more than 73,200 kWh (typically domestic customers and smaller business premises); and Larger Supply Points (LSPs), ie meter points that have an annual consumption between 73,200 and 58.6 million kWh. LSPs can be further subdivided into those with annually read meters (73,200 to 293,000 kWh) and monthly read meters (293,000 to 58.6 million kWh).

¹⁵³ UNC Section M.

¹⁵⁴ Ofgem response to Remedies Notice, p 92. Ofgem additional submissions to the CMA, 18 September 2015 and 30 October 2015.

¹⁵⁵ See [UNC 0564R - Review of Annual Read Meter Reading requirements](#).

¹⁵⁶ See Workgroup report, 0564R: Review of Annual Read Meter Reading requirements, p4.

¹⁵⁷ See Workgroup report, 0564R: Review of Annual Read Meter Reading requirements, p4.

accuracy of the gas settlement process and gives rise to the scope for gaming. We note in this respect that the process of submitting a meter read to Xoserve has no, or negligible, costs for shippers and suppliers once the meter has been read.

12.146 With respect to customers on smart or advanced¹⁵⁸ meters, their meters can be read remotely by suppliers and shippers.¹⁵⁹ The cost of doing so is thus small (absent malfunction) and therefore collecting and submitting meter readings on a monthly basis would not face the same problems and costs identified for dumb meters.

- *Recent proposals to increase the frequency of meter readings submitted into settlement*

12.147 Since the publication of our provisional findings report, two modification proposals to the Uniform Network Code have been raised by parties with the aim of increasing the frequency of meter read submission into settlement. Specifically:

- (a) UNC 570, raised by Scottish Power, aims to introduce an obligation on shippers to provide at least one Valid Meter Reading per meter point into settlement per annum;¹⁶⁰ and
- (b) UNC 576, raised by National Grid, proposes to generate an estimated meter read to be used for reconciliation purposes in settlement when a Valid Meter Reading has not been received by Xoserve for seven years or more. The proposal will affect approximately 17,000 supply meter points for which a meter reading has not been accepted since 1 April 2010.¹⁶¹

12.148 We welcome these modification proposals and consider that they are likely to increase the accuracy of gas settlement and therefore contribute to a more efficient allocation of costs to parties. However, we believe that their impact will be marginal for the following reasons:

- (a) UNC 570 would impose the same obligations on gas suppliers for supply points with a dumb or a smart meter. As the roll-out of smart meters progresses, there will be increased scope for more frequent submissions

¹⁵⁸ ie any gas meter which can be read remotely. These meters can be read remotely by suppliers/shippers and have a number of additional functionalities. See Appendix 8.5 for further details.

¹⁵⁹ Both SMETS 1 and SMETS 2.

¹⁶⁰ See UNC 0570 - [Obligation on Shippers to provide at least one valid meter reading per meter point into settlement once per annum](#).

¹⁶¹ See UNC 0576: [Generation of an estimated Meter Reading at the Code Cut Off Date in the absence of an actual Meter Reading](#).

of meter readings into settlement, which will increase accuracy and lead to a more efficient allocation of settlement costs to parties.

(b) UNC 576 will affect approximately 17,000 supply points out of a total of over 20 million.

12.149 We also note that both proposals are at an early stage of development and there is uncertainty around their likelihood of being approved and implemented in the short term.¹⁶²

12.150 For the reasons set out above, we have decided to implement a remedies package consisting of the following elements:

(a) With respect to all non-daily metered supply points in Great Britain with a dumb meter,¹⁶³ we will impose an order on gas suppliers (and amend the gas suppliers' standard licence conditions accordingly) to submit to Xoserve Valid Meter Readings as soon as they become available (eg if provided by the customer or obtained by the shipper/supplier), and at least once per year (ie consistent with the existing obligation under the Uniform Network Code to read customers' meters at least once a year).

(b) With respect to all non-daily metered supply points with a smart or advanced meter, we will impose an order on gas suppliers (and amend the gas suppliers' standard licence conditions accordingly) to submit to Xoserve Valid Meter Readings at least once per month (unless for reasons of malfunction or related issues it was not possible to take such a meter reading).

(c) A recommendation to Ofgem to take appropriate steps to ensure that a performance assurance framework is established within a year of the publication of the CMA's final report (see paragraph 12.177 below).

12.151 The first two elements of this remedies package are obligations on gas suppliers that are designed to increase the accuracy of the gas settlement process. The third element is designed to facilitate compliance with these two obligations and to put in place additional measures which are aimed at reducing the amount of unidentified gas. Another objective of the performance assurance framework is to contribute to a more efficient

¹⁶² We understand that UNC 0576 will be considered by the Uniform Network Code panel in July 2016, according to the initial timetable proposed by National Grid. UNC 570 will be considered by the Uniform Network Code panel in August 2016.

¹⁶³ ie any gas meter which cannot be read remotely.

allocation of costs arising from the residual unidentified gas between suppliers.

- *Obligations on gas suppliers to submit meter readings to a particular frequency*
 - *Assessment of effectiveness*

12.152 The two obligations we propose to impose on gas suppliers will ensure that (a) as regards dumb meters, meter readings that are collected by suppliers (eg pursuant to the obligation under the Uniform Network Code to read meters at least once per year) are submitted to Xoserve without undue delay; and (b) as regards smart or advanced meters (representing approximately 1.6 million customers¹⁶⁴), meter readings are collected by suppliers and submitted to Xoserve at least once per month.

12.153 Both obligations will improve the accuracy of AQs and facilitate all metered energy consumption being reconciled on a timely basis (ie using actual rather than estimated consumption in the settlement process). This in turn should lead to a more efficient allocation of costs between shippers and suppliers (due to the use of actual consumption data) and a reduction in unidentified gas (which would also contribute to a more efficient allocation of its costs between shippers and suppliers). In addition, we note that it would reduce any potential ability for suppliers to delay the reconciliation of any given supply point in order to game the system.

12.154 In view of the above, we have therefore decided to impose an order on suppliers concerning the above obligations, together with the introduction of a licence condition.

12.155 We consider that the simple terms of the order, set out above, would be clear to suppliers, and also to other interested parties such as Xoserve and Ofgem (who would have responsibility, together with the CMA, for monitoring compliance).

12.156 We also consider that the order would be straightforward to implement, given that suppliers are either already obligated to collect the relevant information (as regards the obligation concerning dumb meter readings) or are readily able to collect the relevant information (as regards the obligation concerning smart meters). We note that some parties have expressed reservations (see paragraphs 12.135(a) and 12.135(c)) about the capacity of

¹⁶⁴ See DECC (2015), *Smart Meters, Great Britain, Quarterly report to end September 2015*, p4.

the existing Xoserve systems to accept and process an increased number of meter reads. Our understanding is that Xoserve's systems are already capable of handling a heavier meter read frequency, and this will improve further once Project Nexus has been implemented.

12.157 We note that, by introducing new licence conditions, Ofgem would be under a duty to maintain compliance. It would also be in a position to require the provision of information from suppliers concerning potential breaches of the licence conditions. Xoserve can readily inform Ofgem as to suppliers' compliance with the licence conditions, and Ofgem will be able directly to enforce against any breach of the licence conditions. This will further reduce the incentives of suppliers to game the system.

12.158 In terms of timescale for implementation, we would expect suppliers to start complying with the obligations, at the latest, on the date of publication of our order (subject to any material change in circumstance).

12.159 We have noted parties' views (see paragraph 12.135 above), but consider these to relate to detailed points of implementation to be addressed in the draft of our order.

- *Assessment of proportionality*

12.160 As noted above, we believe that the introduction of these two obligations on gas suppliers will be effective in achieving their aim of increasing the accuracy of the gas settlement process by contributing to the efficient allocation of costs. It will also reduce the amount of unidentified gas and any residual incentive to game the system. Accordingly, the remedy will address, in part, the detriment arising from the Gas Settlement AEC.

12.161 As noted above, no additional costs would arise from the obligation to submit Valid Meter Reading for dumb meters as soon as they have been collected and at least once per year, since this will not require suppliers to collect such meter readings any more frequently than they currently do. As regards the obligation to collect and submit smart and advanced meter readings once per month, given that this can be done remotely by suppliers, we consider that little or no costs will be incurred as a result of the remedy. As also noted, Xoserve will not incur increased costs concerning scaling up its systems, because it is already capable of handling the increased meter read frequency contemplated with this proposed remedy.¹⁶⁵ We consider that

¹⁶⁵ Xoserve has also submitted that it anticipated scaling up its systems in line with projections of shipper demand. This would correspond to increased demand for settlement product 3, ie daily readings submitted in batches available to any supply point.

such costs would be outweighed by the potential benefits from increasing the accuracy and efficiency of the gas settlement system and reducing the ability for such system to be gamed.

12.162 Given the limited impact, if any, this proposed remedy will have on costs, we consider that it is no more onerous than necessary to achieve its aim and that there is no less onerous remedy that would be as effective.

12.163 We have considered the alternative possible remedy of imposing an obligation on suppliers to collect and submit dumb meter readings once per month, but, in light of parties' submissions and further consideration of the evidence, we consider that while such a possible remedy may be effective, it would be disproportionate given (a) the significant costs that would be likely to be incurred by suppliers in satisfying such an obligation; and (b) the fact that any adverse impact arising from less frequent dumb meter readings would be time-limited, and diminish over time, with the roll-out of smart meters. Accordingly, we consider that over the short term, the more limited obligations concerning dumb meter readings will be significantly more proportionate and only marginally less effective than mandatory monthly submission of dumb meter readings.

- *Duty to have regard to Ofgem's statutory duties*

12.164 Where the CMA is considering whether to take action for the purpose of modifying one or more of the conditions of a retail gas or electricity supplier's licence, in deciding whether such action would be reasonable and practicable, the CMA must 'have regard' to the relevant statutory functions of Ofgem.

12.165 Ofgem's statutory functions concerning the transmission of electricity are set out in Part 1 of the GA86, as amended by the EA10, and include (among other things) granting transmission licences, promoting efficiency and economy on the part of persons authorised by licences or exemptions to transmit, distribute or supply gas, and to secure a diverse and viable long-term energy supply.

12.166 Ofgem's principal objective in carrying out such functions is to protect the interests of existing and future consumers of gas and electricity supply.¹⁶⁶ The interests of such consumers are taken as a whole, including their interests in (a) the reduction of greenhouse gases, (b) the security of supply,

¹⁶⁶ See, among others, section 3A and section 6B of the EA89.

and (c) the fulfilment by Ofgem of the objectives set out in Article 40(a) to (h) of the Gas Directive.¹⁶⁷

12.167 We do not consider that these remedies will have any adverse impact on suppliers' ability to meet all reasonable demands for gas supply, achieving sustainable development, security of supply or environmental concerns. In this regard, the remedies will only impact the 'efficiency' limb of the Trilemma considerations built into Ofgem's statutory duties and functions.

12.168 As noted above, we would expect the remedies to increase the accuracy of the gas settlement process, reducing the amount of unidentified gas and leading to a more efficient allocation of costs arising from it between shippers and suppliers. This will be achieved by giving suppliers and shippers appropriate incentives to increase the efficiency of gas settlement. These efficiencies, in turn, should contribute to achieving customer benefits (and in particular for domestic customers since the current system allocates the costs of unidentified gas in a disproportionate manner to such customers). The remedies therefore directly engage Ofgem's principal objective of protecting the interests of existing and future consumers, wherever appropriate through competition, directly pursuing certain objectives set out in the Gas Directive.¹⁶⁸

12.169 In light of the above, we consider that the remedies are consistent with Ofgem's principal objective of promoting the interests of existing and future consumers.

- *The establishment of a performance assurance framework by April 2017*
 - *Assessment of effectiveness*

12.170 We believe that Project Nexus and the more frequent submission of meter reads, in accordance with the above remedy, will partially address the concerns we have identified regarding unidentified gas. However, we do not expect these measures to eliminate it entirely. We believe that a performance assurance framework, could facilitate a more efficient allocation of the residual amount of unidentified gas between gas shippers and suppliers. In addition, a performance assurance framework could further incentivise compliance with the proposed obligations concerning the

¹⁶⁷ Directive 2009/73/EC of the European Parliament and of the Council of 13 July 2009 concerning common rules for the internal market in gas and repealing Directive 2003/54/EC, OJ L211/55 (the Electricity Directive).

¹⁶⁸ In particular Article 40 (d), (f) and (g) of the Gas Directive.

frequency of submissions of meter readings (see paragraphs 12.152 and 12.153 above).

12.171 In Section 9, we noted that Ofgem had approved modification proposal UNC 473,¹⁶⁹ which replaced the existing Reconciliation by Difference methodology and reinstated the Allocation of Unidentified Gas Expert arrangements.

12.172 More recently Ofgem has approved two further modifications to gas industry codes:

(a) CP14/268 which introduces a theft detection incentive scheme within the Supply Point Administration Agreement from a date yet to be determined;¹⁷⁰ and

(b) UNC 506V which sets out a process for establishing a performance assurance framework within the context of the Uniform Network Code.¹⁷¹

12.173 While we acknowledge and endorse these positive developments, we consider that significant work is still required before the major causes of unidentified gas are identified, understood and addressed, and any residual unidentified gas is allocated more efficiently. Although a performance assurance framework can now be established within the context of the Uniform Network Code, as a result of UNC 506V, the role and responsibilities of Ofgem, the code administrator and Uniform Network Code parties for the purpose of establishing and running the performance assurance framework have yet to be defined.

12.174 Further, in Section 9, we noted the long lead time and difficulties of implementing major changes through the existing industry code modification process and reported on Project Nexus and other major modification proposals that have been subject to delays or have not proceeded (see Section 18). We consider that without a remedy from the CMA, we cannot be confident that a performance assurance framework, with appropriate roles and scope set out, will be in place within a reasonable timescale and that appropriate incentives to reduce unidentified gas will be agreed by Uniform Network Code parties given the complexity of factors contributing to unidentified gas.

¹⁶⁹ [Uniform Network Code \(UNC\) 473 and 473A: Project Nexus - Allocation of Unidentified Gas.](#)

¹⁷⁰ [Supply Point Administration Agreement CP14/268: Introduction of the gas theft detection incentive scheme.](#)

¹⁷¹ [Uniform Network Code \(UNC\) 506V/506AV: Gas Performance Assurance Framework and Governance Arrangements.](#)

12.175 We note, in this regard, that the majority of energy suppliers who responded to our provisional decision on remedies (see paragraphs 12.136 to 12.140) were in favour of a performance assurance framework.

12.176 In order to increase incentives to identify, understand and address the causes of unidentified gas, we consider that the performance assurance framework should include, but not be limited to, the following key components:

- (a) appropriate targets for unidentified gas to be reduced;
- (b) allocation of the costs of unidentified gas to shippers and suppliers based on accurate and reliable evidence (this will be facilitated by our proposed remedy above in paragraphs 12.150(a) to 12.150(b)) so as to incentivise them to reduce the amount of unidentified gas; and
- (c) set further appropriate incentives which encourage shippers and suppliers to meet these targets for reducing unidentified gas, including penalties for parties that do not comply with their obligations to submit meter reads as per our proposed remedies package (see paragraphs 12.150(a) and 12.150(b)).

12.177 In light of the above, we have decided to make a recommendation to Ofgem to:

- (a) take responsibility for the development and delivery of a performance assurance framework to increase accuracy of the gas settlement process as soon as reasonably practicable, and at the latest within one year of our final report;
- (b) establish a project plan and allocate responsibility to Uniform Network Code parties to take actions for its implementation;
- (c) supervise its implementation; and
- (d) take appropriate steps to ensure that failure to meet targets under the performance assurance framework are sanctioned.¹⁷²

12.178 As discussed above, we have identified three key components that should, at a minimum, be covered under a performance assurance framework but would encourage Ofgem to consider whether additional components would contribute to the accuracy of the settlement process and the reduction of

¹⁷² We would recommend that such sanctions be imposed by Ofgem.

unidentified gas and should be added to such a performance assurance framework.

12.179 Further, we note some of the comments made by parties (see paragraphs 12.137(b) and 12.138) in response to our provisional decision on remedies regarding the implementation of the performance assurance framework. We consider that these should be taken into account by Ofgem in developing a performance assurance framework.

12.180 We expect that such a performance assurance framework will, in combination with an order to increase the frequency of submissions of meter reads, provide the industry with relevant information for addressing the causes of unidentified gas. This, in turn, should facilitate actions being taken by Xoserve and the industry with a view to facilitating a more efficient allocation of the costs arising from unidentified gas, based on more accurate and reliable evidence, and ensuring that these costs are borne by those parties who are responsible for it.

12.181 We therefore believe that the performance assurance framework, by setting appropriate incentives (eg financial penalties) to reduce the amount of unidentified gas, will be effective in reducing significantly the detriment arising from unidentified gas.

12.182 We consider that Ofgem, as sector regulator, and with its enhanced role concerning industry codes pursuant to our remedies set out in Section 19, will be best placed to implement this remedy following further consideration, in conjunction with Uniform Network Code parties as appropriate, of whether additional components should be included in a performance assurance framework (in addition to the key components we have identified), and the timing of key milestones in the project plan.

12.183 We consider that Ofgem can start to put in place steps concerning the development and delivery of a performance assurance framework immediately. We would expect that a project plan could be agreed and published within six months of this report.

- *Assessment of proportionality*

12.184 As noted above, we believe that the recommendation to Ofgem to deliver a performance assurance framework will be effective in achieving its aim of increasing the accuracy of the gas settlement process. It will contribute to the efficient allocation of costs to parties by facilitating understanding of the causes of unidentified gas and incentivising it to be reduced. It will also reduce any residual incentive to game the system, as suppliers will be

incentivised to meet the targets set out in the performance assurance framework. Accordingly, the remedy will address, in part, the detriment arising from the Gas Settlement AEC.

12.185 We have not estimated the possible costs that may be incurred by Ofgem and/or suppliers from delivery and participation in the performance assurance framework. However, we believe that these will be significantly lower than the estimated cost of unidentified gas (£119 million in 2015/16 – see paragraph 12.1) and, for the reasons set out above, we believe that these costs arising from unidentified gas will be reduced significantly as a result of our remedy.

12.186 Given that the overarching purpose of the performance assurance framework is to facilitate understanding the causes of unidentified gas and incentivising it to be reduced, we believe that the key components we identified in paragraph 12.176 will be the minimum that the performance assurance framework will need to contain in order to be effective. Accordingly, we consider that our remedy is no more onerous than necessary to achieve its aim. We also do not believe that there is an alternative remedy that is less onerous and as effective. As noted above, the current plans to establish a performance assurance framework are not very far advanced, and we do not consider that, absent our remedy, a performance assurance framework would be delivered in a timely fashion.

Remedies to address constraints on competition for prepayment customers

12.187 For the reasons set out in Section 9, we have found that there are features of the domestic retail energy markets that give rise to two distinct, but related, adverse effects on competition concerning prepayment customers: one on the demand side (the Domestic Weak Customer Response AEC), and one principally concerning the supply side (the Prepayment AEC).

12.188 In practice, these features, and the AECs arising from them, are interlinked and therefore the possible remedies we have decided upon contribute to addressing aspects of both AECs.

12.189 In our provisional decision on remedies, we set out remedies that sought to address directly certain of the features giving rise to the Prepayment AEC, in particular:

- (a) Two remedies seeking to make better use of the available tariff codes, so as to reduce the impact of the dumb prepayment meter technical constraints we identified with respect to the Prepayment AEC as a feature that limits the ability of all suppliers, and in particular new

entrants, to innovate by offering tariff structures that meet demand from prepayment customers who do not have a smart meter. These remedies are (a) a softening of SLCs 22B.7(b)¹⁷³ as regards supply to prepayment customers to enable suppliers to make better use of the limited number of tariff codes; and (b) a redistribution of unused gas tariff codes to enhance their availability to suppliers.

- (b) A remedy aimed at increasing all suppliers' incentives, and in particular new entrants' incentives, to compete to acquire prepayment customers by reducing barriers to switching of indebted prepayment customers. This remedy is a recommendation to Ofgem to ensure that the debt assignment protocol is reformed within an appropriate timeframe.

12.190 We note that the roll-out of smart meters has the potential to address many of the technical constraints affecting competition for prepayment customers, and in our Remedies Notice we set out two potential remedies aimed at accelerating the roll-out of smart meters to prepayment customers:

- (a) a potential remedy according to which domestic retail energy suppliers would be required to stop installing dumb prepayment meters in customers' homes and, from the point of implementation, ensure that all future installed prepayment meters are smart meters; and
- (b) a potential remedy according to which domestic retail energy suppliers would be required to install smart meters in homes that currently have prepayment meters before seeking to install them in homes that currently have traditional meters.

12.191 We set out in the provisional decision on remedies that we were not minded to pursue the two possible remedies relating to prioritising roll-out of smart meters to prepayment customers and, for the reasons set out below, we have decided to confirm our provisional decisions.

12.192 In relation to the first potential remedy, since the publication of our provisional findings report and the Remedies Notice, DECC has confirmed that it is planning to implement the New and Replacement Obligation from mid-2018.¹⁷⁴ The New and Replacement Obligation will require suppliers 'to take all reasonable steps to install a compliant smart meter where a meter

¹⁷³ In both gas and electricity suppliers' licence conditions.

¹⁷⁴ DECC (31 July 2015), [Smart Metering Implementation Programme: Government response to the Smart Metering Rollout Strategy consultation](#).

reaches the end of its life or where a meter is installed for the first time (eg in new build properties).¹⁷⁵

- 12.193 We received a wide range of responses to the second potential remedy, the majority of which were not in favour of implementing it.
- 12.194 While Dawn Butler MP and Secure Meters (UK) Ltd both set out their views that smart meters should be prioritised for prepayment customers, several parties outlined a range of concerns with this option, including issues concerning installing smart meters in tall buildings, that it might reduce the efficiency (and therefore increase the cost) of the smart meter roll-out, that it might jeopardise suppliers' ability to meet the current 2020 deadline for rolling out smart meters (for all customers, not only prepayment customers), that it could have significant negative effects on prepayment customers' experiences, and that prepayment customers are likely to suffer greater detriment than other customers if there are early issues with the DCC (eg as it may prevent top-ups registering on a customer's meter). As a result, we do not consider that there is scope for a remedy in this area.
- 12.195 Since the date of implementation of the New and Replacement Obligation reflects DECC's current assessment of what is technically feasible, and we have not seen evidence that would suggest we should recommend an alternative date, we do not consider there is scope for a remedy in this area consisting in imposing an additional obligation on suppliers.
- 12.196 However, we note that a wide range of parties, in their responses to our provisional decision on remedies, set out their views that the roll-out of smart meters will reduce some of the negative impacts customers face from prepayment meters. We agree with this and have therefore sought to accelerate the roll out of smart meters to prepayment customers by incentivising suppliers to do so. We have achieved this result through the design of the price cap. As discussed in Section 14 we have decided to exclude interoperable SMETS2 smart meters from the scope of the cap. We believe that this will help ensure prepayment customers benefit from smart meters on a timely basis.
- 12.197 Other remedies which we have decided upon that concern prepayment customers (either as part of the broader domestic retail markets and associated proposed remedies, or specifically as distinct segments) are considered below in paragraphs 12.356 to 12.451, in Section 13

¹⁷⁵ *ibid.*

(engagement remedies) and Section 14 (price cap). We consider the overall effectiveness and proportionality of the package of remedies in Section 15.

Making better use of the available tariff codes

- 12.198 Section 9 set out our understanding of the technical constraints faced by suppliers offering a range of tariffs to prepayment customers as a result of the scarcity of gas and electricity tariff codes. We consider that the introduction of smart meters will remove some of these issues. The rationale behind considering potential remedies aimed at accelerating the roll-out of smart meters to prepayment customers was that doing so would speed up the removal of these constraints.
- 12.199 Given our decision not to pursue the possible remedies relating to prioritising roll-out of smart meters to prepayment customers (for the reasons set out above), and given that some prepayment customers may not receive smart meters until 2020 (or possibly even later), some prepayment customers are likely to remain affected by these constraints for some time. As a result, we have considered whether it would be appropriate to introduce other remedies to mitigate the impact of these technical constraints in the period ahead of wider smart meter roll-out. In this section we set out three possible remedies aimed at reducing the impact of the technical constraints faced by suppliers resulting from the scarcity of gas and electricity tariff pages.
- 12.200 As noted in Section 9, suppliers need access to gas and electricity tariff codes in order to offer gas and electricity prepayment tariffs to customers with dumb prepayment meters. Both the gas and electricity prepayment systems have a maximum number of tariff codes that can be allocated to suppliers, effectively limiting the number of prepayment tariffs that suppliers are able to offer.
- 12.201 In order to soften these barriers to entry and innovation, we set out below three possible remedies that aim to enable suppliers to make more efficient use of the existing tariff codes. Doing so could enable parties, and in particular independent suppliers, to offer a wider range of prepayment tariffs.

Aim of the remedies

- 12.202 The aim of these remedies is to ensure that the limited number of gas tariff codes are allocated efficiently, and to enable both gas and electricity tariff codes to be used more efficiently. For the reasons set out in Section 9 above, the lack of availability of gas tariff pages for suppliers other than the Six Large Energy Firms serves as a potential barrier to entry into and expansion within the prepayment segments.

12.203 In this section, we therefore set out three remedies aimed at mitigating the impact of the gas tariff code constraint:

- (a) softening SLC 22B.7(b);
- (b) redistributing unused gas tariff codes; and
- (c) managing gas and electricity tariff codes centrally.

- *Softening SLC 22B.7(b)*

12.204 SLC 22B.7(b) requires any difference in charges between payment methods (including costs uplifts) to be applied by a supplier in the same way to all domestic customers with the same payment method (eg across different regions). As the core tariffs offered to direct debit (and standard credit) customers generally differ by region, we understand that the effect of this standard licence condition is that suppliers that wish to offer the same core tariff to their prepayment customers are under an obligation to apply the same regional price variations to these customers. The implication is that, if a supplier decides to offer such a core tariff (ie one that has 14 regional variations) to prepayment customers, it must use different tariff codes for each different regional variation. We note that a single gas tariff page only contains 11 codes.

12.205 Similarly, and as noted in Section 9, the simpler choices component of the RMR rules restricts suppliers' ability to offer core tariffs specifically targeted at prepayment customers. As a result of the limited number of tariff codes available to parties, and of these regulatory constraints, the number of core tariffs offered to prepayment customers may be constrained by suppliers' pricing strategy for credit meter customers.

12.206 The aim of this remedy is to enable suppliers to make more efficient use of the limited number of tariff codes they have (both gas and electricity) in offering prepayment tariffs to prepayment customers without being constrained by their pricing strategy for customers on credit meters. By having more freedom over whether or not to set different prices by region (or the same price across all, or a limited number of regions), suppliers should be able to offer more prepayment tariffs by making better and more efficient use of the tariff codes that have been allocated.

- *Redistributing unused gas tariff codes*

12.207 While redistributing gas tariff codes would not remove the absolute constraint on the total number of prepayment tariffs that could be offered to

customers with dumb prepayment meters, it would be likely to reduce the impact of the constraint on the ability of new entrants and existing independent suppliers to compete. More specifically, this possible remedy would facilitate redistribution of unused tariff codes to suppliers that wish to enter the prepayment segments or offer a wider range of tariffs to customers with dumb prepayment meters.

- *Managing gas and electricity tariff codes centrally*

12.208 As with the possible remedy seeking to redistribute unused tariff codes, we have considered the possibility of introducing a remedy that aims to increase the availability of tariff codes to suppliers, although through a more interventionist and comprehensive remedy.

12.209 For the reasons discussed below, we have decided to soften SLC 22B.7(b) and redistribute unused gas tariff codes. However, we have decided not to proceed with the possible remedy involving the central management of gas and electricity tariff codes.

Parties' views

12.210 We note that the three remedies considered in this section were suggested by parties in response to our Second Supplemental Remedies Notice.¹⁷⁶

12.211 Scottish Power noted that having to offer a different version of its prepayment tariffs in each region exacerbated the technical constraints we provisionally identified in the Addendum. Scottish Power noted that certain elements of the RMR simpler choices rules (which we understand to be SLC 22B.7(b)) typically require a supplier to have 14 different tariff codes for its prepayment SVT in order to account for any regional variation that applies to its non-prepayment SVT. It considered that, with the removal of SLC 22B.7(b), as few as three different versions of a tariff (instead of 14) would be required to offer prices that were sufficiently reflective of regional cost differences.

12.212 Scottish Power also suggested rationalising the use of tariff codes through reallocating unused codes, potentially by auction. Ovo Energy, Robin Hood Energy and Citizens Advice all also considered that we should intervene to ensure a more equitable mechanism for allocating gas tariff codes between suppliers.

¹⁷⁶ See [responses to addendum to provisional findings and second supplemental notice of possible remedies](#).

- 12.213 We received a number of responses to our provisional decision on remedies on these two remedies. Of the parties offering a view, all except one were supportive of our remedy to soften SLC 22B.7(b). This included Centrica, EDF Energy, RWE, Scottish Power,¹⁷⁷ SSE and Citizens Advice. In contrast, First Utility¹⁷⁸ set out its view that the remedy was unlikely to be effective, since suppliers had to set regional prices in order to offer competitive tariffs, and that as a result, suppliers were unlikely to make use of this remedy by grouping regions together.
- 12.214 As set out below, the intention of this remedy is not to force all suppliers to remove regional variations for the purposes of setting prices to prepayment customers. Rather, it is up to suppliers to balance the benefits of lessening the impact of the tariff code constraint against the disadvantages of offering prices that do not reflect perfectly the regional differences in cost to serve. As set out in the section on effectiveness, we consider this remedy to have limited costs to parties. As a result, even if some suppliers opt not to take advantage of the increased flexibility offered by this remedy, we do not think this undermines the case for implementing it.
- 12.215 Three parties (Centrica, SSE and Citizens Advice) set out their concerns that the proposed remedy to introduce a prepayment price cap would vary by region, and that this may prevent suppliers from being able to group regions together for the purposes of setting prices.
- 12.216 As set out in Section 14, the price cap will include a degree of ‘headroom’ in order to help ensure that competition in the prepayment segments can coexist with the cap. Given the expected level of the cap, we consider that there are likely to be instances where suppliers are able to group regions for the purposes of setting prices, should they wish to do so. Our analysis of network charges suggests that within each of three broad regional groups, network charges incurred by suppliers serving dual fuel customers on medium TDCV vary by a maximum of £16.¹⁷⁹ As a result, we consider there is likely to be scope for parties to benefit from this remedy under the price cap. Also as noted above, we consider this remedy to be very low cost, meaning that it is proportionate even if suppliers do not make use of it.

¹⁷⁷ Scottish Power response to provisional decision on remedies, paragraph 6.1 p10.

¹⁷⁸ First Utility response to provisional decision on remedies, p8, paragraph 3.1.

¹⁷⁹ The main regional driver of costs is the difference in transmission and distribution charges across regions. Our analysis of these charges (assuming typical domestic consumption), based on figures from Ofgem (October 2015), [Regional differences in network charges](#), indicates that after grouping each of the 14 regions into one of three groups, network charges vary by up to £16 for a dual fuel customer. This suggests that a supplier opting to group regions in this manner would be able to set prices that are close to those that it may have set if it had set different prices in each region.

- 12.217 Two parties (EDF Energy and Scottish Power) said that they would like more information on how enforcement of this standard licence condition would be deprioritised. Scottish Power¹⁸⁰ thought it would be appropriate for Ofgem to clarify in writing how enforcement of this standard licence condition would be deprioritised. We agree with parties that Ofgem should provide some clarity, for instance by publishing an open letter setting out its intention to deprioritise enforcement of this standard licence condition.¹⁸¹
- 12.218 We received a number of responses to the provisional decision on remedies relating to our remedy to redistribute unused gas tariff pages, all of which appeared to support our remedy in principle, subject to a number of caveats concerning its implementation. This included Centrica,¹⁸² EDF Energy, RWE, Scottish Power, SSE, First Utility¹⁸³, Utilita and Citizens Advice. EDF Energy said that it did not believe that any enduring fixed limit on pages was necessary, and that once new pages are created, and the constraint on new entrants is therefore removed, the limit to 12 pages should also be lifted and any pages released should be returned to suppliers if they require them.¹⁸⁴
- 12.219 Two parties (Centrica and RWE) highlighted concerns with the interaction of this remedy and the price cap. Centrica considered that it would require 126 gas tariff codes just to support a single prepayment tariff (and therefore in order to comply with the price cap).¹⁸⁵ RWE set out its views that the benefits of this remedy would be negated as a result of the price cap, since it would deter entry into the prepayment segments.
- 12.220 We disagree with Centrica's submission that 126 tariff codes would be necessary to comply with the price cap. Any supplier with 14 gas tariff codes and 28 tariff codes for electricity¹⁸⁶ will be able to offer a prepayment tariff in each of the 14 regions that complies with the price cap remedy. Moreover, once our remedy to soften SLC 22B.7(b) has been implemented, suppliers wishing to group regions together for the purposes of setting prices in order to reduce the number of tariff codes they require would be able to comply with the price cap with fewer than 14 codes.
- 12.221 On the second of these points, the price cap has been set at a level which in our view will allow competition to exist under the level of the price cap (see

¹⁸⁰ Scottish Power response to provisional decision on remedies, paragraph 6.1 p10.

¹⁸¹ As it has done, for instance, with respect to the simpler choices component of its RMR rules, see [open letter of 14 April 2016](#).

¹⁸² Centrica response to provisional decision on remedies, paragraph 307, p61.

¹⁸³ First Utility response to provisional decision on remedies, p8, paragraph 3.3.

¹⁸⁴ EDF Energy response to provisional decision on remedies, paragraph 6.12, p28.

¹⁸⁵ Centrica response to provisional decision on remedies, paragraph 310, p61.

¹⁸⁶ ie 14 tariff codes for a single-rate tariff and 14 tariff codes for an Economy 7 tariff.

above paragraph 12.216). As a result, we do not consider that the price cap remedy will prevent entry into the prepayment segments nor the launch of fixed-term tariffs. It is therefore important to ensure that tariff pages (and in particular those which are unused) are effectively allocated in order to stimulate competition until the full roll-out of smart meters¹⁸⁷.

12.222 All respondents offering an opinion (Centrica, RWE and Utilita) were in favour of Ofgem taking control of the reallocation of gas tariff pages,¹⁸⁸ although Centrica expressed concern at the lack of detail regarding how this will happen and what process Ofgem will follow in order to achieve that allocation.

Design considerations

- *Softening SLC 22B.7(b)*

12.223 We identified in Section 9 that if all suppliers offered different prices in each of the 14 distribution regions,¹⁸⁹ the total number of gas tariffs that could be offered to customers with dumb prepayment meters, across the entirety of the prepayment segments, would be approximately 80 tariffs, due to the constraints of the gas tariff codes system.¹⁹⁰ These 80 tariffs could comprise, for example, 30 suppliers each offering just one prepayment SVT and eight suppliers each offering a 12-month fixed tariff that is changed every two months (ie a total of 48 tariffs) – considerably fewer than the tariffs available to customers with credit meters.¹⁹¹

12.224 In contrast, we identified that the 249 electricity tariff codes available to each supplier would allow each supplier to offer one SVT and one 12-month fixed tariff that changes approximately every two months (each with a single rate and Economy 7 variant in each of 14 regions).

12.225 However, Scottish Power put to us that, by offering fewer than 14 different regional versions of each tariff (eg by grouping regions with similar costs together and setting a single price for each group), suppliers could use fewer tariff codes (see paragraph 12.211). Adopting this approach would enable

¹⁸⁷ In addition, it is possible that the price cap may be removed before the full roll-out of smart meters (for instance as a result of the mid-term review of the price cap as set out in Section 14). In such an event, the beneficial effects on competition of a more efficient allocation and use of tariff codes would be more significant.

¹⁸⁸ Centrica response to provisional decision on remedies, paragraph 312, p61.

¹⁸⁹ ie the 14 electricity distribution areas (PES regions). While we note that there are only 13 gas distribution zones, we understand that, in practice, suppliers set regional variations within a core tariff based on the 14 PES regions.

¹⁹⁰ This limits the total number of gas tariff codes to 1,133.

¹⁹¹ Our analysis of Energylinx data suggests that there were in the region of 40 variable and 40 fixed tariffs (of differing lengths) available to customers on credit meters at the end of Q2 2015.

suppliers to offer more prepayment tariffs with the finite number of tariff codes currently available.

- 12.226 Scottish Power estimated that grouping regions into three broader groups for the purpose of setting prices would likely be sufficient to allow suppliers to account adequately for different regional costs. If all existing suppliers did this, the total available number of tariffs that could be offered on the gas prepayment system would be 377 (instead of 80 if prices are set differently in each of the 14 regions). This could allow, for instance, for 30 suppliers to each offer an SVT and a total of 57 12-month fixed tariffs that are changed every two months—considerably more than can be offered at present.¹⁹²
- 12.227 For the electricity prepayment system, this would enable each supplier to offer 41 different tariffs (each with a single rate and Economy 7 variant in each of three broader region groups). This could, for instance, enable each supplier to offer one SVT and up to six different 12-month fixed tariffs, each changing every two months, for example.
- 12.228 Scottish Power submitted that it currently faces restrictions that prevent it from grouping regions together in this manner. SLC 22B.7(b) requires that any difference in charges between payment methods must be applied by a supplier in the same way to all domestic customers with the same payment method. This means that if a supplier charges different prices in each region for its direct debit SVT (for example), it would also need to charge different regional prices for its prepayment SVT (with the same payment method cost adjustment for each region). If the supplier took a different approach to this, the price paid by prepayment customers in a given region may not be the cost-adjusted equivalent of the supplier's SVT in that region, and the tariff could therefore breach SLC 22B.7(b).
- 12.229 We recognise that this condition does not prohibit suppliers from applying the same tariff across all regions (or grouping regions presenting similar costs together for the purpose of setting regional tariff variations) in setting prices to prepayment customers. However, if a supplier chooses not to apply regional variations (or only a few) to a core tariff offered to prepayment customers, it may also have to do so for this core tariff with respect to its direct debit and standard credit customers, in order not to be in breach of SLC 22B.7(b).¹⁹³

¹⁹² As noted above, our analysis of Energylinx data suggests that there were in the region of 40 variable and 40 fixed tariffs (of differing lengths) available to customers on credit meters at the end of Q2 2015.

¹⁹³ In practice, most suppliers' decisions concerning whether to charge regional prices are likely be driven more by the larger direct debit and standard credit segments; they may be unlikely to forego the benefits of charging

12.230 The intention of this remedy is not to propose that all suppliers remove regional variations for the purposes of setting prices in the prepayment segments. Rather the aim of this remedy is to eliminate a barrier to suppliers that wish to do so with respect to customers on dumb prepayment meters in order to make more efficient use of their limited tariff codes, without being constrained by their pricing strategy with respect to other payment methods. We note therefore that, following implementation of the remedy, when deciding whether to set different prices in each region (or group of regions) for prepayment customers, suppliers will have to balance the benefits of lessening the impact of the tariff code constraint against the disadvantages of offering prices that do not reflect perfectly the regional differences in cost to serve.

12.231 In view of its aim, we consider that the remedy should be limited in its scope to the prepayment segments. Accordingly, we have decided to recommend that Ofgem:

- (a) modify suppliers' standard licence conditions to introduce an exception to SLC 22B.7(b) so as to allow a supplier to set prices to customers on dumb prepayment meters without applying regional cost variations which are applied to other payment methods within the same core tariff; and
- (b) deprioritise potential enforcement action pending the modification of SLC 22B.7(b) against any supplier that sets prices to prepayment customers without applying regional cost variations which are applied to other payment methods within the same core tariff.

- *Redistributing unused gas tariff codes*

12.232 As set out in Section 9, the absolute limit on the number of gas tariff codes and the lack of available gas tariff codes are greater constraints on independent suppliers' ability to offer a range of prepayment tariffs to customers with dumb prepayment meters than the absolute limit on the number of electricity tariff codes.

12.233 We consider that once our remedy in relation to SLC 22B.7(b) (set out above) has been implemented, suppliers will be able to make more efficient use of both their gas and electricity prepayment tariff codes. This should address, in part, one of the features (technical constraints) that give rise to the Prepayment AEC. For the reasons set out below, we consider that it is

regional prices in those other segments in order purely to avoid the technical restrictions in the prepayment segments.

necessary to further mitigate the technical issues we have identified. This is particularly appropriate for gas, where a number of suppliers have faced considerable delays when trying to procure one or more gas tariff codes.¹⁹⁴ For the reasons set out below, we have decided to put in place an additional remedy that redistributes some of the unused gas tariff pages currently held by the Six Large Energy Firms, to make them available for existing suppliers and potential future new entrants.

- 12.234 We note that since publishing our provisional decision on remedies, some suppliers have returned gas tariff pages to Siemens, with four pages available (as of 20 May 2016). However, we consider it likely that independent suppliers will request these tariff pages shortly, and that there would be further scarcity of gas tariff pages absent further intervention.
- 12.235 As noted above, given that almost all suppliers' tariff offerings include a dual fuel option, there is a link between the number of gas tariff codes and electricity tariff codes a supplier uses. For example, if a supplier has only enough electricity tariff codes to offer a given number of electricity tariffs to prepayment customers, it is likely to use only enough gas tariff codes to offer the same number of gas tariffs to prepayment customers. As a result, in this case, the number of electricity tariff codes available to a supplier effectively caps the number of gas tariff codes it is able to use in practice, and vice versa.
- 12.236 Since each tariff a supplier offers tends to include an Economy 7 and a single-rate electricity tariff, but only a single-rate gas tariff, suppliers require twice the number of electricity tariff codes as they do gas tariff codes for each tariff they wish to offer.¹⁹⁵ This is the case whether suppliers set different prices in each region, or whether they were to group regions as set out above under our remedy softening the application of SLC 22B.7(b) for supply to prepayment customers.¹⁹⁶
- 12.237 As noted already, each supplier is issued a supplier ID, which allows them to offer up to 249 electricity prepayment tariffs. Given the relationship set out

¹⁹⁴ Robin Hood Energy and Ovo Energy have both outlined to the CMA the struggles they faced in having gas tariff codes allocated to them. Robin Hood Energy said that it took several months to be allocated a gas tariff page, having been told by Siemens initially that none were available; Ovo Energy was seeking a second tariff page in order to offer an additional prepayment tariff and faced similar issues.

¹⁹⁵ In addition, a number of suppliers have set out that they also offer electricity prepayment tariffs for customers with restricted meters. In such cases, suppliers will require more than twice as many electricity tariff codes as they do gas tariff codes. For example, [REDACTED]. [REDACTED]. [REDACTED].

¹⁹⁶ For example, if a supplier sets different prices in each region, it will require 14 gas tariff codes for each tariff, but 28 electricity tariff codes (Economy 7 and single rate in each of 14 regions). Likewise, if a supplier decides to set prices based on three different groups of region (as discussed in paragraph 12.226), it would require three gas tariff codes, but six electricity tariff codes (Economy 7 and single rate in each of three region groups). As noted in footnote 195, some suppliers would require more than this number of electricity tariff codes.

above, if a supplier uses all of its 249 electricity tariff codes to offer prepayment tariffs (with Economy 7 and single-rate versions of each tariff), it would require no more than 125 gas tariff codes to offer the same range of gas tariffs (with only a single-rate gas tariff) to prepayment customers.¹⁹⁷

- 12.238 This means that given the current constraint suppliers face on the electricity prepayment system, where they are able to offer a maximum of 249 tariffs, we consider that they could conceivably use a maximum of only 125 gas tariff codes, or 12 gas tariff pages.
- 12.239 A number of respondents commented on our proposal set out in the provisional decision on remedies to limit the number of gas tariff pages any supplier can hold to 12. Centrica said that the cap should be set at 14 instead of 12, as this would match the number of regions, and would thereby enable suppliers to continue with regional pricing should they wish to. EDF Energy said that it did not see the rationale for setting the cap at this level. SSE said that it considered our proposal to cap the number of gas tariff pages at 12 to be reasonable, while Utilita considered this to be too generous to the Six Large Energy Firms, and that all unused tariff pages should be returned to Ofgem and reallocated. Citizens Advice did not oppose our proposed cap of 12 tariff codes, but noted that it may be necessary to revisit this should more be required in the future.
- 12.240 As set out above in paragraph 12.238, we consider that – given the constraints on the electricity prepayment infrastructure – it is highly unlikely that any supplier would use more than 12 gas tariff pages. In relation to Centrica’s point that the cap should be set at 14 instead of 12 to enable them to engage in regional pricing, we are of the view that suppliers can set regional prices without necessarily having a whole tariff page for each region, and that 12 gas tariff pages is therefore an appropriate number.
- 12.241 Under this remedy, therefore, the first element is to cap the number of gas tariff pages that any supplier can hold at 12. We note that no supplier is currently using more than the 132 gas tariff codes this remedy would afford them. As a result, this remedy should not affect the prepayment tariffs these suppliers offer.¹⁹⁸

¹⁹⁷ As noted above, some suppliers require more than twice the number of electricity tariff codes as gas tariff codes (if they have prepayment customers on restricted meters). As a result, taking this 2:1 ratio gives a conservative (high) estimate of the number of gas tariff codes a supplier could conceivably use, given the constraint it faces in the number of electricity tariffs it is able to offer.

¹⁹⁸ Both suppliers that would have to return gas prepayment tariff pages under this remedy (E.ON and British Gas) currently use tariff codes on more than 12 separate tariff pages. However, both suppliers use fewer than the 132 tariff codes (12 tariff pages) that would be available to them under the remedy. As a result, by optimising their use of the tariff

12.242 This element of the remedy will leave all suppliers required to return one or more gas tariff pages (comprising three of the Six Large Energy Firms) with between five and 11 unused tariff pages each.

12.243 Table 12.1 sets out the number of gas tariff pages held by each of the Six Large Energy Firms, the number of gas tariff pages they are currently using, the number of tariff pages each supplier would have to return under our remedy, and the number of unused gas tariff pages each supplier would have after meeting the conditions of this remedy.¹⁹⁹

Table 12.1: The number of gas tariff pages held by the Six Large Energy Firms (in order of most gas tariff pages currently held)

<i>Supplier</i>	<i>Pages</i>	<i>Unused pages</i>	<i>Number of pages to return with cap at 12 pages</i>	<i>Remaining unused pages</i>
[REDACTED]	29	Currently using 7 slots on 14 of its pages and 1 further whole page (a total of 109 codes, or 10 pages)	17	2
[REDACTED]	14	Currently using 2 slots on 3 of its pages and 1 slot on each of its remaining 11 pages (a total of 17 tariff codes, or 2 pages)	2	10
[REDACTED]	12	11 pages unused (and uses 4 codes on the one page it uses)	0	11
[REDACTED]	10	9 pages unused (and uses 2 codes on the one page it uses)	0	9
[REDACTED]	10	6 pages currently unused; plans to use a further 4 of these pages (leaving 2 unused)	0	6
[REDACTED]	7	16 tariff codes currently unused	0	1.5*
Total			19	

Source: Number of gas pages currently held by suppliers was provided by Siemens; remaining information came from requests for information to the Six Large Energy Firms sent on 25 September 2015.

*Approximately.

12.244 We note that this element of the remedy would increase the number of gas tariff pages allotted or otherwise available for use by independent suppliers from 21 to 40 (or just over 50 if the additional tariff pages being created by Siemens become available).²⁰⁰

12.245 Schedule 25 of the Supply Point Administration Agreement provides that gas tariff pages should be allocated equally among the suppliers based on their

codes available under the remedy, both suppliers would be able to comply with the cap of 12 gas tariff pages without having to reduce the total number of tariff codes they currently use. We note, however, that for the tariff pages these suppliers currently use but would have to free up under the remedy (three pages in the case of [REDACTED] and two pages in the case of [REDACTED]), the suppliers may require some additional time to migrate customers off these tariff pages.

¹⁹⁹ [REDACTED] has advised us that it is in the process of returning a number of unused tariff pages to Siemens ([REDACTED] response to addendum to provisional findings and second supplemental notice of possible remedies, p5).

²⁰⁰ Siemens is in the process of trying to add 12 further tariff pages. It also has longer term ambitions to increase the total number to 179 tariff codes. However, the timing of these developments remain unclear.

customer portfolio size. However, we are concerned that this rule may exacerbate the barrier to entry and expansion for independent suppliers, on the basis that compliance with this rule may lead to a broadly similar distribution of unused tariff pages as currently observed. Also, in view of the relevant provisions set out in the Supply Point Administration Agreement,²⁰¹ and parties' submissions,²⁰² we understand that there are no formal mechanisms in place to monitor the allocation of gas tariff pages and to govern the distribution of tariff pages between suppliers.²⁰³

12.246 In addition to two of the Six Large Energy Firms returning some of their unused gas tariff pages (so they retain no more than 12 tariff pages in total), the second element of the remedy is to recommend that Ofgem monitors the allocation of gas tariff pages and, if appropriate, intervenes further to ensure a fairer and more efficient allocation of the gas tariff pages (see paragraphs 12.254 to 12.259 below for a discussion of the implementation of this remedy). Given the importance of gas tariff codes in helping all suppliers within the prepayment segments to compete to supply customers on dumb meters, we consider it important that an independent third party should control their allocation. As noted above, both Robin Hood Energy and Ovo Energy have noted the difficulties they have experienced in attempting to obtain gas tariff pages under the current system, and we consider that Ofgem, as an independent regulator with specific aims of protecting consumers and monitoring and encouraging competition, is the appropriate body to manage the allocation of gas tariff codes.

12.247 We have also considered which mechanism Ofgem should employ to allocate tariff codes. Scottish Power suggested that suppliers with excess gas tariff codes should auction them to interested suppliers. However, we do not consider this option to be in the interests of consumers. To the extent that the scarcity of gas tariff codes enables suppliers to set prepayment tariffs above the level that would be observed in a competitive market, it is possible that suppliers wishing to acquire gas tariff codes would bid an amount that reflects the rents they would expect from entering this segment of the market. As a result, an auction may serve only to transfer profits to the suppliers that auction the scarce tariff codes.

12.248 One party ([REDACTED]) said that it should be compensated for returning its unused tariff pages, since it paid to acquire them. Siemens manages the process for the release and take up of tariff pages between suppliers. The only fee

²⁰¹ Specifically paragraph 2.14 of the Supply Point Administration Agreement.

²⁰² In response to the Addendum and to requests for information.

²⁰³ Siemens put to us that, in the absence of 'spare' tariff pages, a request for a tariff page could only be satisfied when another supplier released one of its tariff pages.

incurred by suppliers receiving a tariff page is a transactional administration fee paid to Siemens. The supplier which has relinquished this tariff page receives (from Siemens) only this transaction administration fee, being calculated on the basis of the original development cost of the tariff page structure. In implementing this remedy, Ofgem should consider whether it is appropriate to keep these arrangements in place.

12.249 We note the limited time period over which we would expect the gas tariff slots restriction to remain a technical constraint concerning the supply of gas and electricity to prepayment customers, given the national programme for the roll-out of smart meters (for which such constraints do not arise). Accordingly, we have decided not to establish a set of formulaic rules for how Ofgem should allocate these codes to suppliers when implementing this remedy. However, we expect Ofgem to apply a range of principles, including:

- (a) Suppliers with no gas tariff pages (ie new entrants to the prepayment segments) should be prioritised over suppliers that already have tariff pages.
- (b) Ofgem should consider whether to keep some gas tariff pages in reserve in case they are requested by a new entrant. Doing so would likely prevent new entrants being held up while waiting for gas tariff pages to become available.
- (c) If at some point more gas tariff codes are requested than are available through the above mechanism, Ofgem should consider whether further interventions are necessary (eg use-it-or-lose-it conditions on suppliers' gas tariff pages, or an alternative method for redistributing further gas tariff pages).
- (d) Ofgem should monitor which gas tariff pages are controlled by each supplier, and which are being used at any given time. This would make it quicker and less costly if Ofgem has to reallocate tariff codes further in the future.

12.250 We note, by way of illustration, that increasing the number of gas tariff codes available to independent suppliers from 21 to 40 would almost double such suppliers' current allocation. For instance, a supplier with two gas tariff pages (instead of one, as is typical currently) could offer prepayment customers in three regional groups (pursuant to our remedy softening the application of SLC 22B.7(b)) one prepayment SVT and six fixed prepayment tariffs (eg a new 12-month fixed tariff every two months).

12.251 In the first instance, we will seek to implement our remedy by seeking undertakings from the Six Large Energy Firms (as the latter hold 80% of gas tariff pages). Such undertakings would include the following three components:

- (a) a cap on the number of gas tariff pages that the supplier can hold (at 12);
- (b) an obligation for the supplier to provide relevant information for Ofgem to monitor the allocation of the gas tariff codes; and
- (c) a condition that allows Ofgem to mandate the transfer of one or more gas tariff pages to another supplier.

12.252 Absent such undertakings, we recommend that Ofgem introduce a new licence condition in suppliers' standard licence conditions to include the three components set out above.

12.253 We have also noted how the parameters of gas tariff pages 13 and 14 are currently set by the Supply Point Administration Agreement. These tariff pages are available for anyone to use (eg suppliers without tariff pages of their own), so that all suppliers are able to offer prepayment tariffs. Given that the apparent purpose of tariff pages 13 and 14 is to facilitate entry, we believe that an independent sector regulator should set the level of standing charge and unit rate rather than this being done by industry participants. Accordingly, while not making a recommendation on this issue, we would encourage Ofgem to take responsibility for setting the parameters of tariff pages 13 and 14.

How these remedies should be implemented

12.254 In order to make better use of the available tariff codes, and mitigate the impact of the technical constraints on competition, we have decided to recommend that Ofgem:

- (a) modify suppliers' standard licence conditions to introduce an exception to SLC 22B.7(b) so as to allow a supplier to set prices to customers on dumb prepayment meters without applying regional cost variations which are applied to other payment methods within the same core tariff;
- (b) deprioritise potential enforcement action pending the modification of SLC 22B.7(b) against any supplier that sets prices to prepayment customers without applying regional cost variations which are applied to other payment methods within the same core tariff; and

- (c) take responsibility for the efficient allocation of gas tariff pages.
- 12.255 In addition, we are making a recommendation to Ofgem to monitor the allocation of tariff pages so as to ensure that no supplier holds more than 12 gas tariff pages, and if necessary to take appropriate steps to allocate gas tariff pages fairly and more efficiently between suppliers. Within this context, Ofgem should consider whether it is necessary to take steps aimed at facilitating new entry in the markets (for instance by prioritising allocation of unused tariff pages to new entrants and keeping some tariff pages in reserve for this purpose).
- 12.256 In the first instance, we will seek to implement this remedy by seeking undertakings from the Six Large Energy Firms. Such undertakings would include the following three components:
- (a) the cap on the number of gas tariff pages that any supplier can hold (at 12);
 - (b) an obligation for suppliers to provide relevant information for Ofgem to monitor the allocation of the gas tariff codes; and
 - (c) a condition that allows Ofgem to mandate the transfer of one or more gas tariff pages to another supplier.
- 12.257 Absent such undertakings, we recommend that Ofgem introduce a new licence condition in suppliers' standard licence conditions to include the three components set out above.
- 12.258 We would also expect any necessary changes to be made to the Supply Point Administration Agreement.
- 12.259 Moreover, Ofgem should publish a statement setting out the principles (reflecting the aim of this remedy) and process that it intends to follow prior to issuing a formal direction requesting a supplier to transfer unused gas tariff codes to another supplier.

Assessment of effectiveness

- 12.260 In assessing the effectiveness of these remedies, we have considered:
- (a) the extent to which they would be expected to address the technical constraints we have identified;
 - (b) the extent to which they are capable of effective implementation, monitoring and enforcement; and

(c) the timescale over which they are likely to have an effect.

- *Addressing the technical constraints*

12.261 We consider that these remedies, which include a recommendation to soften SLC 22B.7(b) and a recommendation that Ofgem takes responsibility for the allocation of tariff pages will be effective in reducing the impact of the technical constraints we have identified, which contribute to the Prepayment AEC.

12.262 We consider that the softening of SLC 22B.7(b) should enable suppliers to use both the available gas and electricity tariff codes in a more efficient manner, potentially increasing the total number of gas and electricity tariffs that suppliers are able to offer to prepayment customers with dumb meters using their limited tariff code allocations. We believe, however, that on its own, this remedy would have only a limited impact on suppliers' ability to offer a wider range of tariffs.

12.263 We also consider that a recommendation to Ofgem to take responsibility for the reallocation of tariff pages would be effective in further mitigating the impact of the technical constraints affecting independent suppliers. Reallocating 19 currently unused gas tariff pages will almost double (from 21) the number of gas tariff pages available to independent suppliers. We consider that this should significantly reduce the problems independent suppliers face in acquiring gas tariff codes, thereby reducing the barriers to entry faced by new suppliers and barriers to expansion faced by existing suppliers.

12.264 We note that two new entrants in the prepayment segments are Robin Hood Energy and Economy Energy, each of which has a single gas tariff page. While this remedy may not enable suppliers to offer the same range of fixed and variable tariffs they offer to customers with credit meters, these two suppliers have demonstrated that it is possible to operate in this segment with a single tariff page. Making more tariff pages available to similar suppliers, and enabling them to use them more efficiently would likely stimulate competition in the prepayment segments until the full roll-out of smart meters (including in the context of competition that will be possible under the price cap). As a result, this remedy will therefore contribute to addressing the Prepayment AEC.

12.265 We consider that this remedy should result in more suppliers being able to offer a wider range of tariffs to prepayment customers with dumb meters. However, this remedy would not remove the absolute constraint on the number of tariffs that suppliers can offer to customers with dumb

prepayment meters. As a result, suppliers will still face constraints concerning the range of prepayment tariffs they are able to offer; it does not solve the technical issues entirely.

12.266 While we acknowledge that the price cap remedy (see Section 14) might theoretically limit the incentives of suppliers to compete in the prepayment segments, we believe that the price cap has been set at a level that will still allow efficient suppliers to compete. We believe that a redistribution of gas tariff pages is required to stimulate competition under the price cap. It is also possible that, even in the presence of a price cap, suppliers may decide to offer a wider range of tariffs to their prepayment customers than they currently do. It is therefore necessary to address the technical constraints identified in Section 9 to encourage this possibility.²⁰⁴

- *Implementation, monitoring compliance and enforcement*

12.267 In determining whether a remedy is effective, we have had regard to the need for the remedy to be clear to the persons to whom it is directed, such as suppliers; and also to other interested persons, such as Ofgem (which would have responsibility for implementation, monitoring and compliance).

12.268 As regards implementation of the remedies, we have set out in paragraphs 12.254 to 12.259 above the relevant undertakings or licence condition modifications that would need to be made, and the various different levels of responsibility that Ofgem should take as regards allocating gas tariff pages. In certain respects for these remedies, we are leaving it open to Ofgem to determine the detailed implementation, such as to whom it reallocates gas tariff pages, and when and how. In this regard, Ofgem's information-gathering powers will enable it to procure information pertinent to reallocating tariff pages. For these reasons, we consider that Ofgem will be best placed to implement all aspects of these proposed remedies, and therefore consider that a recommendation (with or without undertakings) will be effective.

12.269 As regards monitoring compliance and enforcement, we also note that Ofgem will have a duty to monitor compliance with the new licence conditions and, as sector regulator, will be best placed to gather information concerning compliance with the licence conditions, and any directions made concerning the allocation of gas tariff codes. As regards new licence

²⁰⁴ It is also possible that the price cap may be removed before the full roll-out of smart meters (for instance as a result of the mid-term review of the price cap as set out in Section 14). In such an event, these remedies would be key to the promotion of competition in this segment.

conditions, Ofgem would also have the power to enforce against any breaches.

- *Timescale*

12.270 In evaluating the effectiveness of the remedies, we have considered the timescale over which the Prepayment AEC would be expected to endure, and the timescale over which the remedies would be likely to take effect. As regards the Prepayment AEC, our view is that, absent the remedies, the feature and associated AEC and detriment would persist until the national roll-out of smart meters has been substantially completed. We would expect therefore that the need for these remedies would fall away at that point.

12.271 As regards the timescale for implementation, we consider that the remedy could be implemented by suppliers within reasonable timescales, and therefore Ofgem should revise and introduce the relevant licence conditions as soon as reasonably practicable. In the meantime, we also recommend that Ofgem deprioritise potential enforcement action concerning SLC 22B.7(b) against any supplier that sets prices to prepayment customers without applying regional cost variations which are applied to other payment methods within the same core tariff, and communicates this to suppliers and relevant stakeholders.

12.272 We have also considered whether our remedies are compliant with applicable legislation and regulations. In this regard, we note that EU law requires differences in charges between payment methods to be cost-reflective. By contrast, the provision set out in SLC 22B.7(b), which was introduced as part of Ofgem's RMR rules (with a view to simplifying the tariff choice journey), does not implement an EU provision.

Assessment of proportionality

12.273 In considering whether the remedies would be proportionate, we have considered whether they:

- (a) are effective in achieving their legitimate aim;
- (b) are no more onerous than needed to achieve their aim;
- (c) are the least onerous if there is a choice between several effective measures; and

(d) do not produce disadvantages which are disproportionate to their aim.²⁰⁵

- 12.274 As set out above, we consider that these remedies are likely to be effective in ensuring the gas tariff codes are used and allocated efficiently, so that, in part, they address the technical constraints in the prepayment segments we have provisionally found (among other features) give rise to the Prepayment AEC and associated detriment.
- 12.275 We have also considered the option of centralising the management of gas and electricity tariff pages, as an alternative to one or both of the remedies (see paragraphs 12.291 to 12.303 below). While we feel that this possible remedy could be effective in mitigating the impact of the technical constraints, we consider that it would be complex, time-consuming and costly to implement, and therefore that, given the nature of the technical constraints feature and how long we expect it to persist, we consider that this remedy would not be proportionate (and, possibly, also not effective on a timely basis). We consider that this remedy would require a more thorough overhaul of the prepayment segments, which would not be proportionate given the short period over which consumers can be expected to benefit, given the technical constraints will be entirely removed by the roll-out of smart meters.
- 12.276 As a result, we believe that, even if this alternative possible remedy were effective, the combination of remedies we are proposing is the least onerous of the options we have considered.
- 12.277 We have also considered whether the remedies go further than necessary to achieve their aim. However, given that the individual aspects of the remedies all work together to ensure that the most efficient use and allocation is made of the existing gas tariff pages, we believe that each component part is necessary to achieve the overall aim. Moreover, each component of the remedies goes no further than necessary, in particular, given that Ofgem will have some flexibility concerning the mechanisms of implementation.
- 12.278 We have also considered the implementation costs that will be incurred by Ofgem, which we would expect to be small, and would relate mainly to the modification of the licence conditions and administering the reallocation of the gas tariff pages, which will be largely outweighed by the benefits of increased competition as a result of more tariffs being made available to prepayment customers with a dumb meter.

²⁰⁵ [CC3](#), paragraph 344, citing the principles established in the *Fedesa* case, Case C-331/88, *the Queen v Minister of Agriculture, Fisheries and Food and Secretary of State for Health, ex parte: Fedesa and others*, (1990) ECR I-4023, paragraph 13.

- 12.279 We consider that the costs to suppliers of complying with these remedies are minimal. As regards the softening of SLC 22B.7(b), this would not involve any cost to suppliers. Ofgem told us that this provision was implemented as part of Ofgem's simpler choices component of the RMR rules, ie to simplify the tariff choice journey. We believe that our remedy would not have any material impact on a customer's tariff journey. It is also consistent with our remedy to remove aspects of the simpler choices component of the RMR rules (see below). While we acknowledge that this remedy may lead to distributional impacts between customers of different regions as a result of the removal of regional variations within a core tariff, we believe that these impacts will be limited²⁰⁶ and justified by the greater availability of tariffs that will be allowed by this remedy.
- 12.280 We have also assessed the costs to suppliers of reallocating the unused gas tariff pages. We acknowledge the current constraints on suppliers resulting from the availability of electricity tariff codes, and do not consider that holding more than 12 gas tariff pages would deliver any significant value to a supplier. Redistributing two of the Six Large Energy Firms' excess tariff codes is therefore unlikely to affect the range of tariffs they are able to offer.
- 12.281 We recognise that holding unused gas tariff pages may have some current option value for a supplier (for example, if electricity tariff codes become less scarce in future, suppliers with spare gas tariff codes would be able to offer more dual fuel tariffs). However, we consider it unlikely that there will be significant further availability of electricity tariff codes in the period before the smart meter roll-out is complete. As a result, for the remaining period for which suppliers need to use the dumb prepayment meter infrastructure, we consider it unlikely that our remedy limiting suppliers' gas tariff page holdings to 12 would have a detrimental effect on the ability of any of the Six Large Energy Firms to offer prepayment tariffs.
- 12.282 Furthermore, we consider that the value of facilitating entry or expansion by independent suppliers that would result from redistributing gas tariff pages is likely to exceed any option value to the three of the Six Large Energy Firms holding unused gas tariff pages that would be reallocated pursuant to our remedies.

²⁰⁶ This is because suppliers would be in any event constrained by SLC 27, which requires that pricing differences between payment methods do not exceed the costs-to-serve differential. Moreover, suppliers should be able to group regions into a small number of broader groups with similar costs, and therefore limited distributional impacts between customers in different regions, and between customers and suppliers within a core tariff. As noted above, Scottish Power suggested that three broader groups should be sufficient for this purpose. This should be effective in significantly reducing the number of tariff codes required to offer a core tariff to prepayment customers, while reducing to a minimum any such distributional impact.

12.283 For these reasons, we do not believe that these remedies, individually or in combination, will produce any disadvantage to these suppliers or consumers that is disproportionate to its aim.

12.284 We noted in paragraph 12.249(c) above that should more gas tariff codes be requested than are available through the above mechanism, Ofgem should consider whether further interventions are necessary (eg use-it-or-lose-it conditions on suppliers' gas tariff pages, or an alternative method for redistributing further gas tariff pages). In doing so, Ofgem should consider the proportionality of any further interventions.

Duty to have regard to Ofgem's statutory duties

12.285 As stated above, where the CMA is considering whether to take action for the purpose of modifying one or more of the conditions of a retail gas or electricity supplier's licence, in deciding whether such action would be reasonable and practicable, the CMA must 'have regard' to the relevant statutory functions of Ofgem.

12.286 In reaching our decision to recommend a modification to SLC 22B.7(b), and possible new standard licence conditions concerning gas and electricity supply that sets the maximum number of gas tariff pages a supplier can hold, requires information provision and allows Ofgem to mandate the reallocation of gas tariff pages, we have, as part of our own application of the legal framework requiring us to decide upon remedies that are effective and proportionate,²⁰⁷ explicitly taken into account many of the factors to which Ofgem must have regard when carrying out its functions. We have therefore concentrated below on those considerations not explicitly taken into account elsewhere in this section of the final report.

12.287 In particular, we do not consider that these remedies will have an adverse impact on suppliers' ability to meet all reasonable demands for gas and electricity supply, achieving sustainable development, security of supply or environmental concerns. In this regard, the remedies will only have a bearing on the affordability considerations built into Ofgem's statutory duties and functions.

12.288 As noted above, we would expect the remedies to reduce the technical barriers that restrict suppliers' ability (in particular new entrants) to offer a wide variety of tariffs to prepayment customers with dumb prepayment meters. This in turn should increase competition between suppliers, and

²⁰⁷ CC3, paragraphs 334–347.

customer engagement, as customers would be more likely to find attractively priced tariffs and/or tariffs fitting their need. The remedies therefore directly engage Ofgem's principal objective of protecting the interests of existing and future consumers, wherever appropriate through competition.

12.289 In addition, we note that while not the key driver for the remedies, they will also have the side effect of providing some protection to vulnerable customers, since a higher proportion of low income customers use prepayment meters.²⁰⁸ The remedies therefore indirectly engage Ofgem's duty to have regard to the interests of, among others, individuals with low incomes.

12.290 In light of the above, we consider that the remedies are consistent with Ofgem's principal objective of promoting the interests of existing and future consumers.

Remedy we have decided not to pursue: managing gas and electricity tariff codes centrally

12.291 In addition to the two remedies set out above that aim to ensure efficient use of the available tariff codes, we also considered whether there was a case for pursuing a version of a possible remedy submitted by RWE in its response to the Second Supplemental Remedies Notice.

12.292 Each tariff code sets out both a standing charge and a unit rate, which together tell the prepayment meter the rate at which to decrement the customer's credit. Under RWE's proposal, a number of gas (and potentially electricity) prepayment tariff codes would be set aside to be managed centrally in such a way that they are available for all suppliers to use. The body in charge of managing the tariff codes would set a standing charge and unit rate for each tariff code, with suppliers then free to choose the tariff code (ie the combination of standing charge and unit rate) that best matches the tariff they would like to offer.

12.293 Under this proposed remedy, the standing charges and unit rates for each prepayment tariff code would be set centrally, meaning that no supplier could change the associated prices linked to a tariff code unilaterally.²⁰⁹ As a result, there would be greater scope for multiple suppliers to use the same

²⁰⁸ See Section 9.

²⁰⁹ Under the current gas prepayment system, in theory a supplier can use any gas prepayment tariff code, even if it is controlled by another supplier. However, in practice firms are reluctant to use a tariff code that is not under their direct control, given the possibility that the other supplier could change the standing charge and/or unit rate applying to that tariff code unilaterally. This means that in practice, each firm uses only the gas tariff codes under its own control.

set of tariff codes, thereby mitigating the constraint on the total number of tariffs that suppliers can offer. The objective of this possible remedy, therefore, would be to reduce significantly the absolute constraint on the number of prepayment tariffs that could be offered across the market, if applied to both electricity and gas.

12.294 Table 12.2 below sets out a stylised version of how this possible remedy might work for a gas prepayment tariff. For example, tariff code 23 would allow a gas tariff with a standing charge of 18p/day and a unit rate of 4p/kWh. Suppliers would be able to pick the combination of standing charge and unit rate that best matches the tariff they would like to offer.

Table 12.2: Stylised example of central management of gas tariff codes

Standing charge (p/day)	Unit rate (p/kwh)				
	1	2	3	4	5
10	Code 1	Code 7	Code 13	Code 19	Code 25
12	Code 2	Code 8	Code 14	Code 20	Code 26
14	Code 3	Code 9	Code 15	Code 21	Code 27
16	Code 4	Code 10	Code 16	Code 22	Code 28
18	Code 5	Code 11	Code 17	Code 23	Code 29
20	Code 6	Code 12	Code 18	Code 24	Code 30

12.295 It is important to note that the table above is for illustration purposes only. In practice, considerably more tariff codes would be required to give the level of detail needed by firms in setting their prices (since the increments of standing charge and unit rates would have to be considerably smaller than in Table 12.2). That is, such a remedy would be effective only if it is not overly limiting on the range of tariffs that suppliers are able to offer using the centrally managed tariff codes.

12.296 In deciding how many tariff codes would be needed to make such a system effective, there is a trade-off between the number of codes used and the granularity with which suppliers can set their prices. That is, since each tariff code has a standing charge and unit rate allocated to it by a central body, the supplier has to pick the code that best matches the tariff it would like to offer. As a result, it is possible that the standing charge and unit rate might not match perfectly the tariff the supplier would ideally like to offer. While this would place some limitations on the tariffs that suppliers can set, we do not consider that it makes this an unworkable solution.

12.297 We consider that in order to make such a system effective, it would likely require all the available gas tariff codes to be set centrally. If, for example, only some of the currently unused gas tariff codes were allocated to the central body to set (as was RWE's suggestion), we consider that suppliers may be unable to choose from a sufficiently granular set of standing

charge/unit rate combinations to enable effective competition in the prepayment segments.

- 12.298 In the case of electricity tariff codes, we understand that there is a considerable number of 'supplier IDs' (each coding for up to 249 electricity tariffs) that have not yet been allocated to suppliers. As a result, we consider that for electricity, there are likely to be sufficient unallocated tariff codes to implement this possible remedy. However, it is not clear whether such a remedy would be possible without considerable upheaval in the electricity prepayment segment. As a result, it is not clear whether it would be feasible to introduce this possible remedy for electricity in a timely manner.
- 12.299 It would be important for the central body to monitor closely how the standing charges and unit rates allocated to the tariff codes map to the actual tariffs available in the market. By doing so, it may be better able to recognise which tariff codes have fallen out of use and can therefore be allocated new standing charges and unit rates, thereby making suppliers better able to set tariffs that match those they would like to set ideally.
- 12.300 RWE's proposal suggested that the Gas Prepayment Expert Group Forum should be responsible for setting the standing charge and unit rate assigned to each tariff code. However, we consider that if we were to implement this possible remedy, it would be more appropriate for Ofgem to set and monitor the rates, for the reasons set out above.
- 12.301 In addition, suppliers wanting to offer tariffs lower than those available on the centrally managed tariff codes (eg when cutting prices in response to a reduction in wholesale prices) would have to request an adjustment to the centrally set tariff codes to include options with a lower standing charge and/or unit rate. We do not consider that it would be in the interests of competition for a supplier to have to seek approval from an industry body such as the Gas Prepayment Expert Forum (or an equivalent body for electricity) to offer lower prices than those currently available on the market.
- 12.302 We consider that this possible remedy would be of particular value if it was possible to implement it for both gas and electricity. Implementing such a remedy only for gas would remove the constraint on the total number of gas tariffs that could be offered. However, the constraints faced in the electricity prepayment system would remain, meaning that it would not remove the overall cap on the total number of prepayment tariffs that could be offered.
- 12.303 Notwithstanding the positive aspects of this possible remedy and its potential effectiveness at addressing the underlying feature of technical constraints,

we consider that it would be complex, time-consuming and costly to implement and, given the limited timescale over which this feature is expected to persist, and the timescale within which our other proposed remedies can be implemented concerning the technical constraints, our provisional view is that this possible remedy would not be effective and proportionate. Accordingly, we have decided not to implement this remedy.

Reforming the protocol for the assignment of debt on prepayment meters

- 12.304 One of the features of the Prepayment AEC that we have identified is the softened incentives for all suppliers, and in particular new entrants, to compete to acquire prepayment customers. This is due to, among other things, a low prospect for these suppliers of successfully completing the switch of indebted customers, who represent about 7% of electricity prepayment customers and 10% of gas prepayment customers.
- 12.305 In the Second Supplemental Remedies Notice and provisional decision on remedies, we consulted on a reform of the current Debt Assignment Protocol with a view to facilitating switching for indebted prepayment customers.
- 12.306 Our specific proposed remedy was to recommend that Ofgem amend the relevant licence conditions and industry code provisions, respectively, in order to address the following areas of the Debt Assignment Protocol that Ofgem had identified required further actions by itself and the industry:
- (a) The 'objection letter' sent by an incumbent supplier should not confuse customers as to their right to switch, making clear that the switch will continue; further 'objection letters' should only be sent to customers for whom it is established that they are not eligible to switch.
 - (b) The 'complex debt' aspect of the Debt Assignment Protocol should be revisited in order to diminish the instances in which the switch is disallowed.
 - (c) Issues relating to multiple registrations should be addressed in order to avoid multiple objection letters being sent to customers with such metering arrangements, causing unnecessary confusion for them and adding cost.

Aim of the remedy

- 12.307 The remedy seeks to improve the Debt Assignment Protocol process with a view to removing barriers to switching for indebted prepayment customers. This should increase the number of indebted customers that initiate and

complete a switch to a competing supplier, therefore increasing the competitive constraints in the prepayment segments.

Parties' views

- 12.308 Several parties including Centrica, Dawn Butler MP, Electra Link, EDF Energy, E.ON, Energy UK, RWE,²¹⁰ Scottish Power,²¹¹ Stephen Littlechild et al and Utilita²¹² supported this remedy. Centrica said that it was important to ensure that any changes proposed in this area are subject to an impact assessment and consultation process.²¹³
- 12.309 Ofgem said it welcomed the CMA's recognition of the Debt Assignment Protocol as an issue. It said it had been working with the industry on improvements to the Debt Assignment Protocol and further reform might best be achieved by the industry formulating an action plan with solutions to the issues identified, along with a timetable for implementation in 2016.²¹⁴
- 12.310 The Six Large Energy Firms, apart from SSE,²¹⁵ expressed support for a remedy that improved the Debt Assignment Protocol by building on the industry's existing work in this area, including its development of the Point of Acquisition (PoA) model. Several wanted a remedy that made the Debt Assignment Protocol process and adoption of the Point of Acquisition model mandatory for all suppliers.^{216,217,218,219} Some said the CMA recommending Ofgem to address the issues would be sufficient²²⁰ and the benefits of the CMA using its order-making power to support Ofgem's ongoing work was unclear.²²¹
- 12.311 SSE said the proposed remedy was unnecessary and ineffective because it would be superseded by existing and imminent market developments, with the procedure for suppliers universally adopting the Point of Acquisition model already underway.²²² In particular, SSE claimed that current objection letters were vital in the switching process and were not overly complex or

²¹⁰ RWE said that it broadly supported this remedy.

²¹¹ Scottish Power response to provisional decision on remedies, paragraph 6.3 p10.

²¹² Utilita also noted the need for additional improvements to the Debt Assignment Protocol

²¹³ Centrica response to provisional decision on remedies, paragraph 316, p62.

²¹⁴ Ofgem response to second supplemental notice of possible remedies, p13.

²¹⁵ SSE also said that it was fully supportive of proportionate and effective changes to ensure the Debt Assignment Protocol worked more effectively for prepayment customers.

²¹⁶ Centrica's response to second supplemental notice of possible remedies, p14.

²¹⁷ RWE npower's response to second supplemental notice of possible remedies, p13.

²¹⁸ EDF Energy's response to second supplemental notice of possible remedies, p10.

²¹⁹ E.ON's response to second supplemental notice of possible remedies, pp14–15.

²²⁰ Scottish Power's response to second supplemental notice of possible remedies, pp12–13.

²²¹ E.ON's response to second supplemental notice of possible remedies, pp14–15.

²²² SSE's response to second supplemental notice of possible remedies, p26

confusing, a conclusion that in its view is contrary to the CMA's assessment. Furthermore, it dismissed complex debt as a serious concern, which it alleged constitutes 5% of Debt Assignment Protocol processes.

12.312 Other parties had mixed views on the remedy:

- (a) Some independent suppliers and Energy UK suggested the remedy was unnecessary because of existing industry work on the Debt Assignment Protocol.²²³
- (b) Some independent suppliers expressed some support for the remedy.²²⁴
- (c) Some parties suggested more action than the proposed remedy was necessary to improve the Debt Assignment Protocol.²²⁵

12.313 Citizens Advice said the current Debt Assignment Protocol process was highly flawed. It said it was not confident that the remedy would deliver change promptly enough because the industry had consistently shown a lack of urgency in addressing issues with the Debt Assignment Protocol. It said that if the remedy was implemented, the CMA should use its order-making powers to support Ofgem's work.

Design considerations

12.314 In designing this remedy, we have considered:

- (a) our key concerns set out in Section 9 about the complexity of the switching process for indebted prepayment customers;
- (b) the ongoing work by Ofgem and industry to change the Debt Assignment Protocol so as to improve the switching process for these customers; and
- (c) the need to ensure the delivery of further improvements to the switching process for indebted prepayment customers.

12.315 There is in our view further scope for improving the switching process for indebted prepayment customers, in particular by simplifying it. We acknowledge that Ofgem and the industry are currently working on further changes that would seek to achieve this aim. However, as noted by Citizens Advice, such changes might be at risk of not being delivered quickly if the

²²³ First Utility, Good Energy and Energy UK responses to second supplemental notice of possible remedies.

²²⁴ Ovo Energy and Robin Hood Energy responses to second supplemental notice of possible remedies.

²²⁵ BGL Group, Ecotricity and Our Power Community Benefit Society responses to second supplemental notice of possible remedies.

responsibility of driving this process forward were left to the industry alone. In particular, and in the light of our provisional findings with respect to industry codes governance, we are concerned that the necessary modification to the relevant codes may be unnecessarily delayed.

- 12.316 In our provisional decision on remedies, we acknowledged Ofgem's response to our Second Supplemental Remedies Notice, noting that further reform to the Debt Assignment Protocol may best be achieved by industry formulating an action plan with solutions to the technical issues they have identified, along with a timetable for implementation in 2016.²²⁶
- 12.317 We accept that industry-led change could in principle be a quicker route to achieve the aim of this remedy compared with a licence modification led by Ofgem or the CMA under its order-making powers. Suppliers' incentives, however, may not align with those of indebted prepayment customers, such that suppliers may not necessarily take swift action to further improve the Debt Assignment Protocol process to the benefit of these customers. Therefore, in view of our findings in relation to the Codes AEC, and consistent with our remedies in that area, we expect Ofgem to continue monitoring and supporting the development of changes to the Debt Assignment Protocol.
- 12.318 We believe that Ofgem should ensure that clear objectives and a timetable with appropriate milestones are set out as soon as possible. It should also monitor that appropriate steps are taken by the industry in line with these milestones and signal its willingness to take action if it appears that the industry is not in a position to deliver a satisfactory solution by the end of 2016 (including by initiating a licence modification process). Absent such interventions by Ofgem, implementation by the industry of the expected improvements to the Debt Assignment Protocol may be unnecessarily delayed, or insufficiently focused on the interest of consumers.
- 12.319 We are concerned that, while Ofgem has been involved in developing these improvements to the Debt Assignment Protocol, it is not playing a sufficiently active role to ensure that these improvements (which would involve some code modifications) are delivered in a timely and effective manner (see also on similar issues our provisional findings report and remedies relating to the Governance AEC and the Codes AEC).

²²⁶ While Ofgem noted that this approach would allow changes to be introduced more quickly than would be the case if reforms were made via modifications to the licence conditions, it recognised that modifying the supply licence per the CMA's proposal represented another route to bringing about improvements with the Debt Assignment Protocol, should industry-led action prove ineffective.

12.320 For these reasons, we have decided to recommend that Ofgem take appropriate steps to ensure that changes to the Debt Assignment Protocol, and in particular in areas relating to objection letters, complex debt and issues relating to multiple registrations, as detailed above (see paragraph 12.306), are implemented by the end of 2016. For this purpose, we have also decided to recommend that Ofgem: ensure that clear objectives and a timetable with appropriate milestones are set out; supervise this process against such objectives and milestones; and take all steps, if and when necessary, to ensure delivery of these changes.

Assessment of effectiveness

12.321 We believe that, in light of our findings concerning the Codes AEC, our remedy will be effective in prompting Ofgem to ensure that certain meritorious changes to the Debt Assignment Protocol are made on a timely basis, through effective project management. An improved Debt Assignment Protocol will facilitate indebted prepayment customers to switch, which we expect to address, in part, suppliers' softened incentives to compete to acquire prepayment customers.

12.322 We believe that Ofgem, working together with the industry, is best placed to design and implement the necessary changes to the Debt Assignment Protocol that would ensure improvements to the switching process, and in turn facilitate switching for indebted prepayment customers.

12.323 Ofgem has in our view the appropriate incentives and resources to ensure that the proposed changes to the Debt Assignment Protocol are in customers' interests and are implemented by suppliers in a timely and effective manner, by the end of 2016.

12.324 We want to ensure the changes to the Debt Assignment Protocol are implemented at the earliest opportunity to address the impediments to switching by indebted prepayment customers. In view of parties' responses, we believe it is possible for the necessary changes to the Debt Assignment Protocol to be implemented by the end of 2016.

Assessment of proportionality

12.325 In considering whether the remedy would be a proportionate remedy to achieve its aim, we have considered whether the remedy:

(a) is effective in achieving its legitimate aim;

(b) is no more onerous than needed to achieve its aim;

(c) is the least onerous if there is a choice between several effective measures; and

(d) does not produce disadvantages which are disproportionate to the aim.²²⁷

12.326 For the reasons noted above in paragraphs 12.321 to 12.324, we believe that the proposed remedy will be effective in achieving its aim.

12.327 We do not consider that the remedy will produce any disadvantages which are disproportionate to the aim. It simply supports Ofgem in making changes to the Debt Assignment Protocol which have already been identified by Ofgem and the industry in order to ensure these changes happen. Similarly, we think the costs of implementing the remedy will be minimal because it essentially supports ongoing work by Ofgem and the industry.

12.328 Accordingly, we consider that the remedy is no more onerous than needed to achieve its aim of facilitating switching by indebted prepayment customers. Given the ongoing work by Ofgem in this area, we believe it would be disproportionate to impose an order on suppliers to make the relevant changes. Accordingly, we therefore consider our remedy is the least onerous of effective alternatives.

Remedy we have decided not to pursue: prohibition on the charging of a security deposit

12.329 We noted in Section 9 that prepayment customers face actual or perceived impediments to switching to tariffs available on credit meters (over and above those identified in the domestic retail energy markets as a whole). These impediments limit the opportunity for customers to engage in the markets, which contributes to one of the features identified in our Prepayment AEC, ie the softened incentives for all suppliers, and in particular new entrants, to compete to acquire prepayment customers. One of the impediments we have identified is the requirement (by some but not all suppliers) for customers that wish to switch to a credit meter to pay for a security deposit.

12.330 In our Second Supplemental Remedies Notice, we consulted on a possible remedy consisting in the prohibition of suppliers charging security deposits in specific circumstances.

²²⁷ CC3, paragraph 344, citing the principles established in the *Fedesa* case, Case C-331/88, *the Queen v Minister of Agriculture, Fisheries and Food and Secretary of State for Health, ex parte: Fedesa and others*, (1990) ECR I-4023, paragraph 13.

12.331 The possible remedy attempted to address the lack of clarity about when it is unreasonable to charge a security deposit by setting out specific, achievable criteria for prepayment customers to meet. These criteria were:

- (a) the customer is not in debt; or
- (b) the customer has not incurred any fines, charges or interest for late payment in the last six months.

Aim of the remedy

12.332 The possible remedy sought to address the actual or perceived impediment to switching that prepayment customers face as a result of the potential need to pay a security deposit when switching away from a prepayment meter.

Parties' views

12.333 Ofgem welcomed the CMA's recognition of the potential impact of security deposits on customers' ability to switch. However, it said it was important to note that this issue only applied to a small number of customers because only five suppliers currently requested security deposits. It also suggested that a number of factors should be considered if the CMA decided to proceed with the remedy including the risk that if prescriptive about when security deposits could be applied suppliers could adopt a 'tick box' approach rather than engage with customers individually.²²⁸

12.334 All of the Six Large Energy Firms, apart from E.ON, raised concerns about the remedy. Several were concerned about the impact on suppliers' ability to manage risk.^{229,230} EDF Energy recommended a principles based approach to regulation around security deposits to ensure supplier approaches are fair.²³¹ In addition:

- (a) Centrica said it was not right to prohibit the charging of a security deposit in the circumstances described because a customer satisfying these criteria may still be at a high risk of becoming indebted were credit to be provided. Centrica also said that an unintended consequence of the remedy could be more requests for a meter exchange being refused.²³²

²²⁸ Ofgem response to second supplemental notice of possible remedies, pp8–9.

²²⁹ EDF Energy response to second supplemental notice of possible remedies, p7.

²³⁰ RWE npower response to second supplemental notice of possible remedies, pp9–10.

²³¹ EDF Energy's response to second supplemental notice of possible remedies, p7

²³² Centrica response to second supplemental notice of possible remedies, p11.

- (b) SSE said the remedy was disproportionate, unlikely to be effective and could result in adverse unintended effects. It said the remedy would require suppliers to make significant changes to their billing processes and business models and would affect only a very small number of prepayment customers. It also said it could create a barrier to entry and expansion, increase tariff prices and undermine effective competition.²³³
- (c) Scottish Power said it did not think the CMA's criteria for the application of security deposits would work in practice because customers on prepayment meters could not, in general, make late payments and because most suppliers did not levy fines, charges or interest for late payment.²³⁴

12.335 E.ON said that it supported the remedy on the assumption that a supplier still had the right to refuse a request from an existing prepayment customer to have a credit meter installed where that refusal was objectively justified, for example following an unsatisfactory credit check result.²³⁵

12.336 Some other suppliers also expressed concerns about the possible remedy on the basis that if security deposits were restricted it could result in more customers facing renewed financial difficulty and debt management issues²³⁶ and stop suppliers assessing each customer individually.²³⁷

12.337 Other parties expressed some support for the possible remedy.^{238,239,240,241} These included Citizens Advice although it noted that given the small number of suppliers charging security deposits, the remedy might have only a marginal impact on the number of customers switching away from prepayment meters.²⁴² Alternatively, RWE believed that the Ofgem-led programme remedy could promote awareness of security deposits amongst prepayment customers.

²³³ SSE response to second supplemental notice of possible remedies, p21.

²³⁴ Scottish Power response to second supplemental notice of possible remedies, paragraph 20.11 p10.

²³⁵ E.ON response to second supplemental notice of possible remedies, p9.

²³⁶ First Utility response to second supplemental notice of possible remedies, p7.

²³⁷ Good Energy response to second supplemental notice of possible remedies, p3.

²³⁸ Robin Hood Energy response to second supplemental notice of possible remedies, p6.

²³⁹ Ovo Energy response to second supplemental notice of possible remedies, p4.

²⁴⁰ Ecotricity response to second supplemental notice of possible remedies, p3.

²⁴¹ BGL Group response to second supplemental notice of possible remedies, p6.

²⁴² Citizens Advice response to second supplemental notice of possible remedies, p7.

Assessment of effectiveness and proportionality

- 12.338 In light of parties' responses, we do not consider that this possible remedy would be effective and proportionate in meeting our aim to lower barriers to switching for prepayment customers.
- 12.339 In view of parties' responses, we consider that it is the lack of customer awareness and understanding of their options (over and above the actual cost of the security deposit) that contribute to the perception of barriers to switching. Customers can already choose from a range of tariff options offered by suppliers that do not require a security deposit. We also note that SLC 27.3 prohibits 'unreasonable' security deposits being charged by suppliers.
- 12.340 We believe that such a lack of awareness and understanding of available options can in part be addressed through an informational remedy, whereby suppliers provide clear and relevant information to their customers with respect to security deposits. We suggest that Ofgem consider this issue in the context of our proposal for a programme to identify, test and implement measures to provide customers with different or additional information to prompt them to engage in the retail energy markets (see Section 13).
- 12.341 We also note that there may be potential for adverse consequences from the remedy. While security deposits hamper customers' ability and incentives to switch (as noted above), these can be an efficient tool for suppliers to mitigate the risk (and costs) of bad debt. It is, however, difficult to identify precise rules that strike an efficient balance between these two considerations. We believe that suppliers should be free to decide the level of risk they find appropriate. We are also concerned that precise rules may become, as noted by Ofgem, a 'tick-the-box' exercise which would undermine suppliers' incentives to engage with customers to find an appropriate solution.
- 12.342 For all these reasons, we do not consider that there is scope for a further remedy in this area.

Remedy we have decided not to pursue: prohibition on suppliers from charging customers upfront for the cost of a new meter

- 12.343 In Section 9, we noted that prepayment customers face actual or perceived impediments to switching (over and above those identified in the domestic retail energy markets as a whole). These impediments limit the opportunity for customers to engage in the markets, thereby contributing to one of the features identified in the Prepayment AEC, ie the softened incentives for all

suppliers, and in particular new entrants, to compete to acquire prepayment customers.

12.344 In our Second Supplemental Remedies Notice, we consulted on suppliers being prohibited from charging customers upfront for the cost of a new meter when switching away from prepayment meters. In line with SLC 27.2A suppliers would be able to recover the costs of the meter from the customer, provided this is spread over a period of time.

Aim of the remedy

12.345 The possible remedy sought to lower the barriers to switching by addressing the actual or perceived impediment to switching that prepayment customers may face as a result of the cost of meter installation when switching away from a prepayment meter. In particular, it sought to reduce the burden of the upfront costs which may discourage certain customers to complete the switch.

Parties' views

12.346 Ofgem welcomed the CMA's recognition of the issue of the upfront charges. It highlighted the existing widespread removal of such charges by the industry and said the issue was time sensitive because the roll-out of smart meters should mean suppliers could switch payment modes remotely and not have to charge.²⁴³

12.347 Four of the Six Large Energy Firms expressed support for the remedy.^{244,245,246,247}

12.348 Centrica and SSE opposed the remedy:

(a) Centrica said the remedy was not proportionate because the charges were not a major barrier to meter exchanges and the smart meter roll-out would ultimately resolve the issue.²⁴⁸

(b) SSE said the remedy was disproportionate, unlikely to be effective and could result in unintended adverse effects. It said that for the uncertain benefit of a minimal number of customers, the remedy imposed

²⁴³ Ofgem response to second supplemental notice of possible remedies, p10.

²⁴⁴ RWE npower response to second supplemental notice of possible remedies, p11.

²⁴⁵ EDF Energy response to second supplemental notice of possible remedies, p8.

²⁴⁶ E.ON response to second supplemental notice of possible remedies, p11.

²⁴⁷ Scottish Power response to second supplemental notice of possible remedies, paragraph 20.18 p11.

²⁴⁸ Centrica response to second supplemental notice of possible remedies, p12.

significant constraints on how suppliers managed bad debt and financial risk.²⁴⁹

- 12.349 Some other suppliers also said the remedy was disproportionate,^{250,251} and the issue would shortly be resolved by the roll-out of smart metering.²⁵²
- 12.350 Other parties expressed some support for the remedy^{253,254}. These included Citizens Advice, although it noted that the vast majority of suppliers did not charge for meter installation or removal so the remedy would have only a marginal impact in improving the number of customers switching away from prepayment meters.²⁵⁵

Assessment of effectiveness and proportionality

- 12.351 In light of parties' responses, we do not consider that the remedy will be effective in meeting our aim to lower barriers to switching for prepayment customers.
- 12.352 We note that suppliers must roll out smart meters in the next four years at no cost to customers. The issue of upfront charges is therefore only a temporary concern which affects only a small number of customers.
- 12.353 Having reviewed parties' responses, we consider that it is the lack of customer awareness and understanding of their options (but not the actual cost of the meter replacement) that contribute to the perception of barriers to switching. Customers can already choose from a range of tariff options offered by suppliers that do not charge the costs of replacing the meter upfront (if at all).
- 12.354 We believe that such a lack of awareness and understanding of available options is more effectively addressed through an informational remedy, by ordering suppliers to provide clear and relevant information to their customers with respect to meter replacement costs (see Section 13). We also suggest that Ofgem consider this in the context of our proposal for a programme to identify, test and implement measures to provide customers with different or additional information to prompt them to engage in the energy market (see Section 13). In our view a remedy such as the one envisaged in the Second Supplemental Remedies Notice would not have

²⁴⁹ SSE response to second supplemental notice of possible remedies, p25.

²⁵⁰ First Utility response to second supplemental notice of possible remedies, pp7–8.

²⁵¹ Robin Hood Energy response to second supplemental notice of possible remedies, p7.

²⁵² Good Energy response to second supplemental notice of possible remedies, p4.

²⁵³ Ovo Energy response to second supplemental notice of possible remedies, p4.

²⁵⁴ Ecotricity response to second supplemental notice of possible remedies, p3.

²⁵⁵ Citizens Advice response to second supplemental notice of possible remedies, p9.

any significant additional impact on switching rates, over and above the informational remedy.

12.355 For all these reasons, we do not consider that there is scope for a further remedy in this area.

Withdrawing certain aspects of the simpler choices component of the RMR rules

12.356 We have found that certain aspects of the ‘simpler choices’ component of Ofgem’s retail market review (RMR) rules are a feature of the markets in the domestic retail supply of electricity and gas that gives rise to an AEC by reducing retail suppliers’ ability and incentives to compete and innovate in designing tariff structures, and by softening competition between PCWs (the RMR AEC).²⁵⁶

12.357 To address our concerns in this area, we recommend that Ofgem remove the following aspects of the simpler choices component of the RMR rules:

- (a) the ban on complex tariffs;²⁵⁷
- (b) the maximum limit on the number of tariffs that suppliers can offer at any point in time²⁵⁸ (the ‘four-tariff rule’);
- (c) the restrictions on the offer of discounts;²⁵⁹
- (d) the restrictions on the offer of bundled products;²⁶⁰
- (e) the restrictions on the offer of reward points discounts;²⁶¹ and
- (f) the prohibition against tariffs exclusive to new/existing customers.²⁶²

12.358 The specific provisions that we are proposing to remove and those we are proposing to retain are set out in paragraphs 12.379 below and Appendix 12.1.

12.359 The RMR rules were designed as an integrated package aimed at addressing certain barriers to effective customer engagement arising, in particular, from complex tariff options, the information provided to domestic

²⁵⁶ See [provisional findings report](#), Section 12.

²⁵⁷ SLCs 22A.3(a) and (b).

²⁵⁸ SLC 22B.2 (a) and (b).

²⁵⁹ SLCs 22B.3–6 and SLCs 22B.24–28).

²⁶⁰ SLCs 22B.9–16 and SLCs 22B.24–28.

²⁶¹ SLCs 22B.17–23 and 22B.24–28).

²⁶² SLC 22B.30 and 22B.31.

customers, and low levels of trust in energy suppliers. The RMR rules had three components ('simpler choices'; 'clearer information'; and 'fairer treatment') and were implemented through modifications to the standard licence conditions for the retail supply of gas and electricity.

- 12.360 The simpler choices component was designed to make it easier for customers to understand and compare the energy tariffs offered by suppliers and falls within the scope of this proposed remedy.
- 12.361 The 'clearer information' component was designed to help domestic customers understand the information they receive from suppliers and is considered as part of our assessment of remedies to help customers engage. However, we have also considered the impact that the removal of the simpler choices component of the RMR rules would have on the information tools²⁶³ introduced by the RMR rules in the proportionality assessment of this remedy (in terms of potential unintended consequences).
- 12.362 The 'fairer treatment' component of the RMR rules was designed to ensure that domestic customers are treated fairly in all interactions they have with energy suppliers. The Standards of Conduct rules (SLC 25C), introduced as part of the 'fairer treatment' component of the RMR rules, are considered in Section 13 on the use of principles-based regulation. In particular, we consider the extent to which the Standards of Conduct might mitigate any potential unintended consequences of removing aspects of the simpler choices component of the RMR rules.

Aim of the remedy

- 12.363 The aim of this remedy is:
- (a) to promote competition and innovation between retail energy suppliers in the retention and acquisition of domestic customers by allowing them to offer a wider range of tariffs and discounts than permitted by the simpler choices component of the RMR rules, including tariffs and discounts designed to appeal to certain customer groups; and
 - (b) to facilitate competition between PCWs by addressing the constraints which the simpler choices component of the RMR rules place on the number of tariffs offered by suppliers and, accordingly, allowing PCWs to

²⁶³ The tariff comparison rate, personal projection, cheapest tariff messaging and tariff information label.

negotiate exclusive tariffs with domestic energy suppliers and to offer discounts funded by the commissions they receive from suppliers.

12.364 Accordingly, the aim of this remedy is to address the RMR AEC and to partly address the Domestic Weak Customer Response AEC. We also note that it addresses, in part, the Prepayment AEC.²⁶⁴

12.365 In this report we set out evidence on the impact the RMR rules have had on the ability and incentives for suppliers to compete on price and on the range of tariffs and discounts that suppliers can offer domestic customers (see Section 9 and paragraphs 12.409 to 12.414 below). We also consider that the RMR rules (in particular the four-tariff rule) limit the scope for competition between PCWs for customers switching energy suppliers to exert downward pressure on energy prices. In particular, we consider that, absent the four-tariff rule, PCWs would be in a good position to negotiate favourably priced exclusive tariffs with retail energy suppliers (see paragraph 12.417).

12.366 The ‘four-tariff rule’ is not the only barrier to PCWs negotiating favourable exclusive deals with suppliers. The recent requirement for PCWs to display the whole market also has the potential to undermine the incentives on the part of suppliers to negotiate such deals. We consider this matter further in Section 13.

12.367 We recognise that the simpler choices rules were introduced in an attempt to address concerns that suppliers may have an incentive to mislead customers, by marketing complex tariffs that look attractive but do not in reality provide good value for money. We set out our overall approach to addressing such concerns in Section 11 and Section 13, which explains our proposed remedies to help customers engage. To mitigate any unintended consequences arising from a potentially significant increase in the number of tariffs on offer, we propose a remedy to strengthen the role of principle-based Standards of Conduct (see Section 13).

Parties’ views on the remedy

12.368 We received responses to the remedy set out in our provisional decision on remedies from various parties including the Six Large Energy Firms, the Mid-tier Suppliers, PCWs²⁶⁵ and consumer groups.²⁶⁶

²⁶⁴ See Section 13.

²⁶⁵ In particular Comparethemarket.com, moneysupermarket.com and uSwitch.com.

²⁶⁶ Citizens Advice and National Energy Action.

12.369 All Six Large Energy Firms and two of the Mid-tier Suppliers (Ovo Energy and Utility Warehouse) were supportive of our remedy.²⁶⁷

- (a) Suppliers generally agreed that removing the simpler choices component of the RMR rules would improve suppliers' ability to innovate.^{268,269,270,271}
- (b) Some suppliers said that the remedy would enable suppliers to negotiate exclusive offers with PCWs.^{272,273}
- (c) Some suppliers said that to be fully effective the remedy should remove or amend additional aspects of suppliers' licences.^{274,275,276}

12.370 First Utility said it feared removal of the simpler choices rules would 'lead to a massive proliferation of tariffs and offers, making it difficult for even active customers to navigate [the market]'.²⁷⁷ First Utility said there should be a phased implementation of the proposed changes, allowing suppliers to offer

²⁶⁷ Centrica response to provisional decision on remedies, p7, paragraph 32; EDF Energy response to provisional decision on remedies, p30, paragraph 7.1; E.ON response to provisional decision on remedies, p33, paragraph 153; RWE response to provisional decision on remedies, p58, paragraph 49.1; Scottish Power response to provisional decision on remedies, p11, paragraph 7.1; SSE response to provisional decision on remedies, Annex 1, p4, paragraph 6.1.1; Ovo Energy response to provisional decision on remedies, p30, paragraph 6.1; Utility Warehouse response to provisional decision on remedies, p1.

²⁶⁸ Centrica response to provisional decision on remedies, pp51–52, paragraphs 253–256; EDF Energy response to provisional decision on remedies, p30, paragraph 7.3; E.ON response to provisional decision on remedies, p33, paragraph 153, paragraph 13; RWE response to provisional decision on remedies, p58, paragraph 49.1; Scottish Power response to provisional decision on remedies, p11, paragraph 7.1; SSE response to provisional decision on remedies, Annex 1, p4, paragraph 6.1.1.

²⁶⁹ Co-operative Energy response to Remedies Notice, p4.

²⁷⁰ Ovo Energy response to provisional decision on remedies, p30, paragraphs 6.1–6.3. Ovo also said that in order to prevent a return to customer confusion new Standards of Conduct should be introduced.

²⁷¹ Utility Warehouse response to Remedies Notice, p4.

²⁷² Centrica response to provisional decision on remedies, p52, paragraph 258.

²⁷³ RWE response to provisional decision on remedies, p58, paragraph 49.1. RWE said when combined with the removal of the whole of market view restrictions this remedy will also incentivise PCWs to compete by allowing them to negotiate exclusive tariffs and to offer discounts funded by commissions from suppliers.

²⁷⁴ Scottish Power response to provisional decision on remedies, pp11–13, paragraphs 7.1–7.10. Scottish Power said the CMA should include a recommendation to Ofgem to: (1) review SLC22A.2 which has the effect of prohibiting two-tier 'no standing' charge tariffs; (2) delete or amend SLC22B.7 which requires that the price differential is either incorporated into the standing charge or into the unit rate but not both; (3) remove SLC22C.7 which requires at the end of a fixed-term product, if the customer does not actively choose otherwise, for them to be automatically rolled over onto the cheapest evergreen tariff, which encourage suppliers only to have one evergreen tariff; and (4) review the need for SLC22C.9 which places a restriction on suppliers unilaterally varying the price or other terms and conditions of fixed-term contracts and has the effect of banning 'tracker' or capped fixed-term tariffs which were very popular options prior to RMR.

²⁷⁵ SSE response to provisional decision on remedies, Annex 1, pp4–6. SSE said: reword SLC22A.2 relating to complex tariffs to ensure suppliers are not prevented from offering tiered-rate tariffs; amend SLC22C.11 to include an additional exception to ensure suppliers can offer fixed discount tracker tariffs; and make two other changes in order to relax the ban on new dead tariffs sufficiently to allow suppliers freedom to innovate (1. amend SLC 22D.1A to allow for the withdrawal of a live SVT and the continuation of supply under a new dead tariff; and 2. amend the exception to the prohibition on dead tariffs in SLC22D.2).

²⁷⁶ Centrica response to provisional decision on remedies, pp51–52, paragraph 257. Centrica said that in order to get the full benefit from this proposal, the CMA should mirror changes made in SLC22B with changes to SLC31 D; the licence condition that applies simpler choices to white label suppliers. The CMA should also review SLC 22C.9 because in effect it prohibits all but a narrow range of tracker tariffs.

²⁷⁷ First Utility response to provisional decision on remedies, p12, paragraph 4.2 and p14, paragraphs 4.11–4.13.

product bundles, discounts and partner tariffs first, and then aligning the removal of the four-tariff rule with the introduction of specific information remedies that provide monthly market cheapest tariff messaging to customers and change the SVT name to 'out-of-contract' tariff.²⁷⁸

- 12.371 Co-operative Energy agreed that the RMR requirements had stifled some innovation but said removing all tariff restrictions was not in customers' interests. Co-operative Energy said removal risked a return to a profusion of multiple tariffs, which could cause customer confusion, so it proposed limiting suppliers to providing no more than six tariffs.²⁷⁹
- 12.372 Some parties supported the remedy but identified potential risks, including that the increased complexity of suppliers' offers could adversely affect customer engagement.^{280,281,282,283} The Centre for Competition Policy at the University of East Anglia identified a potential risk of new deals emerging for customers which deliberately exploited consumption uncertainty. It said Ofgem's principle-based regulations would mitigate such risks but that Ofgem's decisions on compliance might over time re-establish the rules.²⁸⁴
- 12.373 We note that the removal of aspects of the 'simpler choices' component of the RMR rules may result in more tariffs and a wider range of products on the market. However, our view is that there are a range of tools which may help customers navigate the tariffs on offer in the market and make decisions and, accordingly, address any such unintended consequences arising from this proposed remedy (see paragraph 12.438 below). In addition, we consider that the 'Standards of Conduct' licence condition (ie SLC 25C) and our recommendation to Ofgem to introduce an additional principle to SLC 25C that would require suppliers to have regard in the design of their tariffs to the ease with which customers can compare value for money with other tariffs they offer (see Section 13) should mitigate the risks associated with our remedy.
- 12.374 Ofgem said it welcomed the recommendation to remove the simpler choices rules, which aligned with its aim to rely more on principles and less on

²⁷⁸ First Utility response to provisional decision on remedies, p16, paragraph 4.19.

²⁷⁹ Co-operative Energy response to provisional decision on remedies, p2.

²⁸⁰ [REDACTED]

²⁸¹ Citizens Advice response to provisional decision on remedies, pp25–28. Citizens Advice said it was eager to avoid a re-emergence of the previous tariff proliferation. It wanted reassurance that the Standards of Conduct would be applicable if there was a re-emergence of poor supplier practices.

²⁸² Moneysupermarket.com response to provisional decision on remedies, p4. It said Ofgem should develop a principle that insisted on the clear differentiation of products from the same supplier.

²⁸³ uSwitch.com response to provisional decision on remedies, p5.

²⁸⁴ Centre for Competition Policy, University of East Anglia's response to provisional decision on remedies, p11.

prescriptive rules to regulate the retail energy markets.²⁸⁵ Ofgem said it expected the remedy to result in suppliers introducing different and more complex tariff offerings, and this would necessitate revisiting the information tools introduced to complement the simpler choices rules.²⁸⁶

12.375 Some parties said the removal of these simpler choices rules would require changes to certain information tools, especially the cheapest tariff messaging.^{287,288,289}

12.376 In response to these comments, as part of this remedy we recommend that Ofgem make any consequential amendments to the standard licence conditions concerning the information tools introduced as part of the 'clearer information' component of RMR (eg the Cheapest Tariff Message) (see paragraph 12.396 below). In addition, as discussed in Section 13 (see the 'Ofgem-led programme'), we recommend that Ofgem should trial changes to the information in domestic bills and how this will be presented, including the provision of information on the availability of cheaper tariffs in the market.

Design considerations

12.377 We considered the following elements in the design of this remedy:

- (a) which standard licence conditions concerning the simpler choices component of the RMR rules we recommend that Ofgem remove;
- (b) which standard licence conditions concerning the simpler choices component of the RMR rules fall outside the scope of our recommendation to Ofgem; and
- (c) how to implement this remedy.

²⁸⁵ Ofgem response to provisional decision on remedies, Annex 2, p6.

²⁸⁶ Ofgem response to provisional decision on remedies, Annex 2, p6.

²⁸⁷ Centrica response to provisional decision on remedies, pp52–53, paragraphs 261–277. Centrica said the Cheapest Tariff Message and Tariff Comparison Rate would become misleading and redundant and the proposed market Cheapest Tariff Message was unworkable. Centrica said the RMR rules relating to clearer information should be set aside in the same way and at the same time as planned for simpler choices rules.

²⁸⁸ EDF Energy response to provisional decision on remedies, pp30–31, paragraph 7.4. EDF Energy said market-wide and supplier Cheapest Tariff Messaging would become impractical and potentially misleading.

²⁸⁹ Moneysupermarket.com response to provisional decision on remedies, p4. Moneysupermarket.com said that due to practical technical issues with suppliers' systems, there was a danger that if any PCW exclusive tariffs with suppliers were required to be included on Cheapest Tariff Messaging, suppliers could not offer such deals.

Which standard licence conditions concerning the ‘simpler choices’ component of the RMR rules we recommend that Ofgem remove

12.378 We have found that certain aspects of the simpler choices component of the RMR rules (individually and in combination) have reduced suppliers’ ability to innovate and softened price competition between suppliers and PCWs.

12.379 Under this remedy, we recommend that Ofgem remove the standard licence conditions concerning the following:²⁹⁰

- (a) the ban on complex tariff structures (SLC 22A.3 (a) and (b));
- (b) the four-tariff rule (SLC 22B.2 (a) and (b));
- (c) the restrictions on the offer of discounts (SLCs 22B.3–6 and 22B.24–28);
- (d) the restrictions on the offer of bundled products (SLCs 22B.9–16 and 22B.24–28);
- (e) the restrictions on the offer of reward points (SLCs 22B.17–23 and 22B.24–28); and
- (f) the prohibition against tariffs exclusive to new/existing customers (SLC 22B.30 and 22B.31).

- *Ban on complex tariff structures*

12.380 We recommend that Ofgem remove the requirement that all tariffs must have a single standing charge (which may be zero) and either a single unit rate or time-of-use rates (which cannot vary according to the level of consumption).²⁹¹ We consider that these restrictions on the structure of tariffs restrict innovation and competition between suppliers as they are prevented from offering new products or tariffs that are beneficial to certain segments of customer population, particularly in relation to energy usage (eg two-tier ‘no standing charge’ tariffs launched by suppliers to meet the needs of low usage customers, which existed prior to the RMR rules).

12.381 We also considered replacing SLC 22A.3(a) and (b) with a requirement on domestic energy suppliers to structure all tariffs as a single unit rate in pence per kWh. This, unlike SLC 22A.3, would in principle enable customers to compare tariffs without recourse to a PCW or the need to carry out an involved calculation. However, any limit on tariff structures has the potential

²⁹⁰ The specific wording of these standard licence conditions is set out in Appendix 5.4.

²⁹¹ SLC 22A.3 (a) and (b).

to stifle innovation and restrict competition. In addition, restricting the structure of all tariffs to a single unit rate would limit suppliers' ability to respond to the smart meter roll-out. While time-of-use tariffs are permitted by the simpler choices component of the RMR rules, no more than one unit rate can apply to any given time period and unit rates cannot vary by the level of consumption. Further, a single unit rate would be of limited benefit in terms of transparency in the presence of discounting.

- *Four-tariff rule*

12.382 We recommend that Ofgem remove the four-tariff rule,²⁹² which prohibits suppliers from offering more than four core tariffs per fuel per metering arrangement in any region. We consider that, in addition to the ban on complex tariffs, the four-tariff rule also restricts suppliers' ability to compete and innovate as they are prevented from offering new tariffs or products to attract customers and respond effectively to tariffs introduced by their competitors. The four-tariff rule is particularly restrictive in relation to the ability of suppliers to offer tariffs that are designed to attract specific groups of customers rather than being targeted at the mass market (eg tariffs aimed at low consumption users, tariffs aimed at certain social groups and tariffs with particular characteristics such as 'green tariffs' and tracker tariffs).

12.383 We also consider that removal of the four-tariff rule is necessary for the removal of other restrictions (in particular, the removal of the requirement that suppliers must ensure that all its tariffs are available to new and existing customers, and removal on restrictions concerning the offering of bundled tariffs) to be effective. This is because the flexibility for suppliers to offer new types of tariff would be limited by the restriction on the number of tariffs they could offer.

12.384 We also consider that, with the removal of the four-tariff rule, competition between PCWs has the potential to exert downward pressure on commissions and tariffs as they will be able to negotiate exclusive tariffs with energy suppliers. For similar reasons, we considered, but have decided not to proceed with, replacing SLC 22B.2(a) and (b) with a restriction containing a higher number of permitted tariff structures.

²⁹² SLC 22B.2 (a) and (b).

- *Restrictions on the offer of discounts*

12.385 We recommend that Ofgem remove the restrictions that limit the type of discounts suppliers can offer, including the prohibition to offer discounts that fall outside of three permitted types of cash discount, ie dual fuel, online account management, and dividend payments.²⁹³ We consider that, in addition to the ban on complex tariffs and the four-tariff rule, such restrictions also restrict competition among suppliers. The removal of these restrictions will allow suppliers to offer other types of discounts which might incentivise customers to switch (eg cashback or one-off introductory discounts) and reward them for behaviour that reduces suppliers' costs (prompt payment discounts).

12.386 We also recommend that Ofgem remove the restrictions that require suppliers to make any discounts they offer available to all customers and to ensure that the value of any discount is the same for all customers across Great Britain. We consider that such restrictions have the potential to stifle price competition between suppliers by reducing the incentives for suppliers to offer discounts to compete to acquire or retain customers (these may be discounts offered to certain groups of customers or customers in certain geographic areas). This is because the effect of these restrictions is to reduce the competitive pressure that any supplier exerts on its rivals and therefore to reduce the pressure suppliers face to offer competitive prices to attract or retain customers (just as it is now recognised that the prohibition of regional price differentials adversely affected the extent of price competition between the Six Large Energy Firms in setting prices of SVTs (see Section 8).

12.387 In summary, the removal of such restrictions will give suppliers more flexibility in respect of the manner in which discounts are offered to domestic customers (for instance, suppliers will be allowed to offer one-off discounts and discounts applying to new or existing customers only, discounts varying across regions) to compete in the acquisition and retention of customers.

- *Restrictions on the offer of bundled products*

12.388 We recommend that Ofgem remove the rules concerning the offering of bundled products which include rules on how products may be bundled with tariffs and the form they take.²⁹⁴ We consider that these rules restrict

²⁹³ SLCs 22B.3–6 and 22B.24–28.

²⁹⁴ SLCs 22B.9–16 and 22B.24–28.

competition among suppliers and restrict innovation.²⁹⁵ In particular, the current bundling restrictions are designed to be applied in tandem with the four-tariff rule with the aim of simplifying suppliers' tariff offerings. The removal of these restrictions will allow suppliers to offer packages of tariffs with other services and allow flexibility in respect of the manner in which such discounts are offered to customers.

- *Ban on reward points*

12.389 We recommend that Ofgem remove the rules concerning the offering of reward points discounts.²⁹⁶ We consider that these rules also restrict innovation and competition among suppliers. The removal of these restrictions will allow suppliers to decide on how reward points are offered with tariffs and the form they take. For instance, they will be able to have a refer-a-friend initiative where existing customers and the individual referred receive a reward (instead of having to make the reward available to all customers).

- *New and existing customers*

12.390 We recommend that Ofgem remove the requirement that suppliers must ensure that all its tariffs are available to new and existing customers subject to some exceptions²⁹⁷ as we consider that this restriction has the potential to dampen competition between suppliers. We also consider that removing this restriction would be effective in allowing suppliers to innovate more.

12.391 We consider that the requirement on suppliers to make all tariffs available to both new and existing customers reduces their incentives to respond, by offering cheaper tariffs, to competition for either the acquisition or retention of customers as the effect is to increase the cost to suppliers of offering cheaper tariffs (which, in turn, reduces the competitive pressure each supplier exerts on their rivals).

12.392 We consider that the adverse effects on competition are exacerbated by the current Cheapest Tariff Messaging requirements under the 'clearer information' component of the RMR rules. This is because suppliers are required in communications with their existing customers to tell them about their cheapest tariffs including white labels, which may create perverse

²⁹⁵ Bundling is a common business practice for which there are many pro-competitive and efficiency reasons. Bundling may breach competition laws if a dominant firm uses it abusively (eg to exclude rivals).

²⁹⁶ SLCs 22B.17–28.

²⁹⁷ SLC 22B.30 and 22B.31.

incentives for suppliers not to offered discounted tariffs or to reduce the extent of discounting in order to avoid alerting the supplier's existing customer base to better deals.²⁹⁸

12.393 We recognise that removing this restriction may risk the unintended consequence of harm to inactive customers by removing a constraint which active customers impose on suppliers' pricing.²⁹⁹ However, we consider that this risk would be offset by the increase in competition that suppliers would face for the retention of their existing customers. In particular, if suppliers were to restrict the availability of their most competitive tariffs to new customers, this could result in the loss of more active customers to rival suppliers who would be expected to respond using similar tactics. Those lost customers would be costly to replace.³⁰⁰ In addition, we were told by suppliers that they made all tariffs available to new and existing customers prior to the introduction of the RMR rules (see Appendix 8.3).

12.394 We also recognise that removing this provision could make the Cheapest Tariff Messaging provisions (which require suppliers to provide their customers with information about their cheapest available tariffs) redundant. In particular, if suppliers are not required to make all their tariffs available to new and existing customers, these provisions could have the effect of encouraging suppliers to restrict the availability of their most competitive tariffs to new customers so as to avoid showing their current customers their best rates. Recent experience with white label and collective selling arrangements demonstrates the risks of suppliers gaming current RMR rules to avoid showing their current customers their best rates.³⁰¹

12.395 However, as discussed in Section 13 (regarding the Ofgem-led programme), we are recommending that Ofgem trials changes to the information in domestic bills and how this will be presented, including the provision of information on the availability of cheaper tariffs in the market. By providing customers with information on cheaper tariffs in the market (as opposed to restricting it to the supplier's own cheap tariffs) such a measure would avoid the perverse incentives that the current Cheapest Tariff Messaging provisions create (namely the perverse incentive not to discount so as to avoid alerting the supplier's existing customer base to better deals).

²⁹⁸ An example is given in paragraph 13.220.

²⁹⁹ This is analogous to the argument that marginal customers protect infra-marginal customers.

³⁰⁰ The Six Large Energy Firms have typically paid commissions to PCWs in the range of £15–£35 per fuel (see Appendix 9.3 to the Final Report).

³⁰¹ Ofgem recently clarified that Cheapest Tariff Messaging should include all the tariffs offered by a supplier including white label and collective switching tariffs.

Consequential amendments

12.396 As part of this remedy, we also recommend that Ofgem make any consequential standard licence condition amendments in light of the restrictions we are recommending being removed. For instance, based on submissions received from parties and Ofgem, we understand that consequential amendments may be required in relation to SLC 22A.2 concerning the recovery of charges and SLC 22B.7 concerning the charges for different payment methods. In addition, Ofgem may wish to consider the impact of removing certain standard licence conditions implemented as part of the ‘simpler choices’ component of the RMR rules on the standard licence condition concerning the information tools introduced as part of the ‘clearer information’ component.

- *Recovery of charges*

12.397 Under this remedy, we are not recommending that Ofgem removes the requirement on suppliers to include all charges for supply activities in the unit rate (or time-of-use rates) and/or the standing charge (see paragraph 12.400 below).³⁰² However, Ofgem may wish to review this requirement in light of the restrictions removed under this remedy so that it does not prevent suppliers from offering tiered-rate tariffs.

- *Charges for different payment methods*

12.398 Under this remedy, we are not recommending that Ofgem removes the restrictions concerning the charges for different payment methods³⁰³ (see paragraph 12.401 below). However, we understand that these restrictions were introduced to allow suppliers more flexibility within the four-tariff rule and may be ineffective following the removal of this rule. Accordingly, Ofgem may wish to review these restrictions in light of our recommendation to remove the four-tariff rule.

Which standard licence conditions concerning the ‘simpler choices’ component of the RMR rules fall outside the scope of our recommendation to Ofgem

12.399 Under this remedy, we are not recommending that Ofgem removes the standard licence conditions concerning the following:³⁰⁴

³⁰² SLC 22A.2.

³⁰³ SLC 22B.7.

³⁰⁴ The specific wording of these standard licence conditions is set out in Appendix 9.7.

- (a) the recovery of charges (SLC 22A.2);
- (b) the tariff name (SLC 22B.2 (c));
- (c) charges for different payment methods (SLCs 22B.7);
- (d) fixed-term supply contracts (SLC 22C); and
- (e) dead tariffs (SLC 22D).

- *Recovery of charges*

12.400 We are not recommending that Ofgem removes the requirement on suppliers to include all charges for supply activities in the unit rate (or time-of-use rates) and/or the standing charge.³⁰⁵ We consider that this requirement helps consumers better understand tariffs and prevent ‘drip pricing’.³⁰⁶ In contrast to the use of discounts and bundles, while the removal of this restriction might be effective in allowing suppliers to innovate more, we consider that it may risk the unintended consequence of harming customers on the basis that there is limited pro-competitive benefit arising from drip pricing and a considerable risk that it may be used to mislead customers by exploiting common behavioural biases.³⁰⁷

- *Tariff name*

12.401 We are not recommending that Ofgem removes the requirement that suppliers must not use (in any region) more than one tariff name for each core tariff at any time.³⁰⁸ We consider that this requirement does not materially affect suppliers’ ability to innovate.

- *Charges for different payment methods*

12.402 We are not recommending that Ofgem removes the requirements concerning the charges for different payment methods (save where relevant concerning the remedy softening the application of SLC 27B.7(b) as regards supply to prepayment customers). Under these requirements, suppliers must ensure that (i) any differences in payment methods comply with SLC 27 (ie

³⁰⁵ SLC 22A.2.

³⁰⁶ Drip pricing is where an advertised headline price does not include additional fees and charges that are later disclosed incrementally in the sales process.

³⁰⁷ See, for example, Office of Fair Trading (2010), Advertising of prices.

³⁰⁸ SLC 22B.2 (c).

must be cost reflective);³⁰⁹ (ii) any differences in charges between payment methods must be applied in the same way to all customers within the same payment method; (iii) any differences in charges between payment methods are subject to the same terms and conditions and are of the same monetary amount across Great Britain for the same payment method in respect of all tariffs, and (iv) any differences in charges between payment methods must be fully incorporated in the unit rate (or time-of-use rates, as applicable) or the standing charge. One of our remedies to address the Prepayment AEC is a recommendation to Ofgem to soften the application of the requirement that any differences in charges between payment methods must be applied in the same way to all customers with the same payment method (see paragraphs 12.223 to 12.231 above).

- *Fixed-term contracts*

12.403 We are not recommending that Ofgem removes the requirements concerning fixed-term contracts, in particular, (i) the prohibition on suppliers to roll over fixed-term contracts, (ii) the requirement to move customers to the cheapest evergreen tariff if, at the end of a fixed contract, customers have not chosen another tariff or supplier, and (iii) the prohibition on suppliers to increase the price of a fixed-term supply contract, or unilaterally vary any terms and conditions in any way which makes the customer worse off.³¹⁰ We note that the restriction in fixed-term contracts on suppliers unilaterally varying the price or other terms and conditions in any way which makes the customer worse off reflects requirements set out in consumer law, ie that terms in contracts between businesses and consumers must be fair and transparent.³¹¹ We also consider that these restrictions make fixed-term tariffs easier to understand and less risky for consumers by aligning offers with their expectations and mitigating concerns about auto-rollover contracts.

³⁰⁹ The requirement that differences in charges between payment methods must be cost reflective is set out in EU law (European Parliament and Council Directive 2009/73/EC ('the Gas Directive') of 13 July 2009 concerning common rules for the internal market in natural gas and repealing Directive 2003/55/EC (2009) OJ L 211/94, Annex I 1(d); and European Parliament and Council Directive 2009/72/EC ('the Electricity Directive') of 13 July 2009 concerning common rules for the internal market in electricity and repealing Directive 2003/54/EC (2009) OJ L 211/55, (Annex I 1(d)).

³¹⁰ SLC 22C.

³¹¹ Part 2 of the Consumer Rights Act 2015 which implements Council Directive 93/13/EEC on Unfair Terms in Consumer Contracts (and replaces the Unfair Terms in Consumer Contracts Regulations 1999 with effect from 1st October 2015). For the application of the fairness test to terms in consumer contracts permitting the business to unilaterally vary price or other contract terms, see in particular the following judgments of the Court of Justice of the European Union: Cases C-472/10 *Nemzeti Fogyasztóvédelmi Hatóság v Invitel Távközlési Zrt* and C-92/11 *RWE Vertrieb AG v Verbraucherzentrale Nordrhein-Westfalen e.V.* EU:C:2013:180. The CMA's view on the application of Part 2 of the CRA to such terms is set out in its Unfair Contract Terms Guidance (CMA37) at paragraphs 5.21.1–5.23.7.

- *Dead tariffs*

12.404 We are not recommending that Ofgem removes the requirements concerning dead tariffs as we see no obvious pro-innovation reasons for allowing suppliers to keep those tariffs.³¹² Under the existing rules, suppliers must not have evergreen tariffs that are not available to new customers (ie dead tariffs) subject to two exceptions: (a) in order to permit suppliers to transfer their customers off dead tariffs; and (b) to permit customers to continue on dead tariffs which are cheaper than the cheapest equivalent evergreen tariff which is available to new customers. We consider that these restrictions address concerns that dead tariffs allow suppliers to segment the market and their removal may undermine our remedies concerning the Domestic Weak Customer Response AEC (see Section 13) by contributing to customer confusion as they may find it difficult to find details of their dead tariffs for comparison.

How to implement this remedy

12.405 We will implement this remedy through a recommendation to Ofgem (a) to modify the gas and electricity standard licence conditions to remove the following conditions: the ban on complex tariff structures, the four-tariff rule, the restrictions on the offer of discounts, the restrictions on the offer of bundled products, the restrictions on the offer of reward points, and the prohibition against tariffs exclusive to new/existing customers; and (b) to make any necessary consequential amendments.

12.406 In our provisional decision on remedies we also recommended that Ofgem should deprioritise potential enforcement action against suppliers concerning such licence conditions pending the necessary amendments. We note that on 14 April 2016 Ofgem issued an open letter to suppliers advising them (i) of their intention to issue a statutory consultation proposing to remove these licence conditions,³¹³ and (ii) that they do not generally envisage that it would be appropriate to take enforcement action in relation to these rules until the consultation process is completed and the changes are implemented.³¹⁴ Accordingly, our recommendation to deprioritise enforcement action is no longer necessary.

³¹² SLC 22D.

³¹³ SLC 22A.3 (a) and (b); SLC 22B.2 (a) and (b); SLCs 22B.3-6; SLCs 22B.9-16; SLCs 22B.17-23; SLCs 22B.24-28 and SLCs 22B.30-31.

³¹⁴ Ofgem (2016), *CMA provisional remedies: removal of certain RMR 'simpler choices' rules*.

Assessment of effectiveness

12.407 In our view, the remedy would be effective in achieving its aim of promoting competition and innovation between retail energy suppliers in the retention and acquisition of domestic customers, and facilitating competition between PCWs in the supply of services to domestic customers (see paragraph 12.364). Accordingly, the remedy would be effective in addressing the RMR AEC and the resulting consumer detriment.

12.408 In assessing the effectiveness of the remedy, we have, in particular, considered the following factors:

- (a) whether our remedy would be expected to promote competition (and innovation) between suppliers and between PCWs;
- (b) the extent to which the remedy is capable of effective implementation, monitoring and enforcement;
- (c) the timescale over which the remedy is likely to have an effect; and
- (d) compliance with existing or expected laws and regulations.

Competition and innovation between retail energy suppliers

12.409 We consider that certain aspects of the 'simpler choices' component of the RMR rules listed above have the effect of dampening price competition between suppliers by either (a) directly restricting their ability to compete to acquire or retain customers through the tariffs or discounts they offer or (b) adversely impacting on the incentives suppliers have to compete by making it more costly to offer customers cheaper prices or discounts (the effect of which is to reduce the competitive pressure suppliers exert on their rivals). We have set out above how the aspects of the 'simpler choices' component of the RMR rules we are recommending that Ofgem removes have the effect of restricting the ability or incentive of suppliers to be more competitive on price (see paragraphs 12.378 to 12.394).

12.410 We consider that further evidence on the effectiveness of the removal of the simpler choices component of the RMR rules to promote competition between suppliers is provided by:

- (a) suppliers' submissions, and our own analysis, of how they behaved prior to the RMR rules, and how they responded to the introduction of those rules; and

- (b) suppliers' submissions on how they would respond to the removal of these rules and the derogations to the relevant standard licence conditions that have been sought, granted and rejected since implementation of these rules.

12.411 We have noted that the introduction of the RMR rules, and specifically the four-tariff rule, resulted in the Six Large Energy Firms withdrawing a number of tariffs and discounts, and changing tariff structures that may have been beneficial to customers and competition (Appendix 9.8).

12.412 All of the Six Large Energy Firms said that if the simpler choices rules were to be removed they would offer (or would consider offering) new tariffs and products to their domestic customers. In particular:

- (a) Centrica said that it would look to market [REDACTED].³¹⁵
- (b) EDF Energy said that it would expect to see the re-emergence of some of the types of tariff that were available before the RMR rules, such as [REDACTED].³¹⁶
- (c) E.ON said that it might continue with some of the ideas that it was working on prior to the RMR rules, [REDACTED]. E.ON also said that the introduction of smart meters was likely to maximise the effectiveness of this remedy.³¹⁷
- (d) RWE said that it would be an opportunity for suppliers to create differentiated and bespoke tariffs positioned to appeal to different customer groups (such as social and green tariffs, tariffs for landlords, tariffs designed in partnership with charities and tariffs for those with electric vehicles) and to offer discounts to target different lower price offers at low and high consumption customers. RWE also said that it might incentivise engagement by, for example, offering lifestyle bundles, and loyalty and reward schemes.
- (e) Scottish Power said that based on previous experience, energy suppliers might consider returning to offering discounted tariffs (where the tariff is priced for a fixed-term at a fixed discount to the SVT), tariffs with no standing charge, cashbacks, and capped and 'tracker' products,

³¹⁵ Centrica response to Remedies Notice, p55.

³¹⁶ EDF Energy response to Remedies Notice, p15, paragraph 3.14.

³¹⁷ E.ON response to provisional findings and Remedies Notice, p20, paragraph 93.

as well as experimenting with time-of-use tariffs when a critical mass of smart meters had been rolled out.³¹⁸

12.413 The Six Large Energy Firms said that there were technical constraints on the number of tariffs that they could offer prepayment customers (see section above dealing with prepayment related remedies), but that the remedy should facilitate greater choice for prepayment customers by enabling suppliers to offer a greater variety of discounts, in particular, for prepayment customers with a smart meter.^{319,320}

12.414 In Appendix 9.7 we provide detailed information on the derogations sought, granted and rejected concerning issues such as the four-tariff rule, the ban on certain discounts, and the prohibition against tariffs exclusive to new/existing customers. Our view is that the number and nature of the derogations sought is further evidence that the simpler choices rules have been a constraint on the tariffs and discounts offered by retail energy suppliers to their domestic customers, but that the number of derogations sought and granted will understate the extent of the constraint imposed by the relevant rules. This is because Ofgem will grant derogations only where an applicant can demonstrate that compliance with one or more relevant standard licence conditions would have substantial unintended or unanticipated negative consequences for consumers.³²¹ In addition, we consider that the need for suppliers to go through a process of seeking derogations in which the onus is on them to demonstrate that these conditions for granting a derogation are met creates delays and uncertainty that could deter suppliers from making applications. Such a process also has the potential to distort competition if some suppliers are in a better position than others to navigate the process.

Competition between price comparison websites

12.415 We consider that the removal of the simpler choices component of the RMR rules together with the removal of the 'whole of the market' requirement from the Confidence Code (see paragraph 12.422 below) should promote competition between PCWs by allowing them to negotiate exclusive tariffs

³¹⁸ Scottish Power response to Remedies Notice, p9, paragraph 3.6.

³¹⁹ RWE response to provisional findings, p44, paragraph 215. RWE said that there were technical constraints on the number of tariffs that they could offer prepayment customers due to the limited number of available tariff slots across the industry but that, notwithstanding the technical constraints, the remedy should facilitate greater choice for prepayment customers by enabling suppliers to offer a greater variety of discounts such as cashback and other non-cash incentives.

³²⁰ Scottish Power response to Remedies Notice, Table 1.

³²¹ Ofgem's Guidance for Derogation Requests says that on an enduring basis it is envisaged that the minimum duration for a derogation will be about six weeks, however the process could take up to six months. See Ofgem (25 September 2013), Guidance for derogation requests from domestic Retail Market Review (RMR) licence conditions.

with retail energy suppliers putting downward pressure on tariff prices and commissions they receive from suppliers. In addition to addressing the RMR AEC, this remedy also therefore addresses part of the Domestic Weak Customer Response AEC.

- 12.416 We have been told that the simpler choices rules are a constraint on PCWs negotiating exclusive tariffs as these tariffs would count towards suppliers' four permitted tariffs, under the four-tariff rule.
- 12.417 We consider that, absent the four-tariff rule, PCWs would be in a good position to negotiate favourably priced tariffs with retail energy suppliers. In particular, we have found that PCWs are becoming an increasingly important sales channel for energy suppliers.³²² In addition, we consider that PCWs could have an incentive to offer suppliers lower commission rates in exchange for exclusive rights to cheaper deals. For both suppliers and PCWs, the attraction of such deals would be achieving a high volume of sales with favourably priced tariffs that might be promoted in joint advertising campaigns.
- 12.418 We consider that the willingness, absent the four-tariff rule, of retail energy suppliers and PCWs to participate in such negotiations is demonstrated by the recent collective switching schemes. In particular, the collective switch schemes have had an exemption from the four-tariff rule (see Section 13) and have offered exclusive tariffs negotiated by the scheme organiser (which in some cases was a PCW) with an energy supplier. First Utility said that PCWs had used the collective switching rules as a way to create exclusive tariffs.
- 12.419 In recent years Centrica, E.ON, RWE and Scottish Power have all participated in schemes which have typically offered customers a discount to their SVT. Commissions have been part of the negotiation. In 2015 E.ON agreed collective tariffs with three organisers (iChoosr, EnergyHelpline and uSwitch) which offered discounts of more than 20% on its SVT and accounted for around [X]% of acquisitions from January to July 2015.
- 12.420 As explained above (see paragraph 12.417), the remedy may be expected to exert downward pressure on the levels of commission charged by PCWs. In Section 10 we give estimates of the detriment to domestic energy customers arising from the prices of the Six Large Energy Firms exceeding competitive levels. These estimates do not, however, allow for lower levels

³²² See Appendix 9.3: Price comparison websites and collective switches.

of commission charged by PCWs. We therefore consider it plausible that there are incremental benefits to customers attributable to this remedy.

12.421 In 2014 the Six Large Energy Firms paid a total of £24 million in commissions to PCWs for the acquisition of domestic customers. Typical commission rates, per fuel, charged by PCWs and those for collective switching schemes have been between £[redacted] per fuel³²³ and £[redacted] and £[redacted]³²⁴ respectively. The wide range in the level of commission rates demonstrates that there is scope for competition to put downward pressure on such rates. If the average commission rate were to fall by just 10%, based on the volume of switches through PCWs in 2014 we estimate a reduction in commission payments paid by the Six Large Energy Firms of about £2.4 million. The potential benefits may be higher if the number of switches through PCWs increases.

12.422 For the reasons set out in Section 13 we consider that the effectiveness of removing the four-tariff rule, in terms of allowing for PCWs to negotiate exclusive deals, would be significantly undermined by the requirement in the Confidence Code to display the whole of the market. Accordingly, we will recommend that Ofgem remove this requirement (see Section 13), as part of a package of remedies aimed at promoting the role of PCWs.

Implementation, monitoring compliance and enforcement

12.423 As regards the implementation of the remedy, we have set out a number of detailed specifications (see paragraphs 12.379 and 12.399 above). In this regard, we have sought to take a detailed approach by describing the terms of the remedy (and the associated licence conditions that would be affected) so that it would not only be clear to Ofgem (as the addressee of our recommendation) to understand, but also be straightforward for it to introduce.

12.424 We have also considered whether to implement this remedy by way of an order on suppliers. However, we do not consider that it would be appropriate to impose an order on suppliers given that they do not ultimately control what conditions are included in their licences. Ofgem, as sector regulator, is

³²³ Specifically for the Six Large Energy Firms:

- (a) Centrica's commission payment ranges from [redacted];
- (b) EDF Energy's commission payment ranges from [redacted] per fuel;
- (c) E.ON's commission payment ranges from [redacted] per fuel;
- (d) RWE's commission payment ranges from [redacted] per fuel;
- (e) Scottish Power's commission payment ranges from [redacted] per fuel; and
- (f) [redacted] per fuel. [redacted].

³²⁴ For the collective switches the Six Large Energy Firms have previously won: (a) Centrica paid commission of [redacted], (b) E.ON paid commission [redacted], (c) RWE paid commission of [redacted] and (d) Scottish Power paid commission of [redacted] per service.

responsible for maintaining suppliers' licences, and their terms and conditions.

12.425 As regards monitoring compliance, Ofgem would be under a duty to monitor compliance with the licence conditions.

Timescale

12.426 In evaluating the effectiveness of the remedy, we have considered the timescale over which the RMR AEC would be expected to endure, and the timescale over which the remedy would be likely to take effect. As regards the RMR AEC, our view is that, absent the remedy, the detriment would persist, and would likely become exacerbated by the national programme for the roll-out of smart meters and the implementation of our other remedies concerning the Domestic Weak Customer Response AEC and the Prepayment AEC.

12.427 As regards timescales for implementation, we consider that the remedy could be implemented by all suppliers within reasonable timescales following removal from their licences. We expect this remedy to have effect within a relatively short time period given:

- (a) the evidence that suppliers previously offered tariffs which they may look to reintroduce;
- (b) the number of derogation requests; and
- (c) that the time to design and launch a new tariff is relatively short. For example, uSwitch said it could take several weeks to create and launch a new tariff.³²⁵

12.428 We expect that Ofgem's consultation on the removal of the relevant standard licence conditions would conclude by the end of 2016. Ofgem could then implement and enforce the revised standard licence conditions from the beginning of 2017 with suppliers permitted to provide a wide range of tariffs. In the meantime, Ofgem has already informed suppliers of its intention to deprioritise enforcement action in relation to the licence conditions we are recommending Ofgem to remove in the context of this remedy pending the change (see paragraph 12.406 above).

12.429 We also expect that this remedy will become more effective with the roll-out of smart meters. While time-of-use tariffs are permitted by the RMR simpler

³²⁵ uSwitch response to Remedies Notice, p8.

choices rules, no more than one unit rate can apply to any given time period and unit rates cannot vary by the level of consumption.

Compliance with existing or expected laws and regulations

- 12.430 Ofgem has submitted that the RMR rules were designed as an integrated package and hence removing one component would have knock-on implications for other aspects. In particular, if the standard licence conditions restricting the number of tariffs (SLC 22B.2 (a) and (b)), tariff structure (SLC 22A.3(a) and (b)) and cash discounts (SLCs 22B.4-6) were removed, Ofgem said the methodologies for calculating the ‘Tariff Comparison Rates’, ‘Personal Projections’ and ‘Cheapest Tariff Messaging’ would need to be revisited to ensure that the tools continue to serve their policy intent. Ofgem has submitted that these tools were not designed to accommodate multi-tier tariffs and a wide variety of discounts and bundles. Ofgem has also submitted that a tariff with multiple unit rates would require multiple lines in the ‘Tariff Information Labels’ which might be confusing.³²⁶
- 12.431 Some of the Six Large Energy Firms said that the ‘Cheapest Tariff Messaging’ requirements would not be compatible with an increase in the number, complexity and range of tariffs.^{327,328}
- 12.432 We will maintain the information tools introduced as part of the RMR rules, and make a recommendation that Ofgem makes any necessary consequential amendments (see paragraph 12.396). Ofgem said that it was well placed to update the tools,³²⁹ and intended to consult on any necessary changes as part of its consultation on removing the licence conditions of the simpler choices component of the RMR rules.³³⁰ We are also recommending that Ofgem, as part of the Ofgem-led programme, should develop and test

³²⁶ Ofgem said that at present all discounts (cash and non-cash) were included in the TCR and PP. However, the licence distinguishes between contingent and non-contingent discounts. The latter are always included but the former are not, except for cash discounts for dual fuel and online account management. If suppliers are able to offer more types of contingent cash discounts, Ofgem will need to consider whether these should also be included in the TCR and PP, and if dual fuel and online discounts should continue to be included. Ofgem may also consider whether suppliers should inform their customers which contingent discounts are included/excluded from the TCR and PP.

³²⁷ Centrica response to provisional decision on remedies, pp52–53, paragraphs 261–277. Centrica said the Cheapest Tariff Message and Tariff Comparison Rate would become misleading and the CMA’s proposed market Cheapest Tariff Message was unworkable. Centrica said the RMR rules relating to clearer information should be set aside in the same way and at the same time as planned for the simpler choices rules.

³²⁸ EDF Energy response to provisional decision on remedies, pp30–31, paragraph 7.4. EDF Energy said the proposed market-wide and supplier Cheapest Tariff Messaging would become impractical and potentially misleading.

³²⁹ Ofgem (18 November 2015), Paper 1: Impact of remedy 3 on consumer engagement, working paper.

³³⁰ Ofgem response to provisional decision on remedies, Annex 2, p6.

proposals for suppliers to provide their customers with information on the availability of cheaper tariffs in the market.³³¹

Assessment of proportionality

12.433 In this section we set out our assessment of whether our remedy would be proportionate to achieve its aim. We do this by considering whether the remedy:³³²

- (a) would be effective in achieving its legitimate aim;
- (b) would not be more onerous than needed to achieve its aim;
- (c) would be the least onerous if there were a choice between several effective measures; and
- (d) would not produce disadvantages which are disproportionate to the aim.

Would be effective in achieving its legitimate aim

12.434 For the reasons set out in paragraphs 12.407 to 12.432 above, we consider that the remedy would be effective in achieving its aim of promoting competition and innovation between retail energy suppliers in the retention and acquisition of domestic customers, and facilitating competition between PCWs in the supply of services to domestic customers. Accordingly, it would be effective in addressing the RMR AEC and the resulting consumer detriment.

No more onerous than needed to achieve its aim

12.435 We also consider that this remedy would be no more onerous than needed to achieve its aim. We have considered each of the individual parts of the simpler choices component of the RMR rules, and reached a decision on whether each part should be removed or retained. We only recommend that Ofgem remove those parts that have a clear detrimental effect on innovation and competition, and where any unintended adverse consequences of their removal can be addressed through other remedies.

³³¹ This is one of four priority areas that we have identified for the programme. See Section 13, 'Ofgem programme to promote customer engagement' for further details.

³³² [CC3](#), paragraph 344, citing the principles established in the *Fedesa* case, Case C-331/88, *the Queen v Minister of Agriculture, Fisheries and Food and Secretary of State for Health, ex parte: Fedesa and others*, (1990) ECR I-4023, paragraph 13.

Least onerous if there were a choice between several effective measures

12.436 As noted above, we have considered several variations concerning the remedy, and whether there may be alternative remedies that achieve the same aim. However, we consider that the remedy is the only form of remedy that would be effective to address fully the RMR AEC and, for each part of the simpler choices component of the RMR rules that we recommend Ofgem removes, we have reached the conclusion that only its removal would be effective (rather than a potentially less onerous alternative of replacing the condition with a less restrictive version, such as an ‘eight-tariff’ rule or allowing certain complex tariffs or discounts to continue to be prohibited). We therefore do not consider that there is a less onerous remedy that would be equally as effective.

Would not produce disadvantages disproportionate to the aim

12.437 We have concluded that the remedy would not produce adverse effects that would be disproportionate to its aim. In particular, we consider that implementation of this remedy should result in minimal cost for suppliers and PCWs as this simply requires amendments to the supplier licence conditions. The cost to suppliers of understanding the implications of the remedy for their business should also be minimal given that the simpler choices component of the RMR rules was only recently introduced. In the context of this assessment, we have considered any unintended consequences resulting from the remedy.

12.438 The removal of the simpler choices component of the RMR rules may result in more tariffs and a wider range of products on the market. However, our view is that there are a range of tools which may help customers navigate the tariffs on offer in the market and make decisions and, accordingly, address any such unintended consequences arising from this remedy. These tools are the following:

- (a) PCWs and other TPIs have an increasingly important role in the market. For example, PCWs are being increasingly used by customers for searching and switching;³³³ PCWs are an important source of domestic customer acquisitions for suppliers;³³⁴ and for energy-focused PCWs, energy accounts for a large part of their revenue.³³⁵ We expect PCWs to be able to handle an increase in the number and range of tariffs. PCWs have the incentive to innovate in response to the emergence of

³³³ See Appendix 8.3: Price comparison websites and collective switches.

³³⁴ Customer acquisition supplier data request.

³³⁵ See Appendix 8.3: Price comparison websites and collective switches.

innovative offerings to help customers compare offers and make informed decisions. uSwitch told us that pre-RMR it did not face such problems and uSwitch said it employed capable mathematicians who could design tools to cut through tariff complexity in order to provide a comparison. In addition, given the importance of PCWs to suppliers, we think that it would not be in suppliers' interests to design tariffs that are too complicated to be displayed on PCWs. Finally, we have remedies that we would expect to promote the use of PCWs (see Section 13).

- (b) QR (Quick Response) codes³³⁶ and Midata³³⁷ can assist customers who have access to and are confident in using the relevant technologies in making comparisons.
- (c) Citizens Advice's price comparison service (which operates as a white label solution with source data provided by Energylinx) should also help customers make comparisons. This may be particularly helpful to customers who do not trust or use commercial PCWs and those without internet access.

12.439 In addition, some of the Six Large Energy Firms told us that there were operational, practical and reputational constraints on the number of tariffs they offered. For example, Scottish Power said that each new tariff had to be built on the billing system at significant cost and the Cheapest Tariff Messaging calculation had a significant impact on the processing time for a billing run, and the time taken would increase with the number of tariffs that needed to be compared.³³⁸ We have found that before the introduction of the simpler choices component of the RMR rules suppliers had reduced the number of tariffs they offered.³³⁹ Centrica said that the market was self-correcting before RMR.

12.440 We have also considered the extent to which the 'Standards of Conduct' licence condition (ie SLC 25C) and our recommendation to Ofgem to introduce an additional principle to SLC 25C that would require suppliers to have regard in the design of their tariffs to the ease with which customers can compare value for money with other tariffs they offer should mitigate the risks associated with our remedy (see Section 13).

³³⁶ QR codes are machine-readable codes used for storing website addresses or other information and are read using the camera on a smartphone. They are present on energy bills, helping customers compare tariffs across the market.

³³⁷ Midata is a voluntary programme the government is undertaking with industry, which over time will give consumers increasing access to their personal data in a portable, electronic format.

³³⁸ Scottish Power response to Remedies Notice, p9, paragraph 3.7.

³³⁹ See Appendix 9.7.

Duty to have regard to Ofgem's statutory duties

- 12.441 Pursuant to Schedule 9 of the 2002 Act the CMA has powers under the EA89 and GA86 to provide for the modification of standard licence conditions to such an extent as may appear to be requisite or expedient for the purpose of giving effect to any provision made by an order under section 160 or 161 of the 2002 Act. Section 168 of the 2002 Act requires the CMA, when it is considering whether to modify licence conditions in a regulated sector by way of an order, to 'have regard to the relevant statutory functions of the sectoral regulator concerned'. As we are recommending the removal of some of the simpler choices standard licence conditions introduced by Ofgem pursuant to its RMR, we have had regard to Ofgem's statutory duties and objectives when reviewing the simpler choices standard licence conditions.
- 12.442 Ofgem's statutory duties and functions, set out in the EA89 and the GA86, as amended by the EA10,³⁴⁰ have set competition as a secondary objective, with the principal objective being the interests of existing and future consumers taken as a whole, including decarbonisation, security of supply and the fulfilment by Ofgem of the objectives set out in Article 40(a) to (h) of the Gas Directive³⁴¹ and Article 36(a) to (h) of the Electricity Directive.³⁴²
- 12.443 Ofgem is generally required to carry out its functions in the manner it considers best calculated to further the principal objective. Before deciding to carry out its functions in a particular manner with a view to promoting competition, Ofgem must consider the extent to which the interests of consumers would be protected by that manner of carrying out those functions and whether there is any other manner (whether or not it would promote competition) in which the Authority could carry out those functions which would better protect those interests,³⁴³ having regard (among other things) to (i) the need to secure that, so far as economical to meet them, all reasonable demands for gas and electricity supply are met and can be financed, (ii) achieving sustainable development, and (iii) the interests of 'vulnerable' consumers.³⁴⁴

³⁴⁰ Sections 4AA(1)(1A), 34, 35, 36, 36A of the GA86; Sections 3A(1)(1B), 43, 47, 48, 49 of the EA89.

³⁴¹ European Parliament and Council Directive 2009/73/EC of 13 July 2009 concerning common rules for the internal market in natural gas and repealing Directive 2003/55/EC (2009) OJ L 211/94.

³⁴² European Parliament and Council Directive 2009/72/EC of 13 July 2009 concerning common rules for the internal market in electricity and repealing Directive 2003/54/EC (2009) OJ L 211/55.

³⁴³ Section 4AA(1)(1C) of the GA86; Section 3A(1)(1C) of the EA89.

³⁴⁴ [Powers and duties of GEMA](#).

- 12.444 As stated above, we recommend that Ofgem remove certain aspects of the simpler choices of the RMR rules, in particular, standard licence conditions concerning:
- (a) the ban on complex tariff structures (SLC 22A.3 (a) and (b));
 - (b) the four-tariff rule (SLC 22B.2 (a) and (b));
 - (c) the restrictions on the offer of discounts (SLCs 22B.3–6 and 22B.24–28);
 - (d) the restrictions on the offer of bundled products (SLCs 22B.9-16 and 22B.24–28);
 - (e) the restrictions on the offer of reward points (SLCs 22B.17–23 and 22B.24–28); and
 - (f) the prohibition against tariffs exclusive to new and existing customers (SLCs 22B.30 and 22B.31).

12.445 In reaching our decision to recommend Ofgem removes each of the aforementioned simpler choices standard licence conditions we have, as part of our own application of the legal framework requiring us to decide upon remedies that are effective and proportionate,³⁴⁵ taken into account Ofgem’s statutory duties and objectives below.

12.446 In particular, we do not consider that any aspect of this remedy will have an adverse impact on suppliers’ ability to meet all reasonable demands for gas and electricity supply, achieving sustainable development, security of supply or environmental concerns. In this regard, the remedy will only affect the ‘efficiency’ limb of the Trilemma considerations built into Ofgem’s statutory duties and functions, insofar as we would expect each restriction being removed under the remedy to result in an enhanced ability for suppliers to innovate when offering tariffs to domestic customers. In turn, we would expect this to translate to greater choice for consumers.

12.447 In addition to generally allowing suppliers to innovate and compete more intensively for domestic customers, we note that the removal of the following restrictions will lead to additional efficiency benefits:

- (a) Structure of tariffs. The removal of the restriction on tariff structure would in particular benefit certain segments of the consumer population that are aware of and interested in their energy usage patterns. We believe such tariffs will become increasingly popular, as the continuing roll-out of

³⁴⁵ See [CC3](#).

smart meters and the industry move towards half-hourly settlement will make it easier and more accurate for customers to monitor their energy usage, and easier for suppliers to tailor tariffs to particular customer groups.

- (b) The 'four-tariff rule'. The removal of the four-tariff rule would incentivise PCWs to compete more intensively by negotiating individual deals with suppliers for particular tariffs or packages of tariffs.
- (c) Discounting and reward points. The removal of the restrictions on certain discounts and reward points would allow suppliers the potential to lower their operating costs as regards domestic customers (as they would have more information on their usage or habits), which could increase the supplier's efficiency. In turn, we would expect this to translate to lower prices.
- (d) Bundling. The removal of the restriction on bundling would allow suppliers to offer packages of tariffs with other services that are ancillary to energy supply or concern other utilities sectors. Energy consumers would therefore benefit from a wider choice of products and services across markets.

12.448 In having regard to Ofgem's principal objective, we have also considered the potential impact that each aspect of the remedy may have on protecting the interests of existing and future consumers, including vulnerable consumers. In this context, we have noted in paragraph 12.438 above a possible unintended consequence of the remedy (were it to be implemented by itself), concerning a potential proliferation of tariffs³⁴⁶ and the potential for such proliferation to lead to harm to consumers, in particular vulnerable consumers or consumers with limited internet access, who may become (or feel) confused.

12.449 However, we note that the remedy would be introduced in conjunction with additional remedies concerning the ability and incentive of PCWs to engage energy consumers (see Section 13), and a new standard of conduct concerning the fair treatment of customers (see Section 13). We are of the view that the former would reduce the search costs of consumers with internet access and that the latter could be appropriately monitored and enforced by Ofgem so as to protect other consumers from unfair treatment.

³⁴⁶ In Ofgem's response to our Remedies Notice, it indicated that it did not consider an increase in the number of tariffs to be a risk to customer engagement as growth in the number of suppliers in recent years had meant that there were already a large number of tariffs on offer.

Accordingly, we believe that these additional remedies will protect consumers and guard against this potential adverse outcome.

12.450 Taken together with these other remedies, our view is that the overall remedies package satisfies Ofgem's principal objective of protecting the interests of existing and future consumers wherever possible by promoting effective competition.

Conclusion

12.451 We conclude that our remedy to recommend Ofgem to remove certain aspects of the simpler choices component of the RMR rules, combined with a recommendation to Ofgem to remove the 'whole of market' requirement in PCWs' Confidence Code and the addition of a new component to the Standards of Conduct (see Section 13), will be an effective and proportionate remedies package.

Interaction with other remedies

12.452 We set out in Section 11 our high-level assessment of how we expect these remedies to interact with the other components of our remedies package, notably measures to help customers engage to exploit the benefits of competition and measures to protect customers who are less able to engage to exploit the benefits of competition. In Section 15, we present an assessment of the effectiveness and proportionality of the remedies package for domestic customers as a whole.

13. Domestic retail: helping customers engage to exploit the benefits of competition

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- 13.1 We have found that a combination of features in the markets for the domestic retail supply of gas and electricity give rise to an AEC through an overarching feature of weak customer response (the Domestic Weak Customer Response AEC) 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 (see Section 9).
- 13.2 The features we have identified include: customers' limited awareness of and interest in their ability to switch energy supplier, arising in particular from the role of traditional meters and bills and the homogenous nature of gas and electricity; actual and perceived barriers to accessing and assessing information; and actual and perceived barriers to switching.

- 13.3 We note that the overall weight of evidence supports a finding that disengagement and weak customer response is a more significant problem among customers on prepayment meters compared with domestic customers on direct debit. We note a number of factors that may explain this:
- (a) Prepayment customers include higher proportions of individuals with low levels of income; with low levels of education; living in social rented housing; and having a disability – demographic characteristics that we have found to be associated with low levels of engagement in retail energy markets.
 - (b) Prepayment customers higher actual and perceived barriers to accessing and assessing information about switching arising, in particular, from relatively low access to the internet and confidence in using PCWs.
 - (c) Prepayment customers face higher actual and perceived barriers to switching arising from (i) the need to change meter to switch to a wider range of tariffs (and the obstacles associated with this requirement such as perceptions on the complexity of the meter replacement process); and (ii) restrictions arising from the DAP hindering indebted prepayment customers' ability to switch supplier.
 - (d) While the need to top up prepayment cards regularly is likely to increase awareness of retail energy markets among prepayment customers, low levels of engagement may have in part been influenced by the outcomes we have observed arising from the Prepayment AEC – notably the lower gains from switching and the confusion surrounding rights to switch when the customer has outstanding debt.
- 13.4 Finally, we also note that the overall weight of evidence supports a finding that disengagement and weak customer response is a more significant problem among customers on restricted meters. We note a number of factors that may explain this:
- (a) Ofgem's research concerning customers on restricted DTS meters demonstrates that customers on restricted meters have particularly limited awareness of, and interest in, their ability to switch energy supplier, which arises in particular from certain aspects of the domestic retail electricity market set out in Section 9 above.
 - (b) Customers on restricted meters face higher actual and perceived barriers to accessing and assessing information arising, in particular, from a general lack of price transparency concerning the tariffs that are

available to them, which results from restricted meter tariffs not being supported by PCWs or suppliers' online search tools and also from low incentives on suppliers to invest in marketing to customers on restricted meters.

- (c) Customers on restricted meters face higher actual and perceived barriers to switching arising, in particular, from the following aspects of the domestic retail electricity market concerning customers on restricted meters:
- (i) the requirement imposed by suppliers on some customers on restricted meters to replace their existing meter with a single-rate or Economy 7 meter, which may be at a cost to the customer, to be able to switch to a wider range of tariffs;
 - (ii) the fact that changing meter might also involve some rewiring in the home; and
 - (iii) the fact that a restricted meter replacement (particularly to a single-rate meter) may entail a loss of functionality to the customer, and possibly higher tariffs in the future, with no option of reverting back to their old meter.

- 13.5 In this section we set out our package of remedies designed to help domestic energy customers engage to exploit the benefits of competition by addressing certain aspects of the features contributing to the Domestic Weak Customer Response AEC.
- 13.6 Engaged customers are an essential component of well-functioning energy markets. If customers are not fully aware of the options available to them, unable to make an informed choice about the relative merits of those options or, having made a choice, are unable to switch, then competitive pressures on suppliers to reduce prices and improve quality of service will be substantially reduced. We have found that considerable numbers of customers are disengaged. From our customer survey we found that 34% of respondents said they had never considered switching supplier, while 56% of respondents said they had never switched supplier, did not know if it was possible or did not know if they had done so.
- 13.7 We have developed a wide range of remedies that attempt to improve domestic customer engagement by addressing aspects of the features

contributing to the Domestic Weak Customer Response AEC.¹ Our remedies package consists of five broad categories of remedy, which focus on the role of different participants in the retail markets – namely, Ofgem, the customer’s own supplier, PCWs, and rival suppliers – in strengthening domestic customer engagement. In particular, the remedies provide for:

- (a) the establishment by Ofgem of a programme to provide customers – directly or through their own suppliers – with information to prompt them to engage;
- (b) creating an Ofgem-controlled database of ‘disengaged customers’ on default tariffs, to allow rival suppliers to prompt these customers to engage in the retail energy markets;
- (c) enhancing the ability and incentives of TPIs to promote customer engagement in the retail energy markets;
- (d) Ofgem making greater use of principles rather than prescriptive rules in addressing potential adverse supplier behaviour concerning the comparability of tariffs; and
- (e) requiring all suppliers to make all their single-rate tariffs available to domestic customers on any type of restricted meter, without making switching conditional on a restricted meter being replaced, and to provide additional information to customers on restricted meters.

13.8 The different market participants identified above differ substantially in terms of the incentives they have to engage customers and their ability to do so and our range of proposed remedies reflects this.

13.9 We consider that customers’ current suppliers have the ability to engage their customers – through the regular communications they send to them – but are likely to face limited incentives to do so. Indeed, as those customers that have not engaged in the markets recently are both less likely to switch and generally on higher tariffs than those who have recently engaged, their suppliers are likely to face a financial incentive to keep them as disengaged as possible. In these circumstances, we recognise that there is an argument for Ofgem to intervene directly to facilitate customer engagement, through

¹ As the Domestic Weak Customer Response AEC affects all domestic customers, including prepayment customers, the remedies can be expected, once they become effective, to also enhance suppliers’ incentives to compete for prepayment customers. There will therefore be a strong interaction between the remedies concerning the Domestic Weak Customer Response AEC and the Prepayment AEC.

influencing the form, content and frequency of communication between suppliers and their existing customers.

- 13.10 Our remedies call for a more evidence-based approach to developing such interventions in the future, through the use of rigorous testing and trialling, where appropriate through randomised controlled trials, with a recommendation to focus such trials on a priority list of measures. If such trials are to provide relevant information that can provide a robust basis for regulatory changes, it is essential that suppliers be required to participate, where the trial design requires it, and our remedies therefore seek to ensure such participation.
- 13.11 We consider that an Ofgem-controlled database of the most 'disengaged customers' (specifically those who have been on the default tariff for three years or more) will be a highly valuable tool for harnessing the incentives of rival suppliers to prompt disengaged customers to engage in the retail energy markets. Ofgem will also be able to use the tool to engage directly with disengaged customers and in monitoring the impact of the remedies on engagement. Customers will have the right to opt out beforehand to avoid receiving communications by post, and will only be contacted electronically if they explicitly opt in to such communications. Operation of the database will have to comply with data protection law and Ofgem will be required to put measures in place to protect against the misuse of data. Ofgem will also be responsible for ongoing monitoring of the impact of the database with a view to maximising its effectiveness.
- 13.12 We consider that PCWs and other TPIs have a strong commercial incentive to engage with domestic customers and are also well placed to: raise awareness among customers; make it easier for them to engage; and exert competitive pressure on energy suppliers. Our remedies serve to enhance these parties' ability to engage domestic customers through lifting certain regulatory restrictions that dull PCWs' incentives to compete to engage customers (amending provisions of the PCW confidence code that undermine incentives for them to be active in the retail energy markets) and liberalising access to data.
- 13.13 We note that increasing customer activity is not an end in itself: our aim is to ensure that customers benefit from increased engagement – ie that it results in them being on better deals than they are at present. In this respect we recognise that there is a potential trade-off between the benefits of liberalising channels of engagement and the need to protect consumers from excessive and/or misleading marketing, and we have reflected this in our design of remedies.

- 13.14 For example, in relation to the Ofgem-controlled database of disengaged customers, Ofgem will have powers to exclude suppliers from accessing the database if misleading information is given to customers and it will be responsible for continual monitoring of the effectiveness of the database, to establish which forms of communication from suppliers genuinely help engagement in the interests of customers. And in other areas of our remedies package, we have looked to improve customer understanding and avoid the risk of confusion without undermining competition in the way previous interventions have done. For example, we are recommending the replacement of the RMR rules that restrict competition and lead to gaming with a principle requiring tariffs to be readily comparable.
- 13.15 We are also aware of the concerns around trust that led to the Confidence Code requirement that PCWs list all tariffs on the market rather than just those for which they earn a commission. We believe that such concerns around trust can be addressed – without undermining their incentives to engage customers – in two ways. First, there should be greater clarity around the role of PCWs – effectively acting as brokers offering their customers good deals and facilitating switches rather than repositories of all available tariffs – and our remedies require greater transparency from PCWs about market coverage. Second, Citizens Advice is now operating a non-transactional PCW that lists all tariffs through a web-based service, which we believe will meet the needs of those customers who wish to see the whole of the market.
- 13.16 In the rest of this section we provide a detailed assessment of each of these remedies. In terms of the interaction between these remedies and our other remedies for domestic customers:
- (a) We set out in Section 11 our high-level assessment of how we expect each of these remedies to interact with the other components of our remedies package, notably measures to help create a framework for effective competition and measures to protect customers who are less able to engage to exploit the benefits of competition.
 - (b) In Section 15, we present a more detailed assessment of the effectiveness and proportionality of the remedies package for domestic customers concerning, in particular, the Prepayment AEC, the RMR AEC and the Domestic Weak Customer Response AEC.

Ofgem programme to promote customer engagement

- 13.17 In Section 9, we have found that two of the features giving rise to the Domestic Weak Customer Response AEC are that certain customers have

limited awareness of, and interest in, their ability to switch supplier, and that customers face actual and perceived barriers to accessing and assessing information. One of the aspects of the energy markets contributing to both features is the complex information provided in bills. Our view is that this aspect of the domestic retail energy markets both contributes to limited awareness of, and interest in engagement and inhibits value-for-money assessments of the available options, particularly on the part of those customers who lack the capability to search and consider options fully.

13.18 Ofgem has also recognised the importance of clear information in facilitating customer engagement and introduced the ‘clearer information’ component of the RMR rules in an attempt to ensure that suppliers’ routine communications to customers were clear, easy to understand and personalised to them. The key provisions included the Cheapest Tariff Messaging, tariff summary box and tariff comparison rate.²

13.19 However, our concern with these provisions is that they were not subject to adequate testing prior to (or after) their introduction. There are many potentially plausible but divergent arguments about the way in which information should be provided to domestic customers to facilitate understanding and engagement.³ The key to unlocking engagement from customers may in some cases be relatively simple – the way in which information is framed or the medium of communication, for example – but is likely to differ between types of customer. Without adequate testing it is not possible to know which approach will work best in practice. Further, even if testing is conducted ex ante, changes in technology and cultural practices are likely to mean that what works changes over time.⁴

13.20 Accordingly, our remedy is a recommendation to Ofgem to:

- (a) establish an ongoing programme to identify, test (through randomised controlled trials (RCTs), where appropriate) and implement (for example, through appropriate changes to standard licence conditions) measures to provide domestic customers with different or additional information with the aim of promoting engagement in the domestic retail energy markets; and

² Ofgem’s current requirements for information on bills as circulated for its effective billing workshop on 25 November 2015.

³ For example, how frequently customers are provided with information, whether information is likely to have more impact if provided in a bill or separately from the bill, how much detail to provide, and whether people understand the graphical presentation of information and/or metrics such as the tariff comparison rate.

⁴ [The Behavioural Insights Team response to Remedies Notice](#), p9.

- (b) introduce (following a consultation) a licence condition to require suppliers to participate in the Ofgem-led programme (see below).
- 13.21 We also recommend that Ofgem develop and test proposals (including through RCTs, where appropriate) concerning the following priority list of measures:⁵
- (a) Changes to the information in domestic bills and how this is presented.
 - (b) Changes to the information provided to customers on the availability of cheaper tariffs in the markets.
 - (c) Changes to the specific messaging that domestic customers receive in bills once they move, or are moved, on to an SVT and/or other default tariffs.
 - (d) Changes to the name of the default tariffs.
- 13.22 We note that, in contrast to our remedy concerning the ‘simpler choices’ component of the RMR rules, we are not recommending that specific provisions of the ‘clearer information’ component of the RMR rules be repealed now. Rather, we recommend that they be subject to a systematic regime of testing through a programme that is led by Ofgem, a potential outcome of which may be the repeal and/or amendment over time of such provisions.
- 13.23 We also consider that the Ofgem-led programme should be used to test aspects of the marketing communications sent by rival suppliers to prompt the disengaged customers in the context of the Database remedy. Accordingly, we are recommending that Ofgem test aspects of the marketing communications by rival suppliers (eg form and frequency) in the context of the Ofgem-led programme (see paragraph 13.141 below).
- 13.24 We have also considered other areas which Ofgem may wish to consider for testing within the context of this programme. These include the form of information that could be presented to prepayment customers to address their lack of awareness and understanding of available options with respect to security deposits.⁶
- 13.25 The application of a similar remedy to the microbusiness segments is covered in Section 17.

⁵ We consider that these measures lend themselves to being tested through RCTs.

⁶ See Section 12.

Aim of the remedy

- 13.26 The aim of this remedy is to identify the most appropriate form of information received by domestic customers in communications with suppliers (eg bills), reducing or minimising the complexity of such information, and providing domestic customers with different or additional information or messaging that will prompt them to switch tariff or supplier. Accordingly, the ultimate aim of this remedy is to address (in whole or in part) two of the features that give rise to the Domestic Weak Customer Response AEC, ie that domestic customers have limited awareness of, and interest in, their ability to switch, and that certain customers face actual and perceived barriers to accessing and assessing information.
- 13.27 The measures to be identified and tested by Ofgem relate to what, how and when information is presented to domestic customers in communications with suppliers. This remedy will ensure that the approach for identifying such measures is responsive to changing market conditions, and will encourage the testing and development of particular measures related to customer information that have been identified by us during the investigation.

Parties' views

- 13.28 Four of the Six Large Energy Firms welcomed the remedy. They said there was merit in trialling information for customers to identify what was most effective in encouraging engagement. E.ON also said that Ofgem should focus on delivering customer outcomes and should not be prescriptive.⁷
- 13.29 RWE said that it welcomed the remedy for Ofgem to establish a programme to identify, test and implement measures to provide domestic customers with different or additional information to increase awareness and promote engagement. It said that it would also support changes that had been robustly trialled to ensure they were within customers' best interests, reflected changing market conditions and implemented through the most appropriate channel for the customer. RWE also suggested that, whilst it agreed that Ofgem was best placed to lead this type of programme, the CMA recommended that suppliers and other parties (such as consumer groups) are consulted on the content of the trials to ensure the best result for customers.⁸

⁷ RWE response to provisional decision on remedies, p60, paragraphs 51.1 & 51.2, EDF Energy response to provisional decision on remedies, p35, paragraph 8.4, Scottish Power response to provisional decision on remedies, p14, paragraph 8.1, E.ON response to provisional decision on remedies, p37, paragraph 179.

⁸ RWE response to provisional decision on remedies, p60, paragraphs 51.1 & 51.2.

- 13.30 SSE said it was not a necessary or appropriate remedy. SSE said the remedy risked causing harm by potentially imposing overly-prescriptive, ‘top down’, requirements on suppliers. SSE proposed an alternative remedy of removing the ‘clearer information’ component of the RMR rules so suppliers could produce their own tailored communications for customers.⁹
- 13.31 Centrica said the remedy would not be effective at identifying the most appropriate form of information for customers, and would result in the introduction of new highly prescriptive regulations. Centrica proposed an alternative remedy of trials led by suppliers, overseen by Ofgem.¹⁰
- 13.32 Energy UK said that suppliers should be empowered to identify, suggest and consider how best to take forward items for improvement and testing.¹¹
- 13.33 We considered whether the identification and testing of measures concerning the information provided to domestic customers should be Ofgem- or supplier-led (see paragraph 13.43). We decided that the programme should be Ofgem-led for the reasons set out in paragraph 13.55. We note, in particular, our view that Ofgem’s interests are better aligned with those of customers than those of suppliers. A concern that would arise if the programme were supplier-led is that suppliers’ commercial interests would be a factor in their decisions on the measures to test and implement.
- 13.34 Two of the Mid-tier Suppliers (First Utility and Co-operative Energy) welcomed the remedy but were concerned about the timescales for implementation. First Utility proposed an alternative, quicker timeline, with a market-wide cheapest tariff message implemented as soon as practicable to assist the 70% of customers currently on SVTs.¹² Co-operative Energy said Ofgem should fast-track the definition of the elements of the existing bill that it wanted to keep so other elements could be removed and the programme could focus on areas of potential change.¹³
- 13.35 We note that the testing of measures that the Mid-tier Suppliers would like fast-tracked are all covered by the priority list of measures identified in paragraphs 13.59 to 13.62. This priority list was informed by submissions made by main and other parties. One reason for including the priority list is

⁹ SSE response to provisional decision on remedies, p50, paragraph 6.1.2.

¹⁰ Centrica response to provisional decision on remedies, p63, paragraphs 320–324.

¹¹ Energy UK response to provisional decision on remedies, p2, paragraph 4.7.

¹² First Utility response to provisional decision on remedies, pp18 & 19, paragraphs 4.32–4.36.

¹³ Co-operative Energy response to provisional decision on remedies, pp2 & 3.

to ensure prompt implementation of the remedy. We recommend that Ofgem prioritise these areas.

- 13.36 Which? welcomed the Ofgem-led programme and said the testing should be ongoing because markets continually change.¹⁴ Citizens Advice said consumer-facing research was needed in relation to customer information, and recommended a clear baseline be established of consumers' current views of supplier communications so any changes could be set against it.¹⁵
- 13.37 The Centre for Competition Policy said it was fully supportive of proposals to give Ofgem powers to conduct research experiments in the energy markets. This is because it should enable better 'road testing' of proposed interventions. RCTs offered a clear means to understand the effectiveness of different 'prompts', and the priority list of measures sounded sensible.¹⁶
- 13.38 A number of parties, including all of the Six Large Energy Firms¹⁷ and certain smaller industry participants,^{18,19} expressed concerns about listing a market-wide Cheapest Tariff Message for testing through the programme and in particular, that a market-wide Cheapest Tariff Message would be unworkable with the removal of the simpler choices component of the RMR rules and potentially misleading for customers. Citizens Advice said it appreciated the intention behind the proposed market-wide Cheapest Tariff Message but it was unclear how this might work in practice.²⁰
- 13.39 In response to these concerns we note that the recommendation to Ofgem is that it should identify and test measures for providing customers with information on the availability of cheaper tariffs in the market. We believe that this is a potentially very important tool in providing customers with information on the range of tariffs available to them, particularly those customers who do not have access to the internet or lack confidence in using PCWs. However, we are not prescriptive as to the precise form this should take. In developing proposals for testing, Ofgem would need to take

¹⁴ Which? response to provisional decision on remedies, p3.

¹⁵ Citizens Advice response to provisional decision on remedies, p36.

¹⁶ Centre for Competition Policy at University of East Anglia response to provisional decision on remedies, p11.

¹⁷ RWE response to provisional decision on remedies, p60, paragraph 51.3.3, EDF Energy response to provisional decision on remedies, p36, paragraph 8.10, Scottish Power response to provisional decision on remedies, p15, paragraphs 8.5 & 8.6; Centrica response to provisional decision on remedies, pp53–55, paragraphs 269–277, SSE response to provisional decision on remedies, p52, paragraph 6.3.9, E.ON response to provisional decision on remedies, p38 paragraph 182.

¹⁸ Utilita response to provisional decision on remedies, pp29 & 30, paragraphs 6.40–6.43.

¹⁹ iChoosr response to provisional decision on remedies, p5, paragraphs 23 & 24.

²⁰ Citizens Advice response to provisional decision on remedies, p38.

into account the implications of the removal of the simpler choices component of the RMR rules for cheapest tariff messaging.

- 13.40 Several parties commented on the approach to securing suppliers' participation in the Ofgem-led programme:
- (a) Ofgem said a CMA order would be the most efficient and effective way of achieving suppliers' participation in the trials.²¹
 - (b) Scottish Power said it was a potentially resource-intensive and long-term programme so it was important the burden was shared equally between suppliers, but suppliers could not be expected to write a blank cheque.²²
 - (c) Centrica said there should be an obligation on all suppliers to participate in the trials.²³
 - (d) RWE said all suppliers should participate in the programme and that without suppliers accepting undertakings, Ofgem would be required to modify suppliers' standard licence conditions to obligate participation.²⁴
 - (e) First Utility said that if an insufficient number of suppliers provided undertakings it agreed with mandating participation.²⁵
- 13.41 We have considered parties' comments on achieving suppliers' participation in the Ofgem-led programme through undertakings. We have noted that some parties did not support suppliers giving undertakings and we believe if undertakings were not forthcoming from all suppliers this would mean a market-wide solution was not possible. In addition, there is a need to future-proof the remedy and provide a mechanism whereby any new suppliers entering the market are also required to participate in the Ofgem-led programme.
- 13.42 In light of the potential difficulties linked to requiring supplier participation through undertakings, we consider that the most effective way to implement this remedy is by recommending that Ofgem introduce a new standard licence condition. As the sector regulator, Ofgem will be in a position to determine what is needed, when and by whom to conduct tests. Ofgem will be required to conduct a proportionality assessment when requiring supplier

²¹ Ofgem response to provisional decision on remedies, p8.

²² Scottish Power response to provisional decision on remedies, p16, paragraph 8.11–8.13.

²³ Centrica response to provisional decision on remedies, p64, paragraphs 327 & 328.

²⁴ RWE response to provisional decision on remedies, pp61 & 62, paragraphs 51.5 & 51.6.

²⁵ First Utility response to provisional decision on remedies, p19, paragraph 4.37.

participation in the testing and this should address parties' concerns about fairness and open ended testing.

Design considerations

13.43 We have considered the following elements in the design of this remedy:

- (a) what approach should be taken to identifying and testing the measures concerning the information provided to domestic customers;
- (b) whether the identification and testing of the measures concerning the information provided to domestic customers should be Ofgem- or supplier-led;
- (c) whether we should identify a priority list of measures for testing;
- (d) whether suppliers should be required to participate in the Ofgem-led programme; and
- (e) how the remedy should be implemented.

What approach should be taken

13.44 Our view is that there is scope to develop Ofgem's approach to testing and evaluating the impact of the 'clearer information' component of the RMR rules.

13.45 Ofgem did undertake qualitative research on aspects of the RMR rules prior to implementation, but we consider that this research was insufficiently rigorous taking into account the scale of the intervention and the potential cost for customers of getting it wrong. In particular:

- (a) Ofgem used focus groups involving only small samples of domestic customers;
- (b) Ofgem used its Consumer First Panel which consists of 80 domestic customers from across Great Britain. Panel members are unlikely to be representative of customers more widely because in meeting regularly they will become more knowledgeable about energy topics; and
- (c) Ofgem did not test the changes in 'real life' situations. What customers say they may do in response to certain information may not reflect what they actually do in practice.

- 13.46 Ofgem is evaluating the impact of the RMR rules, but the approach that it has adopted – primarily conducting a large-scale consumer survey annually for four years – is problematic.²⁶ In particular:
- (a) Establishing a baseline is difficult as the RMR rules were developed over a long period of consultation. We have found that the Six Large Energy Firms were responding to Ofgem’s concerns prior to the implementation of these rules (see Appendix 9.7). This means that an assessment on the impact of the rules based on a comparison of supplier behaviour after-implementation and before-implementation could understate the impact of the rules.
 - (b) Changes in customer behaviour since implementation of the RMR rules cannot necessarily be attributed to the RMR rules given the potential for other unrelated factors to have influenced consumer engagement. In addition, attributing change to individual components of the RMR rules presents yet further complexities, as the RMR rules were designed to work as a package.
- 13.47 Submissions from consumer groups indicate that they share our concerns. Specifically:
- (a) Which? said that, given the past work by Ofgem and others to improve communications to customers, it was now necessary to learn lessons from this work and devote significantly more time to testing any new engagement mechanisms.²⁷
 - (b) Citizens Advice said there should be a research-led review of the regulated content on energy bills to explore what content could be safely removed.²⁸
- 13.48 The Behavioural Insights Team told us that rigorous testing was the best way to ensure that any future changes in supplier communications had their intended effect on customers. The Behavioural Insights Team said that RCTs should be used to test different messages on bills and other communications such as annual statements and product end notifications.²⁹

²⁶ Ofgem outlined its approach to evaluation and the potential challenges in its letter [Domestic Retail Market Review Evaluation – a proposed way forward](#), 31 January 2014.

²⁷ [Which? response to Remedies Notice](#), p6.

²⁸ [Citizens Advice/Citizens Advice Scotland response to Remedies Notice](#), p42.

²⁹ [The Behavioural Insights Team response to Remedies Notice](#), p9.

13.49 The Behavioural Insights Team also told us that RCTs had been effective in testing interventions in other sectors.³⁰ For example, trials of different tax letters had resulted in the development of letters that encouraged more people to pay their taxes and trials of different forms at job centres had resulted in the development of forms that encouraged more jobseekers to get back into work.³¹

13.50 Conducting a RCT would typically involve the following steps:

- (a) identifying two or more interventions to compare (eg old versus new; different variations of the intervention) and qualitative testing with some customers ahead of any full-scale trial;
- (b) determining the outcome that the intervention is intended to influence and how it will be measured in the trial;
- (c) deciding on the randomisation design, including the number of customers in the control and treatment group(s);
- (d) writing a trial protocol specifying the conduct of the trial, including processes to ensure that the trial is implemented correctly by participants;
- (e) running the trial in conjunction with participants according to the protocol;
- (f) measuring the results and determining the impact of the interventions;
- (g) conducting follow-up research with trial customers (typically those in the treatment group(s)) to gain a full understanding of the behavioural response to the intervention; and
- (h) deciding whether and how to implement the intervention. This may be in the precise form in which the intervention was trialled, or it may be modified to take account of new information (arising, for example, from the follow-up research to the trial). If these modifications are not trivial it may be appropriate to conduct a further trial.

13.51 We agree that RCTs can provide the clearest evidence on the potential impact of an intervention.³² In particular, the introduction of a randomly

³⁰The Behavioural Insights Team response to Remedies Notice, p9.

³¹ See The Behavioural Insights Team's [Update report 2013-15](#) for more details of the impact of different messages on consumers tested through RCTs.

³² HM Treasury (April 2011), [The Magenta Book: Guidance for evaluation](#), p27.

assigned control group provides a basis for isolating the impact of an intervention. Conducting the trial in 'real time' tests how customers actually respond to an intervention rather than how they say they would respond.³³

13.52 We consider that RCTs would be appropriate where:

- (a) the treatment can be applied to a sample of customers independently of a control group;
- (b) the desired outcome can be measured;
- (c) the expected impact of an intervention is sufficiently large for there to be a reasonable expectation of being able to detect it;
- (d) the costs of a trial are proportionate to the potential benefits; and
- (e) the intervention is immediately reversible if found to be ineffective or to have unintended consequences.

13.53 Our view is that the overall approach of the Ofgem-led programme should provide for:

- (a) the specification of potential forms of information that domestic customers (on any meter type) may receive in communications with suppliers and messaging aimed at prompting customers to engage (referred to below as 'the measures');
- (b) testing (through RCTs, where appropriate) in the case of the priority list of measures of the impact of the measures identified prior to market-wide implementation;
- (c) the implementation of the measures considered most appropriate following testing (for example, through appropriate changes to the standard licence conditions);
- (d) ongoing monitoring of the impact of the implemented measures (which may involve possible arrangements for independent moderation and quality assurance); and
- (e) adjustments as appropriate where measures may no longer be having the desired effect.

³³ Cabinet Office Behavioural Insights Team (June 2012), *Test, Learn Adapt: Developing Public Policy with Randomised Controlled Trials*, p4.

Whether the programme should be led by Ofgem or suppliers

- 13.54 All of the Six Large Energy Firms³⁴ said they have previously conducted or were already conducting their own research with customers on communications.
- 13.55 However, our view is that Ofgem is better placed than suppliers to take the lead in a programme to identify and test measures aimed at promoting consumer engagement. This is because Ofgem has a market-wide perspective and can therefore ensure that best practice is implemented consistently across the markets. In addition, Ofgem's interests will be better aligned with those of customers than suppliers' interests, since Ofgem's principal statutory objective is to protect the interests of current and future consumers of gas and electricity.³⁵
- 13.56 We recognise that Ofgem will need the resources, expertise and budget to establish and run a robust and credible programme which includes RCTs where appropriate. Ofgem will also need the necessary expertise to oversee the design and implementation of the programme. Ofgem does not necessarily need to have these resources available to it in-house as it can also make use of external resources and expertise, where appropriate.
- 13.57 We have discussed these requirements with Ofgem. Ofgem told us that it was very supportive of the remedy and that it had started work on a plan for implementing the remedy. Ofgem intended to build in-house capability to conduct the programme. Ofgem also said that it would welcome working with Citizens Advice and the Behavioural Insights Team.
- 13.58 We also think that Ofgem would need cooperation from suppliers, at least as regards providing certain information and data, in order to conduct a robust RCT. For example, Ofgem, or a third party appointed by Ofgem, might need, at the very least, the contact details of domestic customers, and information required to assess the effectiveness of the measures that are being tested in the 'treatment' and 'control' groups. The Behavioural Insights Team told us that RCTs were most effective when stakeholders cooperated, citing the examples of HMRC regarding RCTs relating to tax forms and DWP and Jobcentre Plus regarding RCTs relating to information for jobseekers. [✂]

³⁴ [Centrica response to Remedies Notice](#), p73; [EDF Energy response to Remedies Notice](#), p32; [E.ON response to Remedies Notice](#), p38; [Scottish Power response to Remedies Notice](#), p27 (p61 of PDF); and [RWE npower response to Remedies Notice](#) p4 (p100 of PDF); [SSE response to provisional findings and Remedies Notice](#), p63 (p143 of PDF).

³⁵ Sections 4AA(1)(1A), 34, 35, 36, 36A of the GA86; sections 3A(1)(1B), 43, 47, 48, 49 of the EA89.

Whether we should identify a priority list of measures for testing

- 13.59 In light of parties' submissions, we recommend Ofgem develop and test proposals (including through RCTs, where appropriate) in respect of the following priority list of measures:³⁶
- (a) Changes to bill information including shorter bill length, through the removal of certain information, and different layouts – for example, the display of key information required for switching on the first page of the bill.
 - (b) Changes to test the provision of information to customers on cheaper tariffs available across the markets. By testing such measures it will be possible to identify the effect of providing information on tariffs offered by other suppliers on domestic customers' engagement. We note that there might be scope for Ofgem to play a role in collating pricing information and for providing suppliers (and customers) with an indication of average levels of savings available, and that this approach could also be tested.
 - (c) Changes to messaging on bills for domestic customers that are about to be/have moved on to an SVT and/or other default tariff on engagement. This trial may determine how best to capitalise on the potential 'trigger for action' that occurs when such customers reach the end of their fixed-term tariff contracts.
 - (d) Changes to the name for the default tariff from 'standard variable tariff', such as 'default', 'emergency' or 'out of contract' tariff.
- 13.60 We recommend that Ofgem give priority to developing and testing proposals for these measures. We consider that the above measures are particularly suitable for testing through RCTs in particular, given the magnitude of the detriment we have observed as resulting from the Domestic Weak Customer Response AEC.

Whether suppliers should be required to participate in the Ofgem-led programme

- 13.61 We consider that implementing this remedy through a recommendation to Ofgem to implement the programme alone would, in principle, allow suppliers to object to participate in the Ofgem-led programme or otherwise obstruct its progress, which would defeat the aim of this remedy. To ensure effective implementation (see paragraph 13.65 below), suppliers will be

³⁶ We consider that these measures lend themselves to being tested through RCTs.

required to participate in the Ofgem-led programme through an enduring licence condition. Accordingly, we are therefore recommending that Ofgem introduces (following a consultation) a licence condition requiring suppliers to participate in the programme (and in RCTs, where appropriate). The proposed text of the new licence condition is provided in Appendix 13.1.

How the remedy should be implemented

13.62 We will implement this remedy through:

- (a) A recommendation to Ofgem to establish an ongoing programme (the 'Ofgem-led programme') to identify, test (through RCTs, where appropriate) and implement³⁷ measures to provide domestic customers with different or additional information with the aim of prompting engagement in the domestic retail energy markets, including a recommendation to develop and test proposals (including through RCTs, where appropriate) concerning the following priority list of measures:
 - (i) changes to the information in domestic bills and how this is presented;
 - (ii) changes to information provided to customers on cheaper tariffs available across the markets;
 - (iii) changes to the specific messaging that domestic customers receive in bills once they move, or are moved, on to an SVT and/or other default tariffs; and
 - (iv) changes to the name of default tariffs.
- (b) A recommendation to Ofgem to introduce (following a consultation) a licence condition, consistent with the proposed text provided in Appendix 13.1 requiring suppliers to participate in the Ofgem-led programme.

Effectiveness of the remedy

13.63 As we explain below, our view is that the remedy is effective in achieving its aim of identifying the most appropriate form of information to be included in communications from suppliers (eg bills), reducing or minimising the complexity of such information, and providing domestic customers with different or additional information or messaging that will prompt them to switch tariff or supplier. Accordingly, our view is that the remedy is effective

³⁷ For example, through appropriate changes to gas and electricity suppliers' standard licence conditions.

in addressing (wholly, or in part) two of the features that give rise to the Domestic Weak Customer Response AEC (and the resulting customer detriment), ie that domestic customers have limited awareness of, and interest in, the ability to switch, and that certain domestic customers face actual and perceived barriers to accessing and assessing information.

13.64 In assessing the effectiveness of the remedy, we have considered the following factors:

- (a) the effectiveness of the key design elements of the remedy;
- (b) the extent to which the remedy is capable of effective implementation, monitoring compliance and enforcement; and
- (c) the timescale over which the is likely to have an effect.

- *Effectiveness of the key design elements of the remedy*

13.65 We consider that the key design elements of the remedy are effective in achieving its aim for the following main reasons:

- (a) The remedy provides for testing of the impact of the measures identified prior to market-wide implementation and for ongoing monitoring of such impact (see paragraph 13.53 above). Accordingly, Ofgem will be able to identify the most effective measures to promote engagement.
- (b) Ofgem is better placed than suppliers to take the lead in a programme to identify and test measures aimed at promoting customer engagement (see paragraphs 13.55 to 13.57) above).
- (c) The priority list of measures for testing (see paragraph 13.59) and other guidance noted above provide Ofgem with a high-level steer on when RCTs could be appropriate (for example, see paragraph 13.50), enhancing the likelihood of this remedy being effective.
- (d) As indicated above, we consider that a recommendation to Ofgem alone to conduct trials would not be sufficient to ensure the effective implementation of this remedy as suppliers could, in principle, object to participating in the programme. Accordingly, we are recommending that Ofgem introduces (following a consultation) a licence condition, consistent with the proposed text provided in Appendix 13.1, requiring suppliers to participate in the programme.

13.66 We also consider that the Ofgem-led programme will be responsive to future developments in the markets. For example, the introduction of smart

metering and phase 2 of the Midata programme have the potential to change how domestic customers engage in the markets. In the future, customers may have greater access to their data, enabling them to switch more easily and with greater confidence, and may use different forms of technology to communicate with suppliers and TPIs.

- *Implementation, monitoring compliance and enforcement of the remedy*

- 13.67 In determining whether a remedy is effective, we have had regard to how it would be expected to operate. We have also had regard to the need for the remedy to be clear to the persons to whom it is directed, such as Ofgem and suppliers.
- 13.68 As regards the implementation of the remedy, we have set out a number of detailed specifications. In this regard, we have sought to take a detailed approach by describing the terms of the recommendations so that it will not only be clear to Ofgem, in terms of how, when and what to test, but also be straightforward for it to implement. Our recommendation to introduce a licence condition to require suppliers to participate includes a draft licence condition setting out what will be required of suppliers in participating in the Ofgem-led programme. Hence, this recommendation should be straightforward for Ofgem to implement following a consultation.
- 13.69 We have also considered the possible remedies suggested by E.ON, SSE and First Utility as alternatives to the prohibition of the SVT proposed by Centrica and Scottish Power (see our Supplemental Remedies Notice and paragraphs 13.196 to 13.219 below). We consider that both suggestions (of improved messaging in the annual statement and renaming the SVT or other default tariffs) should be incorporated into this remedy.
- 13.70 We have also considered the suggestion by MoneySuperMarket which would involve DECC (or some other trusted intermediaries) writing to customers, and the use of SMS messaging. On the former, we consider that Ofgem, as sector regulator, and which has a principal objective to protect the interests of consumers, is best placed to decide who (if not the suppliers themselves) should write to customers with the relevant information that has been the subject of the Ofgem-led programme and should consider how best such communications should occur, such as whether letter, SMS messaging, email or other form should be used.
- 13.71 In addition, we would expect Ofgem to put in place a governance structure to ensure effective oversight of the design and implementation of the programme.

- 13.72 As regards monitoring compliance of suppliers with the licence condition requiring participation in the Ofgem-led programme, we consider that this should be straightforward given Ofgem's involvement as sector regulator.
- 13.73 As regards enforcement, Ofgem will be able to enforce against the new licence condition.
- *Timescale for the remedy*
- 13.74 In evaluating the effectiveness of the remedy, we have considered the timescale over which the Domestic Weak Customer Response AEC is expected to endure, and the timescale over which the remedy is likely to take effect. We consider that the detriment will persist, absent the remedy, and that the impact of future market developments, including the roll-out of smart meters, is somewhat uncertain (see Sections 11 and 15). Moreover, we consider that the need for rigorous testing of suppliers' communications with domestic customers is likely to be an ongoing need. Therefore we have decided that the remedy will not be subject to a sunset provision.
- 13.75 As regards the timescales for implementation, as noted above, Ofgem told us that it had started work on a plan for implementing the remedy and building its in-house capability to conduct the programme. Ofgem also said that it would welcome working with Citizens Advice and the Behavioural Insights Team. As soon as possible following the CMA's final report, we would expect Ofgem to begin developing proposals concerning the priority list of measures that we recommend that Ofgem test (through RCTs, where appropriate). In particular, we would expect Ofgem to progress such plans simultaneously with a consultation on the new licence condition concerning suppliers' participation in the Ofgem-led programme. We would expect that the first trials could start by mid-2017, by which time Ofgem would have concluded a consultation on the new licence condition requiring suppliers to participate in the programme.
- 13.76 Ofgem could conduct evaluations of the trials from late 2017 onwards, and where trials proved successful, any interventions could be implemented from late 2018 onwards. Subsequently we would expect Ofgem to monitor the effectiveness of the interventions and continue to update the programme on an ongoing basis.
- 13.77 We would therefore expect the remedy to start having an effect in addressing aspects of the features giving rise to the Domestic Weak Customer Response AEC, including the actual and perceived barriers in accessing and assessing information, from the beginning of 2019.

Assessment of proportionality

13.78 In this section we set out our assessment of whether our remedy is proportionate to achieve its aim. We do this by considering whether the remedy:³⁸

- (a) is effective in achieving its legitimate aim;
- (b) is no more onerous than needed to achieve its aim;
- (c) is the least onerous if there is a choice between several effective measures; and
- (d) does not produce disadvantages which are disproportionate to the aim.

- *Effective in achieving its aim*

13.79 For the reasons set out above, we consider that a programme of rigorous testing (involving RCTs where appropriate) is effective in achieving its aim of reducing the complexity of the information included in communications from suppliers, and in providing domestic customers with different or additional information or messaging that will prompt them to switch tariff or supplier. Accordingly, it is effective in addressing (in whole or in part) two of the features that give rise to the Domestic Weak Customer Response AEC, and the resulting detriment.

- *No more onerous than needed to achieve its aim*

13.80 We also consider that this remedy is no more onerous than needed to achieve its aim. In particular, given the need for an ongoing programme of rigorous testing, Ofgem is best placed to identify, develop, test and implement measures for providing domestic customers with different or additional information or messaging to prompt them to engage in the markets.

13.81 In designing the programme, Ofgem will be required to assess the proportionality of the various stages involved in the programme,³⁹ including the testing involved in each specific proposed measure. In this regard, we would expect Ofgem to take into account issues such as the potential costs incurred by suppliers, the duration of the testing process and for how long it

³⁸ [CC3](#), paragraph 344, citing the principles established in the *Fedesa* case, Case C-331/88, *the Queen v Minister of Agriculture, Fisheries and Food and Secretary of State for Health, ex parte: Fedesa and others*, [1990] ECR I-4023, paragraph 13.

³⁹ Section 4AA(5A)(a) of the GA86; section 3A(5A)(a) of the EA89; Article 41(4)(b) of Directive 2009/73/EC (the Gas Directive) and Article 37(4)(b) of Directive 2009/72/EC (the Electricity Directive).

will impose costs on suppliers as part of its proportionality assessment. We expect the costs to suppliers to include those they might incur in working with Ofgem in developing measures for testing and designing the programme for testing measures, compiling the information required by Ofgem, and implementing measures for testing.

13.82 We consider that a programme within the proposed parameters is proportionate.

- *Least onerous if there were a choice between several effective remedies*

13.83 We have considered whether there may be alternative remedies to achieve the same aim. However, we consider that there is no substantive alternative to the remedy that would be effective (for the reasons set out in paragraphs 13.45 to 13.51 above).

- *Does not produce disadvantages that are disproportionate to the aim*

13.84 We have concluded that the remedy does not produce adverse effects that are disproportionate to its aim. We have compared the potential costs of implementing the remedy with the potential detriment at stake.

13.85 The gains available to customers from promoting engagement are potentially high (see Sections 9 and 10). Given the magnitude of the detriment we have observed as resulting from the Domestic Weak Customer Response AEC, we will seek to enhance the effective implementation of the Ofgem-led programme by recommending that Ofgem introduce a new licence condition requiring suppliers to participate.

13.86 We recognise that implementation of the Ofgem-led programme will require substantial additional resources over and above Ofgem's current research budget. [✂] Nevertheless, we consider that this remedy will make a major contribution to the success of the overall package of remedies aimed at promoting engagement and competition in the supply to domestic customers, and therefore to addressing (in part) the Domestic Weak Customer Response AEC. This is discussed further in Section 11.

13.87 We recognise that there will also be costs to suppliers of complying with the requirement to participate in the Ofgem-led programme (including, where used, RCTs) and implementing the resulting interventions. However, we note that our starting point for the proportionality of the Ofgem-led programme, and any individual decision subsequently taken by Ofgem in the context of the programme, is the scale of the detriment, which is very substantial.

- 13.88 Further, any potential costs to one or more individual suppliers that are the focus of any tests will be subject to Ofgem’s obligation to consider the proportionality of any testing and supplier participation (see paragraph 13.81). In this regard, we note that some suppliers have told us they had previously conducted or were already conducting customer research on the design of bills and other communications with their customers.⁴⁰ While some of these tests might be superseded by an Ofgem-led programme, we consider that the impact of the remedy will be lower for those suppliers who already set aside a budget for consumer testing, which could contribute towards a supplier’s participation in Ofgem’s programme.
- 13.89 We have also been told that making changes to billing systems is costly.⁴¹ Centrica said that adequate trials could not be conducted ‘off system’ and was concerned about the lack of detail on how the obligation on suppliers to participate in the trials would operate in practice. Centrica said it would expect to see instructions to ensure the procedures for any trials did not place an undue burden on one or more supplier in particular, and information on how the costs of any trial would be shared equitably between all suppliers.⁴² Ofgem said while no trial would require wholesale changes to a supplier’s billing system, most trials would need to work with real customer data in the context of normal billing cycles and systems.⁴³
- 13.90 We are aware that changes to bill formats are routine for suppliers⁴⁴ and therefore expect that the cost of such changes to the systems could be incorporated into the normal evolution of billing formats over time. More importantly, as set out above (see paragraph 13.87), Ofgem will be required to consider the proportionality of any supplier participation in testing programmes. We also note that Centrica is the only supplier to have expressed concerns about the scope for conducting tests (including running

⁴⁰ [Centrica response to Remedies Notice](#), p73 (Centrica said it had been unable to act on the results of its research due to the current regulations. Centrica submitted that suppliers were better placed than the regulator to determine the best way to engage customers based on their experience and insight and were incentivised to do so by the need to differentiate themselves from competitors. Centrica suggested that the CMA should replace the existing prescriptive rules with regulations that required suppliers to achieve outcome-based goals); [EDF Energy response to Remedies Notice](#), p32; [E.ON response to Remedies Notice](#), p38; [Scottish Power response to Remedies Notice](#), p27 (p61 of PDF); and [RWE npower response to Remedies Notice](#), p4 (p100 of PDF) (RWE told us it was already conducting customer research in conjunction with The Behavioural Insights Team and Ofgem); [SSE response to provisional findings and Remedies Notice](#), p 63 (p143 of PDF).

⁴¹ Co-operative Energy said that complying with prescriptive RMR billing and communication requirements came at a substantial cost in terms of system changes and the associated financial spend. ([Co-operative Energy response to Remedies Notice](#), p16). Ecotricity said, in relation to measures to prompt customers on default tariffs to engage in the market, that system changes came at a cost that the Six Large Energy Firms might be able to absorb, but were challenging for independents ([Ecotricity response to Remedies Notice](#), p8).

⁴² Centrica response to provisional decision on remedies, p63, paragraphs 325–328.

⁴³ Ofgem response to provisional decision on remedies, p8.

⁴⁴ E.ON said that there had been numerous changes to the information provided to customers over the years ([E.ON response to Remedies Notice](#), p37).

RCTs) 'off system' and so avoiding the need for suppliers to make premature changes to their billing and other systems.⁴⁵

Prompts for customers on default tariffs

13.91 We have found that around 70% of the customers of the Six Large Energy Firms are on a SVT, and up to 55%⁴⁶ of these customers have been on the SVT with their current supplier for more than three years. We have considered two remedies for helping these customers on default tariffs engage in the market: the creation of an Ofgem-led database; and the prohibition of evergreen default tariffs.

The Database remedy

13.92 In order to enable suppliers to prompt domestic customers of rival suppliers on default tariffs, this remedy requires energy suppliers to disclose certain details of their domestic customers (on any meter type⁴⁷) who have been on their SVT (or any other default tariff) for three or more years (the Disengaged Domestic Customers) to Ofgem, and recommends that Ofgem retain, use, and disclose this data (via a centrally managed database (the 'Database') to rival suppliers (the 'Database remedy'). The Disengaged Domestic Customers will have the option to opt out of the disclosure process at any point in time. Around 10 million domestic customers currently meet the criteria for inclusion in the Database.⁴⁸

13.93 We consider that this remedy and the Ofgem-led programme will work together to address the feature that certain customers face actual and perceived barriers to accessing and assessing information, and also the feature that domestic customers have limited awareness of, and interest in, their ability to switch. With the Ofgem-led programme these aims are achieved in part through the information provided by suppliers to domestic customers, while the Database remedy harnesses the incentives of suppliers to prompt their competitors' customers to engage, by providing suppliers with an alternative channel for reaching customers who have been reluctant to engage through existing sales channels.

⁴⁵ We note that The Behavioural Insights Team has run RCTs in other sectors without major system changes.

⁴⁶ We note that this is an upper bound estimate as for three suppliers, the data provided was based on the length of the relationship with the supplier rather than the length of time on that supplier's SVT. The figure for gas is 54% and 55% for electricity.

⁴⁷ This remedy would apply to domestic customers on unrestricted meters (including prepayment meters), restricted meters and Economy 7 meters.

⁴⁸ We note that this is an upper bound estimate as for three suppliers the data provided on the percentage of customers who have been on that supplier's SVT for more than three years was based on the length of the relationship with the supplier rather than the length of time on that supplier's SVT. See Section 11.

- 13.94 We consider that the Database remedy will also be a highly valuable tool for Ofgem, enabling it to contact the most disengaged customers directly and to evaluate the impact of measures taken to prompt engagement. Ofgem could also use the Ofgem-led programme to refine the messages and the information customers on the Database receive in communications with suppliers. We recommend that initially Ofgem restrict access to the Database to licensed domestic energy suppliers, but over time may consider extending access to trusted partners such as Citizens Advice.
- 13.95 A limited number of the design considerations of this remedy are specific to customers on restricted meters (see paragraph 13.144), in order to enhance the effectiveness of this remedy in relation to this type of customer. We consider that the limited number of such customers, the lack of information in relation to their location, and the wide range of types of restricted meters is a particular barrier to competition for customers with such meters. In particular, we have been told that the cost to suppliers of designing tariffs to support restricted meters and/or then marketing their products to customers with restricted meters is prohibitively high (see Appendix 9.5). This is because these customers account for only a small proportion of electricity customers across GB, and they have installed in their homes many different meter types supporting different space and heating systems.

Aim of the remedy

- 13.96 The aim of the remedy is to enable rival retail energy suppliers to identify the Disengaged Domestic Customers that have not opted out and prompt such customers to engage in the markets, while also allowing Ofgem to contact these customers directly and to evaluate the impact of measures taken to prompt engagement. The ultimate aim of this remedy is to partly address two of the features we have identified as giving rise to the Domestic Weak Customer Response AEC (and resulting detriment), ie that domestic customers have limited awareness of, and interest in, their ability to switch energy supplier and that domestic customers face actual and perceived barriers to accessing and assessing information.

Parties' views

- 13.97 RWE said it broadly supported the remedy subject to assurances from the Information Commissioner's Office that the sharing of information complies with the Data Protection Act 1998 (DPA) and the Privacy and Electronic Communications Regulations (PECR).⁴⁹ EDF Energy said it welcomed

⁴⁹ RWE response to provisional decision on remedies, pp64, paragraphs 53.1.

remedies that would enable it to engage the disengaged customers of other suppliers but had some concerns about the potential misuse of customer data and customers receiving unwanted marketing.⁵⁰ Scottish Power⁵¹ did not oppose the remedy but identified some significant legal data protection issues which would need to be clarified before it could be implemented successfully. Centrica,⁵² E.ON,⁵³ and SSE⁵⁴ said that they had significant concerns about the remedy. The key concerns raised were as follows:

- (a) That there was no evidence that the remedy would increase customer engagement and there was a risk that it would be damaging to consumer trust by facilitating unsolicited marketing.
- (b) That certain aspects of the remedy may not be fully compliant with data protection legislation in the absence of suppliers obtaining (opt-in) consent from the customers (in particular, suppliers disclosing customer data to Ofgem; Ofgem disclosing such data to other suppliers; and these suppliers using that data to send postal communications to customers).
- (c) That customers should be invited to 'opt-in' rather than 'opt-out' of being on the Database.
- (d) That the remedy could result in breaches of data security or abuse of the data.
- (e) That the CMA should set out principles-based regulations that would apply to suppliers accessing the Database in order to protect customers.
- (f) That the remedy appears inconsistent with the new EU General Data Protection Regulation (GDPR).⁵⁵

13.98 Ofgem said trialling the Database before it was fully rolled-out would 'allow data protection questions to be fully addressed, additional protections for communications with customers to be explored and...[to] understand the effectiveness of different approaches to engage sticky customers.'⁵⁶

⁵⁰ EDF Energy response to provisional decision on remedies, pp41–43, paragraphs 8.35–8.47.

⁵¹ Scottish Power response to provisional decision on remedies, pp18-23, paragraphs 10.1–10.30.

⁵² Centrica response to provisional decision on remedies, pp70–73, paragraphs 354 & 375.

⁵³ E.ON response to provisional decision on remedies, p 41, paragraph 202.

⁵⁴ SSE response to provisional decision on remedies, p10, paragraph 2.5.1.

⁵⁵ Regulation (EU) 2016/679 of 27 April 2016 on the protection of natural persons with regard to the processing of personal data and on the free movement of such data, and repealing Directive 36/46/EC (General Data Protection Regulation).

⁵⁶ Ofgem response to provisional decision on remedies, p2.

Centrica,⁵⁷ SSE,⁵⁸ Which?,⁵⁹ National Energy Action,⁶⁰ and Professor Littlechild⁶¹ also proposed testing in advance of implementation and the ongoing monitoring and evaluation of impact. Similar points were made by several other parties.^{62,63}

- 13.99 We consider all these points below in the discussion on the design of the remedy and our assessment of its effectiveness and proportionality.
- 13.100 First Utility said it was concerned that the Database would not be implemented until 2018 and proposed an alternative remedy that would require suppliers with long-standing SVT customers to replace SVT contracts with contracts for the cheapest available tariff that would come into effect as soon as possible.⁶⁴ Our view is that the alternative remedies proposed by First Utility do not address the features giving rise to the Domestic Weak Customer Response AEC and as such could not be expected to deliver benefits over the longer term. We consider the timetable for the implementation of remedies in Sections 11 and 15.
- 13.101 Ofgem indicated that it would aim to implement this remedy, at least its development phase, as soon as possible following publication of the final report. Ofgem also said that it had started preparing draft implementation plans so that it would be in a good position to start work were we to decide to pursue the proposed remedy.
- 13.102 Ovo Energy said it was not convinced this remedy would bring meaningful benefits to customers and, if implemented, there should be new Standards of Conduct to govern suppliers' use of the data in the Database, and it should only apply to customers of the Six Large Energy Firms.⁶⁵ We note that, as regards the first point, we will be recommending that Ofgem put in place agreements that govern the access and use of data (see paragraph 13.139). On the second point, our view is that, given the broad aims of the remedy at addressing, at least in part, a feature of the domestic retail energy markets (as a whole), no suppliers should be excluded from providing details of their most disengaged customers.

⁵⁷ Centrica response to provisional decision on remedies, paragraph 362.

⁵⁸ SSE response to provisional decision on remedies, paragraph 5.7.3.

⁵⁹ Which? response to provisional decision on remedies, p5.

⁶⁰ National Energy Action response to provisional decision on remedies, paragraph 2.2.

⁶¹ Littlechild et al response to provisional decision on remedies, paragraph 94.

⁶² MoneySavingExpert.com response to provisional decision on remedies, p1. MoneySavingExpert.com said use of the database must be monitored to prevent customers receiving excessive communications.

⁶³ Age UK response to provisional decision on remedies, p3.

⁶⁴ First Utility response to provisional decision on remedies, p2.

⁶⁵ Ovo response to provisional decision on remedies, paragraph 7.1 & paragraph 7.5.

- 13.103 Utility Warehouse said that it was imperative the remedy only applied to genuinely disengaged customers rather than those who had actively chosen evergreen tariffs.⁶⁶ For the reasons given in paragraph 13.130 we consider that customers who have been on the SVT with the same suppliers for three or more years are unlikely to have actively chosen the tariff for a considerable amount of time.
- 13.104 Co-operative Energy said it had concerns that the Database was not appropriately targeted at just the customers of the larger suppliers, and would increase costs disproportionately on smaller suppliers.⁶⁷ Utilita said if the remedy went ahead it should only apply to customers on the Six Large Energy Firms' SVTs who were on those tariffs for more than three years at the date of publication of the CMA's final report.⁶⁸ We note, as above, our view that given the aims of the remedy no supplier should be excluded from providing details of the most disengaged customers. We note, however, that for smaller suppliers the proportion of their customers who would be regarded as disengaged is likely to be small, in particular, given the greater proportion of Mid-tier Suppliers' customers that have been recently acquired (there was a 35% increase in their number of customers between quarter 1 2015 and quarter 1 2016).⁶⁹
- 13.105 Co-operative Energy also said that the remedy would frustrate customers through unsolicited contacts. We note that in this regard the remedy makes explicit provision for customers to be able to opt-out of the Database at any point in time (see paragraph 13.131) and that rival suppliers will be subject to restrictions on the use to which they can put the data in the Database. Protection concerning unsolicited contact will also be in place through the PECR and consumer protection legislation (see paragraph 13.141).
- 13.106 Citizens Advice proposed some additional safeguards to protect customers from unwanted communications, such as restricting the Database to active licensed suppliers only.⁷⁰ Our view is that all licensed suppliers should be allowed access to the Database. All licensed suppliers are required to comply with Ofgem's standard licence conditions which include provisions relating to conduct in sales and marketing activities, and will include a licence condition concerning the Database remedy.

⁶⁶ Utility Warehouse response to provisional decision on remedies, p2.

⁶⁷ Co-operative Energy response to provisional decision on remedies, p3.

⁶⁸ Utilita response to provisional decision on remedies, paragraph 6.52.

⁶⁹ Latest assessment from Cornwall (January 2016).

⁷⁰ Citizens Advice response to provisional decision on remedies, p42.

13.107 Which? said it was concerned the remedy would result in unwanted marketing and that results from a survey it had commissioned found that 37% of the relevant customers were likely to ‘opt-out’ of receiving letters from rival suppliers.⁷¹ Age UK said Ofgem would need to work to prevent the Database adversely affecting customers, including by evaluating the deals offered to them.⁷² We consider that these risks will be mitigated by the testing by Ofgem that we have built into the remedy (see paragraph 13.131 to 13.137).

13.108 Moneysupermarket said that it would like access to the Database, and uSwitch said that if the CMA pursued the Database remedy, there may be a case for TPIs to be allowed to apply for access to the Database.⁷³ However, for the reasons noted in paragraph 13.104, we are recommending that access be limited to licensed suppliers as these suppliers are required to comply with Ofgem’s standard licence conditions which include provisions relating to conduct in sales and marketing activities.

13.109 We also received a number of specific suggestions for the design of the remedy as follows:

(a) Rather than rival suppliers, the Database could be more effective if Ofgem,^{74,75} government (central or local)⁷⁶ and/or consumer groups^{77,78} used it to prompt engagement.

(b) Access to the Database should be withdrawn if suppliers do not abide by the use agreements and their access should be limited if they are under restrictions on sales activity due to customer service issues.⁷⁹

⁷¹ Which? response to provisional decision on remedies, p4.

⁷² Age UK response to provisional decision on remedies, p3.

⁷³ Moneysupermarket.com response to provisional decision on remedies, p7; uSwitch.com response to provisional decision on remedies, paragraph 4.2.

⁷⁴ EDF Energy response to provisional decision on remedies, paragraph 8.40. EDF Energy proposed using the initial ‘opt-out’ letter as a prompt to engage and require suppliers to deliver specific prescribed messaging about switching in this letter, which would be co-branded with Ofgem and trialled by Ofgem first.

⁷⁵ Energy Advice Line response to provisional decision on remedies, p3. Energy Advice Line proposed the data should be used for a national campaign sponsored by Ofgem which could include offering customers the option of using approved PCWs to help them switch.

⁷⁶ uSwitch response to provisional decision on remedies, paragraph 4.2. uSwitch said it would be more effective for DECC and Ofgem to target customers on the Database, building on the successful Power to Switch campaign.

⁷⁷ Flow Energy response to provisional decision on remedies, pp2 & 3. Flow Energy said it would support marketing by either Ofgem, government (central or local) or Citizens Advice to customers on the Database.

⁷⁸ iChoosr response to provisional decision on remedies, paragraphs 20–22. iChoosr said access should be given to trusted and independent organisations such as local authorities, charities and consumer interest groups who could then offer the customers collective switching schemes.

⁷⁹ EDF Energy response to provisional decision on remedies, paragraphs 8.43 & 8.44.

- (c) Limitations should be placed on the time that rival suppliers could keep/use the data on the Database.^{80,81} In particular they should not be able to retain information after using it for its intended purpose.⁸²
- (d) Use of the Database in conjunction with other data/databases for telemarketing purposes should be prohibited.^{83,84}
- (e) Limitations should be placed on the frequency and volume of communications that customers on the Database could receive from rival suppliers.
- (f) Suppliers should be required to include on the first page of any postal communications from rival suppliers to customers on the Database a clear statement of how they can opt out.⁸⁵
- (g) Exclusion from the Database of customers who have already opted out of marketing from their existing supplier.^{86,87}
- (h) Specific timescales for removing customers from the Database and notifying Database users of such changes eg 28 days.⁸⁸
- (i) Ofgem to have an externally assured information security process compliant with a recognised standard (eg ISO27001) and only share data with parties that also have such standards.⁸⁹

13.110 With regard to (a), we consider that suppliers will be well placed to achieve the aim of the remedy (see paragraph 13.96). In particular, the Database remedy will allow suppliers to identify the most disengaged customers and will give them access to the information they will need to provide their rivals' customers with personalised quotes. Suppliers are also well placed to help customers to navigate the process of switching, and they will be able to draw on the knowledge and experience they have gained from their sales and marketing activities in developing their strategies for engaging with customers on the Database. Under this remedy, Ofgem will also be able to use the details of the Disengaged Domestic Customers who have not opted-out to prompt these customers to consider switching, and in monitoring and

⁸⁰ Moneysupermarket.com response to provisional decision on remedies, p7.

⁸¹ SSE response to provisional decision on remedies, paragraph 5.7.2.

⁸² EDF Energy response to provisional decision on remedies, paragraphs 8.45.

⁸³ Centrica response to provisional decision on remedies, paragraph 361.

⁸⁴ Scottish Power response to provisional decision on remedies, paragraphs 10.23 & 10.24.

⁸⁵ Centre for Competition Policy at University of East Anglia response to provisional decision on remedies, p14.

⁸⁶ SSE response to provisional decision on remedies, paragraph 5.7.7.

⁸⁷ E.ON response to provisional decision on remedies, paragraph 207.

⁸⁸ Scottish Power response to provisional decision on remedies, paragraph 10.29.

⁸⁹ E.ON response to provisional decision on remedies, paragraph 208.

evaluating the effectiveness of the Database remedy and other measures. Ofgem may wish to give access to other government or consumer bodies in the future subject to adequate safeguards being in place.

- 13.111 With regard to (b), (c), (d), and (e), we are recommending that Ofgem put in place strict safeguards to mitigate any prejudice to the rights and interests of the data subjects, which will include agreements governing how the data may be accessed and used by rival suppliers (see paragraph 13.139).
- 13.112 With regard to (f), under this remedy the Disengaged Domestic Customers will have a variety of ways to opt-out (eg by email, by calling a freephone number and by post) at any point in time (see paragraph 13.131).
- 13.113 With regard to (g), we do not agree that the Disengaged Domestic Customers who have exercised their rights to prevent direct marketing from their existing supplier or who have signed up to services to stop unaddressed or unsolicited marketing should be automatically excluded from the Database. We consider that such actions by these customers may preclude the existing supplier from processing their data for direct marketing purposes, but do not prevent that supplier from processing data pursuant to a legal obligation, and should not be treated as an indication that the customer does not wish to receive targeted offers from rival suppliers. Moreover, these customers will have the opportunity to opt-out of this remedy before their data is provided to Ofgem, or at any point thereafter (see paragraph 13.131).
- 13.114 With regard to (h), we are recommending that the Database be updated regularly. We consider that it should be for Ofgem to determine how frequently suppliers should provide Ofgem with updated information, but we consider that monthly would be appropriate unless there are practical reasons for doing otherwise (see paragraph 13.138).
- 13.115 With regard to (i), we agree that Ofgem should adopt a publically recognised standard for data security (see paragraph 13.133).

Design considerations

- 13.116 We have considered the following matters in the design of this remedy:
- (a) the French competition authority's successful application for an interim order requiring ENGIE (formerly GDF Suez) to disclose details of its customers on regulated gas tariffs to other suppliers;
 - (b) what approach should be taken to prompt engagement;

- (c) who should be targeted by the remedy;
 - (d) the role of Ofgem and suppliers in implementing this remedy, including in testing the Database;
 - (e) specific requirements regarding the Disengaged Domestic Customers on restricted meters; and
 - (f) how this remedy should be implemented.
- *The French competition authority's successful application for an interim order requiring ENGIE (formerly GDF Suez) to disclose details of its customers on regulated gas tariffs to other suppliers*

13.117 In September 2014, L'Autorité de la concurrence (the French competition authority), in the context of an investigation into the abuse of a dominant position by the incumbent gas supplier (ie ENGIE (formerly GDF Suez)), successfully applied for an interim order requiring ENGIE to share certain customer details with other gas suppliers. In particular, ENGIE was required to:

- (a) provide the name, address, home telephone number, annual consumption, type of regulated tariff and gas usage profile for each of its domestic customers on regulated gas tariffs to competing suppliers; and
- (b) provide the same information for each of its business customers on regulated gas tariffs, plus details of the person in charge of buying gas at the relevant business.

13.118 ENGIE was required to provide this customer data by January 2015 through an ENGIE-maintained database which could be accessed, for free, by its licensed competitors. ENGIE was required to update the database on a monthly basis to ensure it no longer included customers who had switched to unregulated market tariffs either with ENGIE or with other suppliers.

13.119 In the context of this interim order the French competition authority liaised with the French data protection agency to ensure that the process to disclose ENGIE's customer data would comply with French data protection legislation (which is subject to the same EU legislation as applies in the UK). The data protection agency advised of the need to provide an 'opt-out' system for customers who did not wish their data to be disclosed. The French competition authority therefore required ENGIE to send a letter to all the relevant customers advising them of the proposal to share their data with other suppliers and giving the customers an opportunity to object to this proposed disclosure and use of their data. The French competition authority

agreed the content of the letter from ENGIE before it was sent to the customers.

13.120 The French competition authority required ENGIE to set up the database and to sign up to a data processing agreement with each licensed gas supplier that wished to have access to the customer data (for free). These agreements mainly concerned the other suppliers' use of the data. ENGIE was solely in charge of the internet platform that provided the data to other suppliers.

13.121 The French competition authority advised us that a reasonably large proportion of domestic customers, [REDACTED]. As a consequence, [REDACTED] were included in the first iteration of the database.

- *What approach should be taken to prompt engagement*

13.122 We recognise that customers on default tariffs already receive bills, annual statements, and notices of contract variations, and suppliers are required to provide standardised reminders (including Cheapest Tariff Messaging) and standardised information on the customer's current tariff (including the tariff comparison rate).⁹⁰ As discussed above, we also recommend an Ofgem-led programme for identifying, testing and implementing measures for promoting engagement.

13.123 However, the evidence suggests that there remains a substantial proportion of customers who need further encouragement to engage. In particular, our survey found that 38% of customers on SVTs had never considered switching supplier. Of those customers on SVTs who have not switched supplier in the last three years, we found evidence giving insight into the nature of the barriers (actual or perceived) to such customers accessing and assessing the information they need to help them switch on their own initiative, including via PCWs. For instance, our survey shows that of those customers: 21% do not have access to the internet; and 51% either do not have access to the internet or are not confident that they would be able to get the right deal using PCW.

13.124 The information that suppliers are currently required to provide in bills and other communications is helpful to customers who take the initiative to search for better deals or switch supplier. However, this information is provided by customers' current suppliers who have no incentive to prompt their customers to engage and, more importantly, there is currently no

⁹⁰ [Ofgem response to supplementary Remedies Notice](#), Annex 2, p6.

requirement for suppliers to provide their customers with information on the availability of better deals in the market (although, as set out above, we are recommending that Ofgem prioritise exploring ways of providing customers with information on the availability of cheaper tariffs in its programme).

13.125 By contrast, we consider that the Database remedy will provide suppliers with a cost-effective way of reaching their rivals' most disengaged customers and help customers with the process of switching. Specifically, the Database remedy will allow suppliers to target the most disengaged customers in the market by sending them marketing correspondence with personalised quotes. The remedy does not, therefore, rely on customers taking the initiative to engage.

13.126 We therefore consider that the disclosure to rival retail energy suppliers of certain details of the Disengaged Domestic Customers that have not opted out will further contribute to prompting engagement. In particular, we consider that rival suppliers have an incentive to contact these customers to try to win their custom.

- *Who should be targeted by the remedy*

13.127 We have identified that around 70% of the domestic customers of the Six Large Energy Firms are on an SVT. Our analysis of more recent data shows that as at 30 June 2015⁹¹ approximately 72% of electricity customers and 69% of gas customers were on an SVT. Of these, up to 80% had been on an SVT for more than one year, up to 55% for more than three years and up to 40% for more than five years.⁹²

13.128 In total, and on the basis of current figures, we expect that up to 10 million domestic customers would fall within the target population for the remedy,⁹³ but we would expect this number to fall materially as engagement through the remedy is increased.

13.129 We have also found that all of the Six Large Energy Firms have, in recent years, consistently offered direct debit and credit customers fixed-term tariffs

⁹¹ Note that E.ON provided data as at 27 June 2015 and EDF Energy's data has been provided as at 2 July 2015.

⁹² We note that these are upper bound estimates as for three suppliers the data provided was based on the length of the relationship with the supplier rather than the length of time on that supplier's SVT. For electricity the exact figures are 82%, 55% and 40% and for gas 78%, 54% and 39%, respectively.

⁹³ We note that this is an upper bound estimates as for three suppliers the data provided on the percentage of customers who have been on that supplier's SVT for more than three years was based on the length of the relationship with the supplier rather than the length of time on that supplier's SVT. See Section 11.

at substantial discounts to their SVTs.⁹⁴ While this has not been the case for prepayment customers, the prices of SVTs have differed between suppliers meaning that there were, for some, savings to be had from switching suppliers.⁹⁵

13.130 While customers may roll on to default tariffs and choose not to move tariff immediately, we consider that if customers are still on default tariffs with the same supplier after three years they are, for the reasons given above, unlikely to have actively chosen to be on such tariffs, especially where such tariffs are at a substantial premium to fixed-term tariffs. We therefore consider the remedy should apply to all customers who have been on an SVT (or any other default tariff) with the same supplier for a total of three or more years.

- *What should be the roles of Ofgem and suppliers in implementing and testing the Database*

13.131 Under this remedy, suppliers will be required (pursuant to a CMA order) to send a letter to their Disengaged Domestic Customers (the 'Opt-out Letter'). The Opt-out Letter will:

- (a) inform the Disengaged Domestic Customers of the CMA's order requiring suppliers to disclose certain of their details, ie each customer's full name, billing address, consumption address, current supplier, meter type (eg unrestricted, Economy 7 etc), name of their current tariff, annual energy consumption, and MPAN/MPRN to Ofgem;
- (b) inform them of how such data will be used by Ofgem and rival suppliers;
- (c) allow them the possibility to opt out of having such data passed to Ofgem, and inform them of their right to opt out of Ofgem and rival suppliers using their information in this way at any point and the manner for doing so;⁹⁶ and
- (d) be subject to the CMA's and Ofgem's approval before it is sent to the Disengaged Domestic Customers, to ensure that it clearly explains the

⁹⁴ We found that across for the Six Large Energy Firms and the periods Q1 2012 to Q2 2015: dual fuel direct debit SVT customers could have saved, on average, 6% on their annual bills by switching with the same supplier to cheaper direct debit tariffs; and standard credit customers could have saved, on average, 4% on their annual bills by switching to cheaper standard credit tariffs

⁹⁵ We found that across for the Six Large Energy Firms and the periods Q1 2012 to Q2 2015: dual fuel prepayment SVT customers could have saved, on average, 1% on their annual bills by switching internally and 11% by switching supplier.

⁹⁶ Under this remedy, the Disengaged Domestic Customers will have a variety of ways to opt-out (eg by email, by calling a freephone number and by post).

proposed disclosure and use of the customer's data, the reasons for this, and the mechanisms for opting out.

- 13.132 Suppliers will also be required (pursuant to a CMA order) to disclose the data (ie each customer's full name, billing address, consumption address, current supplier, meter type (eg unrestricted, Economy 7 etc), name of their current tariff, annual energy consumption, and MPAN/MPRN) concerning the Disengaged Domestic Customers who have not opted-out (the 'Domestic Customer Data') to Ofgem (in the format prescribed by Ofgem).
- 13.133 We recommend that Ofgem develop, operate and maintain a secure cloud database⁹⁷ to hold the Domestic Customer Data (in an accessible format). Ofgem will be the data controller: it could use external IT/database experts to develop this Database but, once created, Ofgem will operate, control and maintain it.⁹⁸ We are recommending that Ofgem adopt a publically recognised standard for data security in the arrangements for gathering, assembling, and storing the Domestic Customer Data and in providing access to it.
- 13.134 We consider that Ofgem, as the industry regulator, is best placed to collect and disclose the Domestic Customer Data to rival suppliers because it can represent the interests of the Disengaged Domestic Customers fairly. In this regard, the incentives of energy suppliers to control and share the Domestic Customer Data with each other may not align with the interests of the Disengaged Domestic Customers.
- 13.135 Ofgem said that a phased implementation of the Database would be desirable as this would allow it to:
- (a) test the operation of the Database and supporting processes: in particular, to test the process for gathering and updating the data, and the functionality of the IT systems supporting the holding of the data and access to it;
 - (b) test the effectiveness of communications: this would include the content, format and presentation of marketing correspondence and other means that Ofgem might use to promote the Database (such as materials on their website, materials provided to partners such as Citizens Advice); and

⁹⁷ A database accessible from the cloud (a space on transmission lines) and delivered to authorised users via the internet from a cloud database provider's servers.

⁹⁸ Ofgem is not precluded from contracting with a suitably qualified third party data processor to operate and maintain the Database securely.

(c) to test suggestions made in response to the provisional decision on remedies on the design of the remedy.

13.136 Others were also supportive of this approach (see paragraph 13.98).

13.137 We also agree with Ofgem. For the avoidance of doubt, prior to the roll-out of the Database, we recommend that Ofgem test the operation of the Database to identify and address any potential operational problems and ensure data security. After the roll-out of the Database, we are recommending that Ofgem test aspects of the marketing correspondence (eg content and frequency) being sent by rival suppliers for example, in the context of the Ofgem-led programme. We are also recommending that Ofgem monitor the impact of the Database with a view to maximising its effectiveness as regards improving engagement.

13.138 Under this remedy, suppliers will also be required (through a CMA order) to provide Ofgem with updated information on any (new or existing) Disengaged Domestic Customers (who have not opted out), on a regular basis, to enable Ofgem to remove the details of domestic customers who have moved off SVTs (or any other default tariff), and to include the details of customers who have become eligible to be on the Database because they have been on an SVT (or any other default tariff) with the same supplier for a total of three or more years. We suggest that the Database be updated on a monthly basis unless there are good operational reasons for doing otherwise (as this would limit the risk of customers who have engaged from being contacted again). Before the details of any eligible customers were added to the Database, they would first be notified of the disclosure process through the Opt-out Letter, as at the outset of the creation of the Database.

13.139 We also recommend that Ofgem put in place safeguards to mitigate any prejudice to the rights and interests of the data subjects. Such safeguards include:

- (a) measures to ensure that the Domestic Customer Data will be processed only within the EU or transferred out of the EU only in accordance with the requirements of the GDPR;
- (b) building and maintaining a database (working with third parties where appropriate) offering appropriate guarantees of security and protection against a breach including by adopting publically recognised standards for data security;

- (c) entering into binding agreements with suppliers seeking access to the Domestic Customer Data⁹⁹ concerning how the Domestic Customer Data may be accessed and used, which may include limits to the following:
 - (i) the number of postal communications that a supplier may send to any individual customer;
 - (ii) the frequency with which any communication can be sent to any individual customer;
 - (iii) the amount of time a supplier may retain the Domestic Customer Data accessed through the Database before it must be deleted/destroyed; and/or
 - (iv) the use to which the Domestic Customer Data can be put, and whether such use should be restricted to particular forms of direct marketing;
- (d) putting in place enforcement mechanisms to ensure that suppliers comply with the rules relating to access to the Database and use of the Domestic Customer Data; and
- (e) monitoring and reviewing on an ongoing basis the impact of the Database remedy.

13.140 Rival suppliers will be allowed to prompt the Disengaged Domestic Customers who have not opted-out by sending them marketing correspondence by letter. Electronic communications (eg email or SMS text message) from suppliers will be subject to the PECR and consumer protection legislation.¹⁰⁰ Rival suppliers could seek explicit (opt-in)/direct consent from customers to be able to send prompts via electronic means. For clarity, we do not intend that suppliers should use the database to contact customers in person, and we would expect Ofgem to monitor and prevent this, for example by excluding access to the database if necessary. This remedy also allows Ofgem to contact those customers and inform them about their rights to switch, the ways in which switching can be done, and about opportunities in the market to make savings from switching.

⁹⁹ We consider that drafting these agreements should be a matter for Ofgem in consultation with interested parties having regard to the aims of the remedy.

¹⁰⁰ Including the Consumer Rights Act 2015.

13.141 All communications and/or information from suppliers will have to be compliant with relevant standard licence conditions including SLC 25¹⁰¹ which governs sales and marketing practices, and SLC 25C (the Standards of Conduct introduced by the 'Fairer Treatment' component of the RMR rules¹⁰² including our new Standard of Conduct described above in paragraph 13.226).¹⁰³ In addition, as set out above, we would expect that after the roll-out of the Database, Ofgem tests aspects of the marketing letters sent by rival suppliers to the Disengaged Domestic Customers who have not opted-out as part of our remedy providing for an Ofgem-led programme to identify, test and implement measures to improve customer information.

- *Specific requirements concerning Disengaged Domestic Customers on restricted meters*

13.142 As explained in Sections 8 and 9, our further analysis has shown that there are additional aspects of the domestic retail energy markets concerning customers on restricted meters that reduce their awareness of their ability to switch energy supplier and increase the actual and/or perceived barriers to accessing and assessing information to help them switch.

13.143 To enhance the effectiveness of this remedy in achieving its aim in relation to the Disengaged Domestic Customers on restricted meters, we have considered whether the remedy should require suppliers to provide further details for customers on restricted meters than those provided for customers on unrestricted meters (ie each customer's full name, billing address, consumption address, their current supplier, meter type (eg unrestricted, Economy 7), name of their current tariff; and annual energy consumption and MPAN/MPRN).

¹⁰¹ Under SLC 25, the stated Objective is that: (a) all information which the supplier provides to domestic customers in the course of the marketing activities must be complete and accurate, is capable of being easily understood by domestic customers, does not relate to products which are inappropriate to the domestic customer to whom it is directed, does not mislead the domestic customer to whom it is directed and is otherwise fair both in terms of its content and in terms of how it is presented (with more important information being given appropriate prominence); and (b) the suppliers' market activities must be conducted in a fair, transparent, appropriate and professional manner. All suppliers are required to take all reasonable steps: (a) to secure the achievement of the Objective; and (b) to avoid doing anything which jeopardises its ability to achieve the Objective.

¹⁰² SLC 25C requires suppliers to carry out any actions in a Fair, honest, transparent, appropriate and professional manner. One of the specific requirements set out in SLC 25C is that the licensee provide information (whether in writing or orally) to each domestic customer which: (i) is complete, accurate and not misleading (in terms of the information provided or omitted); (ii) is communicated in plain and intelligible language; (iii) relates to products or services which are appropriate to the domestic customer to whom it is directed; and (iv) is otherwise fair both in terms of its content and in terms of how it is presented (with more important information being given appropriate prominence).

¹⁰³ Following a finding of breach, the Gas and Electricity Markets Authority has the power to impose financial penalties and/or make consumer redress orders.

13.144 Our view is that for domestic customers on restricted meters who have been on an SVT or other default tariff with the same supplier for a total of three or more years, who have not opted out of the Database remedy, suppliers should also be required to provide the following information to Ofgem:

- (a) Consumption by specified periods of time. The granularity of this information and the definition of these time periods would be a matter for Ofgem to determine in further discussion with the suppliers. However, for the purposes of our initial order, and for the analysis we have conducted, we have identified five broad periods (peak general consumption, off-peak, off-peak heating (1), off-peak heating (2), and peak heating).
- (b) Details of the standing charges and volume rates, by region and payment method, for each of the tariffs named in the Database, over the relevant period.

13.145 We consider that a requirement on suppliers to provide this additional information is essential to achieving the aims of the remedy. This is because rival suppliers would need this information in order to understand what customers on restricted meters of their rivals have been paying, which would be a necessary input to understanding the commercial opportunities, providing potential customers with personalised offers, and appropriately targeting their marketing efforts.

- *How we should implement this remedy*

13.146 We are implementing this remedy through:

- (a) a CMA order (and amendments to suppliers' standard licence conditions) requiring suppliers to:
 - (i) send Opt-out Letters to their Disengaged Domestic Customers;
 - (ii) disclose the Domestic Customer Data to Ofgem (in the format prescribed by Ofgem); and
 - (iii) provide Ofgem with updated Domestic Customer Data on a regular basis, as specified by Ofgem; and
- (b) a recommendation to Ofgem to:
 - (i) create, operate and maintain a secure cloud database for the purposes of holding the Domestic Customer Data and to adopt a publically recognised standard for data security in the arrangements

for gathering, assembling, and storing the Domestic Customer Data and in providing access to it;

- (ii) hold the Domestic Customer Data;
- (iii) test the operation of the Database (prior to its roll-out);
- (iv) put in place safeguards to mitigate any prejudice to the rights and interests of the data subjects (see paragraph 13.139);
- (v) provide access to the Domestic Customer Data to any rival supplier subject to such safeguards;
- (vi) test aspects of the marketing letters to prompt the Disengaged Domestic Customers who have not opted-out (after the roll-out of the Database); and
- (vii) monitor the impact of the Database with a view to maximising its effectiveness.

Assessment of effectiveness

13.147 As we explain below, our view is that the remedy (including the additional requirements concerning the Disengaged Domestic Customers on restricted meters) is effective in achieving its aims of enabling rival energy suppliers to identify and market to the Disengaged Domestic Customers who have not opted out and prompt them to engage in the domestic retail energy markets. Accordingly, the remedy is effective in partly addressing two of the features giving rise to the Domestic Weak Customer Response AEC, ie that domestic customers have limited awareness of, and interest in, their ability to switch supplier and that domestic customers face actual and perceived barriers to assessing and accessing information.

13.148 In assessing the effectiveness of the remedy we have considered the following:

- (a) the effectiveness of the key design elements of the remedy;
- (b) the extent to which the remedy is capable of effective implementation, monitoring and enforcement;
- (c) the timescale over which the remedy is likely to have an effect; and
- (d) compliance with existing or expected laws and regulations.

- *Effectiveness of the key design elements*

13.149 We consider that the following key design elements of the remedy (including the specific elements concerning the Disengaged Domestic Customers on restricted meters), in combination, assist the remedy in being effective to achieve its aim. In particular:

- (a) Rival suppliers will be able to easily identify the Disengaged Domestic Customers. The Database will provide all the necessary information about the Disengaged Domestic Customers that have not opted-out in one place that is straightforward to access.
- (b) Ofgem's role in testing, operating, controlling and maintaining the Database, and providing access to it, will ensure that it will be set up and administered fairly in customers' interests. Further, its role in monitoring and evaluating the impact of the database will help ensure that is effective in improving engagement ¹⁰⁴
- (c) The Database will be readily accessible to rival suppliers upon request (subject to appropriate safeguards) and will include Domestic Customer Data that is accurate and up to date. The remedy provides for the Domestic Customer Data to be updated on a regular basis.
- (d) Rival suppliers that have an incentive to compete for the Disengaged Domestic Customers that have not opted-out, and will be able to provide them with personalised information as they will know their current supplier, tariff and annual consumption. The Database will also contain information suppliers will need in the switching process. The Database will provide this information in an easily accessible format for each Disengaged Domestic Customer that has not opted out.
- (e) Survey results suggest that if the Disengaged Domestic Customers can be prompted to engage then the experience of doing so should help to build their confidence in switching and that they are less likely to revert to high-priced default tariffs at the end of any fixed-term tariff to which they may switch.
- (f) Protection against suppliers providing customers with misleading or inaccurate information (which could have the effect of deterring future engagement if customers switch supply and do not see the benefits they were expecting) is provided by Ofgem's role in controlling access to the Database, and the opportunity for Ofgem to use the Database to contact

¹⁰⁴ Ofgem's principal objective is to protect the interests of existing and future gas and electricity consumers.

disengaged customers directly. In addition, all suppliers must comply with Ofgem's standard licence conditions governing sales and marketing activities and containing the Standards of Conduct (as discussed above). We note that Ofgem's ability to deny access to the Database will provide immediate sanction for any mis-selling or failure to comply with these standard licence conditions.

- 13.150 Centrica¹⁰⁵ and E.ON¹⁰⁶ said that the remedy could be damaging to customer engagement and SSE¹⁰⁷ said that there was no evidence that the remedy would increase customer engagement.
- 13.151 We consider that the design elements of the Database remedy (as set out in paragraph 13.149), in combination, will assist the remedy in being effective to prompt customer engagement. In particular, we believe that rival suppliers will have the incentive to encourage the customers of other suppliers to switch and we would expect Ofgem to put in place measures to protect against any misuse of the Domestic Customer Data. In addition (and as explained above), we consider that the Database remedy will work with other remedies to promote consumer engagement. For instance, our recommendation that Ofgem test the marketing correspondence will help identify the forms of communication that work best in increasing customer engagement.
- 13.152 Although a number of Disengaged Domestic Customers may choose to 'opt out' of the disclosure, we consider based on the opt-out rate for the similar measure implemented in France, that many customers would not and suppliers would therefore be able to contact a large proportion of Disengaged Domestic Customers to prompt them to engage. For instance, the opt-out rate in France was [X]%. We also note that some of those customers that choose to opt out may do so because they are content with their existing supply arrangements, thus making the remedy more effective at targeting suppliers' customers who are more disengaged.
- 13.153 Several suppliers¹⁰⁸ said that participation should be on an opt-in basis. We do not agree. The aim of the remedy is to prompt the most disengaged customers to participate in the market. We think it is unrealistic to expect that such customers would on receipt of the initial letter be motivated to opt-in to the Database. We also think that participation on an opt-in basis is not

¹⁰⁵ Centrica response to provisional decision on remedies, pp70–73, paragraphs 354–375.

¹⁰⁶ E.ON response to provisional decision on remedies, p41, paragraph 202.

¹⁰⁷ SSE response to provisional decision on remedies, p10, paragraph 2.5.1.

¹⁰⁸ Centrica, EDF Energy and RWE. Scottish Power and Co-operative Energy also commented on the use of 'opt-in' consent in relation to data protection matters.

necessary for the remedy to comply with data protection legislation (see paragraphs 13.161 to 13.171 below).

13.154 We consider that a requirement on suppliers to provide limited additional information for the Disengaged Domestic Customers on restricted meters is essential to achieving the aims of the remedy. This is because rival suppliers will need this information in order to understand the consumption patterns of the restricted meter customers of their rivals which will be a necessary input to understanding the commercial opportunity, provide these customers with personalised offers and target their marketing efforts effectively.

- *Implementation, monitoring compliance and enforcement*

13.155 In determining whether the remedy is effective, we have had regard to the operation and implementation of the remedy.

13.156 As regards the implementation of the remedy, our order on suppliers will place specific requirements on suppliers (see paragraphs 13.131 to 13.141 above). Our recommendation to Ofgem provides an indicative list of the types of issues Ofgem must address in the implementation of this remedy.

13.157 As regards monitoring compliance with the remedy, we note that the CMA will be responsible for monitoring compliance as part of this remedy will be implemented through an order. By introducing a new licence condition that will be consistent with the CMA's order, Ofgem will also be under a duty to perform a monitoring role and can require the provision of information from suppliers concerning potential breaches of a licence condition. In addition, as sector regulator, Ofgem will be well placed to receive any allegations of misuse of the Domestic Customer Data by a rival supplier and will be able to take action under the agreements put in place concerning access to and use of the Domestic Customer Data, or under a supplier's licence.

- *Timescales for the remedy*

13.158 As regards the timescales for implementation, following publication of this report the CMA will start drafting and consulting on an order requiring suppliers to send the Opt-out Letter to their Disengaged Domestic Customers. During this period, we would also expect Ofgem to begin developing the Database and associated agreements, and following publication of the CMA's final order, we will require suppliers to send the Opt-out Letter to all Disengaged Domestic Customers by mid-2017.

13.159 Ofgem has indicated that it would aim to implement this remedy, at least its development phase, as soon as possible following publication of our final

report. We will require suppliers to pass the Domestic Customer Data to Ofgem by October 2017 at the latest, subject to appropriate mechanisms and safeguards for data protection rights being in place. We would therefore expect rival suppliers to start accessing the Database, and contacting the Disengaged Domestic Customers who have not opted-out from the beginning of 2018. The Database will then be updated on a monthly basis from the beginning of 2018 onwards.

13.160 In evaluating the effectiveness of the remedy, we have also considered the timescale over which the Domestic Weak Customer Response AEC will be expected to endure, and the timescale over which the remedy will be likely to take effect. We consider that the detriment will persist, absent the remedy, and that the impact of future market developments, including the roll-out of smart meters, is somewhat uncertain. Therefore, we have decided that the remedy will not be subject to a sunset clause. We would, though, expect Ofgem to keep the operation and impact of the Database under review and report on its impact after five years.

- *Compliance with existing or expected laws and regulations*

13.161 To the extent that this remedy involves the processing of personal data, it has been designed so as to take into account discussions between the CMA and the Information Commissioner's Office, and to be compliant with the following relevant UK and EU data protection legislation: (i) the DPA; (ii) the EU Directive 95/46/EC¹⁰⁹ (the 'Data Protection Directive'); (iii) the PECR; and (iv) the new EU GDPR¹¹⁰ (collectively, the 'Data Protection Regime').

13.162 We have carefully assessed the compliance of this remedy with the Data Protection Regime and have summarised below the key design components concerning how the remedy will be implemented, which we believe will ensure that the remedy will provide adequate protection for customers' privacy rights and, therefore, will comply with the Data Protection Regime.

13.163 The first stage of the remedy will involve energy suppliers being required (by virtue of our order) to send the Opt-out Letter to the Disengaged Domestic Customers, to share with Ofgem the Domestic Customer Data, and to provide Ofgem with updated Domestic Customer Data on a regular basis (as

¹⁰⁹ Directive 95/46/EC of the European Parliament and of the Council of 24 October 1995 on the protection of individuals with regard to the processing of personal data and on the free movement of such data, OJ L 281, 23/11/1995.

¹¹⁰ Regulation (EU) 2016/679 of 27 April 2016 on the protection of natural persons with regard to the processing of personal data and on the free movement of such data, and repealing Directive 95/46/EC (General Data Protection Regulation).

specified by Ofgem). Since our order will place suppliers under a legal obligation to send the Opt-out Letter and provide Ofgem with the relevant Domestic Customer Data, we consider that the processing will be consistent with the first data protection principle under the DPA, and in particular will be necessary for compliance with a legal obligation imposed on that supplier, in accordance with Condition 3 in Schedule 2 to the DPA.¹¹¹

13.164 The second stage of the remedy will involve Ofgem building, operating, maintaining and testing the Database and disclosing the Domestic Customer Data to rival suppliers, subject to appropriate use restrictions. Since Ofgem will be carrying out these functions in order to implement a remedy addressing the Domestic Weak Customer Response AEC, and in pursuit of its own public functions, we consider that such processing by Ofgem will fall within Condition 5 in Schedule 2 to the DPA.¹¹²

13.165 The third stage of the remedy will involve the use of the Domestic Customer Data by rival suppliers in accordance with the terms of the use restrictions, other regulatory requirements, and any other terms and conditions in the agreements with Ofgem concerning access to the Domestic Customer Data. We consider that there is a legitimate public interest in the CMA seeking to address the Domestic Weak Customer Response AEC and, therefore, that with appropriate safeguards in place concerning the use by rival suppliers of customers' data, the processing by rival suppliers of the Domestic Customer Data, strictly for the purposes of giving effect to this remedy, will be consistent with Condition 6 in Schedule 2 to the DPA.¹¹³ Such safeguards will include:

- (a) the ability for each Disengaged Domestic Customer to opt-out of having their data processed in the manner contemplated on an ongoing basis, thereby allowing data subjects to remove their data from the Database at any stage and prevent further processing or marketing by rival suppliers who have accessed their data;

¹¹¹ Condition 3 in Schedule 2 to the DPA permits processing that is necessary for compliance with any legal obligation to which the data controller is subject, other than an obligation imposed by contract. The GDPR contains an equivalent provision to Condition 3 of the DPA: see Article 6(1)(c).

¹¹² Condition 5 in Schedule 2 to the DPA permits, in particular, processing that is necessary for the exercise of any functions conferred on any person by or under any enactment, for the exercise of any functions of a government department, and/or for the exercise of any other functions of a public nature exercised in the public interest by any person. The GDPR contains an equivalent provision to Condition 5 of the DPA: see Article 6(1)(e).

¹¹³ Condition 6 in Schedule 2 to the DPA permits processing that is necessary for the purposes of legitimate interests pursued by the data controller or by the third party or parties to whom the data are disclosed, except where the processing is unwarranted in any particular case by reason of prejudice to the rights and freedoms or legitimate interests of the data subject. The GDPR contains an equivalent provision to Condition 6 of the DPA (Article 6(1)(f)), save that public authorities are not generally able to rely on that provision for the purpose of processing personal data.

- (b) restrictions/safeguards to ensure that the Domestic Customer Data is held and processed securely by Ofgem, is kept up to date, and is not retained or otherwise processed by Ofgem or rival suppliers for longer than is necessary; and
 - (c) proper controls and oversight by Ofgem to prevent misuse of the Domestic Customer Data by rival suppliers.
- 13.166 So far as other data protection principles are concerned, we consider that the provision of the Opt-out Letter, and the information it will contain, together with the other safeguards Ofgem will put in place, will ensure compliance with the data protection principles, including the requirement of transparency in Article 5 of the GDPR.
- 13.167 We consider that some degree of consultation between Ofgem and consumers, and trialling of the Database, may be necessary in order to determine the precise safeguards and limits that need to be put in place concerning how rival suppliers should be allowed to use the Domestic Customer Data. For this reason, we consider that the remedy will be more effective by recommending that certain safeguards be put in place by Ofgem, which include those listed in paragraph 13.139), but ultimately leaving it to Ofgem to determine the precise design.
- 13.168 We also note that certain further safeguards concerning customers' legitimate interests will be built into the operation of the remedy, including that: (a) it does not involve the disclosure of sensitive personal data (although we acknowledge that the data provided would be quite detailed, especially for customers on restricted meters); (b) it involves sharing only a limited amount of personal data; and (c) only involves sharing with licensed rival suppliers, who must comply with use restrictions and other legal obligations when making use of the data or face their access to the data potentially being withdrawn and/or potential enforcement action for breach of licence and/or contract.
- 13.169 We consider that further protection concerning customers' legitimate interests is provided for by: (a) the requirement for all licensed suppliers to comply with Ofgem's standard licence condition concerning suppliers' sales and marketing activities; and (b) the opportunity for Ofgem to use the Database to contact directly disengaged customers. We also note our recommendation that Ofgem explore requiring suppliers to provide their customers with information on the availability of cheaper tariffs in the market.
- 13.170 For the avoidance of doubt, we do not consider that any processing required by the remedy will be dependent on express consumer consent obtained in

accordance with Condition 1 in Schedule 2 to the DPA or article 6(1)(a) of the GDPR.

13.171 In addition, this remedy will not entitle suppliers or Ofgem to send any electronic communications to data subjects. Therefore, we do not think that it is necessary to assess the compatibility of the remedy with the PECR. If suppliers obtain consent from any Disengaged Domestic Customer who has not opted-out to send them electronic communications, those suppliers will have to comply with the PECR (see paragraph 13.140).

Assessment of proportionality

13.172 In this section we set out our assessment of whether the remedy is proportionate.

- *Effective in achieving its aim*

13.173 For the reasons set out in paragraphs 13.147 to 13.171 above, we consider that the remedy is effective in achieving its aim of enabling rival retail energy suppliers to identify the Disengaged Domestic Customers that have not opted out. Accordingly, it is effective in partly addressing two of the features giving rise to the Domestic Weak Customer Response AEC (and the resulting detriment), ie that domestic customers have limited awareness of, and interest in, their ability to switch energy supplier and that domestic customers face actual and perceived barriers to accessing and assessing information.

- *No more onerous than needed to achieve its aim*

13.174 We also consider that this remedy (including the additional requirements concerning the Disengaged Domestic Customers on restricted meters) is no more onerous than needed to achieve its aim. In particular, we have considered very carefully the limitations on the data suppliers will be required to disclose, the customers for whom suppliers will be required to disclose data, the frequency with which suppliers will be required to update the Database, and the procedures providing for the disclosure and access to the Database, and consider that we have designed the remedy so that it is no more onerous than needed to achieve its aim

13.175 With regard to the data that suppliers will be required to disclose, it is our view (informed by the evidence provided by PCWs (see paragraph 13.319), that the Domestic Customer Data will be sufficient for rival suppliers to be able to identify and contact the Disengaged Domestic Customers (who have

not opted out) and to provide potential customers with personalised information on the savings they could make by switching.

13.176 With regard to the customers for whom suppliers will be required to disclose information, we consider that an approach targeted specifically at the Disengaged Domestic Customers is more proportionate than a similar remedy affecting customers who have been on an SVT (or other default tariff) for a shorter duration.

13.177 Finally, with regard to the frequency with which suppliers will be required to update the Database, this remedy gives Ofgem flexibility to decide on this issue, drawing on the evidence obtained from the testing and trialling of the Database. We suggest that the Database be updated on a monthly basis unless there are good operational reasons for doing otherwise (as this will limit the risk of customers who have engaged being contacted again). We expect that the process of extracting, formatting and disclosing the Domestic Customer Data will be moderately costly for suppliers. We also consider that frequent updating will reduce the risk of rival suppliers contacting customers who had recently switched away from an SVT, based on out-of-date information, which may cause annoyance and confusion.

- *Least onerous if there were a choice between several effective remedies*

13.178 We have also considered whether there may be alternative designs of this remedy to achieve the same aim that are less onerous. For the reasons noted above, we consider that the remedy, as designed, appropriately balances the need for the remedy to be effective, and proportionate, in terms of the proportion of a supplier's existing customer base to which the remedy will apply (ie customers on an SVT or other default tariff for three or more years).

13.179 We have also considered below the possible remedies suggested by Centrica and Scottish Power, which would involve a prohibition on evergreen default tariffs. For the reasons discussed below, we consider that these suggested remedies are not effective and/or are disproportionate in terms of the potential unintended consequences. We have also considered the current existence of multiple reminders sent by suppliers to their own customers to help them engage and whether it may be effective (and more proportionate) to suggest changes to such existing reminders. However, given the limited available evidence on the effectiveness of the 'clearer information' component of the RMR rules, we consider that such measures are best assessed through our remedy concerning the Ofgem-led programme. This remedy is in our view the least onerous effective means of introducing a customer prompt by rival suppliers.

- *Does not produce disadvantages that are disproportionate to the aim*

13.180 We have concluded that the remedy (including the additional requirements concerning the Disengaged Domestic Customers on restricted meters) does not produce adverse effects that are disproportionate to its aim. We have compared the potential costs of implementing the remedy relative to the potential gains. In particular:

- (a) the costs of implementing the remedy are small relative to the potential gains (see paragraph 13.182);
- (b) the remedy specifically allows the Disengaged Domestic Customers to opt out when first contacted by their supplier and at any point thereafter; and
- (c) we consider that general consumer and data protection legislation, the PECR, domestic retail suppliers' licence conditions (in particular SLC 25 and SLC 25C), the Use Restrictions and other terms and conditions for accessing the Domestic Customer Data will protect the Disengaged Domestic Customers that have not opted out from mistreatment by rival suppliers of their personal data.

13.181 In contrast, the potential gains available to the Disengaged Domestic Customers that have not opted out from promoting engagement are potentially substantial (see estimates in Section 3 of the domestic retail detriment).

13.182 With regard to the costs of implementing the remedy, we do not think the Database will be an expensive web-based application to build and maintain because it will not require significant, or complex, functionality. The Database will simply need to provide the Domestic Customer Data in an accessible, secure format to a relatively small number of permitted users. For instance, we consider that a cloud database will provide a more straightforward and secure means of sharing the data than through Excel spreadsheets.

13.183 Ofgem has provided some initial cost estimates for the Database, although it has stressed there remain a number of unknown factors at this stage that could affect the costs. Currently, Ofgem estimates the costs as follows: IT development costs (for designing, building and testing the Database) in the region of £200,000 to £300,000; ongoing IT costs to keep the Database operational in the region of £35,000 to £50,000 per year (assuming a simple, cloud hosted database); and additional 'non-business as usual' costs incurred during the development phase such as in relation to engaging suppliers and other stakeholders, and developing supporting business

processes, guidance, pilot design, and the Opt-out Letter. Ofgem has yet to scope the 'non-IT business as usual' costs. Over the next few months, Ofgem will develop its plans for the Database including examining the full range of IT options for developing the Database.¹¹⁴

13.184 There will be certain costs to the suppliers associated with putting in place agreements with Ofgem, and developing and sending letters (including the Opt-out Letter) to customers. We note that communicating with customers is a routine activity for any retail domestic energy supplier. However, we are conscious that, in order for the remedy to be as effective as possible, and to minimise a potential unintended consequence of unsettling, confusing and/or otherwise increasing mistrust in the retail energy markets, the CMA will work closely with Ofgem and suppliers to ensure that the Opt-out Letter is suitably worded so as to mitigate such risks by explaining only to recipient customers the context for, and implication of, the Opt-out Letter.

13.185 We also consider that given our estimates of the detriment arising from Domestic Weak Customers Response and the Prepayment AECs (see Section 10), only a small proportion of the number of Disengaged Domestic Customers likely to be put on the Database (even if we assume that around [X]% of Disengaged Domestic Customers opt out)¹¹⁵ would need to switch from SVT to the best alternative tariff to make the remedy cost effective.

13.186 Finally, we have recognised the concerns raised by several parties that the Database may have adverse consequences on customer engagement, through excessive or misleading marketing information. We consider that the design of the remedy provides protection against such an outcome. In particular (and as discussed above):

(a) We consider that our recommendation to Ofgem to test the use of the Domestic Customer Data, including the form and frequency of communications from rival suppliers, will help ensure it delivers a substantial positive impact on engagement.

(b) We consider that the requirement on all licensed energy suppliers to comply with the standard licence conditions governing marketing and sales activities and the Standards of Conduct (including our new Standard of Conduct regarding the comparability of tariffs) will be a control on misleading marketing communications. As part of its programme of moving to more principles-based regulation (which will

¹¹⁴ Ofgem email of 6 May 2016.

¹¹⁵ This is based on the proportion of customers who opted out of the ENGIE scheme in France.

place an onus on suppliers to ensure compliance), Ofgem is giving priority to reviewing those governing sales and marketing activities.

(c) Ofgem's control over access to the Database will provide immediate sanctions for any concerns Ofgem may have about the conduct of suppliers in the use of information contained in the Database.

13.187 We therefore consider that the safeguards that we recommend Ofgem put in place in their agreements with suppliers will avoid inappropriate use of the Domestic Customer Data.

- *Ofgem's statutory duties*

13.188 Where the CMA is considering whether to modify one or more of the conditions of a retail gas or electricity supplier's licence, in deciding whether such action will be reasonable and practicable, the CMA must 'have regard' to the relevant statutory functions of Ofgem.

13.189 Ofgem's statutory duties and functions, set out in the EA89 and the GA86, as amended by the EA10, have set competition as a secondary objective, with the principal objective being the interests of existing and future consumers taken as a whole, including decarbonisation, security of supply and the fulfilment by Ofgem of the objectives set out in Article 40(a) to (h) of the Gas Directive and Article 36(a) to (h) of the Electricity Directive.

13.190 Ofgem is generally required to carry out its functions in the manner it considers best calculated to further the principal objective. Before deciding to carry out its functions in a particular manner with a view to promoting competition, Ofgem must consider the extent to which the interests of consumers would be protected by that manner of carrying out those functions and whether there is any other manner (whether or not it would promote competition) in which the authority could carry out those functions which would better protect those interests, having regard (among other things) to (i) the need to secure that, so far as economical to meet them, all reasonable demands for gas and electricity supply are met and can be financed; (ii) achieving sustainable development; and (iii) the interests of 'vulnerable' consumers.

13.191 In reaching our decision to introduce a new licence condition concerning gas and electricity supply that requires suppliers to (a) send Opt-out Letters to their Disengaged Domestic Customers; (b) disclose the Domestic Customer Data to Ofgem; and (c) provide Ofgem with updated Domestic Customer Data on a regular basis; we have, as part of our own application of the legal framework requiring us to decide upon remedies that are effective and

proportionate,¹¹⁶ explicitly taken into account many of the factors to which Ofgem must have regard when carrying out its functions.

13.192 In particular, we do not consider that any aspect of our remedy will have an adverse impact on suppliers' ability to meet all reasonable demands for gas and electricity supply, achieving sustainable development, security of supply or environmental concerns. We consider that our remedy will directly engage Ofgem's principal objective of protecting the interests of existing and future consumers, including vulnerable consumers.

13.193 As set out above, the aim of the remedy will be to enable rival retail energy suppliers to identify the Disengaged Domestic Customers that have not opted out and prompt such customers to engage in the markets. Since suppliers will be able to contact other suppliers' Disengaged Domestic Customers and market directly to them (by post), they will be able to design targeted marketing campaigns to encourage such customers to consider switching. With strict safeguards in place to mitigate any prejudice to the rights and interests of the data subjects, which will include agreements governing how the data may be accessed and used by rival suppliers, the Database remedy overall will further facilitate customers' access to information that enables them to conduct a value-for-money assessment.

13.194 In light of the above, we consider that the remedy is consistent with Ofgem's principal objective of promoting the interests of existing and future customers.

Any relevant customer benefits that may be lost

13.195 We do not consider that any relevant customer benefits will be lost as a result of the disclosure of details of the Disengaged Domestic Customers that have not opted out to Ofgem and rival suppliers subject to the Use Restrictions. As noted above, the remedy has several detailed design mechanisms to mitigate the risk of customers receiving unwanted or misleading correspondence that may cause them to disengage further. Instead the remedy will provide for customers who have been on an SVT or other default tariff for a substantial period of time – and who are likely to be paying substantially more for gas and electricity than engaged consumers – to engage in the markets. This greater level of customer engagement will, in turn, help to foster competition and generate lower prices and more choice of tariffs.

¹¹⁶ CC3, paragraph 329.

Remedy we are not adopting – Centrica and Scottish Power proposals to prohibit evergreen default tariffs

- 13.196 In response to our provisional findings and Remedies Notice, we received two separate, but similar, proposals from Centrica and Scottish Power which would prohibit the use of evergreen tariffs. We have considered these as proposals for prompting customers on default tariffs to engage with the domestic retail energy markets.
- 13.197 Our Supplemental Remedies Notice set out details of the proposals and invited views on their effectiveness and proportionality, and the specification and implementation of the possible remedies.
- 13.198 We have decided not to implement the Centrica and Scottish Power proposals.

The proposals

- 13.199 The aim of Centrica's and Scottish Power's proposals would be to increase domestic customer engagement in the domestic retail energy markets by introducing an end date for the supply of energy on an evergreen basis (eg on a standard variable or other default tariff), and providing periodic prompts to customers on evergreen tariffs prior to this date and once they had transitioned to a new fixed-term contract. The industry would move to a system where all customers would be on fixed-term contracts with notifications provided when those contracts came to an end.
- 13.200 Centrica and Scottish Power said that, in their experience, domestic customers on fixed-term contracts tended to engage in significant numbers following the receipt of an end-of-contract notification from their supplier. This response was said to be much greater than that seen following receipt of an annual statement or a price increase notification. They suggested, therefore, that if all domestic customers were to receive such notifications on an annual basis, levels of engagement would increase materially.
- 13.201 Customers who received a notification that their contract was coming to an end but who did not take action, would be rolled onto a fixed-term 'default' tariff. Both Centrica and Scottish Power said that this should be a one-year tariff without exit fees.¹¹⁷ As a result, customers who rolled onto it could switch to an alternative tariff at any time without penalties. They also said that the level of the default tariff should be set by each energy supplier,

¹¹⁷ Centrica also said this should be a variable priced tariff. In contrast, the Scottish Power proposal allowed for this to be variable or fixed-price.

rather than being regulated. Once on this default tariff, customers would receive a notification at the end of each year that their fixed-term default tariff was coming to an end and would be provided with information on the range of tariffs they could choose from, including the one they would be rolled onto if they failed to make a choice. These customers could also receive additional prompts, for example, quarterly or at the mid-year stage.

13.202 We envisaged that a proposal to increase engagement by prohibiting the use of evergreen tariffs would need to be phased in over a period of time, with energy suppliers being required to take the following steps (although not necessarily in the order set out):

- (a) prohibiting the supply of energy to new and existing customers on an evergreen basis as from a future date;
- (b) informing existing evergreen/SVT customers that their tariffs were being phased out and that they would need to choose a new tariff; and
- (c) moving those existing customers who did not respond to these prompts onto the default tariff.

13.203 Within a given period of time, all evergreen tariffs would thus be removed from the markets.

13.204 While Centrica and Scottish Power's proposals are similar, they have some notable differences. Centrica proposed a variable price for the fixed-term default tariff and a phased implementation of the proposal according to the length of time customers have been on the tariff. By contrast, Scottish Power proposed a fixed-rate for the fixed-term default tariff and a phased implementation by region which it said could facilitate suppliers targeting rivals' customer bases and thus increase competition.

Parties' views

13.205 Overall there was a mixed response to any proposal to increase customer engagement by prohibiting evergreen default tariffs:

- (a) Ofgem said it saw an intuitive logic in the proposal but was mindful that consumers on SVTs already received a number of periodic prompts. Ofgem also said that there was a question as to whether less engaged customers would respond to an end-of-contract notice to the same degree as customers that had actively chosen a fixed-term tariff.¹¹⁸

¹¹⁸ Ofgem response to Supplementary Remedies Notice, p1.

- (b) With the exceptions of Centrica and Scottish Power, the Six Large Energy Firms questioned the effectiveness of the proposal.
- (i) EDF Energy said the proposal could be effective but only if combined with other measures.¹¹⁹
 - (ii) E.ON said the proposal could be effective but might not benefit all customers. Some customers who rolled onto the default tariffs might believe that they could not switch until the end of the contract, and some customers on prepayment or complex meters would not benefit because of current restrictions on choice of tariff and switching due to infrastructure.¹²⁰
 - (iii) RWE npower said the proposal could increase customer engagement but it was unclear by how much.¹²¹
 - (iv) SSE said the proposal would have material unintended adverse consequences. It would undermine competition by unduly restricting customer choice through eliminating SVTs and restricting suppliers' ability to innovate and compete. SSE also said it would undermine the pro-competitive measures contained in the CMA's other proposed remedies.¹²²
- (c) Of the Six Large Energy Firms, only Centrica and Scottish Power said the proposal would be effective. Centrica said the proposal would be effective at encouraging customers to engage more frequently in the market if it was phased in as other remedies and market developments were taking effect.¹²³ Scottish Power said the proposal would be effective in securing a substantial improvement in engagement.¹²⁴
- (d) Several of the Mid-tier Suppliers also raised issues about its effectiveness:
- (i) First Utility said that while the proposal was a step in the right direction, it would not be effective in encouraging greater customer

¹¹⁹ [EDF Energy response to Supplementary Remedies Notice](#), p4, paragraph 1.27.

¹²⁰ [E.ON response to Supplementary Remedies Notice](#), pp5–6.

¹²¹ [RWE npower response to Supplementary Remedies Notice](#), p18.

¹²² [SSE response to Supplementary Remedies Notice](#), pp4–p6.

¹²³ [Centrica response to Supplementary Remedies Notice](#), p2.

¹²⁴ [Centrica response to Supplementary Remedies Notice](#), p2 and [Scottish Power response to Supplementary Remedies Notice](#), pp1–2.

engagement because it would only provide for one additional mandatory communication each year.¹²⁵

- (ii) Utility Warehouse said that, in practice, the proposal amounted to the maintenance of the status quo with an additional single annual communication, which would have marginal impact.¹²⁶
 - (iii) Ovo Energy said the removal of evergreen contracts might produce an overall positive outcome for customers but should not be seen as a means of providing direct protection to disengaged customers.¹²⁷
- (e) Several smaller suppliers opposed the proposal outright:¹²⁸
- (i) Citizens Advice said it was unlikely that the proposal would be effective because of substantive similarities with what it would replace, and existing prompts did not work.¹²⁹
 - (ii) The Behavioural Insights Team said there were potentially very significant customer benefits from the proposed approach.¹³⁰
 - (iii) MoneySuperMarket said customers who had not previously responded to written notifications at the end of contracts or to cheaper tariff messaging were unlikely to respond to similar notifications from their supplier while on default tariffs.¹³¹
 - (iv) uSwitch said it could see merits in the proposal but it would not have the impact necessary to raise engagement levels sufficiently.¹³²
 - (v) Utiligroup said there did not seem to be an obvious or evidential link between contract period and customer engagement. It said the remedy was unbalanced, unrepresentative of all customer interests and could have unforeseen consequences.¹³³

13.206 Several of the Six Large Energy Firms indicated that it could take some time to implement any proposal to prohibit evergreen tariffs. In particular:

¹²⁵ [First Utility response to Supplementary Remedies Notice](#), p1.

¹²⁶ [Utility Warehouse response to Supplementary Remedies Notice](#), p1.

¹²⁷ [Ovo Energy response to Supplementary Remedies Notice](#), pp2–3.

¹²⁸ [Opus response to Supplementary Remedies Notice](#), p1, [Green Energy response to supplementary Remedies Notice](#), p1-3, [Corona Energy response to Supplementary Remedies Notice](#), p1-2 and [Good Energy response to Supplementary Remedies Notice](#), p1.

¹²⁹ [Citizens Advice response to Supplementary Remedies Notice](#), pp1–2.

¹³⁰ [The Behavioural Insights Team response to Supplementary Remedies Notice](#), p1.

¹³¹ [Moneysupermarket.com response to Supplementary Remedies Notice](#), p2.

¹³² [uSwitch response to Supplementary Remedies Notice](#), p2.

¹³³ [Utiligroup response to Supplementary Remedies Notice](#), p2.

- (a) Centrica said it would be important to ensure that implementation was phased in over at least three years to minimise the risk of unintended consequences.¹³⁴
- (b) EDF Energy said that implementation would need careful consideration in order to maintain current customer service levels and trust.¹³⁵
- (c) E.ON said that many features of the proposals would require extensive development before implementation.¹³⁶ Most customers would expect to receive a fixed-term, fixed-rate contract (or ‘fixed means fixed’) contract which would need to be considered when designing the contract.
- (d) Scottish Power said that suppliers would need sufficient time to prepare their systems so at least a six-month planning phase and a one-year roll-out phase would be necessary.¹³⁷
- (e) SSE said the complexity and cost made the proposal unjustifiable to implement. It said that such a material and complicated market change would require at least one year for preparation (ie before migration from SVTs could even commence), and a further year to 18 months for the migration of customers to the new default tariffs.¹³⁸ These steps did not take into account possible further delays resulting from changes that would be required to the regulatory framework.

13.207 Several of the Six Large Energy Firms said the proposal could be costly. In particular:

- (a) EDF Energy said suppliers would be likely to incur significant operational costs associated with the expansion of systems.¹³⁹
- (b) E.ON said there were likely to be various costs for implementing the remedy, including for research to identify the best messaging for customers and for renewal, which would be occurred every year the remedy was in place.¹⁴⁰

¹³⁴ [Centrica response to Supplementary Remedies Notice](#), pp8–9. Centrica said that at least six months’ pre-implementation was required followed by a two-year notification period during which each customer would be given an SVT end date 12 months after notification (encouraging them to switch prior to this).

¹³⁵ [EDF Energy response to Supplementary Remedies Notice](#), p8, paragraph 1.54.

¹³⁶ [E-ON response to Supplementary Remedies Notice](#), p10.

¹³⁷ [Scottish Power response to Supplementary Remedies Notice](#), pp9–10.

¹³⁸ [SSE response to Supplementary Remedies Notice](#), pp6–7.

¹³⁹ [EDF Energy response to Supplementary Remedies Notice](#), p10 paragraph 1.67.

¹⁴⁰ [E.ON response to Supplementary Remedies Notice](#), pp14–15.

- (c) RWE npower said the costs could potentially act as a barrier to entry.¹⁴¹
- (d) SSE said significant back office investment would be required, which risked undermining the delivery of innovative market changes that would have a positive benefit to customers.¹⁴²

13.208 Good Energy and Utility Warehouse also raised concerns about costs.¹⁴³

13.209 We also received a number of alternative proposals that parties thought would be as effective or more effective than the Centrica and Scottish Power proposals but would be less costly and/or intrusive:

- (a) E.ON¹⁴⁴ and SSE¹⁴⁵ suggested an enhanced annual statement. E.ON said the statement should have improved messaging and a strong 'call to action'. SSE said an enhanced statement would have material benefits for customers and be capable of fast and effective implementation. We have considered this suggestion as part of our proposed remedy concerning the Ofgem-led programme.
- (b) First Utility proposed a package of alternative measures including renaming the SVT or any default tariff to 'out of contract' tariff and introducing more communications and frequent billing for SVT customers.¹⁴⁶ We have considered this suggestion as part of our remedy concerning the Ofgem-led programme.
- (c) Utility Warehouse proposed a maximum permitted 'delta' (£ or %) that a supplier would be permitted to charge its SVT customers relative to the cheapest price that it charged its newly acquired customers.¹⁴⁷ We have considered this suggestion as part of a proposed remedy concerning the temporary price cap.
- (d) Ovo Energy proposed a regulatory principle of cost reflectivity which it said could help protect customers on SVTs from being overcharged.¹⁴⁸ We have considered this suggestion as part of a proposed remedy concerning the temporary price cap.

¹⁴¹ [RWE npower response to Supplementary Remedies Notice](#), p17.

¹⁴² [SSE response to Supplementary Remedies Notice](#), p8.

¹⁴³ [Good Energy response to Supplementary Remedies Notice](#), p1, [Utility Warehouse response to Supplementary Remedies Notice](#), p5-6, [UEA Centre for Competition Policy response to Supplementary Remedies Notice](#), p6 and [Citizens Advice response to Supplementary Remedies Notice](#), pp12-13.

¹⁴⁴ [E-ON response to Supplementary Remedies Notice](#), p15.

¹⁴⁵ [SSE response to Supplementary Remedies Notice](#), pp9-10.

¹⁴⁶ [First Utility response to Supplementary Remedies Notice](#), p1.

¹⁴⁷ [Utility Warehouse response to Supplementary Remedies Notice](#), p8.

¹⁴⁸ [Ovo Energy response to Supplementary Remedies Notice](#), pp3 & 7.

- (e) MoneySuperMarket suggested more direct communication to SVT customers via a letter from DECC (or other trusted intermediaries) and SMS messaging.¹⁴⁹ We have considered this suggestion as part of our proposed remedy concerning the Ofgem-led programme.
- (f) Citizens Advice suggested a mandatory switch of certain consumers fitting a vulnerability profile (broadly matching the Cold Weather Payments group) or an extension of the current Warm Home Discount to cover all suppliers and a broader group of consumers.¹⁵⁰ We have considered this suggestion below.

Our assessment of effectiveness

13.210 Our assessment of the likely effectiveness of this proposed remedy differs as between the Centrica and Scottish Power variants.

13.211 In relation to the Centrica proposal, we do not consider this to be a substantial departure from the status quo, in that:

- (a) the default tariff would still be a variable tariff, such that the periodic prompt would not be associated with a change in price, which may be expected to reduce its effectiveness in engaging customers; and
- (b) the proposed roll-out by customer tenure would not facilitate other suppliers engaging with customers on default tariffs.

13.212 In effect, the Centrica proposal amounts to a rebranding of the SVT with an additional periodic prompt. Customers on SVTs already receive regular communications from their suppliers so receiving further prompts from them might not in itself prompt these customers to engage. As noted above, we are recommending that Ofgem test new approaches to providing information to customers to help them engage and we do not consider that this proposal is likely to deliver benefits on top of that. In addition, we are setting up a new rival-led prompt, through our Database remedy.

13.213 The Scottish Power proposal is, in contrast, a substantial change to the status quo:

- (a) Default tariffs would be fixed-term and fixed-price, such that that end-of-contract prompt would be associated with a price change, resulting in a meaningful decision point for customers.

¹⁴⁹ [MoneySuperMarket response to Supplementary Remedies Notice](#), p3.

¹⁵⁰ [Citizens Advice response to Supplementary Remedies Notice](#), p13.

(b) The proposed roll out by geographical area would be expected to help rival suppliers target their marketing efforts on customers facing a change in contract, which is likely to increase the effectiveness and reduce the costs of such marketing activity.

13.214 We also note, in relation to both proposals, that while customers who have actively chosen fixed-term tariffs may respond to end-of-contract notifications, it is not clear that far less engaged customers would respond in the same way.

13.215 In the light of the above, our view is that the Centrica proposal would not be effective in addressing any aspect of the features giving rise to the Domestic Weak Customer Response AEC and resulting detriment. We consider that that the Scottish Power proposal is, on balance, effective for the reasons set out above. However, we have not addressed the likely effectiveness of the Scottish Power proposal in detail, because we consider that it would not be proportionate (see below).

Our assessment of proportionality

13.216 Centrica and Scottish Power said the potential costs could be proportionate to the benefits of increased engagement.¹⁵¹ As regards Centrica's views, this was because the benefits of increased engagement would outweigh the costs provided suppliers were able to set their variable-priced default tariff at a level that was not capped by the regulator and that implementation took place over the timescale proposed.¹⁵²

13.217 We note that other suppliers were concerned that the costs of implementation would be high. In addition, several suppliers commented on relevant customer benefits which could be adversely affected by the proposals.

(a) E.ON said that if the default contract was a fixed-rate, fixed-term contract which, as a result of its design, was at a higher rate than the current SVT then this would result in a loss of customer benefit.¹⁵³

(b) RWE npower said it was unlikely that discounts currently enjoyed by customers on non-standard tariffs would continue at the same levels if

¹⁵¹ Centrica response to Supplementary Remedies Notice, p13 and Scottish Power response to Supplementary Remedies Notice, pp12–13.

¹⁵² Centrica response to Supplementary Remedies Notice, p13.

¹⁵³ E.ON response to Supplementary Remedies Notice, p14.

this remedy was introduced due to price convergence between the default and non-default tariffs.¹⁵⁴

- (c) SSE said the cost and complexity of the implementation of the proposals could result in material customer harm: consumers could face a reduced choice of products, increased costs and unnecessary disruption during transition (and over the longer term) which might actually discourage their engagement.¹⁵⁵
- (d) Utility Warehouse said that moving to a marketplace dominated by fixed-term contracts would result in a material transfer of wholesale commodity price risk from suppliers to consumers.¹⁵⁶
- (e) Good Energy said that locking customers into fixed-rate deals could result in them not receiving the benefits of any wholesale market price reductions until their fixed-rate deal ended. It also said the remedy could adversely affect engaged customers through a restriction of choice.¹⁵⁷

13.218 We have taken into account each of the above potential unintended adverse consequences or potential losses of relevant customer benefits, when provisionally deciding not to proceed with Centrica's and Scottish Power's proposals.¹⁵⁸ In particular, we note that neither the Centrica nor the Scottish Power proposal provides for an explicit constraint on the level of the default tariff. We also note that, under the status quo, the public visibility of changes to the SVT might plausibly provide a partial constraint on the ability of suppliers to raise prices rapidly for certain categories of disengaged customer. This potential constraint would be lost under the Centrica and Scottish Power proposals. We are therefore concerned that, under both proposals, there is risk that default tariffs for disengaged customers increase as a result of the reforms, due to the absence of this constraint.

13.219 We also note that the reforms would be relatively costly to implement and difficult to reverse in short order. Therefore, on balance, we have concluded that both proposals are unlikely to be proportionate.

¹⁵⁴ [RWE npower response to Supplementary Remedies Notice](#), p17.

¹⁵⁵ [SSE response to Supplementary Remedies Notice](#), p8.

¹⁵⁶ [Utility Warehouse response to Supplementary Remedies Notice](#), pp7–8.

¹⁵⁷ [Good Energy response to Supplementary Remedies Notice](#), p8.

¹⁵⁸ We have also considered these factors when considering the temporary price cap remedy.

Greater use of principles rather than rules in addressing potential adverse supplier behaviour

- 13.220 As set out in Section 12, one of our remedies is to remove aspects of the simpler choices component of the RMR rules with the aim of promoting competition between suppliers and PCWs.
- 13.221 Ofgem introduced these rules to make it easier for customers to make better choices by stripping away unnecessary complexity in tariff choices, particularly for certain groups of customers.^{159,160} The RMR rules also introduced legally binding fairness principles, implemented as Standards of Conduct in standard licence conditions, the aim of which was to place an onus on suppliers to embed fair treatment of their customers in every level of the organisation.
- 13.222 We consider that there is a balance to be struck in the regulation of the retail energy suppliers between rule-based regulation (such as the simpler choices component of the RMR rules) and principles-based regulation (such as the Standards of Conduct introduced as part of the 'fairer treatment' component of the RMR rules¹⁶¹). Our concern with the aspects of the simpler choices component of the RMR rules that we recommend that Ofgem remove is that:
- (a) Given their complexity, the interactions and effects of these rules are difficult to understand and lead to compliance risk for suppliers.
 - (b) More broadly, there is a risk that overly prescriptive rules are counterproductive and encourage game playing, by implicitly legitimising any behaviour that is not explicitly proscribed by the rules. Since the publication of our provisional findings, we have received evidence that the simpler choices component of the RMR rules has given rise to such behaviour as a result of exemptions granted from the four-tariff rule for collective switching schemes and white-label tariffs. We consider that these examples illustrate the potential for suppliers to game rules. In particular:
 - (i) Ofgem said that it exempted collective switching schemes from the four-tariff rule because they might benefit otherwise difficult-to-engage customers and collective switching schemes had involved a range of models, tariffs and target customer groups.¹⁶² First Utility

¹⁵⁹ See Ofgem (March 2013), *The Retail Market Review – final domestic proposals*.

¹⁶⁰ In addition, Citizens Advice and EDF Energy said that pre-RMR discounts and incentives might have been used to mislead customers. EDF Energy, E.ON and SSE said that effective standards of conduct were necessary to ensure such behaviour did not occur or prevent customers from potentially being deliberately misled

¹⁶¹ SLC 25C.

¹⁶² Ofgem (2013), *The Retail Market Review – Final domestic proposals*.

said switching sites had started offering collective switching schemes, and some were using the collective switching rules as a way to create exclusive tariffs. It said there was nothing ‘collective’ about switching site collective switches – such tariffs were shown to all site visitors within the results table. First Utility also said that E.ON had been most aggressive in terms of price in the uSwitch collective switch. First Utility said this appears to have allowed E.ON to segment the market between existing unengaged customers and new engaged customers, through changes to prices effectively to avoid showing its current customers their market leading rate (as required by the Cheapest Tariff Messaging requirements).

- (ii) Ofgem implemented temporary arrangements which exempted white labels from some aspects of the ‘simpler choices’ and ‘clearer information’ components of the RMR rules, in particular the four-tariff rule and the information rules. First Utility said that in 2014 British Gas’ best tariff was typically lower or similarly priced to Sainsbury’s best tariff, but British Gas had – since the introduction of ‘simpler choices’ – used the Sainsbury’s brand as a lower priced acquisition vehicle, while not showing this rate to British Gas customers. First Utility also said that as new rules came into force on 1 October 2015, requiring white labels to be included in the Cheapest Tariff Messaging, British Gas has increased the price of the Sainsbury’s tariff.

13.223 On 18 December 2015, Ofgem published a consultation on placing greater reliance on principles-based regulation in the domestic retail supply markets.¹⁶³ Ofgem observed that principles-based regulation was being increasingly used by a number of sector regulators and said that it was committed to relying more on general principles rather than detailed rules about how companies should run their businesses. It said that this would better protect consumers’ interests by:

- (a) focusing its efforts as a regulator on good consumer outcomes and more effective and comprehensive consumer protection;
- (b) creating room for innovation, so suppliers can be more flexible in how they meet the needs of customers, including those in vulnerable situations; and

¹⁶³ Ofgem (18 December 2015), The future of retail market regulation.

- (c) putting a much greater onus on suppliers, especially senior management, to treat consumers fairly.

13.224 Ofgem is consulting on, among other things: which areas lend themselves to more prescriptive rules and which to a greater reliance on principles; which areas should be prioritised to shift to a greater reliance on principles; and whether the existing 'treating customers fairly' principle should be supplemented with additional principles. Ofgem identified SLC 25, relating to domestic sales and marketing, as a priority area,¹⁶⁴ as it already contains an overall objective which would underpin the principles-based approach in this area. Ofgem said that it intended to publish a response to the consultation in summer 2016 with a view to making significant progress by the end of 2016.

13.225 For the reasons given above (see paragraph 13.222), we welcome Ofgem's commitment to a more principles-based approach to regulation. In particular, we would endorse:

- (a) Ofgem's statements in relation to the potential benefits of principles-based regulation and its commitment to striking the right balance between rules and principles;
- (b) Ofgem's recognition of the challenges around bringing about the necessary culture change within Ofgem and suppliers for the benefits to customers to be realised; and
- (c) Ofgem's recognition of the need for effective monitoring and enforcement to providing a credible deterrent to non-compliance.

13.226 Against a background of Ofgem moving to a more principles-based approach to regulation, we have considered specific recommendations for Ofgem in relation to the specified principles. In the context of our remedy to remove aspects of the simpler choices component of the RMR rules, we noted in Section 9 that this may result in more tariffs and a wider range of products on the market. However, our view is that there are a range of tools which may help customers navigate the tariffs on offer in the market and make decisions and, accordingly, address any such unintended consequences arising from this remedy. We also consider that any such unintended consequences could be substantially mitigated (or possibly

¹⁶⁴ The overall objective of SLC 25 is to ensure that (i) all information which suppliers provide to domestic customers in the course of marketing activities is complete and accurate, is capable of being easily understood by domestic customers, does not relate to products that are inappropriate to the domestic customer to whom it is directed and is otherwise fair both in terms of its content and in terms of how it is presented; and (ii) suppliers' marketing activities and all contact by suppliers with domestic customers in the course of suppliers' marketing activities are conducted in a fair, transparent, appropriate and professional manner (SLC 25.1).

entirely eliminated) by recommending that Ofgem introduce an additional principle to its 'Standards of Conduct' standard licence condition that would require suppliers to have regard, in the design of tariffs, to the ease with which customers can compare value for money with other tariffs they offer.¹⁶⁵

Aim of the remedy

13.227 The aim of our remedy is to improve customer engagement and to strengthen the provisions of the Standards of Conduct standard licence condition to mitigate unintended consequences associated with removing aspects of the simpler choices component of the RMR rules (see paragraph 13.227).

Parties' views

13.228 Ofgem said that it welcomed the recommendation to remove aspects of the 'simpler choices' component of the RMR rules and that this was aligned with its aim of relying more on principles and less on prescriptive rules to regulate the retail energy markets. Ofgem also said it expected the removal of aspects of the 'simpler choices' component of the RMR rules to result in suppliers introducing different and more complex tariff offerings. As the information tools introduced to complement the 'simpler choices' rules were not designed to work with this additional level of complexity, it would be revisiting these as a matter of priority.¹⁶⁶

13.229 Ofgem said that it strongly agreed with the CMA that consumers should be able to compare and make informed choices about which tariff was best suited to their needs. As part of its wider shift away from prescriptive rules in the retail energy supply markets, it was therefore considering how any new principle(s) might best achieve this goal. Ofgem was also considering how any such principle(s) might be fast-tracked in order to ensure there was sufficient consumer protection in place.¹⁶⁷

13.230 The Six Large Energy Firms had mixed views on this remedy. Scottish Power¹⁶⁸ and E.ON¹⁶⁹ said they supported the remedy. RWE¹⁷⁰ noted this

¹⁶⁵ We also noted that this new Standard of Conduct could work with removing the 'whole of the market' requirement from PCW's Confidence Code which should incentivise expansion and investment in the domestic retail energy markets (see paragraph 6.105 below).

¹⁶⁶ Ofgem response to provisional decision on remedies, Annex 2.

¹⁶⁷ Ofgem response to provisional decision on remedies, Annex 2.

¹⁶⁸ Scottish Power response to provisional decision on remedies, p11, paragraph 7.2.

¹⁶⁹ E.ON response to provisional decision on remedies, p33, paragraph 154.

¹⁷⁰ RWE response to provisional decision on remedies, p59, paragraph 49.5.

remedy was designed to complement the removal of the simpler choices component of the RMR rules. However:

- (a) Centrica strongly opposed the remedy. It said this remedy could limit suppliers' ability to launch more innovative bundles of products and would undermine the effectiveness of the remedy removing the simpler choices component of the RMR rules.¹⁷¹
- (b) SSE said the remedy was unnecessary because existing Standards of Conduct, coupled with consumer protection legislation, would ensure customers were not misled or confused by the design of tariffs. SSE said that if the CMA deemed it indispensable, the requirement should be included in the Standards of Conduct with clarity on how suppliers' compliance would be evaluated.¹⁷²

13.231 We do not agree that the remedy would limit suppliers' ability to launch innovative tariffs. The recommendation is that the additional 'Standard of Conduct' would require suppliers to 'have regard to the ease with which customers can compare value for money with other tariffs they offer'. This would require suppliers, in the design of tariffs, to consider the implications of the features of tariffs for comparability. The new Standard of Conduct would, however, allow for suppliers to consider comparability alongside other considerations such as the potential benefits to customers provided by a new and innovative product.

13.232 EDF Energy said that while it understood the sentiment behind the remedy, value for money was a subjective assessment on the part of the customer. EDF Energy said it would be more appropriate for suppliers to show the 'all in' cost of tariffs over a standardised period (eg the first year) and for all offers to be presented on a consistent total cost basis.¹⁷³

13.233 First Utility said a new methodology around how tariffs should be presented and compared needed to be implemented to help customers, and this should take the form of rules set by Ofgem and introduced as a licence condition on suppliers.¹⁷⁴

13.234 We consider that the effect of EDF Energy's proposal would be to introduce new rules on the information that suppliers are required to provide on the tariffs they offer. As discussed in the previous section, we consider that any such rules should be rigorously tested before implementation. Any proposals

¹⁷¹ Centrica response to provisional decision on remedies, p66, paragraphs 331–335.

¹⁷² SSE response to provisional decision on remedies, Annex 1, p7, paragraph 6.1.9.

¹⁷³ EDF Energy response to provisional decision on remedies, p32, paragraph 7.15.

¹⁷⁴ First Utility response to provisional decision on remedies, pp16 & 17, paragraph 4.20–4.26.

that EDF Energy or First Utility might have relating to the presentation of tariff information should, therefore, be for Ofgem to consider in its Ofgem-led programme. We note that proposals in relation to what and how information is provided to customers in bills and other communications are covered by the priority list of measures (see paragraph 13.21).

13.235 Ovo Energy said the new Standard of Conduct was a good starting point but proposed the following additional principles to supplement the existing Standards of Conduct to ensure tariffs were more easily distinguishable:

- (a) The terms and structure of tariffs should be clear and easily understandable by customers.
- (b) A supplier's suite of individual tariffs should be readily distinguishable between each other.
- (c) Customers should be able to easily compare and select the tariffs that are best suited to their needs.¹⁷⁵

13.236 Three PCWs/TPIs expressed support for the remedy, agreeing that there was a need for a more explicit obligation on suppliers to help customers compare tariffs.^{176,177,178} uSwitch.com said there should be a requirement that suppliers must not construct tariffs in a way that unreasonably restricts consumers' ability to compare them with tariffs on the wider market.¹⁷⁹

13.237 We considered this broader option of requiring suppliers to have regard to comparability with tariffs offered by other suppliers. We came to the view that such a requirement would create practical difficulties (since any individual supplier would need to be aware of the forthcoming tariffs of rivals to ensure their own tariffs were sufficiently comparable) and may have unintended consequences, such as encouraging suppliers to communicate with each other to ensure compliance with the Standard of Conduct. We therefore concluded that we should not pursue this option as it is not proportionate. However, we consider that the remedy that we have adopted, by ensuring that a supplier's own tariffs are directly comparable, will also support comparability across the market.

13.238 Professor Littlechild et al said they were concerned that the remedy could reintroduce the simpler choices component of the RMR rules, increase

¹⁷⁵ Ovo Energy response to provisional decision on remedies, pp31 & 32, paragraphs 6.9–6.13.

¹⁷⁶ BGL Group (Comparethemarket.com) response to provisional decision on remedies, p3, paragraph 3.9.

¹⁷⁷ MoneySupermarket.com response to provisional decision on remedies, p5.

¹⁷⁸ MoneySavingExpert.com response to provisional decision on remedies, p3.

¹⁷⁹ uSwitch.com response to provisional decision on remedies, p6, section 3.2.1.

regulatory uncertainty, and limit valuable innovation because it could be misinterpreted by Ofgem.¹⁸⁰ Professor Littlechild et al subsequently suggested Ofgem had misinterpreted the remedy in guidance it had provided to suppliers following our provisional decision on remedies in response to our recommendation that Ofgem remove specific aspects of the ‘simpler choices’ component of the RMR rules.¹⁸¹ Professor Littlechild et al said Ofgem’s interpretation would impose a more onerous and restrictive condition on suppliers and, as such, the CMA should reconsider this issue, and withdraw the remedy.¹⁸²

13.239 However, we note that in its consultation document Ofgem said that the move towards principles-based regulation would place an onus on suppliers to understand and think for themselves about how to meet the needs of their customers. Ofgem said there was a role for publishing guidance, but in limited circumstances and not in large quantities, so as to avoid reintroducing rules ‘by the back door’.¹⁸³

Design considerations

13.240 In designing the remedy we have considered:

- (a) whether there are gaps in the current provisions of the Standards of Conduct that need to be addressed to mitigate the risks associated with removing aspects of the simpler choices component of the RMR rules;
- (b) how effective Ofgem has been in monitoring compliance with the Standards of Conduct and taking enforcement action where suppliers have been in breach of these standards; and
- (c) how to implement this remedy.

¹⁸⁰ Littlechild et al response to provisional decision on remedies, pp15 & 16, paragraphs 72 & 73.

¹⁸¹ Ofgem open letter to suppliers ‘[CMA provisional remedies: removal of certain RMR ‘simpler choices’ rules](#)’ 14 April 2016.

¹⁸² Littlechild et al supplementary submission on provisional decision on remedies, pp2 & 3, paragraphs 8–13. Littlechild et al said the following:

Ofgem says that “The CMA also proposes introducing a new principles-based requirement on suppliers to enable consumers to compare their tariffs easily.” It then says of “the CMA’s proposed new principle”: “This means that consumers should be able to understand any new tariffs and assess the value for money compared to other tariffs that the supplier offers.” However, the CMA did *not* propose that suppliers be required “to enable consumers to compare their tariffs easily”, and Ofgem’s interpretative sentence is *not* what the proposed new principle means. Rather, the CMA proposed that suppliers be required to “*have regard*” to the ease of comparing value for money. Our reading is that the CMA intended that it would be open to a supplier, having had regard to ease of comparability, then to decide that, on balance, other considerations (such as innovation) outweighed this. Ofgem’s incorrect interpretation would not allow this outcome, and would impose a more onerous and restrictive condition on suppliers.

¹⁸³ See [December consultation document](#), paragraphs 2.31–2.35.

Strengthening provisions of the current Standards of Conduct

13.241 The Standards of Conduct are included in SLC 25C and impose obligations on suppliers regarding their interactions with domestic customers (except price).¹⁸⁴ The obligations on suppliers cover three broad areas, ie behaviour, information, and process.

- (a) Behaviour: suppliers must behave and carry out any actions in a fair, honest, transparent, appropriate and professional manner.
- (b) Information: suppliers must provide information (whether in writing or orally) which is:
 - (i) complete, accurate and not misleading (in terms of the information provided or omitted);
 - (ii) communicated in plain and intelligible language;
 - (iii) relates to products or services that are appropriate to the customer to whom it is directed; and
 - (iv) fair both in terms of its content and in terms of how it is presented (with more important information being given appropriate prominence).
- (c) Process: the supplier must:
 - (i) make it easy for the consumer to contact them;
 - (ii) act promptly and courteously to put things right when they make a mistake; and
- (d) otherwise ensure that customer service arrangements and processes are complete, thorough, fit for purpose and transparent.

13.242 Ofgem said that, in relation to the tariffs a supplier offered, the provisions applied to the terms and conditions of a tariff and to the information that a supplier provided about the tariff, and that the information provisions helped to reduce the risks that consumers did not understand the details of a tariff.

¹⁸⁴ The Standards of Conduct are broadly based on EU Directives (ie Directive 2009/72/EC of 13 July 2009 concerning common rules for the internal market in electricity and Directive 2009/73/EC of 13 July 2009 concerning common rules for the internal market in natural gas) and consumer law (ie the Consumer Rights Act 2015).

This would include details such as multi-tier prices, multiple tariff components or loyalty discounts.¹⁸⁵

13.243 We have found that while the current provisions place an obligation on suppliers to provide customers with information on tariffs that is complete, accurate and not misleading, they place no explicit obligations on suppliers in the design of their tariffs, to help customers compare tariffs.

Effective monitoring and enforcement

13.244 Ofgem said it had a two-pronged approach to monitoring compliance with the Standards of Conduct. Ofgem:

(a) monitors consumer outcomes through indicators and data from across Ofgem and external parties such as Citizens Advice including complaints data; and

(b) monitors suppliers' processes for embedding the principles through bilateral engagement and other processes such as the Standards of Conduct Challenge Panel.¹⁸⁶

13.245 Ofgem has the power to take enforcement action for breaches of relevant conditions and requirements, including the Standards of Conduct. Ofgem's strategic objectives for enforcement include delivering credible deterrence and ensuring meaningful and visible consequences for businesses which do not comply. Before taking enforcement action, Ofgem will consider alternative actions.¹⁸⁷

13.246 Following a finding of breach, Ofgem has the power to impose financial penalties and/or make consumer redress orders.¹⁸⁸ The central objective of imposing financial penalties and making redress orders, and of determining their amount and type, are to obtain fair outcomes for consumers and to

¹⁸⁵ Ofgem (18 November 2015), Paper 1: Impact of remedy 3 on consumer engagement, working paper.

¹⁸⁶ The 2014 Challenge Panel identified examples of good practice. Overall the Panel thought that more needed to be done by suppliers to ensure customers were placed the heart of their business.

¹⁸⁷ These alternatives are set out in paragraphs 3.25 to 3.30 of Ofgem's enforcement guidelines. These include, among other things: entering into dialogue with a company and warning them about potential unlawful conduct; accepting non-statutory undertakings; agreeing a reporting period for the company to show the issue has been addressed and that it will not be repeated; and voluntary commitments. Ofgem said that voluntary commitments could have the advantage of being able to achieve more than could be achieved through a provisional or final order. Sources: Enforcement Guidelines, September 2014

¹⁸⁸ Where Ofgem imposes a financial penalty, makes a consumer redress order requiring payment of compensation, or does both and requires the payment of compensation for the same breach, then the amount (or combined amount) must not exceed 10% of the turnover of the regulated person.

deter future non-compliance. Financial penalties must be reasonable in all the circumstances of a case.¹⁸⁹

13.247 Ofgem will normally seek to ensure that any financial penalty, and compensation or other payment under a consumer redress order, or any combination of them, significantly exceeds the gain to the regulated person (where this can reasonably be calculated or estimated) and the detriment caused to consumers affected by the contravention or failure.¹⁹⁰ When determining the amount of a financial penalty and/or consumer redress payment, Ofgem will consider any remedial measures that have been taken. However, Ofgem may impose a financial penalty significantly in excess of the gain or detriment even where the gain or detriment has been mitigated in full. Ofgem considers that this may be necessary in order to deter non-compliance and provide appropriate encouragement for all regulated persons to comply with their obligations.¹⁹¹

13.248 We consider that ultimately it is the credible threat of enforcement action that would provide suppliers with an incentive to comply. In this context, we note that on 18 December 2015 Ofgem imposed a fine of £26 million on RWE for its failure to comply with the obligation to treat its domestic customers fairly in breach of the Standards of Conduct.¹⁹² Ofgem also said that failure to achieve agreed targets could result in npower companies having to stop all proactive domestic selling until they do.^{193,194} Further, we note that on 26 April 2016 Ofgem published a notice of intention to impose a fine of £18 million on Scottish Power for failure to treat its customers fairly in breach of the Standards of Conduct.¹⁹⁵

13.249 We note that Ofgem has announced that it will issue a statutory consultation on a proposed new Standard of Conduct (as well as a proposal to remove

¹⁸⁹ Ofgem's Enforcement Guidelines and Ofgem's Statement of Policy with Respect to Financial Penalties and Consumer Redress under the Gas Act 1986 and Electricity Act 1989.

¹⁹⁰ The Gas and Electricity Markets Authority's Statement of Policy with respect to Financial Penalties and Consumer Redress under the Gas Act 1986 and the Electricity Act 1986, paragraph 2.4.

¹⁹¹ The Gas and Electricity Markets Authority Statement of Policy with respect to Financial Penalties and Consumer Redress under the Gas Act 1986 and the Electricity Act 1989.

¹⁹² When setting the amount of the fine, Ofgem took into account the fact that RWE had offered to settle the investigation and had also undertaken to make certain consumer redress payments.

¹⁹³ SLC 25C requires suppliers, among other things, to provide information to domestic customers which is complete, accurate and not misleading, and to act promptly and courteously to put things right when they make a mistake.

¹⁹⁴ RWE was found to be in breach of the Standards of Conduct set out in SLC 25C, in particular, the requirements regarding the manner in which the information must be provided to domestic customers by suppliers and the requirements concerning complaint handling procedures. Ofgem's investigation mainly showed that RWE's customers received inaccurate bills with little or no detail on how these were calculated, and that RWE failed to deal with complaints effectively. Accordingly, RWE failed to comply with the obligation to treat its domestic customers fairly in breach of SLC 25C.

¹⁹⁵ Ofgem press release of 26 April 2016: '[ScottishPower to pay £18m for customer service failings](#)'.

the aspects of the simpler choices component of the RMR rules recommended for removal in Section 12).¹⁹⁶ Ofgem has also noted that, in the period prior to it formally removing the relevant aspects of the simpler choices component of the RMR rules and introducing the proposed new Standard of Conduct, it expects suppliers to make sure that any tariffs that are potentially non-compliant with the existing rules are consistent with the proposed new Standard of Conduct.

13.250 Based on these findings our view is that Ofgem has the ability and incentive to take effective enforcement action, including imposing fines, in case of breach of the Standards of Conduct. Ofgem's recent decisions concerning RWE and Scottish Power demonstrate that it is prepared to enforce the Standards of Conduct strongly.

Implementation of this remedy

13.251 We are implementing this remedy through a recommendation to Ofgem to include an additional Standard of Conduct into SLC 25C that would require suppliers to have regard in the design of tariffs to the ease with which customers can compare value for money with other tariffs they offer.

Assessment of effectiveness

13.252 Our view is that the remedy is effective in helping improve engagement and in mitigating the risks of removing aspects of the simpler choices component of the RMR rules as it expressly provides for suppliers to have regard to the comparability of tariffs in their design.

13.253 As explained above, we consider that the effectiveness of the remedy critically depends on Ofgem maintaining its monitoring and enforcement activity. In assessing the effectiveness of the remedy, we have also considered evidence on the impact of the current Standards of Conduct on suppliers' conduct and, by implication, the impact the additional provision could be expected to have on suppliers in the design of tariffs.

13.254 In particular, we asked all of the Six Large Energy Firms, Ovo Energy, The Co-operative Energy and First Utility:¹⁹⁷

(a) what actions they have taken and what processes are in place to ensure compliance with the Standards of Conduct;

¹⁹⁶ Ofgem open letter to suppliers 'CMA provisional remedies: removal of certain RMR 'simpler choices' rules' 14 April 2016.

¹⁹⁷ Ofgem and supplier responses to CMA questions about fairer treatment.

- (b) how the Standards of Conduct influence their decision-making in various areas such as tariff terms and conditions and the information provided to customers; and
- (c) how they ensure PCWs representing them comply with the Standards of Conduct.

13.255 The responses were as follows:

- (a) All suppliers said that they had processes to ensure compliance with (and went above and beyond) the Standards of Conduct.¹⁹⁸
- (b) All of the Six Large Energy Firms provided staff training on the Standards of Conduct.¹⁹⁹
- (c) Some suppliers said that they also monitored their compliance with the Standards of Conduct.²⁰⁰
- (d) Suppliers had different methods for ensuring that PCWs representing them complied with the Standards of Conduct.²⁰¹

13.256 Based on these responses, our assessment is that all of the Six Large Energy Firms have been proactive in putting compliance processes in place. It is, however, difficult for us to judge how effectively compliance with the Standards of Conduct is embedded in the culture of these organisations. Ofgem's monitoring of suppliers will however assess their adherence to such processes.

13.257 We would expect Ofgem's consultation on the new Standard of Conduct to conclude by the end of 2016, such that it could implement and enforce the new Standard of Conduct from 2017 onwards.

13.258 We have concluded that the remedy is effective in mitigating the risks of removing aspects of the simpler choices component of the RMR rules, in light of our findings in relation to Ofgem's monitoring and recent enforcement

¹⁹⁸ For example, E.ON's Fair Decision Form guides decision makers through the core requirements of the Standards of Conduct. EDF's Trust Test is a set of principles staff must consider when making decisions and Centrica's formal Standards of Conduct assessment is embedded within the process of developing new products and processes.

¹⁹⁹ E.ON said that it developed training and toolkits. EDF Energy said that it carried out extensive staff training on the Standards of Conduct. RWE said it had an e-learning programme on the Standards of Conduct. Scottish Power said that it had extensive staff training including a mandatory DVD and briefing sessions. Centrica said that it had workshops and training and SSE said that implementation of the Standards of Conduct included extensive staff training and briefing documents and a review of SSE's existing policies to ensure compliance.

²⁰⁰ For example, SSE said it monitored performance through KPIs and their internal Treating Customers Fairly Panel, and RWE said it had developed a dashboard showing performance against the Standards of Conduct.

²⁰¹ [REDACTED]

activity, suppliers' compliance activities, and Ofgem's appreciation of the challenges it will face in moving towards more principles-based regulation.

Assessment of proportionality

13.259 We consider this remedy to be proportionate for the following reasons:

- (a) It should be of minimal cost for suppliers to comply with the new Standard of Conduct. The new Standard of Conduct will be an additional consideration in the design phase of a new tariff. Suppliers will need to have regard to comparability with their other tariffs.
- (b) Ofgem is moving towards a more principles-based approach to regulation as demonstrated by its recent consultation and letter of clarification to suppliers of 14 April 2016.²⁰²
- (c) Ofgem is well placed and is planning to take this forward within its existing programme of monitoring and enforcement activity.
- (d) A more principles-based approach to regulation enables suppliers to innovate in the face of opportunities offered by new technologies and allows customers to benefit.

13.260 We have also had regard to Ofgem's statutory duties and objectives in reaching a decision concerning the RMR remedy, as set out in Section 12.

Conclusion

13.261 We welcome Ofgem's consultation on placing greater reliance on principles-based regulation in the domestic retail supply markets. In the meantime we are recommending that Ofgem bolster the existing Standards of Conduct to require suppliers to have regard in the design of their tariffs to the ease of comparability with other tariffs they offer. We consider this to be a gap in current provisions that needs to be addressed in order to mitigate the risks associated with the removal of aspects of the simpler choices component of the RMR rules, and for the remedy to be effective and proportionate.

Enhancing the incentives and ability of TPIs to engage customers

13.262 We consider that PCWs and other TPIs are an important means by which effective competition can develop in the domestic retail markets. We have

²⁰² Ofgem open letter to suppliers 'CMA provisional remedies: removal of certain RMR 'simpler choices' rules' 14 April 2016.

recognised that PCWs have a strong commercial incentive to engage with domestic customers and provide access to their services both online and by telephone. PCWs are also well placed to:

- (a) raise awareness among customers of their ability to switch and the potential benefits from doing so;
- (b) reduce search costs for customers; and
- (c) exert competitive pressure on energy suppliers by enhancing price transparency and facilitating the purchasing process for customers.

13.263 While PCWs are the most common type of TPI currently, TPIs are taking a variety of forms that are likely to appeal to different demographic groups. Some, such as automated switching services, can radically reduce the hassle of switching for those who sign up while others, such as collective switching services advertised through a variety of media, may appeal more to customers who are less confident in using the internet.

13.264 Our aim in considering remedies relating to PCWs in the domestic retail markets is to address (in whole or in part) the features giving rise to the Domestic Weak Customer Response AEC. With this in mind, we have decided to introduce remedies aimed at enhancing the incentives and ability of PCWs to participate in the domestic retail energy markets and enabling PCWs to offer customers a better service. In particular, we are:

- (a) recommending that Ofgem remove the requirement on PCWs to show the whole of market from the Confidence Code, which could be damaging to the incentives of PCWs to participate in the domestic retail energy markets and could have particular unintended consequences in light of our recommendation to remove aspects of the simpler choices component of the RMR rules, and introduces a requirement to provide clear messaging concerning what results are displayed. In this context, PCWs will be required to be transparent over the market coverage provided to customers;
- (b) requiring the code administrator or governing body with authority to grant access to the ECOES database and the gas transporters (through an order) to give PCWs (and other TPIs providing similar services) access to the ECOES and SCOGES databases (subject to satisfying reasonable access conditions) in order to reduce the number of erroneous transfers and failed switches and, more generally, to support PCWs in facilitating the switching process; and

- (c) recommending that DECC make several changes to the Midata programme that (subject to customer consent) will give PCWs (and other TPIs providing similar services) increased access to more customer data and, in so doing, enable PCWs to monitor the market on behalf of their customers and advise them of savings.

13.265 We have also considered, but do not intend to pursue further, a remedy that would see the establishment of an Ofgem price comparison service for domestic customers, in the light of Citizens Advice's decision to launch a non-transactional PCW listing all tariffs on the domestic retail energy markets. We set out below our reasoning in greater detail below.

The Confidence Code

13.266 The Confidence Code²⁰³ is a voluntary code of practice for domestic energy price comparison services. The Confidence Code sets out minimum requirements (concerning independence, transparency, accuracy, and reliability) that providers of price comparison services must meet in order to be, and remain, accredited by Ofgem. The main aim of the Confidence Code is to promote consumers' trust in PCWs and thereby increase customers' use of PCWs.

13.267 Ofgem's Confidence Code includes a requirement²⁰⁴ on PCWs to use all reasonable endeavours to include price comparisons for all available domestic tariffs, where applicable for all available payment types, for licensed suppliers (including for any agents, affiliates, and brands operating under the licence of a supplier) (the 'Whole of the Market Requirement'). The Whole of the Market Requirement does not require PCWs to show:

- (a) social tariffs (ie tariffs where consumer eligibility is based upon social or financial circumstances, eg receipt of benefits);
- (b) tariffs that the supplier has requested the PCW to remove from its price comparison service; or
- (c) tariffs that are available only to consumers in a specified region, to consumers that are not within that specified region.

13.268 Notwithstanding the existence of the Whole of the Market Requirement, prior to 2015 PCWs were allowed to set their filtering options to display (as a default) only a selection of tariffs (ie consumers only saw the whole of the

²⁰³ Ofgem, [The Confidence Code](#).

²⁰⁴ Requirement 2(A).

market if they unticked the partial selection option and ticked the whole of the market box). In 2015 Ofgem amended the Confidence Code and introduced a requirement on PCWs to display (as a default option) the whole of the market.²⁰⁵ The main aim of this recent amendment was to strengthen the Whole of the Market Requirement.

- 13.269 In our provisional findings we said that accredited PCWs' inability to display (as a default) only those tariffs for which they are paid commission risks undermining the incentive of PCWs to invest in the domestic retail energy markets and the ability of PCWs to exert competitive pressure on suppliers.
- 13.270 We consider that this reasoning applies to both the 'Whole of the Market Requirement' and to the recent amendments (although, absent the recent amendments, the possibility for PCWs to filter the results displayed would have meant there was a reduced risk of the Whole of the Market Requirement undermining the incentives of PCWs to invest in the domestic retail energy markets).
- 13.271 Ofgem told us that, in practice, PCWs do not provide comparisons that cover all tariffs available in the market. In particular, collective switching schemes hosted by a PCW may not be displayed in searches conducted by rival PCWs. We consider that the fact that this is the case, notwithstanding the Whole of the Market Requirement, is potentially confusing and misleading for customers and therefore has the potential to undermine the confidence of customers in PCWs (see paragraph 13.277(d)). We consider that these risks would be heightened by the removal of the four-tariff rule (which itself limits PCWs' ability to agree bespoke supply contracts), as we are recommending to Ofgem (see Section 12).
- 13.272 We have conducted some analysis that sheds some light on the potential impact of the Confidence Code on accredited PCWs. In particular, we have looked at the evidence on the impact of the recent changes to the Confidence Code on the number of fulfillable tariffs²⁰⁶ and the number of acquisitions via PCWs (as a proportion of total acquisitions).
- 13.273 We consider that a reduction in the number of tariffs in the top 10 (cheapest tariffs) that are fulfillable since the introduction of the recent changes to the Confidence Code could be evidence of a damaging impact on the business model of PCWs. First, it would be consistent with suppliers using PCWs to advertise tariffs while avoiding paying commissions, which could dampen

²⁰⁵ Ofgem letter (25 March 2015), [Publication of revised Confidence Code, Requirements 5F-I](#).

²⁰⁶ Suppliers determine which of their tariffs are 'fulfillable' via PCWs. A fulfillable tariff is one for which a PCW can facilitate the switch and is paid a commission for doing so. A PCW will receive no commission for displaying results for non-fulfillable tariffs.

PCWs' incentives to invest in the domestic retail energy markets. Second, it could be damaging to customer engagement by adding additional steps in the switching process and excluding PCWs from facilitating the switching process.

13.274 Table 13.1 shows information on the number of dual fuel direct debit tariffs in 'Top 10' displays on PCWs that were fulfillable on the uSwitch, MoneySuperMarket and Energyhelpline websites in March (before the change to the Confidence Code), September and December 2015.

Table 13.1: Number of top 10 dual fuel direct debit tariffs that were fulfillable by the PCW

	<i>Total fulfillable out of top 10 dual fuel tariffs</i>		
	<i>March 2015</i>	<i>September 2015</i>	<i>December 2015</i>
uSwitch	6	4	4
MoneySuperMarket	9	6	5
Energyhelpline	10	7	6

Source: Ofgem.

13.275 These results show that, for tariffs available to customers who pay by direct debit (which represent the cheapest deals of all and the most popular form of acquisition tariffs), uSwitch, MoneySuperMarket and Energyhelpline were remunerated for fewer tariffs in the top ten in December 2015 compared with March 2015.

13.276 We also found some evidence that the proportion of acquisitions via PCWs is substantially lower for some suppliers in the period July to December 2015 compared with January to June 2015 (see Table 13.2 below). We consider that if this trend were to continue it could undermine the incentives of PCWs to participate in the retail energy markets.

Table 13.2: Percentage of acquisitions by PCWs (all tariffs, excluding white labels)

	<i>Jan 2015 to Jun 2015</i>		<i>Jul 2015 to Dec 2015</i>		
	<i>Electricity</i>	<i>Gas</i>	<i>Electricity</i>	<i>Gas</i>	<i>Both</i>
[X]	[X]	[X]	[X]	[X]	
[X]	[X]	[X]	[X]	[X]	
[X]	[X]	[X]	[X]	[X]	
[X]	[X]	[X]	[X]	[X]	
[X]	[X]	[X]			[X]
[X]	[X]	[X]			
[X]	[X]	[X]	[X]	[X]	
[X]	[X]	[X]	[X]	[X]	
[X]	[X]	[X]	[X]	[X]	

Source CMA calculations based on information provides by Six Large Energy Firms and Mid-tier Suppliers.

13.277 We have considered the implications of the coexistence of the remedy to remove aspects of the simpler choices component of the RMR rules with the application of the Whole of the Market Requirement. In particular:

- (a) The Whole of the Market Requirement risks reducing the effectiveness of our remedy to remove the relevant aspects of the simpler choices component of the RMR rules, by reducing the ability and incentive on the part of suppliers and accredited PCWs to negotiate exclusive deals available via particular PCWs. This would be the case if the Whole of the Market Requirement meant that exclusive deals had to be displayed on all PCWs, not just on those through which they are fulfillable (which may not be practicable in practice).
- (b) Without the amendment to Ofgem's Confidence Code envisaged by this remedy, suppliers could 'game' the removal of aspects of the simpler choices component of the RMR rules by releasing many similar-priced tariffs to crowd out competitors on PCW results pages (which could also be confusing for customers).²⁰⁷ Citizens Advice,²⁰⁸ uSwitch²⁰⁹ and MoneySuperMarket²¹⁰ said that this behaviour was evident pre-the RMR rules. Ofgem said ²¹¹that such 'crowding out' of the top listings on search results had been raised with it by stakeholders as a risk.
- (c) The Whole of the Market Requirement could be impractical with an increase in the number of tariffs offered in particular where PCWs agree different tariff levels and commissions with energy suppliers.
- (d) In any event, in light of Ofgem's clarification of the current application of the Whole of the Market Requirement, the Whole of the Market Requirement could be misleading (and so undermine trust) as we have been told that an accredited PCW adhering to the Confidence Code is allowed not to show collective switching tariffs that are only available from other PCWs (for example, the Whole of the Market Requirement does not require PCWs to display the E.ON collective switching tariff available through uSwitch).

13.278 We are therefore recommending that Ofgem remove the Whole of the Market Requirement from the Confidence Code and requires accredited PCWs to be transparent over the market coverage provided to domestic customers (by, for instance, displaying a clear message explaining the results on display and clarifying that certain tariffs are not available through their site).

²⁰⁷ The Whole of the Market Requirement prevents PCWs from responding to such behaviour by consolidating very similar/identical tariffs offered by the same supplier into one entry on their results page.

²⁰⁸ Citizens Advice response to Remedies Notice, p12.

²⁰⁹ uSwitch response to Remedies Notice, p9.

²¹⁰ MoneySuperMarket response to Remedies Notice, p6.

²¹¹ Ofgem response to Remedies Notice, p1.

Aim of the remedy

13.279 The aim of the remedy is to help PCWs to promote competition to the benefit of domestic customers. More specifically:

- (a) it will promote the incentive accredited PCWs have to invest in services in the domestic retail energy markets and to promote the use of these services, helping to increase domestic customer engagement;
- (b) it will enhance the effectiveness of the remedy to remove certain aspects of the simpler choices component of the RMR rules as it will facilitate the negotiation of exclusive deals by accredited PCWs; and
- (c) it will allow PCWs to manage any attempts by suppliers to game to their advantage the removal of the relevant aspects of the simpler choices component of the RMR rules (in particular, the constraints on the number of tariffs a supplier can offer) by releasing many similar priced tariffs in order to crowd out competitors on PCW results pages.

Parties' views

13.280 Generally the Six Large Energy Firms supported the remedy (E.ON said that it did not object to the remedy)^{212,213,214} and some suggested further measures as follows:

- (a) Centrica said that if the 'whole of the market' requirement was removed, additional protections would be needed to ensure customers were aware of how much market coverage a PCW was providing. Centrica also said that as PCWs were an increasingly critical channel for customers, the CMA should recommend that Ofgem review the regulatory framework for PCWs as part of its TPI intermediary regulation.²¹⁵
- (b) EDF Energy said that all TPIs should be required to state if they were not providing a 'whole of market' view and show which suppliers were paying them a commission. EDF Energy also said PCWs should have to provide a 'key facts' document and display their accreditation to the Ofgem Code of Practice.²¹⁶

²¹² E.ON response to provisional decision on remedies, p40, paragraph 198.

²¹³ Scottish Power response to provisional decision on remedies, p11, paragraph 7.3.

²¹⁴ SSE response to provisional decision on remedies, Annex 1, p7, paragraph 6.2.1. SSE said it had been supportive of the 'whole of market' requirement in the past but given the removal of the limit to the number of tariffs it seemed sensible to re-evaluate the requirement for practical reasons.

²¹⁵ Centrica response to provisional decision on remedies, p68 & 69, paragraphs 347–350.

²¹⁶ EDF Energy response to provisional decision on remedies, pp39 & 40, paragraphs 8.25–8.29.

(c) RWE said the CMA could recommend to Ofgem that the Confidence Code was the mechanism used to ensure PCWs use a common set of search criteria to enable consumers to compare offers and that Ofgem provide clear guidelines on how the value of any bundle or incentive is displayed.²¹⁷

13.281 First Utility said it agreed with the remedy. First Utility said PCWs could provide a link to the Citizens Advice comparison tool and/or to the 'Be an Energy Shopper' website to assist customers. First Utility also said it did not support allowing PCWs to have fully exclusive tariffs because this might cause those switchers who subsequently find they could have got a cheaper tariff elsewhere to disengage from PCWs or the market altogether.²¹⁸

13.282 National Energy Action supported the commitment to ensure PCWs were transparent about the information they displayed. National Energy Action said all PCWs should provide a link to the Citizens Advice price comparison service before allowing customers to click and switch and all PCWs should clearly inform customers which suppliers are obliged to provide Warm Home Discount rebates and had an Energy Company Obligation.²¹⁹

13.283 We have taken into account the comments made in relation to the positive role that Citizens Advice's price comparison tool can play to assist domestic customers in comparing tariffs and support the development of this tool (see paragraph 13.305 to 13.310 and 13.312 below). However, we do not consider that the design of this remedy need be expanded to achieve the main aim of this remedy, ie to promote competition among PCWs to the benefit of domestic customers.

13.284 Ovo Energy said it could see how suppliers might become incentivised to introduce cheaper tariffs as a result of the remedy but it anticipated these tariffs would only be available to new customers who visit PCWs and it did not see the remedy reducing the cost to customers on default tariffs, who might end up being overcharged more.²²⁰

13.285 BGL Group (Comparethemarket.com) said the Whole of the Market Requirement had given rise to unintended adverse consequences and undermined PCWs' incentives to be active in the market.²²¹ uSwitch said it supported the remedy as a practical step to address the supplier-PCW

²¹⁷ RWE response to provisional decision on remedies, p62, paragraph 52.3.

²¹⁸ First Utility response to provisional decision on remedies, p18, paragraphs 4.30 & 4.31.

²¹⁹ National Energy Action response to provisional decision on remedies, p3.

²²⁰ Ovo Energy response to provisional decision on remedies, p10, paragraph 2.25.

²²¹ BGL Group (COmparethemarket.com) response to provisional decision on remedies, pp 4–6, paragraphs 4.1–4.16.

incentives framework under the proposed removal of the ‘simpler choices’ component of RMR. uSwitch also said the current Confidence Code requirements provided a basis to meet the CMA’s transparency suggestions.²²²

- 13.286 Which? said it broadly welcomed this and other remedies to improve the functioning of the competitive PCW market. Which? agreed with the requirement for transparency by PCWs if the requirement was removed.²²³
- 13.287 Citizens Advice said the argument that this remedy would generate competition within the domestic retail energy markets was not as strong as suggested. In practice, removing the Whole of Market Requirement would increase, not reduce, the hassle associated with switching as consumers would need to check multiple PCWs to be confident they were getting the best deal. Citizens Advice also said removal of the requirement risked compromising the existing quality of accredited PCWs and the impact of the remedy would need to be kept under close review so Ofgem could consider reintroducing the requirement if necessary.²²⁴
- 13.288 We have explained above (see paragraph 13.277(d)) that PCWs are currently allowed not to show collective switching tariffs that are only available from other PCWs, which means that to be sure of getting the best deal customers already need to check multiple PCWs. We also think that there is a risk that customers will believe they are seeing the whole of the market when this may not actually be the case and that with the removal of the ‘four-tariff rule’ the potential for the Whole of the Market Requirement to be misleading will be greater.
- 13.289 The remedy will ensure that the scope of searches conducted by a PCW and results displayed are clear to their customers (see paragraph 13.278). Moreover, this remedy will have enhanced effectiveness in conjunction with our other remedy concerning the recommendation to introduce a new Standard of Conduct requiring suppliers to have regard, in the design of their tariffs, to the ease with which customers can compare value for money with other tariffs they offer. Several parties commented on the potential impact of the remedy on Citizens Advice’s price comparison service.
- 13.290 Citizens Advice said that in order for its price comparison service to provide market-wide coverage it would need access to appropriate data from

²²² uSwitch response to provisional decision on remedies, p7, section 3.3.

²²³ Which? response to provisional decision on remedies, p3.

²²⁴ Citizens Advice response to provisional decision on remedies, pp 28 & 29.

suppliers in good time. In addition, Citizens Advice said further changes might be needed, including more advertising of its PCW, for example through providing the URL on all energy bills and suppliers' websites.²²⁵ Ofgem said that to assist Citizens Advice in providing full market coverage, the CMA might wish to consider whether Citizens Advice's powers would be sufficient and effective in supporting its role to display whole of the market information as some tariff types may not be displayed by accredited sites (eg prepayment tariffs).²²⁶

13.291 In this regard, Citizens Advice have confirmed that they have information gathering powers²²⁷ to require suppliers, on an ongoing basis, to notify Citizens Advice of any changes to their tariffs. Citizens Advice said that as it already had a relationship with Energylinx, it would need to use these powers only to gather information on 'exclusive' tariffs.

13.292 The Centre for Competition Policy also said the remedy had implications for the Citizens Advice price comparison service. In particular, with whole market coverage being a regulatory requirement, it may be relatively cheap and easy for Citizens Advice to procure a whole market comparison from a commercial provider but if this requirement was removed there could be uncertainty about this. It said there were sound arguments for guaranteeing a comprehensive and accredited whole market list of tariffs. It also said it was important to recognise that PCWs were market participants with their own incentives and that evidence obtained from them should be appraised accordingly. It also said an effective framework of rules, monitoring and enforcement for PCWs was needed.²²⁸

Implementation of this remedy

13.293 We are implementing this remedy through a recommendation to Ofgem to remove the Whole of the Market Requirement in the Confidence Code²²⁹ and to introduce a requirement for PCWs accredited under the Confidence Code to be transparent over the market coverage that they provide to energy customers.

Assessment of effectiveness

13.294 In assessing the effectiveness of the remedy, we have considered not only the extent to which it is effective in achieving its aims (see paragraph

²²⁵ Citizens Advice response to provisional decision on remedies, p30.

²²⁶ Ofgem response to provisional decision on remedies, p6.

²²⁷ Under section 24 of the Consumers, Estate Agents and Redress Act, 2007.

²²⁸ Centre for Competition Policy response to provisional decision on remedies, pp15 & 16.

²²⁹ Requirement 2A.

13.279), but also the extent to which the remedy is capable of effective implementation, monitoring and enforcement, and the timescale over which the remedy is likely to have an effect.

13.295 As regards implementation, we consider that Ofgem is well placed to make the necessary changes to the Confidence Code, as it is responsible for managing the Confidence Code, monitoring compliance and accrediting and withdrawing accreditation from PCWs. In particular, given our recommendation to Ofgem to remove aspects of the simpler choices component of the RMR rules, we consider that Ofgem will be best placed to coordinate the timing of the implementation of the removal of the Whole of the Market Requirement.

13.296 We consider that the changes to the Confidence Code could be implemented simultaneously with our recommendations concerning suppliers' licence conditions. In this regard, Ofgem could consult on the removal the Whole of the Market Requirement from the Confidence Code as soon as possible after we publish our final report, with this process expected to conclude by the end of 2016. The change could then be implemented by the beginning of 2017.

13.297 In addition, Ofgem is well placed as the sector regulator to adapt and develop the Confidence Code in light of further developments in the retail markets.

Assessment of proportionality

13.298 We consider this remedy to be proportionate because it will be effective at achieving its legitimate aims identified in paragraph 13.279 and the overall aim of promoting the role of PCWs in the domestic retail energy markets. It will also involve minimal costs to implement, and PCWs will overall face a reduced regulatory burden by replacing a need to verify their own compliance with the Whole of the Market Requirement with a requirement for accredited PCWs to be transparent over the market coverage provided to domestic customers (by, for instance, displaying a clear message explaining the results on display and clarifying that certain tariffs are not available through their website). We believe that requiring PCWs to be transparent over the market coverage they provide will facilitate customer engagement, and work synergistically with our other remedies concerning domestic customer engagement.

13.299 Accordingly, we believe this remedy is no more onerous than necessary and the least onerous of equally effective remedies.

13.300 As part of our proportionality assessment, we have also considered whether the remedy produces adverse effects that are disproportionate to its aim. In the context of this assessment, we have considered any unintended consequences resulting from the remedy. We acknowledge that the removal of Whole of the Market Requirement potentially risks creating confusion on the part of customers and / or a lack of trust in PCWs if customers continue to believe that PCWs provide information on all tariffs available in the market.

13.301 We believe our remedies address any such concerns – without undermining the incentives of PCWs to engage customers - by requiring greater transparency and clarity from PCWs about market coverage. Indeed, we believe this will improve on the current situation, in which, despite the Whole of the Market Requirement, PCWs are not required to list all deals available to customers. Further, Citizens Advice is now operating a non-transactional PCW that lists all tariffs through a web-based service, which we believe will meet the needs of those customers who wish to see the whole of the market.

Remedy we are not adopting: an Ofgem price comparison service for domestic and/or microbusiness customers

13.302 We have identified a number of features of the markets for the retail supply of energy to domestic customers that combine to give rise to the Domestic Weak Customer Response AEC. One of these features is that certain domestic customers face actual and perceived barriers to accessing and assessing information arising from a lack of confidence in and access to PCWs.

13.303 To address our concerns in this area one possible remedy included in our Remedies Notice was for Ofgem to provide an independent price comparison service for domestic customers.

Aim of the remedy

13.304 The aim of this remedy was to improve trust in PCWs, and thereby, to encourage greater use by domestic customers. As discussed above, this might be particularly desirable given our recommendation to remove aspects of the simpler choices component of the RMR rules and the Whole of the Market Requirement in the Confidence Code, with a view to addressing the concerns of those domestic customers that do not wish to shop around different PCWs to understand the best deals available from suppliers.

Citizens Advice domestic price comparison service

- 13.305 Following the publication of our Remedies Notice, Citizens Advice launched a new domestic price comparison service operated as a white-label solution with source data provided by Energylinx, which is Confidence Code accredited. This was launched alongside the Big Energy Saving Week on 26 October 2015.
- 13.306 This Citizens Advice service is information-only (ie users cannot use it to sign up for a particular deal) and provided face to face and online. Citizens Advice said that at some point the service may become transactional, with this decision based on user needs and whether it would be the right approach for Citizens Advice to take. Citizens Advice said it would monitor the service to see if customers would benefit from having assistance over the phone. Where possible Citizens Advice has said it will endeavour to monitor user profiles by channel.^{230,231}
- 13.307 The tool provides full market coverage and the default is set to show all tariffs to customers. Citizens Advice said that the comparison service will display suppliers who currently do not feature on commercial PCWs including Utility Warehouse and other small specialist suppliers. Citizens Advice said it had been able to encourage some additional suppliers to list their tariffs on Energylinx (and, therefore, Citizens Advice's comparison service) including Economy Energy, and E Gas and Electric.
- 13.308 Citizens Advice said that the service was promoted through its website, the telephone Consumer Service, the network of local Citizens Advice, media messages and videos it was launching to help customers understand how to use a prepayment meter. Citizens Advice said that certain larger suppliers had also agreed to signpost customers to the tool via their websites.
- 13.309 Citizens Advice also said that it had recently launched a new suite of energy content on its website, including advice on how to use a PCW and how to switch. The content would also include supplier performance statistics, including comparable information about service performance and customer

²³⁰ The Citizens Advice bureau statistics summarises the profile of bureau clients for England and Wales. These show: (a) the majority (31%) of bureau clients are aged 35 to 49 years old and a further 27% are aged 50 to 64 years old (age not recorded for 10%); (b) 18% are from black and minority ethnic groups (ethnic origin not recorded for 11%); (c) 38% have long-term health problems and/or a disability (disability or health status not recorded for 21%), (d) the majority (33%) are social tenants and a further 27% private tenants (housing tenure not recorded for 41%).

²³¹ Results for Citizens Advice Scotland show that during November 2014: (a) one-third of clients were aged 45 to 59 years old, and 29% lived in council-let properties.

service and educational information to help customers understand the benefits of switching and where to get further help with energy issues.

- 13.310 The cost of the service is funded out of the Citizens Advice programme budget which is from the grant received from BIS to fund its energy work.
[✂]

Parties' views

- 13.311 Centrica, EDF Energy and E.ON said that they supported the decision not to proceed with an Ofgem PCW. In particular:
- (a) Centrica believed an Ofgem PCW would have had a material and negative impact on existing PCWs and their ability to compete in the market. Centrica said it also recognised that the Citizens Advice PCW mitigated the need for this remedy.²³²
 - (b) EDF Energy said there was no reason to believe an Ofgem PCW would improve on the service provided by Citizens Advice and would be an unnecessary burden on the regulator.²³³
 - (c) E.ON said the introduction of the Citizens Advice service had delivered a trusted solution.²³⁴

Our assessment of an Ofgem price comparison service for domestic customers

- 13.312 Our view is that an Ofgem price comparison service would not add significant further value to that already provided by the Citizens Advice service. We also note that Ofgem itself has stated that it does not currently have the expertise to set up and run such a service.

Conclusion

- 13.313 Given that the Citizens Advice service is now available, we have decided not to pursue this remedy. We believe that the Citizens Advice service will be sufficient to address the concerns of those customers that do not wish to shop around PCWs to understand the best deals available from suppliers. We note that there may still be better PCW-specific deals available for those customers prepared to use more than one PCW.

²³² Centrica response to provisional decision on remedies, p69, paragraph 350.

²³³ EDF Energy response to provisional decision on remedies, p40, paragraphs 8.31–8.33.

²³⁴ E.ON response to provisional decision on remedies, p39, paragraph 191.

Providing PCWs (and other TPIs providing similar services) with access to the ECOES and SCOGES databases

- 13.314 We have found that customers face actual and/or perceived barriers to switching, such as where they experience erroneous transfers. While we acknowledge that erroneous transfers represent a small percentage of all successful domestic switches in energy supply, around 1%,²³⁵ they may nonetheless affect customers' ability to switch as well as more broadly their perception of switching. Further, we have noted that the complexity of the switching process can lead to delays, errors and costs, which, in turn, may have an impact on broader customer confidence and the propensity of domestic customers to switch.²³⁶
- 13.315 We considered whether PCWs should be given access to the Electricity Central Online Enquiry Service (ECOES) database²³⁷ (managed by Gemserv Limited (Gemserv)) and the Single Centralised On-Line Gas Enquiry Service²³⁸ (SCOGES) database (managed by Xoserve Limited (Xoserve)), in order to allow them to facilitate the switching process for customers.
- 13.316 The ECOES database was designed to assist suppliers in the customer transfer process by allowing the triangulation of data (pre-registration checking of Meter Point Administration Number (MPAN),²³⁹ address and meter serial number). The ECOES database includes MPAN address, meter profile class and meter serial number database. ECOES can be accessed directly by suppliers, Meter Point Administration Service (MPAS) providers, distribution businesses, supplier agents and non-domestic customers with at least two MPANs.²⁴⁰ TPIs such as PCWs may have limited access to the ECOES database through login details provided by suppliers but suppliers remain responsible for PCWs' usage.
- 13.317 The SCOGES database is available to all gas transporters, shippers and suppliers, and some non-domestic customers.²⁴¹ This database includes

²³⁵ See Section 9.

²³⁶ See Section 9.

²³⁷ It is funded by electricity Suppliers and Distribution Business and governed under the Master Registration Agreement.

²³⁸ The database is also known as the Data Enquiry Service. See [On-Line Meter Point Search Facility: GTC User Guide](#).

²³⁹ MPAN or S Number might be needed when a customer wants to switch energy supplier. See [The Energy Shop: How to find your MPAN and MPRN meter reference numbers](#).

²⁴⁰ Access to other users can be granted subject to fulfilling access criteria and agreeing to terms and conditions. Applications are considered in accordance with the principles set out in Section 4.6.2 of MAP 15.

²⁴¹ Access to other users can be granted subject to fulfilling access criteria and agreeing to terms and conditions. Applications are considered in accordance with the principles set out in Section 7.3 of Schedule 23 of the Supply Point Administration Agreement.

Meter Point Registration Number (MPRN),²⁴² address, meter serial number, Local Distribution Zone ID, Gas Act Owner, Meter Asset Manager ID, designation²⁴³ and other data available only to large transporter sites.²⁴⁴

Aim of the remedy

- 13.318 The aim of the remedy is to reduce actual and perceived barriers to switching resulting from erroneous transfers and failed switches by giving PCWs access to the ECOES and SCOGES databases. Accordingly, the ultimate aim of this remedy is to partly address one of the features contributing to the Domestic Weak Customer Response AEC.
- 13.319 To obtain a quote from a PCW, a customer usually has to provide: postcode, current provider, current tariff name and payment method, meter type and annual consumption (although this last piece of information is not essential). To switch supplier, the customer usually needs to provide: address, contact details and other personal and payment information, and may have to provide their MPAN and/or MPRN. An incorrect MPAN/MPRN entered by a customer can result in an erroneous transfer or a failed switch. If PCWs and other TPIs had access to the ECOES and SCOGES databases, they could retrieve MPAN/MPRN numbers using the address provided by customers, therefore potentially avoiding an erroneous transfer or a failed switch.

Parties' views

- 13.320 The responses we received were generally supportive of the remedy. In particular: EDF Energy; RWE; Scottish Power; SSE; First Utility; Co-operative Energy; Ovo; Ofgem; Citizens Advice; Which?; Make it Cheaper.com; uSwitch; and Moneysupermarket.com all supported the remedy.
- 13.321 However, many parties also raised issues about the use PCWs might make of the data. In particular:

²⁴² MPRN or M Number is the equivalent of MPAN for gas and might be needed when a customer wants to switch gas supplier. See [The Energy Shop: How to find your MPAN and MPRN meter reference numbers](#).

²⁴³ Indication if the site is domestic or industrial or commercial.

²⁴⁴ There are other data fields that are available only to large transporter sites. Suppliers receive a quarterly CD-ROM with the following data: MPRN, Meter Point address and postcode, meter serial number and Local Distribution Zone ID.

- (a) RWE said Gemserv and Xoserve should be directed to consider constraining PCWs in their use of the databases in the same way that suppliers were constrained.²⁴⁵
- (b) SSE said that given the risk of ECOES and SCOGES data being used for marketing purposes, access to the data should be adequately monitored and enforced by Ofgem.²⁴⁶
- (c) EDF Energy said there would need to be restrictions on the use of the data and, to this end, it supported the CMA's proposed restrictions on use of this data.²⁴⁷
- (d) First Utility said that it would want assurance that each PCW accessing the data was following tight security controls and was monitored for compliance. First Utility said this should be covered in the terms and conditions for accessing the Database which should also specify if access would be ongoing or for a limited period of time.²⁴⁸
- (e) Co-operative Energy said that it had general concerns around the potential for the abuse of data and that additional data protection measures were needed eg PCWs had to destroy specific customer data once the switch had been finalised.²⁴⁹
- (f) Ovo Energy said PCWs should only have this access in direct response to a specific request from a customer to switch.²⁵⁰
- (g) Citizens Advice said it would strongly suggest that Confidence Code accreditation was a necessary requirement for PCWs to be granted access to the databases, and that the use being made of data was monitored and transparent.²⁵¹
- (h) Which? said careful oversight of access to consumer data was essential as any misuse of the data would undermine consumer confidence in PCWs and the switching process.
- (i) Flow Energy said it was concerned that customer information provided to suppliers by PCWs was often of poor quality and for this reason

²⁴⁵ RWE response to provisional decision on remedies, p63, paragraph 52.4.

²⁴⁶ SSE response to provisional decision on remedies, p4, paragraph 2.1.2 (c); Annex 1, p7, paragraph 7.1.3.

²⁴⁷ EDF Energy response to provisional decision on remedies, p38, paragraphs 8.18 & 8.19.

²⁴⁸ First Utility response to provisional decision on remedies, pp20 & 21, paragraphs 4.41–4.43.

²⁴⁹ Co-operative Energy response to provisional decision on remedies, p5.

²⁵⁰ Ovo Energy response to provisional decision on remedies, pp28 & 29.

²⁵¹ Citizens Advice response to provisional decision on remedies, p39.

supported PCWs having access to the ECOES and SCOGES databases.²⁵²

- (j) Haven Power said it acknowledged allowing PCWs access to the ECOES database might allow them to facilitate switching for customers and hopefully reduce erroneous transfers. Haven Power also said the access should be with explicit authorisation from the customer and rigorously monitored to prevent abuse of the data.²⁵³

13.322 Centrica said the remedy would not be effective or proportionate because suppliers already completed checks against the databases before completing an acquisition so an additional check by the PCW was unlikely to reduce the number of erroneous transfers. Centrica said it was also concerned that providing PCWs with access to customers' personal data created risks of misuse.²⁵⁴

13.323 E.ON said it was still not clear that giving PCWs access to the databases would deliver a reduced number of erroneous transfers and failed switches, or improve customers' perceptions of such issues. E.ON also said it would expect all access to ECOES and SCOGES data to be conditional on customers giving consent and access would only be given to organisations that had externally assured information security processes compliant with a recognised standard, eg ISO27001.²⁵⁵

13.324 We agree with suppliers that the terms on which PCWs are provided with access to the ECOES and SCOGES databases should allow for them to check or obtain MPAN and MPRN numbers for customers seeking to switch supplier and to check other information provided by these customers against that held in the database and should be strictly limited to these purposes. We would expect that the conditions for accessing the ECOES and SCOGES databases to include conditions that strictly limit the use of data for these purposes.

13.325 We also agree that the number of erroneous and failed transfers avoided might be small. However, we consider that a small number of erroneous and failed transfers could be expected to have a wide impact on customer perceptions (see paragraph 13.352) and disproportionate impact on

²⁵² Flow Energy response to provisional decision on remedies, p3.

²⁵³ Haven Power response to provisional decision on remedies, p3.

²⁵⁴ Centrica response to provisional decision on remedies, p69, paragraphs 351–353.

²⁵⁵ E.ON response to provisional decision on remedies, p40, paragraphs 192–197.

domestic customers' confidence in the use of PCWs and perception about the ease of switching more generally.

- 13.326 Scottish Power said the assumptions of six months' timescales for implementation and negligible costs would need to be reviewed once the design was confirmed.²⁵⁶
- 13.327 First Utility proposed further measures to reduce erroneous transfers by addressing data quality issues.²⁵⁷ Which? said it did not think these remedies would eliminate all failures in the switching process and suggested a regime of providing automatic compensation to consumers when switching goes wrong.²⁵⁸ However, we consider the design of this remedy is sufficient to achieve its aim and, therefore, any additional measures would not be proportionate (see paragraph 13.362)
- 13.328 uSwitch said that for the remedy to be useful, the terms of access for PCWs would need to be fair, the cost not prohibitive and the relevant order should be drafted to ensure the remedy remained in place should the smart meter roll-out be delayed beyond 2020.²⁵⁹
- 13.329 Moneysupermarket.com said there were three areas where it required clarification: whether or not Ofgem accreditation would be a condition of access to the databases; the type of information that would be made available; and how access would be provided including if customers would have to give their consent.²⁶⁰
- 13.330 Ofgem said it strongly agreed with implementing the remedy through an order and suggested that to improve the prospect of timely implementation the CMA should specify a timescale in the order. Ofgem also said the scope of the data that PCWs should be able to access should be clarified to assist speedy implementation.²⁶¹
- 13.331 Gemserv said it did not have authority to grant access to the ECOES database and that the order should be addressed to the Chairman of the MRA Executive Committee and directed to MRASCo Limited.²⁶² The MRA

²⁵⁶ Scottish Power response to provisional decision on remedies, pp16 & 17, paragraphs 9.1–9.4.

²⁵⁷ First Utility response to provisional decision on remedies, pp20 & 21, paragraphs 4.41–4.43.

²⁵⁸ Which? response to provisional decision on remedies, pp3 & 4.

²⁵⁹ uSwitch response to provisional decision on remedies, pp11 & 12.

²⁶⁰ Moneysupermarket.com response to provisional decision on remedies, pp3 & 4.

²⁶¹ Ofgem response to provisional decision on remedies, p9.

²⁶² Gemserv response to provisional decision on remedies, p1.

Executive Committee confirmed that the MRA Executive Committee is responsible for granting access.²⁶³

13.332 Xoserve said an order to grant access to the SCOGES database should be placed on the parties on whose behalf they hold the relevant data. These parties would then be responsible for bringing forward amendments to relevant industry codes and instructing Xoserve to make data available to relevant parties.²⁶⁴ Ofgem said that an order for access to the SCOGES database should be placed on gas transporters.

13.333 These comments have been taken into account in the implementation of this remedy (see paragraph 13.349 below).

Design considerations

13.334 In designing the remedy we have considered:

- (a) evidence on PCWs' access to the ECOES and SCOGES databases; and
- (b) how to implement this remedy.

- *Evidence on PCWs' access to the ECOES and SCOGES databases*

13.335 We asked PCWs whether they had ever applied or considered applying to obtain access to the ECOES or SCOGES databases.

- (a) uSwitch said its application to access the SCOGES database in July 2011 was rejected on the grounds that the Uniform Network Code did not allow for the release of information to a non-Uniform Network Code party. It had recently submitted an application for access to the ECOES database. uSwitch also said that it had been told that previous applications from PCWs for access to the ECOES database had been rejected. Along with the rejection of the SCOGES application, this had deterred uSwitch from formally applying for access to the ECOES database until recently.
- (b) EnergyHelpline said it had made three enquiries for access to the ECOES database over the last five years, with the last one about a year ago, but had been told that it did not qualify for access as it was not a supplier.

²⁶³ MRA Executive Committee (MEC) response to provisional decision on remedies, pp3 & 4.

²⁶⁴ Xoserve response to provisional decision on remedies, p2.

(c) Make It Cheaper said that it applied for access to the ECOES database in 2007/8 but it was rejected. It said it was given no explanation by Gemserv.

13.336 We asked the ECOES database administrator, Gemserv, and the SCOGES database administrator, Xoserve, whether there is any legal requirement or other barrier preventing PCWs from accessing these databases.

(a) Gemserv said that any PCW could apply for access to the ECOES database and would, in principle, be given access if they met a number of access criteria. It said it had received only one application from a PCW over the last few years but the application was incomplete and the PCW had not provided the additional information required for it to be able to process the application. In response to a recent request for information, Gemserv said that it had recently received a number of applications for access to the ECOES database [REDACTED].

(b) Xoserve said that it did not have any record of PCWs applying for access to the SCOGES database. It said that access was governed by the SPAA industry code which sets out the rules and processed for 'Other Users Access'. It added that PCWs' access is dependent upon amendments being made to both the SPAA industry code and the Uniform Network Code.

13.337 Most PCWs said that they currently used a third party data provider, GB Group, to retrieve MPAN and MPRN information on behalf of their customers, but the ECOES and SCOGES databases were generally considered more accurate and up to date than the GB Group database.

13.338 uSwitch said that the GB Group data provided meter numbers based on address, but coverage was limited to approximately 90% of Great Britain and this meant that 10% of customers were required to enter their meter number manually to complete their application, which could act as a barrier to switching. uSwitch also said that in some cases the postcode list in the GB Group database was out of date and an energy region could not be sourced. This meant that some customers would be unable to progress beyond the uSwitch homepage. uSwitch estimated that approximately 1 to 2% of customers attempting to use its website would be unable to receive a quote due to errors caused by this incomplete postcode data.

13.339 PCWs [REDACTED].

13.340 The GB Group database is compiled using a limited MPAS data set supplied by Gemserv on a monthly basis and other various data sources. We also understand that Gemserv and the GB Group have a commercial agreement

in place, whereby they share some of the revenues received from the sale of the GB Group database.

- 13.341 Xoserve submitted that the GB Group currently provided an address management service to Xoserve but that it does not provide any data or information to enable the GB Group to provide this service.
- 13.342 It therefore appears to us that, in practice, PCWs do not have direct access to the ECOES and SCOGES databases. The precise reasons for this are unclear. Whilst they do have access to the GB Group data, at a cost of [redacted], this information is not as accurate or up-to-date as the ECOES and SCOGES databases.
- 13.343 The aim of this remedy is to reduce actual and perceived barriers to switching resulting from erroneous transfers and failed switches, and we consider, based on responses to our provisional decision on remedies,²⁶⁵ that access to the ECOES and SCOGES databases will also benefit other TPIs providing similar services to PCWs.
- 13.344 In light of the above, this remedy will require (through a CMA order) the code administrator or governing body with authority to grant access to the ECOES database to grant access to the database to PCWs (and other TPIs providing similar services). This remedy will also require (through a CMA order) gas transporters to grant access to the SCOGES database to PCWs (and other TPIs providing similar services) on reasonable terms. We understand that amendments to the relevant industry codes may be required. Therefore, this remedy will also require gas transporters to make any necessary amendments to the Uniform Network Code.
- 13.345 This remedy will enable PCWs (and other TPIs providing similar services) to check or obtain MPAN and MPRN numbers for customers seeking to switch supplier and to check other information provided by these customers against that held on the databases. Use of the data by PCWs (and other TPIs providing similar services) should be strictly limited to these purposes. Any charge for access to the data should be based on the incremental cost to the database administrators of providing this access.
- 13.346 Some parties²⁶⁶ considered that access to the ECOES and SCOGES databases would still be relevant after the roll-out of smart meters, although

²⁶⁵ Flipper Ltd response to the provisional decision on remedies.

²⁶⁶ E.ON response to Remedies Notice, p25, paragraph 115 (E.ON just referred to the ECOES database); RWE response to Remedies Notice, p7; Scottish Power response to Remedies Notice, paragraph 4.14, p13 (p47 of PDF); and Utilities Savings response to Remedies Notice, p7.

uSwitch²⁶⁷ said that after the roll-out of smart meters there might be a reduced need for access to the ECOES database by PCWs, and Co-operative Energy²⁶⁸ said that PCWs would be able to access data directly through the DCC. Ofgem said that there would still be a need for a central database²⁶⁹ to facilitate switching.

13.347 In addition, PCWs (and other TPIs providing similar services) will have access to meter number information through phase 2 of Midata, when implemented, and subject to implementation of our remedy described below, on enhanced access terms. Midata will also allow PCWs (and other TPIs providing similar services) to access consumption data and allow them to provide a more accurate comparison of the potential gains from switching (see paragraphs 13.364 to 13.398).

13.348 We recognise that with these developments PCWs (and other TPIs providing similar services) might, in the future, not need access to the ECOES and SCOGES databases for the purposes set out in the remedy. However, given that the time frame for the development of Midata phase 2 and any centralised registration system is uncertain, and that there would still be a need for PCWs (and other TPIs providing similar services) to access the ECOES and SCOGES databases despite the roll-out of smart meters, we have decided not to include a sunset provision for this remedy.

- *Implementation of this remedy*

13.349 We are implementing this remedy through:

- (a) an order on the code administrator or governing body with authority to give access to the ECOES database, to give access to this database to PCWs (and other TPIs providing similar services) upon request when a customer is seeking to switch supplier; on reasonable terms; and subject to satisfaction of reasonable access conditions;
- (b) an order on the gas transporters to:
 - (i) give access to the SCOGES database to PCWs (and other TPIs providing similar services) upon request when a customer is seeking to switch supplier; on reasonable terms; and subject to satisfaction of reasonable access conditions; and

²⁶⁷ uSwitch response to Remedies Notice, p15.

²⁶⁸ Co-operative Energy response to Remedies Notice, p7.

²⁶⁹ Ofgem response to Remedies Notice (Remedy 4), p3.

- (ii) make any necessary amendments to the Uniform Network Code to reflect the requirement set out in our order.

Assessment of effectiveness

- 13.350 As we explain below, our view is that the remedy is effective in achieving its aims of reducing actual and perceived barriers to switching resulting from erroneous transfers and failed switches. Accordingly, our view is that the remedy is effective in partly addressing one of the features giving rise to the Domestic Weak Customer Response AEC (and the resulting detriment).
- 13.351 Our assessment of effectiveness of the remedy has considered the following factors:
- (a) the extent to which the remedy may reduce erroneous transfers and failed switches; and
 - (b) the extent to which the remedy may encourage switching.
- 13.352 We consider that providing PCWs (and other TPIs providing similar services) with access to the ECOES and SCOGES databases has the potential to reduce erroneous transfers and failed switches by avoiding the need for customers switching using a PCW (or a company providing similar services) to enter their meter numbers or for PCWs to rely on the GB Group database, which is less accurate than direct access to the ECOES and SCOGES databases. While, in absolute terms, the number of cases of switching that access to the ECOES and SCOGES databases may directly facilitate may be small, cases of erroneous transfers and failed switches could be expected to have a wider and disproportionate impact on domestic customers' confidence in the use of PCWs (or a company providing similar services) and perception about the ease of switching more generally.
- 13.353 We also consider that giving PCWs (and other TPIs providing similar services) access to the ECOES and SCOGES databases may encourage switching by reducing the need to ask customers to provide their meter numbers to PCWs. For example:
- (a) Citizens Advice²⁷⁰ said that people were more likely to abandon the comparison process when asked for additional data; and
 - (b) uSwitch²⁷¹ said that for the 10% of customers that had to input their meter numbers manually, this reduced the chance of them completing

²⁷⁰ [Consumer groups multi party hearing](#), 2 September 2015.

²⁷¹ uSwitch response to Remedies Notice, p14.

an application form by [X]%; and having to input the data manually led to a higher risk of making an error, which reduced the probability of a switch going live by [X]%.

- 13.354 As regards the implementation, monitoring and enforcement of the remedy, we believe that the code administrator or governing body with authority to grant access to the ECOES database and the gas transporters will readily be able to comply with an order specifying that access must be granted (upon request) to PCWs (and other TPIs providing similar services) on reasonable terms and subject to satisfying reasonable access conditions. We are not being prescriptive as regards the terms and conditions for access, since their determination should rest with the bodies responsible for managing the ECOES and SCOGES databases, respectively, and they will need to adapt what is 'reasonable' according to how the retail markets develop. In terms of monitoring compliance and enforcement, we consider that PCWs (and other TPIs providing similar services) will be incentivised to inform the CMA if they are unreasonably refused access to either database.
- 13.355 In terms of timescale for implementation, the CMA will draft and consult on an order requiring the code administrator or governing body with authority to grant access to the ECOES database and the gas transporters to provide PCWs (and other TPIs providing similar services) with access to the specified data in the six-month period following publication of this report, with this process expected to conclude by the end of 2016. The code administrator or governing body with authority to grant access to the ECOES database, and the gas transporters could then be expected to provide access to PCWs (and other TPIs providing similar services) from the beginning of 2017 onwards.
- 13.356 Our assessment of the effectiveness of this remedy has also assessed compliance with existing laws and regulations. We acknowledge that access to the ECOES and/or SCOGES databases may involve data protection issues arising, in particular, from the potential misuse of the data by PCWs (ie PCWs and other TPIs providing similar services) using the data for sales and marketing rather than to facilitate a switching request), and may therefore be subject to the DPA.
- 13.357 The Information Commissioner's Office²⁷² has informed us that the ECOES data linked to a domestic property is likely to be personal data and therefore access to the ECOES database by PCWs (and, by analogy, other TPIs providing similar services) would need to be compliant with the DPA. We

²⁷² The Information Commissioner's Office response to Remedies Notice, paragraph 59.

understand that this includes having a legitimate justification for accessing the information held on the ECOES database, and ensuring that individuals are made aware of what information is being accessed and why. We consider that this advice would apply equally to SCOGES data.

13.358 We have also considered the potential for this remedy to interact with our remedies concerning the Microbusiness Weak Customer Response AEC, in particular, the remedy concerning price transparency which may facilitate PCWs' (and other TPIs providing similar services) entry into the microbusiness segments. Given that any such PCW (or company providing similar services) will also be able to access the ECOES and SCOGES databases pursuant to this remedy, we consider that the beneficial effect of this remedy will also be felt in the microbusiness segments and has the potential to address (in part) the equivalent feature giving rise to the Microbusiness Weak Customer Response AEC.

Assessment of proportionality

13.359 In addition to assessing how the remedy is effective in achieving its aim of reducing actual and perceived barriers to switching resulting from erroneous transfers and failed switches, we have also assessed whether the remedy is no more onerous than needed to achieve its aim, is the least onerous if there is a choice between more than one effective measure, and does not produce disadvantages which are disproportionate to its aim.

13.360 As noted above, we have decided not to be prescriptive as regards the terms and conditions for PCWs (and other TPIs providing similar services) to be given access to allow for the code administrator or governing body with authority to grant access to the ECOES database and the gas transporters to refuse unmeritorious applications where a set of reasonable criteria are not satisfied. Our order will also allow the code administrator or governing body with authority to grant access to the ECOES database and the gas transporters the flexibility to change access conditions over time. In doing so, we consider that the remedy will be no more onerous than necessary and is the least onerous of equally effective measures.

13.361 In terms of the costs of implementing this remedy, we consider that these will be negligible, in terms of limited additional processing costs for the code administrator or governing body with authority to grant access to the ECOES database and the gas transporters and the potential loss to Gemserv of any fee-sharing arrangement with the GB Group (in the event that fewer PCWs purchase the GB Group database having accessed the ECOES database directly).

13.362 We have also considered whether there may be alternative designs of this remedy to achieve the same aim that are less onerous. For the reasons noted above, we consider that the remedy, as designed, appropriately balances the need for the remedy to be effective, and proportionate.

Conclusion

13.363 Our conclusion is that the remedy is effective and proportionate in reducing the number of erroneous transfers, failed switches and facilitating the switching process more generally in the short term and prior to future developments which have the potential to address this issue.

Revising the Midata programme

13.364 We have found that:

- (a) Customers have limited awareness of and interest in their ability to switch energy supplier. This arises partly from the role of traditional meters and bills, which give rise to a disparity between actual and estimated consumption.
- (b) Customers face actual and/or perceived barriers to switching, such as where they experience erroneous transfers which have the potential to cause material detriment to those who suffer from them. Erroneous transfers may thereby affect customers' ability to switch as well as their perception of switching.

13.365 In the interim period pending the introduction of smart meters, and notwithstanding their introduction, we have considered whether any other remedies may be required to address the existing, and residual, level of confusion around consumption and barriers to switching for domestic customers in the short and long term respectively. We consulted in the provisional decision on remedies on whether the Midata programme, as currently envisaged, provides sufficient access to customer data by PCWs to facilitate ongoing engagement in the domestic retail markets, and whether PCWs should be able to access consumer data at a future date (with customers' permission).

The Midata programme as currently envisaged

- 13.366 Midata is a voluntary programme the government is currently developing with the energy and other industries.²⁷³ Its overall aim is to provide consumers with information that companies hold on their transactions in electronic, machine-readable format, and make it easier to compare the different offers available.²⁷⁴
- 13.367 Other sectors where Midata has been considered are banking (personal current accounts and credit cards)²⁷⁵ and mobile phones.²⁷⁶ Implementation of Midata in the domestic retail energy markets is being led by DECC. Phase 1 of the project, which has already been implemented, allows consumers to view and download their consumption data as a csv file from their supplier's website. Currently, it is offered by the seven largest suppliers,²⁷⁷ whose combined market share in the domestic markets totals 93% for both gas and electricity.²⁷⁸
- 13.368 Phase 2 of Midata is expected to be launched by the end of 2016 and we support the introduction of phase 2 of Midata with mandatory participation by all suppliers as soon as possible.
- 13.369 We note that implementation of phase 2 of Midata requires the resolution of a number of technical issues such as identifying and clarifying outstanding points from design specification; needing suppliers and third parties to build solutions (the timing of which depends on the systems and work schedules of participating suppliers and TPIs); needing suppliers and third parties to carry out joint testing and launch an additional alternative authentication route for a consumer which does not involve online account management; conform inconsistencies around data items (such as tariff names) and the specified sequence of data; enter into third party and supplier agreements;

²⁷³ The programme has been voluntary since its launch in November 2011. In 2013 the government gained the powers to require companies to release data through the Enterprise and Regulatory Reform Act 2013 for the energy, personal current accounts, credit cards and mobile phones sectors.

²⁷⁴ Department for Business, Innovation and Skills, [midata: Government response to the 2012 consultation](#), p3.

²⁷⁵ In the personal accounts sector, a number of retail banks have signed up to the Midata initiative, allowing their customers to download their own transaction data from the previous 12 months for their current account in a single file, which can then be uploaded to a PCW to obtain the comparison. However, only one PCW (GoCompare) currently offers a Midata comparison tool in this sector (see CMA Retail Banking market investigation: provisional findings report, [Appendix 3](#)).

²⁷⁶ In the mobile phones sector, all of the major telecoms companies provide customers with online accounts and the ability to download .pdf bills, but most do not provide the facility to download mobile phone usage data in a machine-readable, reusable format. There are already comparison sites that exist that provide automated access to customers' usage records (eg Billmonitor). BIS (July 2014), [Personal data: Review of the midata voluntary programme](#).

²⁷⁷ The Six Large Energy Firms and First Utility.

²⁷⁸ Source: Cornwall Energy data submitted to the CMA (data from Q1 2015 on meter points), in the [provisional findings report](#), Table 7.4.

and agree the participation of other suppliers. Notwithstanding changes to the technical specification, we propose that making participation mandatory for all suppliers be implemented first and then changes made to the specification of Midata.

- 13.370 When implemented, domestic customers under current proposals for phase 2 will be able to give a third party (eg a PCW) access to download their Midata file in a 30-minute window, without having to download or upload the csv file themselves, and TPIs could then use this data to provide a comparison between tariffs.²⁷⁹
- 13.371 According to the most recent specification, Midata will include, but will not be limited to, the following data: postcode, current gas and electricity provider(s), current electricity and gas tariff(s), actual annual electricity and gas usage,²⁸⁰ MPAN and MPRN.²⁸¹

Aim of the remedy

- 13.372 The aim of the remedy is to help domestic customers understand the best tariffs available for their consumption levels and consumption patterns, and to simplify the search and switching process for domestic customers, by giving TPIs direct access through Midata to customer data held by suppliers. Accordingly, the ultimate aim of this remedy is to address the features that customers have limited awareness of, and interest in, their ability to switch energy supplier and that certain customers face actual and perceived barriers to accessing and assessing information, and to help address the Domestic Weak Customer Response AEC.

²⁷⁹ In terms of process, the third party will redirect the customer to their current supplier's website for authentication and consent. The current supplier will then create an access token that the third party will use to be able to access the customer's Midata within a 30-minute window. The customer will then be redirected to the third party's website and be shown a list of the switching options.

²⁸⁰ Annual usage, estimated annual consumption and estimated annual cost are only available after a consumer has been with the current energy supplier for over 12 months.

²⁸¹ Other data fields: customer reference number, current electricity payment method, current gas payment method, start date of the contract with the current energy supplier, estimated annual consumption, estimated annual cost, payload creation date, last updated date and contract end date.

Parties' views

13.373 Many parties, including all of the Six Large Energy Firms, First Utility,²⁸² Citizens Advice,²⁸³ some PCWs/TPIs^{284,285,286} and Professor Littlechild et al,²⁸⁷ were broadly supportive of the remedy, especially making suppliers' participation in Midata mandatory.

13.374 Several parties raised issues about data protection and data security:

- (a) Centrica said that, in expanding access to PCWs, there should be a review of the security arrangements for Midata.²⁸⁸
- (b) EDF Energy said it had concerns over the management of third party access to data handled by the DCC from smart meters, in particular regarding consumption data and the potentially serious privacy implications. It therefore believed that the availability of consumption data needed careful control, potentially through additional regulation.²⁸⁹
- (c) EDF Energy also said measures were needed to ensure third parties did not sell or transfer the data to other third parties without direct permission from the customer.²⁹⁰
- (d) E.ON said there was a need for all parties accessing Midata to be in strict compliance with data protection legislation.²⁹¹
- (e) Co-operative Energy said it had general concerns around PCWs having access to industry data and the potential for the abuse of this through inappropriate marketing to customers. Co-operative Energy said clear additional data protection measures were needed.²⁹²
- (f) Moneysupermarket.com sought clarification on whether Ofgem accreditation would be a condition for PCWs to access Midata.²⁹³

²⁸² First Utility response to provisional decision on remedies, pp21 & 22, paragraphs 4.44–4.47.

²⁸³ Citizens Advice response to provisional decision on remedies, pp39–41.

²⁸⁴ Moneysupermarket.com response to provisional decision on remedies, p7.

²⁸⁵ BGL Group (Comparethemarket.com) response to provisional decision on remedies, pp6 & 7, paragraphs 4.21–4.24.

²⁸⁶ Moneysavingexpert.com response to provisional decision on remedies, p2. MoneySavingExpert.com said it supported changes to Midata but said the process could be further improved if there were rule changes and regulations to provide for a trusted intermediary to switch consumers, if they wished.

²⁸⁷ Littlechild et al response to provisional decision on remedies, p19.

²⁸⁸ Centrica response to provisional decision on remedies, pp67 & 68, paragraphs 339–344.

²⁸⁹ EDF Energy response to provisional decision on remedies, pp38 & 39, paragraphs 8.22–8.24.

²⁹⁰ EDF Energy response to provisional decision on remedies, pp38 & 39, paragraphs 8.22–8.24.

²⁹¹ E.ON response to provisional decision on remedies, p41, paragraphs 200 & 201.

²⁹² Co-operative Energy response to provisional decision on remedies, p5.

²⁹³ Moneysupermarket.com response to provisional decision on remedies, p5.

13.375 Ovo Energy said that, while it acknowledged that PCWs had an important role to play, it did not believe the remedy or the other PCW remedies would solve the pricing or engagement problems in the energy market.²⁹⁴ Ovo Energy also said it disagreed that the consent process in relation to Midata should be opt-out and said consent should be opt-in to be consistent with data protection laws.²⁹⁵

13.376 We note that data protection and data security issues have already been taken into account in the development of the Midata programme, which we understand is consistent with data protection laws and regulations. We would expect DECC to continue to have regard to these issues when implementing the remedy.

13.377 Several parties commented on expanding the scope of Midata to include further data items:

- (a) RWE, SSE²⁹⁶ and E.ON²⁹⁷ said more consideration needed to be given to including the Warm Home Discount Indicator in Midata. E.ON said that careful consideration was required given the sensitivity of this information and the risk for it to be misused. RWE said that while including the Warm Home Discount Indicator in Midata could help PCWs to promote the best offers to customers, it could limit the tariff choice for these customers.²⁹⁸
- (b) Centrica said it had concerns about the inclusion of half-hourly consumption data in Midata. Centrica said this would materially increase the scale of data transmitted, with fundamental implications for the cost and complexity of Midata, and that annual consumption data would be sufficient.²⁹⁹
- (c) Flipper Ltd said the CMA should be more prescriptive on Midata. The CMA should set out what customer data, supplier pricing and tariff data should form part of the standards and mandate that it be implemented by open APIs, and be delivered in 12 months.³⁰⁰

²⁹⁴ Ovo Energy response to provisional decision on remedies, pp10 & 11, paragraphs 2.22–2.27.

²⁹⁵ Ovo Energy response to provisional decision on remedies, p28, paragraphs 5.3 & 5.4.

²⁹⁶ SSE response to provisional decision on remedies, Annex 1, p7, paragraphs 7.2.1–7.2.4.

²⁹⁷ E.ON response to provisional decision on remedies, p41, paragraphs 200 & 201.

²⁹⁸ RWE response to provisional decision on remedies, pp63, paragraph 52.8.

²⁹⁹ Centrica response to provisional decision on remedies, pp67 & 68, paragraphs 339–344.

³⁰⁰ Flipper Ltd response to provisional decision on remedies, pp3 & 4.

- (d) Citizens Advice said it would be supportive of increasing the scope of the Midata programme data fields, with the caveat that ‘consumption data’ needed clarification.³⁰¹

13.378 We consider there is merit in expanding the scope of Midata to include the Warm Home Discount Indicator and half-hourly consumption data because this will enable TPIs to provide accurate personalised estimates on the potential gains from switching (see paragraph 13.385(b) for more details).

13.379 We are not, though, prescribing in detail the items to be added to Midata but rather establishing a general principle that Midata needs to be available in sufficient detail to enable customers to engage effectively in the market. We are recommending that DECC make changes to the Midata data fields that will ensure all domestic customers have Midata that allows them to understand their options and compare tariffs.

13.380 Several parties commented on extending the period of time for PCWs’ access to Midata:

- (a) Centrica said it supported PCWs having a longer period of access to Midata, providing it was done with the customer’s express consent and access was not enduring.³⁰²

- (b) SSE said that, should PCWs be given continuous or recurring access, the following measure should be in place: suitable data protection and security measures; customers must be required to give consent and be sure of what they are giving consent to; customers must be able to revoke access; and customers must be able to know who has access to their data.³⁰³

- (c) Scottish Power said that of the two access options that PCWs present to customers, one should be of a specified frequency eg annual. Scottish Power said it did not believe it was reasonable for PCWs to have access to Midata on a continuous basis unless it was clear to the customer at the time they give their consent what all the circumstances would be in which the PCW might use Midata.³⁰⁴

³⁰¹ Citizens Advice response to provisional decision on remedies, pp39–41.

³⁰² Centrica response to provisional decision on remedies, pp67 & 68, paragraphs 339–344.

³⁰³ SSE response to provisional decision on remedies, Annex 1, p7, paragraphs 7.2.1–7.2.4.

³⁰⁴ Scottish Power response to provisional decision on remedies, p17, paragraphs 9.7–9.10.

(d) E.ON said that while it was supportive of PCWs having access to Midata beyond 30 minutes, this should be something that the customer explicitly consents to, and was thus controlled.³⁰⁵

(e) First Utility said it had some concerns about PCWs accessing Midata especially if the consumer could not control the frequency of access.³⁰⁶

13.381 We consider the remedy provides an adequate balance between giving TPIs longer access to Midata to enhance their ability to prompt customers to engage and giving customers a choice on this matter. Specifically, the remedy provides for TPIs to seek customer consent on the frequency with which they can access the customer's Midata. TPIs will be required to present at least two options when seeking customers' consent, one option is for access on an annual or ongoing basis and the other option is for access on a specified frequency (see paragraph 13.386(c)). We also consider that, when seeking customers' consent, TPIs should explain to customers how the data will be used, and customers should be able to revoke TPIs' access to the Midata.

13.382 Scottish Power said there would be merit in the development of a plan by DECC in consultation with stakeholders to implement the remedy.³⁰⁷

13.383 We agree (see paragraph 13.390) and understand DECC intends to consult on changes to the Midata programme when implementing the remedy. DECC has told us that it would seek to implement the remedy by, first, mandating all suppliers to participate in Midata and, second, changing the specification for Midata following consultation.³⁰⁸

Design considerations

13.384 In the design of this remedy, we have considered:

(a) whether any specifications concerning phase 2 of Midata should be amended; and

(b) if so, how to implement this remedy.

³⁰⁵ E.ON response to provisional decision on remedies, p41, paragraphs 200 & 201.

³⁰⁶ First Utility response to provisional decision on remedies, pp21 & 22, paragraphs 4.44–4.47.

³⁰⁷ Scottish Power response to provisional decision on remedies, p17, paragraphs 9.7–9.10.

³⁰⁸ Telephone call with DECC about retail remedies on 3 May 2016.

- *Key design elements*

13.385 We have considered whether the following specifications concerning phase 2 of Midata should be amended:

- (a) We note that participation in Midata is not currently intended to be mandatory. Given our concerns around the first-mover disadvantage, which have been broadly endorsed in parties' responses, and the delays we have seen concerning the implementation of phase 1, we consider that participation in Midata should be made mandatory for all suppliers. This will allow for the timely and successful implementation of phase 2, which will allow TPIs direct access to their Midata file, without having to download or upload the csv file, and so avoiding the need for customers to input data manually. In this regard, we understand that the government already has, but has not used, power to make participation in phase 2 of Midata mandatory, and we therefore recommend to DECC to use this power.
- (b) We note that Midata is intended to include certain information listed in paragraph 13.371. In light of PCWs' submissions concerning additional data fields that would assist the tariff comparison process, our finding concerning the complexity of information available to consumers concerning their meter and consumption, and the likely growth in time-of-use tariffs (with the roll-out of smart meters), we have decided to recommend that DECC amend the specification for Midata to include access to the following data fields: meter type, Warm Home Discount Indicator, consumption data by time of use for those customers on Economy 7 or other time-of-use tariff. These fields will help TPIs to provide accurate personalised estimates on the potential gains from switching.³⁰⁹
- (c) We consider that giving TPIs only one 30-minute window in which to access a customer's Midata data will restrict PCW's ability to prompt customers to engage at the end of a fixed-term contract. We have received several responses endorsing these concerns. Accordingly, we have decided to recommend that DECC amend the specifications for Midata to allow customers the ability to choose the frequency of TPIs' access to Midata when giving their consent. This would:
 - (i) enable TPIs to send personalised savings alerts to customers, based on their updated actual consumption (which could have

³⁰⁹ uSwitch told us that only [X]% of its customers used their annual consumption figure to obtain their quote. The rest of the customers entered their direct debit payment, or used the estimator.

changed since the original comparison), and accounting for new tariffs in the markets;

- (ii) give TPIs direct access to Midata and, as a result, customers subscribing to such services would no longer have to update their details manually (eg when they change their address, energy usage or switch supplier via a different route); and
- (iii) enable TPIs to target consumers around the end of their fixed-term tariff, thereby helping them avoid being put on a default tariff.

13.386 In light of the above design considerations, we recommend that DECC make the following changes to the current specifications of Midata phase 2:

- (a) Participation in Midata is mandatory for all gas and electricity suppliers.
- (b) The scope of Midata is expanded to include the following data fields: meter type, Warm Home Discount indicator, consumption data by meter and time-of-use for those customers on Economy 7 meters or other time of use tariffs.
- (c) TPIs are given the ability to seek customer consent on the frequency with which they can access the customer's data through Midata; are required to present at least two options to a customer when seeking consent to access Midata (including one option for access on an annual or ongoing basis, and another option for access on a specified frequency); and are given the ability to send updated tariff comparison information based on any subsequent access granted to a customer's Midata.

13.387 We therefore consider that the above design elements are particularly effective in helping domestic customers to realise the benefits from Midata at least until the roll-out of smart meters is complete (ie 2020 according to current plans), and possibly beyond, when more complex time-of-use tariffs are likely to be more prevalent.

Assessment of effectiveness

13.388 As we have explained above, our view is that the remedy is effective in achieving its aims of helping domestic customers understand the best tariffs available for their consumption, and to simplify the search and switching process, and to prompt engagement. Accordingly, our view is that the remedy would be effective in partly addressing two of the features giving rise to the Domestic Weak Customer Response AEC.

13.389 In our view, access to Midata will make the searching and switching process easier and more reliable, as more people are likely to complete the process:

- (a) Citizens Advice said that people were more likely to abandon the switching process when asked for additional data.³¹⁰ For example, we received responses that asking for the MPAN and MPRN might be a barrier to switching; and
- (b) those of uSwitch's customers who had to input their meter number manually were [✂] % less likely to complete their application,³¹¹ or more likely to make an error, which reduced the probability of a successful switch.³¹²

13.390 In assessing the effectiveness of the remedy we have considered the extent to which the remedy is capable of effective implementation, monitoring and enforcement. As regards implementation, given that our changes either exist in current legislation as a power for DECC to exercise, or concern the future specification of Midata as will be set out in legislation, we consider that a recommendation to DECC to implement the remedy is effective. We envisage that DECC would consult on the changes as soon as possible following publication of this report, with a view to introducing the requisite changes in its ongoing legislative programme for inclusion in the next energy sector or omnibus bill.

13.391 We note that smart meters will provide customers with near real-time information about their energy use and costs and Midata has some limitations as a channel for accessing smart data. In particular, the current Midata specification does not support multi-tier readings (eg customers with a smart meter would only be able to see an aggregated consumption figure). However, the changes we are recommending to DECC to make to the Midata specification do not address this aspect of phase 2 of Midata, as following the roll-out of smart meters there will be alternative means for domestic customers to access smart data. As part of the smart meter roll-out, suppliers will be required to provide customers with the in-home display for access to their half-hourly consumption data, as well as historical consumption. There are also plans to allow customers to share this data with TPIs. Additionally, customers could pair a smart device³¹³ to their home area

³¹⁰ [Consumer groups multiparty hearing](#), 2 September 2015.

³¹¹ PCWs can usually find meter numbers from an address, but sometimes their database is incomplete, or incorrect.

³¹² uSwitch response to Remedies Notice, p14. See paragraph 13.353(b) above.

³¹³ The device would need to be speaking the right language to be able to connect to the smart meter home area network. See DECC: additional submission (Follow up information for the CMA on Midata), p7.

network³¹⁴ and be able to access half-hourly consumption data which they could then forward to a service provider.

13.392 In addition, we consider that even when the vast majority of customers have a smart meter, Midata might still be of some additional value for two main reasons: (i) Midata will contain data fields such as MPAN, MPRN and Warm Home Discount which will not be stored on a smart meter under current proposals,³¹⁵ and (ii) Midata will continue to benefit those customers who for various reasons (eg installation of smart meter being not possible) will not have a smart meter.

Assessment of proportionality

13.393 In this section we set out our assessment of whether the remedy is proportionate.

13.394 For the reasons set out above, we consider that the remedy is effective in achieving its aim.

13.395 In addition, given that this remedy will not involve any costs or restrictions on DECC, suppliers or TPIs, we consider that this remedy is no more onerous than necessary and there is no alternative remedy that is less onerous but as effective.

13.396 In addition, allowing TPIs to make the searching and switching process easier and more reliable for customers, and to prompt customers (for example, when a tariff is near term), should help customers to realise the gains from switching.

13.397 Accordingly, we have concluded that the remedy does not produce adverse effects that are disproportionate to its aim.

Conclusions

13.398 Our view is that the remedy is effective and proportionate in simplifying the search and switching process for customers, prompting engagement and helping customers to realise the benefits from switching, by giving TPIs direct access through Midata to customer data held by suppliers.

³¹⁴ A home area network is a network that is deployed and operated within a small boundary, typically a house or small office/home office. See Appendix 8.4: Smart meter roll-out in Great Britain for further details.

³¹⁵ We understand that a limited amount of information can be stored on a smart meter and that at the moment this includes: half-hourly consumption data for both gas and electricity; current tariff information; and conversion factor for gas. See DECC leaflet, *Smart Meters, Smart Data and Smart Growth*.

Engagement remedies for customers on restricted meters

- 13.399 We have found that a combination of features of the markets for domestic retail supply of gas and electricity in Great Britain give rise to the Domestic Weak Customer Response AEC.
- 13.400 As set out in detail in Section 9, our analysis of the retail supply of electricity to domestic customers with restricted meters has confirmed that the same features also affect domestic customers on restricted meters, and has shown that there are additional aspects of the domestic retail electricity market concerning customers on restricted meters that contribute to some of these features.³¹⁶ In particular, we have found that customers on restricted meters have lower awareness of, and interest in, their ability to switch; face higher barriers to accessing and assessing information; and higher actual and/or perceived barriers to switching.
- 13.401 In this section, we set out the remedies that are aimed at addressing certain aspects of the domestic retail electricity market concerning customers on restricted meters contributing to the above features and (together with the other engagement remedies we have decided upon concerning both the domestic retail gas and electricity markets) that we consider are effective and proportionate in addressing the Domestic Weak Customer Response AEC and the resulting customer detriment.
- 13.402 In particular, the remedies are:
- (a) to require all suppliers (through an order and a new licence condition) to make all their electricity single-rate tariffs available to all domestic customers on restricted meters, and to ensure that switching to these tariffs cannot be made conditional on a restricted meter being replaced; and
 - (b) to ensure that domestic customers on restricted meters have access to information on the options available to them.
- 13.403 We have observed that there does not appear to be an industry-wide definition of what constitutes an Economy 7 meter. In particular, meters can be identified by their Standard Settlement Code used by Elexon in the settlement process and we have observed that (in a minority of instances)

³¹⁶ For these purposes, we define 'restricted meters' to exclude customers with Economy 7 meters unless otherwise specified. As outlined in Section 8 we had identified that the options available to customers with Economy 7 meters are similar to those available to customers with single-rate meters. However, we note that the gains from switching (see Section 8) and detriment (see Section 14) for customers with Economy 7 meters are larger than for customers with single-rate meters.

while one supplier may classify a meter with a particular Standard Settlement Code as an Economy 7 meter another supplier may not.

- 13.404 The remedies below relate to restricted meters excluding Economy 7 meters (ie where the majority of suppliers classify a particular meter as an Economy 7 meter). However, given the discrepancy we have noted above, we suggest that Ofgem establish an industry-accepted classification of Economy 7 meters. This definition can then be used by Ofgem, suppliers and Citizens Advice to inform the implementation of this remedy.

Removing the barriers to switching

- 13.405 We have received little, if any, evidence that either the Six Large Energy Firms as a group or the Mid-tier Suppliers as a group are actively competing to attract customers with restricted meters. We were also told that there are no technical reasons why suppliers cannot make their single-rate tariffs available to customers on restricted meters. This requires suppliers to be able to either: aggregate consumption across registers (and, possibly, meters) and to apply the single-rate tariff to the aggregated consumption on an ex post basis; or by setting up meter-specific tariffs where the standing charge and all unit rates are the same as those for the relevant single-rate tariff. That this is technically feasible is demonstrated by the practice of two suppliers. First Utility told us that it did not offer specific tariffs for customers on restricted meters and that single-rate tariffs were available to customers with these meters. Utility Warehouse told us that all its current tariffs were available on restricted meters. (See Appendix 9.5 for further details).
- 13.406 We asked all of the Six Large Energy Firms whether they allow their existing customers on restricted meters to switch to their single-rate tariffs and whether they offer their single-rate tariffs to potential customers on restricted meters. We found that:
- (a) RWE npower will require [✂];
 - (b) all of the other of the Six Large Energy Firms said that they might require the replacement of a customer's existing meter; and
 - (c) Centrica (£70), E.ON (£65 to £82) and Scottish Power said that they would charge the customer to replace their meter. Additionally Scottish Power told us that if some rewiring in the home was required, this would be an additional expense to the customer.

Aim of the remedy

- 13.407 The aim of the remedy is to promote competition in the restricted meter segments by:
- (a) ensuring that all customers on restricted meters have the option of switching to any single-rate electricity tariff offered by suppliers; and
 - (b) reducing the costs to customers on restricted meters of switching supplier and switching to single-rate electricity tariffs.
- 13.408 The ultimate aim of the remedy is to partly address two of the features giving rise to the Domestic Weak Customer Response AEC (and resulting detriment), that are particularly relevant to customers on restricted meters, ie that such customers face actual and/or perceived barriers to switching, and have limited awareness of, and interest in, their ability to switch energy supplier.

Parties' views

- 13.409 Two of the Six Large Energy Firms³¹⁷ and two of the Mid-tier Suppliers³¹⁸ supported this remedy along with various other parties.³¹⁹
- 13.410 RWE npower said that it was unable to provide a view on the effectiveness or proportionality of this remedy due to the lack of clarity around the change of occupier and tariff end processes. These points are addressed in our assessment below.³²⁰
- 13.411 Consistent with the restricted meter bills analysis, Scottish Power showed that whether a specific customer would be better off on the cheapest single-rate tariff depended on that customer's usage split between peak and off-peak usage.³²¹ In particular, Scottish Power looked at a sample of its customers on direct debit SVTs in South Scotland, splitting customers into those with low off-peak usage (less than 50%) and those with high off-peak usage (more than 50%). Scottish Power looked at the extent to which each group would be better off on the 'best competitor single rate tariff' and

³¹⁷ See Centrica response to provisional decision on remedies and E.ON response to provisional decision on remedies.

³¹⁸ See Ovo Energy response to provisional decision on remedies and First Utility response to provisional decision on remedies.

³¹⁹ See Ofgem response to provisional decision on remedies, Centre for Competition Policy response to provisional decision on remedies and MoneySupermarket response to provisional decision on remedies.

³²⁰ See RWE npower response to provisional decision on remedies, p67, paragraph 54.1.2.

³²¹ That is, customers are more likely to be better off on a tariff specific to their restricted meter when their off-peak usage is higher relative to their peak usage as this means they will be taking advantage of the cheaper off-peak rates. See Appendix 9.5 and Scottish Power response to provisional decision on remedies, pp24–27.

showed that while the majority of customers with low off-peak usage would be better off on the 'best competitor single rate tariff' the majority of customers with high off-peak usage would be worse off on the 'best competitor single rate tariff'. Scottish Power also said that there may be deals other than SVTs open to customers dependent on their meter type. For example, Scottish Power offered a complex meter version of its Help Beat Cancer product on which customers in the vast majority of cases would be better off on when compared to Scottish Power's SVT.

- 13.412 Scottish Power told us therefore that this remedy may lead to customers, in particular those with high off-peak usage who made up [X] of their sample,³²² making ill-advised switching decisions - that is, choosing single-rate tariffs when they would be better off on a meter-specific tariff. In particular, Scottish Power noted that this risk was exacerbated if switching websites did not calculate the advantages and disadvantages of a switch correctly.³²³
- 13.413 Scottish Power also noted that even where customers benefited from a switch to a single-rate tariff there was a risk that customers may not re-engage and would therefore end up on a single-rate SVT. Scottish Power noted that these customers would lose the benefit of low off-peak rates while the gains from switching to a low-cost single-rate tariff would be short-lived.³²⁴
- 13.414 Scottish Power said that in light of the risks identified above, in particular, in relation to those with high off-peak usage, this remedy should be a recommendation to Ofgem to take forward the issues with a view to increasing access to single-rate tariffs (and requiring suppliers or obtaining their commitment to make the appropriate communications) where this was likely to be beneficial to consumers. Scottish Power said that work of this nature could also usefully increase understanding of why there were a relatively large number of low heating users who still had complex meters.³²⁵
- 13.415 We recognise that for some customers on restricted meters it will not be in their interests to move to a single-rate tariff and there may be alternative meter-specific tariffs which represent a better option for some customers.³²⁶ In particular, the best choice may depend on a customer's usage split

³²² In the restricted meter bills analysis around 65% of customers, in both Q2 2014 and Q2 2015, had high off-peak usage as defined by Scottish Power.

³²³ See Scottish Power response to provisional decision on remedies, paragraph 11.14.

³²⁴ See Scottish Power response to provisional decision on remedies, paragraph 11.12.

³²⁵ See Scottish Power response to provisional decision on remedies, paragraph 11.6.

³²⁶ Flow Energy also noted that it was not clear that all would benefit from being on a single-rate tariff as they may end up paying more for their heating load. See Flow Energy response to provisional decision on remedies, p2.

between peak and off-peak and the structure of their existing tariff and possible alternative meter-specific tariffs. Therefore it is important that customers are able to make an informed choice about the value for money of the options available to them as this will minimise the risk of ill-advised switching by customers. In this regard, this remedy complements our Restricted Meter Information Remedy (see paragraph 13.468).

13.416 In light of the above we do not consider that it is appropriate to implement this remedy through a recommendation to Ofgem to engage in further work in this area. In particular, we think that the requirements of the remedy and the information remedy outlined below will mitigate the risks identified and that a recommendation would lead to a material delay to the implementation of the remedy to the detriment of customers.

13.417 SSE told us that the remedy should allow for certain exceptions.³²⁷ In particular, SSE told us that, when a customer wanted to switch, the new supplier should be able to recommend a meter exchange where that would allow for a cheaper tariff to be provided.

13.418 We note that this remedy does not prevent suppliers or others recommending a meter change where that would be in the interest of the customer (eg to an Economy 7 meter).³²⁸ In particular, the aim of the Restricted Meter Information Remedy set out below is to provide customers with information that is necessary for them to make informed choices which may include information in relation to alternative meters which may benefit certain customers.

13.419 SSE also said that the CMA recognised in its provisional decision on remedies that the remedies in relation to customers on restricted meters were unlikely to be effective.³²⁹

13.420 We note that this remedy has a sunset clause linked to the roll-out of smart meters. We consider that the short space of time over which this remedy will be relevant, given the sunset clause, and the inevitable lag between the implementing of the remedy, effectively addressing the relevant aspect of the feature and reducing detriment, will limit the scope for substantially reducing detriment. However, given the scale of the total customer detriment that we have identified for customers on restricted meters of around £40

³²⁷ See SSE response to provisional decision on remedies, Annex 1, p9.

³²⁸ We note that National Energy Action provided an example of an initiative in London to replace certain restricted meters to help residents in tower blocks to access cheaper electricity for communal areas. Again we note that this remedy does not prevent suppliers or others recommending a meter change where that would be in the interest of the customer. See National Energy Action response to provisional decision on remedies.

³²⁹ See SSE response to provisional decision on remedies, Annex 1, p9.

million in Q2 2015, even very small reductions in prices during the transitional period would lead to benefits that would far exceed any implementation costs.

13.421 Several suppliers noted that there were operational challenges or costs related to this remedy. In particular:

- (a) Centrica noted that the billing process would require manual intervention and therefore be more expensive (but noted that despite these costs the remedy was proportionate);³³⁰
- (b) RWE npower noted that a system development would be required such that it could register new customers on restricted meters;³³¹
- (c) SSE noted that the remedy would entail significant changes to systems and processes;³³²
- (d) Ovo Energy noted that it anticipated that significant changes to suppliers' billing platforms would be required and that there should be an exemption from complying if after having used reasonable efforts suppliers were unable to comply without expending disproportionate cost and effort;³³³ and
- (e) Scottish Power noted that suppliers faced higher rental, operational and reading costs in relation to restricted meters when compared to single-rate meters, for example, for legacy meters the additional rental costs ranged from 1p per day to 3p per day depending on the type of meter and would be higher for non-legacy meters.³³⁴

13.422 We note that in relation to the costs raised in (a) to (d) and the operational and reading costs raised by Scottish Power in (e) none of the Parties have provided any evidence concerning the magnitude of these costs. As outlined above (see paragraph 13.462) we do not expect the costs to suppliers to be significant and note that at least one of the Six Large Energy Firms has noted that the remedy is proportionate despite such costs. However the remedy does provide for a supplier to seek specific exemptions from the

³³⁰ See Centrica response to provisional decision on remedies, p74.

³³¹ See RWE npower response to provisional decision on remedies, p68, paragraph 54.2.4.

³³² See SSE response to provisional decision on remedies, Annex 1, p9.

³³³ See Ovo Energy response to provisional decision on remedies, p38. We note that Ovo Energy said that the simplest solution to offering single-rate tariffs to customers on restricted meters would be through smart meters, although this would involve the cost of changing the meter and potentially rewiring work. We note that this remedy prevents the installation of a smart meter being a condition of offering customers on restricted meters single-rate tariffs. However, as outlined above this remedy does not prevent suppliers recommending a meter change.

³³⁴ See Scottish Power response to provisional decision on remedies, p28, paragraph 11.19.

obligation to offer single-rate unit tariffs to restricted meter customers in circumstances where, for technical reasons, it can demonstrate that it cannot comply with the order, or where the costs of doing so would be disproportionate to the gains (see paragraph 13.448).

13.423 In relation to meter rental costs identified by Scottish Power in (e) we do not think it is disproportionate for suppliers to absorb these costs. In particular, given the limited number of customers on restricted meters relative to the number of customers on unrestricted meters we would not expect these additional costs to be significant in aggregate.

13.424 Scottish Power noted that on launch of a new tariff there would be a possible need to configure billing systems individually for each meter type and that, unless accounted for, this may delay the introduction of new tariffs to the detriment of customers. In particular, Scottish Power suggested that this remedy should include a waiver such that a supplier was not obliged to offer every tariff-meter permutation from day one of a new tariff being launched (with five working days' grace in relation to restricted meters they currently supported and 30 days' grace in relation to restricted meters they did not currently support). Further, Scottish Power said that while reducing the cost to suppliers and increasing their ability to react to market conditions neither of these waivers would significantly impair the effectiveness of this remedy and, as customer relations issues would arise if a significant number of customers were affected, would be used sparingly.³³⁵

13.425 We believe that such a waiver would have an impact on the effectiveness of this remedy. In particular, some of the most competitive single-rate tariffs are only available for short periods of time, therefore allowing such waivers may prevent customers on restricted meters from accessing these tariffs. In these circumstances we would expect suppliers to be able to put in place (and agree these with Ofgem) administrative arrangements to accommodate the configuration of billing systems.

13.426 Citizens Advice noted that:³³⁶

- (a) this remedy may not benefit those on prepayment restricted meters given the lack of competition in the prepayment segment; and
- (b) switching to an Economy 7 meter and associated cheap tariffs may, depending on the customer's usage split, benefit these customers more than access to single-rate tariffs and therefore customers on restricted

³³⁵ See Scottish Power response to provisional decision on remedies, p27 & 28, paragraphs 11.17 & 11.18.

³³⁶ See Citizens Advice response to provisional decision on remedies.

meters should be able to switch to Economy 7 meters for free (including any physical works if required, such as rewiring).

13.427 In relation to Economy 7 meters, Citizens Advice estimated bills for customers with Total Heating Total Control meters and Economy 10 meters in North Scotland supplied by the incumbent, SSE. Citizens Advice then compared these bills to the bills the customers would have paid on the cheapest single-rate tariff and the cheapest Economy 7 tariff. Citizens Advice assumed a total usage of 9,146 kWh split 82% off-peak usage and 18% peak usage.³³⁷ Citizens Advice found that the savings from being on the cheapest Economy 7 tariff were larger than the savings on the cheapest single-rate tariff. Citizens Advice said that the results were similar when the split was altered such that customers used 3,100 kWh or roughly 34% of their usage during peak periods.³³⁸

13.428 Further, in relation to free meter exchanges Citizens Advice said that this would be proportionate because:³³⁹

- (a) energy suppliers had benefited from stable profits from customers on restricted meters since liberalisation;
- (b) Citizens Advice had agreed to provide the necessary advice for the customers involved (a task Citizens Advice considered suppliers should already provide); and
- (c) rewiring may in any case be necessary to install a smart meter in these circumstances.

13.429 In relation to prepayment restricted meters we note that these customers will also be subject to the price cap as set out in Section 14.

13.430 In relation to switching to Economy 7 meters we note that this may, depending on the customer's circumstances, be the best option for some customers. However, as outlined in Annex B of Appendix 9.5 we have not been able to assess the extent to which customers on restricted meters would be better off on the cheapest Economy 7 tariffs. This is because any comparison depends on the specific meter configuration and the heating system in place. In particular, the extent to which a customer is willing and able to only use their heating system during Economy 7 off-peak periods. In

³³⁷ Based on Ofgem's reported mean consumption for those with electric heating. A report for Ofgem by the Centre for Sustainable Energy (2013), *Beyond average consumption. Development of a framework for assessing impacts of policy proposals on different consumer groups*.

³³⁸ 3,100 kWh is Ofgem's medium Typical Domestic Consumption Value for customers with single-rate meters. See Ofgem's *Decision on revised Typical Domestic Consumption Values for gas and electricity*.

³³⁹ See Citizens Advice response to provisional decision on remedies.

this respect we note that on average our gains from switching analysis indicated that Economy 7 customers use 62% of their usage during peak periods which is materially higher than the assumed percentages used by Citizens Advice. Therefore it is not clear to what extent customers on restricted meters could be better off on Economy 7 meters and tariffs. Given this we do not think that it would be proportionate to require suppliers to provide free Economy 7 meter installations (including any physical works).

- 13.431 Energyhelpline noted that at present some customers with Economy 7 meters were on single-rate tariffs and that when these customers tried to switch to another single-rate tariff on a PCW this could lead to a failed switch. This was because the ECOES database still recorded their meter type as Economy 7. In light of this Energyhelpline said that this remedy would be a barrier to entry unless all suppliers allowed customers on restricted meters to adopt single-rate tariffs. To prevent this occurring Energyhelpline outlined that either the ECOES database could be changed when a customer with an Economy 7 meter switched on to a single-rate tariff or suppliers allowed applications through PCWs to come through as single-rate with a note that the customer had an Economy 7 meter.³⁴⁰
- 13.432 Whilst Energyhelpline's comment concerns principally Economy 7 meter customers (who will fall outside the scope of our remedy unless on a restricted meter tariff), we note that a similar concern could arise for customers on a restricted meter. However, this remedy requires suppliers with over 50,000 customers to offer their single-rate tariffs to all customers irrespective of meter type. Therefore we would expect suppliers with over 50,000 customers to ensure that their systems enable customers, either switching directly or through a PCW, to switch to a single-rate tariff irrespective of the meter type recorded on the ECOES database. We consider it would not be proportionate to extend this remedy to suppliers with less than 50,000 customers. In particular, this is consistent with the current regulatory position on the scale of operation at which it is appropriate for suppliers to comply with certain obligations.
- 13.433 Further, we note that the ECOES database should accurately reflect customers' meter types as it is important a supplier not subject to this remedy can identify a prospective customer's meter type as that supplier may not support the prospective customer's meter type.
- 13.434 National Energy Action noted that our analysis indicates that only some customers will benefit from switching to a single rate tariff. Therefore

³⁴⁰ See Energyhelpline response to provisional decision on remedies.

National Energy Action said that the CMA should investigate the implications for those who would not benefit from switching to a single-rate tariff and, if any negative impact was identified, consider whether a further targeted intervention may be required.³⁴¹

- 13.435 As explained above, we agree that some customers would not be able to reduce their annual bills by switching to a single-rate tariff. We would, however, still expect these consumers to benefit from the remedies in relation to restricted meters. In particular:
- (a) We would expect single-rate tariffs to increase the competitive constraint on meter-specific tariffs to the benefit of customers on restricted meters; and
 - (b) We would expect the Restricted Meter Information Remedy outlined below to help all customers on restricted meters engage such that customers have a better understanding of their metering and heating configuration and understand the options they have available to them (including whether any other suppliers offer tariffs for their restricted meters).
- 13.436 Although it welcomed this remedy the Centre for Competition Policy noted that careful communication of this remedy may be required as it may involve consumers losing ‘features’ provided by their meter which energy firms have previously extolled and consumers may feel that the market is failing if the tariffs available do not allow the technology in their homes to be fully utilised.³⁴²
- 13.437 Comhairle nan Eilean Siar (Comhairle) said that the proposed remedies will do little to deal with embedded anti-competitive effects in the North of Scotland electricity market. In particular, Comhairle said that there are physical barriers to switching to some tariffs in the North Scotland that should be recognised, for example, in relation to Total Heating Total Control meters and Economy 10 meters.³⁴³
- 13.438 As outlined in Section 9 we agree that customers on these meters face particularly strong barriers to accessing and assessing information and barriers to switching supplier and/or tariff. We consider that this remedy, in addition to the Restricted Meters Information Remedy outlined below, is effective and proportionate in promoting competition and engagement in the restricted meter segment, by increasing customer awareness and reducing

³⁴¹ See National Energy Action response to provisional decision on remedies.

³⁴² See Centre for Competition Policy response to provisional decision on remedies.

³⁴³ See Comhairle nan Eilean Siar response to provisional decision on remedies.

barriers to searching and switching. In particular, in relation to the meters identified by Comhairle we note that a material number of customers, paying by direct debit and standard credit, on the meters identified by Comhairle [✂], would have gained from switching to the cheapest single-rate tariff [✂].

Design considerations

- 13.439 As noted above, we found that some suppliers require any new customer or existing customer switching to an Economy 7 or single-rate tariff to replace their restricted meter and they may also charge the customer for the replacement costs. We consider that this increases the actual and perceived barriers to switching faced by customers on restricted meters. In particular, this requirement adds to the number of factors that a customer needs to take into account in making an assessment of the options available to them and create uncertainties around the costs of switching (including the loss of the ability to take advantage of any efficiencies provided for by their meter and the heating systems that the meter supports).
- 13.440 Accordingly, we are implementing this remedy through an order (and a new licence condition) on gas and electricity suppliers with more than 50,000 domestic customers (i) requiring such suppliers to make all their single-rate electricity tariffs available to all (existing and new) domestic electricity customers on restricted meters, and (ii) prohibiting such suppliers from making their single-rate electricity tariffs available to domestic electricity customers on restricted meters conditional upon the replacement of their existing meter.
- 13.441 Licensed gas and electricity suppliers have an obligation to install smart meters for all their domestic customers by the end of 2020. An order to require all licensees that supply gas or electricity to more than 50,000 domestic customers to make single-rate tariffs available to all their customers on the basis set out above will therefore have a sunset provision linked to the roll-out of smart meters.
- 13.442 Consultation on this remedy identified a number of detailed matters to be addressed in the design of the remedy. We consider these below:
- 13.443 First, in relation to prepayment restricted meters it may be necessary for suppliers to create mirror tariffs³⁴⁴ in order to offer their single-rate tariffs to

³⁴⁴ In this context a mirror tariff is where a tariff is set up in the format of a restricted meter specific tariff, but with all unit rates set equal to the unit rate on a single-rate tariff such that the structure of the single-rate tariff is replicated for the restricted meter tariff.

customers with prepayment restricted meters.³⁴⁵ However, as regards dumb prepayment restricted meters, each mirror tariff will take up a tariff slot, which may mean that suppliers are unable to create all the necessary mirror tariffs for each type of restricted meter and / or each single-rate tariff given the constraints on the number of electricity tariff slots as identified in Section 9.

- 13.444 We expect such tariff slot constraints to be partly addressed through our remedies aimed at addressing the Prepayment AEC (see Section 12). However, to deal with any unaddressed technical constraints that suppliers may face in respect of prepayment, or other, customers on restricted meters, the new licence condition will include a derogation mechanism which will allow Ofgem to determine whether it may be appropriate to impose an alternative obligation on suppliers who, for technical reasons, can demonstrate that they cannot comply with the order (see paragraph 13.448).
- 13.445 Second, where there is a change of occupier the default deemed tariff for customers on restricted meters will depend on the tariffs offered by the supplier in question.³⁴⁶ In particular, for a given restricted meter:
- (a) Where the supplier does not offer any tariffs that are compatible with that meter then the deemed tariff should be a single-rate tariff for customers on the meter.
 - (b) Where the supplier does offer tariffs that are compatible with that meter then it is for the supplier to decide what the appropriate deemed tariff is for customers on that meter.
- 13.446 Third, when a single-rate fixed-term tariff expires the default tariff for customers on restricted meters will depend on the tariffs offered by the supplier in question.³⁴⁷ In particular, for a given restricted meter:
- (a) Where the supplier does not offer any tariffs that are compatible with that meter then the customer will default on to a single-rate tariff.
 - (b) Where the supplier does offer tariffs that are compatible with that meter then the customer will default on to a tariff compatible with that meter.

³⁴⁵ Itron said that generally prepayment restricted meters would be unable to operate on a standard single-rate tariff. Consequently Itron said for each single-rate tariff a duplicate would be required for each restricted meter type. Itron call 6 May 2016.

³⁴⁶ RWE npower said that it was unclear how this remedy interacted with the change of occupier process. See RWE npower response to provisional decision on remedies, p68, paragraph 54.2.3.

³⁴⁷ RWE npower said that it was unclear how this remedy interacted with the tariff end process. See RWE npower response to provisional decision on remedies, p68, paragraph 54.2.6.

13.447 We note that the remedy does not require suppliers to allow customers to switch back or default on to preserved meter-specific tariffs. If a customer switches away from a preserved meter-specific tariff then that customer will not be able to switch back or default on to that preserved meter-specific tariff. This applies to customers who switch to another tariff offered by their existing supplier or to another supplier.

Implementation

13.448 We are implementing the remedy through an order on electricity suppliers with more than 50,000 domestic customers:

- (a) requiring such suppliers to make all their single-rate electricity tariffs available to all (existing and new) domestic electricity customers on restricted meters; and
- (b) prohibiting such suppliers from making their single-rate electricity tariffs available to domestic electricity customers on restricted meters conditional upon the replacement of their existing meter.

13.449 We will also introduce a new licence condition with a derogation mechanism that will allow Ofgem to apply an alternative obligation where suppliers demonstrate that, for technical reasons, they are unable to comply with the requirement to make all their single-rate electricity tariffs available to customers on restricted meters.

Assessment of effectiveness

13.450 As we explain below, our view is that this remedy will be effective in achieving its aim of promoting competition in the restricted meter segments. Accordingly, this remedy will be effective in partly addressing two of the features giving rise to the Domestic Weak Customer Response AEC that are particularly relevant to customers on restricted meters, ie that such customers face actual and/or perceived barriers to switching, and that such customers have limited awareness of, and interest in, their ability to switch energy supplier.

13.451 In assessing the effectiveness of the remedy, we have considered the following factors:

- (a) the effectiveness of the key design elements of this remedy ;
- (b) the extent to which the remedy is capable of effective implementation, monitoring and enforcement; and

(c) the timescale over which the remedy is likely to have an effect.

- *Effectiveness of the key design elements*

13.452 For the reasons given above (see paragraph 13.439), we consider that ensuring that all customers on restricted meters have the option of switching to single-rate tariffs (offered by suppliers with more than 50,000 domestic customers) with no requirement to change their meter will contribute to reducing the barriers to searching and switching for these customers. The remedy will work in combination with the second of our remedies that focuses on customer on restricted meters, the aim of which is to ensure that all customers on restricted meters are aware of the options available to them and can access the information they need to make informed decisions.

13.453 Increasing customer awareness (and possibly also their interest in switching), and reducing actual and perceived barriers to switching in the manner envisaged under this remedy, in turn will increase the constraints that suppliers face in pricing tariffs designed for any specific restricted meter. As a result of this increased competitive constraint, and likely higher levels of customer engagement, we would expect a lower proportion of customers on restricted meters to remain on meter-specific tariffs that are more expensive than the cheapest single-rate tariff available to them, either because:

(a) the tariffs designed for restricted meters that are currently more expensive than existing single-rate single-fuel tariffs will be reduced or withdrawn; and/or

(b) customers on restricted meters that are currently on meter-specific tariffs will move to a cheaper single-rate tariff.

13.454 We also consider that the derogation mechanism included in the new licence condition will enhance the effectiveness of this remedy as it will allow Ofgem to impose an alternative obligation on suppliers that, for technical reasons, cannot comply with the requirement set out in the Order.

- *Implementation, monitoring compliance and enforcement*

13.455 In determining whether this remedy is effective, we have had regard to the operation and implications of this remedy.

13.456 Given the straightforward nature of the requirement that will be imposed on suppliers to make all single-rate tariffs available to customers on restricted meters, and the prohibition on suppliers making such availability conditional on such customers replacing their meter or paying a replacement fee or

other cost associated with replacement (or both), we consider that our order will be clear to suppliers. It will also be simple to implement since suppliers can apply the single-rate tariff to the aggregated consumption of the customer on an ex post basis or set up meter-specific tariffs where the standing charge and all unit rates are the same as those for the relevant single rate tariff (as First Utility and Utility Warehouse currently do).

13.457 As regards monitoring compliance with this remedy, we note that, by introducing a new standard licence condition, Ofgem will be under a duty to perform a monitoring role and could periodically check suppliers' compliance, for example, by mystery shopping. Ofgem could also require suppliers to provide information evidencing compliance.

Timescales for the remedy

13.458 In terms of timescale for implementation, the CMA will start drafting and consulting on an order in the six-month period following publication of our final report. We would expect suppliers to be able to make the necessary adjustments to their billing systems within three months of the date of a CMA order, and therefore to start offering all customers on restricted meter tariffs the ability to switch to their single-rate unrestricted meter tariffs, by April 2017. We would expect this to lead to increased engagement from customers on restricted meters from April 2017.

Assessment of proportionality

13.459 In this section we set out our assessment of whether the remedy is a proportionate remedy.

- *Effective in achieving its legitimate aim*

13.460 For the reasons given above, our view is that the remedy is effective in achieving its aim of promoting competition in the restricted meter segment from single-rate tariffs being available to customers on restricted meters. Accordingly, it is effective in partly addressing two of the features giving rise to the Domestic Weak Customer Response AEC (and resulting detriment) that are particularly relevant to customers on restricted meters, ie that such customers face higher actual and/or perceived barriers to switching and have limited awareness of their ability to switch.

- *No more onerous than needed to achieve its aim*

13.461 As regards the remedy being no more onerous than necessary, we note that the remedy provides only for suppliers making their existing single-rate tariffs

available to restricted meter customers without certain conditions. It will not require suppliers to design tariffs specifically to support restricted meters. The remedy is also limited to suppliers with more than 50,000 domestic customers. We consider this to be consistent with the current regulatory position on the scale of operation at which it is appropriate for suppliers to comply with certain obligations. For example, SLC 27.2 – which requires suppliers to offer a wide range of payment methods – applies only to suppliers with more than 50,000 domestic customers.

13.462 We recognise that the implementation of the remedy might impose costs on suppliers. In particular, billing systems will need to be able to record and aggregate consumption across all registers on a meter and, possibly, all meters in a home or allow for meter-specific tariffs where the standing charge and all unit rates are the same as those for the relevant single-rate tariff. However, given that First Utility and Utility Warehouse currently make their single-rate SVT and single-rate fixed-term tariffs available to new and existing customers (with no requirement to change meters), we would not expect these costs to suppliers to be significant.

13.463 In addition, as set out in Appendix 9.5 , given the efficiencies inherent to the operation of the heating systems supported by restricted meters, we would expect the direct costs to suppliers of supplying customers with these systems to be lower.

- *Least onerous if there is a choice between several effective measures*

13.464 As regards potential alternative remedies, our view is that there are no alternatives to the remedy that are both less onerous and as effective in achieving the aims of the remedy. The options we have considered for making the remedy less onerous would be to either exclude more suppliers from the obligation to comply with the remedy (but this could have the effect of removing some of the cheapest single-rate tariffs from the scope of the remedy) or exclude certain customers on restricted meters from the scope of the remedy (which would undermine the aim of the remedy for all customers on restricted meters). Therefore neither alternative is as effective as the remedy we have decided to proceed with.

13.465 However, the derogation mechanism included in the new licence condition makes the remedy less onerous for suppliers facing technical problems in offering single-rate electricity tariffs to prepayment customers on restricted meters.

- *Does not produce disadvantages which are disproportionate to the aim*

13.466 In relation to potential unintended adverse consequences arising from this remedy, we note that, according to our analysis, it will not necessarily be in the interests of all customers on restricted meters to move to a single-rate meter tariff, so it is important that customers are able to make an informed choice about the value for money of the options available to them. In this regard, this remedy complements our recommendation to Citizens Advice (see below).

Conclusion

13.467 Our view is that, by making single-rate tariffs available to all customers on restricted meters, the remedy is effective and proportionate in promoting competition and engagement in the restricted meter segment, by increasing customer awareness and reducing barriers to searching and switching.

Access to information and advice

13.468 In order to address the heightened feature we have found (among others) to be giving rise to the Domestic Weak Customer Response AEC concerning customers on restricted meters, ie that such customers face additional barriers to accessing and assessing information, we will implement a remedy concerning the information provided, and made available, to customers on restricted meters about their ability to switch supplier. This remedy will also address, in part, the limited awareness that customers on restricted meters have of their ability to switch. In particular, we will implement:

- (a) An order on gas and electricity suppliers (and amendments to suppliers' standard licence conditions) requiring suppliers to:
 - (i) remind their domestic electricity customers on restricted meters, in their regular communications with them, that they have the option to switch supplier or to switch to a single-rate tariff without having to change their meter or incur replacement costs;
 - (ii) provide their domestic electricity customers on restricted meters with contact details for Citizens Advice in their regular communications with them;
 - (iii) provide their domestic electricity customers on restricted meters the following information on request: total consumption, consumption by register, meter type, tariff type, and MPAN number; and

(iv) provide, on a timely basis, Citizens Advice with the information it may reasonably require concerning customers on restricted meters in the format specified by Citizens Advice.

(b) A recommendation to Citizens Advice to become a recognised provider of information and support to domestic electricity customers on restricted meters.

Aim of the remedy

13.469 The aim of the remedy is to reduce barriers to accessing and assessing information for customers on restricted meters and to increase the awareness of customers on restricted meters of their ability to switch. Accordingly, the ultimate aim of this remedy is to partly address two of the features giving rise to the Domestic Weak Customer Response AEC (and resulting detriment).

Parties' views

13.470 SSE noted that, depending on the information suppliers were required to provide to Citizens Advice, there may be data protection issues.³⁴⁸ Similarly EDF Energy noted that it did not have any specific concerns about sharing the contact information of restricted meter customers with Citizens Advice other than general data protection issues.³⁴⁹

13.471 We note that although not specified above we would expect the information provided by suppliers to Citizens Advice to relate to factual non-customer specific information including, but not limited to, information on the restricted meters they support with meter-specific tariffs, details of the meter-specific tariffs they offer (ie standing charge and unit rates) and the operational hours of the different registers on that restricted meter.

13.472 SSE noted that if any information, beyond that which is already provided in customer communications, must be included in communications with customers on restricted meters, suppliers should be given the freedom to choose the most effective and appropriate means to communicate this information.³⁵⁰

13.473 We note that this remedy only requires suppliers to remind customers on restricted meters that they have the option to switch suppliers or to a single-

³⁴⁸ See SSE response to provisional decision on remedies, Annex 1, p9.

³⁴⁹ EDF Energy response to provisional decision on remedies, p44, paragraph 8.51.

³⁵⁰ See SSE response to provisional decision on remedies, Annex 1, p9.

rate tariff without having to change their meter or incur replacement costs, provide them with the contact details for Citizens Advice and provide certain information to customers on request. Further, this remedy does not specify exactly how this information should be provided. However, as noted above the Ofgem-led programme may lead to a requirement to provide certain information to customers in regular communications with them.

- 13.474 EDF Energy said that given the complexity of some of these meters and tariffs, and how they were often integral to hot water and heating functionality, it was important that customers received the correct advice so that it did not negatively impact the functionality of the customer's system (and experience).³⁵¹
- 13.475 We agree that it is important that customers receive the correct advice, and accurate information, about their restricted meter and the options available to them. In particular, it is important that suppliers provide Citizens Advice and, on request, customers with the information required such that customers can make informed decisions.
- 13.476 Scottish Power told us that this remedy may encourage consumers to make poor decisions, in particular, those who had a high level of off-peak usage and therefore were more likely to benefit from lower off-peak prices.³⁵²
- 13.477 As outlined above we agree that there is a risk that some customers may switch to a single-rate tariff when they would be better off on a meter-specific tariff. However, we believe that providing customers with the information necessary to make an informed choice is a necessary part in making sure they make informed decisions and this, overall, will benefit customers. Further, this remedy will benefit those who have a high level of off-peak usage as it makes it easier for them to access information on whether suppliers offer tariffs for their restricted meters and help them to make informed choices between meter-specific tariffs.
- 13.478 RWE npower noted that the comparison tools of PCWs and Citizens Advice, in its role as an information provider, would have to be substantially developed if they were to include multi-rate tariffs. In relation to PCWs we note that there is no requirement on them to include multi-rate tariffs in their comparison tools.³⁵³

³⁵¹ EDF Energy response to provisional decision on remedies, p44, paragraph 8.51.

³⁵² See Scottish Power response to provisional decision on remedies, paragraph 11.23.

³⁵³ See RWE npower response to provisional decision on remedies, p68, paragraph 54.2.2.

13.479 Citizens Advice noted that given the complexity involved in discussing and comparing the options open to customers on restricted meters a specific comparison website which automates the comparison process to the extent possible would be useful.³⁵⁴

13.480 Citizens Advice also said that to determine the best course of action for any individual customer, its advisers would need to know:³⁵⁵

- (a) the customer's usage split between peak and off-peak;
- (b) the operational time for the customer's restricted meter (noting that this may vary for restricted meters that are dynamically teleswitched);
- (c) the customer's payment method; and
- (d) the customer's pattern of demand for electricity (eg to assess whether another time-of-use tariff would be the most cost-effective option).

13.481 We note that the information outlined by Citizens Advice is either factual non-customer specific information which, based on this remedy, suppliers will be required to provide to Citizens Advice or customer specific information that customers will either be provided in their bills or, based on this remedy, customers can request from their supplier.

Design considerations

13.482 In the following section, we have considered:

- (a) whether we should specify that any information, in addition to that outlined above, be provided to customers on restricted meters by their supplier in their regular communications with them;
- (b) whether we should make a recommendation to a designated body that it should become a recognised provider of information and support for customers on restricted meters;
- (c) whether Ofgem or Citizens Advice would be better placed to be a recognised provider of information and support for customers on restricted meters; and
- (d) whether we should specify the scope of the information and support provided to customers on restricted meters by the designated body.

³⁵⁴ See Citizens Advice response to provisional decision on remedies.

³⁵⁵ See Citizens Advice response to provisional decision on remedies.

- 13.483 We have considered whether it would be appropriate to specify additional information, such as total consumption, consumption by register, meter type and tariff type, and MPAN number, be provided to customers on restricted meters by their supplier in their regular communications with them. In particular, this is information that may be necessary for customers to be able to understand and fully engage with the options available to them.
- 13.484 We considered that this is not appropriate within the scope of this remedy and rather falls within the scope of the Ofgem-led programme to promote customer engagement (see paragraphs 13.26 to 13.27). Further, we note that suppliers will be collecting information in relation to customers' total consumption, consumption by register, meter type, tariff type, and MPAN number for the purpose of the Database remedy. The remedy concerning access to information and advice provides for customers to request this information from their existing supplier.
- 13.485 In relation to whether there should be a recommendation to a designated body we consider that we cannot rely on suppliers to provide their customers on restricted meters with the information they need to understand the options available to them and to make informed decisions, as suppliers' incentives are not, in this instance, aligned with those of their customers. In particular, an existing supplier will not have the incentive to provide its customers with information that could result in its customers switching to rival suppliers. In addition, an existing supplier will not necessarily be in a position to advise its customers on what rival suppliers could offer them.
- 13.486 For these reasons, our view is that having a recognised and trusted source of market-wide information is essential to promoting engagement among customers on restricted meters.
- 13.487 With regard to who this body should be, we have considered Ofgem and Citizens Advice. On balance, our view is that Citizens Advice is better placed. In particular, this role seemed to have a good fit with the remit of Citizens Advice. Citizens Advice is already providing information online, by telephone and face-to-face on energy suppliers and their offers; and it has an established reputation for providing advice to customers. Finally it was consumer bodies including Citizens Advice that drew our attention to particular problems faced by customers with certain types of restricted meters and the outcomes for them. In contrast, Ofgem is less widely recognised by customers and does not provide detailed advice to specific consumers.

13.488 With regard to the scope of the information and support provided by Citizens Advice to energy customers, we would expect Citizens Advice to be in a position:

- (a) to advise customers on their rights to switch suppliers and to switch to single-rate tariffs retaining their current meter;
- (b) to advise customers on the factors to take into account in comparing the options available to them; and
- (c) to help customers access the information they need to compare their options. We consider that Citizens Advice is well placed with the launch of its price comparison facility to help energy customers to access and understand information on how tariffs and bills might compare.

Assessment of effectiveness

13.489 As explained below, our view is that this remedy will be effective in achieving its aims of reducing barriers to accessing and assessing information by customers on restricted meters and increase customers' awareness of their ability to switch. Accordingly, the ultimate aim of this remedy will be to partly address two of the features giving rise to the Domestic Weak Customer Response AEC (and resulting detriment).

13.490 In assessing the effectiveness of the remedy, we have considered the following factors:

- (a) the effectiveness of the key design elements of the remedy;
- (b) the extent to which the remedy is capable of effective implementation, monitoring and enforcement; and
- (c) the timescale over which the remedy is likely to have an effect.

- *Effectiveness of key design elements*

13.491 We consider that the design element of this remedy will be effective in achieving its aim. In particular, we consider that suppliers will be able to easily (a) identify their domestic customers on restricted meters; (b) amend their communications with these customers to provide them with the relevant information; and (c) provide Citizens Advice with the information that they require concerning customers on restricted meters.

13.492 As set out above, we also consider that Citizens Advice is well placed to provide information and support to customers on restricted meters. In

particular, this would just be an extension of its existing activities in the provision of the information and support it provides to energy customers online, by telephone and face-to-face. Also, the remedy will explicitly provide for the cooperation of suppliers in providing Citizens Advice with information it might need from them.

- *Implementation, monitoring compliance and enforcement*

13.493 As regards the implementation of the remedy, our approach (as set out above) is to specify what the remedy will require of suppliers and Citizens Advice. For suppliers the remedy should be straightforward to implement. All that will be required of them is to advise their customers on restricted meters of their rights to switch suppliers and to switch to single-rate tariffs using existing routine communications, and to cooperate with requests for information from Citizens Advice.

13.494 As regards monitoring compliance with the remedy, we note that this should be straightforward, as Citizens Advice and Ofgem can report to the CMA if any supplier fails to comply with the order, and Ofgem will be responsible for monitoring compliance with the licence conditions.

- *Timescale for implementation*

13.495 As regards the timescale for implementation of the remedy, the CMA will start drafting and consulting on an order in the six-month period following publication of our final report. We would expect suppliers to be able to start providing the relevant information by April 2017. We would expect this to lead to increased engagement from customers on restricted meters from April 2017.

13.496 As regards the recommendation to Citizens Advice to become a recognised provider of information and support for customers on restricted meters, we would expect Citizens Advice to be able to progress the implementation of this remedy as soon as possible following publication of the CMA's final report.

Assessment of proportionality

13.497 In this section we set out our assessment of whether the remedy is proportionate.

- *Effective in achieving its legitimate aim*

13.498 For the reasons given above (see paragraph 13.489 to 13.496), our view is that the remedy is effective in achieving its aim of reducing barriers to accessing and assessing information by customers on restricted meters and increasing such customers' awareness of their ability to switch. Accordingly, it will partly address two of the features giving rise to the Domestic Weak Customer Response AEC (and resulting detriment).

- *No more onerous than needed to achieve its aim*

13.499 We also consider that the remedy is no more onerous than required. In particular, as stated above, the information that suppliers will be required to give their customers on restricted meters is limited and straightforward, and could be provided in existing communications. We therefore consider that the cost imposed on suppliers will be minimal.

13.500 For the reasons given in paragraph 13.487, we consider that Citizens Advice is well placed to provide customers with information on the options available to them and provide support when assessing this information. We also consider that the recommendation in relation to information and support that Citizens Advice should provide (see paragraph 13.488) is no more than may be required by customers on restricted meters to understand the options available to them and to make informed choices. We consider that without providing customers with access to such information, we cannot expect engagement to be promoted effectively.

- *The least onerous if there is a choice between several effective measures*

13.501 As regards potential alternative remedies, our view is that there are no alternatives to this remedy that are both less onerous and effective in achieving the aims of the remedy. In particular, the remedy provides for ensuring that customers are aware of the options available to them (which will change as a result of the remedy) and where they can get reliable information and advice. Any changes to the remedy that would require less of suppliers and/or Citizens Advice would, in our view, be seriously damaging to the aims of promoting customer awareness and ensuring customers have access to the information they need to make informed choices.

- *Does not produce disadvantages which are disproportionate to the aim*

13.502 In relation to potential adverse consequences arising from this remedy, we have not identified any disadvantages to customers on restricted meters arising from being advised by their existing suppliers, in routine communications, of their rights to switch supplier and to single-rate tariffs and being provided with contact details for Citizens Advice.

Conclusion

13.503 Our view is that the remedy is effective and proportionate to reduce barriers to accessing and assessing information for customers on restricted meters and to increase the awareness of customers on restricted meters of their ability to switch.

Ofgem's statutory duties

13.504 As stated above, where the CMA is considering whether to take action for the purpose of modifying one or more of the conditions of a retail gas or electricity supplier's licence, in deciding whether such action would be reasonable and practicable, the CMA must 'have regard' to the relevant statutory functions of Ofgem. In reaching our decision to introduce new licence conditions on suppliers concerning these remedies focused on customers on restricted meters we have, as part of our own application of the legal framework requiring us to decide upon remedies that are effective and proportionate, taken into account Ofgem's statutory duties and objectives.

13.505 In particular, we do not consider that any aspect of the aforementioned remedies will have an adverse impact on suppliers' ability to meet all reasonable demands for gas and electricity supply, achieving sustainable development, security of supply or environmental concerns. We consider that our remedies will directly engage Ofgem's principal objective of protecting the interests of existing and future consumers, including vulnerable consumers.

13.506 As noted above, the remedies will enhance competition in the restricted meter segment as suppliers will be required to make available more tariffs to customers in the restricted meter segment. This could potentially exert downward pressure on the tariffs available to customers on restricted meters. The remedies will also ensure that there are no barriers for customers to switch to cheaper single-rate electricity tariffs (as they will not be required to change the meter or incur in any replacement costs to avail of these tariffs), and that customers on restricted meters are informed about

their tariff options by energy suppliers and Citizens Advice. Accordingly, as a result of the remedies we would expect customers on restricted meters to benefit from cheaper single-rate tariffs.

13.507 Our view is that both remedies satisfy Ofgem's principal objective of protecting the interests of existing and future consumers wherever possible by promoting effective competition.

14. Retail supply to domestic customers: protecting customers who are less able to engage to exploit the benefits of competition

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14.1 This section sets out our decision on the introduction of a price cap remedy to address the detriment suffered by customers on prepayment meters. It is structured as follows:

- (a) First, we discuss the rationale for the remedy and its scope, drawing on the analysis presented in the previous sections of this report.
- (b) Then we set out the aim of the remedy.
- (c) Then we provide a summary of parties' views.
- (d) Next, we discuss the design options that we have considered, including:
 - (i) the structure and form of the cap;
 - (ii) how the price cap would be specified;

- (iii) how the base level of the price cap is determined; and
- (iv) how the price cap is updated in each price cap period;
- (e) We then consider the stringency and impact of the price cap.
- (f) We then outline practical arrangements for implementing and monitoring the price cap.
- (g) Finally, we set out our assessment of the effectiveness and proportionality of the remedy.

Rationale for the remedy and scope of the price cap

- 14.2 We have identified a number of AECs affecting domestic retail energy markets – in particular, the Domestic Weak Customer Response AEC, the Prepayment AEC and the RMR AEC (the Domestic AECs).¹ In Sections 9 and 10, we set out our updated thinking and analysis concerning the features contributing to the Domestic AECs and the detriment arising from them, distinguishing between customers according to a variety of dimensions, including tariff type, meter type and payment method.
- 14.3 Our updated analysis of prices and bills suggests that the Domestic AECs have led to substantial levels of detriment for domestic customers, of around £1.4 billion per year over the last three and a half years. We have noted a considerable variation in the detriment suffered by customers of different suppliers and between different categories of customer of the Six Large Energy Firms. For dual fuel customers at Ofgem’s medium Typical Domestic Consumption Value (TDCV), for example, detriment for prepayment customers was substantially higher over the period (equivalent to 12% of the bill) than that for standard credit customers (7% of the bill) and direct debit customers (8% of the bill).²
- 14.4 In Sections 12 and 13, we have set out a range of remedies designed to address aspects of the features contributing to the Domestic AECs directly, including measures to help create a framework for effective competition and a range of measures to help improve customer engagement. We noted in Sections 11 and 15 that, while we believe such measures will be effective in addressing the features contributing to each of the Domestic AECs, they will take time to implement before they start to address the features we have identified and, in turn, reduce the detriment to domestic customers arising

¹ We also note the likely impact that our remedies concerning the Gas settlement AEC and Electricity settlement AEC will have in increasing engagement by domestic (and microbusiness) customers.

² See paragraph 10.43.

from them. We noted that there were likely to be greater delays in reducing detriment for prepayment customers compared with other customers.

- 14.5 We have considered prepayment and non-prepayment customers separately:
- (a) For non-prepayment customers – for whom overcoming barriers to engagement is the main challenge – a number of important remedies will be taking effect to improve engagement from 2017, with major new remedies introduced in each year over the period 2017 to 2020. Two of the most significant engagement remedies – the Database remedy and the Ofgem-led programme – would start to take effect in 2018 and 2019 respectively. Electricity settlement reform could provide substantial further cost reductions, a greater role for suppliers and greater opportunities for engagement, but again may not be completed before 2020.
 - (b) For prepayment customers, technical constraints which contribute to the Prepayment AEC will only be fully addressed when the roll-out of smart meters is completed. While the prepayment remedies (ie reallocation of certain gas tariff pages and softening of SLC 22B7(b)) will result in more suppliers being able to offer a wider range of tariffs to prepayment customers with dumb meters, which is required to stimulate, at least, supply side competition, the overall number of tariffs that suppliers can offer to their customers will remain constrained. The roll-out of smart meters (in particular of SMETS 2 meters in view of their interoperability) will also increase suppliers' incentives to compete to acquire prepayment customers and help improve customer engagement.³ However, the roll-out is not due to be completed until the end of 2020.
- 14.6 As noted in Sections 11 and 15, for the majority of domestic customers, detriment could be reduced straight away if they could be persuaded to shop around and switch. In contrast, for prepayment customers, we expect that addressing the features and reducing detriment will involve an iterative process of greater supply- and demand-side pressures until more competitive prices emerge that customers can take advantage of.
- 14.7 The implication of this is that we expect detriment arising from the Domestic AECs we have identified to persist for the next few years, particularly for prepayment customers. Therefore, given the size of the detriment we have observed, we have considered the need to intervene to address domestic

³ See our discussion in Section 11.

customer detriment directly in this transitional period, through the introduction of a price cap.

- 14.8 Given the interventionist nature of a price cap remedy, and the potential for adverse consequences, we have considered very carefully both the need for, and the appropriate scope of, a price cap. We have considered two options: introducing a price cap focused on prepayment customers; and introducing, in addition, a broader cap covering all customers on the SVT.
- 14.9 We have decided to introduce a cap for domestic customers on prepayment customers (the PPM Price Cap Remedy) but the majority of us have decided not to introduce one for all customers on the SVT (the SVT Price Cap Remedy). Overall, our decision was balanced, with one group member believing such a broader cap was also necessary. Our reasoning concerning a broader price cap is set out in Section 11, while our reasoning in relation to the prepayment price cap is set out in paragraphs 14.10 to 14.25 and Section 15.

Assessment of the case for a prepayment price cap

- 14.10 We have concluded that a price cap should apply to domestic customers on prepayment meters for a transitional period (2017 to the end of 2020), covering all domestic prepayment customers except those on SMETS 2 smart meters when these are rolled out.⁴
- 14.11 In reaching this decision, we have given particular consideration to the following:
- (a) The Domestic AECs we have identified, the features contributing to them, the relative strength of those features as they apply to different categories of customer, and the extent to which, and when, our other remedies concerning the Domestic AECs will address aspects of those features.⁵
 - (b) The scale of the detriment that we have observed, as well as the extent to which the detriment differs between different categories of customer and will be affected by our other remedies.⁶

⁴ See paragraphs 14.89–14.94 for more detail.

⁵ See Section 9.

⁶ See Section 10.

- (c) The impact of our prepayment remedies⁷ and engagement remedies⁸ on the features giving rise to the Domestic AECs, and their interaction with the price cap (see Sections 11 and 15), including the need for an iterative process of greater supply- and demand-side pressures for more competitive prices to emerge.
 - (d) The potential for adverse consequences from the introduction of a price cap,⁹ and how these might be expected to differ according to the scope, design and duration of the price cap remedy.
 - (e) The practicability of implementing a cap on a sufficiently timely basis to address the detriment, in particular during the period while our other remedies take effect.
- 14.12 In relation to the Domestic AECs, we have taken particular account of the strength of the features contributing to the Prepayment AEC and the Domestic Weak Customer Response AEC as it applies to prepayment customers.
- 14.13 Compared to other customers, prepayment customers have not been able to access the cheaper tariffs available to other customers and on average pay higher prices. In that regard we have seen recent changes in the prepayment segments including an increase in the share of independent suppliers offering smart tariffs.¹⁰ However, we have not seen significantly lower prices or, most importantly, evidence of a substantial reduction in detriment.
- 14.14 We believe that our prepayment remedies¹¹ and engagement remedies¹² will help improve the conditions for competition in the prepayment segments, but these will take some time to implement and have an effect on detriment, and will not fully address the detriment arising from the Prepayment AEC until smart meters have been substantially rolled out (scheduled for the end of 2020).¹³
- 14.15 In relation to the Domestic Weak Customer Response AEC, we note that in our survey prepayment customers were considerably less likely to have ever considered switching or to consider switching in the next three years than

⁷ See Section 12.

⁸ See Section 13.

⁹ We discuss the interaction of the price cap remedy with our other remedies in Sections 11 and 15.

¹⁰ See Section 10.

¹¹ See Section 12.

¹² See Section 13.

¹³ See Sections 11 and 15 for further consideration of the timescales over which we expect our remedies to remedy the detriment and the timescales for their implementation.

direct debit customers. We also note that lower engagement by prepayment customers will contribute to the features giving rise to the Prepayment AEC concerning softened incentives for suppliers to compete to acquire prepayment customers.

- 14.16 The level of detriment suffered by prepayment customers is particularly high. Over the period 1 January 2012 to 30 June 2015, detriment expressed as a proportion of the bill for prepayment customers of the Six Large Energy Firms was substantially higher than that for direct debit and standard credit customers. For dual fuel customers – who comprise 69% of the electricity customers of the Six Large Energy Firms and 81% of their gas customers – detriment was on average 12% for prepayment customers, 7% for standard credit customers, and 8% for direct debit customers, while for single fuel electricity customers average detriment equated to 11% of a standard bill for prepayment customers, 5% for standard credit and 6% for direct debit.¹⁴ This relationship did not hold for single fuel gas customers, but the levels of detriment were high for the three payment types (between 13% and 16%).¹⁵
- 14.17 As discussed in Section 10, these results somewhat understate the detriment faced by prepayment customers relative to standard credit customers. This is because customers paying by prepayment suffer additional costs (notably, the inconvenience of needing to top up cards and needing to pay for energy in advance) while those paying by standard credit enjoy some additional benefits (flexibility of payment timing). Further, we have not quantified the impact of consumption being depressed due to prices being set above the level we would expect to see in a well-functioning market, and we expect that this effect will be strongest in the prepayment segments because of the nature of the prepayment product, whereby consumption is curtailed when a customer runs out of credit.
- 14.18 The detriment we have calculated for prepayment customers is also increasing, reaching £147 a year by 30 June 2015 for a dual fuel single rate meter prepayment customer consuming at Ofgem’s medium TDCV, and £388 million a year for all prepayment customers.
- 14.19 We have assessed the potential for adverse consequences arising from a price cap in more detail below, in the section on proportionality.¹⁶ However, we note that in principle, the potential for adverse consequences is reduced

¹⁴ All figures reflect consumption at Ofgem’s medium TDCV.

¹⁵ We note, as discussed in Section 10.43, that our benchmark for single fuel gas is based on far fewer accounts than the benchmark for dual fuel and single fuel electricity.

¹⁶ See paragraphs 14.381–14.458.

where any price cap covers a relatively restricted proportion of consumers, such as prepayment customers¹⁷ as opposed to a broader group.¹⁸

- 14.20 The practicability of a price cap is also closely linked to its detailed design which we consider below. However, we consider that, in principle, the use of an easily identifiable criterion for qualification (such as being a prepayment customer) will help ensure that the remedy is easily implementable within a short period of time. This is in contrast, for example, to potential approaches based on the use of data matching through the benefits system to try to target customers with particular demographic characteristics.¹⁹
- 14.21 There are initial indications that competition for smart prepayment customers may be developing. In particular, we note E.ON's previously announced plans to roll out its smart pay-as-you-go offering in 2016, having piloted it in 2015. We further note E.ON's response to our provisional decision on remedies in which E.ON commented that 'this demonstrates that the PPM market opportunity is attractive and one that suppliers are actively pursuing'. We consider that this also provides evidence that competition may develop in the prepayment segments.
- 14.22 E.ON's smart pay-as-you-go initiative suggests that the options available to smart prepayment customers may become more attractive in future. We consider that this development – if implemented – would be positive, but will not be sufficient to address, over the next few years, with respect to prepayment customers, the features giving rise to the Prepayment AEC and the Domestic Weak Customer Response AEC. In reaching this conclusion, we have had regard for the considerations set out above.
- 14.23 We consider the rationale for a prepayment price cap and how this relates to the wider package of remedies in Sections 11 and 15.²⁰

Summary of decision on price cap scope

- 14.24 We have therefore decided to implement a transitional price cap on the maximum level of annual bills for domestic prepayment customers excluding

¹⁷ 15% of gas customers and 16% of electricity customers have a prepayment meter.

¹⁸ We note that the larger the group of customers affected by a price cap, the greater the magnitude of any distorted incentive and that similarly a greater number of customers would be affected by any distorted incentives if the scope of the price cap were wider.

¹⁹ We have considered the relationship between demographic characteristics and disengagement in Appendix 6.3.

²⁰ See in particular the subsection in Section 15 entitled 'Protecting customers less able to engage to exploit the benefits of competition'.

interoperable SMETS 2 smart meters when these are available. The operation of this remedy is described in paragraphs 14.36 to 14.246 below.

14.25 We have decided not to implement a price cap for all SVT customers.

Aim of the remedy

14.26 The aim of the PPM Price Cap Remedy is to mitigate the detriment suffered by domestic prepayment customers arising from the Prepayment AEC and the Domestic Weak Customer Response AEC during the transitional period. The transitional period is the period during which our other remedies concerning the Prepayment AEC and the Domestic Weak Customer Response AEC are being implemented and will take full effect, until the substantial completion of the roll-out of smart meters by the end of 2020.

14.27 The price cap will be a transitional measure which will be closely linked to the national programme for the roll-out of SMETS 2 smart meters, reflecting our view that the features that we have observed that give rise to the Prepayment AEC will be, to a significant extent, addressed once the large majority of prepayment customers have a SMETS 2 smart meter and are able to benefit from suppliers being appropriately able and incentivised to compete for their business. We also believe, albeit over a longer period, that smart meters will help to improve customer engagement and help address the features contributing to the Domestic Weak Customer Response AEC and associated detriment.

14.28 In this way, the price cap will mitigate the detriment while our other remedies are implemented, and will mitigate the residual detriment once the other remedies have been introduced until the conclusion of the national programme for the roll-out of smart meters. In designing the remedy we have sought to help preserve suppliers' (both existing suppliers' and new entrants') incentives to compete and mitigate the risk that suppliers are not able to earn adequate revenues under the cap.

Parties' views and our response

14.29 We received responses to our provisional decisions in respect of proposing not to proceed with the SVT Price Cap Remedy and proposing to proceed with the PPM Price Cap Remedy. We have included a comprehensive summary of responses in Appendix 14.1. The large majority of the responses we received focused on the PPM Price Cap Remedy.

14.30 Those comments that related to the proposal not to proceed with the SVT Price Cap Remedy were varied. Some parties agreed that we were right to

drop the SVT Price Cap Remedy while others disagreed. An alternative approach was also suggested, where the PPM Price Cap Remedy would be extended where necessary to meet the specific objective of protecting various customers in vulnerable circumstances.

- 14.31 Responses in respect of the PPM Price Cap Remedy were also varied. Again some parties supported our provisional decision while others thought that it was not appropriate. The parties that opposed the PPM Price Cap Remedy broadly did so on the grounds that it was an unnecessary, inappropriate and disproportionate intervention. Some parties went on to make suggested changes to the design of the PPM Price Cap Remedy which would address some of the concerns expressed. Many parties noted various risks and possible unintended consequences associated with the PPM Price Cap Remedy.
- 14.32 As discussed in 14.24 above, we have decided to impose the PPM Price Cap Remedy. We have, however, made a number of changes to the design of the price cap in response to the feedback that we received to our provisional decision on remedies. We have, however, maintained the overall approach of using a hybrid referencing price design, which we explain further below.
- 14.33 The areas where we have updated the design in response to feedback to provisional decision on remedies are as follows:
- (a) The price cap will now apply to gas and electricity tariffs separately. There will not be a separate price cap for dual fuel tariffs.
 - (b) The price cap is now defined with respect to two points (rather than three) to ensure a linear relationship between cost and volume.
 - (c) We have considered the impact of the price cap at different levels of consumption in calibrating the price cap.
 - (d) We have refined the definition of the wholesale cost index and changed the length of price cap periods from 12 to six months.
 - (e) We have updated our analysis of competitive benchmarks, thereby increasing the underlying base level of the price cap.²¹
 - (f) We have provided additional clarity in relation to the treatment of policy and other costs. We now calculate network costs separately in each

²¹ See paragraphs 10.18–10.38 for detail of our approach to determining the competitive benchmarks.

period using data from charging statements rather than updating in line with an index. We have updated our analysis of the prepayment cost differential from £54 to £63.²²

- 14.34 In light of these changes we have also reconsidered what is a suitable level of headroom. In summary, we consider that as a result of these design enhancements – and considerations relating to impacts on customers, suppliers and competition – a lower level of headroom is warranted. Accordingly we have decided to allow headroom of £15 per fuel rather than the £25 proposed in the provisional decision on remedies. See further paragraphs 14.250 to 14.275 below for our assessment of a suitable level of headroom.
- 14.35 In the sections that follow we address these issues in more detail, considering specific issues raised by parties, before reaching our conclusions in relation to the PPM Price Cap Remedy.

Design considerations

- 14.36 In this section:
- (a) we set out some of the high-level price cap design options we considered for the prepayment price cap;
 - (b) we set out the criteria that we took into account in evaluating those design options and which we considered when making decisions on finer detailed aspects of the design;
 - (c) we describe our final decision on the design of the price cap remedy;
 - (d) we set out our view on the stringency of the price cap,²³ presenting the results of our analysis of the impact of the cap on prepayment customers and suppliers; and
 - (e) finally we present our conclusions on sunset provisions and the way in which we propose to implement the cap.
- 14.37 We have evaluated the effectiveness and proportionality of different options for the design of the PPM Price Cap Remedy against several key design criteria, notably:

²² While the prepayment cost differential is used in the price cap the detailed analysis is presented separately, see Appendix 9.8, since it is also used in other areas of our investigation.

²³ Considering, in particular, the headroom we propose to incorporate into the price cap.

- (a) practicability (whether the cap can be implemented on a timely basis, easy to calculate in an objective way and easy to comply with and monitor);
- (b) minimal impact on supplier incentives (whether the design minimises the scope for perverse and distorted incentives and allows for competition);
- (c) accuracy (whether the cap accurately reflects changes in competitive market conditions over time, and any changes in the costs that an efficient supplier would be expected to bear); and
- (d) impact on customers and suppliers (whether the cap reduces prices for prepayment customers while allowing efficient suppliers to compete beneath the level of the price cap while still earning a normal rate of return, without leading to a reduction in quality).

14.38 The first three criteria are particularly relevant for considering the structure and form of the cap, while the fourth is largely a function of the stringency of the cap, including the extent to which we include headroom in the level of the cap. Accordingly, we first explain our decision on the structure and form of the cap against the first three criteria, before considering impact in a separate section on the stringency of the cap.

14.39 We present our overall assessment of the effectiveness and proportionality of the PPM Price Cap Remedy at the end of this section.²⁴

The structure and form of the cap

14.40 We considered a range of options for the structure and form of the price cap, including approaches based on bottom-up cost modelling, internal and external reference pricing and a hybrid reference price and cost index approach.

Bottom-up cost approach

14.41 We gave some consideration to an approach based on bottom-up cost modelling, which would involve constructing a cap based on a detailed assessment of the costs incurred in the supply of energy to customers, an adjustment for efficiency and an allowance for an appropriate rate of return

²⁴ We note that the above criteria are wholly consistent with the criteria set out in our guidance regarding the assessment of effectiveness and proportionality as set out in paragraphs 14.349–14.459 below, and that a proportionate remedy must (a) be effective in achieving its legitimate aim; (b) be no more onerous than needed to achieve its aim; (c) be the least onerous if there is a choice between several effective measures; and (d) not produce disadvantages which are disproportionate to the aim.

on capital. This is broadly the sort of approach that is typically used in the regulation of natural monopolies. However, we concluded that this approach did not meet our practicability criterion as it could not feasibly be implemented within the required timescales.

Internal reference pricing approach

14.42 Ovo Energy and RWE suggested to us variations of what we consider to be an 'internal reference pricing' approach, which could be considered to be broadly comparable to the economic concept of non-discrimination. Under RWE's proposed approach²⁵ suppliers would be obliged to offer their fixed-term contract offers to all payment methods with suppliers prevented from charging any differential between standard credit and prepayment prices. In this way there would be some form of constraint not on the overall level of a supplier's prices, but on the difference between the prices that a supplier offered to different categories of customer.

14.43 Ovo Energy was supportive of a price cap but had concerns that such a measure might harm innovation to a greater extent than an alternate proposal that it favoured – a cost-reflective principle (CRP), which would consist in requiring that any differences in prices be justified in relation to differences in costs. Ovo Energy submitted that:

the introduction of a CRP, coupled with clear guidelines and a framework for robust enforcement, would significantly reduce the current price difference between fixed and variable tariff offerings in line with the true costs associated with each. This would mean that a supplier's ability to compete would be wholly dependent on how well they deliver efficiency savings and innovative products.²⁶

14.44 We note that internal reference pricing approaches are generally easy to implement (since they tend to be based on principles defined ex ante). However, we have reviewed the effectiveness of previous non-discrimination remedies applied in the retail energy markets, and we consider that there have been difficulties in effective implementation and in some cases unintended consequences. In particular, when Ofgem prohibited suppliers from offering out-of-area discounts for new customers, the effect was to

²⁵ RWE.

²⁶ Ovo Energy.

increase prices for out-of-area customers and reduce the strength of competition.²⁷

- 14.45 We expect therefore that, in the case of the PPM Price Cap Remedy, preventing discrimination in prices paid by prepayment and non-prepayment customers would result in an increase in prices paid by non-prepayment customers and reduce the scope for suppliers to target particular tariffs at one segment or another. We further note that suppliers' cost reporting processes systems do not appear sufficiently detailed to robustly assess compliance with such a cost-reflectivity requirement.²⁸
- 14.46 We have therefore decided not to pursue internal reference price approaches of this sort as they lead to excessive risks of perverse supplier incentives and harmful impacts on competition (ie failing our second criterion).

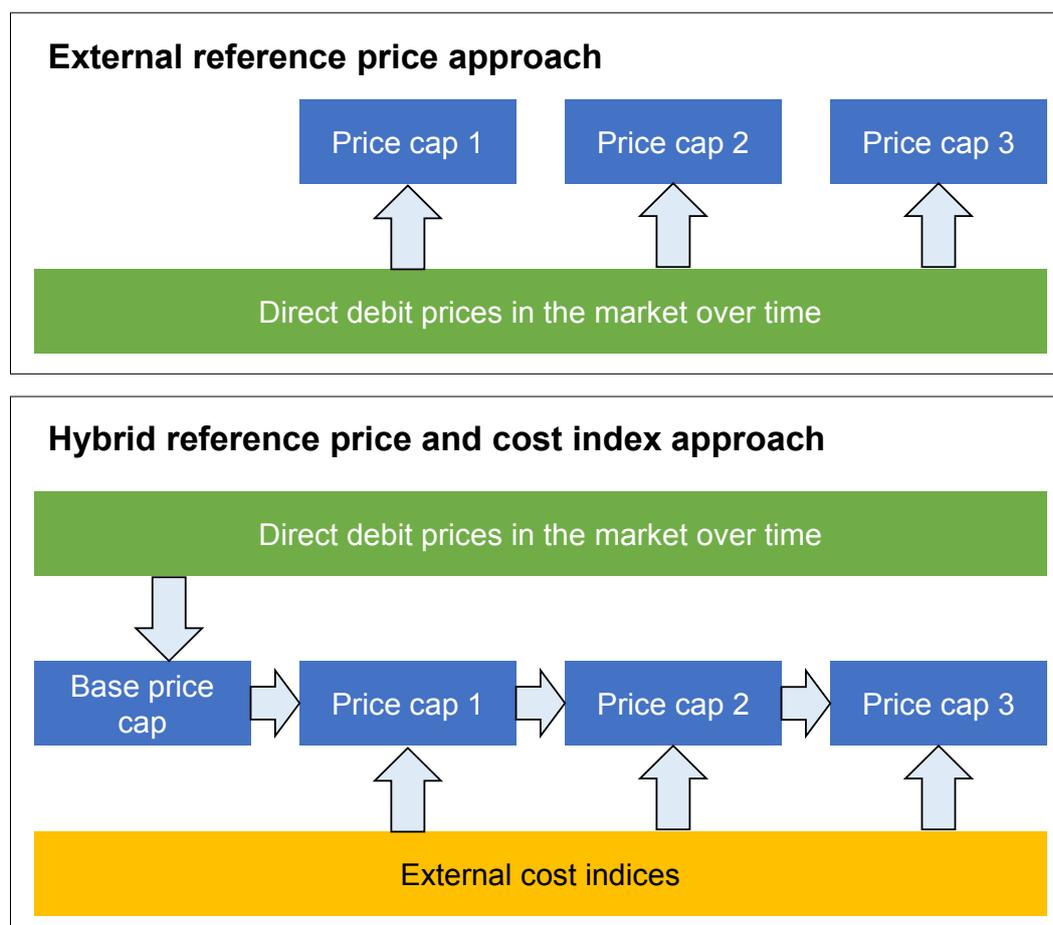
External and hybrid reference pricing approaches

- 14.47 We gave detailed consideration to two main options for a PPM Price Cap Remedy, which in principle meet all of our design criteria. These are:
- (a) a hybrid reference price and cost index approach, which would involve setting a base level of the prepayment cap based on our competitive benchmark analysis and then allowing the cap to change over time according to movements in exogenous cost indices; and
 - (b) an external reference price approach, which would involve setting a cap on prepayment tariffs based on non-SVT direct debit tariffs in the market plus an uplift reflecting our assessment of the costs associated with prepayment.
- 14.48 These two options are illustrated in Figure 14.1 below.

²⁷ See [provisional findings report](#), paragraph 8.254.

²⁸ See Appendix 9.8.

Figure 14.1: Illustration of price cap design options



Source: CMA.

- 14.49 We discuss in this section how the hybrid and external reference price approaches could work.
- 14.50 We consider that the hybrid reference price and cost index approach is a viable option for setting the price cap. The detailed analysis that we have conducted of prices and bills has allowed us to calculate a competitive benchmark bill for prepayment customers as of 30 June 2015.²⁹ Under this approach, the competitive benchmark bill would then change every six months according to changes in exogenous costs relating to: wholesale costs; network costs; policy costs and inflation.
- 14.51 In our provisional decision on remedies we suggested that these cost components would all be updated in line with certain indices. Our final decision retains that approach for wholesale costs, policy costs and inflation. Our final decision for updating network costs is that the cost allowance

²⁹ See Section 10.

should be calculated for each price cap update using the charging statements of the relevant network companies.³⁰

- 14.52 The particular benefits of the hybrid reference price and cost index approach are that it is easy to implement and, since suppliers are unable to shift the cost indices used to change the cap year on year, it mitigates the risk that suppliers seek to manipulate the level of the price cap. This avoids one of the principal risks of the external reference approach, as we explain below.
- 14.53 The external reference price approach could have been a viable and timely approach to setting the PPM Price Cap Remedy, we did, however, identify some significant weaknesses in this approach, which are not apparent in the hybrid approach.
- 14.54 We considered several variants of this external reference approach, which primarily concerned differences in the population of external reference tariffs (the 'reference basket'). In one variant, the reference basket was composed of non-SVT acquisition tariffs in the previous period, while in another the reference basket was composed of the stock of non-SVT tariffs paid by customers in the previous period (the 'stock approach'). We found that the former was preferable against our 'accuracy' criterion (since acquisition tariffs more closely reflected changes in market conditions), while the latter was preferable in relation to the 'supplier incentives' criterion (since the reference basket drew on a broader range of tariffs and hence was more robust against manipulation).
- 14.55 However, under each of these variants, we identified several drawbacks associated with the external reference price approach. This included: the existence of perverse incentives and potential mechanisms for suppliers to game the cap (for example, through manipulation of the reference basket tariffs in order to drive up the level of the cap); potential accuracy concerns as a result of the lag between the date reference tariffs were brought onto the market and the implementation of the cap informed by these tariffs (for example, where prices achievable when reference basket tariffs were first brought onto the market are no longer achievable based on market conditions when the cap is effective); practicality in terms of the significant, regular data required by Ofgem to calculate updated caps; and potential changes in the nature of competition in the reference basket which may reduce the effectiveness of the cap (for example, a move to bundled or heavily discounted tariffs in the reference basket which would not be

³⁰ Charging statements are documents published by the network companies which specify how users of the network (such as suppliers) will be charged for their use of the network. See paragraphs 14.187–14.201 for discussion of this change.

adjusted for in the price cap calculation and therefore may give rise to an ineffective cap) and added to the concerns around perverse incentives.

14.56 Our final decision is that we should adopt the hybrid reference price and cost index approach, as we consider it is more consistent with our identified criteria, taken together, as follows:

- (a) **Practicability:** our preferred approach is easier to implement than the external reference price approach. In particular, it is less burdensome for both Ofgem and suppliers, since there is no requirement for updated information on tariffs to be submitted on a periodic basis and the cost index information we have prescribed is readily available. This reduces the cost of this form of remedy.
- (b) **Supplier incentives:** under the hybrid reference price approach there appears to us to be minimal scope for perverse incentives, since the indices we have identified are not manipulable by suppliers. In contrast, even under the more robust variant of the reference price approach (the 'stock' approach), there is some potential for the cap to be manipulated or inflated through changes in the nature of competition (eg suppliers might compete more by offering discounts and other benefits which would not be reflected in the cap, rather than reducing prices, which would be).
- (c) **Accuracy:** in relation to accuracy, the comparison of the two options is more balanced. The advantage of the reference basket approach is that new tariffs offered by suppliers should reflect expected changes in efficient costs, without each of the cost components needing to be specified. Against this, the more robust of the reference basket variants (the 'stock' approach) introduces a longer period of lag into these expectations, reducing accuracy. Our preferred approach will accommodate changes in wholesale and network costs relatively simply and quickly,³¹ but it is more challenging to accommodate changes in policy costs with the same degree of accuracy. This is discussed further below in paragraphs 14.202 to 14.226.

14.57 In summary, we believe that the hybrid reference price and cost index approach is the one that achieves the best balance against the above criteria, particularly given the need to implement the PPM Price Cap Remedy in the near future to maximise its effectiveness.

³¹ There is still a lag period in our preferred approach as described in paragraphs 14.146–14.160.

Design of the price cap

- 14.58 The price cap will be based on our estimated benchmark for a competitive prepayment tariff as at 30 June 2015³² (base level of the cap – period 0) plus allowances for the cost to serve prepayment customers, network costs and headroom. The price cap is then adjusted at regular intervals for movements in input costs since 30 June 2015 ('cost indexing'). The adjustments will explicitly allow for movements in wholesale energy costs, network costs, policy costs and 'other' costs due to inflation.³³
- 14.59 Two parties suggested in response to our provisional decision on remedies that it would be simpler if the price cap were set exclusive of VAT such that any changes in the VAT rate do not affect the level of the price cap and are automatically factored in to the prices offered to customers.³⁴ We considered that this was a reasonable and practical argument and agree that this is the simplest and most logical way to treat VAT as regards the price cap. We have therefore decided that the price cap will be specified exclusive of VAT and compliance assessed on the price exclusive of VAT.

Application of the cap

- 14.60 In this section we set out how the price cap will be specified for each fuel, region and consumption level.
- 14.61 Separate price caps are necessary for each region, to reflect differences in network charges. There will be price caps for prepayment customers in each region for:
- (a) single fuel, single rate, electricity;
 - (b) single fuel, Economy 7, electricity; and
 - (c) single fuel gas.
- 14.62 Dual fuel tariffs offered during the period of application of the PPM Price Cap Remedy must ensure that the prices charged for each fuel component comply with the relevant single fuel price cap. We agree with respondents to the provisional decision on remedies who suggested that this approach

³² Using the competitive benchmark tariffs determined in Section 10, adjusted in accordance with paragraphs 14.103–14.131.

³³ In our provisional decision on remedies we referred to this 'other' category as 'indirect' costs. That label was not wholly appropriate since that category also included an allowance for a reasonable profit.

³⁴ Scottish Power, SSE.

would be simpler and more robust than specifying a separate dual fuel price cap.

- 14.63 In particular we agreed with respondents who suggested that assessing compliance for a dual fuel price cap would:³⁵
- (a) be overly complex – for example, we would have to choose a suitable weighting between gas and electricity wholesale indices. Whichever weighting we chose would not be accurate for all suppliers so would introduce unnecessary distortion. We are therefore satisfied that single fuel price caps are more proportionate (although note that single fuel price caps introduce different issues, which we have considered and addressed as we explain below in paragraphs 14.66 to 14.68);
 - (b) create anomalies and ambiguities concerning dual fuel to single fuel differential – to assess dual fuel price cap compliance we would have to specify how suppliers determine the split between gas and electricity consumption. Since this split will never be accurate for all customers this approach risks introducing unnecessary distortion;
 - (c) be impractical – applying dual fuel price caps would create practical issues where, for example, a customer switches between dual and single fuel which could result in unnecessary and unexpected price changes; and
 - (d) be inconsistent with pricing practices in the prepayment segments – we note that the existence of separate dual fuel and single fuel price caps could unduly constrain suppliers’ flexibility in determining prices for single fuel products relative to dual fuel products.
- 14.64 We thus consider that single fuel price caps are a more effective and proportionate way to implement the PPM Price Cap Remedy. As a result, dual fuel customers will be protected by the combination of two single fuel price caps, rather than by a (single) dual fuel price cap.
- 14.65 This change to single fuel price caps required us to revisit our choice of the competitive benchmark used to set the level of the price cap. Given that separate price cap levels will be set for single fuel gas and electricity tariffs, our starting point was to apply the competitive single fuel benchmarks determined in Section 10 in setting the level of the price cap. As explained in Section 10, we have estimated separate benchmarks for both single fuel

³⁵ See Appendix 14.1 for further detail of parties’ views.

electricity and single fuel gas which correspond to single fuel caps, and which we use to establish a base level for the price cap.

- 14.66 However, as also noted in Section 10 (paragraphs 10.58 – 10.62), the single fuel tariffs – and single fuel gas tariffs in particular – of Ovo and First Utility have significantly fewer customers and overstate the competitive price when compared to the gas and electricity components of our dual fuel benchmark. This is reflected in the single fuel gas benchmark being £19 more expensive than the gas component of the competitive dual fuel benchmark (and the single fuel electricity benchmark being £5 more expensive than the electricity component of the competitive dual fuel benchmark).
- 14.67 As a result, our decision to use the single fuel benchmarks, and gas in particular, to set the level of the price cap will lead to a more conservative approach than a price cap set on an alternative benchmark based on the single fuel components of the competitive dual fuel benchmark.
- 14.68 In order to ensure that our remedy is effective, we have therefore used the competitive dual fuel benchmark as a cross-check to facilitate our understanding of the impact of the single fuel gas price cap and to inform our overall decision on the appropriate level of headroom.
- 14.69 The price cap for each fuel will be defined in each of the 14 distribution network operator regions.³⁶ We consider that regional price caps are appropriate in order to accurately allow for network costs which vary on a regional basis. In total there would therefore be 42 price caps.³⁷
- 14.70 Calculation of the price cap over different levels of consumption will be determined on the basis of the cost of supplying energy at two consumption levels:³⁸
- (a) Nil consumption.
 - (b) The medium TDCV (3,200 kWh for electricity, 13,500 kWh for gas).
- 14.71 The price cap for each fuel/meter type would be defined in terms of these two points and the straight line they define. The line would be extrapolated to

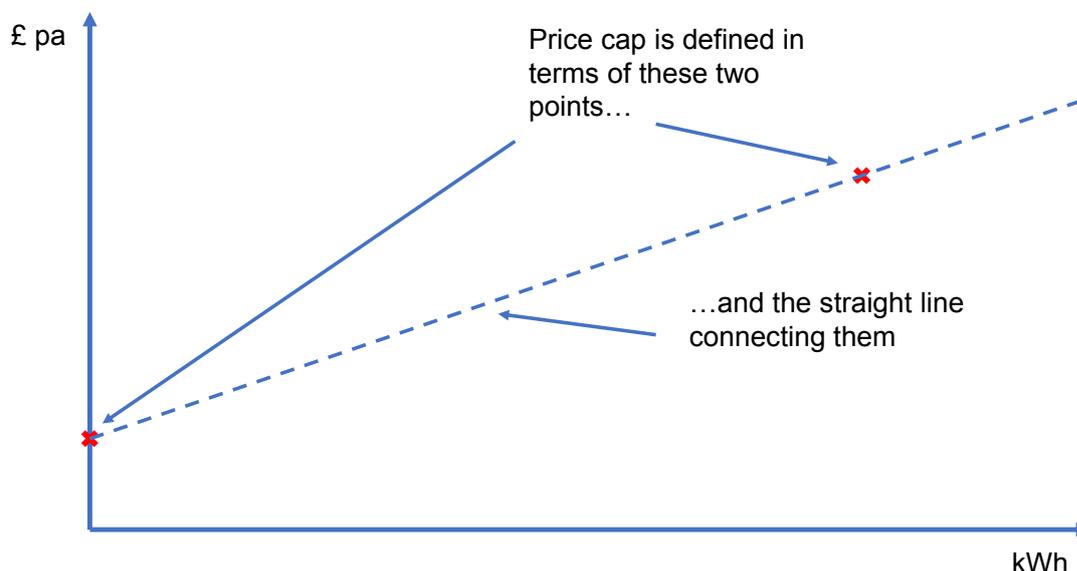
³⁶ These regions relate to the different electricity distribution networks. The gas price cap will be defined for these regions also to minimise the compliance burden on suppliers – ie no need for a complicated array of different tariffs for each combination of gas and electricity regions. See paragraphs 14.441 & 14.442 for further consideration of this point.

³⁷ For each of 14 regions there would be a price cap for each of the three categories shown in paragraph 14.61. See paragraphs 14.196–14.198 for consideration of how gas price caps are defined using electricity regions.

³⁸ The figures shown here are those that are prevailing at the time of writing. The TDCVs used for the competitive benchmark analysis were those prevailing for the period January 2014 to August 2015 as the tariffs informing the competitive benchmark were in the market in this period. Further information about [TDCVs](#) can be found on the Ofgem website.

define the price cap for levels of consumption greater than the medium TDCV. Tariffs subject to the price cap must result in lower annual bills than the price cap at all consumption levels as illustrated below.

Figure 14.2: Illustration of how the price cap is defined



Source: CMA.

- 14.72 The base level of the cap at zero consumption has been calculated as the average standing charge paid by the prepayment customers of the Six Large Energy Firms (weighted by customer numbers) as of 30 June 2015.
- 14.73 We take medium TDCV as the other consumption level at which to define the price cap. The base level of the cap at medium TDCV is based on our estimate of the competitive benchmark tariff at 30 June 2015³⁹ plus inclusion of £15 headroom per fuel.
- 14.74 Our aim is to ensure that the level of the cap at medium TDCV is reflective of our estimate of a competitive price for customers on non-smart prepayment meters, with an uplift that reflects our judgement as to the appropriate balance between reducing customer detriment, allowing competition to co-exist with the cap and minimising adverse supplier impact. Our judgement and analysis on these matters is set out from paragraph 14.247.
- 14.75 By setting the cap at zero consumption at a level consistent with prevailing standing charges of the Six Large Energy Firms, we have ensured that the structure of the cap is broadly reflective of the structure of existing

³⁹ Including network costs plus the prepayment uplift.

prepayment tariffs.⁴⁰ We compare the structure of our cap, as updated by relevant exogenous costs, with prepayment tariffs in the market as at the end of May 2016 in paragraph 14.312.

- 14.76 We note that setting the cap at zero consumption in relation to average prepayment standing charges is a departure from the approach we proposed in the provisional decision on remedies, which would have resulted in a cap at zero consumption substantially higher than average prepayment standing charges.⁴¹ Several parties commented on this.⁴² In particular, SSE submitted that this approach might result in suppliers increasing standing charges, which 'would be particularly disadvantageous to lower users, a group which includes some of the most vulnerable customers. This was clearly not the intention of the CMA when devising the price cap but shows the potential pitfalls of the current approach being complex and not fully transparent.'⁴³
- 14.77 To avoid this outcome we have amended our approach, by setting the cap at zero consumption in relation to average prepayment standing charges of the Six Large Energy Firms. One implication of this is that, in relation to our competitive benchmark bills, the cap is more stringent (ie reduces a greater proportion of detriment) at low levels of consumption compared to high levels of consumption.⁴⁴

Assessment of compliance with the price cap

- 14.78 Suppliers would be responsible for ensuring their own compliance ex ante. Pursuant to the licence conditions that would also be introduced with our order, Ofgem would also check compliance ex post on a tariff-by-tariff basis and would have at its disposal the usual array of enforcement tools should it encounter instances of non-compliance. To facilitate monitoring and enforcement of the order, Ofgem should publish a report annually setting out the tariffs that suppliers have offered in the year in question and assessing compliance with each.

⁴⁰ See paragraphs 14.295–14.310 for analysis of how the price cap relates to existing tariffs for different levels of consumption.

⁴¹ This issue arises because, as discussed in Section 10, in calculating detriment we have adjusted bills for payment cost differentials by subtracting a fixed amount from the annual bill which is equivalent to a reduction in the standing charges of the Six Large Energy Firms, such that for very low levels of consumption benchmark bills are higher than average actual bills – ie there is negative detriment.

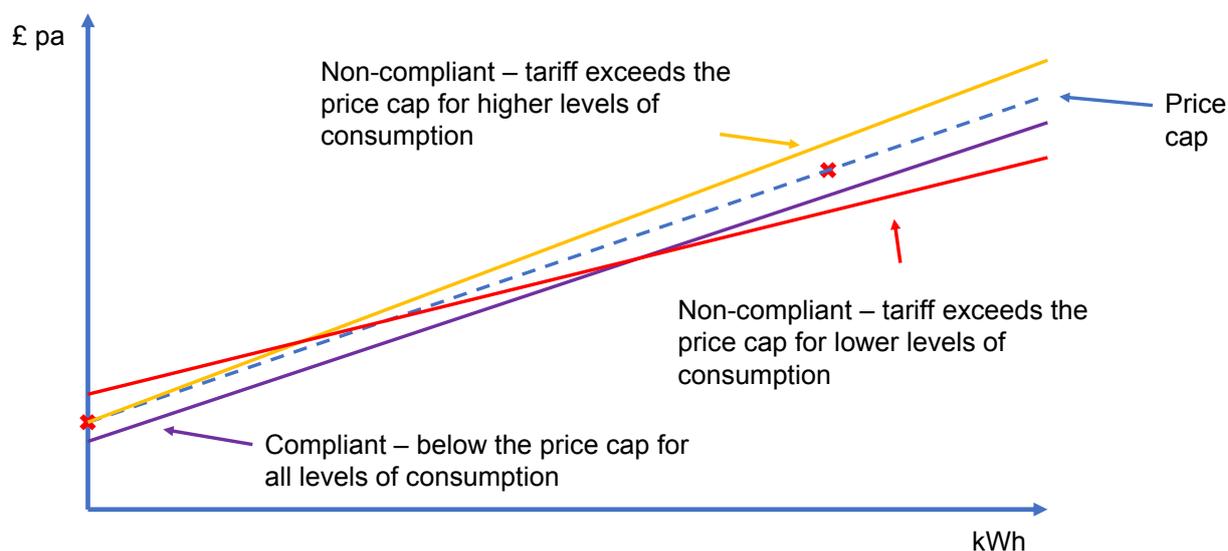
⁴² See Appendix 14.1, paragraph 106.

⁴³ SSE, [Supplementary submission on a tariff cap](#).

⁴⁴ We note, however, as set out in paragraph 14.125 below, that, when comparing the cap to existing tariffs, it is in fact less stringent at lower levels of consumption and more stringent at higher levels of consumption. This again follows from the relationship between our benchmark bills and prevailing tariffs, as discussed in Section 10.

14.79 A tariff would be compliant if the annual cost is less than the line defined by the price cap for all levels of consumption. The figure below illustrates how compliance would be assessed:

Figure 14.3: Price cap compliance example



Source: CMA.

14.80 At any point in time while the PPM Price Cap Remedy is in force, all tariffs that are on offer to prepayment customers, or which prepayment customers are currently on, would need to be compliant.⁴⁵ When the level of the price cap is reset, tariffs might then also need to be reset to remain compliant with the new price cap. This could result in price reductions. We expect that as competition develops in the prepayment segments with the introduction of our other remedies and the smart meter roll-out it will be competition rather than the price cap which becomes the more stringent constraint on pricing.⁴⁶

14.81 Our review of tariffs within the market suggests that most tariffs are based on a similar pricing structure, with a (positive) standing charge and unit rate. However, there are a limited number of tariffs which have a different approach, and which might not be compliant with our price cap for some volumes.

14.82 In light of this, we consider that it is appropriate to provide some flexibility over the way in which compliance is assessed. We have therefore decided

⁴⁵ Subject to any derogations in force, see paragraph 14.82.

⁴⁶ See Section 11.

to include a derogation mechanism to allow suppliers to request a variation in the way in which compliance is assessed.

- 14.83 We are aware that some suppliers have innovated through offering tariffs with zero standing charges.⁴⁷ A consequence of having nil standing charge is that the unit rate is larger. This in turn means that zero standing charge tariffs may exceed the price cap for higher levels of consumption and hence would not comply with the cap, even if customers who were on such tariffs consumed sufficiently low levels of energy to pay less, at their prevailing level of consumption, than is allowed by the cap.
- 14.84 In order to sustain this sort of innovation in the prepayment segments where it genuinely benefits customers, it could, in principle, be possible for compliance to be assessed ex post, based on the actual consumption of individual customers. Provided that no customer paid more than the price cap for their actual level of consumption then the supplier would be compliant.
- 14.85 We note that while this approach offers greater flexibility it also increases the compliance burden on suppliers and Ofgem since it requires compliance to be assessed for each customer rather than for each tariff. We therefore considered that a proportionate solution was to build in the flexibility for suppliers to offer such tariffs when granted a derogation by Ofgem. Where a supplier obtains a derogation to monitor compliance ex post we expect that the onus would be on the supplier to demonstrate compliance.
- 14.86 We have therefore decided:
- (a) where a supplier believes that ex ante compliance assessment does not allow for a proper assessment of the cost (to customer) and volume relationship in a given tariff they may apply to Ofgem for a derogation such that they may assess compliance in a different way, for example ex post; and
 - (b) suppliers will only be able to request a derogation on the basis that their business model involves a different relationship between cost to customer and volume to that implied by the price cap.

⁴⁷ One such supplier is Ebico.

- *Model illustrating application of the cap*

14.87 To aid understanding of the possible impact of our final decision we are publishing an illustrative price cap model (the ‘illustrative model’) alongside our final report.⁴⁸ The illustrative model illustrates how the price cap is to be calculated and updated in each region, for each fuel and for each period. We plan to consult on this illustrative model, as an appendix to our order, with a view to developing it further into a model which can be used to ultimately calculate the price cap level for each update.

14.88 Publishing such an illustrative model provides a great deal of transparency as to the likely operation of the price cap and its possible implications. In particular, suppliers will all be able to produce their own calculation of each new price cap level. In this way all parties will be able to independently calculate the updated level and thereby corroborate the official value calculated by Ofgem.

- *Application of the price cap to smart meters*

14.89 We have reconsidered the application of the price cap to smart meters in light of comments made in response to the provisional decision on remedies. E.ON suggested that the price cap should not apply to customers with smart meters, while Scottish Power suggested that the price cap should not apply to customers with SMETS 2 smart meters.⁴⁹

14.90 As noted in paragraph 14.24, the PPM Price Cap Remedy would not apply to domestic prepayment customers who have a SMETS 2 smart meter. The SMETS 2 specification has been designed such that these meters can communicate with any supplier via the data and communications company (the DCC). The infrastructure needed to allow this communication is not currently in place and there are currently no SMETS 2 meters installed. However, we expect that SMETS 2 meters will be installed during the life of this remedy (see Appendix 8.4 for more details).

14.91 Therefore, as at the date of this report, the price cap would initially apply to all domestic prepayment customers.⁵⁰ Where a customer subsequently has a SMETS 2 smart meter installed they will no longer be subject to the price cap. We consider that this is appropriate since the greater functionality that a

⁴⁸ The illustrative model does not form part of our final report. In the event that there is any inconsistency between the final report and the illustrative model then the final report shall prevail.

⁴⁹ See Appendix 14.1 for further detail of parties’ views.

⁵⁰ We note that some suppliers may have installed SMETS2 meters in customers’ homes at the time of the introduction of the cap. Such customers would be excluded from the scope of the price cap.

SMETS 2 meter offers, in particular its ability to communicate with any supplier,⁵¹ provides the basis for effective competition, such that customers should have access to a much wider range of tariffs than at present⁵². For example, customers with SMETS 2 meters would more easily be able to access credit tariffs available from other suppliers since there would be no need to have their meter changed (as is the current situation).⁵³

14.92 Further, in order to be moved onto a SMETS 2 smart meter (and therefore removed from the cap) the customer will have voluntarily entered into a new supply contract, such that we would expect customers exiting the scope of the price cap upon SMETS 2 meter installation to enjoy prices below the price cap.⁵⁴

14.93 We note that some SMETS 1 meters have functionality additional to that required by the SMETS 1 specification. In particular, some SMETS 1 meters can communicate with different suppliers. However, this communication is only possible where the supplier who acquires a customer with the SMETS 1 meter enters into a commercial agreement with the relevant Smart Meter System Operator (see Appendix 9.6). While it is encouraging to see some interoperability developing organically, it does not guarantee that all customers with SMETS 1 meters will be able to access competitive smart tariff prices where these are offered by another supplier. We therefore consider that it is appropriate that customers with SMETS 1 meters are protected by the price cap.

14.94 Where a customer refuses to have a SMETS 2 meter installed they would remain protected by the price cap (see paragraph 14.340).

- *Application of the price cap to Economy 7 and restricted meters*

14.95 Prepayment customers who have a restricted meter would be within scope of the prepayment price cap. In our provisional decision on remedies we suggested that the price cap that would apply to customers on non-Economy 7 restricted meters would be the single rate price cap (regardless of the tariff that they are on).

14.96 EDF Energy and RWE noted that single rate meter customers and Economy 7 meter customers typically had quite different consumption

⁵¹ SMETS 1 meters are only interoperable in limited circumstances, see paragraph 14.93.

⁵² See Section 11.

⁵³ Prepayment customers with an outstanding debt may still face barriers to switching, as discussed in Section 9.

⁵⁴ This expectation reflects an understanding that customers would need to be presented with an attractive offer in order to switch and lower prices are a key part of an offer being attractive. We expect this to generally be the case even if customers value the better functionality and convenience of the SMETS 2 meter, which may factor in their consideration of the new deal proposed by the supplier.

profiles. We note that the different consumption profiles are also relevant to the issue of how compliance with the price cap is assessed for these different meter types. SSE requested that we provide further detail on how compliance would be assessed for Economy 7 meter customers.

- 14.97 Each Economy 7 tariff will be assessed for compliance ex ante by calculating the annual bill assuming 38% off peak consumption,⁵⁵ unless otherwise directed by Ofgem. The benchmark consumption which determines the level of the Economy 7 price cap is the medium profile class 2 consumption level of 4,600 kWh.⁵⁶
- 14.98 Where a supplier believes that 38% off peak consumption does not accurately reflect the usage patterns of their customers they may propose an alternative split to Ofgem and provide evidence to support their argument. Ofgem would then determine whether the suppliers' proposed alternative split better reflects the affected customers' consumption. Where Ofgem is satisfied that the supplier's alternative split is a more accurate reflection of actual consumption patterns then Ofgem will direct the supplier in question to use that alternative split instead.
- 14.99 We have also reconsidered how the price cap should apply to restricted meter customers. Compliance for each restricted meter tariff would be assessed by applying a split between time-of-use registers⁵⁷ where the split is specific to the restricted meter type and the relevant region.
- 14.100 To identify these splits suppliers would be required, on a yearly basis, to provide Ofgem with the splits between time-of-use registers that they propose to apply in assessing compliance. If required, suppliers will need to be able to satisfy Ofgem that these predetermined splits are reasonable, for example with reference to historical data. We believe this represents a more robust, less distortive and easier to apply approach than the one set out in our provisional decision on remedies.
- 14.101 With these splits it is possible to calculate a projected annual bill for each restricted meter tariff for any given level of consumption. Compliance for restricted meter tariffs can then be assessed in the same way as for single rate and Economy 7 tariffs, ie ex ante assessment using a split of consumption between peak and off peak.

⁵⁵ This split is in line with observed consumption patterns in the gains from switching data set and consistent with the split used in the competitive benchmark analysis.

⁵⁶ Source: Ofgem (13 September 2013), [Letter regarding decision on new typical domestic consumption values](#).

⁵⁷ 'Time-of-use registers' refers to the different rates that restricted meters record. While non-restricted meters record only a single rate restricted meters have more than one rate. Commonly there are two rates: peak and off-peak.

14.102 We are aware that some customers have multiple meters for the same fuel. We expect that in the majority of cases the price cap will apply equally to them without need for special application. Any special application arrangements for customers with multiple meters for the same fuel will be subject to consultation during the implementation phase.

Base level of the cap ('period 0')

- *Competitive benchmark and value at nil consumption*

14.103 The calculation of the price cap will be determined on the basis of two specific levels of consumptions:

(a) Nil consumption.

(b) The medium TDCV (3,200 kWh for electricity, 13,500 kWh for gas).

14.104 The base level of the cap at medium consumption is calculated as an estimate of a relevant competitive benchmark tariff using the same approach that we used in Section 10 to estimate detriment from the pricing policies of the Six Large Energy Firms.

14.105 As explained in Section 10, our competitive benchmark is a hypothetical construct based on the tariffs offered by the two most competitive Mid-tier Suppliers: Ovo Energy and First Utility, adjusted where appropriate for a range of factors including cost elements that are outside their control.

14.106 We recognise that smaller suppliers may not yet be operating at an efficient scale to the same extent that our competitive benchmark suppliers do. While we have not made an allowance in the price cap for an inefficient scale, we note that those smaller suppliers are not yet subject to the full cost of meeting environmental and social obligations which have been factored into our competitive benchmark. Given the size of those costs (as discussed in Appendices 8.1 and 10.1), we are satisfied that the price cap calculated on the basis of our competitive benchmark is at an appropriate level for smaller suppliers.

14.107 The competitive benchmark includes all tariff types weighted by the respective number of accounts within each of Ovo Energy and First Utility.⁵⁸ For the purposes of setting the base level of the price cap we would use only

⁵⁸ The competitive benchmark we use for setting the price cap is based on prices for direct debit tariffs and we allow for an uplift to reflect the incremental costs of serving prepayment customers – see paragraphs 14.121–14.123 below.

figures for 30 June 2015. The relevant competitive benchmarks which we will use in setting the base level of the price cap are as follows:

Table 14.1: Summary of base values

	£	
	<i>Price cap at nil consumption*</i>	<i>Benchmark at medium TDCV†</i>
Gas	94	392
Electricity	82	331
Economy 7	86	416

Source: CMA analysis.

*These are the figures for the level of the price cap at nil consumption. These figures therefore include the PPM uplift. There is nil network cost at nil consumption.

†These figures exclude network costs and PPM uplift.

14.108 The competitive benchmark at medium TDCV will be uplifted to include regional network costs and the additional costs to serve prepayment customers (the PPM uplift) (see paragraphs 14.121 to 14.123).⁵⁹

14.109 We define the level of the price cap at nil consumption to be equal to the average standing charge of the Six Large Energy Firms' prepayment tariffs as at 30 June 2015, weighted by customer numbers. This level is then broken down into components for headroom, prepayment uplift, policy costs and other costs. Note that network costs and wholesale costs at nil consumption are defined to be equal to nil.

14.110 We have taken this approach so as to help ensure that the price cap at nil consumption is at a suitable level⁶⁰ which allows for recovery of efficiently incurred costs and which does not unduly distort competition. A number of respondents to the provisional decision on remedies⁶¹ suggested that since the competitive benchmark is based on the tariffs of Ovo Energy and First Utility it reflects a structure of charges which is not applicable for prepayment customers. Defining the price cap at nil consumption to be equal to the existing standing charges⁶² of the Six Large Energy Firms' prepayment tariffs therefore provides comfort that the price cap at nil consumption is compatible with current tariff levels.

14.111 We note that by defining the price cap to be equal to existing standing charges of the Six Large Energy Firms' prepayment tariffs the price cap becomes more stringent for lower levels of consumption. We have

⁵⁹ The value of the price cap at nil consumption does not include, nor need to include, network costs since these are volume driven. The value of the price cap at nil consumption will be updated for changes in the components making it up, namely: policy costs, other costs, PPM uplift, headroom.

⁶⁰ See paragraphs 14.295–14.310.

⁶¹ See Appendix 14.1 paragraph 106 for further detail.

⁶² Specifically, the average of the Six Large Energy Firms' standing charges as at 30 June 2015, weighted by customer numbers.

considered this effect when determining the overall level of the price cap and the amount of headroom.⁶³

- 14.112 As noted in paragraph 14.62 the base level of the cap would be defined separately for prepayment customers in each region for:
- (a) single fuel, single rate, electricity;
 - (b) single fuel, Economy 7, electricity; and
 - (c) single fuel gas.
- 14.113 Each gas and electricity tariff that suppliers offer must be compliant with the relevant price cap, regardless of whether the tariffs are part of a dual fuel bundle.
- 14.114 The base level of the cap would be rolled forward to the period when the cap takes effect using cost indices and updated allowances for network costs, and changed on a six-monthly basis thereafter using the same cost indices.
- 14.115 We expect that the effect of the price cap would be an immediate and substantial reduction in average bills based on our assessment of where the price cap would be relative to tariffs as of June 2016.⁶⁴ Prices for prepayment tariffs would need to fall very significantly (with costs remaining static) between June 2016 and the beginning of the cap in order for the application of the price cap to not have such an effect.
- 14.116 We have also considered whether it is appropriate to include an explicit allowance for headroom in the level of the price cap. We have concluded that an element of headroom should be included to produce a price cap which is compatible with competition and balances the impact of the remedy on customers and suppliers.
- 14.117 A number of parties told us in response to our provisional decision on remedies that a price cap may restrict or reduce the strength of competition.⁶⁵ We have sought to minimise the distortions which could weaken competition when considering the design of the price cap. In particular we have set cost allowances and indices with the aim of ensuring that the price cap accurately tracks the costs suppliers face and excluded SMETS2 smart meters from the scope of the cap.

⁶³ See paragraphs 14.250–14.275.

⁶⁴ See paragraphs 14.311–14.313.

⁶⁵ See paragraphs 14.405–14.413.

14.118 Even with a price cap design that accurately tracks costs we consider it is appropriate to include a headroom allowance so that suppliers are able to compete to offer a range of profitable tariffs at different levels. To the extent that there are also small deviations between the costs facing suppliers and those reflected in the price cap, the headroom allows some margin for error such that these costs to be recovered while still remaining compliant with the price cap.

14.119 In addition, we note that all smart meters have lower costs to serve, which means that suppliers have the opportunity to offer even more competitive smart meter tariffs. In particular, the bulk of the PPM uplift of £63⁶⁶ relates to costs that do not apply for smart meters.

14.120 In summary, the level of the cap at medium consumption will be set at:

- (a) a baseline level based on the actual tariffs of Ovo Energy and First Utility adjusted as described in paragraph 14.105;
- (b) updated to reflect changes in input costs;
- (c) plus prepayment uplift;
- (d) plus headroom.

- *The prepayment uplift*

14.121 The competitive benchmark tariffs set out in Section 10 are based on tariffs available to customers on direct debit, and therefore reflects the costs to serve those particular customers. Since we will be using these competitive benchmarks to produce a price cap which will apply to prepayment customers, it is necessary to take into consideration the costs-to-serve differentials between these two payment methods.

14.122 In Appendix 9.8 we consider what a reasonable level of costs-to-serve differential between those customers on direct debit and those on prepayment should be. We have determined that a costs-to-serve differential of £63 (£24 electricity; £39 gas⁶⁷) is appropriate.⁶⁸ We therefore use these values as an element of the price cap.

⁶⁶ See Appendix 9.8.

⁶⁷ Note that the allowance for gas is larger than that for electricity. This reflects the higher costs of serving gas PPM customers which arise due to, among other things, the more sophisticated meters needed for managing gas as it is a hazardous substance. For further detail of our analysis of the PPM uplift see Appendix 9.8.

⁶⁸ See Appendix for 9.8.

14.123 These cost-to-serve differentials will be adjusted in line with CPI at each annual update of the price cap (see paragraphs 14.239 and 14.240).

- *Headroom*

14.124 As described in paragraph 14.116 above we have concluded that it is appropriate to include an element of headroom in the price cap to allow for competition. The approach we set out in our provisional decision on remedies was that the level of headroom would be fixed across all levels of consumption. Two respondents⁶⁹ suggested that it would be appropriate for headroom to scale with consumption. We have considered this point alongside other comments parties made in response to our provisional decision on remedies.⁷⁰

14.125 We agree that it is appropriate for headroom to scale with consumption since the level of the price cap itself scales with consumption. Therefore the absolute margin that suppliers would seek to achieve would also vary with consumption. We note that taking this approach also results in the price cap being more stringent for low levels of consumption, and less stringent for high levels of consumption, relative to the position set out in the provisional decision on remedies. This reduces the risk, noted by respondents to the provisional decision on remedies,⁷¹ that the level of the price cap is unduly high for low consumption customers and, vice versa, too low for high consumption customers.

14.126 We note that there is a trade-off of stringency for low and high consumption customers under the cap but consider that given the price cap is based on the nil consumption standing charges of the Six Large Energy Firms, competition can prevail for low consumption customers.

14.127 We have therefore decided that headroom will be specified as a percentage of the pre-headroom price cap level. In order to calibrate the price cap we have looked at headroom in absolute terms. Based on our analysis of headroom we have concluded that at medium TDCV £15 is a suitable level of headroom for each fuel so as to allow competition to develop under the price cap at all consumption levels.⁷² As a result, an efficient supplier offering tariffs at the level of the price cap would achieve a return on capital employed in excess of its cost of capital.

⁶⁹ EDF Energy, Scottish Power.

⁷⁰ See Appendix 14.1 paragraphs 63–65.

⁷¹ RWE, SSE.

⁷² See paragraphs 14.263–14.269.

14.128 Headroom will be applied to the price cap building blocks before network costs are included. This is because network costs vary regionally and are known with a reasonable degree of precision. We therefore considered that it was inappropriate for the level of headroom to vary regionally.

14.129 For the purposes of defining headroom on an ongoing basis (ie to reflect movements in cost indices) we calculated £15 as a percentage of the base level of the price cap pre-headroom and excluding network costs at medium TDCV. We have decided therefore that the headroom allowance will be as follows:

Table 14.2: Headroom allowances

<i>Fuel type</i>	<i>%</i>
Single fuel electricity (single rate meter)	4.23
Single fuel gas	3.48
Single fuel electricity (Economy 7)	3.41

Source: CMA analysis.

14.130 In our provisional decision on remedies we proposed £25 headroom for each fuel. The reduced level of headroom we have finally decided upon reflects some adjustments made to the calculation of the price cap, which have led to the use of more conservative inputs. In particular we are now using competitive single fuel benchmarks⁷³ for the entirety of the prepayment segments. It also reflects our assessment of the reduced risk profile of the price cap relative to that set out in our provisional decision on remedies given, in particular, the exclusion of SMETS 2 meters. In particular we note the various design enhancements⁷⁴ which we consider make the price cap more accurate.

14.131 Further detail on our assessment of a suitable level of headroom is contained in paragraphs 14.250 to 14.275.

Cost indexing

14.132 The competitive benchmark is defined as at 30 June 2015. To this benchmark we add network costs and the prepayment costs to serve differential.⁷⁵ The resulting total is then decomposed into five cost components:

(a) wholesale costs;

⁷³ See paragraph 14.66.

⁷⁴ See paragraph 14.33 for a summary of these design enhancements.

⁷⁵ The differential is calculated relative to direct debit costs.

- (b) network cost;
- (c) policy cost;
- (d) other costs; and
- (e) PPM uplift.

14.133 These components are then used for updating the price cap for subsequent price cap periods. The formulae below describe how the prepayment price cap at medium consumption would initially be determined on the basis of these components and then updated:⁷⁶

$$\begin{aligned}
 \text{Price cap (region i, period j) =} \\
 & \text{(Wholesale cost (period j)} \\
 & + \text{Policy cost (period j)} \\
 & + \text{Other costs (period j)} \\
 & + \text{PPM uplift (period j))} \\
 & \times (1 + \text{Headroom}) \\
 & + \text{Network cost (region i, period j)}
 \end{aligned}$$

Where:

$$\begin{aligned}
 \text{Wholesale cost (period j) =} \\
 & \text{Wholesale cost (period 0)} \\
 & \times \text{Wholesale index (period j)} \\
 & / \text{Wholesale index (period 0)}
 \end{aligned}$$

$$\begin{aligned}
 \text{Policy cost (period j) =} \\
 & \text{Policy cost (period 0)} \\
 & \times \text{Policy index (period j)} \\
 & / \text{Policy index (period 0)}
 \end{aligned}$$

$$\begin{aligned}
 \text{Other cost (period j) =} \\
 & \text{Other cost (period 0)} \\
 & \times \text{CPI (period j) / CPI (period 0)}
 \end{aligned}$$

$$\begin{aligned}
 \text{PPM uplift (period j) =} \\
 & \text{PPM uplift (period 0) } \times \text{CPI (period j) / CPI (period 0)}
 \end{aligned}$$

⁷⁶ In these formulae when a term is identified as 'period j' we mean the value of that term which relates to period j. In practice these terms will be determined ahead of the period to which they relate. The process for identifying each index value ahead of the price cap period is described in the rest of this section.

Network cost (region i, period j) would be calculated for each region and period using the charging formulae set out in network companies' charging statements applying for the period of the price cap.

14.134 The following would be specified in the final order and associated licence conditions:

- (a) All costs in period 0.
- (b) All index values in period 0.
- (c) The method of determining the value of each index value in period j.

14.135 We describe in the rest of this cost indexing section how these values are defined.

14.136 Table 14.3 summarises the frequency with which each component of the price cap would be indexed and the basis for updates.

Table 14.3: Frequency of updates

<i>Component</i>	<i>Frequency of updates</i>	<i>Geographical basis</i>	<i>Basis for update</i>
Wholesale	6 monthly	National	ICIS data
Network	6 monthly	Regional	Network company charging statements
Policy	6 monthly	National	OBR
Other	6 monthly	National	CPI
PPM uplift	6 monthly	National	CPI

Source: CMA.

- *Determining the costs in period 0*

14.137 As of 30 June 2015, the competitive benchmarks⁷⁷ (which were calculated excluding network costs and additional costs to serve prepayment customers) were as shown in Table 14.1.

14.138 In order to form a baseline for the price cap, these competitive benchmark prices need to be decomposed into three cost components (wholesale, policy and other costs), in order that these can subsequently be indexed. This requires us to make an assumption as to how the baseline cost should be allocated to these relevant input costs based on prevailing market data. The assumed costs in period 0 for wholesale, policy and other costs will be determined according to the formulae below:

⁷⁷ See Section 10.

Wholesale cost (period 0)
= Benchmark x wholesale%

Policy cost (period 0)
= Benchmark x policy%

Other cost (period 0)
= Benchmark x other%

14.139 We calculated these percentages by first using the 2015 consolidated segmental statements⁷⁸ to estimate the split of costs among these categories at an average level for each of gas and electricity. We then used those splits as the percentages for gas and (single rate) electricity at medium consumption. The Economy 7 tariff differs only in respect of the time-of-use structure which is assumed to lower the cost of energy. Therefore, to calculate the percentages for Economy 7 at medium consumption we assumed that policy and other costs would be the same and that the difference between the competitive benchmark for Economy 7 and the competitive benchmark for single rate electricity relates to differences in wholesale cost.

14.140 To calculate the percentages at nil consumption we defined wholesale costs to be equal to zero and maintained the ratio between policy and other costs observed at medium TDCV.

14.141 The percentages for each different fuel type and consumption level are as follows:⁷⁹

⁷⁸ Our source for this data was the consolidated segmental statements for 2015 for five of the Six Large Energy Firms. SSE's consolidated segmental statements were not available at the time due to their later year end of 31 March 2016.

⁷⁹ We have calculated the breakdown of the competitive benchmarks between wholesale, policy and other costs based on costs reported in the 2015 Consolidated Segmental Statements (CSS) for the Six Large Energy Firms (excluding SSE which was not available). For some suppliers, Warm Home Discount costs were either not included within the environment and social obligation costs or not reported as separate line items in the CSS. In order to ensure these costs are appropriately reflected in the breakdown of the competitive benchmark, we have adjusted the CSS cost breakdowns to reflect environmental and social obligation costs provided by suppliers in response to our information request on 06/05/2016.

Table 14.4: Bill breakdown percentages for determining the base level of the price cap

	%					
	<i>Nil consumption</i>			<i>Medium TDCV</i>		
	<i>Electricity</i>	<i>Economy 7</i>	<i>Gas</i>	<i>Electricity</i>	<i>Economy 7</i>	<i>Gas</i>
Wholesale	0.0	0.0	0.0	57.2	65.9	70.9
Policy	47.2	47.2	16.2	20.2	16.1	4.7
Other	52.8	52.8	83.8	22.6	18.0	24.4
Total	100.0	100.0	100.0	100.0	100.0	100.0

Source: CMA.

14.142 Network costs are not included within these percentages since the competitive benchmark is calculated net of network costs. Network cost allowances are to be calculated directly from the charging statements of the relevant network companies.⁸⁰ Network cost allowances are to be calculated by Ofgem based on the data in network company charging statements. We have set out in the illustrative model how these costs may be calculated. We note that in practice it may be impractical to specify the network cost calculations in this level of detail in the order. We will consider during the implementation period how best to specify network costs.

14.143 Our assessment of network costs for period 0 is as shown in the table below.

Table 14.5: Period 0 network cost allowances (medium consumption)

<i>Region</i>	£		
	<i>Electricity</i>	<i>Economy 7</i>	<i>Gas</i>
East Anglia	118	131	138
East Midlands	116	126	128
London	110	124	152
Merseyside and North Wales	165	183	138
Midlands	121	131	137
North East	132	150	139
North Scotland	152	178	122
North West	127	130	140
South East	130	146	144
South Scotland	126	146	122
South Wales	136	145	132
South West	151	166	146
Southern	126	132	154
Yorkshire	124	138	126

Source: CMA.

14.144 Note that the network costs are specified only for medium consumption. The price cap at nil consumption does not include an allowance for network costs since the network charging statements define use of system charges to be nil at nil consumption.

⁸⁰ See paragraphs 14.187–14.201 for detail on how we calculate network costs.

14.145 We used the TDCVs that applied for the period January 2014 to August 2015 as the tariffs informing the competitive benchmark tariffs that were in the market in this period.⁸¹

- *The update process*

14.146 The level of the price cap will be updated every six months on 1 April and 1 October. All tariffs on offer to prepayment customers would have to comply with the prevailing level of the price cap at all times.

14.147 We considered the possibility of updating the price cap more or less frequently.

14.148 In our provisional decision on remedies we proposed that the price cap would be updated annually. Our change in design is driven by our understanding of the risks associated with having a price cap that remains fixed for 12 months. Centrica noted that updating the price cap on 1 April each year meant that there would be significant uncertainty in relation to the volumes and prices for the forthcoming winter. Utilita noted that smaller suppliers would face constraints and/or additional costs when buying wholesale energy far in advance of delivery.

14.149 RWE suggested that annual updates were appropriate as this avoided introducing seasonality into the level of the price cap. Centrica noted that it would be possible to have a six-monthly price cap in combination with an index of wholesale prices which took an annual average so as to avoid seasonality. Centrica noted that using a 12-monthly average price for a six-monthly price cap period would introduce some basis risk⁸² but that on balance this would be easier for suppliers to manage than the volume risk presented by annual price caps updated in April.

14.150 We considered the evidence presented by parties and how this relates to our objectives in relation to determining a suitable length of the price cap period, namely:

(a) the price cap should avoid seasonal variation;

(b) the price cap should not be excessively volatile; and

(c) the price cap period should allow for a wholesale index which:

⁸¹ The single rate meter medium values were for electricity 3,200 kWh and for gas 13,500 kWh.

⁸² Basis risk in this context refers to the risk that by observing prices for delivery in one period and applying those to a price cap which applies to a different period the level of the price will be materially out of line with the wholesale purchase price.

- (i) accurately reflects the costs in the price cap period; and
- (ii) does not produce undue risk for suppliers (in particular volume risk, liquidity risk and basis risk).

14.151 We note that the choice of wholesale index also has a significant bearing on these objectives. We therefore considered the length of the price cap update period alongside the design of the wholesale index.

14.152 We considered that six-monthly updates to the price cap would allow for greater accuracy in tracking costs, in particular network costs⁸³ and wholesale costs. We considered that six-monthly price cap updates do not materially increase the risk of volatility or seasonal variation provided that an appropriate wholesale index is used. We set out our consideration of wholesale indexation in paragraphs 14.161 to 14.186.

14.153 We considered that more frequent updates would introduce an undesirable level of volatility into the prices paid by prepayment customers. We note that two updates per year is the approximate frequency with which SVT prices have been updated in recent years.⁸⁴

14.154 We also note that there is no charge for using the vending network⁸⁵ on 1 April and 1 October.⁸⁶ Any more frequent updates to the price cap could potentially impose additional costs on suppliers if the price cap update required tariff prices to also be updated.

14.155 We considered the practicality of updating the price cap twice a year and the potential impact this may have on the prepayment infrastructure system. Some parties suggested that the prepayment infrastructure would not be able to cope with the volume of messages being sent if all suppliers updated their tariffs on the same day.^{87,88}

14.156 We sought clarification on this issue from Siemens and Itron as they are the parties responsible for operating the prepayment infrastructure for gas and electricity respectively. Itron confirmed that when a tariff is updated this does not require a message to be sent to each customer though there would be a

⁸³ Ofgem noted that gas network charges could update in October each year and that this would be difficult to accurately track with an annual price cap.

⁸⁴ See Section 8.

⁸⁵ The vending network is the infrastructure by which tariff updates, including price changes, are communicated from suppliers to customer meters.

⁸⁶ This was confirmed by Siemens, which operates the prepayment meter infrastructure for gas.

⁸⁷ Centrica made this point in its response to the provisional decision on remedies. Utilita made a similar point in its hearing.

⁸⁸ We note that this issue applies chiefly to dumb meter infrastructure. Smart meters do not have the same tariff slot restrictions.

peak in workload involved in updating many tariffs at the same time. Siemens also confirmed that a tariff update does not require a message to be sent to each customer and confirmed that ‘there are no issues with suppliers updating tariffs on the same day’.

- 14.157 We have therefore concluded that a six-monthly price cap update period is more effective and proportionate. In reaching this conclusion we also considered the design of the wholesale index as this is closely related. See paragraphs 14.161 to 14.186 for discussion of the wholesale index design.
- 14.158 We also considered the need for a lag period between determining the level of the price cap and the price cap coming into effect. Centrica noted the need for suppliers to provide 30 days’ notice to customers of price increases. We agree that there needs to be a period of lag to allow for the price cap to be calculated and for suppliers to make practical arrangements (including notifying customers and updating tariffs). Siemens and Itron confirmed that it takes two weeks to update prepayment meter tariff prices.
- 14.159 We note that longer lag periods introduce many of the same issues associated with longer price cap periods, for example increasing hedging costs (particularly for smaller suppliers) and increasing the risk that the indices used no longer accurately reflect costs during the price cap period. We have therefore sought to minimise the length of the lag period while still allowing sufficient time for the practical arrangements needed to effect price cap updates.
- 14.160 We have therefore concluded that a two-month lag period would be effective and proportionate. In practice this allows for the 30-day notification period plus a month for suppliers to make any other practical changes.⁸⁹

- *Wholesale energy costs*

- 14.161 The remedy involves the CMA constructing (for setting the price cap in a final order), and subsequently Ofgem applying, a wholesale energy cost index using information available from ICIS⁹⁰ on market prices for standard wholesale products – specifically using market prices for energy products traded for delivery in the day(s), month(s), quarter(s) and season(s) ahead. This index should measure movements since the end of June 2015 in the cost of delivering gas and electricity to domestic customers.⁹¹ We use June

⁸⁹ We note that suppliers may also make practical changes during the 30-day notification period.

⁹⁰ ICIS is a market information provider.

⁹¹ We define the base value of the wholesale index in paragraph 14.181.

2015 as the base period for this index as this is the date for which we constructed the competitive benchmark price.

14.162 The index for wholesale energy costs would be applied to the competitive benchmark price as described in paragraphs 14.161 to 14.186. We consider that this approach will be somewhat favourable to suppliers given the decline in wholesale gas and electricity prices since 2014. This is because the benchmark price is based on tariffs First Utility and Ovo Energy customers were on as at the end of June 2015, and such prices would have been set some time before June 2015 when wholesale energy prices were higher.⁹²

14.163 In our provisional decision on remedies we proposed that the wholesale index would reflect prices for the year ahead. We have reconsidered the choice of wholesale index in light of responses to the provisional decision on remedies.

14.164 A number of respondents suggested that we should adopt a rateable approach in determining the wholesale index.⁹³ Under this approach the index value on any given date would be a demand-weighted average of the prices for products for the coming 12, say, months. SSE said that the CMA must ensure that suppliers could hedge prepayment customer demand at a price compatible with the level of the cap throughout the lifetime of this transitional measure. We also received responses suggesting that we should determine the wholesale index value using a pricing-in period.⁹⁴ Under this approach the prices of products for delivery of energy in the price cap year would be observed during a period (the pricing-in period) prior to the start of the price cap period. We have considered both of these approaches as well as variants on them and hybrid approaches which contain elements of both approaches.

14.165 In considering a suitable approach for determining the wholesale index value we had the same objectives as for determining the length of the price cap update period. Namely, our objectives in relation to determining a suitable wholesale index approach were that:

- (a) the price cap should avoid seasonal variation;
- (b) the price cap should not be excessively volatile; and

⁹² [redacted]

⁹³ Centrica, Ovo Energy.

⁹⁴ Utilita, Centrica.

- (c) the price cap period should allow for a wholesale index which:
- (i) accurately reflects the costs in the price cap period; and
 - (ii) does not produce undue risk for suppliers (in particular volume risk, liquidity risk and basis risk).⁹⁵

14.166 We note that there is inherent conflict between some of these objectives. For example, in the context of a six-monthly price cap, the more accurately the index tracks wholesale costs the greater potential there is for the resulting index values to be volatile and seasonal. We therefore sought to achieve a balance between achieving each of these objectives.

14.167 In considering the approach to specifying the wholesale index we were mindful of responses to the provisional decision on remedies. Four respondents noted that our proposed approach risked all suppliers buying commodity at the same time in order to match the hedging strategy implicit in the price cap. These parties noted too that this spike in demand in the wholesale market may distort liquidity.⁹⁶ We agree that this would be a concern with any wholesale indexation approach which observes prices over a short period of time.

14.168 EDF Energy suggested that the price cap could use a similar indexation approach as was used for determining the baseload reference price in the CfDs. We considered this option and note that since it was designed for a different purpose it does not perform well against the objectives we identified above. For example, being a baseload reference price it does not reflect the cost of peak electricity and would also not provide a basis for determining gas wholesale costs.

14.169 Ovo Energy responded to the provisional decision on remedies requesting that whatever approach we used for determining the wholesale index values we used only trading days subsequent to the date of the final report. Ovo Energy noted that if the wholesale indexation approach made use of trading days prior to the date of the final report it would not be possible for suppliers to align their purchasing with the wholesale index. This in turn would create the risk that suppliers would not be able to recover their wholesale costs through the price cap.

⁹⁵ We considered that one way in which the wholesale index approach could avoid exposing suppliers to undue risk would be if they were able to match the wholesale unit costs implied by the index. We therefore considered suppliers' ability to match the index when evaluating the options.

⁹⁶ Centrica, EDF Energy, E.ON and SSE.

14.170 We considered at a high level several approaches for determining the wholesale index values. For example, we considered whether a semi-annual price cap could be phased to run January to June and August to December to avoid seasonality. We considered that this approach would still involve some seasonality, would incur costs for use of the vending network and does not offer benefits over the approaches we considered in more detail.

14.171 We have considered in detail three possible options for determining the wholesale index values:⁹⁷

- (a) A 6-2-12 pricing-in period used in conjunction with annual price cap updates;⁹⁸
- (b) A 6-2-12 pricing-in period used in conjunction with semi-annual price cap updates;⁹⁹ and
- (c) A 12-month rateable approach in which prices are observed daily for delivery of energy over the next 12 months. The index value for the price cap would be taken as the average of the daily values over a 12-month period.

14.172 These options are illustrated below.

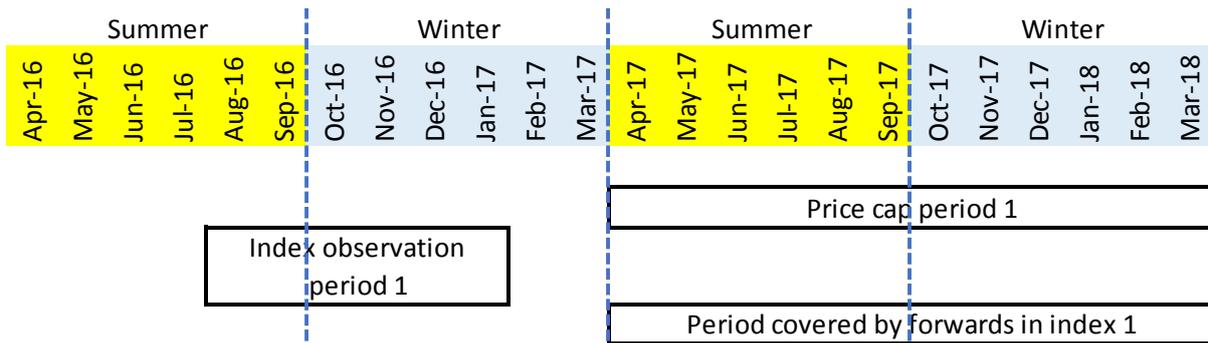
⁹⁷ We concluded that the stability of the price cap in the context of seasonality and volatility of prices was particularly important. As a result, we considered further only price cap options which were based on some form of 12-month averaging of prices.

⁹⁸ 6-2-12 refers to the different periods involved – wholesale prices would be observed over a six-month period. There would be a two-month lag between the end of the observation period and the start of the price cap period. The wholesale prices observed would be the forward prices for energy delivered over a 12-month period, as illustrated in Figure 14.4.

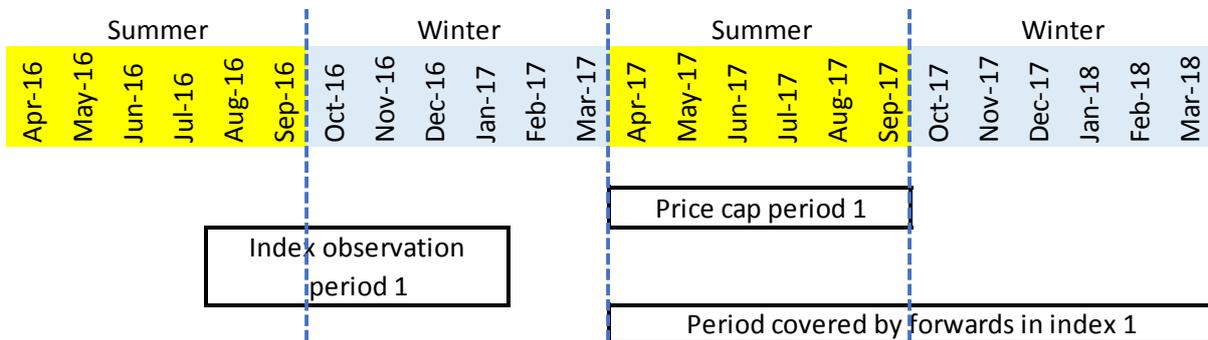
⁹⁹ The 12 months covered by the forwards in the index starts on the same date as the price cap. It is theoretically possible that the 12 months could start at a different point. For example, the 12-month period could be set to start three months ahead of the price cap. For example, the index could look at forward prices for the year January to December and apply that to the price cap running April to September. However, we considered that this would be incompatible with using seasonal products for the electricity index.

Figure 14.4: Illustration of wholesale indexation approaches

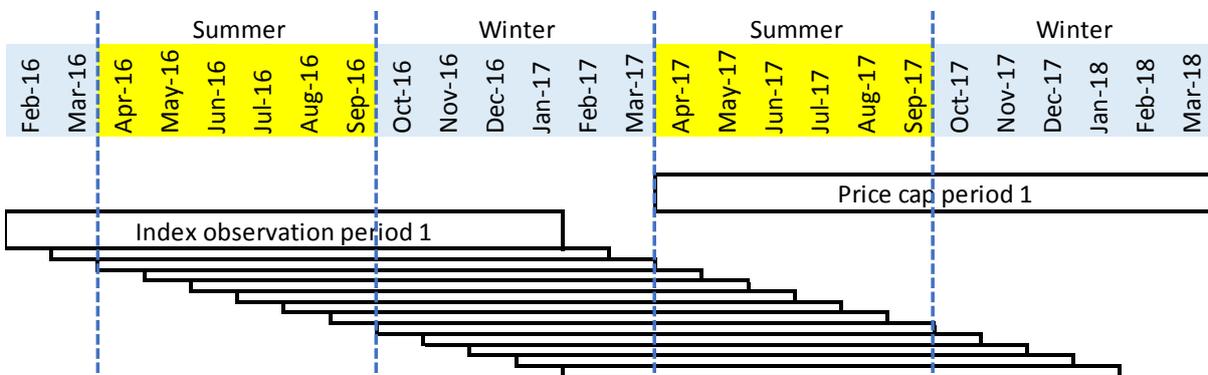
6-2-12 pricing-in period with annual price cap



6-2-12 pricing-in period with semi-annual price cap



12-month rateable strategy

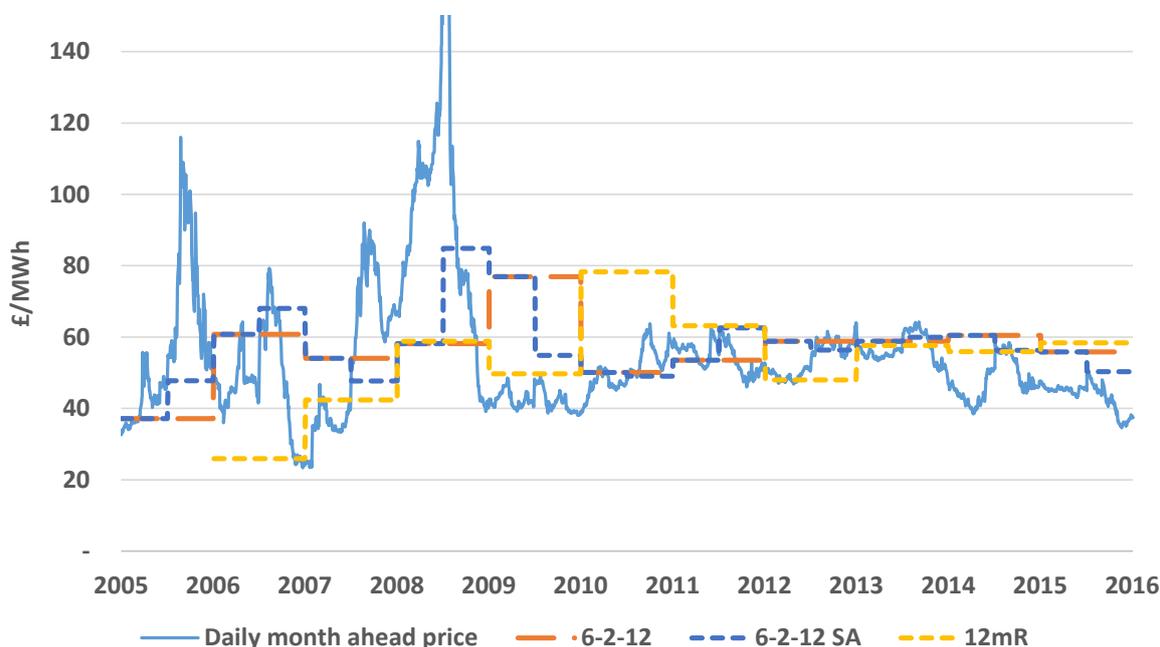


Source: CMA.

14.173 We modelled each of the three main options listed above to see what index values they would have produced had they been applied in the past. The results are shown below. For the purposes of comparing indexation options we focused our analysis on electricity peak load products. From our analysis of the energy wholesale markets (see Section 5) we understand that the fundamental dynamics are comparable for baseload and peak electricity and gas.

14.174 In interpreting the level of risk associated with the different indices, we have compared them to month ahead prices as these reflect day-to-day expectations for the cost of delivering energy a short time into the future.

Figure 14.5: Comparison of wholesale index options for electricity peak load



Source: CMA analysis.

14.175 The graph illustrates that the actual scale of the lag effect was in some cases material as, for example, with the 12-month rateable approach. In addition, the use of a 12-month period did not in practice materially reduce volatility of the index, where short-term volatility was the main driver of volatility in the level of the index. We considered therefore that the 12-month rateable approach would present a significant risk of producing price cap levels which are materially out of line with prices in the market.

14.176 We also looked at volatility in terms of the range and spread of values they produced. This analysis showed that the 6-2-12 semi-annual index is the least volatile.

14.177 Our analysis suggested that there was no clearly 'better' alternative between the 6-2-12 semi-annual and the 6-2-12 annual and both these options balanced our objectives in designing the test. For example:

- (a) the 6-2-12 semi-annual index has the advantage that it introduces less lag;

- (b) the 6-2-12 semi-annual index has the advantage that it presents a lower level of volume risk for suppliers;¹⁰⁰
- (c) the 6-2-12 annual index has the advantage that it presents the least basis risk though we note that basis risk with the 6-2-12 semi-annual is not very significant;¹⁰¹ and
- (d) neither index produced seasonally affected values.

14.178 Having considered the above analysis we have concluded that the 6-2-12 semi-annual approach provides the best balance of the objectives described in paragraph 14.165 and would therefore be the most effective and proportionate option. We have therefore decided that the wholesale index values will be determined using the 6-2-12 pricing-in period approach and that the price cap will be updated every six months.

14.179 For completeness, the products and weightings that will be used in determining the wholesale index values are as follows. In Table 14.6 a 1 indicates that the price of the product in question would be observed in the month shown. A 0 indicates that the product's price is not observed in that month.

Table 14.6: Wholesale index weightings and products

Electricity

Month	Weighting		
	S+1	S+2	S+3
<i>For price cap periods starting 1 October</i>			
Feb	0	1	1
Mar	0	1	1
Apr	1	1	0
May	1	1	0
Jun	1	1	0
Jul	1	1	0
<i>For price cap periods starting 1 April</i>			
Aug	0	1	1
Sep	0	1	1
Oct	1	1	0
Nov	1	1	0
Dec	1	1	0
Jan	1	1	0

¹⁰⁰ The shorter price cap periods allow for a greater level of visibility of the expected level of demand at the time that suppliers are procuring wholesale energy.

¹⁰¹ Since the mismatch between semi-annual price cap and observation of annual prices introduces basis risk in the 6-2-12 semi-annual index.

Gas

Month	Weighting					
	Q+1	Q+2	Q+3	Q+4	Q+5	Q+6
<i>For price cap periods starting 1 October</i>						
Feb	0	0	1	1	1	1
Mar	0	0	1	1	1	1
Apr	0	1	1	1	1	0
May	0	1	1	1	1	0
Jun	0	1	1	1	1	0
Jul	1	1	1	1	0	0
<i>For price cap periods starting 1 April</i>						
Aug	0	0	1	1	1	1
Sep	0	0	1	1	1	1
Oct	0	1	1	1	1	0
Nov	0	1	1	1	1	0
Dec	0	1	1	1	1	0
Jan	1	1	1	1	0	0

Source: CMA.

- 14.180 For electricity the index is calculated using a weighted average of peak and baseload products. Baseload is weighted 70%, peak is weighted 30% reflecting Ofgem's assumptions in the supply market indicators analysis. We received mixed views on the suitability of this split in response to the provisional decision on remedies with an equal number of parties suggesting it should be higher as lower. We note that the split will vary for each supplier based on their customers' own consumption profiles. On balance we consider that it is reasonable to retain a 70:30 split.
- 14.181 The base value for the wholesale index will be the value that would have applied for the price cap period 1 April 2015 to 30 September 2015 (had the price cap been in effect then). This reflects expectations in the period August 2014 to January 2015 for the cost of wholesale energy for delivery in the period 1 April 2015 to 30 September 2015. We consider that this is a reasonable proxy for the wholesale costs that would be reflected in the tariffs informing the competitive benchmark.
- 14.182 For price cap periods starting 1 April the wholesale index value will be the average of the daily index values for the six months starting 1 August in the previous calendar year and ending on 31 January. For price cap periods starting 1 October the wholesale index values will be the average of the daily index values of the six months starting 1 February and ending on 31 July of the same calendar year. This approach avoids creating an incentive for all suppliers to purchase commodity on the same day which may cause liquidity concerns.
- 14.183 RWE suggested in its response to the provisional decision on remedies that the costs of shaping a customer's demand are material and therefore the wholesale cost allowance for electricity should also take account of the costs

of shaping products.¹⁰² We note that while the cost of shaping products may vary significantly day to day in the long run these costs would be expected, on average, to follow the costs of longer-term products.

14.184 The base allowance for wholesale costs includes all costs relating to wholesale purchasing, including shaping costs. We therefore consider that by updating this allowance in line with the indices described above we would provide a sufficient allowance for the costs of shaping.

14.185 We note that the wholesale unit cost implied by the competitive benchmark figure¹⁰³ is different to the base level of the wholesale index as shown in the table below.

Table 14.7: Comparison of implied wholesale unit cost and base level of the wholesale index

	<i>£/MWh</i>	
	<i>Implied wholesale unit cost</i>	<i>Base level of the wholesale index</i>
Gas	20.8	19.2
Electric	59.7	51.8

Source: CMA analysis.

14.186 This difference can be explained since the implied wholesale unit cost is ultimately derived from a range of tariffs offered by Ovo Energy and First Utility and which will result from their particular approach to purchasing energy for the tariffs that informed the competitive benchmark.¹⁰⁴ To the extent that Ovo Energy and First Utility followed different purchasing strategies from that set out in our price cap design this will drive a difference in the figures shown in Table 14.7.

- *Network costs*

14.187 The costs of transferring energy from the producer to the end user are referred to as network costs. Network costs refer to the cost of building, maintaining and operating the energy network and system infrastructure to deliver energy to the customer. These are split between the transmission companies (who take the energy from the producers and deliver it to the

¹⁰² Shaping products are contracts to purchase an amount of gas or electricity for delivery over a specific period a short time into the future. So, for example, purchase of electricity for delivery over a specified 30-minute period in the next 24 hours.

¹⁰³ We calculate the implied unit cost by taking the percentage of the competitive benchmark which relates to wholesale cost and dividing by the consumption level at which the competitive benchmark was calculated.

¹⁰⁴ In particular, it is quite possible that for the tariffs in the market on 30 June 2015 Ovo Energy and First Utility had already bought a certain amount of the required commodity before 30 June 2015. Given that both gas and electricity wholesale prices have, broadly speaking, fallen in the last two years the wholesale prices informing the competitive benchmark would have been higher than those reflected in the index.

different areas of the country) and distribution companies (who arrange for the energy to be transported from the transmission end point to the final users).

- 14.188 The revenues that transmission and distribution companies can earn are regulated by Ofgem under the RIIO price framework.¹⁰⁵ These are set for an eight-year period with an annual mechanism to update for factors such as actual company performance, RPI inflation and any additional investment requirements under various uncertainty conditions. In practice the total revenues move by relatively small amounts year on year.
- 14.189 Ofgem calculates and publishes the updated allowed revenues for transmission and distribution operators in December of each year to take effect from the following April. Network companies then publish charging statements which specify how users will be charged for using the network.
- 14.190 Five respondents to the provisional decision on remedies suggested that the approach to indexing electricity network costs outlined in the provisional decision on remedies was inaccurate.¹⁰⁶ SSE also stated that there were errors in the initial level of network costs published in the provisional decision on remedies. We recognise that using network company allowed revenues as an index for updating electricity network costs can introduce inaccuracy. We have therefore reconsidered our approach to updating electricity network costs.
- 14.191 We have decided that network cost allowances will be calculated for each price cap period using network company charging statements.¹⁰⁷ This approach is simpler, avoids the potential inaccuracy of using network company allowed revenues and still allows for the price cap to be calculated in advance of the price cap period.¹⁰⁸
- 14.192 This is also the approach that we proposed in the provisional decision on remedies for updating network cost allowances for the gas price cap. We will retain this approach for gas network cost calculations.
- 14.193 To calculate these network costs for the purposes of our analysis we have used Ofgem Supply Market Indicator information and instructions for compiling data on the network cost components per energy bill.

¹⁰⁵ Further information on the network price controls can be found on the Ofgem website: [gas distribution](#) and [gas transmission](#); [electricity distribution](#) and [electricity transmission](#).

¹⁰⁶ Centrica, Ofgem, Ovo Energy, RWE, SSE.

¹⁰⁷ See paragraph 14.142 for further details.

¹⁰⁸ As noted in paragraph 14.160 the level of the price cap will be determined two months prior to the start of each price cap period.

- 14.194 The level of disaggregation of the Ofgem data allowed us to extract the rates of the single components of transmission and distribution network charges for both electricity and gas.
- 14.195 Ofgem data was cross-checked with the annual 'Statement of charges' of GB transmission and distribution companies. Whenever discrepancies were found, we used these documents to either correct or supplement Ofgem data.
- 14.196 There are 13 gas distribution zones (known as Local Distribution Zones or LDZ) and 14 electricity distribution areas (PES regions). Since gas and electricity regions do not correspond exactly, the overlap of PES regions across LDZ had to be mapped.
- 14.197 After compiling single data sets on transmission and distribution network charges for each fuel, these were merged together by using a list of postcodes for which the PES region is known and the Xoserve mapping of postcodes to LDZ.
- 14.198 There are several gas exit points (relative to gas transmission) within each gas distribution area and each is differently priced. Consistently with the Ofgem methodology, we selected one gas exit point in each LDZ and computed the gas transmission charge at that point.
- 14.199 We have decided to apply the same method for calculating network charges in each subsequent price cap period.
- 14.200 Ovo Energy suggested that the network cost allowance and index did not allow for the cost of balancing supply and demand, so-called BSUoS costs which Ovo Energy anticipates will increase in the coming years. We note that BSUoS costs are included in our calculations of network costs. The allowance for BSUoS costs is calculated using out-turn balancing costs from the preceding period.
- 14.201 For the avoidance of doubt, there is no separate allowance for the costs of offshore transmission since this is not necessary. The TNUoS charges associated with a customer are for access to the whole national electricity transmission system, including offshore and onshore transmission networks. There is no separate TNUoS charge for demand customers in respect of offshore assets. There is, therefore, no need to separately calculate supplier costs related to the offshore transmission networks.

- *Policy costs*

14.202 Policy costs are becoming an increasingly large component of the overall costs borne by suppliers.¹⁰⁹ We note that the costs of complying with various social and environmental schemes are recovered through electricity and gas bills. The level of the price cap would be updated to recognise changes in the costs of complying with these schemes.

14.203 We note that actual policy costs are uncertain as they depend on external factors, namely:

(a) the level of contracted generation;

(b) the wholesale price of electricity; and

(c) the amount of renewable electricity generated by qualifying generators.

14.204 Changes in these external factors since the levy control framework was introduced led to DECC updating, in July 2015,¹¹⁰ its projections of the aggregate cost of complying with these schemes. These updated figures of July 2015 aligned with the Office for Budget Responsibility's (OBR's) assessment of the projected costs of these schemes to 2020.

14.205 We considered design options that would involve adjustments for observed changes in each component of policy costs – such as CfD costs, ROC prices and the costs of implementing the ECO – but judged that this introduced excessive complexity and uncertainty into the design of the cap.

14.206 We have concluded that the best way to accommodate policy costs within our preferred approach is to use projections of the maximum allowed costs arising from such policies, as set out in the most recent projections from the OBR.¹¹¹ We note that adopting this approach is relatively robust since the projections reflect latest expectations for actual spend and consider that this approach has considerable merits in terms of simplicity.¹¹²

¹⁰⁹ Ofgem's analysis of the components of a typical customer's bill estimates that environmental and social costs will have increased from £62 in the year to 31 December 2014 to £71 in the year to 31 March 2016. Source: Ofgem, [Breakdown of an electricity bill over time](#).

¹¹⁰ See DECC press release: [Controlling the cost of renewable energy](#).

¹¹¹ Office for Budget Responsibility (July 2015), [Economic and fiscal outlook](#).

¹¹² The OBR publishes these figures for its own purposes and is not bound to continue to publish them in the same manner in order to support the price cap. Should the basis of the OBR's figures change then we would expect Ofgem to review the situation and identify suitable figures to be used in lieu.

14.207 We have decided that the OBR’s projections for the total actual out-turn cost will be used as the index values for policy costs for the price cap applying to electricity tariffs.

14.208 In our provisional decision on remedies we suggested that the policy cost index values would be specified in the final order in real terms with separate allowance for CPI inflation. We have reconsidered this approach and concluded that it is unnecessarily complicated.

14.209 The policy cost projections produced by the OBR are stated in nominal terms. We have therefore decided that the policy index will be stated in nominal terms and thus there is no need for CPI inflation to be dealt with separately for these cost items.

- *Electricity*

14.210 The policy index values, in nominal terms, for the electricity price cap would therefore be as shown in the table below.

Table 14.8: Summary of index values for policy costs (electricity)

<i>Price cap period</i>	<i>Index value (nominal)</i>
Base value	6.2
2016/17 Summer	7.4
2016/17 Winter	7.4
2017/18 Summer	8.6
2017/18 Winter	8.6
2018/19 Summer	10.4
2018/19 Winter	10.4
2019/20 Summer	11.9
2019/20 Winter	11.9
2020/21 Summer	12.3
2020/21 Winter	12.3

Source: CMA analysis. These figures are taken from the [Economic and Fiscal Outlook](#) published by the OBR in March 2016. See supplementary fiscal table 2.7.

14.211 In light of the uncertainty in the out-turn costs, compared with the projections used in the index, we have considered whether it would be appropriate to have an ex post update such that the policy index values align with out-turn policy costs. However, we have concluded that determining outturn values would duplicate the work already undertaken by the OBR as it has a duty to update annually projections of expenditure.

14.212 We note that the cost of the Warm Home Discount is not included within the OBR projections though do not expect these costs to escalate relative to the above policy cost index. We therefore do not make any adjustment for the Warm Home Discount.

14.213 Therefore we have decided that the index values would be updated annually to reflect the OBR’s latest projections for the annual cost of the renewables

obligation, contracts for difference scheme and feed-in-tariffs scheme and that these updated values would supersede the index values shown above.¹¹³ In the event that the OBR ceases to publish these projections Ofgem would specify alternative index values to use for updating the price cap.

- *Other known adjustments to policy costs*

14.214 In this section we consider two other changes which we have become aware of: the ECO and the energy intensive industries exemption.

14.215 We note that in July 2015 DECC announced measures to limit the cost of certain policy costs.¹¹⁴ We consider that these measures mitigate the risk that policy costs in future years will increase above the level published by DECC in July 2015. We further note that the OBR's projections for the cost of these schemes has reduced between the July 2015 and March 2016 economic and fiscal outlooks as shown below.

Table 14.9: Comparison of OBR projections for policy costs

	<i>Out-turn</i>	<i>Forecast</i>					
	<i>2014/15</i>	<i>2015/16</i>	<i>2016/17</i>	<i>2017/18</i>	<i>2018/19</i>	<i>2019/20</i>	<i>2020/21</i>
July 2015	3.6	6.0	7.3	8.3	10.2	12.3	13.6
March 2016	3.6	6.2	7.4	8.6	10.4	11.9	12.3

Source: OBR.

14.216 We considered the impact of the energy intensive industries exemption.¹¹⁵ DECC is currently consulting on implementing an exemption which would mean that energy-intensive industries would not face the costs of certain environmental schemes. The costs of these schemes would instead be recovered from non-exempt customers.

14.217 The 2015 Spending Review and Autumn Statement¹¹⁶ estimated that the cost of the exemption would be an additional £5 per year per household.

14.218 We have decided that there is no need to provide a specific cost allowance for this cost as it nets off with the expected changes in the costs of the ECO scheme relative to the level included within our competitive benchmark, as we explain below.

¹¹³ For the avoidance of doubt these changes to the index values would be purely prospective and there would be no retrospective change in the level of policy index values.

¹¹⁴ DECC, [Controlling the cost of renewable energy](#).

¹¹⁵ See DECC consultation (2016), [Implementing an exemption for energy intensive industries from the indirect costs of the RO and the FITs](#).

¹¹⁶ See HM Treasury, [Spending Review and Autumn Statement 2015](#).

14.219 As described in Appendix 10.1 we uplifted the competitive benchmark figures such that they reflected a level of social and environmental costs in line with those of the Six Large Energy Firms. We note that while other (non-ECO) policy costs are projected to increase, ECO costs are projected to reduce in 2017 and remain flat (in real terms) thereafter. The projected profile of ECO costs is shown in the table below.

Table 14.10: Projected profile of ECO costs

	<i>£m</i>						
<i>ECO supplier spend, Including Admin</i>	2015/16	2016/17	2017/18	2018/19	2019/20	2020/21	2021/22
2015 prices	809	809	617	617	617	617	617

Source: [2014 ECO impact assessment](#), [2015 Spending Review](#) and [Autumn Statement](#).

14.220 By scaling ECO costs in line with other policy costs we have incorporated an allowance which exceeds the actual cost. We have calculated the magnitude of this effect and the results are shown below.

Table 14.11: Impact of scaling ECO costs with general policy costs

	<i>£</i>			
	2017/18	2018/19	2019/20	2020/21
Policy cost allowance if scaling all with policy index	89.1	107.7	123.2	127.4
Policy cost allowance if splitting out ECO and scaling separately				
– ECO	18.1	18.5	19.0	19.5
– Other policy costs	<u>69.6</u>	<u>84.1</u>	<u>96.3</u>	<u>99.5</u>
Total	<u>87.6</u>	<u>102.7</u>	<u>115.3</u>	<u>119.0</u>
Surplus allowance arising from scaling all with policy cost index	1.4	5.0	8.0	8.4

Source: CMA analysis.

14.221 This approach therefore allows an average of £5.70 per customer per year. We consider that it is a reasonable simplification to net this effect off against the effect of the energy-intensive industries exemption.

14.222 We note that there is a difference in the timings of the cash flows. We have compared the two effects assuming a 10% nominal discount rate and found that the net present value of the energy-intensive industries exemption is £15.8 while the effect of the ECO scaling over-allowance is £17.1. We consider that allowing an additional £1.30 in the level of the price cap over its four-year life is more proportionate than developing bespoke mechanisms to separately track each of these effects.

- *Gas*

14.223 We note that the only policy costs included within gas bills relate to the ECO and the Warm Home Discount. The ECO scheme has been extended to March 2017 and DECC have estimated the annual cost of ECO compliance ‘broadly in line with projected delivery costs and the central scenario in DECC’s Impact Assessment’.¹¹⁷ It is not clear if the scheme will be extended beyond that point although DECC has suggested that ‘The future of the ECO scheme from 2017 onwards will be part of discussions around a new, better integrated policy for home energy efficiency’.¹¹⁸ We have assumed that these costs, which are already factored into bills, will continue over the period the cap is in effect at the same level in real terms.

14.224 We note that the Warm Home Discount has now been extended to 2020/21. We note that the total cost of this scheme in 2014/15 was £326 million¹¹⁹ and make the assumption that it will not increase in real terms to differentially impact energy bills (ie it sits outside of the projection shown but remains neutral in its’ impact on bills).

14.225 The table below shows the policy index values, in real terms, for the gas price cap. Note that gas policy costs would be indexed to CPI to preserve the real value of the initial policy allowance.

Table 14.12: Summary of index values for policy costs (gas)

<i>Price cap period</i>	<i>Index value</i>
2016/17 Winter	1
2017/18 Summer	1
2017/18 Winter	1
2018/19 Summer	1
2018/19 Winter	1
2019/20 Summer	1
2019/20 Winter	1
2020/21 Summer	1
2020/21 Winter	1

Source: CMA analysis.

- *Other costs*

14.226 In the provisional decision on remedies we referred to these costs as ‘indirect’ costs since many of the costs are indirect. We now use the term ‘other’ costs since this category includes other items, notably an allowance for an EBIT margin of 1.25%.

¹¹⁷ DECC, [Energy Company Obligation delivery costs](#), paragraph 9.

¹¹⁸ [DECC blog announcing changes to green home improvement policies](#).

¹¹⁹ Ofgem, [Warm Home Discount Annual Report 2014-15](#).

14.227 The base level of the price cap is based on our analysis of tariff prices and therefore includes an allowance for other costs. As discussed in Section 10, the calculation of the competitive benchmark is based on Ovo Energy and First Utility tariffs. We have assessed the sustainability of these suppliers¹²⁰ and uplifted their tariff prices to inform the competitive benchmark as described in Section 10 so that these tariffs were compatible with an EBIT margin of 1.25%. We therefore consider that this competitive benchmark allows for a level of profit consistent with competitive pricing by an energy supplier which has reached an efficient scale (ie a large supplier) and which is in a steady state. In addition, the price cap will include headroom equivalent to £15 per customer for medium TDCV. This profit allowance is included within the other costs element of the price cap level.

14.228 We expect that over time the 'other costs' element of the competitive benchmark will be subject to two opposing forces:

(a) Inflation – costs are likely to increase over time in line with general inflation.

(b) Efficiency – we expect that suppliers will achieve ongoing efficiencies in their internal costs.

14.229 It is hard to know what the net impact of these forces will be over time though it is likely that the net impact will vary from time to time. To be prudent in setting the level of the price cap we have decided that the base level of other costs will be subject to inflation in line with the CPI.¹²¹

14.230 We consider that this could result in the other costs element of the price cap being less stringent over time. We consider that this is appropriate as periods further in the future are subject to greater uncertainty and therefore it is reasonable to adopt an approach which could result in the price cap becoming less stringent over time.

14.231 A number of parties responded to the provisional decision on remedies suggesting that we had not allowed for certain other costs,¹²² specifically the costs of:

- Hydro Benefit Replacement Scheme;
- faster switching;

¹²⁰ See Appendix 10.1.

¹²¹ Using CPI value for December for price caps starting 1 April and the CPI value for June for price caps starting 1 October.

¹²² See Appendix 14.1 for further details.

- half-hourly settlement;
- BSUoS;
- capacity mechanism; and
- the smart meter roll-out;

14.232 The future of the Hydro Benefit Replacement Scheme is currently the subject of consultation and the scheme is reported to cost less than £1 per customer per year.¹²³ We therefore do not propose to provide a specific allowance for this cost.

14.233 Similarly we do not consider that the costs of faster switching or half-hourly settlement are sufficiently material as to require a separate allowance. We note that Ofgem estimated the cost of reliable next day switching and that the most expensive option had a net present cost of £207 million over 15 years¹²⁴ – this would translate to less £1 per year for each domestic energy customer even if all costs were borne by the domestic markets.

14.234 We consider that the costs of implementing half-hourly settlement are likely to be immaterial in the context of the price cap. Further, these costs are likely to be offset by savings in respect of distribution network and wholesale energy costs.¹²⁵ We therefore have not included an allowance for the costs associated with half-hourly settlement for electricity.

14.235 In respect of gas we note that Project Nexus is a major upgrade of the gas settlement process and should be implemented by April 2017.¹²⁶ Therefore we expect that the majority of costs associated with Project Nexus will fall outside of the period covered by the price cap. We therefore have not included an allowance for the costs associated with Project Nexus.

14.236 We note that BSUoS costs are included within the calculations for electricity network costs. Similarly, the costs of the capacity mechanism are included within the OBR's projections for policy costs.

14.237 We have considered whether it is appropriate to provide an additional allowance for the costs of the smart meter roll-out. We sought evidence on the costs and benefits of the smart meter roll-out from DECC. DECC noted that in the CMA-derived benchmark bill some costs for smart metering were

¹²³ See DECC (December 2015), [Hydro Benefit Replacement Scheme & Common Tariff Obligation. Three year review of statutory schemes: consultation](#).

¹²⁴ See Ofgem consultation (2014), [Moving to reliable next-day switching](#).

¹²⁵ See Section 12.

¹²⁶ See Ofgem (2016), [Project Nexus: consultation on options for a successful implementation](#).

already included (owing to the substantial smart meter populations and associated investment by the energy suppliers that informed the benchmark bill). DECC further noted that in the case of prepayment customers the additional costs of smart metering would be offset by the savings expected over the life of the price cap.

14.238 We have also considered the cost estimates contained within the smart meter roll-out impact assessment.¹²⁷ This shows that the estimated annual net cost to business is £36 million per year. This translates to approximately £1.50 per customer per year. We note that this is significantly less than the prepayment uplift allowance (£24 for electricity, £39 for gas). While not all the costs making up the prepayment uplift relate to the specifics of the dumb meter infrastructure we consider that the prepayment uplift is sufficient that for any smart meters in scope of the price cap (eg SMETS 1 smart meters) the prepayment uplift more than covers the associated costs.

- *Prepayment uplift*

14.239 The costs making up the prepayment uplift will be indexed to CPI inflation. We consider that this is appropriate since the items making up the PPM uplift are largely driven by labour and systems costs for which CPI is a suitable index.

14.240 Each update will use the CPI figure for the month three months prior to the start of the price cap period. So, for price caps starting in April the December CPI figure will apply and for price caps starting in October the June CPI figure will apply. CPI figures are typically available in the middle of the month after the month to which they relate. This should therefore provide sufficient time for the updated price cap value to be determined and for practical arrangements (eg informing customers, updating systems) to be made before the new price cap comes into effect.

- *Other issues relating to indexing*

14.241 Ofgem and SSE suggested that it was necessary to specify how the price cap would operate in the event that the TDCVs were updated.

14.242 We have used TDCVs in two places in the price cap:

(a) in calculating the network cost allowances for each period; and

¹²⁷ See [DECC 2014 smart meter roll-out impact assessment](#).

(b) in calculating the base level of the price cap.

14.243 We have decided that the TDCVs prevailing two months before the start of a price cap period (ie on 1 February and 1 August) will be those used for determining the network cost allowance. In this way the network cost allowances will continue to reflect expected typical consumption.

14.244 We do not believe that there is a need to update the base level of the price cap when the TDCVs are updated. This is because the TDCVs are only used to determine the base level of the price cap. Subsequent changes in level are adjusted using the cost indices.¹²⁸

14.245 We have considered whether it was necessary to have a mechanism by which the price cap parameters could be updated outside of the usual process. We note that wholesale prices are potentially volatile and that policy costs can change unexpectedly. However, we consider that our mechanism for tracking wholesale costs is sufficiently accurate that it can accommodate changes in wholesale cost within the usual update process.

Stringency of cap and impact on suppliers and customers

14.246 The previous section provides an explanation of the price cap that the CMA has decided to implement. In this section we consider how the cap will work in practice. We estimate the likely impact on customers and suppliers. On this basis, we test whether our cap should be effective in achieving our objectives.

Assumptions, data and methodology

14.247 In order to estimate the impact of the price cap on customers and suppliers, we have used tariff data, consumption levels and customer numbers as at 30 June 2015 and compared these against the respective price cap calculated on this date. We have also rolled forward the price cap to the level it would be at if it were in place as at the date of this report and compared against the level of tariffs currently in the market.

14.248 A number of assumptions have been adopted in performing this comparison. These are outlined below.

(a) Calculations have been performed exclusive of VAT.

¹²⁸ For example, if the medium TDCV were updated by Ofgem then it would refer to a different level of consumption. However, the price cap would still track the cost of energy supply, albeit that it would do so at the original level of consumption.

- (b) The tariff data used in this analysis consists of the Six Large Energy Firms' prepayment customers only unless otherwise stated. We consider that this allows us to produce a reasonable estimate of the impact of this remedy since the Six Large Energy Firms account for just under 85% of customer accounts across all payment types.¹²⁹
- (c) We have calculated annual prepayment customer bills at actual consumption levels as at 30 June 2015, based on tariff data used in our gains from switching analysis.¹³⁰ These annual bills are calculated in line with the assumptions in the gains from switching analysis (see Appendix 9.2). Exclusions have been applied to remove, for example, tariffs with incomplete data, time-of-use and bundled tariffs from this data set.
- (d) Some exclusions applied to the gains from switching analysis and detriment analysis have not been applied to the price cap impacts analysis. The exclusions not applied to this analysis include: collective switch tariffs; deemed tariffs; green tariffs; social tariffs; tariffs with a small number of accounts; and tariffs classed as outlier tariffs based on the descriptive statistics.¹³¹ The price cap impact analysis therefore includes a slightly larger number of accounts compared with the detriment calculations.
- (e) As a result of the exclusions applied the detriment calculations and price cap impact are not based on the full prepayment population. As such, the level of detriment calculated does not include any detriment associated with these exclusions and the detriment, along with the impact of the price cap on suppliers, may therefore be understated.
- (f) We have calculated the impact of the price cap on customers and suppliers using customers' median consumption levels, as reported in the gains from switching data set. This approach has been adopted for consistency with the detriment analysis and to facilitate comparability between detriment and supplier revenue reduction. We have also noted the impact on suppliers based on customers' mean consumption levels.
- (g) We have assumed off-peak consumption for Economy 7 customers of 38%.¹³²

¹²⁹ See Section 8.

¹³⁰ See Appendix 9.2.

¹³¹ These customers on these tariffs were considered to value certain non-price characteristics of the tariff more highly than most other customers. See our provisional findings, [Appendix 3.2](#), Annex B for further detail.

¹³² See paragraph 14.97.

- (h) We have assumed that any suppliers with tariffs on the market where the annual bills calculated are below the cap, will remain at this level¹³³ (ie the cap does not introduce a focal point effect on existing competitive tariffs netting off supplier revenue reduction). For dual fuel, we have assessed each constituent single fuel bill against the relevant single fuel cap separately.
- (i) We have assumed that annual savings under the cap are equivalent to the difference between annualised bills under the cap and annual bills under customers' existing tariffs as at 30 June 2015.
- (j) When comparing to the minimum prepayment bill, we have calculated annual bills at each separate regional average consumption, based on the gains from switching data for prepayment customers at 30 June 2015 and identified the cheapest tariff in each region. These tariffs are not necessarily those available for new customers and include historical tariffs where customers remain on the tariff as at 30 June 2015. In the majority of instances the cheapest tariff is a smart prepayment offering.
- (k) The regional average consumption has been calculated based on a weighted average (by accounts) of each tariff's median consumption for each region.
- (l) We have calculated the impact of the price cap on Utilita at 30 June 2015 based on average gas and electricity customer consumption provided by this supplier and the assumption that all Utilita customers are on its 'smart energy' tariff.¹³⁴ We note that there are other prepayment specialist suppliers in the market and consider that our analysis of the impact on Utilita provides a reasonable indication of the anticipated impact on any such specialist since Utilita does not have any unique, intrinsic advantage.
- (m) In the analysis of the price cap's impact we do not distinguish between the impact on prepayment customers with smart meters as distinct from those with dumb prepayment meters. We do not expect that the impact would be materially different for smart meter customers since existing smart meters are all SMETS 1 and these are in scope of the price cap.

¹³³ See paragraphs 14.311–14.313 for an indication of how the price cap compares with existing prices.

¹³⁴ See paragraphs 14.325–14.327.

14.249 We consider that these assumptions are reasonable, both individually and in aggregate, and produce an appropriate estimate of the impact of the price cap on both suppliers and customers.

Headroom and the overall level of the cap

14.250 As noted in paragraph 14.66, the base level of the cap at medium TDCV is based on our estimate of the competitive benchmark tariff as at 30 June 2015 (including network costs plus the prepayment uplift) plus a level of headroom per fuel.¹³⁵

14.251 In assessing the appropriate level of headroom – and hence the level of the cap at medium TDCV – we have considered the impact of the price cap on customers and suppliers, taking into account the need to reduce detriment for prepayment customers while allowing efficient suppliers to compete beneath the level of the cap while still earning a normal return on capital. We have therefore taken account of:

- (a) the reduction in detriment that would be achieved by different levels of the cap, compared to the total level of detriment we calculate for each category of customer;
- (b) the impact on supplier profitability of different levels of the cap, considering both the impact on existing suppliers' EBIT and the implied EBIT that different levels of the cap would allow the notional supplier used to construct our competitive benchmark to earn; and
- (c) the need to allow for competition by considering the prevailing level of tariffs for prepayment customers in different regions, both as of 30 June 2015 and the end of May 2016 (updating the cap using the cost indices identified above).

14.252 In our provisional decision on remedies we considered a fourth criterion for setting the level of headroom – namely that it was required to offset risks arising from potential inaccuracies and approximations in the design of the cap. We consider that the design enhancements we have made since the provisional decision on remedies make the price cap more accurate in tracking prices, such that headroom is no longer required to meet this purpose.

¹³⁵ Note that headroom is initially defined at medium TDCV though will be implemented as a percentage such that it scales with consumption.

14.253 Taking account of these factors, we have decided to set the level of headroom at £15 per fuel, or £30 for a dual fuel customer, at medium TDCV. We note that the overall stringency of the price cap is comparable to the level set out in the provisional decision on remedies. Indeed, we estimated in the provisional decision on remedies that the price cap would reduce annual revenues of the Six Large Energy Firms by £303 million (assuming £25 headroom per fuel) whereas we now estimate the reduction would be £316 million.¹³⁶

14.254 In the rest of this section we summarise our reasoning for setting the cap at this level, considering each of the above criteria and drawing on the analysis presented in more detail in the following section ('price impacts analysis').

- *Reduction in detriment*

14.255 In relation to reduction in detriment, we used our competitive benchmark analysis to estimate the detriment currently suffered by each of following categories of customer:¹³⁷

- (a) single fuel gas;
- (b) single fuel electricity (single rate meter);
- (c) single fuel electricity (Economy 7 meter);
- (d) dual fuel (single rate meter); and
- (e) dual fuel (Economy 7 meter).

14.256 This established a lower bound for the price cap, on the basis that we did not think it would be proportionate to reduce more than the total level of detriment for any of these categories of customer.

14.257 Including an allowance for headroom necessarily means that the price cap will leave some proportion of the detriment we have identified un-remedied. We therefore considered how far setting headroom at different levels would result in the detriment we have identified being addressed.

¹³⁶ Based on actual customer mean consumption, see paragraph 14.279. Note that when assessing at actual customer median consumption, this results in a Six Large Energy Firm revenue reduction of £282 million. The results are therefore broadly comparable.

¹³⁷ Note that we consider dual fuel as a separate category for the purposes of this analysis though in practice dual fuel customers will be subject to each of the single fuel price caps as described in paragraphs 14.60–14.77.

14.258 As shown in Table 14.13 below, headroom of £15 per fuel at medium TDCV results in around two thirds of the detriment being reduced for dual fuel customers on single rate meters (the majority of prepayment customers); dual fuel customers on Economy 7 meters; and single fuel electricity customers on single rate meters.¹³⁸

Table 14.13: Summary of average annual savings of the Six Large Energy Firms' prepayment customers compared with detriment by fuel/meter combination (30 June 2015), £15 headroom

	<i>Average saving (£)</i>	<i>Detriment (£)</i>	<i>Number of accounts</i>	<i>Total savings (£m)</i>	<i>Total detriment* (£m)</i>
Dual fuel, single rate meter	66	100	2,325,926	153	231
Dual fuel, Economy 7	125	188	229,978	29	42
Single fuel electricity, single rate meter	29	43	1,006,597	29	42
Single fuel electricity, Economy 7	87	95	400,221	35	37
Single fuel gas, single rate meter	50	51	712,216	36	36
				282	388

Source: CMA analysis.

*As noted in paragraph 14.248 (d), some data-set exclusions applied within the detriment analysis have not been applied to the price cap impact analysis, resulting in a different number of accounts in each of these data-sets, with the price cap data-set being approximately 75,000 accounts greater than the detriment analysis. As a result, the total detriment figures above are not equal to the detriment per account multiplied by the number of accounts shown in the table (which reflect the number of accounts in the price cap analysis).

14.259 We note that for single fuel gas customers, almost 100% of the detriment calculated using our competitive benchmark would be reduced through the application of the cap at this level. As a cross-check of the impact of the price cap on the overall detriment identified in Section 10, we have calculated the impact of the price cap on single fuel gas customers using our competitive benchmark based on an adjusted detriment using the single fuel component of the competitive benchmark dual fuel tariffs. This results in an adjusted detriment that is £18 per single fuel gas customer higher than the calculation based on our competitive single fuel benchmark.¹³⁹ On this basis, we conclude that allowing headroom of £15 at medium consumption for single fuel gas customers is not overly stringent, since it reduces the adjusted detriment for such customers by an amount comparable to that for dual fuel customers. Within that context, we note that the substantial majority of gas prepayment customers purchase gas on the basis of a dual fuel contract rather than a single fuel gas tariff. Further, we have cross-checked the level of headroom taking account of the returns it would allow suppliers to earn and the relationship to prevailing tariffs.¹⁴⁰

14.260 We also note that the price cap appears to be more stringent at lower levels of consumption due to the use of standing charges to define the price cap at

¹³⁸ Average across all prepayment customers of the Six Large Energy Firms as of 30 June 2015.

¹³⁹ There is also an upwards adjustment to the detriment arising for single fuel electricity customers, albeit this adjustment is more modest, at £8 per customer (and £12 for Economy 7 customers).

¹⁴⁰ See paragraphs 14.280–14.285.

nil consumption.¹⁴¹ We note that the effect is more pronounced for single fuel gas than single fuel electricity.¹⁴² This effect contributes to the above result in which the amount of detriment for single fuel gas appears to be almost entirely eliminated by the level of the price cap, even after allowing for headroom at £15 at medium TDCV.

14.261 Overall, with £15 of headroom per fuel the price cap reduces detriment by £282 million,¹⁴³ with an average saving of £71 per customer, out of the total detriment for the prepayment customers of the Six Large Energy Firms of £388m in Q2 2015.

14.262 We have therefore decided that a price cap set so as to allow headroom of £15 at medium TCDV would be effective to address a substantial proportion of the detriment to consumers which we have identified.

- *Impact on supplier profitability*

14.263 Our analysis in paragraphs 14.314 to 14.328 shows that the reduction in revenues expected under the application of the cap would be equal to around 25% of the domestic supply EBIT of the Six Large Energy Firms in 2014, with the impact varying by supplier. This will still allow efficient suppliers to achieve a return on capital employed in excess of the cost of capital.

14.264 The cap would also apply to suppliers outside of the Six Large Energy Firms, of whom Utilita has the largest share of the prepayment segments. Our analysis suggests that if the price cap had been in place in 2014/15, Utilita would have still generated an EBIT margin of between [X]% and [X]%, with a similar outcome in 2016. The fact that Utilita, which is focused almost exclusively on prepayment customers and growing very rapidly¹⁴⁴, would still earn a reasonable profit after application of the cap provides support for our view that, while we have substantially reduced prepayment customer detriment, the level of the cap will allow suppliers to continue to compete.¹⁴⁵

¹⁴¹ See paragraphs 14.74 - 14.77 and 14.103 – 14.129 and the ‘Robustness check’ section of Section 10.

¹⁴² This is due to their lower usage (relative to TDCVs) and the fact that the difference between the level implied by the competitive benchmarks at nil consumption and the average of the Six Large Energy Firm standing charges is greater for single fuel gas than for single fuel electricity. See the ‘Robustness check’ section of Section 10.

¹⁴³ Based on customers median consumption which is in line with the approach to the calculation of detriment. At mean consumption the detriment addressed is £316 million.

¹⁴⁴ As our analysis in Section 10 and Appendix 10.1 suggests, rapid growth is likely to depress EBIT due to customer acquisition costs and other factors.

¹⁴⁵ We note that Utilita makes extensive use of smart meters and this may confer a cost benefit relative to suppliers who predominantly use dumb meters. We note that the option of using smart meters is open to all suppliers and as the smart meter roll-out progresses smart metering will become the default option.

- 14.265 We have also estimated the EBIT corresponding to different levels of headroom for the notional supplier that forms the basis of our competitive benchmark. As explained in Section 10, the competitive benchmark bills have been calculated on the basis of Ovo Energy's and First Utility's tariffs, adjusted to allow an EBIT margin of 1.25%.
- 14.266 We note that, by designing the price cap on the basis of the competitive benchmark for single fuel tariffs, a price cap with £nil headroom would allow for recovery of efficient costs by our hypothetical supplier, and allow it to achieve an EBIT margin of 1.25% for its single fuel prepayment tariffs.
- 14.267 As regards dual fuel prepayment tariffs a price cap with £nil headroom would theoretically allow our hypothetical supplier to achieve a somewhat higher EBIT margin of 2.7%¹⁴⁶ rather than 1.25% above recovery of efficient costs. This is due to the competitive single fuel benchmarks being somewhat conservative¹⁴⁷ and combining under the design of the price cap when applied to dual fuel tariffs.
- 14.268 We have taken this aspect of the design into account when determining the appropriate level of headroom. Adding £15 headroom at medium TDCV increases the weighted average EBIT margin across all tariff types under the price cap to around 5%. Specifically, the price cap using the competitive single fuel benchmark bills with an additional £15 headroom per fuel at medium TDCV implies that our notional supplier, pricing at the level of the price cap, could recover efficient costs plus EBIT of around 5% on a weighted average basis. This again suggests that the level of the cap would allow an efficient supplier to offer tariffs below the cap while still earning a normal rate of return, even at low consumption.
- 14.269 We note that we received a large number of submissions in relation to our profitability analysis.¹⁴⁸ The Six Large Energy Firms submitted that ROCE was an inappropriate means of assessing profitability in an asset-light industry such as retail supply and put forward a range of views on the appropriate level for EBIT margins (from around 3% to 9%, with most parties suggesting margins of around 4% to 5%).¹⁴⁹ While we did not agree with these submissions and consider an EBIT margin of 1.25% to represent a

¹⁴⁶ For this calculation we average across the fuel types (single fuel gas, single fuel electricity, single fuel Economy 7 electricity, dual fuel (non Economy 7) and dual fuel (Economy 7)) and weight by the number of customer accounts.

¹⁴⁷ See paragraph 14.66.

¹⁴⁸ These views and our analysis is set out in detail in Appendices 9.10 (ROCE) and 9.13 (Profit margins).

¹⁴⁹ EDF Energy and Co-operative Energy told us that an EBIT margin of 3% represented a fair level of profit; Ovo Energy suggested that an efficient firm should earn a margin of between 3% and 4%; Centrica told us that an appropriate competitive margin for energy retailing was between 4% and 6%; RWE and Scottish Power indicated that around 5% represented a reasonable profit margin; SSE told us that it targeted an EBIT margin of 5% but considered that the competitive margin would lie between [X].

reasonable EBIT margin, the effect of this headroom uplift is to allow energy suppliers to earn an EBIT margin of approximately 5% at medium TDCV. We note that this higher margin is broadly in line with the Six Large Energy Firms' views on a reasonable competitive margin for retail supply.

- *Relationship between level of the cap and prevailing prepayment tariffs*

14.270 Our analysis also considered how different levels of the price cap would compare with average and minimum prepayment tariff prices in the market.¹⁵⁰ As shown in paragraphs 14.289 to 14.293, allowing for £15 headroom per fuel at medium TDCV results in a price cap which is generally in line with or slightly above the minimum prepayment tariff prices in the market in many regions.

14.271 Further, we compared updated levels of the cap, using different levels of headroom and updated according to the above cost indices, with prices observed in June 2016. At £15 headroom per fuel at medium TDCV, the updated price caps for single fuel gas and electricity were generally between the minimum and lower quartile of available tariffs across most of the consumption profile, with the single fuel electricity cap generally closer to the minimum than single fuel gas. This indicates again that there is potential for competition to undercut the level of the cap.

14.272 This analysis therefore gives us further comfort that allowing for £15 of headroom per fuel at medium TDCV produces a sustainable level of the price cap and thereby mitigates the likelihood and potential severity of some of the potential unintended consequences that may arise from the introduction of a cap.¹⁵¹

- *Conclusion on headroom and the overall level of the cap*

14.273 We have taken account of a number of criteria in making our final decision on the appropriate level of headroom to include and hence on the stringency of the cap. We recognise that different plausible levels of the cap against these criteria necessarily involves an element of judgement. However, the evidence we have reviewed suggests that £15 of headroom per fuel at medium TDCV strikes an appropriate balance between the various considerations we have identified, including the need effectively to reduce detriment for prepayment customers, the recovery of efficient costs by

¹⁵⁰ See Figures 14.7–14.11.

¹⁵¹ See paragraphs 14.398–14.458 for consideration of potential unintended consequences.

suppliers and the facilitation of competition between suppliers below the level of the cap.

14.274 Had the cap been in place in 2015, it would have eliminated around three quarters of prepayment customer detriment in that year. While we could have opted for a more stringent cap to reduce more of the detriment – while still allowing for an efficient supplier to make a normal rate of return – this would have increased the risk of pushing the cap too low, and below the cheapest prepayment tariff for certain categories of customer in different regions. This would entail greater risk of undermining competition. Conversely, while a less stringent cap would reduce the risks for suppliers, we were concerned that the remedy should be effective substantially to mitigate the detriment which it is intended to address.

14.275 We have therefore decided to include headroom of £15 per fuel at medium TDCV in the cap (ie £30 headroom in the dual fuel cap).

Price cap impact analysis overview

14.276 We have estimated the impact of the price cap on both customers and suppliers based on the 30 June 2015 prepayment tariff and customer data. As outlined in the assumptions above, this data-set is limited to the Six Large Energy Firms' prepayment customers only and does not represent the complete prepayment population. As such, the aggregate impact on the supplier may be slightly understated.

14.277 The data set used to assess the impact of the price cap consisted of 4.7 million prepayment accounts, which we have estimated to represent around four million customers.¹⁵² This therefore reflects the vast majority of prepayment customers.

14.278 A detailed breakdown of the number of accounts by region is outlined below.

¹⁵² The number of accounts does not directly match the number of customers, as some customers may have more than one account (eg one single fuel gas account and one single fuel electricity account). We have estimated the number of customers, based on the number of accounts, as dual fuel (single rate and Economy 7) accounts, plus single fuel electricity (single rate and Economy 7), based on the assumption that all customers have at least electricity.

Table 14.14: Number of prepayment accounts of the Six Large Energy Firms informing analysis of price cap impact

	<i>Dual fuel, single rate meter</i>	<i>Dual fuel, Economy 7</i>	<i>Single fuel electricity, single rate meter</i>	<i>Single fuel electricity, Economy 7</i>	<i>Single fuel gas, single rate meter</i>
East Anglia	172,716	77,736	71,217	84,695	67,263
East Midlands	179,658	41,658	57,860	36,550	47,757
London	220,897	7,316	145,467	18,675	100,343
Merseyside and North Wales	178,108	3,467	88,634	15,870	53,499
Midlands	222,567	12,325	76,026	33,735	57,370
North East	144,835	2,788	42,495	9,744	36,389
North Scotland	50,923	1,762	41,564	9,356	15,230
North West	213,859	5,348	71,236	18,186	61,558
South East	109,448	46,391	42,813	42,796	43,612
South Scotland	210,536	7,925	115,185	28,986	73,365
South Wales	136,853	1,122	44,854	5,679	28,437
South West	104,633	8,642	59,072	39,505	26,188
Southern	166,706	7,079	86,609	41,368	49,019
Yorkshire	214,187	6,419	63,565	15,076	52,186
Total	2,325,926	229,978	1,006,597	400,221	712,216

Source: CMA analysis.

14.279 We have estimated the total suppliers' revenue reduction based on this population as £316 million¹⁵³ a year. This translates to an average saving of £79 for the Six Large Energy Firms' prepayment customers.¹⁵⁴

Impact on customers

14.280 As noted above the £79 per customer saving is an average across fuel and meter types and across regions. In this section we analyse the savings for each of these different categories.

14.281 We have calculated the price cap across each fuel/meter combination as at 30 June 2015, in line with the methodology set out in paragraphs 14.103 and 14.131. We consider separately the possible impact of unintended consequences in paragraphs 14.398 to 14.458.

14.282 Table 14.14 shows the impact of the price cap across the different fuel/meter combinations, based on £15 headroom per fuel (at medium TDCV). We have subsequently illustrated the level of the cap on a regional basis compared with the average prepayment bill and the cheapest prepayment tariff bill for the Six Large Energy Firms' and the Mid-tier Suppliers' customers based on actual customer tariffs at 30 June 2015. This is outlined

¹⁵³ Based on actual customer mean consumption, see paragraph 14.279. Note that when assessing at actual customer median consumption, this results in a Six Large Energy Firm revenue reduction of £282 million.

¹⁵⁴ This is based on the total detriment reduction of £316 million and the total number of Six Large Energy Firm prepayment accounts in our analysis as at 30 June 2015 of four million. The actual impacts on individual customers will be dependent on various factors, including fuel and meter combination, consumption, existing tariffs and region. Further breakdown is outlined in the 'Impact on customers' subsection below.

in the charts below. Generally the cheapest prepayment tariff bill relates to a smart offering.

- 14.283 Table 14.13 shows that 66 to 98% of the detriment is addressed. We note that in the case of single fuel gas 98% of the detriment is eliminated through the introduction of the cap. This is a result of the price cap's greater stringency for lower levels of consumption.¹⁵⁵
- 14.284 As noted in paragraph 14.66, we use competitive single fuel benchmarks which produce a higher benchmark than the single fuel components of the competitive dual fuel benchmarks would do.¹⁵⁶ Therefore we consider that use of the competitive single fuel benchmarks is conservative.
- 14.285 Accordingly, as noted in paragraph 14.259, we have cross-checked against the detriment implied by the competitive dual fuel benchmark as a way to verify the proportionality of the PPM Price Cap Remedy. The results are shown in Figure 14.6 and demonstrate that, taking account of the detriment implied by the single fuel components of the competitive dual fuel benchmarks, the cap would eliminate around two thirds of the detriment for single fuel gas customers, a similar proportionate reduction to that for dual fuel customers.¹⁵⁷

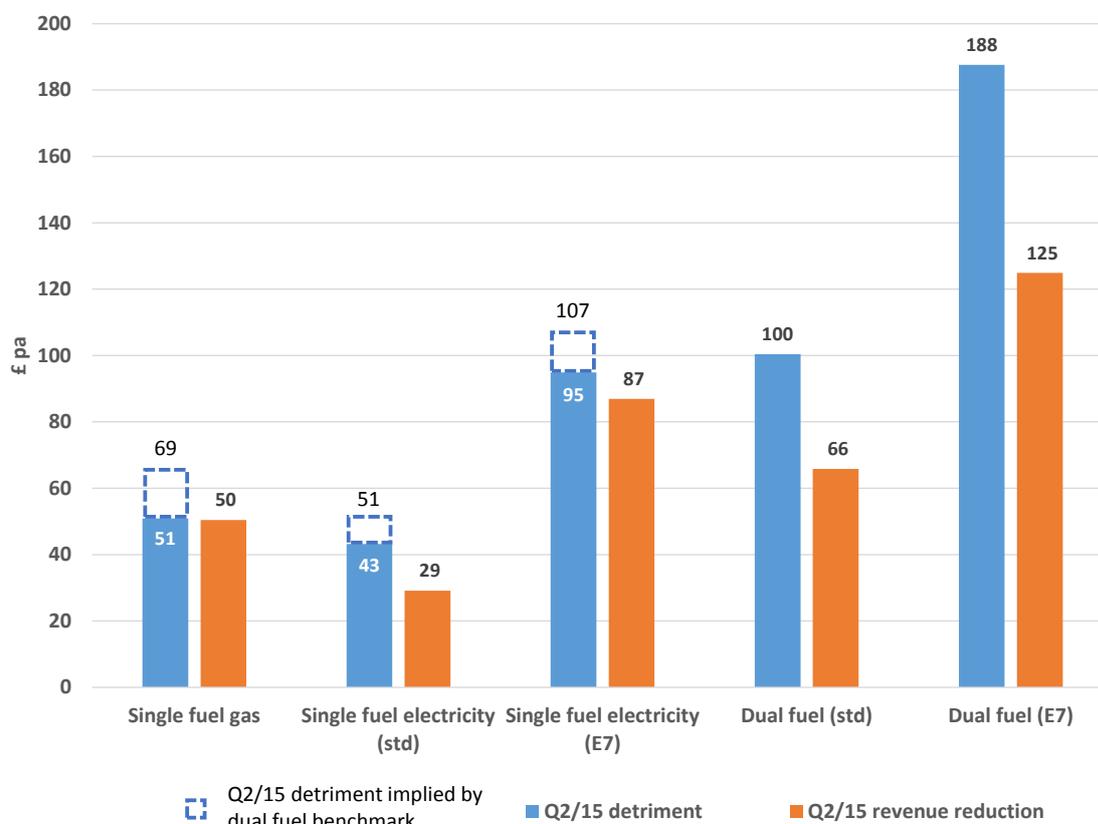
¹⁵⁵ See paragraphs 14.74 – 14.77 and 14.103–14.129 and the 'Robustness check' section of Section 10.

¹⁵⁶ For example, Ovo Energy does not offer single fuel gas tariffs to new customers though it does have single fuel gas customers as a result of customers who previously had dual fuel with Ovo Energy switching electricity supplier.

¹⁵⁷ The values shown in Figure 14.6 for the detriment implied by using the single fuel components of the dual fuel competitive benchmark are calculated as at 30 June 2015. Elsewhere in this document we refer to the detriment implied by the single fuel components of the dual fuel competitive benchmark over the period 2012–2015. It is this different time basis which explains certain small differences observed (eg for single fuel gas £18 is the detriment implied as at 30 June 2015, £19 is the detriment implied over the period 2012–2015).

Figure 14.6: Average Six Large Energy Firm prepayment customer annual savings compared with detriment by fuel/meter combination (30 June 2015), £15

Headroom



Source: CMA analysis.

14.286 We have illustrated the level of the cap on a regional basis compared with the average prepayment bill and cheapest prepayment tariff bill for the customers of the Six Large Energy Firms and the Mid-tier Suppliers, based on actual customer tariffs at 30 June 2015, for each of the fuel/meter combinations, below.

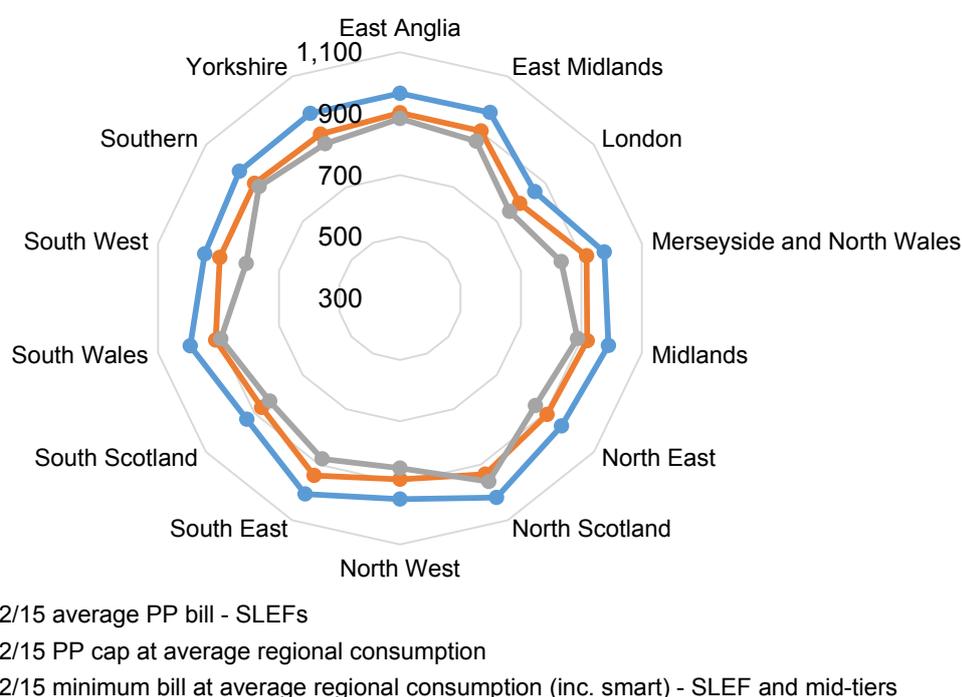
14.287 These charts outline the impact of £30 dual fuel (ie £15 per fuel) headroom within the price cap. Generally this cheapest prepayment tariff bill relates to a smart offering.

14.288 Customer impacts outlined below are based on customers' actual average consumption in each region. We have estimated the average impact of the price cap on Six Large Energy Firm prepayment customer bills as a reduction of approximately £79 per customer.¹⁵⁸

¹⁵⁸ The figure of £79 saving per customer uses the mean consumption level.

- *Dual fuel, single rate meter customers*

Figure 14.7: Price cap vs average Six Large Energy Firm prepayment customer annual bill (dual fuel, single rate meter, 30 June 2015, regional average consumption, £15 headroom per fuel)



Source: CMA analysis.

14.289 On a national basis, the average bill across all dual fuel, single rate meter prepayment customers will reduce from £958 to £892, a reduction of £66 (7%) under a price cap with £30 dual fuel headroom (ie £15 per fuel) at medium TDCV. A regional breakdown of these impacts are outlined below.

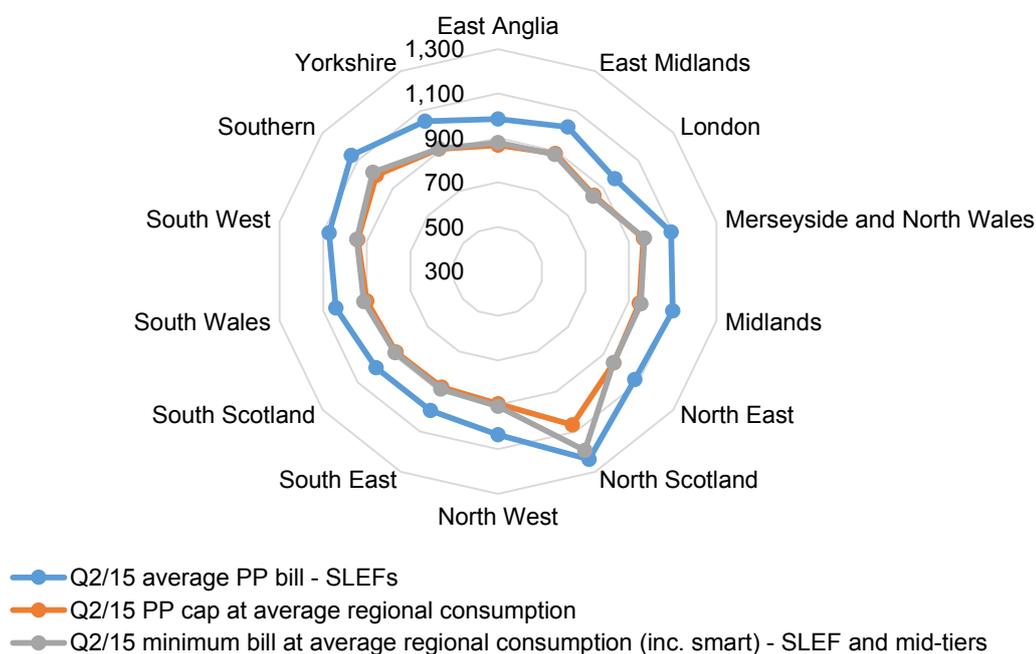
Table 14.15: Summary of average dual fuel, single rate meter Six Large Energy Firm prepayment customer annual savings by region (30 June 2015), £15 headroom

	Average gas consumption (kWh)	Average electricity consumption (kWh)	Average uncapped bill (£)	Average bill under cap (£)	Average bill reduction (£)
National average	8,727	3,125	958	892	66
East Anglia	8,824	3,243	965	903	63
East Midlands	9,231	3,188	970	904	67
London	7,732	2,647	856	794	62
Merseyside and North Wales	8,508	3,092	976	917	59
Midlands	9,043	3,259	990	919	71
North East	9,781	2,914	967	907	60
North Scotland	8,978	3,235	1,019	935	84
North West	8,717	3,043	953	888	64
South East	8,443	3,525	1,006	939	67
South Scotland	9,057	2,943	932	870	62
South Wales	9,051	3,085	993	909	84
South West	7,147	3,341	946	895	51
Southern	8,256	3,217	962	899	63
Yorkshire	9,412	3,020	966	891	75

Source: CMA analysis.

- *Dual fuel, Economy 7 customers*

Figure 14.8: Price cap vs average Six Large Energy Firm prepayment customer annual bill (dual fuel, Economy 7, 30 June 2015, regional average consumption, £15 headroom per fuel)



Source: CMA analysis.

14.290 On a national basis, the average bill across all dual fuel, Economy 7 prepayment customers will reduce from £1,015 to £890, a reduction of £125 (12%) under a price cap with £30 dual fuel headroom (ie £15 per fuel) at medium TDCV. A regional breakdown of these impacts are outlined below.

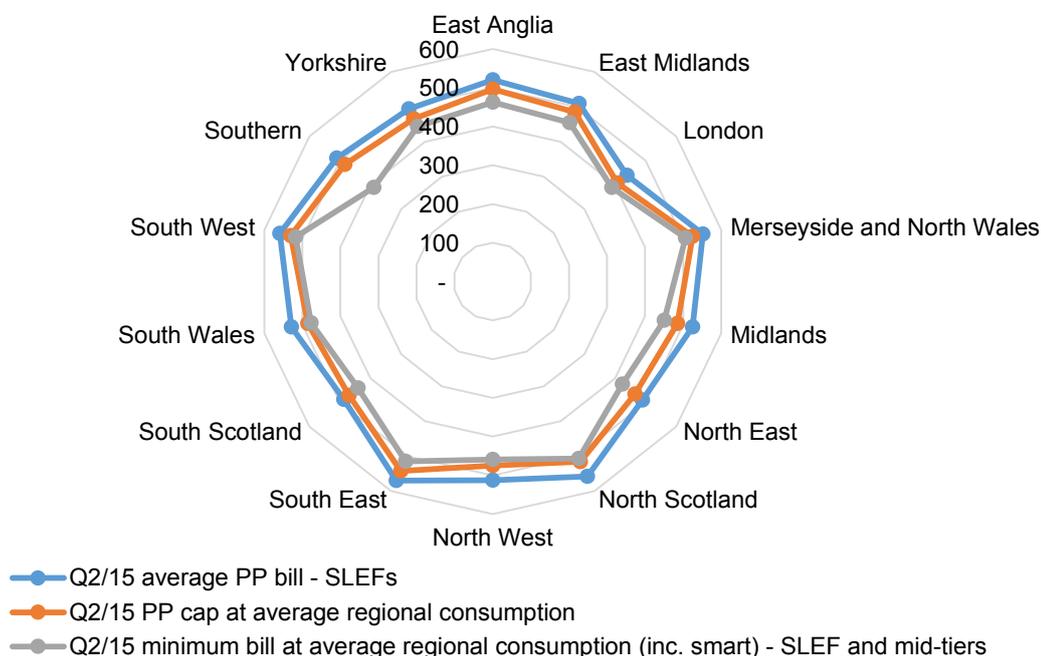
Table 14.16: Summary of average dual fuel, Economy 7 Six Large Energy Firm prepayment customer annual savings by region (30 June 2015), £15 headroom

	<i>Average gas consumption (kWh)</i>	<i>Average electricity consumption (kWh)</i>	<i>Average uncapped bill (£)</i>	<i>Average bill under cap (£)</i>	<i>Average bill reduction (£)</i>
National average	8,711	3,836	1,015	890	125
East Anglia	8,853	3,359	985	867	119
East Midlands	9,284	3,512	1,020	888	132
London	7,655	3,557	967	847	120
Merseyside and North Wales	8,463	3,987	1,093	966	127
Midlands	9,064	4,034	1,100	947	153
North East	9,742	3,784	1,081	961	120
North Scotland	8,844	4,838	1,238	1,066	172
North West	8,722	3,668	1,035	896	139
South East	8,527	3,443	994	879	115
South Scotland	9,042	3,438	996	883	113
South Wales	9,018	3,559	1,042	901	141
South West	7,144	4,285	1,074	942	132
Southern	8,231	4,634	1,137	993	144
Yorkshire	9,372	3,611	1,049	910	139

Source: CMA analysis.

- *Single fuel electricity, single rate meter customers*

Figure 14.9 Price cap vs average Six Large Energy Firm prepayment customer annual bill (single fuel electricity, single rate meter, 30 June 2015, regional average consumption, £15 headroom per fuel)



Source: CMA analysis.

14.291 On a national basis, the average bill across all single fuel electricity, single rate meter prepayment customers will reduce from £509 to £480, a reduction of £29 (6%) under a price cap with £30 dual fuel headroom (ie £15 per fuel) at medium TDCV. A regional breakdown of these impacts is outlined below.

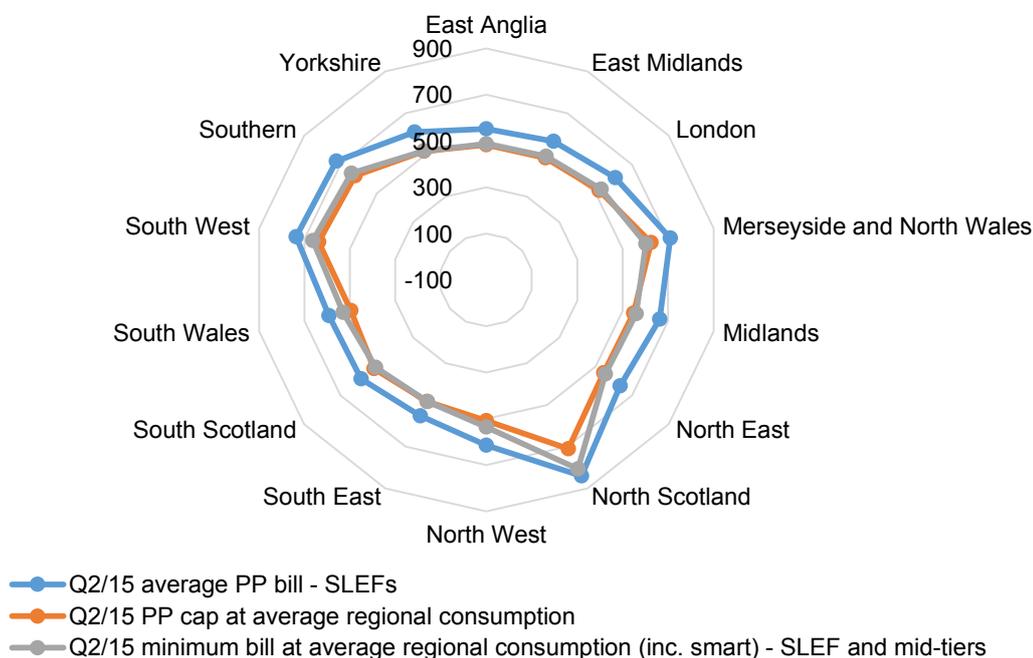
Table 14.17: Summary of average single fuel electricity, single rate meter Six Large Energy Firm prepayment customer annual savings by region (30 June 2015), £15 headroom

	Average electricity consumption (kWh)	Average uncapped bill (£)	Average bill under cap (£)	Average bill reduction (£)
National average	3,053	509	480	29
East Anglia	3,266	520	496	24
East Midlands	3,193	509	485	24
London	2,621	439	408	31
Merseyside and North Wales	3,124	552	524	28
Midlands	3,154	525	485	40
North East	2,929	490	465	25
North Scotland	3,157	558	516	42
North West	3,029	512	475	37
South East	3,533	570	543	27
South Scotland	3,004	488	471	17
South Wales	3,049	528	486	42
South West	3,266	559	530	29
Southern	3,111	511	485	26
Yorkshire	2,984	494	466	28

Source: CMA analysis.

- *Single fuel electricity, Economy 7 customers*

Figure 14.10: Price cap vs average Six Large Energy Firm prepayment customer annual bill (single fuel electricity, Economy 7, 30 June 2015, regional average consumption, £15 headroom per fuel)



Source: CMA analysis.

14.292 On a national basis, the average bill across all single fuel electricity, Economy 7 prepayment customers will reduce from £624 to £537, a reduction of £87 (14%) under a price cap with £30 dual fuel headroom (ie £15 per fuel) at medium TDCV. A regional breakdown of these impacts is outlined below.

Table 14.18: Summary of average single fuel electricity, Economy 7 Six Large Energy Firm prepayment customer annual savings by region (30 June 2015), £15 headroom

	<i>Average electricity consumption (kWh)</i>	<i>Average uncapped bill (£)</i>	<i>Average bill under cap (£)</i>	<i>Average bill reduction (£)</i>
National average	4,068	624	537	87
East Anglia	3,659	553	484	70
East Midlands	3,706	565	485	80
London	4,043	608	519	89
Merseyside and North Wales	4,488	710	625	85
Midlands	4,246	662	548	115
North East	4,053	634	543	90
North Scotland	5,250	840	710	130
North West	3,899	615	509	106
South East	3,555	552	484	68
South Scotland	3,838	587	516	71
South Wales	3,663	592	495	96
South West	4,738	737	637	100
Southern	4,913	723	621	102
Yorkshire	3,907	609	517	92

Source: CMA analysis.

- *Single fuel gas, single rate meter customers*

Figure 14.11: Price cap vs average Six Large Energy Firm prepayment customer annual bill (single fuel gas, single rate meter, 30 June 2015, regional average consumption, £15 headroom per fuel)



Source: CMA analysis.

14.293 On a national basis, the average bill across all single fuel gas, single rate meter prepayment customers will reduce from £462 to £412, a reduction of £50 (11%) under a price cap with £30 dual fuel headroom (ie £15 per fuel) at medium TDCV. A regional breakdown of these impacts is outlined below.

Table 14.19: Summary of average single fuel gas, single rate meter Six Large Energy Firm prepayment customer annual savings by region (30 June 2015), £15 headroom

	Average gas consumption (kWh)	Average uncapped bill (£)	Average bill under cap (£)	Average bill reduction (£)
National average	8,759	462	412	50
East Anglia	8,943	471	419	52
East Midlands	9,381	484	428	56
London	7,729	427	383	44
Merseyside and North Wales	8,559	452	405	47
Midlands	9,113	479	424	54
North East	9,823	497	451	45
North Scotland	9,159	475	416	59
North West	8,798	461	415	46
South East	8,496	456	406	49
South Scotland	9,090	470	413	57
South Wales	9,204	480	424	56
South West	7,263	393	362	31
Southern	8,386	456	408	47
Yorkshire	9,462	491	429	62

Source: CMA analysis.

- *Summary by fuel/meter type*

14.294 The table below summarises the average savings for customers under the price cap for each fuel/meter combinations across all regions under a price cap with £30 dual fuel (ie £15 per fuel) headroom at 30 June 2015.

Table 14.20: Summary of average Six Large Energy Firm prepayment customer savings as a percentage of average annual bills (30 June 2015), £30 dual fuel (ie £15 per fuel) headroom

	<i>Average customer savings (£)</i>	<i>% annual bill reduction</i>
Dual fuel, single rate meter	66	7
Dual fuel, Economy 7	125	12
Single fuel electricity, single rate meter	29	6
Single fuel electricity, Economy 7	87	14
Single fuel gas, single rate meter	50	11

Source: CMA analysis.

- *Analysis of savings across consumption levels*

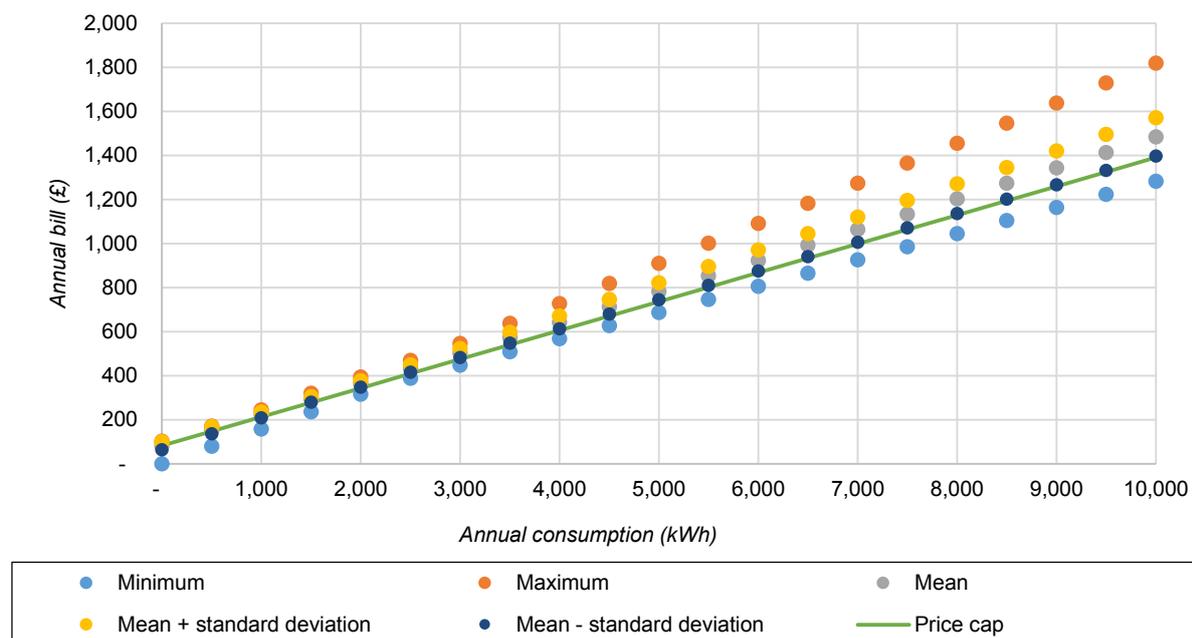
14.295 The above analysis shows the impact on customers at average consumption levels, based on the actual consumption data within the gains from switching data set. In order to understand the distribution of savings based across different consumption levels, we have performed an illustrative analysis of the price cap against the prepayment customer bills of the Six Large Energy Firms across consumption levels. This analysis is performed based on the implied standing charge and unit rate within the price caps and the actual standing charges and unit rates which customers were on as at 30 June 2015.¹⁵⁹

14.296 Some suppliers offer zero standing charge tariffs which are cheaper than the price cap at very low consumption, but may become more expensive at higher consumption. Conversely some suppliers offer higher standing charge tariffs, which are more expensive at low consumption, but may become cheaper at high consumption.

14.297 As discussed in paragraphs 14.86, suppliers may continue to offer tariffs below the cap and where they consider that the structure of such tariffs are not compatible with the cap may seek derogations from the ex ante assessment of compliance to ensure these tariffs can still be offered going forward.

¹⁵⁹ For this analysis we look at each of the single fuel tariffs as this is the basis on which the price caps are defined. We note that dual fuel tariffs will have to comply with the price cap applying to each component single fuel. The population we use in this illustrative analysis is solely based on single fuel customers. To the extent to which most dual fuel tariffs for prepayment customers are combinations of single fuel tariffs, this will be a tolerable approximation of distributional impacts across a broader customer base.

Figure 14.12: Price cap versus Six Large Energy Firm prepayment tariffs analysis by consumption (single fuel electricity, single rate meter, 30 June 2015, £15 headroom per fuel, average all regions)*



Source: CMA analysis.

*We have calculated the level of the mean plus (and minus) one standard deviation to give an indication of the dispersion of tariffs at each consumption level. However, we do not have evidence that tariffs are normally distributed at each consumption level and therefore do not identify these levels as particular percentiles.

14.298 The average annual consumption for single fuel electricity, single rate meter customers at 30 June 2015 was 3,053 kWh. Based on an analysis of the prepayment tariffs which customers were on at 30 June 2015, 7% of the Six Large Energy Firms' single fuel electricity single rate meter customers were on tariffs with a structure below the price cap level at this consumption.

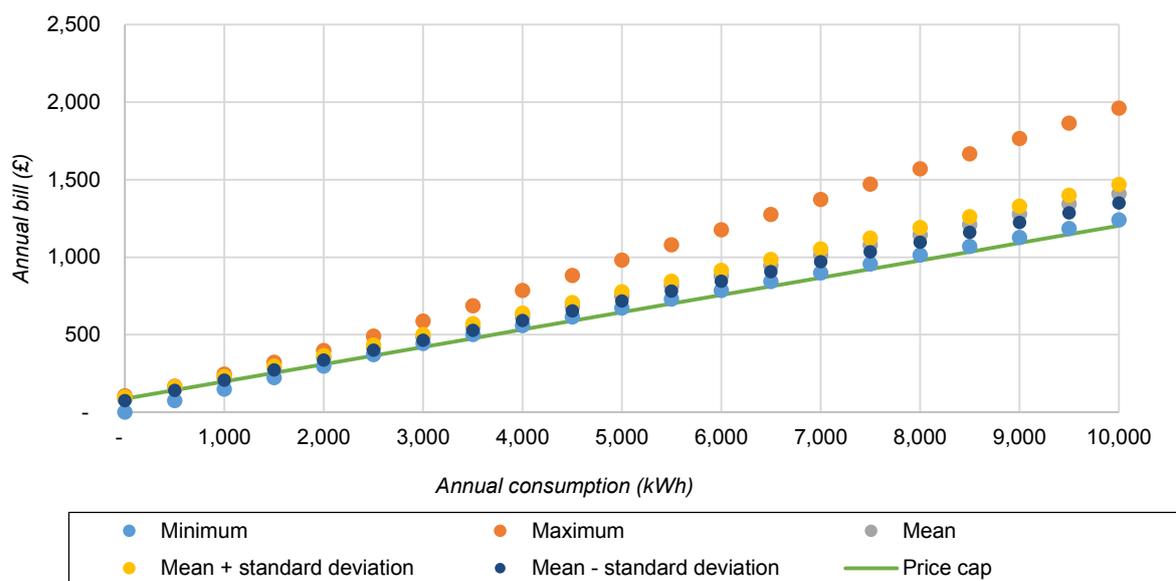
14.299 At consumption between zero and 1,500 kWh ([~~£~~]), up to 31% of the Six Large Energy Firms' tariffs (weighted by customer accounts) had a structure below the price cap level.

14.300 Similarly consumption greater than 4,500 kWh ([~~£~~]), between 11% and 14% of the Six Large Energy Firms' tariffs (weighted by customer accounts) had a structure below the price cap level.

14.301 For all other consumption levels less than 10% of the Six Large Energy Firms' customers were on tariffs with a structure below the price cap level.

14.302 Data is not available for the number of non-Six Large Energy Firm customers on tariffs with a bill less than the price cap level.

Figure 14.13: Price cap versus Six Large Energy Firm prepayment tariffs analysis by consumption (single fuel electricity, Economy 7, 30 June 2015, £15 headroom per fuel, all regions)



Source: CMA analysis.

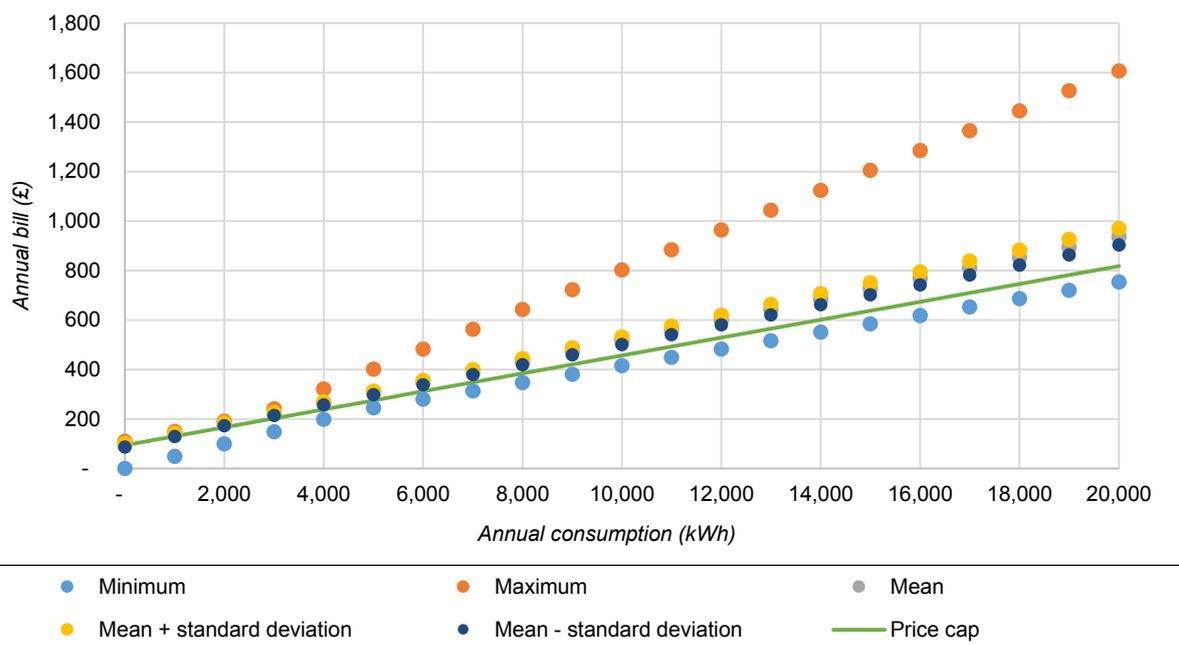
14.303 The average annual consumption for single fuel electricity, Economy 7 customers at 30 June 2015 was 4,068 kWh. Based on an analysis of the prepayment tariffs which customers were on at 30 June 2015, no single fuel electricity, Economy 7 customers were on tariffs with a structure below the price cap level at this consumption.

14.304 At consumption between zero and 1,000 kWh ([X]), up to 32% of Six Large Energy Firm tariffs (weighted by customer accounts) had a structure below the price cap level.

14.305 For all consumption levels above 2,500 kWh ([X]) no Six Large Energy Firm customers were on tariffs with a structure below the price cap level.

14.306 Data is not available for the number of non-Six Large Energy Firm customers on tariffs with a bill less than the price cap level.

Figure 14.14: Price cap versus Six Large Energy Firm prepayment tariffs analysis by consumption (single fuel gas, single rate meter, 30 June 2015, £15 headroom per fuel, all regions)



Source: CMA analysis.

14.307 The average annual consumption for single fuel gas, single rate meter customers at 30 June 2015 was 8,759 kWh. Based on an analysis of the prepayment tariffs which customers were on at 30 June 2015, less than 1% of single fuel gas customers were on tariffs with a structure below the price cap level at this consumption.

14.308 At consumption between zero and 1,000 kWh ([~~£~~]), up to 59% of the Six Large Energy Firms' tariffs (weighted by customer accounts) had a structure below the price cap level.

14.309 For all consumption levels above 1,000 kWh ([~~£~~]), less than 1% of the Six Large Energy Firms' customers were on tariffs with a structure below the price cap level.

14.310 Data is not available for the number of customers of the independent suppliers on tariffs with a bill below the price cap level.

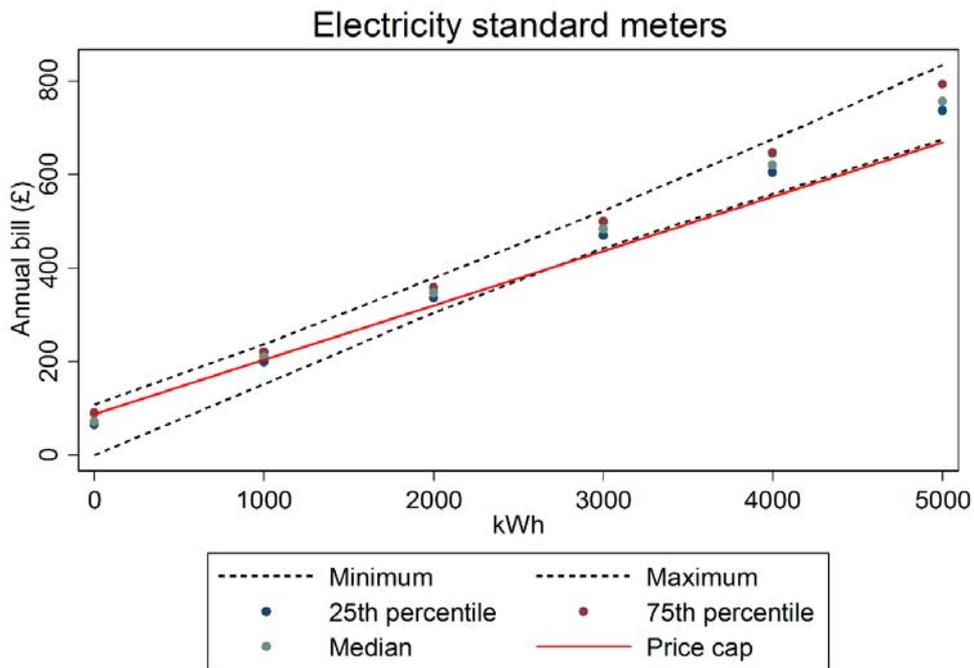
- *Updated price cap for April 2016 to September 2016*

14.311 In order to understand developments in the prepayment segments since 30 June 2015, we have also performed an analysis of the updated price cap,

which would have been in effect from April 2016 to September 2016,¹⁶⁰ compared with tariffs on the market at the beginning of June 2016¹⁶¹ for each region.

14.312 The charts below show the price cap compared with prevailing tariffs on the market at the beginning of June 2016 for single fuel electricity (single rate meter) and single fuel gas customers across consumption levels. We present the charts for London and North of Scotland as these regions have different physical characteristics which influence costs (eg network costs).¹⁶²

Figure 14.15: Price cap versus prevailing prepayment tariffs analysis by consumption (single fuel electricity, single rate meter, June 2016, £15 headroom per fuel, London, all suppliers)



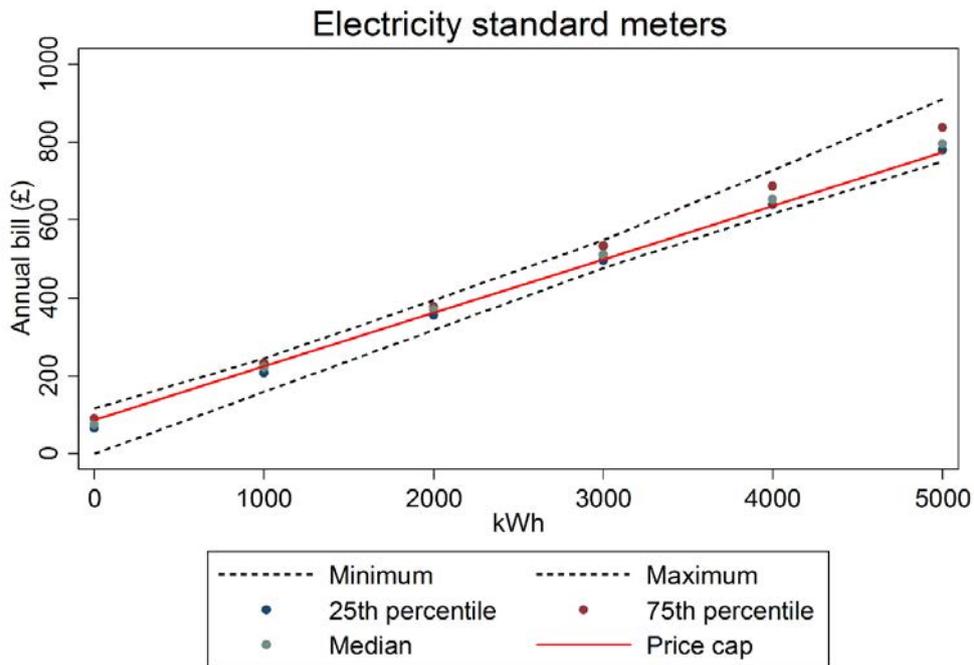
Source: uSwitch, CMA analysis.

¹⁶⁰ This is calculated based on the price cap calculated at 30 June 2015, updated as set out in the indexation methodology in paragraphs 14.132–14.245.

¹⁶¹ Tariffs on the market for a customer in this region at the beginning of June 2016 were using the uSwitch price comparison website on 6 June 2016. These are not weighted for customer numbers.

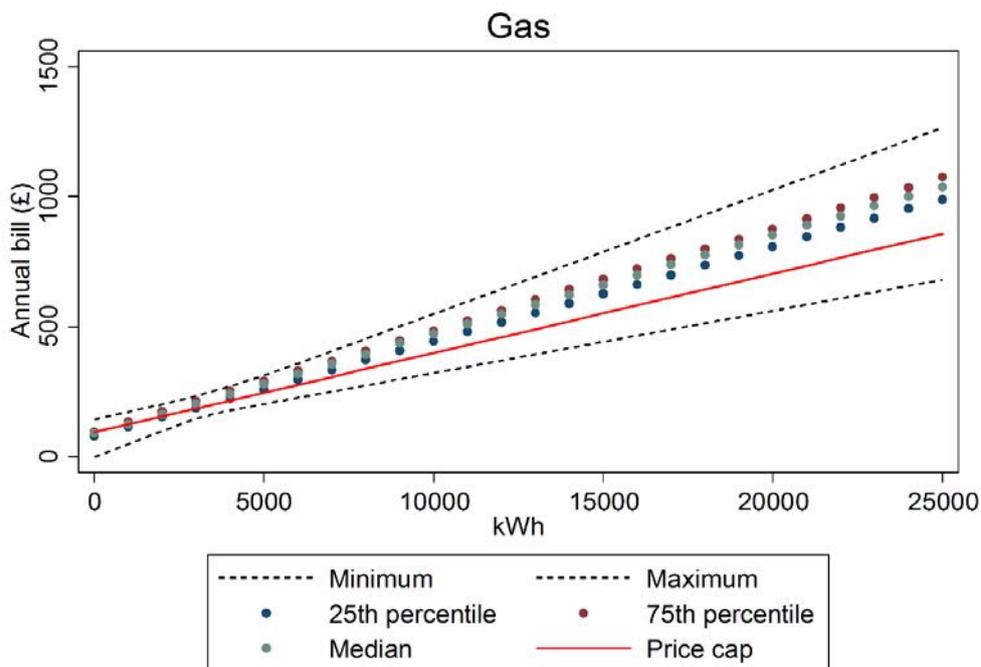
¹⁶² We have carried out the same analysis for the other regions of Great Britain. The results were consistent with the assessment set out in this section.

Figure 14.16: Price cap versus prevailing prepayment tariffs analysis by consumption (single fuel electricity, single rate meter, June 2016, £15 headroom per fuel, North Scotland, all suppliers)



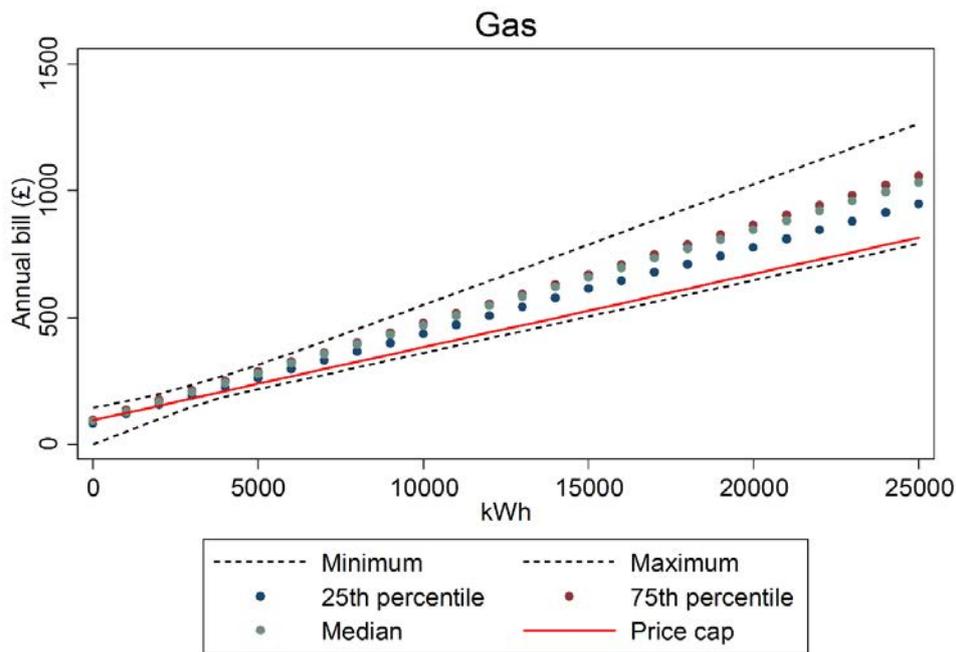
Source: uSwitch, CMA analysis.

Figure 14.17: Price cap versus prevailing prepayment tariffs analysis by consumption (single fuel gas, single rate meter, June 2016, £15 headroom per fuel, London, all suppliers)



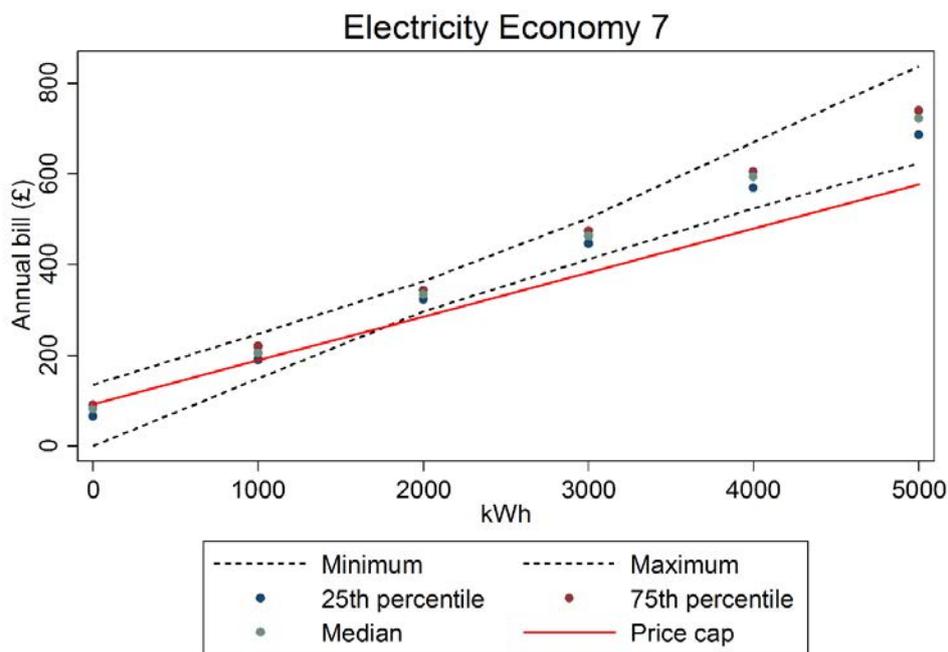
Source: uSwitch, CMA analysis.

Figure 14.18: Price cap versus prevailing prepayment tariffs analysis by consumption (single fuel gas, single rate meter, June 2016, £15 headroom per fuel, North Scotland, all suppliers)



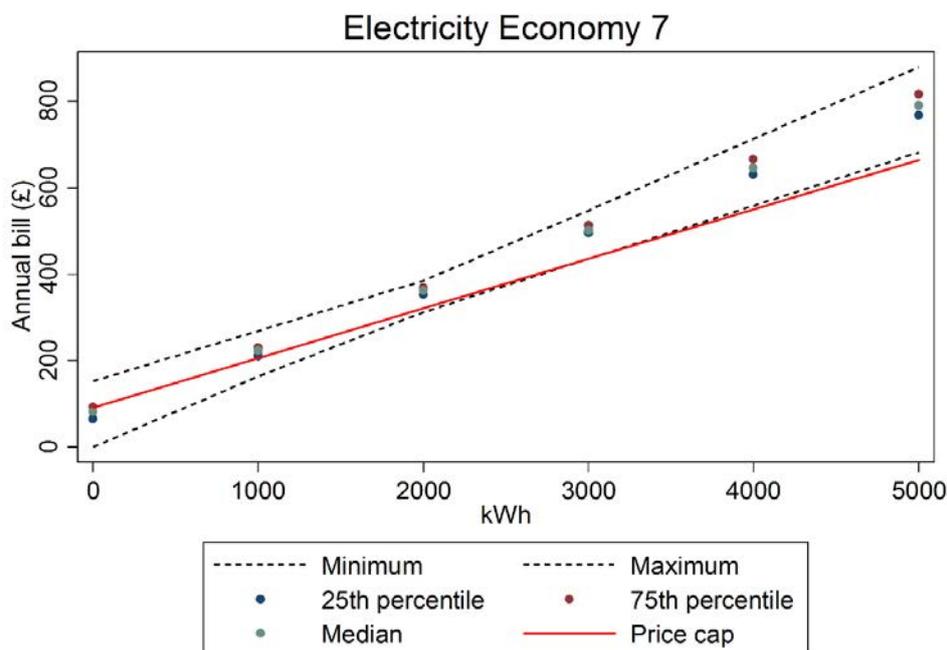
Source: uSwitch, CMA analysis.

Figure 14.19: Price cap versus prevailing prepayment tariffs analysis by consumption (single fuel electricity, Economy 7 meter, June 2016, £15 headroom per fuel, London, all suppliers)



Source: uSwitch, CMA analysis.

Figure 14.20: Price cap versus prevailing prepayment tariffs analysis by consumption (single fuel electricity, Economy 7 meter, June 2016, £15 headroom per fuel, North Scotland, all suppliers)



Source: uSwitch, CMA analysis.

14.313 The charts above show that the updated electricity price caps are broadly in line with the minimum tariffs whilst the gas price caps are between the 25th percentile and the minimum. We note that the Economy 7 price caps are below the level of the cheapest tariff in the market above low levels of consumption. We consider that this reflects the greater magnitude of detriment in the Economy 7 segments.¹⁶³ This demonstrates that the cap remains effective.

Impact on detriment and suppliers

14.314 The application of the price cap will reduce the level of detriment we have identified. We have observed detriment attributable to prepayment customers of the Six Large Energy Firms at 30 June 2015 of £388 million.¹⁶⁴

14.315 We have estimated the impact of a price cap with £15 headroom per fuel across the prepayment population at 30 June 2015. This results in a total reduction in suppliers' revenues of £282 million a year, reflecting 73% of detriment being addressed by this remedy. This impact on suppliers has

¹⁶³ See Figure 14.6.

¹⁶⁴ The gains from switching data set which informed this analysis included a variety of exclusions (for example, due to incomplete tariff data). As such the actual level of detriment and the impact of the price cap on supplier revenue may be in excess of the amounts stated in this analysis.

been calculated based on the median customer energy consumption as at 30 June 2015, in line with the detriment calculation.¹⁶⁵

Figure 14.21: Price cap impact on suppliers versus observed detriment (30 June 2015, £15 headroom per fuel, median customer energy consumption)

[✂]

Source: CMA analysis.

14.316 The graph shows that the size of the detriment and the proportion of it addressed by the price cap varies between suppliers. We note that the proportion of detriment addressed by the price cap varies between 67% and 83%. This variation reflects the variation in stringency of the cap (relative to measured detriment¹⁶⁶) for different fuel types and regions and each mix of customers.

14.317 As discussed in paragraph 14.268, based on a notional supplier used to calculate the competitive benchmark bills which inform the cap, it is possible for an efficient supplier to achieve an earnings before interest and tax (EBIT) margin of around 5% across all prepayment customers if pricing at the level of a price cap with headroom of £15 per fuel.

14.318 We have also conducted an analysis of the impact of the price cap on suppliers and customers. Whereas the analysis of detriment above is based on median customer energy consumption, the analysis below is based on mean customer energy consumption.

14.319 In financial year 2014, EBIT generated by the Six Large Energy Firms from their domestic supply was £1,193 million. With an impact of £316 million, the domestic supply EBIT of the Six Large Energy Firms would reduce to £877 million, a reduction of 26%.

Figure 14.22: Price cap impact on suppliers versus 2014 domestic supply EBIT (30 June 2015, £15 headroom per fuel, mean customer energy consumption)

[✂]

Source: CMA analysis.

¹⁶⁵ Assessing the supplier impact based on mean customer energy consumption at 30 June 2015 would give a supplier revenue reduction of £316 million a year. We note the difference in impact estimate resulting from use of either the mean or median consumption. We use the median consumption when assessing the proportion of detriment addressed by the price cap remedy, consistent with the use of median in calculating the detriment. We use the mean consumption when looking at impacts on suppliers and customers.

¹⁶⁶ See Figures 14.7–14.11.

14.320 The graph shows the variation in the level of revenue reduction expected for each supplier. We note that this is due to the variation in customer mix as well as the absolute number of customers each supplier has. [REDACTED]

14.321 We have outlined the approximate impact of the price cap on the Six Large Energy Firms' 2014 domestic supply EBIT as a percentage of their revenue generated from domestic supply in 2014 in the table below.

Table 14.21: Price cap impact on suppliers' 2014 domestic supply EBIT (30 June 2015, £15 headroom per fuel)

	<i>2014 domestic supply revenue (£m)</i>	<i>2014 domestic supply EBIT (£m)</i>	<i>2014 domestic supply EBIT percentage (%)</i>	<i>2014 domestic supply adjusted EBIT (£m)</i>	<i>2014 domestic supply adjusted EBIT percentage (%)</i>
Centrica	[REDACTED]	[REDACTED]	[REDACTED]	[REDACTED]	[REDACTED]
EDF Energy	[REDACTED]	[REDACTED]	[REDACTED]	[REDACTED]	[REDACTED]
E.ON	[REDACTED]	[REDACTED]	[REDACTED]	[REDACTED]	[REDACTED]
RWE	[REDACTED]	[REDACTED]	[REDACTED]	[REDACTED]	[REDACTED]
Scottish Power	[REDACTED]	[REDACTED]	[REDACTED]	[REDACTED]	[REDACTED]
SSE	[REDACTED]	[REDACTED]	[REDACTED]	[REDACTED]	[REDACTED]
Total Six Large Energy Firms	[REDACTED]	[REDACTED]	[REDACTED]	[REDACTED]	[REDACTED]

Source: CMA analysis.

14.322 The price cap will also apply to Mid-tier Suppliers and smaller suppliers and will therefore result in revenue reductions outside of the Six Large Energy Firms. Although detriment has not been explicitly calculated for suppliers outside of the Six Large Energy Firms, as the price cap is calculated on the basis of the competitive benchmark bill, which incorporates an EBIT margin of 1.25% plus headroom of £15 per fuel, any reduction in other suppliers' revenue will by definition correspond to a reduction in the detriment existing within these suppliers' returns on their prepayment customer base.

14.323 In this regard the price cap would not treat the prepayment customer base of the Mid-tier Suppliers and the independent suppliers any differently from the prepayment customer bases of the Six Large Energy Firms. In customer bill terms, the reductions that would be felt in the revenues of the Six Large Energy Firms, the Mid-tier Suppliers and other suppliers would be smaller than the detriment levels which we have observed. We thus expect that any revenue reduction would still result in per customer revenues in excess of efficient prices, and so all suppliers should be able to supply at a profit in the prepayment segment. We consider that this is appropriate to allow for competition in the prepayment segments.

14.324 Given the focus of the Mid-tier Suppliers on the direct debit segments, revenue from prepayment customers reflects a relatively low proportion of total revenue of the Mid-tier Suppliers, although we have noted that some smaller suppliers have gained market share in the prepayment segments.

14.325 Of the smaller suppliers, Utilita has the largest share of the prepayment segments, with a total of 186,000 customers and total revenue of approximately £144 million.¹⁶⁷ We note, given Utilita's high proportion of prepayment customers, that the price cap may have a significant impact on this supplier's revenue. We therefore consider that other suppliers will be no more severely affected by the price cap.

14.326 Utilita reported EBIT for the year ended 31 March 2015 of £10.7 million (7.5%),¹⁶⁸ which is substantially in excess of the reasonable EBIT margin estimated as part of our competitive benchmark analysis of 1.25%.¹⁶⁹ We have estimated the impact of the price cap on Utilita using its average customer consumption of [X] kWh and [X] kWh a year for gas and electricity respectively¹⁷⁰ and average tariff rates at 30 June 2015.¹⁷¹ This analysis suggests that if the price cap had been in place in 2014/15, Utilita would have [X]; resulting in a revised EBIT margin of between [X]% and [X]%.¹⁷² We have also reviewed the projected impact for 2016 using Utilita's management account information. That review suggests that the impact in 2016 would be comparable to that which we estimated for 2015.

14.327 The fact that Utilita, which is focused almost exclusively on prepayment customers and growing very rapidly, would still earn a reasonable profit after application of the cap provides further support for our view that, while we have substantially reduced prepayment customer detriment, the level of the cap will allow suppliers to continue to operate profitably and compete.¹⁷³

Sunset provision and mid-term review

14.328 We have also considered the need for a sunset clause to ensure the duration of the price cap is both certain to the industry, and to ensure it is a proportionate remedy. Respondents to the Remedies Notice expressed a strong preference to ensure that any price cap was transitional and had a clearly defined sunset clause. There were also differing views on whether

¹⁶⁷ Source: Utilita Energy Limited statutory accounts for the year ended 31 March 2015.

¹⁶⁸ Source: Utilita Energy Limited statutory accounts for the year ended 31 March 2015 and PWC submission on behalf of Utilita in response to the post-provisional decision on remedies energy market investigation data room.

¹⁶⁹ See Section 10.

¹⁷⁰ Utilita consumption distribution provided on 28 April 2016.

¹⁷¹ This is based on a simple average of regional unit rates and standing charges outlined within the Energylinx data-set, assuming all Utilita customers are on the 'Smart energy' tariff.

¹⁷² We consider that the price cap is still effective even though it allows Utilita to generate EBIT margins in excess of 1.25% since our analysis of impact suggests that customers will still benefit from lower annual bills.

¹⁷³ As previously noted, Utilita makes extensive use of smart meters and this may confer a cost benefit relative to suppliers who predominantly use dumb meters. We note that the option of using smart meters is open to all suppliers and as the smart meter roll-out progresses smart metering will become the default option. See Appendix 10.1 for further analysis of the impact of rapid growth on the profitability of energy suppliers.

the exit should be linked to the roll-out of smart meters. We have carefully considered these concerns in the scoping and design of the price cap.

- 14.329 Respondents to the provisional decision on remedies also commented on the sunset provision. There was broad consensus that it was desirable to have certainty as to the end date of the price cap though views differed on the extent to which the provisional decision on remedies proposal provided certainty on the actual end date of the price cap. EDF Energy and SSE suggested that the price cap be sunset on a per customer basis as smart meters were installed. SSE also suggested that any sunset clause should also make provision both for circumstances where there was clear evidence of the price cap having an adverse effect on competition and where changes in government policy regarding support for vulnerable customers made the price cap inappropriate. Citizens Advice noted the possibility that the smart meter roll-out might be slower than anticipated.
- 14.330 The PPM Price Cap Remedy is intended to be transitional as we expect that, as the national programme for the roll-out of smart meters reaches substantial completion and our other remedies take effect over time to allow and incentivise suppliers to compete more effectively for new prepayment customers and prepayment customers' engagement levels increase, the detriment suffered by prepayment customers will fall.
- 14.331 In particular, it is our view that widespread adoption of smart meters will eliminate the technical constraints on suppliers' ability to offer prepayment customers any number of tariffs, including tariffs that are equivalent to those on offer to customers on direct debit.¹⁷⁴ It will also make it possible to switch customers remotely (at little or no cost) to a credit tariff with a smart meter. It follows that, following substantial completion of the roll-out of SMETS 2 smart meters, the tariffs on offer to prepayment customers should be constrained by those that are on offer to customers on direct debit (or other low-priced tariffs in the markets). SMETS 2 meters will reduce costs to acquire and to serve prepayment customers, therefore increasing suppliers' incentives to compete in the prepayment segments. We also expect prepayment customers to be engaging more frequently, and more effectively, as our remedies concerning the Domestic Weak Customer

¹⁷⁴ As described in Section 9, dumb prepayment meters have a limited number of tariff slots which restrict the number of tariffs that can be offered. We understand that there is no such restriction applying to smart meters. Prepayment customers can already request a smart meter but may view any associated cost as a marginal cost caused by the switch (or, at least, a perception of a cost). This switching cost could therefore deter customers seeking out the most competitive prices when these are only available to customers with a smart meter. Smart meters can work in prepayment or credit mode. The smart meter roll-out will result in all customers having a smart meter such that there is no incremental cost in switching to another tariff.

Response AEC take effect (and we note that smart meters will facilitate customers' engagement, therefore increasing the effectiveness of our engagement remedies).

- 14.332 Further, there will be little or no inherent difference in the cost to serve prepayment customers relative to direct debit customers once the roll-out of smart meters has been substantially completed as all such customers will be using the same metering infrastructure.¹⁷⁵ This in turn should contribute to strengthen suppliers' incentives to compete to acquire prepayment customers.
- 14.333 For the above reasons, we have decided to include a sunset provision for the price cap that is linked to the roll-out of smart meters being substantially completed.¹⁷⁶
- 14.334 As noted in Appendix 8.4 and Section 11, the roll-out of smart meters to domestic customers¹⁷⁷ is due to be completed by the end of 2020. We expect that by 31 December 2020 the supply of energy to domestic prepayment customers will have evolved significantly as a result of:
- (a) our other remedies concerning promoting customers' engagement; and
 - (b) the roll-out of smart meters with the improved functionality.
- 14.335 Hence we do not expect that these customers will still suffer from the Domestic Weak Customer Response AEC or Prepayment AEC or associated detriment to an extent which would justify the continuation of any price cap.
- 14.336 This approach to terminating the PPM Price Cap Remedy provides certainty to suppliers, customers and other key stakeholders including government, Ofgem, consumer bodies and investors in the energy sector. We believe this is particularly important in facilitating suppliers' longer-term decisions such as deciding to innovate. This certainty is also beneficial for customers as it

¹⁷⁵ As described in paragraph 14.16 current prepayment meter tariff prices are above the level we would expect if there were effective competition in the prepayment segments. While the increased costs to serve associated with prepayment meters are a contributing factor to higher prepayment tariffs, we have observed that they are not currently driving prepayment meter tariff prices.

¹⁷⁶ For the avoidance of doubt, the PPM Price Cap Remedy will terminate on 31 December 2020. It is this choice of date which is linked to the roll-out of smart meters.

¹⁷⁷ Suppliers are under an obligation to take all reasonable steps to ensure that a smart metering system is installed on or before 31 December 2020 at each domestic premise and most microbusiness (profiles 3 & 4) it supplies.

makes the workings of these segments of the domestic retail energy markets more transparent.

14.337 We note in Section 11 that there is some inherent uncertainty over exactly when the roll-out of smart meters in the domestic retail energy markets will be completed. Accordingly, while we would propose to incorporate a sunset provision into the PPM Price Cap Remedy that is linked to the current forecast of the successful completion of the roll-out of smart meters, we also propose to conduct a focused mid-term review in January 2019¹⁷⁸ of the progress that has been made concerning the roll-out of smart meters.¹⁷⁹ In the event that the roll-out of smart meters were materially ahead of schedule, we would consider whether to terminate the price cap early (ie an early termination provision would be included).

14.338 In the event that, at the date of the mid-term review, the roll-out of smart meters does not appear likely to be completed by 31 December 2020, we would consider whether to encourage Ofgem to review the situation and take whatever action it considers appropriate (including whether to introduce a similarly structured price cap in the prepayment segments as from the start of 2021). We believe that this approach is more proportionate than extending the PPM Price Cap Remedy for a further specified period. While this creates some uncertainty about the possibility of a price cap being in place beyond 2020, this uncertainty is narrowed to the issue of the extent of roll-out.

14.339 We note the link between the sunset provision and the scope of the price cap. Customers with SMETS 2 smart meters will be outside of the price cap. Since there are currently no SMETS 2 meters installed there will be a gradual process of customers leaving the scope of the price cap as the smart meter roll-out progresses.

14.340 We noted in the provisional decision on remedies that it would be unduly onerous to monitor compliance if customers who had refused smart meter installation were excluded from the scope of the price cap. We maintain this view and therefore customers who refuse¹⁸⁰ installation of a SMETS 2 smart meter will remain protected by the price cap.

¹⁷⁸ January 2019 is suggested as the date for this mid-term review as the approximate midpoint between the potential commencement of the PPM Price Cap Remedy in April 2017 and the termination of the remedy in December 2020.

¹⁷⁹ We believe it is the installation of SMETS 2 meters which is relevant to our assessment of the ongoing need for a price cap as these have features such as interoperability which are necessary to realise the full benefits of smart metering.

¹⁸⁰ We use the term 'refuse' though recognise that in practice there could be a range of reasons why a person may not have a smart meter installed when they are offered one.

Implementation, monitoring and enforcement

14.341 We have considered how the PPM Price Cap Remedy would be implemented, monitored and enforced.

The means of implementing the remedy

14.342 The operation and implications of the remedy need to be clear to the persons to whom the remedy is directed as well as to other interested parties, ie to affected suppliers and to Ofgem.¹⁸¹

14.343 We are implementing the PPM Price Cap Remedy by way of an order on suppliers. In addition, and for the purposes set out below, we believe it is appropriate to modify, by way of an order, the gas and electricity supply standard licence conditions, with a view to introducing an obligation to comply with the PPM Price Cap Remedy.

14.344 As regards enforcement, the CMA will be able to directly enforce against the order. Ofgem, as energy regulator, has a duty to monitor suppliers' compliance with the licence condition and the power to sanction any contravention of a standard licence condition (including by imposing penalties up to 10% of the contravening supplier's turnover).¹⁸² We would expect that resolution of any non-compliance will involve suppliers issuing a rebate to customers who had previously paid tariffs which were in excess of the price cap. The suitable course of action will, however, be a matter for Ofgem to decide, based on the relevant facts and circumstances.

14.345 Ofgem will have an additional role in determining the updated level of the price cap, as set out in the relevant suppliers' licence conditions. This will involve Ofgem collecting information relating to each of the cost indices¹⁸³ and using these to calculate the updated price cap level in line with methodology specified in the licence. This process would be mechanical and objective.

14.346 To aid understanding of the possible impact of our final decision we are publishing an illustrative price cap model (the 'illustrative model') alongside

¹⁸¹ As regards affected customers, we believe that only the key implications of the remedy must be clear to them but it would be a matter for suppliers and Ofgem to determine how to inform these customers appropriately. In practice, while the remedy will have practical benefits for customers, it will not require any direct involvement from customers.

¹⁸² See paragraph 14.359.

¹⁸³ This information would come from the Office for Budget Responsibility, ICIS Heren, the Office for National Statistics and network company charging statements.

our final report.¹⁸⁴ The illustrative model illustrates how the price cap would be calculated and updated in each region, for each fuel and for each period. We plan to consult on this illustrative model with a view to developing it further into a model which can be used to ultimately calculate the price cap level for each update.

Timescale for the implementation of the PPM Price Cap Remedy

14.347 Subsequent to implementation of the final order, we expect that suppliers will need a period of at least two months to make any practical changes such as updating prices and informing their customers.

14.348 We consider that it is desirable to align the price cap periods with the seasonal products for wholesale electricity and the usual pricing update days of 1 April and 1 October. This allows suppliers to better manage their wholesale purchasing under the price cap and to make price changes as described in paragraphs 14.158 to 14.160. Therefore the first price cap will apply from 1 April 2017 and will be updated every six months as shown in the table below.

Table 14.22: Summary of price cap update timings

<i>Date new level of price cap determined</i>	<i>Start of price cap period</i>	<i>End of price cap period</i>
1 February	1 April	30 September
1 August	1 October	31 March (following year)

Source: CMA.

Assessment of effectiveness

14.349 We believe that our prepayment remedies¹⁸⁵ and engagement remedies¹⁸⁶ will help improve the conditions for competition in the prepayment segments. However, in view of the strength of the features contributing to the Domestic Weak Customer Response AEC as they apply to prepayment customers, we are concerned that the engagement remedies will take time to mitigate materially the detriment that affects prepayment customers (while we expect these remedies to impact other segments in a timelier manner). Similarly, we note that certain supply-side features specific to the prepayment segments, may not be fully addressed until smart meters have been substantially rolled

¹⁸⁴ The illustrative model does not form part of our final report and does not alter any aspect of the final report. In the event that there is any inconsistency between the meaning contained in the final report and that implied by the illustrative model then the meaning in the final report shall prevail.

¹⁸⁵ See Section 5.

¹⁸⁶ See Section 6.

out (which is scheduled for the end of 2020).¹⁸⁷ As noted in Section 15, while we believe that our prepayment remedies and engagement remedies¹⁸⁸ will help improve the conditions for competition, including in the prepayment segments, we have come to the conclusion that, on their own, these remedies will not fully address the levels of detriment we have identified for prepayment customers before the roll-out of smart meters is substantially completed.

14.350 As a result, given the size of the detriment we have observed, we have considered the need to intervene to address domestic customer detriment directly in this transitional period, through the PPM Price Cap Remedy.

14.351 We consider that, for the reasons set out in this section and summarised below, the PPM Price Cap Remedy would be effective in achieving this aim. In summary we believe that the PPM Price Cap Remedy would be effective as the design specifies a base level which is derived from the level of detriment we observe¹⁸⁹ and the indexing mechanism has been designed to result in the price cap remaining at a level which is both sustainable (in terms of allowing suppliers to recover their efficient costs plus a reasonable profit margin) and which mitigates the detriment.¹⁹⁰

14.352 We expect that the principal benefit of this remedy will be the reduction in customer bills. The size of this impact relative to each supplier's revenue varies significantly across suppliers as prepayment customers make up a larger proportion of the customer base for some suppliers than others. We estimate that the PPM Price Cap Remedy could reduce customer bills as shown in table below.

Table 14.23: Summary of average of the Six Large Energy Firms' prepayment customers' annual savings compared to detriment by fuel/meter combination (30 June 2015), £15 headroom

	<i>Average saving</i>	<i>Detriment</i>
Dual fuel, single rate meter	£66	£100
Dual fuel, Economy 7	£125	£188
Single fuel electricity, single rate meter	£29	£43
Single fuel electricity, Economy 7	£87	£95
Single fuel gas, single rate meter	£50	£51

Source: CMA analysis.

¹⁸⁷ See Section 4 for further consideration of the timescales over which we expect our remedies to remedy the detriment.

¹⁸⁸ See Section 13.

¹⁸⁹ See paragraphs 14.103–14.131.

¹⁹⁰ See paragraphs 14.132–14.245.

14.353 We consider that these savings are appropriate as prevailing prepayment tariff prices on 30 June 2015 appear to be of the order of £100¹⁹¹ more expensive than the competitive benchmark direct debit dual fuel single rate meter tariff prices, allowing for a cost-to-serve differential. In customer bill terms, these reductions are smaller than the detriment levels which we have observed.¹⁹² We thus expect that supplier revenue reductions resulting directly from the price cap would still result in per customer revenues in excess of efficient cost.

14.354 We note that building in headroom necessarily reduces the extent to which the cap will lower prices to customers. However, the results shown in table 14.23 suggest that customers would benefit from a significant reduction in their annual bill, and in our view the inclusion of headroom within the price cap is appropriate for the reasons discussed in paragraphs 14.124 to 14.132 above.

14.355 In assessing the effectiveness of the remedy we have in particular considered the following factors:

- (a) the extent to which the remedy is capable of effective implementation, monitoring and enforcement;
- (b) the timescale over which the PPM Price Cap Remedy is likely to have an effect;
- (c) compliance with existing laws and regulations; and
- (d) its interaction with our other remedies.

Implementation, monitoring and enforcement

14.356 For the reasons set out in paragraphs 14.342 and 14.343, we are implementing the price cap by way of an order on suppliers and associated licence conditions changes that will facilitate monitoring, enforcement and updating of the price cap. We consider that implementing the price cap by way of an order and associated licence conditions changes will provide a higher degree of certainty over the timing of implementation, in particular given that the base price cap would be set on the basis of analysis that has already been conducted by the CMA (set out in Section 9).

¹⁹¹ This figure of £100 is the level of detriment for a dual fuel single rate meter prepayment customer at their average actual level of consumption. The figure set out in paragraph 14.18 represents the level of detriment that a dual fuel single rate meter prepayment customer would face at Ofgem's medium TDCV.

¹⁹² See discussion in paragraphs 14.250–14.275 regarding the size of the single fuel gas detriment.

- 14.357 In this regard, we have noted above that we consider that the PPM Price Cap Remedy is capable of being in force from 1 April 2017. The price cap would be determined upon publication of a final order by the CMA, at least two months ahead of the date the price cap would come into effect in order to give suppliers sufficient time to assess compliance of their tariff offers and make changes as necessary. Each supplier would have to assess compliance of its prepayment tariffs with the PPM Price Cap Remedy as described in paragraph 14.78. A tariff will be compliant if the structure of charges is such that for any consumption level the projected customer bill is no more than the level specified by the price cap.
- 14.358 In this way suppliers would be able to take steps to ensure they are compliant from the outset and can remain compliant throughout the relevant period.
- 14.359 Similarly, the process for updating the level of the cap (in line with the movement of the exogenous indices) will be objective, with the update being introduced into the price cap by Ofgem following a mechanical process.¹⁹³ We expect that Ofgem, as sector regulator, will monitor compliance with the relevant licence conditions by reviewing tariffs on offer. The information needed to assess compliance in this way would be the publically available information about the standing charge and unit rate of each domestic prepayment tariff.
- 14.360 The method for assessing compliance would be entirely objective as the projected level of the customer bill could be readily calculated and compared to the price cap at all consumption levels. We therefore consider that it would be practical for Ofgem (and the CMA) to monitor compliance with this remedy.
- 14.361 Enforcement of the order and/or the licence conditions could be led by the CMA or Ofgem as appropriate, or by any third party who suffered a loss as a result of a contravention of the order.

Timescale for the PPM Price Cap Remedy

- 14.362 In evaluating the effectiveness of the remedy, we have considered the timescale over which the Domestic Weak Customer Response AEC and the Prepayment AEC would be expected to endure, and the timescale over which the remedy would be likely to take effect (see Appendix 11.1 and Section 15). As noted, we believe that this consideration is of particular

¹⁹³ See paragraphs 14.87 & 14.88 for further details.

importance for this remedy as the price cap would only be in place as a transitional measure pending development of effective competition for prepayment customers. We expect that this will develop over the period to the end of 2020, once the roll-out of smart meters has been substantially completed.

- 14.363 As noted in paragraph 14.37 above, given the magnitude of the detriment being suffered by prepayment customers from the Prepayment AEC and the Domestic Weak Customer AEC, which will take time to be addressed by our remedies and the roll-out of smart meters, timely implementation is a key criterion for the price cap. We consider that there is a trade-off between implementing a remedy which can be effective in the short term versus taking a longer period of time to develop a remedy which may more precisely track costs. We note that these considerations apply not only to the initial implementation of the remedy but also to ongoing updates.
- 14.364 As noted above, the PPM Price Cap Remedy will be in force be effective from April 2017.^{194,195} As a result, it will be effective in achieving its aim of mitigating the detriment arising from the Domestic Weak Customer Response AEC and Prepayment AEC in the short term.

Compliance and consistency of the PPM Price Cap Remedy with existing laws and regulations

- 14.365 As part of our assessment of the effectiveness of the PPM Price Cap Remedy and the approach we have taken to some of the detailed design components, we have taken into account the need for the PPM Price Cap Remedy to comply with relevant laws and regulations. A particular focus of our assessment of this aspect has been the interaction of the PPM Price Cap Remedy with existing standard licence conditions and relevant EU legislation (in particular Directive 2009/72/EC¹⁹⁶ concerning electricity supply (the 'Electricity Directive'), and Directive 2009/73/EC¹⁹⁷ concerning gas

¹⁹⁴ As described in paragraphs 14.347 & 14.348.

¹⁹⁵ Suppliers may reduce their prices in anticipation of the price cap so as to avoid a negative public perception of their prices being excessive. In such circumstances the price cap remedy may be considered to be effective prior to its implementation rather than simply not being effective at all. We note that the distinction between effective prior to implementation and ineffective is hard to draw as there may not be a clear indication of the motivation for lowering prices so it may be argued that any such price decrease was caused by something other than the price cap remedy.

¹⁹⁶ Directive 2009/72/EC of the European Parliament and of the Council of 13 July 2009 concerning common rules for the internal market in electricity and repealing Directive 2003/54/EC (which contained a similar provision to Article 3(2)).

¹⁹⁷ Directive 2009/73/EC of the European Parliament and of the Council of 13 July 2009 concerning common rules for the internal market in natural gas and repealing Directive 2003/55/EC (which contained a similar provision to Article 3(2)).

supply (the 'Gas Directive') (collectively, the 'Energy Directives'), and case law.

14.366 Our assessment of effectiveness of the PPM Price Cap Remedy has assessed compliance with the requirement concerning the charges for different payment methods included in SLCs 22B.7 (a) and SLC 27.2A, ie suppliers must ensure that any differences in charges between payment methods are cost reflective.¹⁹⁸ We understand that SLC 27.2A prohibits suppliers from applying a tariff to prepayment customers that means they are charged more than non-prepayment customers (after allowing for differences in costs) on the same tariff, but does not prevent suppliers from applying a lower payment differential.¹⁹⁹ Therefore, to the extent that the PPM Price Cap Remedy imposes a maximum annual bill that suppliers can charge to prepayment domestic customers, we consider that the PPM Price Cap Remedy would not lead to suppliers being in breach of SLCs 22B.7 (a), SLC 27.2A and the Energy Directives. In addition, we do not consider that our price cap remedy would result in a cap on the prices of non-prepayment tariffs.

14.367 In addition, we have considered compliance of the PPM Price Cap Remedy with (i) Article 3(2) of the Energy Directives; and (ii) the judgment of the Court of Justice delivered on 20 April 2010 in the *Federutility* case (the 'Federutility Judgment').²⁰⁰

14.368 A number of respondents made comments in relation to the Federutility Judgement. Centrica and SSE responded to the provisional decision on remedies suggesting that the price cap did not meet the Federutility criteria. RWE and Spark Energy responded to the provisional decision on remedies suggesting that annual reviews of the price cap were required. Our assessment of how the Federutility Judgement applies to the PPM Price Cap Remedy remains as set out in the provisional decision on remedies, and is repeated below.

14.369 Article 3(2) of the Energy Directives allows EU member states to price regulate through the imposition of public service obligations on companies operating in the electricity and gas sectors, and broadly sets out the requirements that the public service obligations must fulfil to be compatible

¹⁹⁸ This requirement is underpinned by the Energy Directives (Annex I 1(d)).

¹⁹⁹ Ofgem's open letter dated 20 May 2014 and Ofgem's guidance dated 17 December 2009. We understand that this interpretation of SLC 27.2A is consistent with the Energy Directives.

²⁰⁰ Case C-265/08, *Federutility and others v Autorità per l'energia elettrica e il gas*, [2010] ECR I-3377. As part of our assessment, we have also considered the Court of Justice judgment delivered on 10 September 2015 in the *Commission v Poland* case, Case C-36/14, which broadly upheld the Federutility Judgment.

with EU law. The Federutility Judgment sets out additional criteria that a national retail price regulation measure under Article 3(2) of the Energy Directives must satisfy, including the following conditions:²⁰¹

- (a) the public service obligation must be adopted in the general economic interest;
- (b) the public service obligation had to be necessary to achieve the objective in the general economic interest; and
- (c) the public service obligation must be clearly defined, transparent, non-discriminatory, verifiable, and must guarantee equal access for EU gas companies to consumers.

Adopted in the general economic interest

14.370 We note that services of a general economic interest capture a wide range of services.²⁰² The domestic retail supply of gas and electricity, in particular, have each been identified as being in the general economic interest by EU case law,²⁰³ legislation²⁰⁴ and guidance from the European Commission.²⁰⁵ We also note that the Energy Directives²⁰⁶ impose an obligation on member states to ensure that customers are supplied with gas and electricity at reasonable prices.

14.371 In this regard, we note that the ultimate aim of the PPM Price Cap Remedy is to ensure that the prices for the retail supply of gas and electricity to domestic prepayment customers in Great Britain are affordable (or, in other words, maintained at a reasonable level). The PPM Price Cap Remedy is designed to do so by mitigating the harm to domestic prepayment customers that we consider arises and will continue to arise from the Prepayment AEC and the Domestic Weak Customer Response AEC while our remedies concerning the prepayment framework, and concerning domestic customer

²⁰¹ While the Federutility Judgment focused on Article 3(2) of Directive 2003/55 concerning gas, this Article is identical to Article 3(2) of the Gas Directive, and almost identical to Article 3(2) of the Electricity Directive. Accordingly, the Federutility criteria applies to Article 3(2) of both directives.

²⁰² Subject to EU legislation, EU member states are generally free to determine those services which they consider to be of the general economic interest, Communication from the Commission 'Services of general interest in Europe' (OJ 2001 C 17, p. 4), paragraph 22.

²⁰³ The ECJ has held a large and varied group of services to be of general economic interest in utilities industries, including the supply of gas (eg Case C- 159/94 *Commission v France* [1997] ECR I- 5815), and electricity (eg Case C- 393/92 *Municipality of Almelo and Others* [1994] ECR I- 1477).

²⁰⁴ Article 3(2) of the Energy Directives, including a reference to Article 106 of the Treaty.

²⁰⁵ For example, Communication from the Commission to the European Parliament, the Council, the European Economic and Social Committee and the Committee of the Regions '[A Quality Framework for Services of General Interest in Europe](#)', 20 December 2011.

²⁰⁶ Recitals 45 and 50 and Article 3(2) of the Electricity Directive, and recital 43 of the Gas Directive.

engagement more generally, take effect, and until the roll-out of smart meters has been substantially completed. In particular, we envisage that the PPM Price Cap Remedy will reduce the prices being paid by prepayment customers and reduce the highest of them²⁰⁷ to the level of a cost-adjusted benchmark level based on competitively priced acquisition tariffs in the rest of the domestic markets (see paragraph 14.58) plus headroom.

14.372 Accordingly, we consider that the aim of the PPM Price Cap Remedy, of ensuring reasonable prices in relation to the supply of gas and electricity to PPM customers, is consistent with the Energy Directives and being adopted in the general economic interest.

Necessary to achieve the objective in the general economic interest

14.373 In addition to being adopted in the general economic interest, we have considered whether the PPM Price Cap Remedy would go no further than necessary to achieve the objective in the general economic interest. Save as noted below, we consider that our usual proportionality assessment, following the criteria set out in the CMA's guidelines for market investigations,²⁰⁸ is consistent with this general requirement (see paragraphs 14.381 to 14.465 below). In addition, we have had particular regard to ensuring that the scope of the PPM Price Cap is justified by reference to the domestic customer segments that will be protected by this measure, and to ensuring the PPM Price Cap Remedy would be limited in time, and subject to a mid-term review.

14.374 As set out in section 11, we have assessed the application of a broader price cap across all SVT customers. While we note that SVT customers will also suffer detriment during the transitional period, the PPM Price Cap Remedy will address particularly high detriment arising in part from a set of specific technological constraints that have impeded competition, and will involve less risk of undermining the competitive process in the long run than a broader price cap. Accordingly, we consider that the PPM Price Cap Remedy is justified in terms of its scope.

14.375 As part of our assessment of the effectiveness of the PPM Price Cap Remedy, which takes into account the need to apply a sunset clause, we have considered how long the Prepayment AEC (and the resulting detriment) could be expected to persist and, accordingly, how long

²⁰⁷ We consider that our other remedies should enable competition to take place below the level of the price cap.

²⁰⁸ CC3.

prepayment customers will need to be protected by the PPM Price Cap Remedy (see paragraphs 14.328 to 14.340 above).

14.376 We consider that smart meters, in combination with our other remedies concerning the Prepayment AEC and domestic customer engagement, will change the competitive dynamic in the prepayment segments, and more broadly across the domestic retail energy markets, and the way that customers and suppliers interact. As a result, we believe that the PPM Price Cap Remedy will no longer be required once smart meter roll-out has been concluded by the end of 2020 (by which time our other remedies would also be taking, or have taken, effect) (see paragraphs 14.328 to 14.340 above). Accordingly, our remedy will expire on 31 December 2020 to coincide with the scheduled substantial completion of smart meter roll-out. We have also excluded SMETS 2 meters from the scope of the price cap.

14.377 As noted in Section 11, we note that there is some inherent uncertainty over exactly when the roll-out of smart meters in the domestic retail energy markets will be completed, and so it is possible that smart meter roll-out could be substantially completed ahead of 31 December 2020. It is also possible that the smart meter roll-out may fall behind schedule such that it is not complete by 31 December 2020. If the smart meter roll-out falls behind schedule it is possible that the Prepayment AEC, and the Domestic Weak Customer Response AEC may persist beyond 31 December 2020. Accordingly, while we have incorporated a sunset provision into the PPM Price Cap Remedy that is linked to the successful completion of the roll-out of smart meters, we also propose to conduct a focused mid-term review in January 2019²⁰⁹ of the progress that has been made concerning the roll-out of smart meters.

Must be clearly defined, transparent, non-discriminatory, verifiable, and guarantee equal access

14.378 We consider that these considerations are broadly consistent with our usual effectiveness and proportionality assessment when deciding upon any given remedy.

14.379 Our assessment of effectiveness of the PPM Price Cap Remedy (see paragraphs 14.356 to 14.361 above) has taken into account the need to be capable of implementation, monitoring and enforcement, which all require

²⁰⁹ January 2019 is suggested as the date for this mid-term review as the approximate midpoint between the potential commencement of the PPM Price Cap Remedy in April 2017 and the termination of the remedy in December 2020.

that the PPM Price Cap Remedy is clearly defined, transparent, and with a verifiable scope.

14.380 Our design of the PPM Price Cap Remedy takes into account the requirement to be non-discriminatory and guaranteeing equal access. In this context, we have considered the likely impact of the PPM Price Cap Remedy on suppliers and note, in this regard, that the PPM Price Cap Remedy would treat all suppliers' prepayment customer bases in the same way, and would treat all companies serving prepayment customers in the same way.

Assessment of proportionality

14.381 We assess the proportionality of our remedies in line with the criteria set out in our guidance²¹⁰ which states that a proportionate remedy is one that:²¹¹

- (a) is effective in achieving its legitimate aim;
- (b) is no more onerous than needed to achieve its aim;
- (c) is the least onerous if there is a choice between several effective measures; and
- (d) does not produce disadvantages which are disproportionate to the aim.

Effective in achieving its aim

14.382 As described in the effectiveness section²¹² we believe that the PPM Price Cap Remedy is likely to be effective in achieving its aim of limiting the prices paid by prepayment customers in the short to medium term while other remedies to the Prepayment AEC and Domestic Weak Customer Response AEC are taking effect, so mitigating the detriment resulting from those AECs during the transitional period (ie until the end of 2020).

14.383 We have also considered other potential impacts on suppliers. We anticipate that suppliers will face some costs associated with implementing the remedy.²¹³ We do not expect these costs to be large as we expect that they will relate only to monitoring compliance and updating tariff prices as necessary to remain compliant.

14.384 We note the risk that the level of the price cap is set too low to allow for recovery of efficient costs. To the extent this risk materialises it would reduce

²¹⁰ CC3.

²¹¹ CC3, paragraph 344.

²¹² See paragraphs 14.349–14.380.

²¹³ See paragraphs 14.436–14.438 for further detail.

revenues by more than the excess which we have observed relative to prices offered on direct debit.

- 14.385 We sought to ensure that the design results in the level of the price cap allowing suppliers to compete beneath the level of the price cap while still earning a normal return on capital, in particular by designing the price cap to take competitive prices in the market²¹⁴ as a starting point, adjusting it with headroom and then setting up an effective update process based on indices tracking the key components of a customer's bill. We have also carefully analysed the options for different indices²¹⁵ and chosen indices which we believe should reliably track the underlying costs. Additionally the existence of headroom mitigates the risk that the level of the cap will be below efficient costs.
- 14.386 We have also considered potential second order effects such as the risk of the PPM Price Cap Remedy distorting incentives. Our assessment of these risks is set out in paragraphs 14.400 to 14.458. In summary we are aware of a number of possible distorting effects and have taken steps to mitigate these risks where possible. We consider that the residual risks are sufficiently small both in terms of likelihood and impact.

No more onerous than needed

- 14.387 We consider that the price cap is the only effective way to deal with the harm to customers which is expected to persist until effective competition develops, supported by our other remedies and the smart meter roll-out.
- 14.388 We consider that the PPM Price Cap Remedy is no more onerous than needed to achieve its aim. We have sought to ensure that it is no more onerous than necessary by limiting the scope (SMETS 2 smart meters are out of scope) and limiting the duration with a fixed termination date.
- 14.389 We have identified two specific respects in which the PPM Price Cap Remedy may be onerous:
- (a) Specifying a maximum level for prices which does not allow reasonable opportunities for the recovery of efficient costs.
 - (b) Imposing costs associated with complying with the price cap, for example costs relating to monitoring and compliance.

²¹⁴ The benchmark is based on the prices offered by Ovo Energy and First Utility. We consider that these tariffs are competitive.

²¹⁵ See 'Cost indexing' section for further detail.

- 14.390 As noted in paragraph 14.385 we have designed the price cap so as to help allow for recovery of efficiently incurred costs. We have also sought to minimise the cost of compliance by assessing compliance on an ex ante basis. This allows for compliance to be monitored on a tariff-by-tariff basis.
- 14.391 We recognise that while this approach minimises compliance costs it may also reduce flexibility and have therefore allowed suppliers to seek derogation from this means of assessing compliance.²¹⁶
- 14.392 Thus we consider that the PPM Price Cap Remedy is no more onerous than necessary to achieve its legitimate aim.

Is the least onerous if there is a choice between several effective measures

- 14.393 We have considered multiple alternative design options, including an external reference price approach which involves setting a cap on prepayment tariffs based on direct debit tariffs in the market, plus an uplift reflecting our assessment of the costs associated with serving prepayment customers.
- 14.394 Our assessment of these alternative options is set out in paragraphs 14.47 to 14.57. In our view, the PPM Price Cap Remedy involving a hybrid reference price and cost index approach is the design that achieves the best balance between practicability, minimising the scope for gaming, accuracy, and our key criterion of being capable of implementation in the near future (in order to maximise its effectiveness).
- 14.395 Accordingly, we consider that, of the multiple alternative design options we have considered, our chosen design option would be the most effective at meeting its aim. We also considered that the external reference pricing approach would be significantly more onerous as it would require suppliers to submit a large volume of data relating to all their tariffs (not just prepayment tariffs) to Ofgem on a regular basis.
- 14.396 We considered too whether it is possible to limit the prices paid by domestic prepayment customers without imposing a price cap. In particular we looked at the possibility of using principles-based regulation to mandate the approach suppliers must take when setting prices for domestic prepayment customers, for example by imposing a cost-reflectivity requirement. We note

²¹⁶ See paragraph 14.82.

that there is already a cost-reflectivity obligation relating to differences in the price charged for different payment methods with the same tariff.²¹⁷

14.397 We considered that a cost-reflectivity obligation is not sufficient to achieve the aims of the PPM Price Cap Remedy since it does not protect customers from the Prepayment AEC should a supplier's high prices reflect inefficient costs. We also believe there is significant scope for such a requirement to be gamed, for example by manipulating internal cost allocation.

Does not produce disproportionate disadvantages

14.398 To assess whether the PPM Price Cap Remedy produces disadvantages which are disproportionate to the aim we have considered the potential impact of the PPM Price Cap Remedy on suppliers and customers. Our assessment of these impacts is detailed above in paragraphs 14.280 to 14.327.

14.399 We have considered the possible unintended consequences of the PPM Price Cap Remedy. In particular we have considered possible unintended impacts on the behaviour of customers and suppliers as described below. In the following paragraphs we note at a high level some of the comments made in response to the provisional decision on remedies. For a comprehensive summary of parties' responses please see Appendix 14.1.

Possibility of reduced customer engagement

14.400 A possible unintended consequence we have identified is that the existence of a price cap would reduce customer engagement. A number of respondents to the provisional decision on remedies also commented on this risk.²¹⁸ Some respondents to the provisional decision on remedies also noted the potential impact on engagement associated with smart meter introduction. EDF Energy suggested that the price cap might weaken incentives to engage upon smart meter installation and Centrica suggested that the price cap would reduce the gains available from smart meter installation.²¹⁹

14.401 The risk is that some customers may feel they benefit sufficiently from the price cap such that there is no need to investigate alternative tariffs in the market. We note that the level of the price cap provides the opportunity for

²¹⁷ This obligation is imposed by SLC 27.2A of the supply licence which was introduced to reflect requirements in EU Directives – Annex A(d) of Directive 2003/54/EC concerning common rules for the internal market in electricity and of Directive 2003/55/EC concerning common rules for the internal market in natural gas.

²¹⁸ BGL Group, RWE, SSE, Utilita – see Appendix 14.1 for further detail of parties' views.

²¹⁹ See Appendix 14.1 for a comprehensive summary of parties' responses.

customers to benefit from switching to a cheaper supplier, thus mitigating the risk that customers do not engage in the market.

- 14.402 We have considered the possible consequences of widespread disengagement among affected customers, ie prepayment customers. Such widespread disengagement may inhibit strong competition from developing in the prepayment segments. We expect that the direct disincentivising effect would be limited to customers on dumb prepayment meters over the life of the PPM Price Cap Remedy. We note that currently there appears to be limited competition in the segments for non-smart prepayment customers and thus the marginal impact of any disincentivisation resulting from the PPM Price Cap Remedy, relative to the current status quo, may be relatively small.
- 14.403 We note that in the counterfactual scenario competition in the prepayment segments may intensify such that the marginal impact of a price cap would be more significant. However, based on the evidence of significant detriment available to us and our assessment of the counterfactual we believe it is appropriate to implement a price cap remedy over the period until 2020.
- 14.404 Beyond the life of the PPM Price Cap Remedy levels of engagement among prepayment customers may remain low if customers have ‘lost the habit’ of engaging in the market. However, we consider that the implementation of our engagement remedies and the introduction of fully functional smart meters is likely to increase, potentially significantly, the levels of engagement, particularly if these attract tariffs below the cap.

Reduced competition for prepayment customers

- 14.405 Another possible unintended consequence may be that suppliers do not attempt to compete in the prepayment segments as strongly or at all as they instead seek to minimise risk by structuring tariffs to align as closely as possible with the price cap. This risk was noted by several respondents to the provisional decision on remedies²²⁰ with some suggesting that suppliers might exit the market.²²¹
- 14.406 Respondents to the provisional decision on remedies also commented on the possibility that the price cap would reduce suppliers’ incentives to offer different sorts of tariffs. Three respondents commented on the possibility of the price cap reducing incentives to offer fixed-term tariffs²²². Centrica also

²²⁰ BGL Group, Centrica, E.ON, RWE, Spark Energy, SSE, Utilita. See Appendix 14.1 for further detail of parties’ views.

²²¹ Centrica, SSE, Utilita.

²²² E.ON, Centrica, RWE.

commented on the risk that the price cap made the prospect of acquiring new prepayment customers less appealing such that PCWs might stop serving prepayment customers and suppliers might be less incentivised to acquire credit customers (as they might later switch to prepayment). E.ON suggested that the price cap could distort incentives to offer attractive smart prepayment tariffs to customers, resulting in reduced offerings.²²³

- 14.407 A comprehensive summary of responses to the provisional decision on remedies can be found in Appendix 14.1.
- 14.408 We consider that it is possible that suppliers would offer tariffs akin to the SVT where the price changes every six months in line with the price cap. We expect that suppliers would be hesitant to offer fixed-term tariffs of more than six months in duration as a means of mitigating the risk that they under-recover costs should the price cap be lowered during the fixed-term tariff period. In this way it seems possible that the price cap may act to reduce the strength of competition in the prepayment segments. Theoretically this could result in prices under the price cap being higher than they would have been in the counterfactual scenario (in which competition develops but no price cap is applied).
- 14.409 However, against the current counterfactual of limited effective competition in the prepayment segments (as evidenced by the substantial detriment we have found), in the short term we would expect that the price cap would be effective at lowering prices. This is consistent with our impact analysis which suggests that the price cap would initially be at a level beneath prices currently in the market and would therefore result in substantial customer savings upon implementation.²²⁴
- 14.410 In the medium term it is possible that prices in such a scenario may be higher than they would be in the counterfactual. That is, prices, when subject to the price cap, could in principle be higher than they would have been if the other remedies concerning the Prepayment AEC and the Domestic Weak Customer Response AEC were introduced but the PPM Price Cap Remedy was not. However, in practice, given the timetable for the possible implementation of the other remedies as compared with the implementation and expected removal of the PPM Price Cap Remedy, and our design of the cap (in particular the exclusion of customers with SMETS 2 meters from the cap) we do not think that there is a significant risk of prices being inflated in the medium term.

²²³ This comment predates our decision to exclude SMETS 2 meters from the cap.

²²⁴ See paragraphs 14.280–14.313.

- 14.411 In response to more general concerns that the price cap could distort incentives (eg for PCWs and in respect of credit customers) we note that the design of the price cap and the allowance for headroom allows for competition to develop. We consider that while suppliers may not compete through fixed-term tariffs as they do at present in the direct debit segments, they would nonetheless be able to compete, for example by offering cheaper variable tariffs. We therefore expect that competition will determine prices in the medium term and therefore that any distortions to incentives are not likely to be material. Additionally, as noted in paragraph 14.445 we expect that direct debit prices will be below the level of the price cap so the price cap is unlikely to distort incentives for direct debit and standard credit customers.
- 14.412 A number of respondents to the provisional decision on remedies suggested that the price cap might act as a focal point for pricing.²²⁵ This risks the price cap increasing prices relative to the counterfactual. We note that upon implementation the price cap is expected to reduce prices. Our analysis of the price cap base level in June 2015 shows that it would, on average, reduce prepayment prices – see paragraphs 14.280 to 14.313 for further detail.
- 14.413 We also note that there is a risk that in the medium term pricing under the price cap could be higher than it would otherwise have been as a result of the price cap acting as a focal point. However, we have sought to ensure that the price cap is compatible with competition by setting the level such that it was generally somewhat above the minimum prepayment tariffs available in the market and excluding SMETS 2 smart meters from the scope of the price cap.

Risk that suppliers attempt to game the cap

- 14.414 We have considered the risk that suppliers attempt to game the cap. We consider that suppliers will not have the ability to game the price cap as the level of the price cap is determined solely with reference to parameters which the suppliers are unable to influence.²²⁶

²²⁵ See Appendix 14.1, paragraph 117.

²²⁶ We note that some of the suppliers are vertically integrated and are part of a corporate group that also owns and operates energy network infrastructure. We note that the RIIO price control regulations stipulate the revenue that these network businesses are allowed to earn and therefore the suppliers are not able to influence this aspect of the price cap even when part of a vertically integrated corporate group.

Risk of suppliers exiting the market

- 14.415 Several respondents to the provisional decision on remedies noted that there was a risk that suppliers might attempt to exit the market in response to the price cap.²²⁷
- 14.416 We acknowledge that there is a risk that under-recovery of costs, or the fear of costs not being recovered, leads some suppliers to seek to exit the prepayment segments. However, condition 22 of the supply licence requires that suppliers provide an offer to supply to any customers that request one (which must include an offer to pay by prepayment meter²²⁸). Thus the only way for a supplier with more than 50,000 domestic customers to completely exit the prepayment segments would be to entirely cease licensed activity and relinquish its supply licence. We consider that the incentives against doing so are strong enough that the likelihood of this outcome is low.
- 14.417 We note that suppliers could attempt to effectively exit the prepayment segments while retaining their licence and remaining compliant. For example, suppliers could avoid taking on new customers by only offering prepayment meter tariffs with onerous conditions such that customers would not choose these tariffs. Suppliers could also seek to sell their existing stock of prepayment customers.²²⁹ We note that existing regulations relating to Standards of Conduct²³⁰ limit the extent to which suppliers can treat existing prepayment customers poorly. A number of respondents to the Second Supplemental Remedies Notice suggested that these regulations would be effective in this regard.
- 14.418 Our expectation is that while the price cap will initially reduce prices, the new level of prices will still be at such a level that profitable competition is possible beneath the level of the cap. Further, our analysis of supplier impact, see paragraphs 14.314 to 14.327, suggests that suppliers would be able to continue to profitably supply and compete below the level of the price cap. Thus we do not expect that suppliers would have significant incentive to exit the market. We also note the scope for a final order to be reviewed on the basis of a material change in circumstance.

²²⁷ Centrica, SSE, Utilita.

²²⁸ When a supplier has more than 50,000 domestic customers. See SLC 27.1 and 27.2.

²²⁹ We have not considered in detail the structure of any such disposal beyond identifying that it would likely be possible to create a new licensed subsidiary which administers all prepayment meter contracts with customers and to then sell this business in its entirety.

²³⁰ Specifically SLCs 7B and 25C of the gas and electricity supply licences specify the standards of conduct to which suppliers must adhere. These conditions require that suppliers treat customers fairly.

Reduced quality of service

14.419 We have considered the possibility that the existence of a price cap could reduce the quality of service received by affected customers. We do not consider that this is a significant risk as suppliers noted in their response to the Second Supplemental Remedies Notice that the Standards of Conduct,²³¹ which suppliers are obliged to deliver, mitigate this risk. One supplier noted, in response to the Second Supplemental Remedies Notice, that the pressure of competition and need to increase or maintain market share would also mitigate this risk. Other suppliers suggested, in response to the Second Supplemental Remedies Notice, that there was a risk that a price cap could result in reduced quality of service but did not provide persuasive arguments to support this view.

Increased perception of regulatory risk

14.420 There is a risk that investors perceive increased regulatory risk in the sector as a result of a price cap being implemented. This perception of greater regulatory risk could result in investors seeking higher rates of return²³² which in turn would increase costs for suppliers and ultimately the prices paid by customers. Several respondents to the provisional decision on remedies noted the risk that the price cap might deter new entry and/or investment in the sector.²³³

14.421 To the extent that investors currently benefit from a weaker level of competition and the consequential elevated prices, the current level of perceived risk in the sector may be lower than it would be if there were robust competition. Thus we do not believe that we should act with the aim of ensuring there is no increased perception of risk.

14.422 We are, however, mindful of the need to act in a rational manner and to avoid increasing the risk, or perceived risk, in the domestic retail energy markets unduly. Accordingly we have sought to mitigate the risk of a number of adverse scenarios (such as the risk of cost under-recovery). Further, we consider that the limited scope of the PPM Price Cap Remedy, the rationale for its introduction, its design and level, the objective nature of the

²³¹ See provisional decision on remedies, [Appendix 7.1](#), Annex B, paragraph 20.

²³² We note that one investor (Invesco Perpetual) responded to the Remedies Notice indicating that increased regulatory uncertainty would likely increase its perception of risk in the sector and, therefore, companies' costs of capital.

²³³ GL Group, RWE, Littlechild et al, SSE, Utilita.

application of the cap, the clearly defined termination date and the limited duration, all act to moderate the extent of any increased perception of risk.

Risk of reduced innovation

- 14.423 Several respondents to the provisional decision on remedies noted the risk that the price cap might act to reduce innovation.²³⁴ EDF Energy and SSE noted that the price cap might limit the application of time-of-use tariffs in the prepayment sector. Ebico and SSE suggested that the price cap could effectively prevent suppliers from offering tariffs with zero standing charges. Similarly, RWE and SSE suggested that the price cap, in the form proposed, could result in suppliers increasing standing charges and Utilita suggested that the price cap could result in pricing increasing to the level of the price cap to the detriment of vulnerable customers.
- 14.424 We acknowledge that there is a risk that suppliers reduce their level of innovation in response to the lower profits available from prepayment customers. Should this happen then it is possible that non-prepayment customers and prepayment customers will suffer negative unintended consequences of the PPM Price Cap Remedy during the time it is in place, and beyond the point at which the PPM Price Cap Remedy is removed.
- 14.425 Pursuant to our remedy to remove aspects of the simpler choices components of the RMR rules,²³⁵ suppliers will have greater scope to innovate in their tariff construction. We consider that since the price cap allows for an EBIT margin of around 5% there is sufficient incentive for suppliers to continue to innovate to win prepayment customers. Where innovation is capable of reducing costs it will be possible for suppliers to achieve larger still EBIT margins.
- 14.426 In response to concerns about the impact of the price cap on standing charges we note that the level of the price cap at nil consumption is defined as the level of average standing charges seen in the market. Suppliers will have the ability to apply to Ofgem for a derogation concerning a particular tariff that, due to its structure, may only comply with the cap at certain levels of consumption. If granted a derogation then compliance for that tariff could be assessed on an ex post basis.²³⁶

²³⁴ Centrica, E.ON, RWE, Spark Energy.

²³⁵ See paragraphs 11.48–11.50 for further detail.

²³⁶ See paragraph 14.82.

- 14.427 This approach allows for suppliers to design innovative tariff structures should they so wish. Thus a supplier would still be able to offer a tariff with nil standing charge.
- 14.428 In response to concerns about the price cap's impact on time-of-use tariffs we note that SMETS 2 smart meters are out of the scope of the price cap.²³⁷ The price cap therefore does not prevent suppliers from offering time-of-use tariffs for SMETS 2 smart meters. Consequently we do not expect the price cap to have any significant impact on the introduction of time-of-use tariffs.
- 14.429 Centrica and SSE responded to provisional decision on remedies commenting on the possible impact of a price cap on suppliers' wholesale hedging strategies. As described in paragraph 14.165 we have developed an approach to indexing wholesale costs which allows suppliers to manage their wholesale risk under the price cap. We note there is a risk that, if many or all suppliers follow the wholesale purchasing approach implicit in the price cap, this could reduce innovation in wholesale hedging.
- 14.430 We consider that this risk is mitigated by the price cap being set at a level which allows for suppliers to profitably compete. We further consider that by designing the price cap to track wholesale cost movements we broadly mimic the incentives suppliers would face in respect of wholesale costs in the absence of a price cap. Finally, we note that the magnitude of this risk is limited by the fact that prepayment customers represent only 16% of customers.

Risk that the price cap becomes permanent

- 14.431 Some respondents to the Second Supplemental Remedies Notice²³⁸ noted the risk that a price cap may become permanent due to the potential negative consequences of removing the cap and possible political pressure to retain the cap. If the PPM Price Cap Remedy were to stay in force indefinitely then it could potentially act to limit the development of competition for prepayment customers with an associated detrimental impact on customers.
- 14.432 In response to the provisional decision on remedies, RWE commented on the possibility that negative impacts upon customer engagement associated

²³⁷ We note that time-of-use tariffs currently exist in the form of Economy 7 and other restricted meter tariffs. In this context we are specifically considering the wider diversity of time-of-use tariffs possible with smart meters. We note that these smart time-of-use tariffs are not currently available and we expect that since SMETS 2 meters are the standard of meter that will form the basis of the smart meter roll-out it will be SMETS 2 meters for which time-of-use tariffs are eventually offered.

²³⁸ See provisional decision on remedies, [Appendix 7.1](#), Annex A, paragraph 19.

with the price cap might persist beyond the 2020 termination of the price cap.²³⁹ Professor Littlechild et al noted that the PPM Price Cap Remedy might increase the likelihood of price caps being applied elsewhere in the energy markets which could in turn harm regulatory certainty.²⁴⁰

14.433 We consider that the PPM Price Cap Remedy is justified due to the specific circumstances that apply to PPM customers.²⁴¹ We consider that since these circumstances apply to PPM customers but not energy customers more generally there is a clear distinction between where a price cap is justified (namely PPM customers) and the rest of the market where it is not. We therefore do not consider there to be a significant risk that the PPM Price Cap Remedy increases the likelihood of price caps being applied elsewhere in the energy sector.

14.434 We note that due to the positive impacts that we believe the PPM Price Cap Remedy is capable of delivering, the removal of these positive impacts at the end of the remedy may be perceived negatively. We believe that this risk is mitigated by the tapering of PPM Price Cap Remedy as smart meters are rolled out. Specifically, customers would cease to be covered by the price cap once they have a SMETS 2 smart meter. This would have two relevant effects:

(a) The removal of the PPM Price Cap Remedy would be objectively determined and its removal could be anticipated by affected customers and suppliers.

(b) The removal of the PPM Price Cap Remedy would coincide with an expected increase in ease with which prepayment customers may engage in the market and switch tariffs. Accordingly we expect that once the PPM Price Cap Remedy is removed, competition for prepayment customers would strengthen further such that the net result of the removal of the PPM Price Cap Remedy would be positive.

14.435 We note that one possible outcome of the mid-term review is that the CMA may decide to recommend that Ofgem take whatever action it considers appropriate (such as introducing a new price cap) from the start of 2021. However, we would only expect to recommend a further price cap in the event that the roll-out of smart meters was materially behind schedule at the time of the mid-term review. In light of the above we do not consider that

²³⁹ See Appendix 14.1 paragraph 133 for further detail on RWE's position.

²⁴⁰ See Appendix 14.1 paragraph 153 for further detail on Littlechild et al's position.

²⁴¹ See paragraphs 14.2–14.25 and Section 11, which contrasts the case for the price cap on prepayment customers with that for a broader cap over all customers on the SVT.

there is a significant risk of the PPM Price Cap Remedy becoming a permanent feature of the market.

Costs and benefits of implementing the price cap

14.436 We have considered the possibility of calculating the net present value for customers of the PPM Price Cap Remedy. We consider that while we have a reasonable estimate of the potential benefit for customers in the short term we lack precision in our estimate of the costs for suppliers. Further, the benefits in the quantum of the medium-term benefits is uncertain as it depends on the extent to which competition develops over this time frame.

14.437 We expect that each supplier would face the costs of collecting and reporting its tariff data to Ofgem and of maintaining a monitoring function to ensure its prices remain compliant. We note too that Ofgem will incur costs in updating the price cap and monitoring compliance. We note that Ofgem's 2014/15 Annual Report and Accounts shows that the total cost of the smarter grids and governance division (ie the part of Ofgem responsible for price controls) was £19.7 million in 2014/15 (and £19.0 million in 2013/14).²⁴² We note too that the Water Industry Commission for Scotland (WICS) spent £0.9 million in 2014/15 (and £1.0 million in 2013/14)²⁴³ on 'determination of prices and monitoring of performance' and that this covered the period in which WICS determined the price control for 2015–2021. Given the scale of Ofgem involvement anticipated in administering the PPM Price Cap Remedy we expect that the incremental cost for Ofgem would be closer to the costs that WICS incurred.

14.438 We estimate that annual savings for customers, assuming medium TDCV for all prepayment customers and headroom of £15 per fuel, could be of the order of £282 million per year. We expect that the monitoring and compliance costs imposed on suppliers by this remedy will therefore not be material relative to the expected benefits for customers.

Other possible unintended consequences

14.439 Several respondents to the provisional decision on remedies commented on the risk that a price cap could reduce the incentives for suppliers to install a prepayment meter with the possible consequence that suppliers face an increased bad debt risk.²⁴⁴ We consider that by setting the price cap at an appropriate level which allows for profitable competition beneath the level of

²⁴² See Ofgem [Annual Report and Accounts 2014-15](#), note 2.

²⁴³ See [WICS resource accounts 2014-15](#), note 3.

²⁴⁴ Centrica, RWE, Utilita.

the price cap this risk is effectively mitigated and is further mitigated by excluding SMETS 2 meters from the cap.

- 14.440 RWE and Littlechild et al commented on the possibility that EU regulations relating to cost-reflective pricing for different payment methods could result in the price cap constraining non-prepayment prices.²⁴⁵ As noted in paragraphs 14.365 to 14.369 we consider that the regulations allow sufficient flexibility that the price cap would not constrain non-prepayment prices.
- 14.441 RWE noted the possibility that using electricity regions for setting the price cap for gas created the risk of distortion. We have analysed the variation in the different gas distribution charges that are amalgamated into a single region. We found that East Anglia was the only region in which the difference in gas distribution charges for the gas regions combined was greater than £15 (being the headroom allowance at medium TDCV).²⁴⁶ In East Anglia the maximum difference was less than £22.
- 14.442 We consider that while this creates the possibility of distortion the effect is small. The risk is that variation in network costs results in the price cap being unduly constraining in some regions and unduly lenient in others. We consider that the level of the cap mitigates the risk of the price cap being too lenient to a large extent since it creates conditions such that engaged customers ought to always be able to obtain a better price than the price cap. We note that the risk that the price cap is too harsh is mitigated since all gas network costs are properly reflected and weighted in the calculation of the price cap, suppliers will still be able to recover their costs.
- 14.443 Littlechild et al suggested that a prepayment meter price cap would lead to suppliers increasing prices for other customers. RWE, Ovo Energy and Utilita commented on the possibility of waterbed effects. We consider that the risk here would be that either:
- (a) suppliers increase prices outside of the price cap in order to offset the impact of the price cap; or
 - (b) the price cap attracts customers into the prepayment segments thus incentivising suppliers to lower non-prepayment prices.

²⁴⁵ The regulation in question is SLC 27.2A of the supply licence which was introduced in response to EU directives as described in paragraph 14.396.

²⁴⁶ This analysis was conducted at medium TDCV and excluded gas regions which contributed less than 5% to the weighting when mapping onto electricity regions on the grounds that any potential distortions here would apply to a very small group of customers.

- 14.444 We note that due in part to the additional prepayment-specific costs and in part to the stronger competition in the direct debit segments, we expect that customers on credit meters will always be able to achieve lower prices by switching to the best available direct debit tariff. This mitigates the risk that the price cap attracts customers into the prepayment segments.
- 14.445 In order for the price cap to affect non-prepayment prices there would need to be demand or cost linkages between the segments. We consider that the option of switching to a cheaper direct debit tariff means that the demand linkage is insufficient to produce material waterbed effects. We have also considered whether there are cost linkages such that the price cap could alter the marginal cost of serving non-prepayment customers or result in suppliers not recovering their common fixed costs.
- 14.446 We note that the construction of the price cap as cost plus headroom allows for recovery of common fixed costs.²⁴⁷ We have also not been able to identify any mechanism by which the price cap could alter the marginal cost of serving non-prepayment customers. We therefore consider that the price cap is unlikely to result in waterbed effects.
- 14.447 On a similar note, Centrica and E.ON suggested that any unintended consequences of the price cap might be magnified if the price cap attracts customers to switch to dumb prepayment meters. E.ON specifically suggested that the price cap be excluded from the cheapest tariff messaging to mitigate the risk of this unintended consequence.
- 14.448 As noted above, we expect that the additional cost to serve prepayment customers means that engaged customers will always be able to find a lower priced direct debit tariff than those on offer for prepayment. We consider it unlikely therefore that the price cap will attract new customers into the prepayment segments. In addition, we note that dumb prepayment meters entail a number of non-price costs (inconvenience) which further reduces this risk.
- 14.449 Centrica suggested that the price cap could make prices more volatile. With the price cap updating every six months then there would be at most two price changes per year driven by the price cap. Were this to be the case then the frequency of updates would be broadly comparable to the frequency of updates to the SVT. We consider therefore that the frequency of updates would not contribute to pricing being more volatile. We note that the approach we have taken to wholesale indexation seeks to avoid volatility

²⁴⁷ See paragraphs 14.103–14.123.

also.²⁴⁸ We therefore consider that the price cap does not pose a significant risk of increasing the volatility of pricing.

- 14.450 Several respondents to the provisional decision on remedies commented on the price cap's possible impact on the roll-out of smart meters. Centrica suggested that the price cap could incentivise suppliers to prioritise prepayment customers for roll-out. Co-operative Energy and E.ON suggested that there may be a reduced incentive to install smart meters for prepayment customers.²⁴⁹
- 14.451 We consider that the existence of the price cap and the exclusion of SMETS 2 meters from the scope of the price cap is likely to give suppliers greater incentives to roll-out SMETS 2 smart meters to existing prepayment customers.²⁵⁰
- 14.452 We note that suppliers already have obligations in respect of smart meter installation. To the extent that prepayment customers receive smart meters earlier than they would otherwise we consider that this is likely to be positive for the customers (for instance through greater convenience and by facilitating switches to tariffs that may be materially cheaper).
- 14.453 Centrica commented on the risk that suppliers may face losses on existing long-term contracts for which they have bought energy prior to the price cap being implemented.
- 14.454 We note the possibility that suppliers have bought for a significant period ahead for their variable contracts. However, we consider that where suppliers have done this it represents them taking a position on future prices rather than hedging against them (since they do not have a fixed contract for the sale of the commodity they are buying). Therefore we do not consider that the price cap introduces a new risk that these suppliers would be faced with selling this speculatively purchased energy below cost.
- 14.455 In particular, to the extent that wholesale prices fall then suppliers would be unable to recover costs resulting from more expensive, speculative, purchasing. We consider that this is consistent with the incentives a supplier would face in a well-functioning market. To the extent that prices rise

²⁴⁸ See paragraph 14.153.

²⁴⁹ We note that these comments were made in response to the provisional decision on remedies and that these parties may take a different view in light of the revised scope in which customers with SMETS 2 smart meters are not subject to the price cap.

²⁵⁰ This would be because suppliers would be unconstrained by future changes in the cap and therefore would have more flexibility in terms of the range of tariffs that they could offer, eg fixed-term contracts.

suppliers would be able to profitably offer tariffs further below the price cap than suppliers who had not made equivalent wholesale purchases.

14.456 Further we note that our approach to wholesale indexation uses only future trading days. This allows suppliers to purchase commodity in line with the price cap should they choose to do so.

14.457 Centrica suggested that there was a risk that the price cap might require use of many or all of the available tariff slots within the prepayment infrastructure. We note that the price cap requires that all prepayment tariffs are compliant with the price cap²⁵¹ but it does not require suppliers to change the number of tariffs they currently offer. We therefore consider that the price cap will not automatically increase the number of tariff slots suppliers require.

Relevant customer benefits

14.458 We have considered whether the Prepayment AEC gives rise to any relevant customer benefits²⁵² which may be lost as a result of the implementation of the PPM Price Cap Remedy. However, we do not believe that any such relevant customer benefits arise. We considered the possibility that other customers benefit from lower prices that suppliers are only able to offer because of the excess prices being charged to prepayment customers. If prepayment customers were subsidising other customers, suppliers would be able to offer other (non-prepayment meter) tariffs which were not profitable. We concluded that, while this is possible in principle, there is no evidence that this takes place, as suppliers have told us that they typically price tariffs to be profitable over the period for which they retain the customer. (See paragraphs 14.445 to 14.446 for our discussion of potential waterbed effects.)

Consideration of Ofgem's statutory duties

14.459 Where the CMA is considering whether to modify one or more of the conditions of a retail gas or electricity supplier's licence, in deciding whether such action would be reasonable and practicable, the CMA must 'have regard' to the relevant statutory functions of Ofgem.²⁵³

²⁵¹ Notwithstanding that some suppliers may assess compliance differently where this has been agreed by way of derogation.

²⁵² Section 134(7)–(8) of the 2002 Act.

²⁵³ Section 168 of the Act and paragraph 347 of [CC3](#).

- 14.460 Accordingly, in reaching our decision to introduce a new standard licence condition to implement the PPM Price Cap Remedy, we have, as part of our own application of the legal framework requiring us to decide upon remedies that are effective and proportionate,²⁵⁴ taken into account Ofgem's statutory duties and objectives.
- 14.461 In particular, we do not consider that any aspect of the PPM Price Cap Remedy will have an adverse impact on suppliers' ability to meet all reasonable demands for gas and electricity supply (so far as it remains economical to do so), achieving sustainable development, security of supply or environmental concerns. In this regard, the PPM Price Cap Remedy will only impact the 'efficiency' limb of the trilemma considerations built into Ofgem's statutory duties and functions (also known as the 'affordability' limb), insofar as the ultimate aim of the PPM Price Cap Remedy is to ensure that the prices for the retail supply of gas and electricity to domestic prepayment customers in Great Britain are affordable (or, in other words, maintained at a reasonable level).
- 14.462 The PPM Price Cap Remedy is designed to do so by mitigating the residual harm to domestic prepayment customers that we consider arises and will continue to arise from the Prepayment AEC and the Domestic Weak Customer Response AEC while our remedies concerning the prepayment framework and concerning domestic customer engagement more generally, take effect, and until the roll-out of smart meters has been substantially completed. In particular, we envisage that the PPM Price Cap Remedy would reduce the prices being paid by prepayment customers and equilibrate the highest of them²⁵⁵ with a cost-adjusted benchmark level based on competitively priced acquisition tariffs in the rest of the domestic markets (see paragraph 14.58).
- 14.463 In having regard to Ofgem's principal objective, we have also considered the potential impact that each aspect of the PPM Price Cap Remedy may have on protecting the interests of existing and future consumers, including vulnerable consumers. A remedy of this type has the benefit of providing direct protection to existing and future prepayment customers, many of whom are, and are likely to be, on low incomes or otherwise vulnerable, and who are suffering substantial harm, at least, from the Prepayment AEC, and also the Domestic Weak Customer Response AEC, and will continue to do so up until, at least, the roll-out of smart meters has been substantially completed (see paragraphs 14.328 to 14.340 above)(notwithstanding the

²⁵⁴ CC3, pp71–73.

²⁵⁵ We consider that our other proposed remedies should enable competition to take place below the level of the price cap.

implementation of our other remedies concerning the Prepayment AEC and the Domestic Weak Customer Response AEC).

- 14.464 We note that we have considered the potential unintended adverse consequences the PPM Price Cap Remedy may have on certain aspects of competition in the prepayment segments, and retail domestic markets more broadly, and whether it may dampen the effectiveness of our other remedies concerning the Prepayment AEC or the Domestic Weak Customer Response AEC. For the reasons given in paragraphs 14.405 to 14.413 above, we believe that the PPM Price Cap Remedy will not unnecessarily cut across the beneficial effects that competition has the potential to bring to customers. We expect that our engagement, and other prepayment, remedies will introduce sufficiently strong competition for prepayment customers, such that competition will determine the prices paid by prepayment customers rather than the price cap. In this context, the price cap is set at a level to allow efficient suppliers to offer profitable tariffs below the level of the cap as outlined in paragraph 14.273 above. The PPM Price Cap Remedy has been carefully designed so as to appropriately target those customers who are clearly identifiable, are significantly harmed (by the combined effects of Prepayment AEC and the Domestic Weak Customer Response AEC), and for whom competition has been least effective to date, and has the furthest to improve to address the detriment we have observed from the Prepayment AEC and the Domestic Weak Customer Response AEC.
- 14.465 Accordingly, in the paragraphs above we have balanced the potential unintended adverse consequences against the substantial benefit we consider the PPM Price Cap Remedy will bring to prepayment customers, and have decided to implement the PPM Price Cap Remedy. In doing so, we have had regard to Ofgem's statutory duties and objectives and in particular, its principal objective of protecting the interests of existing and future consumers, wherever possible by promoting effective competition.

15. Effectiveness and proportionality of our package of remedies

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- 15.1 Based on the assessment in Sections 11 to 14 above, we have identified a number of measures to be included within a package of remedies that will be effective in addressing the Domestic AECs (and/or associated detriment) that we have identified.¹
- 15.2 In our assessment of the effectiveness of this package of remedies, we have considered below:
- (a) how the package of remedies addresses the AECs and/or associated customer detriment (paragraphs 15.3 to 15.68);
 - (b) other aspects of the effectiveness of our package of remedies (paragraphs 15.69 to 15.117);
 - (c) relevant customer benefits (paragraphs 15.118 to 15.121); and

¹ In addition, we have also identified remedies aimed at addressing the Settlement AECs which concern the domestic (and SME) retail energy markets; the effectiveness and proportionality of the remedies concerning the Settlement AECs are assessed in Section 12.

- (d) the proportionality of our package of remedies (paragraphs 15.122 to 15.164).

How the package of remedies addresses the AECs and the resulting customer detriment

- 15.3 As set out in Section 11, we have identified five AECs affecting the domestic retail energy markets – the Domestic Weak Customer Response AEC, the Prepayment AEC, and three AECs relating to the regulatory framework, namely, the systems of electricity and gas settlement (the Settlement AECs)² and aspects of the ‘simpler choices’ component of the RMR reforms (the RMR AEC). We estimate that the detriment arising from these AECs is very substantial – at around £1.4 billion per year over the period from 2012 to 2015 for the Domestic AECs,³ with a marked increase in detriment year on year over the period.
- 15.4 We have discussed the aim of each element of the package of remedies addressing the Domestic AECs in Sections 11 to 14. In this subsection, we draw upon those sections and summarise how the elements of the remedies package work together to effectively address those features of the domestic retail energy markets that give rise to each of the AECs and/or associated detriment.
- 15.5 We have found a number of features of the markets for the domestic retail supply of gas and electricity in Great Britain relating specifically to the prepayment segments that give rise to the Prepayment AEC and/or associated detriment.⁴ These features are as follows:
- (a) technical constraints that limit the ability of all suppliers, and in particular new entrants, to compete to acquire prepayment meter customers and to innovate by offering tariff structures that meet demand from prepayment customers who do not have a smart meter (the technical constraints feature); and
 - (b) softened incentives for all suppliers, and in particular new entrants, to compete to acquire prepayment customers due to:
 - (i) actual and perceived higher costs to engage with, and acquire, prepayment customers compared with other customers; and

² The Settlement AECs concern the SME retail energy markets as well as the domestic retail energy markets.

³ The Domestic Weak Customer Response AEC, the Prepayment AEC and the RMR AEC.

⁴ See Section 10.

- (ii) a low prospect of successfully completing the switch of indebted customers, who represent about 7–10% of prepayment customers.

- 15.6 We have found that certain aspects of the simpler choices component of Ofgem’s RMR rules (including the ban on complex tariff structures, the maximum limit on the number of tariffs that suppliers will be able to offer at any point in time, the restrictions of the offer of discounts, the restrictions on the offer of bundled products, the restrictions on the offer of reward points and the requirement to make all tariffs available to new and existing customers) are a feature of the markets for the domestic retail supply of electricity and gas that gives rise to the RMR AEC by reducing retail suppliers’ ability to compete and innovate in designing tariff structures, and by softening competition between PCWs.
- 15.7 In addition, we have found that a combination of features in the markets for the domestic retail supply of gas and electricity give rise to the Domestic Weak Customer Response AEC 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.
- 15.8 These features are: customers’ limited awareness of and interest in their ability to switch energy supplier, actual and perceived barriers to accessing and assessing information, and actual and perceived barriers to switching. We have identified additional aspects of the restricted meter segments that strengthen these features for domestic customers on restricted meters and support a finding that disengagement and weak customer response is a more significant problem among customers on restricted meters compared to domestic customers with standard credit meters.⁵ We have also identified additional aspects of the prepayment segments that strengthen these features for prepayment customers, and support a finding that disengagement and weak customer response is a more significant problem among prepayment customers compared with domestic customers on direct debit.⁶
- 15.9 As noted in Section 11, our remedies package concerning the Domestic AECs is based on the principles of: creating a framework for effective competition; helping customers to engage; and protecting customers who are less able to engage to exploit the benefits of competition. The component parts of the remedies package concerning each of these principles are set out in turn below. Our view is that the remedy package will

⁵ See Section 9.

⁶ See Section 9.

be effective in addressing each of the Domestic AECs and/or associated detriment.

Creating a framework for effective competition

Remedies to address constraints on competition for prepayment customers

- 15.10 For the reasons set out in Section 9, we believe that, in addition to the RMR AEC and the Domestic Weak Customer Response AEC, there are features of the domestic retail energy markets that give rise to a distinct, but related, AEC concerning prepayment meter customers, arising principally from supply side constraints (the Prepayment AEC).
- 15.11 As regards the Prepayment AEC, we recommend that Ofgem take a number of actions which we consider will be effective in addressing in part certain aspects of the features giving rise to the Prepayment AEC. Further details are set out in Section 12.
- 15.12 In relation to the technical constraints feature imposed by the dumb prepayment infrastructure, we are proposing a range of remedies that will make better use of the available tariff slots, so as to reduce the impact of the dumb prepayment meter technical constraints on the ability of suppliers, and in particular new entrants, to compete and innovate by offering tariff structures that meet demand from prepayment meter customers who do not have a smart meter.
- 15.13 Specifically, these remedies include recommendations to Ofgem that it take responsibility for the efficient allocation of gas tariff pages. Moreover, we are proposing to seek undertakings from the Six Large Energy Firms (and, absent such undertakings, recommend that Ofgem change gas suppliers' standard licence conditions) so as to (i) set up a cap on the number of gas tariff pages that a supplier can hold; (ii) set up an obligation for suppliers to provide relevant information for Ofgem to monitor the allocation of the gas tariff codes; and (iii) enable Ofgem to mandate the transfer of unused gas tariff codes to another supplier.
- 15.14 To further mitigate the impact of tariff codes on competition for customers on dumb prepayment meters, we recommend that Ofgem change SLC 22B.7(b) to allow suppliers to set prices to prepayment customers with no obligation to apply the regional cost variations that are applied to other payment methods within the same core tariff. As a result, suppliers will be able to make better and more efficient use of the tariff codes that have been allocated. We also recommend that Ofgem deprioritise potential enforcement action against suppliers in relation to this licence condition

pending the change. This will allow suppliers to make better use of their limited tariff codes.

- 15.15 The feature of softened incentives for all suppliers (and in particular new entrants) to compete to acquire prepayment customers arising from a low prospect of successfully completing the switch of indebted customers will be partly addressed by our recommendation to Ofgem to take appropriate steps to ensure that certain changes to the Debt Assignment Protocol are implemented by the end of 2016. This remedy mainly involves removing some of the barriers that prepayment customers without a debt face when attempting to switch to a credit meter.
- 15.16 In light of the above, we consider that the remedies specific to the prepayment segments are complementary, and will be effective in addressing in part the Prepayment AEC and associated detriment by increasing both suppliers' ability, and their incentives, to compete for customers in the prepayment segments. However, as discussed below, the roll-out of SMETS 2 meters is a necessary element for fully addressing the features giving rise to this AEC, and for enhancing the effectiveness of our engagement remedies with respect to prepayment customers.

Withdrawal of certain aspects of the simpler choices component of the RMR rules

- 15.17 Our package of remedies includes remedies that will be effective in addressing the RMR AEC and associated detriment. Further details are set out in Section 12.
- 15.18 The remedy takes the form of a recommendation to Ofgem to remove a number of standard licence conditions relating to the simpler choices component of the RMR rules (including the ban on complex tariff structures, the four-tariff rule, the restrictions on the offer of discounts, the restrictions on the offer of bundled products, the restrictions on the offer of reward points and the requirement to make all tariffs available to new and existing customers).⁷ Our recommendation will enhance competition and innovation between retail energy suppliers in the retention and acquisition of domestic customers and, accordingly, will address not only the RMR AEC, but will also in part enhance suppliers' ability to compete for new customers (including prepayment customers), thus also addressing part of the Prepayment AEC. Increased choice for domestic customers may also raise

⁷ See Section 12 for further details.

customers' interest in switching, and thereby address part of one of the features giving rise to the Domestic Weak Customer Response AEC.

15.19 In addition, our recommendation will facilitate competition between PCWs by addressing the constraints which the simpler choices component of the RMR rules place on the number of tariffs offered by suppliers and, accordingly, by allowing them to negotiate exclusive tariffs with domestic energy suppliers and to offer discounts funded by the commissions they receive from suppliers. As the incentive on the part of suppliers to negotiate exclusive deals with PCWs can also potentially be undermined by the current Whole of the Market Requirement included in Ofgem's Confidence Code,⁸ our recommendation to Ofgem also provides for the removal of the Whole of the Market Requirement, and the introduction of a requirement for accredited PCWs to be transparent over the market coverage they provide to domestic customers.⁹ We have noted that TPIs play a key role in removing barriers for domestic customers to access and assess information and, accordingly, in facilitating customer engagement. Therefore, our remedy will also address part of one of the features giving rise to the Domestic Weak Customer Response AEC.

15.20 In order to mitigate any potential unintended consequences arising from a potentially significant increase in the number of tariffs on offer, we also recommend that Ofgem introduce an additional Standard of Conduct into retail suppliers' standard licence conditions that will require suppliers to have regard in the design of tariffs to the ease with which customers can compare 'value for money' with other tariffs they offer.¹⁰ We have noted in Section 13, with encouragement, Ofgem's broader intentions to move to more principles-based regulation concerning the retail energy markets, and Ofgem's recent enforcement actions against the existing Standards of Conduct.

Helping customers engage to exploit the benefits of competition

15.21 Our package of remedies concerning domestic customer engagement involves remedies that are targeted at addressing one or more aspects of the features giving rise to the Domestic Weak Customer Response AEC and associated detriment. Since the Domestic Weak Customer Response AEC affects all domestic customers, including prepayment customers, the remedies can be expected, once they become effective, to also enhance

⁸ Involving a requirement on PCWs to use all reasonable endeavours to include price comparisons for all available domestic tariffs, where applicable for all available payment types, for licensed suppliers (including for any agents, affiliates, and brands operating under the licence of a supplier).

⁹ See Section 13.

¹⁰ See Section 13.

suppliers' incentives to compete for prepayment customers. There will therefore be a strong interaction between the remedies concerning the Domestic Weak Customer Response AEC and the Prepayment AEC.

- 15.22 We discuss each of the remedies concerning domestic customer engagement in turn below, and how they interact to address the features of the Domestic Weak Customer Response AEC and/or associated detriment, before discussing their interaction with the price cap for prepayment customers. We have discussed the rationale for each engagement remedy comprising the package in Section 13.
- 15.23 We have considered first how the package of remedies addresses those features of the markets that give rise to weak customer response by limiting customers' awareness of and interest in their ability to switch energy supplier, create actual and perceived barriers for certain customers to access and assess information relating to gas and electricity retail supply, and create actual and perceived barriers to switching. We consider the synergies between the various measures and the coherence of the package of remedies later in this section (see paragraphs 15.102 to 15.116).

Customers' limited awareness of, and interest in, their ability to switch energy supplier

- 15.24 We have found that customers have limited awareness of, and interest in, their ability to switch energy supplier.
- 15.25 The package of remedies will address, in part, this feature of the Domestic Weak Customer Response AEC by increasing both customers' awareness of, and their interest in, their ability to switch energy supplier. We consider below the contribution made by each element of the package of remedies to addressing this feature.
- 15.26 First, we recommend that Ofgem establish a programme (the Ofgem-led programme) to identify, test (through randomised controlled trials (RCTs), where appropriate) and implement (for example, through appropriate changes to gas and electricity suppliers' standard licence conditions) measures to provide domestic customers with different or additional information with the aim of promoting engagement in the domestic retail energy markets.¹¹ We are not aware that rigorous testing of this type has ever been carried out by Ofgem in relation to previous measures introduced in the retail energy markets to ensure that changes in supplier

¹¹ See Section 13.

communications have their intended effect on customers. The programme that we are recommending be introduced (involving RCTs, where appropriate) would be a key factor distinguishing measures introduced pursuant to the programme from previous interventions in the sector. The effective implementation of the Ofgem-led programme is also enhanced through our recommendation that Ofgem introduce a new licence condition requiring suppliers to participate in the Ofgem-led programme.

- 15.27 We have identified a priority list of measures to be developed through the Ofgem-led programme, which includes testing (i) changes to the information in domestic bills and how this is presented; (ii) changes to the information provided to customers on the availability of cheaper tariffs across the markets; (iii) changes to the specific messaging that domestic customers receive in bills once they move, or are moved, onto an SVT and/or other default tariffs; and (iv) changes to the name of default tariffs. We expect effective trials to lead to more effective engagement measures, which in turn will increase awareness and interest in switching on the part of domestic customers.
- 15.28 Second, one of our remedies will involve the creation of a database (the Database remedy) of certain domestic customers¹² who have been on a supplier's SVT (or any other default tariff) for three or more years (the Disengaged Domestic Customers), to whom rival suppliers will have access and, subject to strict safeguards being in place concerning data protection and the use of the database, could then contact the Disengaged Domestic Customers that have not opted out.¹³ We have noted in Section 13 that this remedy is modelled on the French competition authority's successful application for an interim order requiring ENGIE (formerly GDF Suez) to disclose details of its customers on regulated gas tariffs to other suppliers. Although a number of Disengaged Domestic Customers may 'opt out' of the disclosure, based on the opt-out rate for the similar measure implemented in France, we consider that many customers will not do so and suppliers will therefore be able to contact a large proportion of Disengaged Domestic Customers to prompt them to engage.
- 15.29 By giving rival suppliers access to certain customer information, we believe that they will be able to prompt such customers to engage through targeted marketing, thereby increasing such customers' awareness of, and possibly also their interest in, their ability to switch supplier.

¹² Excluding customers who opt out.

¹³ See Section 13.

15.30 Third, we will implement specific measures targeted at customers on restricted meters¹⁴ for whom we have observed that their awareness of their ability to switch is particularly limited.¹⁵ We will order suppliers to remind their domestic electricity customers on restricted meters, in their regular communications with them, that they have the option to switch supplier or to switch to a single-rate tariff without having to change their meter or incur replacement costs. We are also recommending that Citizens Advice become a recognised provider of information and support to domestic electricity customers on restricted meters, and to order suppliers to provide their customers on restricted meters with contact details for Citizens Advice, and to provide Citizens Advice with information it may reasonably require concerning customers on restricted meters. These measures will directly increase the awareness of customers on restricted meters of their ability to switch.

Actual and perceived barriers to accessing and assessing information relating to energy supply

- 15.31 We have found that certain customers face actual and perceived barriers to accessing and assessing information arising, in particular, from the complex information provided in bills and the structure of tariffs which combine to inhibit the value-for-money assessment of available options (particularly for customers with low levels of education or income, the elderly and/or those without internet access, and a lack of confidence in, and access to, PCWs by certain customers, including the less well-educated and the less well-off).
- 15.32 The package of remedies will address, in part, this aspect of the Domestic Weak Customer Response AEC by improving domestic customers' own ability to access and assess the information needed to make a value-for-money assessment (as regards the value for money of their existing tariff, and as compared with those offered by other suppliers). It will also improve domestic customers' use of PCWs and other TPIs to access and assess the information needed for such assessments.
- 15.33 First, the Ofgem-led programme, by measuring the effect on engagement of a range of different changes to bills, changes to the information provided to customers on the availability of market-wide cheaper tariffs, and names for the SVT, can be expected, once successful trials have been concluded, to lead to clearer, and less complex, information being provided to customers, thereby (in addition to enhancing their awareness of and interest in their

¹⁴ See Section 13.

¹⁵ See Section 9.

ability to switch) improving their access to and ability to assess information to help them decide whether to switch. In particular, we expect the Ofgem-led programme to be capable of targeting particular customer groups, such as those on prepayment meters.

- 15.34 Second, the Database remedy will further facilitate such customers' access to information that enables them to conduct a value-for-money assessment. Since suppliers and Ofgem will be able to contact other suppliers' Disengaged Domestic Customers and market directly to them (by post), they will be able to design targeted marketing campaigns to encourage such customers to consider switching.
- 15.35 Third, we are proposing to increase the ability and incentives of PCWs to engage with domestic customers by, as noted above, removing the Whole of the Market Requirement on PCWs, and also by recommending that Ofgem introduce a new Standard of Conduct that will require suppliers to have regard in the design of tariffs to the ease with which customers can compare 'value for money' with other tariffs. These remedies will improve the price comparison services offered by PCWs. Any adverse unintended consequences arising from the removal of the Whole of the Market Requirement will be mitigated by Citizens Advice's market-wide non-transactional price comparison tool.
- 15.36 Fourth, we are recommending to DECC that certain changes are made to the specification of Midata phase 2.¹⁶ Such changes will increase supplier participation in Midata (thus ensuring that all customers' data is available for a price comparison), will expand the scope of data included (thus broadening the categories of customer that can receive a price comparison service), and give TPIs the ability to seek customer consent to have access, at a later point in time, or on an ongoing basis, to the customer's updated Midata. In combination, we expect such remedies, among other things, to allow TPIs to provide enhanced price comparison services to customers.
- 15.37 Finally, and as noted in Sections 12 and 13, we note that the remedy concerning the removal of aspects of the simpler choices component of the RMR rules is likely to lead to increased tariff complexity. However, for the reasons noted in Sections 12 and 13, when combined with the removal of the Whole of the Market Requirement, and the introduction of a new Standard of Conduct, we do not consider that greater confusion will result. We therefore do not consider that the effectiveness of the remedies targeting

¹⁶ See Section 13.

actual and perceived barriers to accessing and assessing information will be undermined.

Actual and perceived barriers to switching

- 15.38 We have found that customers face actual and perceived barriers to switching, such as where they experience erroneous transfers, which impact customers' ability to switch as well as their perception of switching. In addition, as noted in Section 9, we have observed that certain suppliers require customers on restricted meters to replace their restricted meter (the cost of which may or may not be covered by the supplier).¹⁷ Similarly, a meter replacement is required for customers to access a wider range of tariffs. We consider that this increases the actual and perceived barriers to switching faced by such customers, in particular, by adding to the number of factors that a customer needs to take into account in a value-for-money assessment.
- 15.39 The package of remedies will address, in part, this aspect of the Domestic Weak Customer Response AEC by improving TPIs' access to customer meter information, and thereby help reduce the number of erroneous transfers. It will also remove the actual and perceived barriers to switching faced by customers of certain suppliers on restricted meters who are required to replace their meter (the cost of which may or may not be covered by the supplier), when switching to that supplier.
- 15.40 First, we will order the code administrator or governing body with authority to grant access to the ECOES database and the gas transporters to provide access to PCWs (and other TPIs providing similar services) to the ECOES and SCOGES databases on reasonable terms and subject to reasonable access terms.¹⁸ By accessing such databases, they will be able to access more accurate metering information concerning domestic customers (rather than relying on customer information or information from GB Group), which will result in a reduction in the number of erroneous transfers.
- 15.41 Second, we will order electricity suppliers with more than 50,000 domestic customers to make all their single-rate electricity tariffs available to all (existing and new) domestic electricity customers on restricted meters without making such tariffs available conditional upon the replacement of their existing meter.¹⁹ By prohibiting suppliers from forcing customers to change meter, our view is that this remedy will address this aspect of the

¹⁷ See Section 9.

¹⁸ See Section 13.

¹⁹ See Section 13.

feature giving rise to the Domestic Weak Customer Response AEC as regards customers on restricted meters.

- 15.42 This remedy is also specifically designed to work in conjunction with the informational remedy noted above concerning customers on restricted meters.²⁰ The effectiveness of both remedies will be increased as customers on restricted meters are provided with more information about their alternative tariff options, have more sources of information available to them (with greater focus by Citizens Advice), and will not be limited to other tariffs available for their specific restricted meter, since suppliers will be prohibited from forcing a customer to switch meter if the latter wished to switch to one of their unrestricted meter tariffs.

Overall impact on customer engagement and suppliers' unilateral market power

- 15.43 We recognise that it is not easy to quantitatively assess the likely impacts of our remedies package on customer engagement, and how the detriment we have found will be addressed by the different elements of the remedies package.
- 15.44 We have identified a number of developments in the market including the presence of TPIs with an incentive to promote engagement, the opportunities offered by smart meters and the removal of actual or perceived barriers to switching as a result of our other remedies, which led us to believe that, notwithstanding the uncertainties inherent in adopting such a package of remedies, our engagement remedies will materially improve engagement and overcome many aspects of the features that we have identified as giving rise to the Domestic Weak Customer Response AEC and associated detriment. In particular, we believe that our remedies, together with the substantial completion of the national programme for the roll-out of smart meters, will address the Domestic Weak Customer Response AEC and associated detriment (in particular as regards direct debit customers, who face lower barriers to switching and to accessing and assessing information as compared with customers on restricted meters and prepayment customers²¹). Accordingly, suppliers' unilateral market power over their inactive customer base will be reduced significantly.
- 15.45 However, we noted in Section 11 and paragraphs 15.74 to 15.96 below that our engagement remedies will take time to become fully effective (some more than others). Substantial remedies will be taking effect to improve

²⁰ See Section 13.

²¹ See Section 9.

engagement from 2017, with major remedies introduced each year over the period 2017 to 2020.

- 15.46 For most domestic customers, as the detriment will be reduced as soon as they engage effectively, we would expect detriment to be reduced throughout the period 2017 to 2020 and in particular from 2018 as the Database remedy and Ofgem-led programme start to take effect. This is in contrast with the situation for prepayment customers, who currently do not have access to cheap tariffs, and who face heightened features giving rise to the Domestic Weak Customer AEC and additional features giving rise to the Prepayment AEC.
- 15.47 Given the size of the detriment we have observed across all segments, we considered whether it was appropriate to intervene through a price cap in this transitional period, and the scope for such an intervention (see our views in Section 11). In general, we believe that the most sustainable approach to reducing the detriment we have identified in the long term is through fully competitive markets, in which more efficient suppliers gradually replace less efficient suppliers. However, for the reasons set out in Section 11 and below, we have decided that a price cap applying to prepayment customers in the period until 2020 is an effective and proportionate remedy.
- 15.48 The majority view is that a broader price cap would be disproportionate. This decision was balanced, and four of the five members felt that, for the reasons set out in Section 11, there were material risks of adverse consequences from the introduction of a price cap for a large number of customers which outweighed the short-term reduction of detriment. One member dissented from this view, preferring to extend the protection of a short-term price cap to a wider segment of customers. This difference in view reflects, in part, members' respective judgements on the likelihood that better outcomes will be delivered through competitive markets with more engaged customers over the next few years.

Protecting customers less able to engage to exploit the benefits of competition

- 15.49 In assessing the need for a prepayment price cap to address detriment directly, we have taken particular account of:
- (a) the strength of the features contributing to the Prepayment AEC and the Domestic Weak Customer Response AEC as it applies to prepayment customers;

- (b) the scale of the detriment that we have observed from the Domestic AECs, and the extent to which the detriment differs between prepayment customers and other categories of customer;
 - (c) the impact of our prepayment remedies²² and engagement remedies²³ on the features giving rise to the Domestic AECs, and their interaction with the price cap (see Sections 11 and 15), including the need for an iterative process of greater supply- and demand-side pressures for more competitive prices to emerge.
 - (d) the potential for adverse consequences from the introduction of a price cap, and how these might be expected to differ according to the scope, design and duration of the price cap remedy; and
 - (e) the practicability of implementing a cap on a sufficiently timely basis to address the detriment during the period while our other remedies take effect.
- 15.50 As noted above in paragraphs 15.5 and 15.8, prepayment customers face supply-side features specific to their segments, ie technical inefficiencies relating to the dumb prepayment infrastructure and softened incentives for suppliers to compete to acquire prepayment customers. Also, we have found that prepayment customers overall are less engaged than direct debit customers, and face higher barriers to engagement. In addition, suppliers incur higher costs to serve prepayment customers using a ‘dumb’ meter.
- 15.51 The prepayment-specific concerns may explain why prepayment customers have a materially lower number of prepayment tariffs to choose from (see Section 8) in comparison with the direct debit segments, as well as the significant price differential between tariffs available to prepayment customers (even those using smart meters) and customers on direct debit.
- 15.52 For the reasons set out above, we believe that our prepayment remedies²⁴ and engagement remedies²⁵ will help improve the conditions for competition, including in the prepayment segments. However, we have come to the conclusion that, on their own, these remedies will not fully address the levels of detriment we have identified for prepayment customers before the roll-out of smart meters is substantially completed.

²² See Section 12.

²³ See Section 12.

²⁴ See Section 12.

²⁵ See Section 13.

- 15.53 The technical constraints which contribute to the Prepayment AEC will only be fully addressed when the roll-out of smart meters is completed. While the prepayment remedies (ie reallocation of certain gas tariff pages and softening of SLC 22B7(b)) will result in more suppliers being able to offer a wider range of tariffs to prepayment customers with dumb meters, which is required to stimulate, at least, supply-side competition, the overall number of tariffs that suppliers can offer to their customers will remain constrained.
- 15.54 We also found that suppliers have softer incentives to compete to acquire prepayment customers compared with non-prepayment customers (see Section 9). One cause for these softened incentives are the low prospect of successfully completing the switch of indebted customers, who represent about 7 to 10% of prepayment customers. This is because indebted prepayment customers face actual or perceived barriers to switching between different suppliers' prepayment tariffs arising from the Debt Assignment Protocol. This aspect will be addressed in part by our recommendation to Ofgem to improve the Debt Assignment Protocol.
- 15.55 But there are other aspects of the prepayment segments which soften suppliers' incentives to compete to acquire prepayment customers. These include, among other things, actual and perceived higher costs to serve, and acquire, prepayment customers (compared with other customers). In addition, disengagement and weak customer response is a more significant problem among prepayment customers compared with domestic customers on direct debit (see paragraph 15.8). Accordingly, we are concerned that the combination of the supply-side features of the Prepayment AEC and the heightened features of the Domestic Weak Customer Response AEC will mean that the engagement remedies will take more time to materially address the demand-side features. This concern is heightened by the current dearth of competitively priced prepayment tariffs, and therefore the limited gains available to prepayment customers from switching.
- 15.56 The roll-out of SMETS 2 meters will in our view address some of these aspects directly (eg reducing suppliers' costs to serve and acquire prepayment customers and customers' barriers to switching), and will enhance the effectiveness of our remedies in tackling prepayment customer disengagement.
- 15.57 Accordingly, we expect the detriment arising from the Domestic AECs to persist in substantial form, with respect to prepayment customers, over the next few years. Given the size of the detriment concerning prepayment customers we have observed, of around £388 million a year over the last three and a half years, we have decided to impose a price cap remedy on suppliers to prepayment customers. More particularly, we have decided to

require suppliers to ensure that the annual bills paid by prepayment customers (assuming a predetermined consumption level) do not exceed a specified benchmark reference level.

- 15.58 Considering that smart meters eliminate some aspects of the features contributing to the Prepayment AEC, and enhance the effectiveness of our engagement remedies, we have decided to exclude SMETS 2 meters²⁶ from the scope of the price cap and to terminate the price cap at the end of 2020, as we expect the roll-out of smart meters to be substantially completed by then (see Section 14). As discussed above, we believe that the combination of our remedies with the benefits of SMETS 2 meters, in particular for prepayment customers, will be effective in addressing the features giving rise to the Prepayment AEC and Domestic Weak Customer AEC (as it applies to prepayment customers).
- 15.59 The CMA will conduct a focused mid-term review in January 2019 of the progress that has been made concerning the roll-out of smart meters. It will then consider whether to terminate the price cap early (eg if the roll-out of SMETS 2 meters is ahead of schedule) or to encourage Ofgem to take further actions to protect prepayment consumers (eg if the roll-out of SMETS 2 meters is behind schedule).
- 15.60 Before deciding to impose a price cap remedy on suppliers to prepayment customers, we have considered the interaction of our price cap with the other remedies concerning the Domestic AECs (in particular, the remedies addressing the Prepayment AEC and the Domestic Weak Customer Response AEC in respect of prepayment customers). We recognise that a price cap remedy is likely to have an impact on suppliers' incentives to compete to acquire prepayment customers, as well as on prepayment customers' incentives to engage with the markets while benefiting from the protection of the price cap. This, in turn, risks reducing in the short-term some of the benefits arising from our prepayment and engagement remedies in respect of prepayment customers. However, for the reasons set out below, we consider that the aim of the price cap, and its design components, will allow for competition under the level of the price cap, and that over time the scope for such competition will grow as our price cap falls away for customers with SMETS 2 meters and our engagement remedies start to take effect.
- 15.61 We have set the price cap at a level that will allow efficient suppliers to compete beneath the level of the price cap while still earning a normal return

²⁶ We also note that prepayment customers on SMETS 2 meters have access to a wider range of tariffs.

on capital (through the inclusion of headroom and the selection of an appropriate competitive benchmark). We believe that this consideration is of particular importance as the price cap will only be in place as a transitional measure pending development of effective competition for all prepayment customers. We recognise, however, that as a result, the price cap remedy will leave unaddressed part of the detriment concerning prepayment customers.

- 15.62 It is essential that our other remedies are implemented in parallel with the price cap so as to stimulate the development of competition for all prepayment customers (including those on dumb meters) during this transitional period. This will further contribute to addressing the detriment in the short term and ensuring that competition delivers beneficial outcomes for prepayment customers in the longer term, after the termination of the price cap.
- 15.63 We acknowledge that the price cap remedy might dampen the incentives of suppliers to offer multiple tariff options to prepayment customers on dumb prepayment meters, despite the implementation of the tariff slots remedy. However, for the transitional period, we believe that the tariff slots remedies are still necessary in order to facilitate entry in the prepayment segments,²⁷ and to allow suppliers to offer a range of tariffs to their prepayment customers.²⁸
- 15.64 We have also assessed the impact of the price cap on the effectiveness of our engagement remedies (in particular, the Ofgem-led programme, the Database remedy and the engagement remedies for customers on restricted meters). As noted in Section 9, we consider that the Domestic Weak Customer Response AEC is a more significant problem among prepayment customers compared with domestic customers on direct debit.²⁹ Given that the price cap has been designed to allow scope for competition in the prepayment segments (see above), our engagement remedies will, to some extent, also be effective to help prepayment customers engage while the price cap is in operation. Accordingly, our engagement remedies will be effective in partly addressing the Domestic Weak Customer Response AEC (in respect of prepayment customers) under the price cap.
- 15.65 As regards the Ofgem-led programme remedy, one of the measures that we recommend that Ofgem test under the programme may involve changes to

²⁷ Suppliers may enter the prepayment segments either by choice or as a result of the regulatory obligation set out in SLC 27 when reaching 50,000 customers.

²⁸ In addition, the tariff slots remedies will be critical in the event that the price cap is removed before the full roll-out of smart meters (for instance, as a result of the mid-term review of the price cap as set out in Section 14).

²⁹ See Section 9.

the provision of information on market-wide tariffs offered by other suppliers to customers. This remedy may thus facilitate the access by prepayment customers to information about cheaper tariffs (including tariffs below the cap) which may prompt them to engage. In addition, measures identified under the Ofgem-led programme concerning changes to messaging on bills will be effective to prompt prepayment customers that are about to be/have been moved to an SVT (or other default tariff) to look for a better deal.

- 15.66 The Database remedy will capture details of prepayment customers who have been on a supplier's SVT or any other default tariff (below the cap) for three or more years, and who have not opted out. To the extent that these customers will be prompted to switch supplier through marketing letters, the Database remedy can coexist with the price cap as it will be effective at helping suppliers identifying the disengaged prepayment customers and prompt them to engage in the markets.
- 15.67 Our remedies package also includes remedies aimed at helping prepayment customers with restricted meters engage. We note within that context that these remedies are designed to offer more choice and better information to these consumers, and therefore these remedies are complementary to the price cap remedy.
- 15.68 In light of the above, and having regard to the design of the price cap (including the inclusion of headroom, the exclusion of SMETS 2 meters from its scope and the limits on its duration, linked to the roll-out of smart meters), we do not believe the effectiveness of the other remedies will be materially dampened by the application of the prepayment price cap.

Other aspects of the effectiveness of our package of remedies

- 15.69 Our assessment of the effectiveness of our remedy package has focused on the following factors:
- (a) the means by which the remedies will be implemented, monitored and enforced;
 - (b) the timescale over which the remedy measures will take effect;
 - (c) the consistency of the package of remedies with existing and likely future laws and regulations; and
 - (d) its coherence as a remedies package.

Implementation, monitoring and enforcement

- 15.70 In developing each of the remedy measures, we have considered how each remedy measure could best be implemented, monitored and enforced in Sections 12, 13 and 14, and our decision as regards each remedy is set out in Section 20.
- 15.71 We note that our package of remedies contains a large number of recommendations compared with some other market investigations. We consider that this is appropriate to the particular facts and circumstances of this investigation, as the ongoing regulatory role of Ofgem means that it is best placed to integrate many of the further actions necessary to address the various aspects of the Domestic AECs and associated detriment with its other interventions in the domestic retail energy markets.³⁰ It is ultimately a matter for Ofgem to decide whether and how to implement our recommendations and over what timescale.
- 15.72 We also recommend that Ofgem remove or amend certain conditions in suppliers' standard licences, having concluded that an order on Ofgem to do so is unnecessary in circumstances where Ofgem has issued an open letter to suppliers or can take other action advising of its intention to issue a statutory consultation proposing to remove or amend such licence conditions, and to deprioritise potential enforcement action concerning such licence conditions.³¹
- 15.73 We therefore conclude that each of the measures is capable of effective implementation, monitoring and enforcement.

The timescale over which our remedies will have effect

- 15.74 In evaluating the effectiveness of the remedies aimed at addressing the Domestic AECs, we have considered the timescales over which these remedies will be likely to be implemented, will be likely to take effect in addressing the relevant aspects of the AECs and, ultimately, their impact on detriment.
- 15.75 In making our assessment, we have considered how they will work in combination with other remedies in the package. We consider that the impact and effect of the remedies will be greater as a part of a package.

³⁰ See [CC3](#), paragraph 390.

³¹ See Section 12.

- 15.76 The time taken to implement remedies following a CMA investigation will depend, in part, on whether the CMA is taking action itself or recommending action be taken by others.
- 15.77 Where the CMA is taking action itself, the implementation of remedies following a CMA investigation typically involves two stages. In the first stage, the CMA makes an order or accepts undertakings.³² The CMA must make a final order within six months of the date of publication of the market investigation report.³³
- 15.78 We acknowledge that the implementation of some of the remedies may not be a straightforward exercise, and that the time frame to implement the remedies package may raise some operational challenges to energy companies, the government, Ofgem and other stakeholders. However, we consider that the timescales identified for implementing the individual remedies are realistic and will help ensure effective implementation of the remedies package.

Remedies to create a framework for effective competition

- *Redistributing gas prepayment tariff codes*

- 15.79 We expect Ofgem to take responsibility for the efficient allocation of gas tariff pages as soon as possible following publication of the CMA's final report. Where undertakings are not being negotiated with the CMA, we expect Ofgem to commence a consultation on the cap on the number of gas tariff pages that any supplier can hold, plus other obligations on information provision and compliance with directions. We expect such consultation to conclude by the end of 2016, following which, we estimate that, Ofgem will require a further three months to make the relevant amendments and redistribute the gas tariff pages. As a result, we expect this remedy will be in effect from mid-2017. However, we consider that this could be achieved significantly earlier if final undertakings are agreed with the CMA.

- *Softening SLC 22B.7(b)*

- 15.80 We consider that the relevant changes to SLC 22B.7(b) could be in place by the start of 2017. However, in order for our remedy to take effect as soon as

³² Suppliers are invited to offer undertakings concerning the remedy concerning gas tariff pages.

³³ The CMA may extend this six-month period by up to a further four months if it considers there are special reasons why a final order cannot be made within the statutory deadline. Section 138A of the 2002 Act. These time limits do not apply to any further implementation required after final undertakings have been accepted or a final order made.

possible, we are also recommending that Ofgem deprioritise potential enforcement action against any supplier that sets prices to prepayment customers on the basis of grouping regional cost variations.

- *Debt Assignment Protocol*

15.81 As regards implementing the further changes we have identified concerning the Debt Assignment Protocol, we expect Ofgem to integrate these changes into its ongoing work programme concerning the Debt Assignment Protocol so that these changes are implemented by suppliers in a timely manner, by the end of 2016.

- *Withdrawing the simpler choices component of the RMR rules*

15.82 Similarly to the softening of SLC 22B.7(b), we expect that Ofgem's consultation on the removal of the relevant standard licence conditions will conclude by the end of 2016. Ofgem could then implement and enforce the revised standard licence conditions from the beginning of 2017 with suppliers permitted to provide a wider range of tariffs. However, we note that Ofgem has issued an open letter to suppliers advising of its intention to issue a statutory consultation proposing to remove these licence conditions, and to deprioritise potential enforcement action against any supplier that operates in breach of the licence conditions pending completion of such consultation process. We note the interaction of this remedy with the introduction of a new Standard of Conduct and the removal of the Whole of the Market Requirement from the Confidence Code. These are discussed in paragraphs 15.86 and 15.87 below.

Remedies to help customers engage

- *Ofgem programme to promote customer engagement*

15.83 We expect Ofgem to begin developing proposals concerning the priority list of measures that we recommend are the focus of the testing as soon as possible following the CMA's final report. In particular, we expect Ofgem to progress such plans simultaneously with a consultation on a new licence condition concerning suppliers' participation in the Ofgem-led programme.

15.84 Ofgem could conduct evaluations of the trials from late 2017 onwards, and where trials proved successful, any interventions could be implemented from late 2018 onwards. In 2019, we would expect further interventions arising from the Ofgem-led programme to be progressively implemented.

Subsequently we expect Ofgem to monitor the effectiveness of the interventions and continue to update the programme on an ongoing basis.

15.85 We therefore expect this remedy to start having an effect in addressing aspects of the features identified in Section 9, including the actual and perceived barriers in accessing and assessing information, from the beginning of 2019.

- *Greater use of principles – addition to standards of conduct*

15.86 As with the other recommendations concerning changes to suppliers' licence conditions, we expect Ofgem's consultation on the new standard of conduct to conclude by the end of 2016, such that it could implement and enforce the revised standard of conduct from 2017 onwards. As explained in Section 13, we consider that the effectiveness of the remedy critically depends on Ofgem maintaining its monitoring and enforcement activity concerning all Standards of Conduct.

- *Enhancing the ability and incentives of TPIs to prompt engagement*

15.87 We consider that the changes to the Confidence Code could be implemented simultaneously with our recommendations concerning suppliers' licence conditions. In this regard, we expect Ofgem to consult on the removal of the Whole of the Market Requirement from the Confidence Code as soon as possible after we publish our final report, with this process expected to conclude by the end of 2016. The change could then be implemented by the beginning of 2017.

15.88 The CMA will draft and consult on an order requiring the code administrator or governing body with authority to grant access to the ECOES database and the gas transporters to provide PCWs (and other TPIs providing similar services) with access to data in the six-month period following publication of the final report, with this process expected to conclude by the end of 2016. The code administrator or governing body with authority to grant access to the ECOES database and the gas transporters could then be expected to provide access to PCWs (and other TPIs providing similar services) from the beginning of 2017 onwards.

15.89 As regards the recommendation to DECC to make changes to the Midata programme, we envisage that DECC will consult on the changes as soon as possible following publication of our final report, with a view to introducing the requisite changes in its ongoing legislative programme for inclusion in the next energy sector or omnibus bill.

15.90 We therefore expect this package of remedies aimed at promoting the role of TPIs in addressing actual and perceived barriers in accessing and assessing information and promoting competition among TPIs and, in turn, suppliers to take effect during 2017.

- *Prompts for customers – customer database remedy*

15.91 Following publication of our final report, the CMA will start drafting and consulting on an order requiring suppliers to send an opt-out letter (the Opt-out Letter) to their domestic customers who have been on the SVT or other default tariff for three or more years (Disengaged Domestic Customers). During this period, we also expect Ofgem to begin developing the database and associated access agreements, and following publication of the CMA's final order, we will require suppliers to send the Opt-out Letter to all Disengaged Domestic Customers by mid-2017.

15.92 We will require suppliers to pass certain details of the Disengaged Domestic Customers who have not opted out to Ofgem by October 2017 at the latest. We will therefore expect rival suppliers to start accessing the database, and contacting the relevant Disengaged Domestic Customers from the beginning of 2018. The database will then be updated on a regular basis from the beginning of 2018 onwards.

- *Customers on restricted meters*

15.93 As regards the suppliers making all their single-rate tariffs available to any domestic customers on any type of restricted meter without making switching conditional on a restricted meter being replaced, and the provision of certain information to such customers and Citizens Advice, the CMA will start drafting and consulting on an order in the six-month period following publication of our final report. We expect suppliers to be able to make the necessary adjustments to their billing systems within three months of the date of a CMA order, and therefore to start offering all customers on restricted meter tariffs the ability to switch to their single-rate unrestricted meter tariffs, and providing the relevant information, by April 2017. We expect this to lead to increased engagement from customers on restricted meters from April 2017.

15.94 As regards our recommendation that Citizens Advice become a recognised provider of information and support for customers on restricted meters, we expect Citizens Advice to be able to progress the implementation of this remedy as soon as possible following publication of the CMA's final report.

Price cap

- 15.95 As regards the price cap, we expect that once the final order is published specifying the level of the price cap, suppliers will need at least two months to notify their customers of any price changes required in order to comply with the price cap and to implement these changes. We therefore anticipate that the price cap could be in force and effective from April 2017.

Conclusion on timescale for remedies to address the Domestic AECs

- 15.96 We have concluded that we could reasonably expect all elements of the remedy package to be in place within around 12 to 18 months of publication of our final report. We have also concluded that the remedies will have a significant beneficial impact on competition within two to three years of publication of our final report and that this effect will continue to grow, as competition and innovation between suppliers is enhanced in their offerings of products to domestic customers, and domestic customers become more aware of the potential benefits of shopping around and of the tools available to help them to do so.

Consistency of our remedies with existing and future laws and regulations

- 15.97 As part of our consideration of the design of each of the remedies in our package, we have considered whether these remedies will be inconsistent with other relevant laws and regulations applicable to the domestic retail energy markets. A particular focus of our assessment of this aspect of remedy design has been the interaction of our remedies with EU legislation; data protection legislation; legislation concerning privacy and electronic communications; general consumer protection legislation; existing standard licence conditions; and future legislative programmes.
- 15.98 In this regard, compliance with EU legislation (in particular, the Energy Directives³⁴) has been a relevant design consideration of the removal of the simpler choices component of the RMR rules, the softening of SLC 22B.7(b) to partly address the Prepayment AEC and the price cap. Compliance with data protection legislation (in particular, the Data Protection Act 1998, the Privacy and Electronic Communications Regulations 2003 and the forthcoming General Data Protection Regulation³⁵) has been a relevant design consideration of our Database remedy and, to a lesser degree, the remedies to give PCWs (and other TPIs providing similar services) access to

³⁴ Directive 2009/72/EC of 13 July 2009 concerning common rules for the internal market in electricity and Directive 2009/73/EC of 13 July 2009 concerning common rules for the internal market in natural gas.

³⁵ European Commission, [Proposal for a General Data Protection Regulation](#).

the ECOES and SCOGES databases. Compliance with general consumer legislation and existing standard licence conditions (and in particular, the Standards of Conduct) has been a relevant design consideration of our removal of aspects of the simpler choices component of the RMR rules. As regards the price cap, we have had particular regard to the Energy Directives and the Federutility Judgment.³⁶

- 15.99 DECC's proposed legislative programme for Midata phase 2 has also been a relevant aspect of our remedy to give TPIs access to Midata.
- 15.100 As regards forthcoming regulatory developments, we have, where relevant, taken these into account in our design of individual remedies, such as Ofgem's ongoing work concerning the Debt Assignment Protocol. Where our remedies involve amendments to suppliers' licences, we have also had regard to Ofgem's statutory duties and objectives concerning each individual remedy.
- 15.101 In light of the above, we have concluded that our package of remedies, and the elements within it, are consistent with current and expected laws and regulations applicable to the domestic retail energy markets.

Coherence of our remedies as a package

- 15.102 We have considered the extent to which the remedy measures contained within our package of remedies are likely to be mutually reinforcing.
- 15.103 We have identified in Section 11 a number of important synergies between the different elements of the package of remedies.
- 15.104 Each of the remedies, concerning the Prepayment AEC, the RMR AEC and the Domestic Weak Customer Response AEC addresses, in a different and complementary way, various aspects of the features giving rise to the Domestic AECs and the detriment arising from them.
- 15.105 First, the remedies that we are proposing that concern only the Prepayment AEC (namely, the amendment of SLC 22B.7(b), the redistribution of gas tariff pages, and amendments to the Debt Assignment Protocol) are mutually reinforcing in addressing aspects of the features we have identified concerning the technical constraints of the prepayment system and softened incentives for suppliers to compete to acquire new prepayment customers.

³⁶ Case C-265/08, *Federutility and others v Autoita per l'energia elettrica e il gas*, (2010) ECR I-3377. As part of our assessment we have also considered the Court of Justice judgment delivered on 10 September 2015 in the *Commission v Poland* case, Case C-36/14, which broadly upheld the Federutility Judgment.

- 15.106 However, despite such supply-side remedies, we do not believe they will, by themselves, be effective at addressing the full extent of the Prepayment AEC, nor the substantial detriment that we have observed being suffered by prepayment customers.³⁷ In this regard, as set out in Section 11, there are substantial synergies between the remedies targeted exclusively at the Prepayment AEC, and the other remedies concerning the Domestic Weak Customer Response AEC and RMR AEC, which also impact prepayment customers. These remedies, in combination, contribute to addressing the features of these AECs.
- 15.107 Second, our remedies concerning the Domestic Weak Customer Response AEC all have the synergy of simultaneously addressing different components of the features we have identified.³⁸ In addition to facilitating engagement by some of the most disengaged domestic customers (such as those who have been on a SVT for three or more years), the remedies are also expected to improve engagement levels across the domestic retail energy markets as a whole. This includes customers on restricted meters, who we have observed are subject to heightened features giving rise to weak customer response.
- 15.108 This also includes prepayment customers, who we have observed are paying particularly high prices compared with the rest of the markets and are suffering more significantly from weak customer response than domestic customers on direct debit tariffs.³⁹
- 15.109 More specifically, as regards the domestic engagement remedies, we believe there are certain aspects which will mutually reinforce once such remedies start to become effective.
- 15.110 The Ofgem-led programme is potentially wide-ranging in scope (beyond the initial priority list of measures that we have identified as being particularly suitable for testing). Some of our other remedies involve new communications with certain domestic customers (eg aspects of the marketing letters concerning the Database remedy), and may also be suitable candidates for inclusion in the Ofgem-led programme after prioritisation of our priority list of measures.
- 15.111 The remedies that enhance TPIs' ability and incentives to engage domestic customers will also work synergistically with the remedies concerning customers on restricted meters. Such customers' awareness of and interest

³⁷ See Section 11.

³⁸ See paragraphs 15.3–15.54.

³⁹ See Section 10.

in their ability to switch is expected to increase simultaneously with a reduction in the actual and perceived barriers to switching that they face. At the same time, PCWs (and other TPIs providing similar services) will have better access to accurate meter numbers (through the ECOES and SCOGES databases), stronger incentives to negotiate individual deals with suppliers (which could, for instance, focus on particular customer groups such as prepayment customers, or encouraging customers on restricted meters to switch to single-rate tariffs), and in due course will have access to more comprehensive customer data through an enhanced Midata programme.

15.112 However, while we believe that the remedies will help create a framework for effective competition and improve customer engagement for the reasons set out above and in Section 11, we believe it is necessary to introduce a price cap for a limited period of time for prepayment customers.

15.113 We have considered the interaction of such a price cap with our other remedies, in particular, the broader remedies targeting the Domestic Weak Customer Response AEC and those concerning exclusively the Prepayment AEC.

15.114 However, we expect such interaction to be limited in the interim period pending our engagement remedies becoming effective.⁴⁰ We note that the removal and reduction of certain technical and regulatory constraints on suppliers offering tariffs to prepayment customers (in particular, concerning gas tariff codes and the removal of the four-tariff rule), and the enhanced ability and incentives for TPIs to engage with domestic customers, are all remedies that could become effective early in 2017. Such remedies have the capacity to and, indeed, it is our expectation that they will, increase suppliers' ability and incentives to engage prepayment customers, and increase some prepayment customers' ability to access and assess information to help them decide whether to switch. However, the effectiveness of such remedies will be limited as regards prepayment customers, on the one hand, because certain technical constraints concerning the dumb prepayment infrastructure will persist (there will continue to be a limited total of gas and electricity tariff pages), and on the other, because prepayment customers are less likely to use a PCW for searching when switching, have confidence in using a PCW and have access to the internet, than direct debit customers.⁴¹

⁴⁰ See Sections 11 and 14.

⁴¹ See Section 9.

15.115 In any event, we have sought to design the price cap to ensure that there are benefits available to customers who engage once it is in place and our other remedies have started to take effect. These design considerations are set out in Section 14.

15.116 We have therefore concluded that this represents a coherent package of remedies, whose elements are mutually reinforcing and support the statutory duties and objectives of Ofgem, where relevant.

Conclusion on effectiveness of the remedy package

15.117 In light of the above, we have concluded that the package of remedies represents an effective solution to the Domestic AECs that we have identified.⁴²

Relevant customer benefits

15.118 In deciding the question of remedies, the CMA may 'have regard to the effect of any action on any relevant customer benefits (RCBs) of the feature or features of the market concerned'.⁴³ RCBs are defined in the 2002 Act and are limited to benefits to relevant customers in the form of:

- (a) lower prices, higher quality or greater 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) greater innovation in relation to such goods or services.

15.119 The 2002 Act provides that a benefit is only an RCB if the CMA believes that:

- (a) the benefit has accrued as a result (whether wholly or partly) of the feature or features concerned or may be expected to accrue within a reasonable period of time as a result (whether wholly or partly) of that feature or those features; and
- (b) the benefit was, or is, unlikely to accrue without the feature or features concerned.

15.120 In the Remedies Notice, Supplemental Remedies Notice and the Second Supplemental Remedies Notice we invited parties to inform us of any RCBs

⁴² As noted above, the assessment of the effectiveness and proportionality of the remedies concerning the Settlement AECs is addressed in Section 12.

⁴³ Section 134(7) of the 2002 Act.

to which we should have regard. We have considered any RCBs raised under each individual remedy assessment (including those we have decided not to proceed with), whether specifically under a separate consideration of RCBs, or in the context of the design of the remedy and a consideration of its possible unintended adverse consequences.

15.121 We have concluded that there are no RCBs that might be lost as a result of introducing our package of remedies. Consequentially, we see no need to modify our remedy package to take account of RCBs.

Proportionality of our package of remedies

15.122 In this section, we have summarised our assessment of whether our package of remedies will be proportionate to address the Prepayment AEC, the RMR AEC and the Domestic Weak Customer Response AEC that we have found and/or the associated detriments. We have done this by considering whether the package of remedies:

- (a) is effective in achieving its aim;
- (b) is no more onerous than necessary to achieve its aim;
- (c) is the least onerous if there is a choice; and
- (d) does not produce adverse effects which are disproportionate to the aim.

Effective in achieving its aim

15.123 For the reasons set out in Sections 12, 13 and 14, we have concluded that our package of remedies will be effective in its legitimate aim of remedying the Prepayment AEC, the RMR AEC and the Domestic Weak Customer Response AEC that we have identified and/or the associated detriments.

No more onerous than necessary to achieve its aim

15.124 In assessing whether the package of remedies is no more onerous than necessary, we have considered:

- (a) whether each measure within the package of remedies is required to remedy, mitigate or prevent the Domestic AECs and/or their detrimental effects that we have found; and
- (b) whether the design of each remedy measure within the package of remedies is no more onerous than it needs to be.

Is each element of the package of remedies necessary?

- 15.125 We have considered whether it is possible to achieve a sufficiently comprehensive solution to the Domestic AECs and/or their detrimental effects that we have identified without implementing all of the measures in our package of remedies.
- 15.126 Based on our assessment in Sections 11, 12, 13 and 14 of how the elements of the remedy package contribute to remedying, mitigating or preventing the Domestic AECs and/or their detrimental effects, we took the view that each measure makes a material contribution to the effectiveness of the remedy package, such that its overall impact would be weakened if any single measure were removed from the package. The contribution to the overall impact of the package varies between remedies but each has an important role to play in remedying, mitigating or preventing the Domestic AECs and/or their detrimental effects that justifies its inclusion in the package, and they are mutually reinforcing (see paragraphs 15.3 to 15.61 and 15.102 to 15.116).
- 15.127 While the measures work together to address the Domestic AECs, we have nonetheless considered some elements to be of particular importance to make a significant contribution to remedying the Domestic AECs even in the absence of the other remedies.
- 15.128 For instance, the removal of certain aspects of the simpler choices component of the RMR rules is of particular importance in enhancing competition and innovation between suppliers in their offerings to domestic customers and, accordingly, will make a significant contribution to addressing the RMR AEC and associated detriment.
- 15.129 The Ofgem-led programme (involving RCTs, where appropriate) and the Database remedy are of particular importance in prompting domestic customers to engage in the markets and, accordingly, will make a significant contribution to addressing the Domestic Weak Customer Response AEC and associated detriment. These two remedies in particular work together by seeking to (a) improve the correspondence that customers receive where suppliers' incentives are not fully aligned (especially in terms of highlighting the alternative options available to customers), and (b) give those rival suppliers (which have an incentive to engage customers) the ability to market directly to the most disengaged customers.
- 15.130 The price cap remedy is of particular importance to protect prepayment customers against the low competitive pressures in the prepayment segments, and the detriment that, in our view, arises and will continue to

arise from the Prepayment AEC and the Domestic Weak Customer Response AEC while our other remedies aimed at addressing these AECs take effect, and until the roll-out of smart meters (expected to be substantially completed by the end of 2020).

15.131 We believe that the features giving rise to the Prepayment AEC (and to a certain extent the Domestic Weak Customer Response AEC insofar as it applies to prepayment customers) will be mitigated (or entirely eliminated, as regards technical constraints that limit suppliers' ability to offer a variety of tariff structure) in the medium term as a result of the roll-out of SMETS 2 meters and the implementation of the package of prepayment and engagement remedies. However, for the reasons set out above and in Section 11, we believe the prepayment price cap is necessary to protect prepayment customers over the short term from a detriment of the magnitude that we have found. Accordingly, we consider that the price cap remedy is a necessary element of our remedies package.

15.132 We consider that the complementary effect of the various elements of the remedies package is an important aspect of the effectiveness of the package as a whole. Accordingly, we have concluded that it is necessary to include each of the measures in our package of remedies in order to achieve a sufficiently comprehensive solution to the Domestic AECs we have identified.

Is the design of each remedy measure within the package of remedies no more onerous than it needs to be?

15.133 Our consideration of the design and implementation of each of the measures is set out in Sections 12, 13 and 14.

15.134 In reaching our decisions on remedy design, we have sought to avoid imposing costs and restrictions on parties that go beyond what is needed to achieve an effective remedy.

15.135 We have also sought to strike a similar balance in terms of remedy implementation. For example, we will seek undertakings where possible to achieve certain of our remedies where we consider it may be effective and appropriate do so.

15.136 As regards the price cap, we have considered whether it may be possible to limit the prices paid by prepayment customers without imposing a price cap, for example, through using principles based regulation concerning a cost-reflectivity requirement. We have also taken into account the potential for the price cap to be more onerous than necessary in its design. In this regard, we

have specifically taken into account the potential for the price cap to be set at a level that does not allow reasonable opportunity for suppliers to recover efficient costs, and as regards implementation costs. We have sought to mitigate these risks by taking competitive prices from outside the prepayment segments, adjusted to reflect cost differentials, and then updating such prices in line with indices tracking key components of a customer's bill. Additionally, the existence of headroom allows efficient suppliers to compete beneath the level of the cap while still earning a normal return on capital.

15.137 By following the above approach, we have sought to ensure that no measure within the package of remedies is more onerous than it needs to be, in order to address the Domestic AECs.

15.138 In light of the above, we have therefore concluded that our package of remedies is no more onerous than necessary in order to remedy the Domestic AECs and resulting customer detriment.

Least onerous if there is a choice

15.139 If the CMA is choosing between two remedy measures which appear to be equally effective, it should choose the remedy measure that imposes the least cost or is least restrictive.

15.140 We have not been able to identify an alternative package of remedies that would be both as effective, and less onerous, in addressing the Domestic AECs and associated detriment as the package we have identified. However, when deciding on the measures to be included in our package of remedies, we have considered some other possible ways of addressing the Domestic AECs and/or customer detriment. These include measures that we have proposed for consideration, and some other measures that have been proposed by parties in response to the Remedies Notice, Supplemental Remedies Notice and Second Supplemental Remedies Notice.

15.141 Our detailed assessment of these alternative measures is set out in Sections 12 and 13. We have concluded that a number of measures should not be pursued as part any package.

15.142 As regards the efficient allocation of gas tariff pages, we have decided not to proceed with centralising the management of gas (and potentially electricity) tariff pages, which we consider would have been more complex, time-consuming and costly than the alternative remedy of seeking undertakings from certain suppliers and/or a new licence condition.

- 15.143 We have also considered whether the remedies suggested by Centrica and Scottish Power, which would involve a prohibition on evergreen default tariffs and prompting customers on fixed-term contracts, would achieve the same aim as, but would be less onerous than, our engagement remedies. However, in our view these proposals fail to meet the effectiveness and proportionality tests. Centrica's proposal would not be effective to address (in whole or in part) the Domestic Weak Customer Response AEC and/or associated detriment as we do not consider this proposal to be a substantial departure from the status quo. While Scottish Power's proposal could potentially be effective to address (in whole or in part) the Domestic Weak Customer Response AEC, we consider that this proposal would not be proportionate based on its potential high implementation costs, and its potential adverse unintended consequences on domestic customers and, in particular, the risk of higher prices for default tariffs.
- 15.144 In our package of remedies, we have also decided not to include measures that will not make a material contribution to remedying the Domestic AECs. For instance, in the context of the removal of the simpler choices component of the RMR rules and the removal of the Whole of the Market Requirement, we have decided not to recommend that Ofgem provide an independent price comparison service as this service would not add significant further value to that already provided by the Citizens Advice service.
- 15.145 As regards the price cap, we have considered multiple alternative design options, including an external reference price approach which involves setting a cap on prepayment tariffs based on direct debit acquisition tariffs in the market plus an uplift reflecting our assessment of the costs associated with prepayment, and options that would be more complex, costly to and time-consuming to implement and monitor. Our consideration of these alternative options are set out in Section 14. Our preferred design option, involving a hybrid reference price and cost index approach is, in our view, the design that achieves the best balance between practicability, minimising the scope for gaming, accuracy, and our key criterion for being capable of implementation in the near future (in order to maximise its effectiveness). We believe such a design will meet our key criterion for the price cap remedy to be timely to implement, given the timescales involved with our other remedies. In addition, we have sought to ensure that it is no more onerous than necessary by limiting the scope (SMETS 2 smart meters are out of scope) and limiting the duration with a fixed termination date and a mid-term review in 2019.
- 15.146 In light of the above, we have concluded that, to the limited extent that we have a choice between effective remedies, we have identified the package of remedies that imposes the least cost and is least restrictive.

Does not produce adverse effects which are disproportionate to the aim

- 15.147 We have considered whether the package of remedies is likely to produce adverse effects which are disproportionate to the aim of remedying the Domestic AECs and/or the resulting customer detriment.
- 15.148 In reaching a judgement about whether to proceed with a particular remedy, the CMA considers its potential effects – both positive and negative – on those persons most likely to be affected by it. The CMA pays particular regard to the impact of remedies on customers. The CMA also has regard to the impact of remedies on those businesses subject to them and on other affected parties, such as other businesses (eg potential entrants, or firms active in upstream or downstream markets), government and regulatory bodies, consumer organisation, and other monitoring agencies.

Benefits of the remedies package

- 15.149 We have considered the likely benefits of the package of remedies.
- 15.150 As described in paragraph 15.9 above, the key benefits of the package of remedies that we have are threefold: (a) to create a framework for effective competition, (b) to improve customer engagement, and (c) to protect prepayment customers.
- 15.151 In Sections 10 and 14, we have concluded that the scale of detriment caused by the Domestic AECs was substantial, in particular, as regards prepayment customers. We have also observed heightened features for customers on restricted meters. The magnitude of the detriment involved supports a decision that a wide-ranging package of remedies, of the kind we are proposing, is necessary and appropriate.
- 15.152 As discussed in paragraphs 15.102 to 15.116, we believe the package we are proposing is a coherent package of mutually reinforcing remedies. This is particularly the case concerning the remedies addressing exclusively the Prepayment AEC, those addressing the RMR AEC and those addressing aspects of the Domestic Weak Customer Response AEC, which will free suppliers from regulatory restrictions that unnecessarily restrict competition, while putting in place measures aimed at overcoming suppliers' misaligned incentives with those of customers seeking to conduct 'value-for-money' assessments, and enhancing the ability and incentives of those participants in the markets whose incentives are aligned with those of customers.
- 15.153 While the price cap will reduce the extent to which prepayment customers are overpaying for their gas and electricity, and so reduce the scope for further price reductions by suppliers, we nevertheless consider that there

remains an important role for competition between suppliers to prepayment customers, and for engagement by prepayment customers, and we have carefully designed our price cap remedy to allow such competition and engagement to develop.

15.154 In light of this assessment, we have considered the scope for customers to benefit from increased competition and engagement as a result of our remedy package, which we consider will be substantial. We reached this view, in light of the following considerations:

- (a) Our assessment of the detriment that has been, and is being suffered, by domestic customers as a result of the Domestic AECs is around £1.4 billion per year over the last three and a half years,⁴⁴ with a marked increase in detriment year on year. We have noted a considerable variation in the detriment suffered by customers of different suppliers and between different categories of customer.
- (b) In particular, we have observed particularly high detriment for prepayment customers of £388 million per year⁴⁵ for a dual fuel prepayment customer with medium consumption.⁴⁶

Costs of the remedies package

15.155 We have considered the potential scale of the costs generated by the remedy package in Sections 12, 13 and 14.

15.156 The following aspects of our package may generate material costs:

- (a) The Ofgem-led programme is a potentially resource-intensive and long-term programme that will involve material costs being incurred by Ofgem. The Behavioural Insights Team told us that the costs of the trials that it had conducted to date had been between £[~~300~~], although we note that costs may vary substantially, depending on the size and complexity of the trial. We also note that the requirement to participate in the Ofgem-led programme will be costly for suppliers. However, we note that Ofgem would be required to assess the proportionality of any testing and supplier participation before proceeding.
- (b) The Database remedy could be expected to involve costs in the region of £200,000 to £300,000 to create a secure cloud database capable of securely holding the relevant details of the Disengaged Domestic

⁴⁴ Section 9.

⁴⁵ Based on information relating to the Six Large Energy Firms for the first two quarters of 2015 only.

⁴⁶ See Sections 10 and 14.

Customers, and £35,000 to £50,000 per year to operate the database. In addition, suppliers and Ofgem will incur certain costs to put in place agreements concerning access to the database, and Ofgem will incur ongoing costs concerning the maintenance and operation of the database. However, many suppliers' costs of entering into agreements with Ofgem are likely to be displaced (in whole or in part) by profits from potential new customers that switch to the supplier pursuant to a targeted marketing campaign. Consequently, we did not consider any additional costs of entering into access agreements with Ofgem as a material cost of this remedy. We have also noted the importance of the Opt-out Letter being appropriately worded so as to avoid unsettling customers, minimise confusion and otherwise avoid developing mistrust. While some costs will therefore be incurred by the CMA, Ofgem and suppliers in developing a suitable Opt-out Letter (during the period prior to publication of the CMA's final order), we expect such costs to be modest.

- (c) The requirement on suppliers to offer their single-rate tariffs to customers on restricted meters without making such offers conditional on changing their meter may impose costs on suppliers, as regards updates to their billing systems. However, given that two of the Mid-tier Suppliers currently make their single-rate SVTs and single-rate fixed-term tariffs available to new or existing customers, we do not expect such costs to be significant.
- (d) As regards the price cap, we note that we have sought to minimise implementation costs by choosing a straightforward design for the cap. We consider the particular design of the price cap that we have decided to introduce will have modest costs in terms of implementation, and will principally relate to updating tariff prices according to the exogenous cost indices, and also the costs of monitoring compliance with the price cap. We note in this regard that the Water Industry Commission for Scotland (WICS) spent £0.9 million in 2014/15 (and £1.0 million in 2013/14)⁴⁷ on 'determination of prices and monitoring of performance' and that this covered the period in which WICS determined the price control for 2015–2021. Given the scale of Ofgem's anticipated involvement in administering the price cap we expect that the incremental cost for Ofgem will be closer to the costs we note WICS incurred. We expect that suppliers will incur low implementation costs, since they will merely need to inform relevant customers that are subject

⁴⁷ See [WICS resource accounts 2014-15](#), note 3.

to the price cap that their annual bill will not exceed a predetermined level assuming an average consumption level.

15.157 We have also noted the potential impact of the price cap on the annual bills for the Six Large Energy Firms, which will be reduced as a result of the price cap by an amount of around £300 million, equivalent to a reduction in the average annual bills paid of around £75.⁴⁸ [✂] However, we have not assessed this estimated bill reduction as a cost of the remedy given that the purpose of the remedy is to achieve reasonable prices for prepayment customers, and bill reduction will be the direct effect of any remedy that was effective in addressing the associated customer detriment (which as noted above, our assessment has shown is almost £388 million per year⁴⁹).

15.158 As regards the other remedies comprising the package we do not consider they will generate material costs.

(a) We do not believe the remedies exclusively concerning the Prepayment AEC will involve substantial costs, in particular as regards the softening of SLC 22B.7(b) and the recommendation concerning the Debt Assignment Protocol, which supplements Ofgem's ongoing work in this area. As regards agreeing undertakings to release certain gas tariff codes and/or amending suppliers' licence conditions to set a cap on the number of gas tariff pages that a supplier can hold, we recognise that an unused tariff page may have some option value for a supplier. However, we have not received any evidence that any such value would be significant. We have also sought to ensure that any of the Six Large Energy Firms that will be required to release gas tariff pages will have a sufficient number remaining.

(b) We do not believe the remedies concerning the RMR AEC will involve substantial costs, which involve, at most, a short consultation on changes to suppliers' licence conditions.

(c) We do not believe that providing access to PCWs (and other TPIs providing similar services) to the ECOES or SCOGES databases will involve substantial costs for the code administrator or governing body with authority to grant access to the ECOES database or the gas transporters. Similarly, we do not believe our remedy concerning an enhanced Midata specification and access for TPIs will involve material costs.

⁴⁸ See Section 14.

⁴⁹ Based on information relating to the Six Large Energy Firms for the first two quarters of 2015 only.

(d) We do not believe that requiring suppliers to provide certain additional information to their customers on restricted meters, and recommending Citizens Advice to become a recognised provider of information and support to such customers will involve material costs.

15.159 Finally, we have also considered the risks of our package of remedies leading to unintended adverse consequences, and they have been designed in such a way as to minimise the risk of unintended adverse consequences. In particular:

(a) We do not expect our price cap to have a material adverse impact on competition in the prepayment segments, which we have identified as currently exhibiting limited effective competition and engagement by prepayment customers, leading to substantial detriment that we expect to continue, in particular, in the period leading to the effective implementation of our other remedies.

(b) The duration of the price cap will be limited, and closely linked to the substantial completion of the roll-out of smart meters, thereby minimising any medium-term and eliminating any long-term unintended adverse consequences. In addition, SMETS 2 meters will be excluded from the scope of the price cap.

(c) Many of our other remedies will, to a greater or lesser extent, involve Ofgem in their implementation, monitoring and/or enforcement. As sector regulator, Ofgem will be able to assist with the mitigation of any unintended adverse consequences that may arise from our remedies.

15.160 In light of the assessment we have conducted above and in Sections 11 to 14, we consider that the costs and unintended adverse consequences associated with our remedy package are likely to be modest in comparison with the levels of detriment that we have observed as arising, in particular, from the Prepayment AEC and the Domestic Weak Customer Response AEC.

Balance of benefits and costs

15.161 We have considered whether the benefits of the remedy package are likely to exceed the likely costs.

15.162 We have concluded in paragraphs 15.149 to 15.154 that the benefits of increased competition and engagement as a result of our remedy package will be substantial, in particular, in light of the detriment that we have observed as arising from the Domestic Weak Customer Response of £1.4 billion per year for domestic customers, and as arising from the

Prepayment AEC and the Domestic Weak Customer Response AEC specifically concerning prepayment customers of £388 million per year.⁵⁰ Set against these benefits, we have considered, for the reasons set out in paragraphs 15.155 to 15.160, that the costs of implementing our remedy package are likely to be modest in comparison to the levels of detriment that we have observed as arising, in particular, from the Prepayment AEC and the Domestic Weak Customer Response AEC. We have not quantified precisely every aspect of our remedies, nor is it possible to do so given the nature of some remedies such as the Ofgem-led programme which by necessity leave considerable discretion for Ofgem to determine what and how it should test as part of its research programme, taking into account what will be proportionate for the programme to be effective.

15.163 We have therefore concluded that the benefits of the remedy package are likely to exceed its costs and that, consequently, the remedy package is unlikely to give rise to adverse effects that are disproportionate to its legitimate aim.

Conclusion on proportionality

15.164 We have concluded that our package of remedies represents a proportionate solution to the Domestic AECs and resulting customer detriment.

⁵⁰ Based on information relating to the Six Large Energy Firms for the first two quarters of 2015 only.

16. Microbusinesses

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Introduction

16.1 This section discusses the retail supply of energy to microbusinesses.

16.2 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

- 16.3 The terms of reference for this market investigation¹ 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.
- 16.4 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
 - (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.²

¹ Ofgem (2014), *Decision to make a market investigation reference in respect of the supply and acquisition of energy in Great Britain*, p30.

² If a non-domestic customer qualifies under only one of the consumption criteria, it is regarded as a microbusiness only for that fuel.

- 16.5 However, information is not always specifically available for microbusinesses. In various places, this section 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).
- 16.6 This issue is partly due to the fact that suppliers generally do not distinguish between microbusinesses and SMEs.³ 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.⁴ Furthermore, each of the Six Large Energy Firms categorises SMEs in a different way, and these differ from the Ofgem microbusiness definition.
- 16.7 In 2014, Ofgem reported that microbusinesses accounted for an estimated 1.6 million electricity meter points and 0.55 million gas meter points.⁵

Parameters of competition

- 16.8 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 9, in particular, concerning the role of traditional meters and bills, which are also a fundamental characteristic of the SME retail energy supply markets. These 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 segments, as 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.

³ We understand that this is partly because it is difficult for suppliers to collect and update information on customers' turnover and employee count.

⁴ RWE told us [REDACTED].

⁵ Ofgem (2014), *Proposals for non-domestic automatic rollovers and contract renewals*, pp40 & 41.

Customer differences

- 16.9 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).⁶
- 16.10 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.⁷ This compares with a mean figure for electricity and gas combined of £1,276 for domestic customers.⁸
- 16.11 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.
- 16.12 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.
- 16.13 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 41% of microbusinesses and small businesses use both mains electricity and mains gas.⁹

Differences between supply to microbusinesses and domestic customers

Contracts

- 16.14 Unlike the domestic markets, microbusiness contracts are largely single fuel, even among customers using both fuels. This is in part due to non-domestic

⁶ As of Q1 2012. Ofgem (2012), *The Retail Market Review – draft impact assessment for the updated proposals for businesses*.

⁷ 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.

⁸ TNS BMRB (2014), *Retail Market Review baseline survey: report prepared for Ofgem*, cited in Ofgem, Micro-Business Consumers Memo, p6.

⁹ BMG Research (2016), *Micro and Small Business Engagement in Energy Markets* (report for Ofgem), p10.

customers using varying proportions of gas and electricity, meaning that a dual fuel tariff would be less well-suited for many.

- 16.15 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.¹⁰
- 16.16 Tariffs for non-domestic customers are or can be set on an individual basis, unlike the domestic markets where there are 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).
- 16.17 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 16.28).¹¹ Since 2013, the largest suppliers of energy to small businesses (including the Six Large Energy Firms and Opus Energy) have gradually withdrawn auto-rollover contracts, as a result of pressure from Ofgem¹² and the government.¹³ 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).
- 16.18 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).

¹⁰ Ofgem (2014), *Proposals for non-domestic automatic rollovers and contract renewals*, p41.

¹¹ 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.

¹² Opus Energy told us that there had been pressure from Ofgem and the government for it to stop using auto-rollovers.

¹³ Number 10 and DECC launched a [small business energy working group](#).

Suppliers

- 16.19 There are more suppliers active in the SME markets than in the domestic markets.¹⁴ The Six Large Energy Firms are important players in both markets, but some of them only have small SME gas supply activities.
- 16.20 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 segments (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

- 16.21 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.
- 16.22 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.
- 16.23 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.¹⁵ Ofgem decided not to formally ban a particular type of contract known as ‘auto-rollover’, although it said that it would carry out further work in this

¹⁴ As of June 2015 there were 31 active suppliers in the domestic retail markets, most of which offered both gas and electricity; this compared with 41 active gas suppliers and 42 active electricity suppliers in the non-domestic markets (SME and I&C).

¹⁵ 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.

area.¹⁶ The maximum length of auto-rollover contracts has been restricted to one year since 2009.

- 16.24 The level of regulation in the microbusiness segments, which as noted above is generally lower 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.¹⁷

Costs and prices

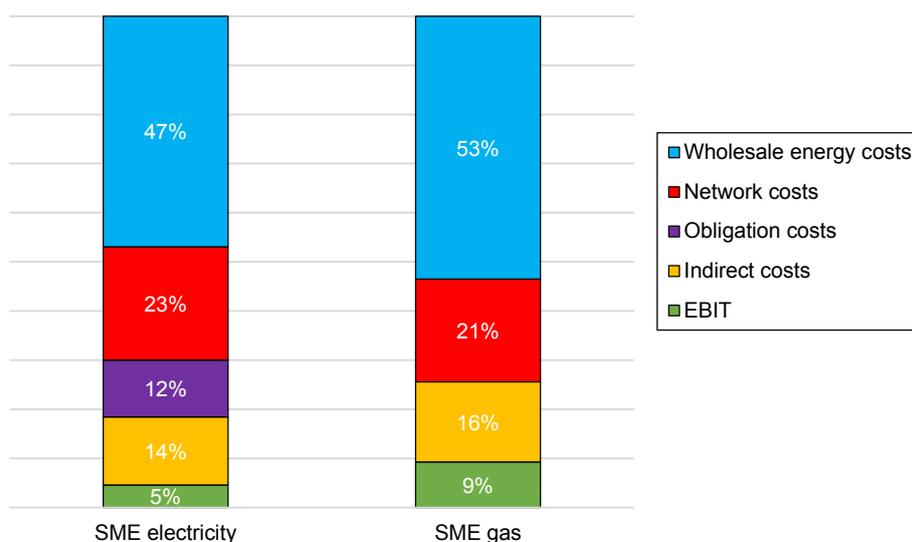
- 16.25 Unit revenues are slightly lower for SME customers than for domestic customers. For example, in FY14, the average electricity unit revenue across the Six Large Energy Firms was £130/MWh in the SME markets, compared with £144/MWh in the domestic markets.¹⁸ However, there are some differences between 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.
- 16.26 Figure 16.1 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 8 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.

¹⁶ Ofgem (2014), [Decision on automatic rollovers and contract renewals for micro-business consumers \(letter to interested parties\)](#), p5.

¹⁷ Number 10 and DECC launched a [small business energy working group](#).

¹⁸ See Appendix 9.13: Retail energy supply profit margin analysis and comparators.

Figure 16.1: Structure of the costs incurred by the Six Large Energy Firms to supply SME electricity and gas customers (FY 2014)



Source: CMA analysis of P&L data submitted by the Six Large Energy Firms.
 Note: Figures do not include VAT.

16.27 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.¹⁹

Tariff types

16.28 The broad tariff types available to microbusinesses²⁰ 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

¹⁹ Section 8 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.

²⁰ In general, the same broad tariff types are offered by the Six Large Energy Firms and other suppliers.

generally does not 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, this may automatically be followed by an extension of the existing fixed-term contract or a new fixed-term contract (if the customer takes no action); often at 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).²¹ Some suppliers have replaced auto-rollover contracts with fixed-term contracts which a customer can leave after giving notice ('notice products'). We consider that these notice products differ from auto-rollover contracts. We use the term 'replacement products' to refer to the broad set of tariff types that suppliers now use in place of auto-rollover contracts.

(b) Tariffs with variable prices:

- (i) Evergreen contracts: These contracts have no termination date and the prices are changed periodically.²² 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 deemed tariffs, which requires suppliers to ensure that the terms of these tariffs are not unduly onerous.²³
- (iii) OOC: This applies to non-domestic customers that have terminated their contracts, but have not yet switched to a new supplier. Non-

²¹ Some customers currently remain on these tariffs until their existing contracts expire.

²² These may also be known as 'tariff' or 'variable' products.

²³ Standard Licence Condition 7 of the Electricity/Gas Supply Standard Licence Conditions.

domestic customers are defaulted to this type of tariff after termination²⁴ and will remain on this tariff unless they take action to switch, with price changes being applied automatically.

Shares of supply

- 16.29 There was no single comprehensive or accurate source of shares of supply information for either the SME markets or the microbusiness segments, and therefore we considered a range of sources (see Appendix 16.1). The general pattern was fairly consistent across them, but we view our share estimates as indicative.²⁵ 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.²⁶ We report below the results for 2014.
- 16.30 We look first at electricity. For the smallest electricity meters (with under 30 MWh of annual consumption), Figure 16.2 shows that three suppliers ([X]) each 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 16.2: Shares of supply by volume to electricity meters with an annual consumption under 30 MWh, 2014

[X]

Source: CMA analysis of data from the Six Large Energy Firms, Corona, Extra Energy, Gazprom, GDF Suez, Haven Power, Opus Energy and Total.

- 16.31 In gas, [X] also had the largest share, as shown in Figure 16.3, 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 is fairly high, and that there is higher concentration for supply to smaller microbusinesses in gas than in electricity.

²⁴ This will have been provided for in the original contract.

²⁵ 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.

²⁶ 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.

Figure 16.3: 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

- 16.32 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.
- 16.33 A 2015 survey for Ofgem also found that a sizeable minority of microbusinesses had not switched supplier over the past five years. 39% of businesses with zero employees (ie owner-operators), 34% 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.²⁷
- 16.34 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

- 16.35 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

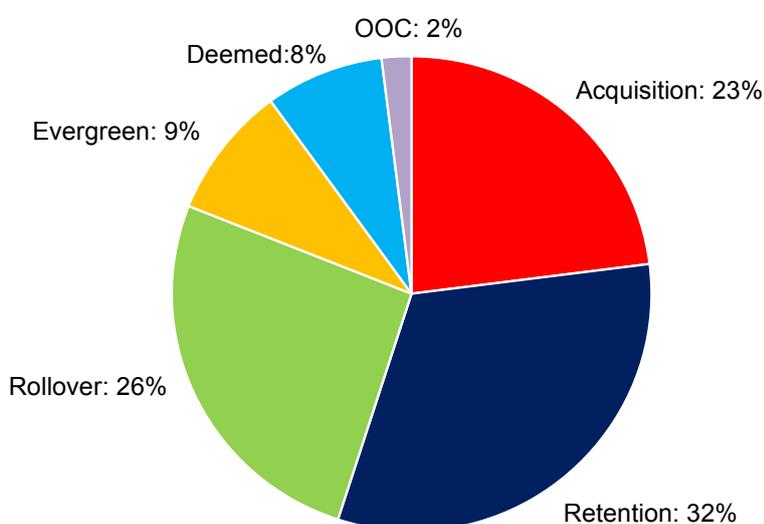
- 16.36 A substantial minority of microbusiness customers did not arrive on their current tariff as a result of an active decision. We refer to these products as default tariffs. Within this category, we include the following tariff types: auto-rollover contracts, evergreen, deemed, and OOC. As we report below, prices

²⁷ BMG Research (2016), *Micro and Small Business Engagement in Energy Markets* (report for Ofgem), p36.

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 significant potential gains from switching away from more expensive products, such as SVTs.)

16.37 To illustrate this, Figure 16.4 shows the split of tariff types in 2013 for customers treated by suppliers as microbusinesses.²⁸ In electricity, 45% of microbusinesses were on default tariffs. The largest proportion of these were on auto-rollover contracts (26% of microbusinesses). Our more recent data obtained from the Six Large Energy Firms suggests that default tariffs are still highly prevalent.²⁹

Figure 16.4: 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

16.38 We have made a number of observations about switching among microbusinesses:

- (a) 24% of businesses with zero employees, 25% of businesses with one to four employees and 23% of businesses with five to nine employees switched supplier in the past year (according to a 2015 survey for Ofgem).³⁰ (These categories all fall within Ofgem’s microbusiness definition.)

²⁸ Although, as noted above, suppliers do not apply a common definition of microbusinesses.

²⁹ Figures 11 and 12 in Appendix 16.1 illustrate the proportion of customers on the different tariff types for SMEs as at January 2015.

³⁰ BMG Research (2016), *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.³¹
 - (c) However, switching among microbusinesses is lower than among larger SMEs.³²
 - (d) Switching among microbusinesses is comparable to the switching rate among small business insurance customers.³³
 - (e) The reported switching rate for microbusinesses and small businesses increased in each year between the surveys carried out for Ofgem in 2013, 2014 and 2015.
- 16.39 There are a variety of potential causes for the recent increase in switching. These could include: several suppliers ending the use of auto-rollover contracts, the regulations around contract renewals recently introduced by Ofgem,³⁴ 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.
- 16.40 As noted in paragraphs 16.32 to 16.34 above, some SME customers have not switched supplier for a significant period of time.

Contract search activity

- 16.41 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.³⁵ However, there was a proportion of customers who had never considered switching. This varied by customer size, with 26% of businesses

³¹ TNS BMRB (2014), *Retail Market Review baseline survey: report prepared for Ofgem*, p10.

³² BMG Research (2016), *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).

³³ Datamonitor (2013), *Switching on the rise in SME insurance*.

³⁴ Described in paragraph 16.2316.23 above.

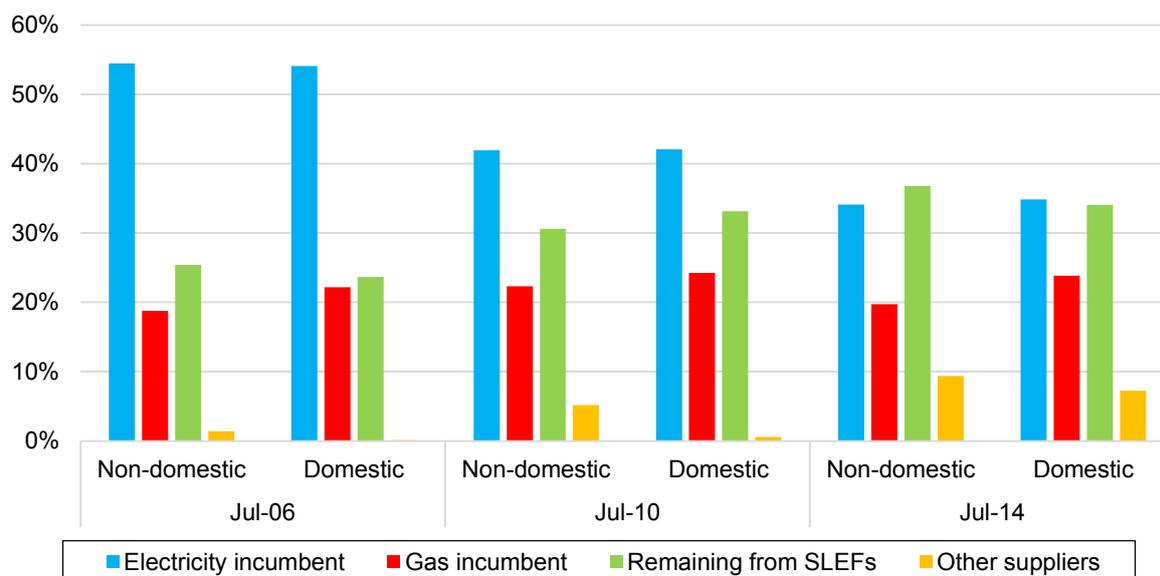
³⁵ BMG Research (2015), *Micro and small business engagement in energy markets* (report for Ofgem), p29. This is consistent with the level reported in BMG's 2016 report for Ofgem, which stated that 'Just under half of businesses (47%) have looked into other supplier or tariff options (with their existing supplier) or 'shopped around' in the last 12 months'.

with zero employees (ie owner-operators) having never considered switching, compared with 10% of businesses with 10 to 49 employees.³⁶

Regional incumbency

16.42 The average share of the former electricity incumbent in each region has fallen over time. (Figure 16.5 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 16.5: 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.

16.43 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

³⁶ *ibid*, p38.

former incumbent suppliers to microbusinesses in their home regions, but only 2% of the volume supplied by these firms to microbusinesses in other regions.

The role of traditional meters and bills

16.44 As set out in Section 9, we consider that traditional meters and bills 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. 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.

Parties' views – engagement

16.45 A summary of the key comments raised in response to our findings concerning engagement in the microbusiness segments is outlined below. Further information on these comments and our responses are outlined in Appendix 16.1, Annex E.

Views concerning the CMA's assessment of the homogenous nature of gas and electricity products

16.46 Some suppliers and TPIs disagreed with the CMA's assessment of the homogenous nature of gas and electricity, considering that differentiation existed in the form of contractual terms and preferences, customer service and other factors.³⁷ We have discussed our consideration and response to parties concerning the homogenous nature of gas and electricity supply in Section 9, which also applies to microbusinesses.

Views concerning the CMA's assessment of engagement in the microbusiness segments

16.47 Some parties considered that the indicators used by the CMA to assess engagement were not appropriate.³⁸ Several suppliers did not agree with the CMA's finding that suppliers have unilateral market power over micro-business customers; the suppliers did not consider that the evidence concerning the level of engagement of microbusiness customers supported this finding.³⁹ Some suppliers also noted that developments in the

³⁷ Appendix 16.1, Annex E, paragraph 2.

³⁸ Appendix 16.1, Annex E, paragraph 4.

³⁹ Appendix 16.1, Annex E, paragraph 5.

microbusiness supply segments had resulted in improved engagement among microbusinesses and increased competition.⁴⁰ Some suppliers considered that these developments were not recognised in the CMA's analysis, which was no longer an accurate reflection of the current state of competition in the segments.⁴¹

- 16.48 We have considered 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. Based on the assessments in paragraphs 16.36 to 16.43 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 some microbusinesses do take an active interest in their energy supply contracts by switching or searching, however we remain concerned that a significant proportion of microbusinesses appear to show limited engagement and that they have limited interest in their ability to switch energy supplier. Figures 9 and 10 in Appendix 16.1 show that 45% of microbusiness electricity customers and 49% of microbusiness gas customers were on default tariffs as at 1 April 2013. Our more recent data obtained from the Six Large Energy Firms in January 2015, as outlined in Appendix 16.1, indicates that default tariffs remain highly prevalent.
- 16.49 In order to ensure that our assessment of the microbusiness segments reflect the latest developments, we have updated our analysis to include the results of Ofgem's most recent survey in late 2015. We considered that this appropriately reflected key developments in the SME markets in recent years, such as the regulatory developments, increased number of TPIs and cessation of auto-rollovers by many suppliers.
- 16.50 As noted in paragraph 16.38, we have observed that the reported switching rates for microbusinesses increased across the periods covered by the Ofgem surveys carried out in 2013, 2014 and 2015. There are a variety of potential causes for the recent increase in switching. However, there remained a sizeable minority of microbusinesses that had not switched supplier over the past five years. 39% of businesses with zero employees, 34% of businesses with one to four employees, and 28% of businesses with five to nine employees had not switched supplier over the past five years⁴² and who have therefore remained on default products for a substantial period of time.

⁴⁰ Appendix 16.1, Annex E, paragraph 6.

⁴¹ Appendix 16.1, Annex E, paragraph 7.

⁴² BMG Research (2016), *Micro and Small Business Engagement in Energy Markets* (report for Ofgem), p36.

Views concerning the role of traditional meters and bills

- 16.51 Some suppliers outlined that there was a lack of evidence that the complexity of traditional meters or bills was a barrier to engagement.⁴³ Other suppliers agreed with the CMA's assessment that a lack of visibility and high complexity associated with traditional meters and bills might deter customers from considering whether to switch energy supplier and therefore that the roll-out of smart meters would increase engagement.⁴⁴ We have discussed our consideration and response to parties concerning the role of traditional meters and bills further in paragraphs Section 9, which also applies to microbusinesses. Views concerning transparency in the microbusiness segments is discussed at paragraphs 16.73 to 16.79.

Summary – engagement

- 16.52 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).
- 16.53 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 9, 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.
- 16.54 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.

⁴³ Appendix 16.1, Annex E, paragraph 13.

⁴⁴ Appendix 16.1, Annex E, paragraph 14.

Transparency

Importance of transparency

- 16.55 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.
- 16.56 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.⁴⁵ 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 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.
- 16.57 In this section we examine what information on prices is available from suppliers, TPIs, and PCWs.

Information from suppliers

- 16.58 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, however these are unlikely to be the best deals available.
- 16.59 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 16.81 to 16.124 below).

⁴⁵ However, RWE said that it would only take half an hour to get a tailored quote.

Information from third party intermediaries

- 16.60 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.
- 16.61 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.⁴⁶
- 16.62 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 been contacted by a TPI in the past year.⁴⁷ 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.⁴⁸ Similarly, Ofgem's survey in 2015 reported that only 19% of microbusinesses and small businesses described their overall view of energy brokers as positive.⁴⁹
- 16.63 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'.⁵⁰ Poor behaviour by some TPIs may reduce trust in TPIs more generally, and lead to customers being less engaged.

⁴⁶ BMG Research (2015), *Micro and Small Business Engagement in Energy Markets* (report for Ofgem), p49.

⁴⁷ *ibid*, p51.

⁴⁸ *ibid*, pp57 & 58.

⁴⁹ BMG Research (2016), *Micro and Small Business Engagement in Energy Markets* (report for Ofgem), p44.

⁵⁰ Last quote from Cornwall Energy (2011), *Brokerage services for micro-business energy consumers*, report for Consumer Focus, p16.

- 16.64 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 and 2015 surveys reported that only 5% and 8% of microbusinesses and small businesses who had used a broker reported that they had been charged for this service.^{51,52} 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).
- 16.65 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 cover all suppliers in the market. 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.
- 16.66 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 Misleading Marketing Regulations in November 2013, which it can use to address certain forms of poor behaviour by TPIs.

Summary on third party intermediaries

- 16.67 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.

⁵¹ BMG Research (2015), [Micro and Small Business Engagement in Energy Markets](#) (report for Ofgem), p53.

⁵² BMG Research (2016), [Micro and Small Business Engagement in Energy Markets](#) (report for Ofgem), p43.

Information from price comparison websites

- 16.68 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 other PCWs (eg Confused.com and comparethemarket.com).
- 16.69 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.
- 16.70 We have investigated why PCWs are not more prevalent for non-domestic energy supply. We consider that demand may exist 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).
- 16.71 Conversely, however, we received a number of suggestions concerning potential issues that may 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.⁵³ These reasons did not appear to indicate that developing and promoting a non-domestic energy PCW was not feasible.

Summary on price comparison websites

- 16.72 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.

⁵³ 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 16.1.

Parties' views – transparency

16.73 A summary of the key comments raised in response to our findings concerning transparency in the microbusiness segments is outlined below. Further information on these comments and our responses are outlined in Appendix 16.1, Annex E.

Views concerning the level of transparency in the microbusiness segments and the impact on engagement among microbusiness customers

16.74 Several suppliers agreed that there was a lack of transparency in the microbusiness segments, although some highlighted the importance of tailored pricing due to the varied requirements of microbusinesses.⁵⁴ Some suppliers did not consider that the lack of published prices was an issue, with price information readily available and ease of access to TPIs.⁵⁵

16.75 As discussed in paragraphs 16.55 and 16.56, we consider that transparency is an important factor in facilitating engagement. Low visibility of market prices may result in lower customer awareness that there are better deals available, increased search costs and a weak negotiating position for customers.

Views concerning the concerns over the conduct of some TPIs and the impact on engagement amongst microbusiness customers

16.76 Several suppliers recognised the perceived issues around the conduct of some TPIs, although some suppliers and other parties highlighted that this predominantly related to only a small minority of TPIs.⁵⁶ One supplier considered that the suggested lack of trust in TPIs, or concerns of how they charged customers, had had little impact on customer engagement.⁵⁷

16.77 While recognising parties' comments that many of the concerns with the conduct of TPIs may relate to a small minority, in Ofgem's 2015 survey 46% of microbusinesses and small businesses described their overall view of energy brokers as negative. This lack of trust and understanding of TPIs may reduce their effectiveness and lead to lower levels of engagement than would otherwise be the case.

⁵⁴ Appendix 16.1, Annex E, paragraph 16.

⁵⁵ Appendix 16.1, Annex E, paragraph 17.

⁵⁶ Appendix 16.1, Annex E, paragraph 19.

⁵⁷ Appendix 16.1, Annex E, paragraph 20.

Views concerning the potential for PCWs to increase the levels of engagement among microbusiness customers

- 16.78 One supplier agreed that PCWs might help to make customers more informed, with some suppliers agreeing that conditions existed for the entrance of PCWs in the microbusiness segments.⁵⁸ Some parties considered that the complexity of customer demand and preferences and the variety of products on the market had resulted in PCWs struggling to establish themselves.⁵⁹
- 16.79 Our view is that PCWs could deliver benefits for microbusiness energy customers through providing increased transparency over prices, although the complex nature of the microbusiness segments may result in a greater level of challenge in operating a non-domestic PCW than a domestic one; although it appears that there could be a viable business model for a non-domestic energy PCW.

Summary – transparency

- 16.80 Based on the evidence above, we consider 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

⁵⁸ Appendix 16.1, Annex E, paragraph 22.

⁵⁹ Appendix 16.1, Annex E, paragraph 23.

- (ii) 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.

Margins

16.81 Our analysis of retail profit margins⁶⁰ found that there were substantial differences in EBIT margins between retail markets for the Six Large Energy Firms. Over the six years⁶¹ 2009 to 2014, 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 8.0%, compared with 3.5% in the domestic markets.

(b) The combined EBIT margin was lowest in the I&C markets at 1.9%.

16.82 We also looked at combined EBIT margins by fuel. The margin was larger for SME gas supply (9.9%) than for SME electricity supply (7.4%).

16.83 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. These are discussed in Appendix 9.13. In our view, the SME markets would have to be much more exposed to systematic risk,⁶² or require a much higher level of capital employed than other markets, in order to justify the extent of the difference in EBIT margins. We concluded that the evidence did not support the parties' views that serving SMEs was riskier than other customer segments.⁶³ In contrast, we found that there was some evidence that serving SMEs required a higher level of capital employed. We have considered this in Appendix 9.10. We concluded that differences in capital employed were unlikely to be sufficient to justify the size of the differences in margins.

⁶⁰ Appendix 9.13: Retail energy supply profit margin analysis and comparators.

⁶¹ These years are the financial reporting years for each firm, which differ in some cases from the calendar year.

⁶² 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.

⁶³ We observe that these higher margins on SME customers were earned during a period of economic recession when bad debt costs could be expected to be above the average level. This implies that average SME margins may be above the level measured.

16.84 We also investigated whether prices⁶⁴ and gross margins were higher for specific categories of customers. Based on our work, we identified the following areas of interest:

- (a) default products (rollover,⁶⁵ evergreen, deemed and OOC);
- (b) smaller customers; and
- (c) former incumbent regions (for electricity).

16.85 Figures 16.6 to 16.9 below show average revenues and gross margins⁶⁶ for gas and electricity. For each fuel, we defined four bands⁶⁷ 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.⁶⁸ 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.

16.86 These broad points were largely consistent across suppliers (see Appendix 16.1, Annex A).

⁶⁴ 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.

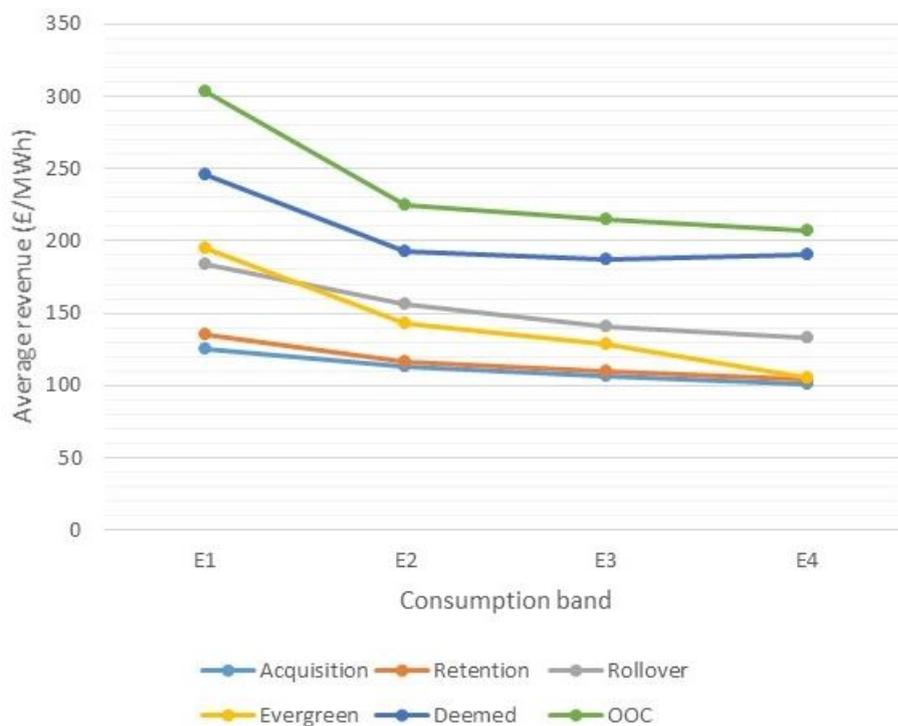
⁶⁵ By 'rollover' we include all tariffs that customers are rolled over on to by default. This includes, but is not limited to, auto-rollovers. For example, a customer could be rolled over on to an evergreen contract, or a fixed-term contract with an exit clause.

⁶⁶ 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.

⁶⁷ 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.

⁶⁸ 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 16.6: Overall average revenues by tariff type and consumption band – electricity

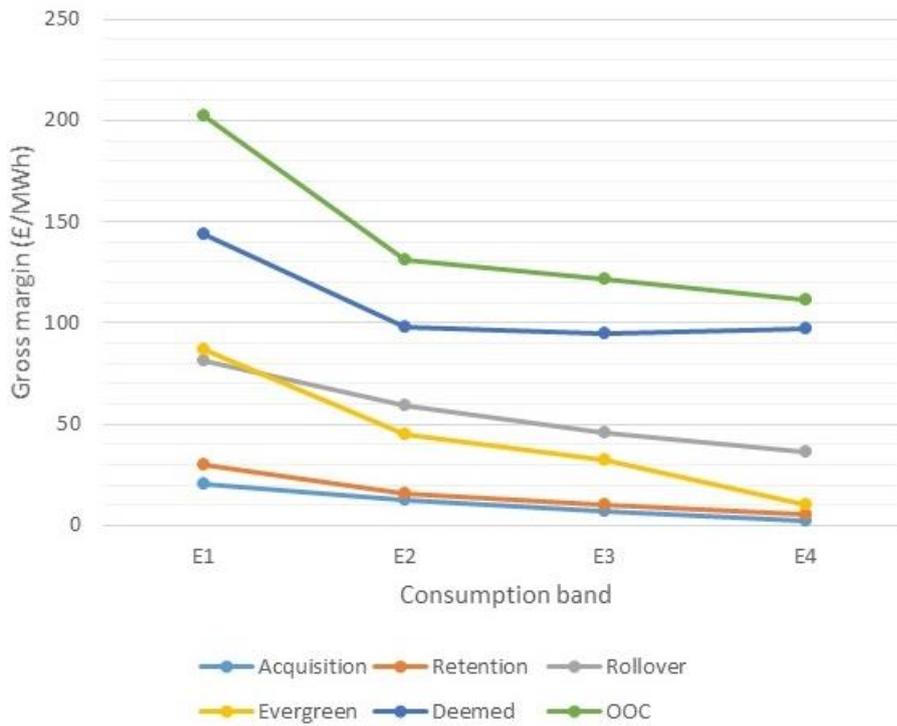


Source: CMA analysis of data from the Six Large Energy Firms (except SSE), Gazprom, Opus Energy, and Total Gas and Power.

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 16.1.
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 16.7: Overall gross margins by tariff type and consumption band – electricity

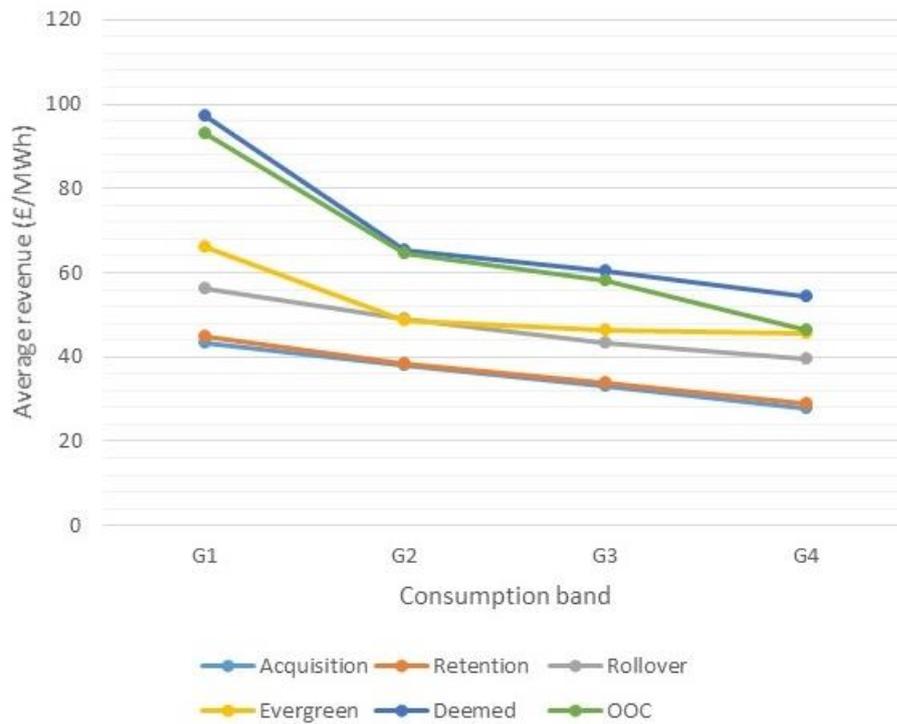


Source: CMA analysis of data from the Six Large Energy Firms (except SSE), Gazprom, Opus Energy, and Total Gas and Power.

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 16.8: Overall average revenues by tariff type and consumption band – gas

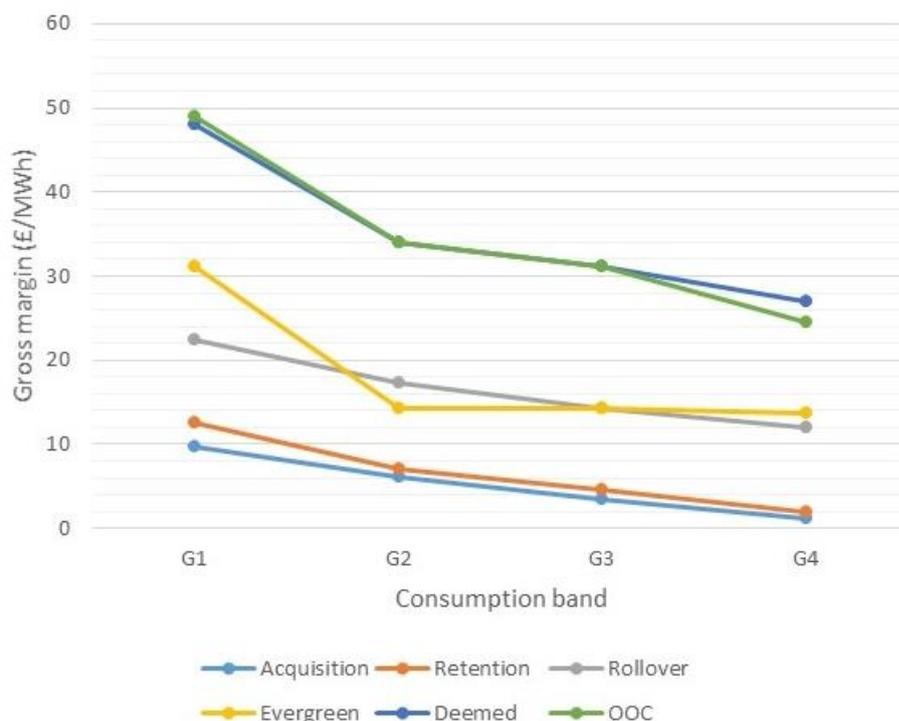


Source: CMA analysis of data from the Six Large Energy Firms (except EDF Energy and SSE), Gazprom, Opus Energy, and Total Gas and Power.

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 16.1.
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 16.9: 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:

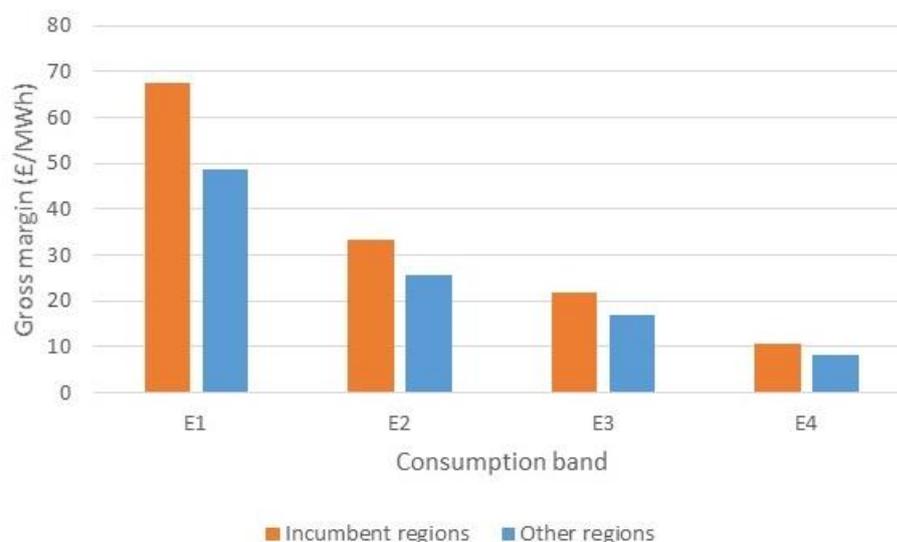
1. Data is 2012–2014, except Scottish Power (2014 only).

2. The rollover category is mostly made up of customers on auto-rollovers, but also includes the replacement products for a couple of suppliers.

16.87 We also looked at gross margins on a regional basis in electricity, to look for potential incumbency effects. Figure 16.10 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 16.1, Annex A).⁶⁹

⁶⁹ 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 16.10: 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).

16.88 Our findings (both nationally, and regionally for electricity) were largely consistent across suppliers (see Appendix 16.1, Annex A). However, we recognise that differences in gross margins may be justified by differences in costs.

16.89 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

16.90 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-rollover contracts; deemed and OOC tariffs; smaller business customers; and regional incumbency.

Outcomes: auto-rollover contracts

16.91 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-rollover contracts: 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 contract⁷⁰ 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.
- 16.92 In each case,⁷¹ 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 period or notice term ends) and the price may change each time.
- 16.93 As noted above, until 2013,⁷² auto-rollover contracts were widespread in the SME markets. Since then, the largest energy companies (including the Six Large Energy Firms and Opus) have gradually withdrawn auto-rollover contracts in favour of replacement (notice or evergreen) contracts.
- 16.94 We have some continuing concerns in principle about auto-rollover contracts in the SME markets. The OFT has in the past found that auto-rollover contracts (in general) could reduce switching because of inertia and/or increased switching costs, and that this could potentially dampen competition.⁷³ 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.
- 16.95 Many smaller suppliers⁷⁴ continue to offer auto-rollover contracts, 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

⁷⁰ This has some similarities to a domestic SVT. However, in this case prices may be personalised to an individual microbusiness.

⁷¹ Except OOC, which is a published rate.

⁷² EDF Energy stopped automatically renewing customers in October 2013.

⁷³ OFT (2013), *Key issues in ongoing contracts: a practical guide*, p10.

⁷⁴ In Appendix 16.1: 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.

in to any rollover term and can now switch without penalty. We note that the removal of auto-rollover contracts by the suppliers noted above has been due to informal pressure (from Ofgem and the government⁷⁵), and that, absent regulation or legislation formally prohibiting such contracts, they could in principle be reintroduced by these suppliers.

- 16.96 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.
- 16.97 As noted above, we observed much higher average unit revenues and gross unit margins on auto-rollover contracts compared with acquisition or retention tariffs.⁷⁶ We did not receive any suggestions that cost differences could explain the size of these differences in average revenues and gross margins.⁷⁷ The combination of disengaged and inactive customers with these relatively high prices could indicate that competition may not function as an effective constraint.
- 16.98 The removal of auto-rollover contracts 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 received very limited evidence on adverse outcomes under the default products that have specifically replaced auto-rollover contracts.⁷⁸ We looked at the average prices paid by customers of some suppliers (Centrica, RWE and SSE⁷⁹) since they discontinued auto-rollover contracts.⁸⁰ 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

⁷⁵ Number 10 and DECC launched a [small business energy working group](#).

⁷⁶ Figures 16.6–16.9.

⁷⁷ Discussed in more detail in Appendix 16.1.

⁷⁸ Replacement tariffs have been introduced gradually, as customers came to the end of their existing auto-rollovers.

⁷⁹ Centrica's replacement is an evergreen tariff, RWE's is a notice contract, and SSE applies OOC rates.

⁸⁰ Appendix 16.1, Annex C describes the caveats to and limitations of this data, and gives full results.

suppliers.⁸¹ We do not therefore have evidence at present that the move away from auto-rollover contracts has led to lower prices for customers on default products.

Outcomes: deemed and out of contract

- 16.99 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 16.6 and 16.8 above). The expected lack of effective competitive constraint explains why there is a licence condition relating to the pricing of deemed tariffs.⁸² However, there is no equivalent licence condition for OOC tariffs.
- 16.100 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.⁸³
- 16.101 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.
- 16.102 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.⁸⁴ 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 441 days for electricity and 373 days for gas and the upper quartile customer tenure on these tariffs was 1,067 days for electricity and 806 days for gas.
- 16.103 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

⁸¹ See Appendix 9.1: Customer survey.

⁸² See paragraph 16.28.

⁸³ See the discussion of outcomes on deemed and out-of-contract tariffs in Appendix 9.1: Customer Survey.

⁸⁴ Ofgem (2014), *Proposals for non-domestic automatic rollovers and contract renewals*, pp43 & 44.

difference in average gross unit margins between deemed and retention tariffs, and between OOC and retention tariffs. Table 16.1 reports the median differences across suppliers.

Table 16.1: 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 16.7 and 16.9 above.

16.104 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.⁸⁵ This suggests that customers on these tariff types were substantially worse off than those who engaged to choose retention products.

16.105 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.

16.106 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 16.1). Comparing them with the figures in Table 16.1 (and making the same comparison for individual suppliers⁸⁶), it appears that bad debt write-offs could explain some (but in most cases not all) of the above

⁸⁵ All figures from Ofgem (2014), *Proposals for non-domestic automatic rollovers and contract renewals*, pp42 & 43.

⁸⁶ See Appendix 16.1: Microbusinesses for individual results.

difference in gross margins between deemed and retention tariffs, and between deemed and OOC tariffs.

- 16.107 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.⁸⁷ 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.
- 16.108 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.
- 16.109 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.
- 16.110 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.
- 16.111 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

- 16.112 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.⁸⁸ As noted

⁸⁷ 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.

⁸⁸ Ofgem, [initial submission](#), 21 July 2014, p67.

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.

16.113 We saw above (paragraph 16.85) 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

16.114 We observed above (paragraph 16.85) that we found the highest average revenues and gross margins for customers we classified as small microbusinesses.⁸⁹ However, our other evidence suggests that this does not translate into higher profits or NPVs.

16.115 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

16.116 We also observed⁹⁰ higher gross margins for medium-sized microbusinesses⁹¹ than for larger SMEs.⁹² Again, one reason for this was costs that are incurred on a per customer basis.

16.117 We found that for acquisition and retention contracts, per customer costs may largely account for higher electricity gross margins for medium-sized microbusinesses than larger SMEs.⁹³ 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

⁸⁹ Meters with an annual consumption below 10 MWh of electricity or 30 MWh of gas.

⁹⁰ See Appendix 16.1: Microbusinesses and specifically the section 'Outcomes: by customer size'.

⁹¹ Meters with an annual consumption between 10 and 30 MWh of electricity (E2), or between 30 and 100 MWh of gas (G2).

⁹² Meters with an annual consumption between 100 and 500 MWh of electricity (E4), or between 293 and 1,500 MWh of gas (G4).

⁹³ See Appendix 16.1: Microbusinesses, and specifically the section 'Outcomes: by customer size'.

possible explanation for the larger differences on these tariffs might be if suppliers expect medium-sized microbusinesses to have lower engagement than larger SMEs, and thus offer them worse rollover rates.

- 16.118 It also appears that differences in per customer costs could broadly explain differences in average gross margins in gas between medium-sized microbusinesses and larger SMEs.⁹⁴
- 16.119 We also found indications for specific suppliers that NPVs were higher on medium-sized 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.⁹⁵
- 16.120 Based on the range of evidence available, there are some indications that supplying medium-sized 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 larger 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-sized microbusinesses compared with larger SMEs.

Outcomes: regional incumbency

- 16.121 We found that the former electricity incumbents generally had higher gross margins in their home regions than elsewhere.⁹⁶ 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.
- 16.122 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.⁹⁷ The weighted average across four⁹⁸ suppliers was £19/MWh higher gross margin in home regions for the smallest microbusinesses, £6 for medium microbusinesses, and £4 for the largest

⁹⁴ See Appendix 16.1: Microbusinesses, and specifically the section 'Outcomes: by customer size'.

⁹⁵ See Appendix 16.1: Microbusinesses, and specifically the section 'Outcomes: by customer size'.

⁹⁶ See Appendix 16.1: Microbusinesses, and specifically the section 'Outcomes – regional incumbency'.

⁹⁷ See Appendix 16.1, and specifically the section 'Outcomes – regional incumbency'.

⁹⁸ SSE was unable to provide gross margin data.

class of microbusinesses. For larger SMEs, there was no significant difference.

- 16.123 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 1 in Appendix 16.1, Annex D compares these differences for medium-sized microbusinesses across tariff types.⁹⁹ This suggests that suppliers are not systematically receiving much higher gross margins on other tariff types in their home regions compared with elsewhere.
- 16.124 We consider 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.

Parties' views – outcomes

- 16.125 A summary of the key comments raised in response to our findings around outcomes in the SME markets is outlined below. Further information on these comments and our responses are outlined in Appendix 16.1, Annex E.

Views concerning outcomes in the SME markets

- 16.126 One supplier considered that the CMA's analysis of tariff types attached undue weight to a relatively small number of customers on default tariffs.¹⁰⁰ In addition, some suppliers noted that separate analysis should be performed to consider the respective findings from the perspective of individual suppliers, rather than the Six Large Energy Firms combined.¹⁰¹
- 16.127 We have discussed our approach to profitability calculations in Appendix 9.13. Our analysis of retail profit margins found that there were substantial differences in EBIT margins between retail markets for the Six Large Energy Firms. The SME retail markets generated a significantly higher period EBIT margin of 8.0% when compared with the lower period EBIT margin generated by the domestic retail markets of 3.5%. The I&C retail markets,

⁹⁹ Those with an annual electricity consumption between 10 and 30 MWh.

¹⁰⁰ Appendix 16.1, Annex E, paragraph 25.

¹⁰¹ Appendix 16.1, Annex E, paragraph 26.

which did not form part of our reference market, generated the lowest period EBIT margin of 1.9%.

- 16.128 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. These are discussed in Appendix 9.13. We concluded that the evidence did not support the parties' views that serving SMEs was riskier than other customer segments. In addition, as outlined in Appendix 9.10, we concluded that differences in capital employed were unlikely to be sufficient to justify the size of the differences in margins.

Views concerning the definition of microbusiness and allocations of indirect costs applied in the CMA's comparison of profitability

- 16.129 Some parties questioned the appropriateness of segmenting the markets using the definition of microbusiness used by Ofgem, and one party considered that the definition ought to be removed and for all businesses to be given the protections currently on offer to microbusinesses.¹⁰²
- 16.130 One supplier highlighted that the CMA's comparison of the profitability of SME suppliers was dependent on the differing definitions of SME applied by each supplier, with particular sensitivities in respect of allocation of indirect costs between SME and I&C activities.¹⁰³ We have discussed our approach to the profitability calculations in Appendix 9.13.

Views concerning the assessment of margins between deemed and OOC products compared with retention products

- 16.131 Some suppliers highlighted that the CMA's assessment of margins between deemed and OOC products compared with retention products was not appropriate due to the different nature of customers on these products. The CMA recognises that the increased risk of bad debt write-offs may explain some of the differences identified, however suppliers also outlined additional factors giving rise to this difference. One supplier outlined that additional volume risk associated with customers who could leave at any time was a key driver for the differences noted, with another supplier highlighting that this led to shorter-term cash flow and hedging exposure.¹⁰⁴
- 16.132 As discussed in Appendix 16.1, deemed and OOC tariffs are special cases. They provide a valuable function by giving customers continuous access to

¹⁰² Appendix 16.1, Annex E, paragraph 30.

¹⁰³ Appendix 16.1, Annex E, paragraph 31.

¹⁰⁴ Appendix 16.1, Annex E, paragraph 33.

energy, even when a contract is not in place. Given the nature of these tariffs, they have certain costs which are higher than other tariffs (especially bad debt). These tariffs only apply to a small 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 microbusinesses¹⁰⁵) and many customers spend only a short period of time on these tariffs (although some customers do spend much longer on these tariffs).¹⁰⁶ Taken together, these factors suggest that the materiality of any issues with these tariffs may be limited. Therefore, we have not attempted to assess whether prices are fully cost-justified. This seems an area which Ofgem is well-positioned to investigate if it has concerns about individual suppliers' pricing.

Views concerning the assessment of outcomes based on customer size and regional incumbents

16.133 Some parties outlined their agreement with the CMA's conclusions concerning outcomes for small microbusinesses and regional incumbency.¹⁰⁷

Microbusiness AECs

16.134 We have 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).¹⁰⁸ 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 believe that the less engaged customers on these tariffs are not exerting sufficient competitive constraints on energy suppliers, particularly as regards 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-rollover contracts and replacement contracts), or if they are receiving energy supply in

¹⁰⁵ This information was only available for some of the Six Large Energy Firms (E.ON, EDF Energy, RWE, Scottish Power and SSE for electricity; E.ON, RWE, Scottish Power and SSE for gas). We calculated the proportion of the total volumes supplied to microbusinesses by these suppliers which were supplied on deemed or OOC tariffs. (This was based on data between 2012 and 2014, except for Scottish Power (2014 only)).

¹⁰⁶ As highlighted in paragraph 16.102, Ofgem's 2013 survey provided an indication of the amount of time spent on deemed and OOC tariffs, with a median duration of 441 days for electricity and 373 days for gas. The upper quartile customer tenure on these tariffs was 1,067 days for electricity and 806 days for gas.

¹⁰⁷ Appendix 16.1, Annex E.

¹⁰⁸ As explained in the section on margins above (paragraphs 16.81–16.85), suppliers were only able to provide EBIT margin information for SMEs, rather than for microbusinesses specifically.

circumstances where they have not agreed a contract (deemed and OOC tariffs).

16.135 Overall, we consider 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 microbusinesses¹⁰⁹ 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 otherwise (the Microbusiness Weak Customer Response AEC). 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.

16.136 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

¹⁰⁹ We refer to weak customer response as an overarching feature as synonymous with it being a source for an AEC (CC3, paragraph 170).

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 contracts (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).

16.137 For the reasons given in Section 9 in relation to the regulatory framework governing the markets for domestic retail gas and electricity supply, we have 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, as set out in section 12, we are

concerned at the slow pace of the implementation. Moreover, we are concerned that the incentives that shippers face to place a higher priority on adjusting AOs down and delaying adjusting AOs up might 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 microbusiness¹¹⁰ electricity customers and of a cost-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.

Assessment of detriment arising from the Microbusiness Weak Customer Response AEC

16.138 To assist us in deciding on appropriate remedies, we have assessed the nature and extent of detrimental effects on energy customers resulting from the AECs that we have identified. This section sets out the results of the analysis of customer detriment that we have undertaken in relation to the Microbusiness Weak Customer Response AEC. We discuss our finding on the detriment arising from the AECs in relation to the regulatory framework governing the markets for domestic retail gas and electricity supply in Section 8.

16.139 In general, a detrimental effect on customers could arise as a result of an AEC from:

- (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.¹¹¹

16.140 In the microbusiness segments, we have identified customer detriment in the form of gas and electricity microbusiness customers of the Six Large Energy Firms paying higher prices, on average, than would otherwise be the case in a well-functioning market.¹¹² Furthermore, we consider that there is likely to be detriment arising from the microbusiness customers of suppliers that

¹¹⁰ The majority of microbusinesses are currently assigned to profile classes 3 and 4, ie Non-Domestic Unrestricted Customers and Non-Domestic Economy 7 Customers.

¹¹¹ CC3, paragraph 326.

¹¹² CC3, paragraph 30.

were not one of the Six Large Energy Firms (the independent suppliers). This is because the features that give rise to the Microbusiness Weak Customer Response AEC are the same for the microbusiness customers of the Six Large Energy Firms and independent suppliers, and certain features may be heightened for customers of the independent suppliers, such as regards microbusiness customers on auto-rollover contracts. Hence, we have considered a package of remedies that applies to the Six Large Energy Firms and the independent suppliers in the microbusiness segments.

Analysis of detriment in the provisional findings report

- 16.141 In the provisional findings report, we calculated an annual detriment of approximately £500 million for the SME customers of the Six Large Energy Firms,¹¹³ from FY 2009 to FY 2013 using the 'competitive benchmark revenue' analysis. This detriment equated to approximately 15% of SME revenues of the Six Large Energy Firms. This analysis made adjustments for cost inefficiencies and capital charges on the asset base of the Six Large Energy Firms using the industry weighted average cost of capital (WACC).
- 16.142 The annual SME detriment of £500 million for the Six Large Energy Firms can be broken down into two key elements. First, approximately £325 million (65%) related to 'profits in excess of the cost of capital'. Second, approximately £175 million (35%) related to relative inefficiencies (with an immaterial amount related to wholesale energy cost purchases).¹¹⁴
- 16.143 Separately, in the provisional findings report, we analysed the profit margins of the Six Large Energy Firms from FY 2009 to FY 2013. The results of this analysis showed that the combined EBIT margin for the Six Large Energy Firms in the SME markets was 8.4%, compared with 3.3% in the domestic retail markets and 2% in the I&C markets.¹¹⁵
- 16.144 In the provisional findings report, we also observed that the Six Large Energy Firms earned the highest average revenues and gross margins on deemed and OOC contracts, which were substantially higher than those relating to acquisition and retention contracts.¹¹⁶

¹¹³ Provisional findings report, [Appendix 10.5](#), paragraph 76a.

¹¹⁴ We note that there are challenges associated with quantifying any detriment arising from indirect costs or reported energy costs in the SME markets (see Appendix 3.5, efficiency analysis, paragraph 23).

¹¹⁵ Provisional findings report, [Appendix 9.1](#), paragraph 159.

¹¹⁶ [Provisional findings report](#), paragraph 9.36. Also, acquisition contracts are energy contracts made available by energy suppliers to acquire new microbusiness customers and retention contracts are energy contracts made available by energy suppliers to retain their existing microbusiness customers. Microbusinesses explicitly choose to enter into these contracts (see the provisional findings report, [Appendix 9.1](#), paragraph 9.29 for further details).

Updated analysis of detriment for the final report

16.145 We have amended our approach to assessing microbusiness detriment in several key respects since the provisional findings report:

- (a) We have confined our estimate of detriment to a consideration of profits in excess of the cost of capital – that is, we have not included an estimate of inefficiency. We also note that we have not been able to conduct an analysis of supplier bills to produce an alternative, and more direct, estimate of detriment, as we have done for domestic customers (see Appendix 9.7).
- (b) We have included FY 2014 numbers in the financial results.
- (c) We have made some amendments to capital employed based on company-specific representations.
- (d) We have estimated the proportion of the SME detriment that covers the microbusiness segments.

16.146 In relation to inefficiency, we have taken on board comments in relation to the heterogeneity of the SME markets and microbusiness segments. This heterogeneity consists of differences between suppliers in respect of:

- (a) scale: for example, several independent suppliers have greater market shares than some of the Six Large Energy Firms;
- (b) financial reporting: for example, lack of consistency in the way suppliers define SMEs; and
- (c) customer types: for example, the diversity of businesses and types of tariffs/contracts that they are on is more varied than the domestic retail markets.

16.147 Given parties' responses we have decided not to calculate the inefficiency of suppliers operating within the microbusiness segments. Therefore our current estimate of the detriment is solely based on profits in excess of the cost of capital. We note that this is a conservative assumption – there may well be inefficiencies in serving microbusiness customers, but it is problematic to assess the extent of inefficiency from the data for the reasons set out above. In addition, our estimate of detriment is based on the profits of the Six Large Energy Firms and does not, therefore, take into account any additional profits of independent suppliers that are in excess of the cost of capital. The revised estimate can therefore be considered a lower bound estimate of overall detriment as regards the microbusiness segments.

- 16.148 We have therefore assessed detriment by assessing the extent to which the Six Large Energy Firms earned profits¹¹⁷ in excess of their cost of capital in relation to the microbusiness segments.
- 16.149 Our revised estimate is that the profits in excess of the cost of capital earned by the entire retail supply businesses (including domestic, I&C and SME) of the Six Large Energy Firms were approximately £560 million¹¹⁸ to £800 million¹¹⁹ per year, from FY 2007 to FY 2014¹²⁰ of which the supply of gas and electricity to SME customers accounted for profits of approximately £220 million (per year) in excess of the cost of capital.
- 16.150 In the absence of financial reporting data for the microbusiness segments of the Six Large Energy Firms, we have estimated the proportion of the £220 million of SME profits in excess of the cost of capital that could be attributed to the microbusiness segments. We did so by asking the Six Large Energy Firms what proportion of their revenues from FY 2007 to FY 2014 could be attributed to the microbusiness segments, ie we assumed that profits in excess of the cost of capital earned across the microbusiness segments and the larger SME markets would broadly be in proportion to their respective revenues. Based on the parties' responses, this proportion amounted to 83% on average across all of the Six Large Energy Firms.¹²¹ On this basis, we have estimated that approximately £183 million per year of the £220 million profits in excess of the cost of capital earned by the Six Large Energy Firms in the SME markets, related to microbusiness customers.¹²²
- 16.151 We note that the revenue apportionment methodology that we have adopted may not provide a completely accurate number for profits in excess of the cost of capital. Nevertheless, given the lack of availability of accurate data for the microbusiness segments, we consider that the apportionment of profits in excess of the cost of capital by revenue would give a reasonable

¹¹⁷ We sourced the profitability numbers from the financial statements provided by the Six Large Energy Firms as part of the Supplier Questionnaire responses.

¹¹⁸ The £560 million per year estimate includes the profits in excess of the cost of capital and losses of all of the Six Large Energy Firms including the losses of two firms.

¹¹⁹ The £800 million per year estimate only includes the profits in excess of the cost of capital made by four of the Six Large Energy Firms, ie the losses made by two of the Six Large Energy Firms were excluded.

¹²⁰ See Appendix 3.4, paragraph 142.

¹²¹ EDF Energy and RWE could only provide the revenue split for the microbusiness segments from FY 2012 to FY 2014. Therefore, we applied the same split from FY 2007 to 2014 for these firms – as the most appropriate estimate for the entire period of review.

¹²² We note that Centrica's and E.ON's SME consumption thresholds are significantly higher than Ofgem's microbusiness consumption thresholds, that RWE's is moderately higher than Ofgem's and that Scottish Power's and EDF Energy's SME definitions have similar consumption thresholds or profile classes to Ofgem's microbusiness definition. SSE's definition is based on profile class and covers a generally similar group of customers to Ofgem's definition. (see provisional findings report, [Appendix 9.1](#), Table 1).

approximation of the profits in excess of the cost of capital for the micro-business segments, although again this approach is relatively conservative. As noted in paragraph 16.85, we have observed higher average revenues and gross margins for smaller customers compared with larger ones. This applied to some extent across consumption bands, though it was particularly noticeable for small microbusinesses. In addition, certain of the features giving rise to the Microbusiness Weak Customer Response AEC are heightened for smaller SMEs (such as regards transparency of prices). This suggests that the detriment is more likely to be concentrated in the microbusiness segments.

- 16.152 For the above reasons, we consider that our estimated profits in excess of the cost of capital of £183 million is a lower bound of overall profits in excess of the cost of capital for the microbusiness segments.
- 16.153 Despite this conservative approach, we believe that the size of the microbusiness profits in excess of the cost of capital that we have identified is significant. The annual profits in excess of the cost of capital amounted to 5% of average annual microbusiness revenues for the Six Large Energy Firms from FY 2007 to FY 2014. This suggests that prices were on average 5% higher between FY 2007 to FY 2014 than would have been the case in a well-functioning market. If aggregated over the review period from FY 2007 to FY 2014, the profits in excess of the cost of capital amounted to approximately £1.8 billion.
- 16.154 We also note that a disproportionate share of the profits in excess of the cost of capital that we have identified for the entire retail supply businesses of the Six Large Energy Firms can be attributed to the microbusiness segments. The microbusiness segments contributed approximately 9.5% of total revenue of the entire supply businesses of the Six Large Energy Firms between FY 2007 to FY 2014, but between 29% and 42% of the profits in excess of the cost of capital that we have identified over the same period.
- 16.155 For the microbusiness segments, we have not attempted to quantify any possible detriment arising from non-price sources of detriment (such as impacts on innovation or quality of service).

17. Retail supply to microbusinesses

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Introduction

- 17.1 We have found that a combination of features of the markets for the retail supply of gas and electricity to SMEs in Great Britain gives rise to an AEC through an overarching feature of weak customer response from microbusiness customers. These features give suppliers a position of unilateral market power over their inactive microbusiness customers, which the suppliers are able to exploit through their pricing policies or otherwise (the Microbusiness Weak Customer Response AEC).¹
- 17.2 We note that the features that give rise to the AEC concern the markets for the retail supply of gas and electricity to SMEs in Great Britain. However, it is microbusiness customers, as opposed to larger customers within the SME sector, that are most affected by these features. In addition, the terms of reference of the energy market investigation focus on microbusiness customers.² Therefore, our remedies concern the microbusiness segments only.

¹ Section 16, paragraph 16.136.

² Energy market investigation, [terms of reference](#).

17.3 First, this section of our final report sets out the strategic approach that we have adopted to remedies design. Thereafter, it identifies the individual remedies, which we have decided to implement that will address the Microbusiness Weak Customer Response AEC, followed by the remedies that we considered but have decided not to proceed with. Finally, it includes our assessment of the effectiveness and proportionality of the overall package of remedies in relation to the microbusiness segments of the retail supply markets.

Strategic approach to remedies design

17.4 At a high level, the package of remedies for microbusiness customers can be divided into two strategic components:

(a) Measures that will help microbusiness customers engage, and thus exploit the benefits of competition. These include remedies to:

- (i) increase price transparency;
- (ii) end auto-rollover contracts with certain restrictions (such as termination fees) that restrict microbusiness customers' ability to switch;
- (iii) establish a programme to provide microbusiness customers with information that will prompt them to engage; and
- (iv) provide prompts to microbusiness customers on default contracts by enabling rival suppliers to contact them.

(b) Measures that will help create a framework for effective competition. Our remedies regarding reforms of the settlement system for gas and electricity, discussed in Section 12, also apply to microbusiness customers. These include remedies to:

- (i) develop a firm plan to move microbusiness electricity customers to half-hourly settlement while also implementing a cost-effective option for elective half-hourly settlement; and
- (ii) increase the accuracy of the gas settlement system.

Engagement remedies

17.5 We consider that our engagement remedies will, in combination with the roll-out of smart meters, be effective in addressing the features giving rise to the Microbusiness Weak Customer Response AEC. The features include:

- (a) microbusiness customers face actual and perceived barriers to accessing and assessing information. This arises from two aspects of the energy markets: a general lack of price transparency concerning the contracts that are available to microbusiness customers, and the role of third party intermediaries (TPIs);
 - (b) microbusiness customers have limited awareness of and interest in their ability to switch energy supplier; and
 - (c) some microbusiness customers are on auto-rollover contracts, which may limit their ability to switch contract or supplier.³
- 17.6 We consider that the four remedies outlined below will be effective in addressing these features and, accordingly also the Microbusiness Weak Customer Response AEC and the resulting customer detriment.
- 17.7 The price transparency remedy will require suppliers to disclose the prices of all their available acquisition and retention contracts (for electricity and gas) to a large proportion of their microbusiness customers. As an additional measure, it will also require suppliers to disclose on their websites the prices of their out-of-contract (OOC) and deemed contracts. This remedy, in relation to acquisition and retention contracts, will significantly increase microbusiness customers' ability to access and assess price information. We consider that it will also facilitate the development of PCWs catering to microbusiness customers, further reducing the high search costs faced by microbusiness customers.
- 17.8 As a result, the price transparency remedy will partly address the actual and perceived barriers to accessing and assessing information experienced by microbusinesses without the need to implement an alternative remedy we considered in relation to the role of TPIs. This remedy may also contribute towards increasing the level of trust in TPIs, and as a consequence the use of TPIs. This is because microbusiness customers will be able to effectively assess and verify online whether the prices they are quoted by TPIs are reasonable.
- 17.9 The auto-rollover remedy will partly address certain barriers to switching that microbusiness customers on default contracts (including auto-rollover contracts) face by: (a) increasing the time window during which microbusiness customers will be able to give their termination notice to

³ The features that give rise to the Microbusiness Weak Customer Response AEC are listed in paragraph 16.136.

suppliers; and (b) prohibiting suppliers from including certain restrictions (termination fees and the use of no-exit clauses).

- 17.10 Our remedies will also prohibit termination fees in relation to evergreen and OOC contracts. This measure, together with the measure to prohibit termination fees in relation to auto-rollover contracts, will ensure that suppliers will no longer be permitted to charge termination fees on default contracts with their microbusiness customers.⁴ It will thereby reduce the barriers to switching for microbusiness customers on evergreen and OOC contracts. This will bring the treatment of microbusiness customers in line with that in the domestic retail markets, where suppliers tend not to charge termination fees on the SVT.
- 17.11 The remedies to establish a programme to identify different or additional information from suppliers to prompt microbusiness customers to engage, and to disclose the details of their most disengaged microbusiness customers to rival suppliers will serve to increase the engagement of microbusiness customers on default contracts. By encouraging microbusiness customers to engage, we expect the competitive constraint on energy suppliers to increase. This would encourage suppliers to reduce the prices of their available acquisition and retention contracts for microbusiness customers.
- 17.12 We note that the price transparency and auto-rollover remedies are specific to the microbusiness segments. However, the other two remedies, which relate to the establishment of a programme to provide microbusiness customers with information and access to microbusiness customers' data, mirror two remedies we have outlined in the domestic retail markets. In the design of these remedies for the microbusiness segments, we have adopted a similar framework to that used for domestic retail markets.

Other remedies

- 17.13 Our remedies concerning the electricity and gas settlement systems, as discussed in Section 12, will also apply to microbusiness customers. In particular, the plan to move customers in profile classes 1 to 4 to half-hourly settlement in electricity will affect the majority of microbusiness customers (almost 90% of which currently fall into profile classes 3 and 4).
- 17.14 The other remedies that we have decided to introduce with a view to improve the framework for competition for domestic customers either affect

⁴ We note that currently SLC 7.6 does not permit suppliers to apply termination fees on deemed contracts to non-domestic customers.

very few microbusiness customers or do not apply at all in the microbusiness segments. In particular:

- (a) the simpler choices component of the RMR rules only applies to domestic customers; and
- (b) very few microbusiness customers (less than 1% of the total) are on prepayment meters. For those that are, the remedies that we have decided to introduce to address technical constraints relating to prepayment tariff slots should improve the range of tariffs available.

17.15 We have also considered the case for introducing a price cap for microbusiness customers on prepayment meters. We have decided not to do so, on the grounds that the costs associated with implementing a price cap for the microbusiness segments would be large relative to the potential benefits which would accrue to a very small number of microbusiness customers. Furthermore, we have not received any evidence to suggest that the features that we have identified as giving rise to an AEC for domestic prepayment customers (as distinct from the Domestic Weak Customer Response AEC; see Section 9) are present in the microbusiness segments.

17.16 In developing our remedies, we have been mindful to ensure that they work together as a coherent package, which, as a whole, provides an effective and proportionate means of addressing the Microbusiness Weak Customer Response AEC, and the resulting customer detriment. Our overall assessment of the package of remedies against these criteria, including an assessment of costs and benefits, is provided below (see paragraph 17.281). We have concluded that the benefits of the package as a whole are likely to exceed the costs by a substantial degree.

Helping customers engage to exploit the benefits of competition: Remedies to address the Microbusiness Weak Customer Response AEC

Price transparency remedy

17.17 One of the features of the SME retail energy markets that we have identified as giving rise to the Microbusiness Weak Customer Response AEC (and the resulting detriment) is that customers face actual and perceived barriers to accessing and assessing information arising from certain aspects of those markets. One of these aspects is a general lack of price transparency concerning the contracts (or tariffs) that are available to microbusiness customers, which results from:

- (a) many microbusiness tariffs not being published by suppliers;

(b) a substantial proportion of tariffs being individually negotiated between customers and suppliers; and

(c) the nascent state of PCWs for non-domestic customers.

17.18 We set out a price transparency remedy that will require energy suppliers to disclose prices for all contracts on offer for a 'Relevant Segment' (which we explain in paragraph 17.20 below) via suppliers' online quotation tools or third party online platforms such as PCWs. This reflects comments we received on our Remedies Notice that the means of price disclosure should be an online tool and that the price transparency remedy should only apply to a specific sub-segment of microbusiness customers.

17.19 We consider that online quotation tools will be a more practical solution than the publication of price lists because they will reduce the costs on suppliers and allow suppliers to frequently update the prices of their available contracts.⁵ We have therefore concluded that the means of price disclosure in the context of this remedy will be an online quotation tool on suppliers' websites (see paragraph 17.48 below).

17.20 Based on the feedback received from the parties, we have decided that Ofgem's definition of microbusiness would be too broad as regards the scope of the remedy. This is due to the complexities and costs (also see paragraph 17.36 below) involved in disclosing prices for larger microbusinesses; and also evidence that the larger microbusinesses prefer to negotiate contractual matters through offline channels (eg suppliers' telephone sales channels).⁶ Accordingly, we have decided to apply the price transparency remedy to microbusiness customers that meet specific requirements (the 'Relevant Segment'). In particular:

(a) In respect of the supply of electricity, this remedy will apply to non-domestic customers with single meter points, meeting all of the following criteria:

(i) falling under profile classes⁷ 1 to 4; and

⁵ For example, suppliers' online quotation tools would be able to price contracts on a real-time basis by accounting for the wholesale energy costs, which can fluctuate frequently.

⁶ See Appendix 17.1 for further details, specifically the sections on parties' views on characteristics of larger microbusinesses and parties' arguments in favour of profile classes 3 and 4 for electricity and small supply points for gas.

⁷ Profile classes relate to the electricity settlement process (see Appendix 8.6 for further details). Profile classes 3 and 4 concern non-domestic customers, which have relatively more straightforward metering and consumption profiles, compared to those on profile classes 5 to 8. In addition, profile classes 1 and 2 relate to domestic customers. However, we understand that some non-domestic customers are included in profile classes 1 and 2. Such non-domestic customers (meters) that are solely on non-domestic contracts will be included within the

- (ii) consumption threshold equal to or below 50,000 kWh per year; and
- (iii) on simple meters.⁸

(b) In respect of the supply of gas, this remedy will apply to non-domestic customers with small supply points only. This will include microbusiness customers with consumption levels of less than 73,200 kWh per year.

17.21 The Relevant Segment includes almost all⁹ customers within the definition of microbusiness used by Ofgem and in the terms of reference,¹⁰ while excluding larger microbusinesses. We understand that larger microbusinesses generally prefer to negotiate contracts through offline channels (eg directly over the telephone)¹¹ and would, therefore, benefit to a lesser extent from this remedy and would be the most expensive and complex to serve through an online quotation tool. Also, such large customers constitute a small minority of the overall microbusiness customer base,¹² and including them would significantly increase the costs for suppliers to comply with the remedy. In contrast, the smaller end of the microbusiness customers, whose energy needs are more akin to those of domestic customers, will gain most from this remedy.

17.22 The Relevant Segment is consistent with the settlement process and suppliers would be able to easily identify the relevant meters. We also note that there was broad-based support among suppliers for our definition of the Relevant Segment (see paragraphs 17.32 to 17.43 below for further details on the Relevant Segment).

Aims of the price transparency remedy

17.23 The main aim of this remedy is to increase the price transparency of available contracts to microbusiness customers in the Relevant Segment. Specifically, as noted in Appendix 16.1, paragraph 278, many tariffs (contracts and their prices) are not published on line by suppliers. First, most

scope of this remedy, ie customers in profile classes 1 and 2 on domestic tariffs or those having dual use (domestic and non-domestic) tariffs will be excluded from the scope of this remedy.

⁸ We define simple meters as (the number of meter registers/rates is set out in brackets): Single Rate (1); Off-Peak (1); Day/Night (2); Day/Evening/Weekend (2); and Day/Evening/Weekend/Night (3). This excludes standard time of day (SToD) meters. However, this will include customers with smart/advanced meters who opt for contracts/tariffs with up to three rates (see paragraph 17.37 below).

⁹ See Appendix 17.1 for the proportion of non-domestic and microbusiness customers that the Relevant Segment would include.

¹⁰ Energy market investigation, [terms of reference](#).

¹¹ See Appendix 17.1 for further details, specifically the sections on parties' views on characteristics of larger microbusinesses and parties' arguments in favour of profile classes 3 and 4 for electricity and small supply points for gas.

¹² See Appendix 17.1 for further details, specifically the section on parties' arguments in favour of profile classes 3 and 4 for electricity and small supply points for gas.

suppliers (including one of the Six Large Energy Firms) do not have online tools or do not disclose online the prices of their available contracts. Second, suppliers that have online quotation tools do not publish the prices of all available contracts to microbusiness customers. For instance, we observe that some suppliers do not disclose the prices of the retention contracts that are available to their existing microbusiness customers.

- 17.24 As we discuss below, the price transparency remedy will require suppliers to disclose the prices of all available acquisition and retention contracts to non-domestic customers in the Relevant Segment.
- 17.25 The first effect of this remedy will be to reduce the high search costs currently faced by microbusiness customers. Non-domestic customers in the Relevant Segment will be able to check the prices of gas and electricity not only through direct telephone contact with individual energy suppliers and/or TPIs, but also through the suppliers' websites. This will reduce the steps and time required for these customers to obtain price information. Moreover, the remedy is likely to facilitate the development of PCWs in the microbusiness segments, which would allow these customers to compare prices across suppliers by visiting a single website, reducing their search costs.
- 17.26 An additional benefit of the development of PCWs would be to increase microbusiness customers' awareness of their ability to switch energy suppliers or contract because PCWs will have an incentive to advertise their services to potential microbusiness customers and to encourage them to switch.

Parties' views on a price transparency remedy

- 17.27 Parties were generally supportive of the need for greater price transparency in the microbusiness segment as set out in the Remedies Notice. Following parties' submissions on the Remedies Notice, we consulted concerned parties on the design of the remedy. Certain independent suppliers raised concerns over the costs of developing a price comparison tool and the difficulty of implementing the remedy. We took these concerns into account in developing the remedy set out in the provisional decision on remedies. We set out these responses in full in Appendix 17.1.
- 17.28 In response to the provisional decision on remedies, there was strong support among the parties with regards to the design of the remedy, particularly the Relevant Segment. Nevertheless, we received the following main challenges, which we have summarised below. We have also listed these submissions and our response in greater detail in Appendix 17.1:

- (a) EDF Energy said that suppliers should be required to disclose the prices of their contracts through rate cards (price lists) for certain contracts, in addition to the online quotation tool. We are not minded to do so for reasons outlined in paragraph 17.49.
- (b) Scottish Power said that suppliers could potentially circumvent the remedy by disclosing relatively high prices and then offering lower prices in the form of discounts to customers who chose to negotiate. Similarly, Haven Power submitted that the remedy would result in published prices being less competitive than if prices were negotiable. Utility Warehouse also said that published prices would result in higher prices. We note that suppliers will have an incentive to disclose prices that are relatively competitive in order to win new business. Hence, in our view the remedy will not result in higher prices.
- (c) RWE said that if quoted prices would be subject to a credit check, then it would result in higher prices, particularly for those customers with a good credit rating. It also said that this feature could lead to offers being withdrawn, resulting in customer disengagement. Haven Power said that ‘appealing tariffs’ may not be available to microbusiness customers after a credit check, thus resulting in a ‘disappointing consumer experience’. Our position is that suppliers will be able to offer customers (with good credit ratings) lower prices (than those published) both online or offline. Therefore such customers will not necessarily be paying higher prices than the price they would have paid had the credit check been done before the generation of a price quotation. Also, under the remedy, suppliers will be able manage credit risk (for those customers that fail a credit check) in a number of ways without necessarily withdrawing an offer. This would not result in customer disengagement.
- (d) Inenco, a TPI, said that the remedy would ‘destroy switching’ by putting 1,400 TPIs and independent suppliers at risk. It said that [redacted]. Additionally, EDF Energy argued for consistency in regulation of prices between suppliers and TPIs. We note that our remedy permits competition by channel and prices will be allowed to differ by channel. Hence, it will not damage the business of TPIs or independent suppliers.
- (e) Centrica, Opus Energy¹³ and RWE told us that the remedy, as proposed in the provisional decision on remedies,¹⁴ could result in increased search costs for businesses because suppliers would potentially have to disclose the prices of a large number of contracts, which could confuse

¹³ Opus Energy was referring specifically to bespoke/negotiated contracts.

¹⁴ RWE specifically highlighted quotation process involving two primary information inputs.

customers. Utility Warehouse told us that it would be impractical for suppliers to disclose the prices of all contracts. On the contrary, we expect that the easy-to-use online quotation tools will result in reduced search costs and easier price discovery for customers. We also consider that it would be practical for suppliers to disclose the prices of all their available contracts.

- (f) As a consequence of the above point, Centrica told us that it would better facilitate price comparison across suppliers if the number of contracts under the scope of this remedy be reduced. Separately, RWE suggested that contracts which were sold 'exclusively offline' should be excluded from the scope of this remedy. Our position is that if only selected contracts were to be included in the scope of this remedy, then suppliers could circumvent the remedy. This would not improve the price transparency of contracts, which is the key aim of the remedy.
- (g) The FSB also suggested that suppliers be compelled to disclose the prices of a few contracts with the exact same terms and conditions. The FSB said that this would aid in comparability. We note that customers could easily compare prices and contract features using the secondary information inputs to filter the search results and tailor the contracts.
- (h) SSE, Centrica and RWE submitted that the remedy include a sunset clause for when non-domestic customers in the Relevant Segment are moved to half-hourly settlement. SSE and RWE said that suppliers would have to develop complex and expensive tools (to cater for half-hourly-settled customers) and that time-of-use tariffs under half-hourly settlement were better contracted over the phone. RWE added that this would result in online quotation tools becoming less relevant. We note that currently, there are no firm plans to move microbusiness customers to half-hourly settlement. In addition, we have decided not to include a sunset provision. However, the Relevant Segment of microbusiness customers may be subject to review (also see paragraph 17.80).
- (i) Citizens Advice argued against the Relevant Segment and that the price transparency remedy should include all microbusiness customers as defined by Ofgem. It said that the Relevant Segment would be complicated for suppliers. We note that suppliers have clearly understood and supported the Relevant Segment.
- (j) Citizens Advice also suggested that the CMA recommend Ofgem to review the prices of default contracts, which it considered to be unjustifiably high. We note that our package of remedies will encourage customers to switch away from default contracts.

- (k) EDF Energy argued for a quicker implementation deadline for those suppliers that choose the third party online platform option. However, for the purposes of consistency and clarity, we are not minded to set separate implementation deadlines for suppliers.
- (l) E.ON told us that the best place for suppliers to disclose the prices of OOC contracts would be within the terms and conditions of other tariffs. We note that suppliers will be permitted to determine the online location of where they choose to disclose the prices of their OOC contracts.

17.29 In their responses to the provisional decision on remedies, some parties requested clarifications to the design (see Appendix 17.1 for further details) and we have amended the ‘design consideration’ section of this document to provide this clarity.

17.30 In light of these responses, we have therefore not changed the fundamental design of this remedy since the provisional decision on remedies.

Design considerations of the price transparency remedy

17.31 We have considered the following elements in the design of the price transparency remedy:

- (a) The scope of the remedy.
- (b) The types of contracts for which prices need to be disclosed.
- (c) The means of price disclosure.
- (d) How the remedy should be implemented.¹⁵

- *Scope of the price transparency remedy*

17.32 As indicated in paragraphs 17.20 to 17.22 above, we consider that Ofgem’s definition of microbusiness (and the definition in our terms of reference) would be too broad for the purposes of this remedy. Accordingly, we have decided to apply the price transparency remedy to non-domestic customers in the Relevant Segment.

¹⁵ See Appendix 17.1 for evidence regarding the design considerations of the price transparency remedy.

- 17.33 The terms of reference for the energy market investigation refer to Ofgem's definition of microbusiness set out in SLC 7A.14.¹⁶ Ofgem classifies a microbusiness as any non-domestic customer that:
- (a) employs fewer than ten employees (or their full time equivalent) and has an annual turnover or balance sheet no greater than €2 million; or
 - (b) consumes no more than 100,000 kWh of electricity per year; or
 - (c) consumes no more than 293,000 kWh of gas per year.¹⁷
- 17.34 Some suppliers said that it would be complex and expensive to build online quotation tools if the remedy were scoped as per Ofgem's microbusiness definition. They mentioned that microbusiness customers at the top end of Ofgem's microbusiness definition could also be in profile classes 5 to 8 or be half-hourly settled, and not have simple meters.¹⁸ Suppliers also told us that their experience showed that such customers preferred individually tailored contracts, which were contracted through offline channels such as the telephone. Suppliers told us that such customers should fall outside the scope of the price transparency remedy.¹⁹
- 17.35 Ofgem told us that its microbusiness definition was intentionally broad.²⁰ For example, a customer at the top end of Ofgem's microbusiness consumption threshold can have an annual bill of £10,000 per fuel (before VAT).²¹ Ofgem suggested that the CMA should consider narrowing the scope of the remedy to target smaller microbusiness customers, which are less engaged, less likely to use a broker and find it more difficult to navigate around energy contracts. It said that suppliers may be able to offer standardised contracts that could be transacted online to cater for these smaller microbusiness customers.²²
- 17.36 We agree with Ofgem that smaller microbusinesses are more likely to face barriers to accessing and assessing information as a result of the lack of price transparency due to their lack of size and sophistication. In addition, as suggested by the suppliers, we acknowledge that larger microbusinesses

¹⁶ Energy market investigation, [terms of reference](#).

¹⁷ The definition of microbusinesses has changed over time. It was originally defined by government for the purposes of the complaints handling standards and redress scheme. The definition was then updated following Ofgem's Energy Supply Probe and again changed following its RMR.

¹⁸ We define simple meters as (the number of meter registers is set out in brackets): Single Rate (1); Off-Peak (1); Day/Night (2); Day/Evening/Weekend (2); and Day/Evening/Weekend/Night (3). In effect these are meters other than SToD meters.

¹⁹ See Appendix 17.1 for further details.

²⁰ Ofgem's working paper on non-domestic regulatory regime dated 18 November 2015.

²¹ Appendix 16.1, paragraph 5.

²² Ofgem's working paper on non-domestic regulatory regime dated 18 November 2015.

may prefer to negotiate contracts directly with suppliers over the telephone (see paragraph 17.20 above).

- 17.37 Subsequent to the publication of the provisional decision on remedies, Ofgem told us that 24% of all non-domestic meters in profile classes 1 to 4 were already smart or advanced as of December 2015. It added that the number of non-domestic customers with smart/advanced meters is likely to increase over the coming years. Hence, Ofgem suggested that CMA include smart/advanced meters within the definition of the Relevant Segment. It clarified that the definition of simple meters (see paragraph 17.20 above) in the provisional decision on remedies appeared to exclude smart/advanced meters. Ofgem added that if the CMA were to exclude smart/advanced meters from the scope of this remedy, an increasing proportion of non-domestic customers falling in the Relevant Segment (as defined in the provisional decision on remedies) would be excluded from the scope of this remedy in future. In light of Ofgem's comments, we clarify that non-domestic customers²³ with smart/advanced meters will be included in the remedy. However, this will only include customers with smart/advanced meters that opt for contracts/tariffs with up to three rates.²⁴ We note that these customers will have the same contracts available to them that will also be available to those customers with simple meters. We also consulted the Six Large Energy Firms and certain independent suppliers on this proposal. A significant majority of suppliers told us that they would be able to implement this proposal.
- 17.38 The Relevant Segment will be based on single meter points per fuel. So, a customer in the Relevant Segment will be able to get a quote for each meter (and on a per fuel basis). In a few cases²⁵ where a non-domestic customer has more than one meter per fuel, it will have the option of obtaining separate online quotes for each meter, or telephoning the supplier to obtain a quote for all of its meter points for that fuel. We also note that suppliers' non-domestic online tools and EnergyLinx currently offer quotes for single meter points as well.
- 17.39 This approach with regards to single meter points was supported by all suppliers that responded to the consultation before the provisional decision

²³ In profile classes 1 to 4 and with consumption equal to or below 50,000 kWh per year.

²⁴ Examples of such contracts/tariffs include types (the number of meter registers is set out in brackets): Single rate (1); Off-Peak rate (1); Day/Night rate (2); combination of two rates for Day/Evening/Weekend Rates (2); and combination of three rates Day/Evening/Weekend/Night (3).

²⁵ Based on our consultation with suppliers, we understand that non-domestic customers with more than one meter point per fuel are unlikely to fall within the Relevant Segment. This is because they tend to be the larger SMEs and I&C customers.

on remedies. It will be cost-effective for suppliers because the online quotation tool will not have to calculate price permutations for multiple meters. In relation to meter types, compared to simple meters (included within the Relevant Segment), SToD²⁶ meters require a greater number of price permutations for price production, and including them would thus increase the costs of the online tool. Therefore we have excluded StoD meters from the Relevant Segment.

- 17.40 In respect of the Relevant Segment for the supply of electricity, non-domestic customers in profile classes 1 to 4²⁷ (and with lower levels of consumption below 50,000 kWh per year and with simple meters) tend to include smaller non-domestic customers (including microbusiness) who would benefit most from reduced search costs, given that they have limited resources to search for the best deals compared to larger businesses. Moreover, compared to non-domestic customers in profile classes 5 to 8 (excluded from the Relevant Segment), non-domestic customers in profile classes 1 to 4 tend to have straightforward metering and contract/tariff requirements that are well suited to online price production.
- 17.41 We note that even though a significant majority of non-domestic customers²⁸ and a significant majority of microbusiness customers are included within profile classes 3 and 4, we have included non-domestic customers in profile classes 1 and 2²⁹ within the scope of the remedy because these businesses represent the smallest customers in microbusiness segments, which are likely to face the greatest barriers to searching for price information.
- 17.42 In respect of the Relevant Segment for the supply of gas, an important consideration was distinguishing between various sizes of supply points. Our view is that only small supply points should be included within the scope of this remedy because smaller microbusinesses face the greatest barriers to searching and the highest search costs. In its response to the provisional decision on remedies, EDF Energy suggested that the Relevant Segment should exclude profile classes 1 and 2 because customers in profile classes 1 and 2 constituted an insignificant proportion of its non-domestic customers and different VAT rates between domestic and non-domestic customers would lead to confusion with domestic customers accessing non-domestic tariffs that may not be appropriate due to different terms and conditions, and

²⁶ SToD are meters with greater than three meter registers, ie these are not 'simple meters'.

²⁷ We understand that non-domestic customers in profile classes 1 and 4 are not half-hourly settled. By implication we are excluding half-hourly settled customers from the scope of this remedy. We note that such half-hourly settled non-domestic customers tend to be larger SMEs and I&C customers.

²⁸ Non-domestic customers include microbusiness, SME and I&C customers. See Appendix 17.1 for details on the proportions of non-domestic and microbusiness customers included within the scope of this remedy.

²⁹ Profile classes 1 and 2 are for domestic customers. However in some instances, non-domestic customers are included in profile classes 1 and 2.

VAT rate. However, on consideration, we are minded to include profile classes 1 and 2, and have also considered the VAT issue by only including non-domestic customers in profile classes 1 and 2 (see paragraphs 17.20 and 17.41).

17.43 In relation to consumption thresholds for both the supply of gas and electricity, we note that consumption is a good proxy for the size of the non-domestic customer, and whether its energy and contract requirements are straightforward. For instance, large SMEs and I&C non-domestic customers are more likely³⁰ to have higher consumption than microbusiness customers. By incorporating the consumption thresholds set out in the Relevant Segment, we have included smaller non-domestic customers, which will benefit most from increased price transparency and reduced search costs; and have excluded those larger non-domestic customers, which prefer to contract over the telephone. The lower consumption thresholds will also make it less burdensome for independent suppliers to comply with this remedy and reduce the costs to them of developing online quotation tools. Even after adopting a consumption threshold, the Relevant Segment still includes a significant majority of customers failing within Ofgem's definition of a microbusiness.

- *Types of contracts for which prices must be disclosed*

17.44 In order to enhance price transparency in the microbusiness segments, suppliers will be required to disclose the prices of all of their available acquisition and retention contracts³¹ within the Relevant Segment, via their online quotation tools or third party online platforms. This will enhance price transparency even among suppliers with online quotation tools because the Six Large Energy Firms with online quotation tools currently do not disclose the prices for all their available acquisition and retention contracts (see paragraph 17.23).

17.45 In their responses to the provisional decision on remedies, parties were supportive of price transparency. However, some parties sought clarification

³⁰ There may be exceptions in the case of microbusinesses that are highly energy intensive businesses, which may have high consumption of energy. We understand that such businesses might be expected to be more engaged already in searching and switching due to the relative importance of the energy inputs to their businesses. Therefore, if they were excluded from the scope of this remedy due to their high consumption level, such businesses would unlikely be significantly negatively affected.

³¹ These contracts are used to acquire new customers or retain existing customers. The structure of the contract would be at the supplier's discretion. For example, suppliers could determine the duration (term) of the contract on offer and also whether price would be fixed or variable for the duration of the contract on offer.

on the definition of all available contracts and we have addressed this in paragraphs 17.46, 17.47, 17.51 and 17.62.³²

- 17.46 As an additional measure to increase the price transparency of default contracts, suppliers will be required to disclose the prices of their OOC and deemed contracts on their websites (suppliers will not be required to disclose the prices of OOC and deemed contracts through the online quotation tool for acquisition and retention contracts). In their responses to the provisional decision on remedies, all parties that responded to this feature agreed with this requirement.
- 17.47 We have not outlined any additional measures in relation to evergreen contracts.³³ This is because microbusiness customers on evergreen contracts have different contract prices, depending on when they started the contract and so producing price lists for these customers would be onerous for suppliers. Moreover, customers on evergreen contracts are able to view the price of their individual contract on their bills and compare this with the prices of other contracts currently available from suppliers. In their responses to the provisional decision on remedies, none of the parties that responded (to this feature) disagreed.
- *The means of price disclosure*
- 17.48 We have decided to require suppliers to disclose prices for microbusiness customers within the Relevant Segment through the use of online quotation tools made available on their websites, or through one or more third party online platforms (eg PCWs). In their responses to the provisional decision on remedies, all parties that responded to this feature were in agreement on this option.
- *Online quotation tools*
- 17.49 Many parties supported the use of online quotation tools over price lists.³⁴ They said that published price lists would be static and therefore unsuitable because several factors contributed to price production. These factors would make the price lists (or rate cards) burdensome to produce for suppliers, and

³² Also see Appendix 17.1, paragraphs 263–268.

³³ For the purpose of the price transparency remedy, evergreen contracts are those that are not used to acquire new customers or retain existing customers, ie a customer is already on an evergreen contract. We understand that these contracts could have no termination date and the prices could change periodically; and that these contracts are of limited importance for acquiring new non-domestic customers (see Appendix 16.1, paragraph 29).

³⁴ See Appendix 17.1, specifically the section on parties' views on their preference for online quotation tools, compared with price lists.

confusing to interpret for microbusiness customers. Suppliers also noted that it would be cumbersome to update price lists frequently. For example, they pointed out that wholesale energy costs fluctuated frequently and that these fluctuations would need to be reflected in a timely manner in the price quotations. Some parties also pointed out that online quotation tools would facilitate the development of PCWs in the microbusiness segments.³⁵

17.50 We also observe that all of the Six Large Energy Firms (except for Scottish Power)³⁶ currently have automated online quotation tools for the microbusiness customers, and that none of the suppliers³⁷ use static price lists to disclose the prices of acquisition and retention contracts for their microbusiness customers.

17.51 As this remedy aims to reduce the search costs for customers within the Relevant Segment, we consider it important that the online quotation tools should be reasonably easy to use for these customers. Accordingly, suppliers will be required to provide an achievable quote, ie one that the customers can transact upon, subject only to them passing a credit check. Specifically, suppliers:

- (a) must disclose the prices of all³⁸ available acquisition and retention contracts³⁹ once a customer enters its primary information inputs (postcode and consumption) into the online quotation tool;
- (b) have complete discretion on choosing any number of 'secondary information inputs', which will act as filters on the search results from the primary information inputs; and
- (c) must make the quote valid for as long as it does not change the prices for the contract (or tariff), or make it clear to the customer how long the quote will be valid for.

17.52 We consider that it should be possible for customers within the Relevant Segment to obtain a quote based on entering their primary information

³⁵ See Appendix 17.1 for a summary of parties' views on why they support online quotation tools over price lists.

³⁶ In its [response to the Remedies Notice](#), Scottish Power told us [§§].

³⁷ Except for EDF Energy, which publishes the price of its non-domestic variable 'Freedom' tariff.

³⁸ If a supplier were to offer a specific contract/tariff directly through its offline channel (telephone sales) or through TPIs (online or offline), then it would be required to disclose the price of that specific contract on its online quotation tool or via the third party platform. However, the price of that specific contract could differ between the various channels and the price would be open to negotiation. Also, if a supplier wanted to have an exclusive 'TPI only' contract, then it would be required to comply with this remedy by having a weblink (to the third party platform) for that contract.

³⁹ If a supplier offers bundled products, then the prices of such contracts would also have to be disclosed alongside all acquisition and retention contracts. Bundled products have a component(s) of additional services/features, such as energy advice, that are embedded within the price of energy supply.

inputs (ie postcode and consumption) into the online quotation tool. The postcode, followed by address selection,⁴⁰ will allow the supplier to identify the customer's address⁴¹ and region, which will allow the supplier to determine the locational pricing. The postcode will also allow the supplier to obtain the MPAN and MPRN numbers via the ECOES, SCOGES or another third party database. This will allow the supplier to identify the meter type, profile class, and other meter specific information that contributes to price production.

- 17.53 These inputs (ie postcode and consumption) will be mandatory fields on online quotation tools. However, suppliers will also be allowed to add two additional fields – MPRN and/or MPAN and spend (£) – to complement the primary information inputs, in case the customer's meter is not registered with the ECOES or SCOGES databases, or in case the customer does not immediately have access to its consumption figure.
- 17.54 The function of the secondary information inputs is to allow for more tailored and cost reflective quotations, especially in cases when the search results for a given set of primary information inputs display the prices of many contracts. Examples of secondary information inputs include contract start/end date, contract duration, payment type, fixed/variable price, paperless billing, billing frequency and contract type. In addition, the secondary information inputs must be a clearly separate step and selecting the relevant inputs on the online tool must be at the customer's discretion.
- 17.55 We note that the emphasis of this remedy is on contracts 'available' to customers in the Relevant Segment. Therefore, suppliers will have discretion on when to bring contracts to the market. For instance, this remedy does not compel suppliers to offer renewal quotations to their microbusiness customers, who have recently started a fixed-term contract.⁴²
- 17.56 Suppliers will be permitted to quote the prices of negotiable contracts, ie suppliers and their customers can negotiate prices, and suppliers will be permitted to contract at a price below the published rate (initial quote) for that contract. Suppliers will also be permitted to offer price and non-price discounts through online and offline channels. This allows suppliers to offer channel-related discounts to enable customers to use lower cost channels.

⁴⁰ For example, the address selection could be via a drop-down menu.

⁴¹ If there is more than one meter at an address, then the customer would have the option filling in its MPRN/MPAN or calling the supplier.

⁴² For example, this remedy would not compel a supplier to offer a renewal quote to a microbusiness customer that is on day 2 of its three-year fixed-term acquisition contract.

However, to make it easier for customers to compare the prices of acquisition and retention contracts, suppliers will be required to:

- (a) quote a single price⁴³ per fuel for a given set of primary and secondary information inputs for the duration of the contract;⁴⁴
- (b) identify what charges or costs⁴⁵ are included in the quote; and
- (c) to avoid the possibility of hidden charges, if the customer passes the credit check suppliers will not be permitted to increase the price of the published rate/price (initial quote), which was based on the customer's primary information inputs.

17.57 Suppliers will be required to clearly signpost, in a prominent way, the location of their online quotation tools on their websites. For example, their websites' homepages and non-domestic homepages must have web link(s) to the online quotation tool or the third party online platform(s).

17.58 Requiring customers to undergo credit checks prior to obtaining a quote would create a significant disincentive to search the market and would significantly delay the price discovery process. Furthermore, credit risk is not one of the key determinants of price production (see paragraphs 17.52 above). Nevertheless, suppliers will be able to alter the quoted price if a customer were to fail a credit check. We note that suppliers have other options to manage credit risk, such as taking a security deposit or choosing not to supply that customer.

- *Use of third party online platforms*

17.59 As noted in paragraph 17.48 above, suppliers have the choice of disclosing prices for customers within the Relevant Segment through an online quotation tool on their websites, or through third party online platforms such as PCWs. The primary motivation for this approach was to not increase the costs of smaller suppliers. We understand that providing prices to PCWs would be a low cost option with a minimal administration burden for suppliers. For example, based on our discussion with suppliers, we

⁴³ For example, in relation to annual quote, suppliers would be required to quote a single price, and not simply a range between £X and £Y. Suppliers would also be required to disclose a single price for the unit rate(s) and standing charge(s).

⁴⁴ If a supplier has products with multiple price points for a given set of information inputs, then that supplier would be required to disclose each of them as separate contracts, with the scope to filter these contracts by way of secondary information inputs.

⁴⁵ This should include clarity on 'pass-through' elements such as, but not limited to, feed-in tariffs/contracts, electricity market reform costs and renewable obligation costs.

understand that this would only require a supplier to send price lists to a PCW in a flat file format such as a CSV. Additionally, we consider that smaller suppliers would have an incentive to have their prices disclosed on PCWs.⁴⁶

- 17.60 A supplier will be required to comply with the key conditions (see paragraphs 17.20, 17.44, 17.46, 17.51, and 17.53 to 17.58), whether it chooses to use its own online tool or a third party platform. Most importantly, the supplier will be responsible for ensuring that the third party online platforms disclose all of the available acquisitions and retention contracts, and comply with the primary information input requirements.
- 17.61 Suppliers may choose any number of third party online platforms. However, suppliers will be required to have web links on their websites to the prices of all of their available acquisition and retention contracts. It would not be necessary for one particular link (or third party hosting platform) to disclose the prices of all available contracts, although the supplier could choose to arrange its marketing channels in this way.
- 17.62 Separate from the requirements of the price transparency remedy, we note that suppliers may also choose to sell their contracts through TPIs.⁴⁷ The terms and conditions including prices offered by these TPIs will be at the discretion of the suppliers and TPIs. Hence, the prices of such contracts offered by these TPIs may differ from those offered by suppliers⁴⁸ in order to comply with this remedy.

- *Implementation of the price transparency remedy*

- 17.63 We have decided to implement the price transparency remedy through the following:
- (a) A CMA order (and amendments to suppliers' standard licence conditions) that will:
- (i) require energy suppliers to disclose the prices of all available acquisition and retention contracts to non-domestic customers falling within the Relevant Segment either through an online quotation tool made available on their websites, or through one or more third party online platforms (and including a web link on their own website to

⁴⁶ CSV is the abbreviated form for 'comma separated values'.

⁴⁷ These could include online TPIs such as PCWs or offline TPIs such as brokers.

⁴⁸ Via online quotation tools or third party platforms

direct non-domestic customers to such third party online platform(s)); and

(ii) require suppliers to disclose the prices of all their OOC and deemed contracts on their websites.

(b) A recommendation to Ofgem to make any necessary consequential amendments to suppliers' licences.

Assessment of effectiveness of the price transparency remedy

17.64 In this section, we consider whether the price transparency remedy will be effective in achieving its aim.

17.65 In evaluating the effectiveness of the remedy, we have considered:

(a) the effectiveness of the key design elements;

(b) the extent to which it is capable of effective implementation, monitoring and enforcement;

(c) the timescale over which it is expected to take effect; and

(d) the remedy's consistency and compliance with existing or expected laws or regulations.

• *Effectiveness of the key design elements*

17.66 Following the implementation of the remedy, we expect non-domestic customers within the Relevant Segment, to engage to a greater extent than they are currently doing. The remedy will therefore achieve its aim in addressing, in part, the feature of the Microbusiness Weak Customer Response AEC concerning microbusiness customers' ability to access and assess information (see paragraphs 17.23 to 17.26 above).

17.67 Non-domestic customers in the Relevant Segment will be able to obtain quotes for all available acquisition and retention contracts by entering just two pieces of information – the primary information inputs. This will enhance price transparency by reducing the time taken to collect and compare quotes from a number of suppliers.

17.68 Suppliers will not be able to circumvent the remedy by only disclosing their most competitive and/or best prices in an obscure location: suppliers will be required to disclose the prices of all their available acquisition and retention contracts in a prominent way with signposting (see paragraph 17.57 above).

- 17.69 In addition, suppliers will not be able to circumvent the remedy by having contracts that are sold exclusively by their direct telephone sales teams or by TPIs, without disclosing the prices of those contracts as part of this remedy. However, suppliers could have different prices for these contracts between the various channels, thus permitting competition between channels (see paragraphs 17.51 and 17.62 above).
- 17.70 Suppliers will also be required to disclose their prices in a prominent way, irrespective of the means of price disclosure. Suppliers will be required to signpost either the online quotation tool on the suppliers' websites or the relevant third party online platform websites. Customers will then be able to enter their relevant information and see the prices for the relevant and available contracts.
- 17.71 We consider that giving suppliers the choice of disclosing prices via online quotation tools or third party online platforms will not undermine the effectiveness of this remedy. For instance, if all suppliers were to opt for the third party online platform, it would not reduce the effectiveness of the remedy. This is because suppliers will be required to meet the same conditions under both means of disclosure (see paragraph 17.60 above). So regardless of the means of price disclosure, non-domestic customers in the Relevant Segment will be able to access the same information. Hence, both means will be effective in increasing price transparency. In addition, suppliers choosing the third party online platform will be required to provide web links on their websites to all available contracts.
- 17.72 Therefore, we consider that the key design elements of the remedy will be effective in achieving its aim.
- *Implementation, monitoring compliance and enforcement of the remedy*
- 17.73 In determining whether a remedy is effective, we have considered how it will be implemented, and the need for the remedy to be clear to the parties to whom it is directed such as suppliers; and also to other interested parties, such as Ofgem (which will have responsibility, together with the CMA, for monitoring compliance), and microbusiness customers.
- 17.74 As regards implementation of the remedy, we have set out a number of detailed specifications (see paragraphs 17.63 above). We have described the terms of the remedy (and associated new licence condition) so that it will be clear to suppliers to understand, and straightforward for them to implement.

- 17.75 In defining the scope of the Relevant Segment, we have taken into account the existing settlement system (eg profile classes) so that suppliers will be able to easily identify the relevant customers.
- 17.76 Although there are no firm plans in place yet for the introduction of half-hourly settlement, we would expect that soon after the roll-out of smart meters is completed, all of the profile class 1 to 4 non-domestic customers for electricity could potentially be settled on a half-hourly basis.⁴⁹ We understand that, at this point, suppliers would be able to continue to identify the same relevant meters (currently in the 'Relevant Segment) and the relevant non-domestic customers, and suppliers could continue to offer them online quotations. We also note that suppliers would be able to start the quotation process for new customers on smart meters and half-hourly settlement by obtaining the historical annual spend information instead of consumption. Therefore our remedy will continue to be effective, irrespective of and even after the roll-out of smart meters.
- 17.77 As regards monitoring compliance with the remedy, we note that, by introducing a new licence condition, which will be consistent with the CMA's order, Ofgem will be under a duty to perform a monitoring role. Monitoring compliance with the remedy should be straightforward. It will involve periodically checking suppliers' websites to verify that they are adhering to the terms of the order by making available links to the information concerning the pricing of all of the contracts that they offer to non-domestic customers within the Relevant Segment. Ofgem is well placed as the sector regulator to receive, and follow up on, complaints made by microbusiness customers concerning suppliers' ongoing compliance with the licence condition.
- 17.78 As regards enforcement, by introducing the remedy by way of order and new licence condition, Ofgem will also be able directly to enforce against any breach of the new licence condition, without making an application to the court (as compared to enforcing against a breach of an order, for which a court application would be required).
- *Timescale for the price transparency remedy*
- 17.79 In evaluating the effectiveness of the remedy, we have considered the timescale over which the Microbusiness Weak Customer Response AEC would be expected to endure, and the timescale over which the remedy will be likely to take effect. As regards the Microbusiness Weak Customer Response AEC, our view is that, absent the remedy (and the other remedies

⁴⁹ See Appendix 17.1.

we have decided upon concerning this AEC), the detriment would persist. While future market developments such as the completion of the national programme for the roll-out of smart meters and the implementation of our other remedies may go some way to addressing the Microbusiness Weak Customer Response AEC or its associated detriment, they will not fully address either this AEC or the associated detriment.

17.80 In this regard, we do not consider that a move ⁵⁰ to half-hourly settlement for profile classes 1 to 4, which is currently planned to be completed around 2020, will fully address the Microbusiness Weak Customers Response AEC or associated detriment, and that the remedy will continue to be necessary. This is because lack of price transparency is the key aspect of the feature that gives rise to the AEC and this lack of price transparency will not be entirely remedied by the introduction of half-hourly settlement. For these reasons, we have decided that the remedy will not be subject to a sunset provision. However, in light of these developments, the Relevant Segment of microbusiness customers for this remedy may be subject to review.

17.81 As regards the timescales for implementation, we consider that the remedy could be implemented by all suppliers relatively quickly. For example, suppliers' range of estimates to build online quotation tools range from 6 to 18 months, with most giving timeframes of less than 12 months.⁵¹ Suppliers choosing merely to provide links to one or more third party online platforms would be able to implement this remedy within an even shorter timeframe.

17.82 We have therefore set a deadline for implementation by suppliers within 12 months of the publication of the final report by which time suppliers will be required to have their online quotation tools or third party online platforms fully functional concerning the Relevant Segment. We consider that, in light of suppliers' submissions, this will give suppliers adequate time to prepare their online quotation tool or to put in place arrangements with third party online platforms.

- *Consistency and compliance with existing or expected laws or regulations*

17.83 As part of our consideration of the design of the remedy, we have considered whether any elements of the remedy would be inconsistent with

⁵⁰ We note that currently there are no firm plans to move microbusiness customers to half-hourly settlement.

⁵¹ Time periods given by suppliers indicate the time they would need to adapt/build the online quotation tools. We considered that suppliers would most likely start building or modifying their online tools (and/or platforms) once they had a good level of clarity of how the remedy would work in practice. This would have to include all the prescriptive detail. We considered that this would upon the publication of the final report.

other relevant laws and regulations. A particular focus of our assessment of this aspect of remedy design has been the interaction of our remedy with the possible⁵² changes governing the move to half-hourly settlement for profile classes 1 to 4 (see paragraphs 17.277 to 17.280), and Ofgem's desire to move towards a more principles based system of regulation concerning the retail supply markets, more generally (see Section 13). We have incorporated the scope of such interactions, where relevant, into the design of this remedy. Therefore, this remedy will be consistent and compliant with the existing and forthcoming expected changes to applicable laws and regulations.

- *Conclusion on the effectiveness of the remedy*

17.84 In light of the above analysis, we conclude that this remedy will be effective in reducing the actual and perceived barriers to accessing and assessing information faced by microbusiness customers, which is a feature of the retail energy markets that gives rise to the Microbusiness Weak Customer Response AEC, and the resulting customer detriment.

Assessment of proportionality of the price transparency remedy

17.85 In this section we set out our assessment of whether the remedy will be a proportionate remedy. We have done so by considering whether the remedy will:

- (a) be effective in achieving its legitimate aim;
- (b) not be more onerous than needed to achieve its aim;
- (c) be the least onerous if there were a choice between several effective measures; and
- (d) not produce disadvantages that are disproportionate to the aim.⁵³

- *Effective in achieving its aim*

17.86 For the reasons set out above, we consider that the remedy will be effective in achieving its aim of increasing price transparency. Accordingly, it will be effective in partly addressing one of the underlying features that gives rise to

⁵² We note that there are currently no firm plans to move microbusiness customers to half-hourly settlement.

⁵³ CC3, paragraph 344, citing the principles established in the *Fedesa* case, Case C-331/88, *The Queen v Minister of Agriculture, Fisheries and Food and Secretary of State for Health, ex parte: Fedesa and others*, [1990] ECR I-4023, paragraph 13.

the Microbusiness Weak Customer Response AEC, and the resulting customer detriment.

- *No more onerous than needed to achieve its aim*

17.87 We have considered whether there were other channels to disclose prices (eg via letters or over the telephone) that would be as effective as the online means outlined under this remedy. However, we did not identify any such means, nor were any proposed by the parties. In addition, we considered that letters might quickly become outdated as wholesale energy costs changed, limiting their effectiveness as a means of increasing price transparency. The disclosure of prices over the telephone would not reduce search costs and a customer would be unable to compare prices across all or most of the market. In contrast, online search, as outlined under the remedy, will bring benefits to customers as a whole in terms of allowing them to easily compare prices and reduce their search costs.

17.88 We considered whether a narrower Relevant Segment could be less onerous, for example, if the Relevant Segment were to only include profile class 4. However any such reduction in scope would result in non-domestic customers in profile classes 1 to 3 being harmed, ie they would continue to experience high search costs. Therefore, we concluded that a narrower Relevant Segment would not be effective.

17.89 In addition, we will allow all suppliers the choice of the means of price disclosure between the online quotation tool and third party online platforms. They will therefore be able to choose the option that represents the more cost-effective option for them. This will specifically reduce the potential burden of the remedy on small suppliers, which might have insufficient resources to establish an online quotation tool.

17.90 We therefore conclude that this remedy will be no more onerous than needed to achieve its aim. In particular, we note that the remedy will not impose costs and restrictions on suppliers that go beyond what is needed to achieve price transparency for non-domestic customers in the Relevant Segment.

- *Least onerous if there were a choice between several effective measures*

17.91 As noted above, we have considered several variations concerning the remedy, and whether there may be alternative remedies that achieve the same aim. However, we have found that the remedy is the only form of remedy that will be effective (for the reasons discussed in paragraphs 17.87

to 17.90 above). We therefore do not consider that there is a less onerous remedy that will be effective.

- *Would not produce disadvantages disproportionate to the aim*

- 17.92 The scope of the Relevant Segment is designed so that it will target the non-domestic customers (including microbusiness customers) which most commonly use such online systems to search for prices; and it will not require suppliers to make available their prices to larger microbusinesses with considerably more resources to devote to negotiating their prices with suppliers directly (see paragraphs 17.35, 17.36, 17.40, 17.41 and 17.43 above).
- 17.93 Targeting our remedy on the Relevant Segment as opposed to the whole microbusiness customer base (which formed part of our terms of reference) will significantly reduce the costs borne by suppliers (see paragraphs 17.21 and 17.39 above). It will also reduce the remedy's complexity during implementation: extending the remedy beyond the Relevant Segment would significantly increase the number of price permutations that the online quotation system or the third party online platform would need to manipulate in order to produce a quote.
- 17.94 Finally, we have compared the potential costs of implementing the remedy via an online quotation tool to the size of the detriment that the remedy may be expected to address.
- 17.95 The Six Large Energy Firms provided the following cost estimates to amend their current⁵⁴ online quotation tools in order to comply with the price transparency remedy: [redacted] (£nil); [redacted]⁵⁵ (£100,000 to £150,000); [redacted] (£200,000⁵⁶); [redacted] (£250,000⁵⁷); [redacted] (£1 million); and [redacted] (£3 million to £5 million). None of the parties brought to our attention that the running costs of the online quotation tool would be significant, subject to the functionality specified in the remedy design.

⁵⁴ In its [response to the Remedies Notice](#), Scottish Power said that it did not currently operate an online quotation tool. [redacted].

⁵⁵ [redacted] provided the set-up cost estimate for a brand new online quotation tool. It clarified that if the Relevant Segment were to include meters with three registers (as opposed to only one or two meter registers), then the costs would increase from £100,000 to £150,000.

⁵⁶ [redacted] said that its costs would likely be in excess of £200,000 of development costs plus internal business change costs.

⁵⁷ Subject to the precise design of the remedy.

- 17.96 Certain other suppliers provided the following cost estimates to build new⁵⁸ online quotation tools in order to comply with the price transparency remedy: [redacted]⁵⁹ (minimal costs); [redacted] (£40,000), [redacted] (£160,000 to £200,000); [redacted] (£300,000); [redacted] (£300,000 to £500,000); [redacted] (£550,000); [redacted] (significant costs).⁶⁰
- 17.97 Additionally, based on suppliers' submissions, we understand that the third party online tool (ie the PCW option) will not require significant set-up and running costs (see Appendix 17.1). Therefore the costs that this remedy will impose on suppliers can be reduced to a relatively insignificant level, if the suppliers were to opt for the PCW option as opposed to the online quotation tool.
- 17.98 We have compared the estimated costs provided by the Six Large Energy Firms to amend or build new online quotation systems, to our estimate of the detriment of around £183 million per year.⁶¹ As regards the combined estimated costs of all of the Six Large Energy Firms' costs, the upper bound⁶² of their reported estimates to build/amend online quotation tools totalled £6.6 million, although this included [redacted] £5 million estimate, which is substantially higher than the cost estimates provided by all other suppliers.
- 17.99 We consider that a more realistic⁶³ figure for all of the Six Large Energy Firms could be derived by using [redacted] estimate as a benchmark. [redacted] estimate is based on it building a new quotation tool, which would normally be more expensive than modifying an existing system. If the modification of an existing system were more expensive than purchasing a new online system, then the supplier could chose the latter option. For the Six Large Energy Firms,⁶⁴ this would give a total one-off cost of approximately £750,000. For the approximately 30 suppliers within the Relevant Segment, the total cost would be approximately £4.5 million. These figures, which relate to one-off set-up costs, are still significantly lower than the estimated profits in excess of the WACC of £183 million per year.⁶⁵ We also consider these figures are

⁵⁸ Except for Good Energy, we observe that none of the other independent suppliers have an online quotation tool on their websites.

⁵⁹ We observe that [redacted] has an online quotation tool, which largely complies with the price transparency remedy. For instance, a microbusiness customer could obtain quotes by only entering its primary information inputs.

⁶⁰ See Appendix 17.1 for suppliers' submissions of the estimated costs.

⁶¹ Section 16, paragraph 16.150.

⁶² This includes the £5 million estimated by [redacted], which we considered to be an outlier.

⁶³ We also note that [redacted] estimate was within reasonable range to the higher estimates provided by [redacted].

⁶⁴ Excludes [redacted] because it told us that it would not incur any costs to comply with the remedy because its online quotation tool already met the design specifications that would be required under the remedy.

⁶⁵ Section 16, paragraph 16.150.

an upper bound because some suppliers might opt for the third party online platform, which would be a cheaper option.

17.100 We also note that the inclusion of smart/advanced meters⁶⁶ within the scope of this remedy (see paragraph 17.37 and Appendix 17.1) will not increase the costs on suppliers to develop their online quotation tools or having their prices disclosed via third party platforms.

17.101 As regards our estimate of the likely benefits arising from increased price transparency, we note that it was not possible to accurately predict the increase in switching rates and any price reductions from increased customer response that could result from this remedy. Nevertheless, using the Six Large Energy Firms' upper bound estimates of the costs incurred in implementing this remedy via an online quotation tool, we estimated that prices would only need to fall by 0.3% as a result of this remedy for the benefits to exceed the costs. Using a more reasonable estimate of costs, prices would only need to fall by 0.03%.⁶⁷ Given the very small scale of this price reduction, and the likely effectiveness of the remedy in increasing the transparency of prices and in facilitating more effective competition, we are satisfied that such price benefits could be expected even if only a small proportion of microbusiness customers made use of the enhanced price transparency to search for a lower priced energy supplier.

17.102 We have therefore concluded that the remedy will not produce adverse effects that would be disproportionate to its aim.

- *Ofgem's statutory duties*

17.103 Where the CMA is considering whether to modify one or more of the conditions of a retail gas or electricity supplier's licence, in deciding whether such action would be reasonable and practicable, the CMA must 'have regard' to the relevant statutory functions of Ofgem.⁶⁸

17.104 Ofgem's statutory functions concerning gas and electricity supply are set out in Part 1 of the Electricity Act 1989 (EA89) and the Gas Act 1986 (GA86), as amended by the Energy Act 2010, and include (among other things) granting supply licences, keeping under review retail supply, and ancillary, activities,

⁶⁶ For non-domestic customers that opt for contracts/tariffs with up to three rates (as described in paragraph 17.37).

⁶⁷ We have not conducted comparable analysis to include the independent suppliers due to a lack of availability of data.

⁶⁸ Section 168 of the 2002 Act, and [CC3](#), paragraph 347.

publishing advice and information about consumer matters, taking action under Part 4 of the 2002 Act, and requiring the provision of information.⁶⁹

- 17.105 Ofgem's principal objective, in carrying out such functions, is to protect the interests of existing and future customers of gas and electricity supply. For these purposes, 'consumers' includes microbusinesses. The interests of such consumers are taken as a whole, including their interests in (i) the reduction of greenhouse gases, (ii) the security of supply, and (iii) the fulfilment by Ofgem of the objectives set out in Article 40(a) to (h) of the Gas Directive⁷⁰ and Article 36(a) to (h) of the Electricity Directive.⁷¹
- 17.106 Ofgem is generally required to carry out its functions in the manner it considers best calculated to further the principal objective, wherever appropriate by promoting effective competition between (among other things) suppliers of gas and electricity.⁷² Before deciding to carry out its functions in a particular manner with a view to promoting competition, Ofgem is required to consider the extent to which the interests of consumer would be protected by that manner of carrying out its functions and whether there is any other manner (whether or not it would promote competition) in which Ofgem could carry out the functions which would better protect those interests, having regard (among other things) to: (i) the need to secure that, so far as economical to meet them, all reasonable demands for gas and electricity supply are met and can be financed; (ii) achieving sustainable development; and (iii) the interests of 'vulnerable' consumers.⁷³ Subject to those considerations, Ofgem must also carry out its functions in the manner it considers is best calculated (among other things) to (i) promote efficiency and economy by licensed suppliers, and (ii) secure long-term supply and with regard to the effect on the environment. Lastly, Ofgem must also have regard (among other things) to the principles of transparency, accountability, proportionality, and consistency with best regulatory practice.
- 17.107 In deciding to introduce a new licence condition concerning gas and electricity supply that requires the publication of prices for microbusiness customers with the Relevant Segment (either through an online quotation tool made available on their websites or through third party online platform(s)) (see paragraph 17.48 above), we have, as part of our own

⁶⁹ Sections 34, 34A, 35, 36, 36A of the GA86 (and equivalent provisions of the EA89).

⁷⁰ European Parliament and Council Directive 2009/73/EC of 13 July 2009 concerning common rules for the internal market in natural gas and repealing Directive 2003/55/EC [2009] OJ L 211/94.

⁷¹ European Parliament and Council Directive 2009/72/EC of 13 July 2009 concerning common rules for the internal market in electricity and repealing Directive 2003/54/EC [2009] OJ L 211/55.

⁷² Section 4AA(1)(1A), (1C) of the GA86; Section 3A(1)(1B), (1C) of the EA89; [Powers and duties of GEMA](#).

⁷³ Those who are disabled or chronically sick, of pensionable age, with low incomes or residing in rural areas.

application of the legal framework requiring us to decide upon remedies that are effective and proportionate,⁷⁴ explicitly taken into account many of the above factors to which Ofgem must have regard when carrying out its functions. We have therefore concentrated below on the considerations not explicitly taken into account elsewhere in this section.

- 17.108 In particular, we do not consider that this remedy would have an adverse impact on suppliers' ability to meet all reasonable demands for gas and electricity supply, and nor does it engage Ofgem's duty to have regard to achieve sustainable development, to protect the interests of vulnerable customers, to ensure security of supply and to consider environmental concerns. In this regard, the remedy will only impact the 'efficiency' limb of the considerations built into Ofgem's statutory duties and functions. The remedy would incentivise suppliers to offer more attractive prices in order to attract new microbusiness customers and retain existing ones.
- 17.109 The remedy will also enhance transparency by reducing search costs for microbusiness customers in the Relevant Segment, and we expect this to facilitate the development of PCWs in the microbusiness segments, which will further enhance microbusiness customers' ability to compare prices across suppliers, thus further reducing their search costs (see paragraphs 17.25, 17.26, 17.49 and 17.59 above).
- 17.110 Lastly, not all suppliers voluntarily publish their prices and of those that have online quotation tools not all disclose the prices of all their available acquisition and retention contracts to microbusiness customers. We therefore consider that the introduction of a new licence condition in the terms outlined is a necessary measure, and consistent with best regulatory practice.
- 17.111 We consider that the remedy is consistent with Ofgem's principal objective of promoting the interests of existing and future customers.
- *Conclusion on the proportionality of the remedy*

17.112 In light of the above, we conclude that the remedy will be proportionate to its aim.

Auto-rollover remedy

17.113 We have found that one of the features of the SME retail energy markets that gives rise to the Microbusiness Weak Customer Response AEC (and

⁷⁴ CC3, pp71–73.

the resulting detriment) is that some microbusiness customers are on auto-rollover contracts⁷⁵ and are given a narrow window in which to switch supplier or tariff.

17.114 An auto-rollover contract is a contract with a microbusiness customer that provides for an initial fixed-term period (the 'Initial Period') and allows a supplier to automatically roll the microbusiness customer onto a new fixed-term or non-fixed term period (the 'Roll-over Period') if, by the end of the Initial Period, the microbusiness customer has not terminated the contract or agreed to a new fixed-term period. An important characteristic of the auto-rollover contract is that the price applying during the Roll-over Period is not explicitly negotiated between the microbusiness customer and the supplier.

17.115 The specific concerns we identified in relation to auto-rollover contracts are:

(a) the use of termination fees and/or 'no exit' clauses for the Roll-over Period; and

(b) microbusiness customers were given a narrow window to give a termination notice to their supplier during the Initial Period.⁷⁶

17.116 In the provisional decision on remedies we set out a remedy that prohibited auto-rollover contracts with termination fees and/or no-exit clauses and a narrow window to switch contract or supplier. The remedy sought to give microbusiness customers on auto-rollover contracts more flexibility to terminate these contracts, and prohibit termination fees and/or no-exit clauses during the Roll-over Period.

17.117 In light of the supportive responses to our provisional decision on remedies we have retained the remedy as set out in the provisional decision on remedies. The specific aspects of the remedy that we have decided upon are set out below.

Aims of the auto-rollover remedy

17.118 The aim of the remedy is to increase the ability of all microbusiness customers on auto-rollover contracts to switch contracts or suppliers. This will particularly help the microbusiness customers of those suppliers that still contract on the basis of fixed-term auto-rollover contracts with termination fees and no-exit clauses during the Roll-Over Period.

⁷⁵ Section 16, paragraph 16.136.

⁷⁶ Section 16, paragraph 16.136.

17.119 The remedy will reduce the energy costs of microbusiness customers in a number of ways. First, by switching from higher priced auto-rollover contracts to lower priced contracts, microbusiness customers will lower their energy costs. Second, by reducing the barriers to switching during the Roll-over Period, this remedy will encourage microbusiness customers to search for the cheaper acquisition and retention contracts. Third, as a result of this stronger customer response, we expect the competitive constraint on energy suppliers to increase, which should incentivise suppliers to reduce the price of their available acquisition and retention contracts.

17.120 Therefore this remedy will address the feature that some microbusiness customers are on auto-rollover contracts, which may limit their ability to switch contract or supplier.

Parties' views on the auto-rollover remedy

17.121 In response to the consultations after the Remedies Notice, but before the publication of the provisional decision on remedies, all of the Six Large Energy Firms, certain independent suppliers and Ofgem were supportive of the key components of this remedy (see paragraph 17.128 below). The Six Large Energy Firms also pointed out that they had ended the practice of fixed term Roll-Over Periods and that this remedy should be designed in a way so that it benefits all microbusiness customers currently in a Roll-Over Period.⁷⁷ Separately, [redacted] and [redacted] highlighted that since they had ended fixed-term auto-rollover contracts, they had observed increased engagement from microbusiness customers.

17.122 We received several responses to our initial remedy proposal set out in the Remedies Notice and reflected these comments in the remedy described in our provisional decision on remedies.

17.123 In response to the provisional decision on remedies, all parties (except for Haven Power, see paragraph 17.124) that responded to this remedy were supportive of the key design elements. These parties include the Six Large Energy Firms, Ofgem, Ecotricity, Smartest Energy, Association of Convenience Stores, CIPS, and Citizens Advice. Therefore, we have not changed the design of this remedy since the provisional decision on remedies.

⁷⁷ We note that this would ensure that microbusiness customers on fixed-term Roll-over Periods (when the remedy becomes effective) also benefit from the remedy. With regards to existing customers, we have also decided to implement the remedy 12 months after the publication of the final report, which would give suppliers adequate time to amend their business practices to comply with the remedy (see paragraph 17.155 below).

- 17.124 However, Haven Power raised a number of concerns. It said that the removal of no-exit clauses could backfire and result in lower customer engagement at the point of renewal since the imperative for action was reduced. In addition, it said that the new rules around rollover contracts (specifically the lack of any lock-in and the longer time window over which prices had to be held open) would change suppliers' approach to hedging, resulting in a general increase in the prices that these consumers paid.⁷⁸
- 17.125 We disagree with Haven. First, the removal of the no-exit clause will increase customer engagement because customers will not be locked into fixed-term Roll-over Periods that they did not explicitly agree to (see paragraph 17.114). Second, the removal of no-exit clauses will not necessarily result in higher prices being paid by customers. The purpose of this remedy is to increase engagement so that customers switch from the higher priced auto-rollover contract (specifically concerning the Roll-over Period) to the lower priced acquisition and retention contract. Third, we note that the remedy allows for a 30 days' notice period, which will allow suppliers adequate time to forward purchase energy and manage their risk in an appropriate manner (see paragraphs 17.166 to 17.169 below).
- 17.126 Haven Power also said that in certain instances where a microbusiness customer stops paying the supplier, then the supplier should be allowed to terminate the contract and charge the relevant termination fee.⁷⁹ We note that suppliers can object to a transfer occurring on grounds on debt, under SLC 14 (see Appendix 17.2 for further details). Therefore, we are not minded to change the design of the remedy.
- 17.127 Haven Power also told us that it was concerned with regards to the proposed timescale. It said that the auto-rollover proposals would require changes to its systems and processes that simply could not be put in place in the short time available. It said that it required a minimum of six months and ideally nine months to make and test these changes and to design and implement new hedging strategies.⁸⁰ We note that suppliers would get adequate time to be compliant with the remedy. Suppliers would have 12 months to comply with the remedy in relation to existing auto-rollover contracts (see paragraph 17.155).

⁷⁸ [Haven Power response to the provisional decision on remedies.](#)

⁷⁹ *ibid.*

⁸⁰ *ibid.*

Design considerations of the auto-rollover remedy

17.128 The key measures of this remedy are to:

- (a) allow microbusiness customers to give a termination notice to suppliers up to the last day of the Initial Period;⁸¹
- (b) allow microbusiness customers to give a termination notice⁸² to suppliers at any time during the Roll-over Period (regardless of whether the Roll-over Period is fixed or non-fixed);
- (c) prohibit termination fees and/or a no-exit clause during the Roll-over Period; and
- (d) prohibit the transfer of microbusiness customers that have given a termination notice during the Roll-over Period to a more expensive contract during the relevant notice period.⁸³

- *Existing standard licence conditions concerning auto-rollover contracts*

17.129 In the context of the design of this remedy, we have taken into account existing licence conditions concerning auto-rollover contracts that we are not minded to amend or remove.

17.130 First, we considered the licence condition under which the minimum notice period to terminate a microbusiness contract must be no longer than 30 days (SLC 7A.11) (the 'Minimum Notice Period'). We consider that a Minimum Notice Period of up to 30 days strikes a reasonable balance between offering microbusiness customers the flexibility to exit the auto-rollover contract, and allowing suppliers a practicable time period to manage their commercial risk with regards to their forward purchasing of energy. We also note that most suppliers also said that a 30-day notice period would be reasonable. A longer termination notice period might also be perceived by microbusiness customers as a barrier to switching. Accordingly, we are not minded to amend or remove the Minimum Notice Period.

17.131 We have also considered the licence condition under which a fixed-term Roll-over Period must not be longer than 12 months (SLC 7A.13A(c)). We understand that this was recently introduced by Ofgem following its RMR. Ofgem told us that the purpose of this licence condition was to offer

⁸¹ ie amending SLC 7A.12B to allow microbusiness customers a longer notice period window.

⁸² Subject to any minimum notice period that complies with SLC 7A(11).

⁸³ See Appendix 17.2 for evidence regarding the design considerations of the auto-rollover remedy.

suppliers a higher degree of security of supply, compared to a shorter notice period.⁸⁴ We are not minded to amend this licence condition and, accordingly, suppliers will be able to roll microbusiness customers onto a fixed-term Roll-over Period (as long as the duration of this period does not exceed 12 months). However, we explain (in paragraphs 17.133, 17.135 and 17.136 below) that under the remedy suppliers will not be able to include certain provisions that restrict the ability of microbusiness customers to switch contract or supplier during the fixed-term Roll-over Period.

- *Which restrictions concerning the Initial Period should be addressed*

17.132 Under the current regulatory framework, a microbusiness customer can give a termination notice at any time up to 30 days before the end date of the Initial Period (or a later day specified in the contract).⁸⁵ Customers are typically rolled onto a new contract during the period just before the end date of the Initial Period. The result is that microbusiness customers are unable to give termination notice during the last 30 days of the Initial Period which is when they would be rolled over and is therefore the time they are most likely to contemplate switching.⁸⁶

17.133 Accordingly, we have decided that during the Initial Period:

- (a) Microbusiness customers will be able to give a termination notice at any time up to the last day of the Initial Period.
- (b) The termination of the auto-rollover contract will take effect:
 - (i) at the end date of the Initial Period, if the termination notice is given in accordance with the notice period stated in the contract or at least 30 days before the end date of the Initial Period; or
 - (ii) 30 days after the date when the termination notice has been served by the microbusiness customer, if the termination notice is given in the last 30 days of the Initial Period (ie in this case, the termination

⁸⁴ Ofgem's response to the Remedies Notice.

⁸⁵ SLC 7A.12B. Prior to the implementation of the RMR, microbusiness customers could give termination notice during the 30 days before the end of the Initial Period only. Hence, under the RMR, Ofgem introduced SLC 7.A.12B to ensure that there was a wider window (than before the RMR) within which microbusiness customers could provide termination notice during the Initial Period. This wider window currently runs from the contract start date to up to 30 days before the end of the Initial Period.

⁸⁶ For instance, in its response to provisional findings, p79, paragraph 298, Centrica told us that one of the most powerful triggers for customer engagement was the process customers went through when they were coming to the end of a fixed-term contract. Centrica's evidence showed that up to 60% of all customers in the domestic market now contacted its sales team to talk through their options.

of the auto-rollover contract will take effect during the Roll-over Period).

- *Which restrictions concerning the Roll-over Period should be addressed*

17.134 Under the current regulatory framework, a microbusiness customer on a fixed-term Roll-over Period can give termination notice at any time up to 30 days before the end date of the fixed-term Roll-over Period (or a later day specified in the contract) (SLC 7A.12B). This means that they have to wait until the end of the following fixed-term Roll-over Period to terminate the contract.

17.135 However, we consider that microbusiness customers should be allowed to give a termination notice at any time during the Roll-over Period (regardless of whether the Roll-over Period is fixed or non-fixed). Accordingly, we have decided that, during the Roll-over Period (fixed or non-fixed term):

- (a) microbusiness customers will be able to give a termination notice at any time;⁸⁷ and
- (b) the termination of the Roll-over Period will take effect at most 30 days after the date when the microbusiness customer has given a termination notice.

17.136 The current regulatory framework allows suppliers to include termination fees or no-exit clauses for the Roll-over Period.⁸⁸ Under this remedy, we will prohibit suppliers from including termination fees or no-exit clauses for the Roll-over Period. This will enable microbusiness customers to more easily switch away from an onerous part of a contract that it may feel it did not explicitly agree to or consider before accepting the auto-rollover contract.

17.137 Similarly, we will prohibit suppliers from charging termination fees in relation to OOC⁸⁹ and evergreen⁹⁰ contracts for microbusiness customers. Such a measure will ensure consistency with regards to termination fees on all default contracts⁹¹ in the microbusiness segments. It will also be consistent

⁸⁷ We note that this is currently a requirement for non-fixed Roll-over Periods (SLC 7A.12A).

⁸⁸ We note that, since the RMR, all of the Six Large Energy Firms and independent suppliers have ended these restrictions on a voluntary basis. The independent suppliers include Ecotricity, Good Energy and Ovo Energy.

⁸⁹ OOC contracts apply to non-domestic customers, which have terminated their contracts, but have not yet switched to a new supplier. Non-domestic customers are defaulted to this type of contract and will remain on this tariff unless they take action to switch, with price changes being applied automatically (see Appendix 16.1).

⁹⁰ Evergreen contracts have no termination date and the prices are changed periodically. We understand that these contracts are of limited importance for acquiring new non-domestic customers automatically (see Appendix 16.1).

⁹¹ We note that currently SLC 7.6 does not permit suppliers to apply termination fees on deemed contracts to non-domestic customers.

with the domestic retail markets, where suppliers tend not to charge termination fees on non-fixed term SVTs. We envision that this will result in less confusion for microbusiness customers, especially those that might not be aware of the rules that apply to the various types of default contracts.

17.138 Finally, in order to avoid suppliers engaging in practices that would have the same effect as termination fees or no-exit clauses, the remedy will prohibit suppliers from transferring a microbusiness customer that has served a termination notice during the Roll-over Period to a more expensive contract during the notice period. This type of practice may be perceived as a barrier to switching if a microbusiness customer were to incur a cost to switch, which would be similar in substance to a termination fee. However, suppliers will be able to transfer microbusiness customers to other contracts during the Roll-over Period under the following circumstances:

- (a) if the supplier has given notice of a price change prior to the termination notice being served by the microbusiness customer, then the supplier will be permitted to put in place the price change during the Roll-over Period;
- (b) if the microbusiness customer has served the termination notice and has not switched to a new supplier/contract after the relevant notice period, then the existing supplier will be permitted to place the microbusiness on an OOC contract, which may have a different price to the auto roll over contract; and
- (c) if a microbusiness customer elects to change its contract after serving notice to terminate the auto-rollover contract.

17.139 Separately, we have considered Scottish Power's submission regarding the modifications to the licence conditions in relation to grounds for objections that a supplier can raise to a non-domestic customer seeking to transfer its energy supply to another supplier. Having sought further views from Ofgem and suppliers, our view is not to amend the licence conditions in relation to objections. This is because most objections made by suppliers related to attempted transfers within a fixed term, and debt owed by the non-domestic customer to the supplier. These did not impact the restrictions concerning the Roll-over Period, a contributing feature of the Microbusiness Weak Customer Response AEC, which we have sought to address.⁹²

⁹² See Appendix 17.2 for further details.

- *Scope of the remedy*

17.140 We consider that this remedy will be applicable to all microbusiness customers on auto-rollover contracts, OOC contracts and evergreen contracts, including those on these contracts when the remedy is implemented. This will be regardless of whether the microbusiness customer is in the Initial Period or the Roll-over Period.

- *Implementation of the remedy*

17.141 We will implement this remedy through:

(a) A CMA order (and amendments to suppliers' standard licence conditions) that will:

- (i) prohibit the inclusion of conditions in their existing and future auto-rollover contracts with microbusiness customers that:
 - prohibit the microbusiness customer from giving a termination notice up to the last day of the Initial Period.
 - prohibit the microbusiness customer from giving a termination notice up to the last day of the fixed-term Roll-over Period.
 - impose a termination fees and/or 'no-exit' clause for the Roll-over Period.
- (ii) prohibit the transfer of microbusiness customers that have given a termination notice during the Roll-over Period to a higher priced contract during the notice period; and
- (iii) prohibit the inclusion of a condition in their existing and future OOC and evergreen contracts with microbusiness customers that include termination fees.

(b) A recommendation to Ofgem to make any necessary consequential amendments to the supply licences.

Assessment of effectiveness of the auto-rollover remedy

17.142 As we explain below, the auto-rollover remedy will be effective in achieving its aim of increasing the ability of microbusiness customers on auto-rollover contracts to switch contracts or suppliers. Accordingly, this remedy will be effective in partly addressing one of the features that give rise to the Microbusiness Weak Customer Response AEC (and the resulting customer

detriment), ie that microbusiness customers are on auto-rollover contracts, which may limit their ability to switch contract or supplier.

17.143 In evaluating its effectiveness, we have considered the following factors:

- (a) The effectiveness of the key design elements of the remedy.
- (b) The extent to which the remedy will be capable of effective implementation, monitoring and enforcement.
- (c) The timescale over which the remedy will be expected to take effect.
- (d) The remedy's consistency and compliance with existing or expected laws or regulations.

- *Effectiveness of the key design elements*

17.144 Our view is that this remedy will increase the ability of microbusiness customers on auto-rollover contracts to engage in the markets. Specifically, by allowing microbusiness customers to give a termination notice to suppliers up to the last day of the Initial Period the remedy will allow them to engage, when they are most likely to want to engage. Similarly, the measure that will allow microbusiness customers to serve a termination notice and the measure to prohibit termination fees and/or a no-exit clause during the Roll-over Period will eliminate certain deterrents to switching, thus increasing microbusiness customers' ability to engage. This latter prohibition will be complemented by prohibiting the transfer of microbusiness customers that have given a termination notice during the Roll-over Period to a more expensive contract during the relevant notice period. This will prevent suppliers from circumventing the prohibition on termination fees by recovering them through indirect means.

17.145 In our view, these design elements will increase microbusiness customers' ability to switch from relatively higher priced auto-rollover contracts to acquisition and retention contracts, thus potentially reducing their energy costs. This will also increase the competitive constraint on suppliers' contract prices to microbusiness customers.

17.146 We also consider that there will be no other effective means to address our concerns regarding auto-rollover contracts. In this regard, we note that not all suppliers have ceased to include (in their contracts with microbusiness customers) the particular clauses that raise concerns. As a consequence, we consider that the remedy will only be effective by prohibiting suppliers from entering into contracts that include such restrictive clauses; and from enforcing such clauses in existing contracts.

- *Implementation, monitoring compliance and enforcement of the remedy*

17.147 In determining whether a remedy is effective, we will have regard to the operation and implications of the remedy. We will also have regard for the need of the remedy to be clear to the parties to whom it is directed; and also to other interested parties such as Ofgem (which will have responsibility, together with the CMA, for monitoring compliance), and microbusiness customers.

17.148 As regards the implementation of the remedy, we have set out a number of detailed specifications in paragraphs 17.129 to 17.140 above so that it will be clear to suppliers and straightforward for them to implement.

17.149 As regards monitoring compliance with the remedy, we note that, by introducing a new licence condition that will be consistent with the CMA's order, Ofgem will be under a duty to perform a monitoring role and can require the provision of information from suppliers concerning potential breaches of a licence condition. The CMA will also be responsible for monitoring compliance, as this remedy will be implemented through an order.⁹³

17.150 Monitoring compliance with the remedy will involve periodically checking suppliers' contracts (with their microbusiness customers) to verify that they are adhering to the terms of the order and licence condition eg by not including termination fees for the Roll-over Period. In addition, Ofgem will be well placed as the sector regulator to receive, and follow up on, complaints made by microbusiness customers concerning suppliers' ongoing compliance with the licence condition.

17.151 As regards enforcement of the remedy, by introducing the remedy by way of order and new licence condition, Ofgem will also be able directly to enforce against any breach of the new licence condition, without making an application to the court (as compared to enforcing against a breach of the order, for which a court application would be required).

- *Timescale for the auto-rollover remedy*

17.152 In evaluating the effectiveness of the remedy, we have considered the timescale over which the Microbusiness Weak Customer Response AEC is

⁹³ Section 38 of the GA86 and section 28 of the EA89; section 26 of the Competition Act 1998; section 225 of the 2002 Act; Regulation 13 of the Unfair Terms in Consumer Contracts Regulations 1999; and, Regulation 21 of the Business Protection from Misleading Marketing Regulations.

expected to endure, and the timescale over which the remedy would be likely to take effect.

- 17.153 As regards the Microbusiness Weak Customer Response AEC, our view is that, absent the remedy (and the other remedies we have decided upon concerning this AEC), the detriment would persist. We note that not all suppliers currently include in their contracts with microbusinesses the particular clauses with which we have concerns about and sought to remedy (see paragraph 17.128 above). Furthermore, we have seen no evidence that the suppliers currently using such clauses have future intentions to remove them (absent our remedy). We also note that there is no current licence condition that prevents any supplier from re-introducing such clauses in the future. Therefore, we have decided that the remedy will not be subject to a sunset provision.
- 17.154 As regards the timescales for implementation, we note that many suppliers already comply with the key components of this remedy. Therefore, the timescale for implementation of this remedy principally concerns the other suppliers that will be required to change their practices to comply with the CMA order.
- 17.155 As regards future auto-rollover contracts, our order will take effect immediately upon its publication. As regards the existing auto-rollover contracts, we will set a deadline for implementation by suppliers within 12 months of the publication of the final report. We consider that this will give suppliers adequate time to adjust their forward purchasing strategies in the wholesale energy markets⁹⁴ concerning the Roll-over Periods to which they were already contractually committed as we understand that the furthest period ahead that a supplier typically purchases energy for Roll-over Periods is 12 months ahead.⁹⁵ As a result, any suppliers that purchase energy on the forward markets in this way will, from the date of the final report, be given enough time to manage their risks in relation to the forward purchasing of energy.

⁹⁴ SLC 7A.13A(c) permits a fixed-term Roll-over Period up to 12 months. In its response to the Remedies Notice (remedy 8 on p6), Ofgem said that a fixed-term contract (including a 12-month fixed-term auto-rollover contract) allowed a supplier to hedge the risk of short-term changes in wholesale electricity and gas prices.

⁹⁵ For its microbusiness customers on a fixed-term Roll-over Period of 12 months, which is permitted under SLC 7A.13A(c).

- *Consistency and compliance with existing or expected laws or regulations*

17.156 We have considered whether any elements of the remedy would be inconsistent with other relevant laws and regulations.

17.157 A particular focus of our assessment was the scope of the remedy (as laid out in paragraph 17.140 above), ie the remedy will be applicable to all microbusiness customers on auto-rollover contracts including those on auto-rollover contracts at the time that the remedy is implemented. We will be setting an implementation deadline of 12 months from the publication of the final report and so suppliers will have 12 months to amend their contractual terms and forward purchasing strategies.

Assessment of proportionality of the auto-rollover remedy

17.158 In this section we set out our assessment of whether the remedy would be a proportionate remedy to address one of the three features that we identified in the microbusiness segments. We have done so by considering whether the remedy will:

- (a) be effective in achieving its legitimate aim;
- (b) be no more onerous than needed to achieve its aim;
- (c) be the least onerous if there were a choice between several effective measures; and
- (d) not produce disadvantages that are disproportionate to the aim.⁹⁶

- *Effective in achieving its aim*

17.159 For the reasons set out in paragraphs 17.118 to 17.120 above, our view is that this remedy will be effective in achieving its aim of increasing the ability of microbusiness customers on auto-rollover contracts to engage in the microbusiness segments of the SME retail energy markets. Accordingly, it will be effective in partly addressing one of the underlying features contributing to the Microbusiness Weak Customer Response AEC, and the resulting customer detriment.

⁹⁶ CC3, paragraph 344, citing the principles established in the *Fedesa* case, Case C-331/88, *The Queen v Minister of Agriculture, Fisheries and Food and Secretary of State for Health, ex parte: Fedesa and others*, [1990] ECR I-4023, paragraph 13.

- *No more onerous than needed to achieve its aim*

17.160 We also consider that this remedy will be no more onerous than needed to achieve its aim. The remedy will not impose any upfront costs on energy suppliers. In addition, we have also decided on setting a 12 month implementation deadline from publication of the final report, which will give suppliers adequate time to adjust their contracts and forward purchasing of energy in relation to existing auto-rollover contracts (see paragraph 17.165 to 17.169 below).

- *Least onerous if there were a choice between several effective measures*

17.161 As noted above, we have considered whether there may be alternative means that would achieve the same aim. However, we consider that the remedy is the only effective means of addressing the concerns we have identified, for the reasons discussed in paragraph 17.146 above.

- *Would not produce disadvantages disproportionate to the aim*

17.162 We estimated the profits of the Six Large Energy Firms in excess of the cost of capital at approximately £183 million per year⁹⁷. We have not quantified the amount by which the detriment from the independent suppliers would be reduced solely as a result of the auto-rollover remedy. However we note the beneficial impact on engagement levels of microbusiness customers of the Six Large Energy Firms that have already ceased entering into contracts containing the restrictive clauses with which we have concerns (see paragraphs 17.130, 17.132, and 17.134 above). For the reasons noted above, we consider that the remedy will have a positive impact on engagement levels and competition in the microbusiness segments that would overall lead to lower prices.

17.163 As noted above, we consider that no upfront costs will be imposed on suppliers as a result of this remedy, and we are therefore confident that this remedy will have greater benefits than costs and will be proportionate to its aims.

17.164 Certain parties told us that the prohibition of termination fees and no-exit clauses could lead to greater risks for suppliers, which would lead to suppliers raising their prices to microbusiness customers on auto-rollover contracts. However, we consider that customers are unlikely to be charged a higher price solely because of the implementation of our remedy. We note

⁹⁷ Section 16, paragraph 16.150.

that suppliers could take a number of mitigating actions to manage any potential risk arising from the remedy without having to resort to price increases.

- 17.165 First, there will be no increased risk for suppliers with regards to the effect of our remedy on future contracts with a Roll-over Period. Our remedy will bring into line certain independent suppliers' practices with the current practices of the Six Large Energy Firms and other suppliers. Hence, we consider that such suppliers will be able to adjust their risk and pricing strategies so as to remain, or to become, competitive with the Six Large Energy Firms and other suppliers, which are already conducting their business in line with our remedy.
- 17.166 Second, for microbusiness customers in the Initial Period (on the date the remedy becomes effective), suppliers will have enough time to adjust their purchasing strategies concerning the Roll-over Period so as to accommodate the new exit provisions. For example, a supplier that previously bought energy 12 months ahead (usually during the last 30 days of the Initial Period) for its customer on a 12-month fixed-term Roll-over Period could adjust its purchasing strategy by purchasing 30 days ahead or any other strategy it considered appropriate.
- 17.167 Third, for microbusiness customers in the Roll-over Period (on the date the remedy becomes effective), we note that, for the reasons noted above, the implementation period of 12 months will allow a supplier adequate time to adjust its purchasing strategy to take into account its risks. Such a supplier will have 12 months to adjust its purchasing strategy for a microbusiness customer on the Roll-over Period, which in itself cannot exceed 12 months.
- 17.168 To the extent that any adjusted purchasing strategy might lead to a higher price to microbusiness customers on the Roll-over Period (at the time the remedy becomes effective), we note that suppliers could contact their existing microbusiness customers that are on non-fixed Roll-over Periods and offer them a fixed-term retention contract. However, if such a microbusiness customer did not engage, and the supplier considered that it was unable to manage its risks, then that supplier could choose to terminate the Roll-over Period or offer a variable priced contract that tracked a wholesale energy cost index. Our remedy will not prohibit a supplier from offering acquisition or retention contracts to that, or other, microbusiness customers.
- 17.169 In addition, suppliers will be able to form a reasonable view on the overall customer demand profile for microbusiness customers on Roll-over Periods. This would be possible because such customers would have been with the

supplier for more than one year, and the supplier will be able to collate and analyse the necessary data to form a view on the overall demand profile for all such customers. This will allow the supplier to broadly purchase the correct volumes of energy to match actual demand. Also, the supplier will be able to choose to manage its risks by purchasing ahead only 30 days based on the knowledge that the termination notice period will be 30 days, and it will also have the option to change its prices every 30 days on auto-rollover contracts with variable prices during the Roll-over Period.

- *Ofgem's statutory duties*

17.170 As stated above, where the CMA is considering whether to modify one or more of the conditions of a retail gas or electricity supplier's licence, in deciding whether such action will be reasonable and practicable, the CMA must 'have regard' to the relevant statutory functions of Ofgem.

17.171 In reaching our decision to introduce a new licence condition concerning gas and electricity supply that prohibits suppliers from entering into (a) auto-rollover contracts with certain restrictions (as laid out in paragraph 17.128 above), and (b) OOC and evergreen contracts with termination fees; we have, as part of our own application of the legal framework requiring us to decide upon remedies that are effective and proportionate,⁹⁸ explicitly taken into account many of the above factors to which Ofgem must have regard when carrying out its functions. We have therefore concentrated below on the considerations not explicitly taken into account elsewhere in this section of the decision on remedies.

17.172 In particular, we do not consider that this remedy will have an adverse impact on suppliers' ability to meet all reasonable demands for gas and electricity supply, achieving sustainable development, the interests of vulnerable customers, security of supply or environmental concerns.

17.173 The remedy will enhance transparency by removing terms and conditions that customers may not be fully aware of, or those that may create confusion (for example, the prohibition of termination fees and no-exit clauses on auto-rollover contracts).

17.174 The remedy will also provide some protection to microbusiness customers from becoming locked in to contractual terms that they may not have been fully aware of, or may consider that they did not agree to, at the time of entering into the contract. In this context, the remedy directly engages

⁹⁸ CC3, paragraph 329.

Ofgem's principal objective of protecting the interests of existing and future customers. Additionally, the removal of termination fees on all OOC and evergreen contracts will result in a consistent approach of no termination fees being charged on all default contracts.

17.175 Not all suppliers have taken action voluntarily to remove termination fees concerning Roll-over Periods from their contracts with microbusiness customers or to stop offering contracts with such termination fees altogether, and so we consider that the introduction of a new standard licence condition in the terms outlined is a necessary measure, and consistent with best regulatory practice.

17.176 In light of the above, we consider that the remedy is consistent with Ofgem's principal objective of promoting the interests of existing and future customers.

Ofgem programme to promote microbusiness customers' engagement

17.177 We have identified three features that give rise to the Microbusiness Weak Customer Response AEC, two of which are that microbusiness customers face actual and perceived barriers to accessing and assessing information; and that microbusiness customers have limited awareness of, and interest in, their ability to switch.⁹⁹

17.178 As discussed in Section 13, clear information is important to facilitate customer engagement. However, there are several plausible but divergent ways in which information could be provided to microbusiness customers in order to facilitate their understanding and increase their engagement. It is our view that without adequate testing, it is not possible to know which approach will work best in practice.

17.179 According to Ofgem's most recent data, a little less than half¹⁰⁰ of microbusiness customers were on default¹⁰¹ contracts in 2013. These customers could benefit from additional or different information; and/or from messaging to prompt them to switch to lower priced acquisition and retention contracts. The proportion of microbusiness customers on default contracts may have decreased recently, due to the implementation of the RMR rules and the ending of fixed-term Roll-over Periods by the Six Large Energy Firms and other suppliers. However, they still constitute a significant proportion of the overall microbusiness customer base. Ofgem also told us

⁹⁹ Section 16, paragraph 16.136.

¹⁰⁰ Electricity (45%) and gas (49%).

¹⁰¹ Default contracts comprise: Auto-rollover, deemed, OOC and evergreen contracts.

that the median term of the default contract was greater than one year. This could suggest some degree of disengagement among these customers.

17.180 We have also observed that the Six Large Energy Firms have earned the highest average revenues and gross margins on deemed and OOC contracts, which were substantially higher than those relating to acquisition and retention contracts.¹⁰² We concluded that this implied that most microbusiness customers on default contracts could benefit from switching to acquisition and retention contracts.¹⁰³ We consider that switching will be a positive development in the market, considering that prices of default contracts to non-domestic customers (including microbusiness customers) are significantly higher than those for fixed-term acquisition and retention contracts.¹⁰⁴

17.181 Accordingly, we recommend that Ofgem establish an ongoing programme to identify, test (through randomised controlled trials (RCTs), where appropriate) and implement (for example, through appropriate changes to standard licence conditions) measures to provide microbusiness customers with different or additional information to prompt them to engage in the SME retail energy markets.

17.182 This remedy will be similar to the Ofgem-led programme remedy outlined in Section 13 for domestic customers (the 'Domestic Ofgem-led Programme Remedy').

Aim of the remedy

17.183 The overall aim of this remedy is to:

- (a) identify the most appropriate form of information that should suppliers should provide microbusiness customers;
- (b) reduce or minimise the complexity of this information; and
- (c) provide microbusiness customers with different or additional information or messaging that will prompt them to switch contract or supplier.

17.184 Accordingly, the ultimate aim of this remedy is to address (in whole, or in part) the feature that microbusiness customers face actual and perceived barriers to accessing and assessing information. The remedy will also

¹⁰² Appendix 16.1.

¹⁰³ Appendix 16.1.

¹⁰⁴ Ofgem told us that its April 2013 study had shown that electricity prices for micro-businesses with a non-fixed-term contract (such as OOC and deemed) were on average 80% higher than negotiated contracts such as the acquisition and retention contracts.

address, in part, the feature that microbusiness customers have limited awareness of, and interest in, their ability to switch. Hence, this remedy will work alongside the other remedies to address the Microbusiness Weak Customer Response AEC.

Parties' views on the remedy

- 17.185 We invited parties' comments on a remedy that involved measures to provide microbusiness customers with different or additional information to reduce actual or perceived barriers to accessing and assessing information to help them engage.
- 17.186 Parties said that they had recently noticed increased engagement in microbusiness segments. They also pointed to the voluntary steps, which certain suppliers had taken to increase customer engagement. One of the most important of these voluntary steps was that certain suppliers stopped the practice of fixed-term auto-rollover contracts (see paragraph 17.121 above).
- 17.187 Nevertheless, parties were generally supportive of the remedy to appropriately test measures to improve engagement, before such measures are implemented.¹⁰⁵
- 17.188 Parties' responses to this remedy in the provisional decision on remedies for the microbusiness segments were broadly in line with their more extensive responses in relation to the Ofgem-led programme remedy in the domestic markets. However, SSE told us that there was no need or justification to impose this remedy in relation to microbusinesses, because the lack of information was less of a problem in the microbusiness segments and that the other remedies would address the AEC. Similarly, RWE said that there was less evidence that ineffective microbusiness information was as big a problem as in the domestic segment.
- 17.189 In response, see paragraphs 17.179 and 17.180 for evidence concerning the high proportion of customers on default contracts and the high costs of default contracts, which strongly suggests that customers on default contracts could benefit by switching to lower priced acquisition and retention contracts. We also note that one of the aspects of the microbusiness segments contributing to the feature that microbusiness customers have limited awareness of and interest in their ability to switch energy supplier is

¹⁰⁵ See Appendix 17.3 for parties' views on prompts and what engagement measures are mandated by the standard licence conditions. Also, see parties' responses to this remedy in the provisional decision on remedies.

the role of traditional meters and bills.¹⁰⁶ The role of traditional meters and bills¹⁰⁷ is a fundamental characteristic that gives rise to inaccurate and confusing information for microbusiness customers, and thus dissuades them from engaging. Hence, the Ofgem-led programme will address this aspect of the markets affecting microbusiness customers.

Design considerations

17.190 The key elements that we have considered to design the remedy are set out below. We note that some of these elements are similar to those of the Domestic Ofgem-led Programme Remedy and, accordingly, we cross-refer to these elements where relevant.

17.191 We have considered the following elements in the design of this remedy:

- (a) what approach should be taken to identify and test the measures concerning the information to be provided to microbusiness customers;
- (b) whether the identification and testing of those measures should be Ofgem or supplier led;
- (c) whether we should identify a priority list of measures for testing; and
- (d) how the remedy should be implemented.

- *What approach should be taken*

17.192 Under the remedy, Ofgem will have discretion to specify the criteria to identify, test and review the measures concerning what, how and when information will be presented to microbusiness customers.

17.193 However, regardless of the specific steps taken by Ofgem to identify and test those measures, our view is that the overall approach of the Ofgem-led programme will provide for:

- (a) the specification of potential forms of information that microbusiness customers should receive from suppliers and the messaging aimed at prompting customers to engage (referred to below as ‘the measures’);
- (b) the testing (through RCTs, where appropriate) of the impact of the measures identified prior to segment-wide implementation;

¹⁰⁶ Section 16, paragraph 16.136.

¹⁰⁷ Which give rise to a disparity between actual and estimated consumption, and are complex in their own right.

- (c) the implementation of the measures considered most appropriate following testing (for instance, through appropriate changes to the standard licence conditions);
- (d) ongoing monitoring of the impact of the implemented measures (which may involve possible arrangements for independent moderation and quality assurance); and
- (e) adjustments as appropriate, where measures may no longer have the desired effect.

- *Whether the programme should be led by Ofgem or suppliers*

17.194 Our view is that Ofgem is better placed than suppliers to take the lead in a programme to identify measures aimed at promoting microbusiness customers' engagement, for the same reasons as those concerning the Domestic Ofgem-led Programme (see Section 13).

- *Whether we should identify a priority list of measures for testing*

17.195 Contrary to our approach on the Domestic Ofgem-led Programme, we will not recommend to Ofgem a priority list of measures to be tested.

17.196 In the domestic retail energy markets, we found some evidence regarding the complexity of certain information provided to domestic customers. We also found evidence that the provisions introduced by Ofgem under the 'clearer information' component of the RMR rules were not subject to adequate testing. However, in the microbusiness segments, it has not been possible to ascertain what information should be targeted by this Ofgem-led programme. Therefore, we have not identified a priority list of measures for testing.

- *How the remedy should be implemented*

17.197 We will implement this remedy through a recommendation to Ofgem to establish an ongoing programme to identify, test (through RCTs, where appropriate) and implement measures to provide microbusiness customers with different or additional information with the aim of prompting engagement in the SME retail energy markets.

17.198 Contrary to our approach on the Domestic Ofgem-led Programme, we will not recommend that Ofgem introduce a licence condition to mandate suppliers to participate in the Ofgem-led programme concerning the microbusiness segments for a number of reasons including:

- (a) RCTs are less well established as a testing tool among microbusinesses, as compared with domestic customers; and
- (b) We have less evidence that ineffective microbusiness information is as big an issue as it is in the domestic retail markets.

Assessment of effectiveness of the remedy

- 17.199 As we explain below, our view is that the remedy will be effective in achieving its aim of (a) identifying the most appropriate form of information that suppliers should provide microbusiness customers, (b) reducing or minimising the complexity of that information, and (c) providing microbusiness customers with different or additional information or messaging that will prompt them to switch tariff or supplier.
- 17.200 Accordingly, our view is that the remedy will be effective in addressing, in whole or in part, two of the features that we have identified as giving rise to the Microbusiness Weak Customer Response AEC and resulting detriment, ie that microbusiness customers have limited awareness of, and interest in, their ability to switch, and that microbusiness customers face actual and perceived barriers to accessing and assessing information.
- 17.201 In assessing the effectiveness of the remedy, we have considered the following factors:
- (a) The effectiveness of the key design elements of the remedy.
 - (b) The extent to which the remedy will be capable of effective implementation, monitoring and enforcement.
 - (c) The timescale over which the remedy will be expected to take effect.
- *Effectiveness of the key design elements*
- 17.202 We consider that the key design elements of the remedy will be effective in achieving its aim, for the following main reasons:
- (a) The remedy will allow for the testing of the impact of the measures prior to market wide implementation. It will also provide for ongoing monitoring of the impacts of the various measures (see paragraph 17.193 above). Accordingly, Ofgem will be able to identify the most effective measures to promote engagement.

(b) Ofgem will be better placed than suppliers to take the lead in a programme to identify and test measures aimed at promoting customer engagement (see paragraph 17.194 above).

17.203 We also consider that the Ofgem-led programme will be responsive to future developments in the markets. For example, the introduction of smart metering has the potential to change how microbusiness customers engage in the markets.

- *Implementation, monitoring compliance and enforcement of the remedy*

17.204 In determining whether a remedy is effective, we have had regard to how it will be expected to operate. We have also had regard to ensure that it is clear to whom it is directed. As regards the implementation of the remedy, we have set out a number of detailed specifications, and we expect Ofgem to put in place a governance structure to ensure that there will be effective oversight of the design and implementation of the programme.

- *Timescale for the remedy*

17.205 In evaluating the effectiveness of the remedy, we have considered the timescale over which the Microbusiness Weak Customer Response AEC is expected to endure, and the timescale over which the remedy is likely to take effect. We consider that the detriment would persist absent the remedy, and notwithstanding that the impact of future market developments, including the roll-out of smart meters, is somewhat uncertain.

17.206 Moreover, we consider that the need for testing the changes to the information to be provided by suppliers to microbusiness customers is likely to be an ongoing need. Therefore, we have decided that the remedy will not be subject to a sunset provision.

17.207 As regards the timescales for implementation, Ofgem told us that it has started work on a plan to implement the remedy and is building an in-house capability to conduct the programme. We expect the first trials concerning the priority list of measures for the Domestic Ofgem-led Programme Remedy to start by mid-2017. However, as regards the programme concerning microbusinesses, Ofgem will have greater flexibility to choose what, how and when to test. We, therefore, expect the remedy to start having an effect from the beginning of 2019.

Assessment of proportionality

17.208 In this section, we set out our assessment of whether the remedy will be proportionate to achieve its aim. We have done so by considering whether the remedy will:

- (a) be effective in achieving its legitimate aim;
- (b) not be more onerous than needed to achieve its aim;
- (c) be the least onerous if there were a choice between several effective measures; and
- (d) not produce disadvantages that are disproportionate to the aim.¹⁰⁸

- *Effective in achieving its aim*

17.209 For the reasons set out in paragraphs 17.199 to 17.207 above, we consider that a programme of rigorous testing (involving RCTs, where appropriate) will be effective in reducing the complexity of the information provided to microbusiness customers by suppliers. It will also be effective in providing microbusiness customers with different or additional information that will prompt them to switch contract or supplier. Accordingly, the remedy will be effective in addressing in whole, or in part, two of the features that give rise to the Microbusiness Weak Customer Response AEC, and the resulting customer detriment.

- *No more onerous than needed to achieve its aim*

17.210 We also consider that this remedy will be no more onerous than needed to achieve its aim.

17.211 Given the need for an ongoing programme of rigorous testing, we note that Ofgem is best placed to identify, develop, test and implement the measures. In designing the programme, Ofgem will be required to assess the proportionality of the various stages of the programme.¹⁰⁹ In this regard, we expect Ofgem to take account of issues such as the potential costs on suppliers, the duration of the testing process, and for how long it will impose costs on suppliers, as part of its proportionality assessment. We expect the

¹⁰⁸ [CC3](#), paragraph 344, citing the principles established in the *Fedesa* case, Case C-331/88, *The Queen v Minister of Agriculture, Fisheries and Food and Secretary of State for Health, ex parte: Fedesa and others*, [1990] ECR I-4023, paragraph 13.

¹⁰⁹ Section 4AA(5A)(a) of the Gas Act 1986; section 3A(5A)(a) of the Electricity Act 1989; Article 41(4)(b) of Directive 2009/73/EC (the Gas Directive) and Article 37(4)(b) of Directive 2009/72/EC (the Electricity Directive).

costs to suppliers to include those they might incur in working with Ofgem in developing measures for testing, compiling the information required by Ofgem, and implementing measures for testing.

17.212 In addition, as explained in paragraph 17.198 above, we will not mandate suppliers to participate in the Ofgem-led programme. Accordingly, since we have chosen the least onerous option we consider that a programme within the outlined parameters will be proportionate.

- *Least onerous if there were a choice between several effective measures*

17.213 We have considered whether there may be alternative remedies that could achieve the same aim. However, we consider that there is no substantive alternative to the remedy that will be effective (for the reasons set out in Section 13).

- *Would not produce disadvantages disproportionate to the aim*

17.214 We have concluded that the remedy will not produce adverse effects that would be disproportionate to its aim.

17.215 We consider that the costs of extending the Ofgem-led programme remedy to the microbusiness segments would be similar in nature and scale (eg on a per customer basis) to those identified in Section 13 for the domestic markets. We note that the Ofgem-led programme will be proportionate given the scale of the detriment with regards to the microbusiness segments, and any potential costs to suppliers will be subject to Ofgem's obligation to consider the proportionality of any testing.

The Database remedy

17.216 We have identified three features that give rise to the Microbusiness Weak Customer Response AEC. Two of these features are that microbusiness customers have limited awareness of, and interest in, their ability to switch energy supplier; and that microbusiness customers face actual and perceived barriers to accessing and assessing information arising from certain aspects of the SME retail energy markets.¹¹⁰

17.217 We sought views on possible remedies aimed at prompting customers that were on default contracts that they had not actively chosen. Specifically, we consulted on providing such customers with the information that they will

¹¹⁰ Section 16, paragraph 16.136.

need so that they will be able to identify relevant options and make informed choices.

- 17.218 A little less than half of microbusiness customers were on default contracts in 2013 (see paragraph 17.179 above). These customers will benefit from additional information or messaging to prompt them to switch to lower priced acquisition and retention contracts. Ofgem also told us that the median term of the default contract was greater than one year. This suggests some degree of disengagement among these customers.
- 17.219 In order to enable suppliers to prompt microbusiness customers of rival suppliers on default contracts, the remedy will require energy suppliers to disclose certain details of their microbusiness customers that have been on a default contract (eg auto-rollover, evergreen, deemed and/or OOC contract) for three or more years (the 'Disengaged Microbusiness Customers') and have not opted out to Ofgem, and recommend to Ofgem that it retain, use, and disclose this data (via a centrally managed database) (the 'Database') to rival suppliers (the 'Database remedy'). We are implementing a similar remedy for domestic customers who have been on an SVT, or other default tariff, with the same supplier for three or more years (see details in Section 13).

Aim of the remedy

- 17.220 The aim of the remedy is to enable rival retail energy suppliers to identify Disengaged Microbusiness Customers that have not opted out, and to prompt these customers to engage in the markets. Ofgem will be allowed to contact these customers directly and to evaluate the impact of the measures taken to prompt engagement. The ultimate aim of this remedy is to partly address two of the features giving rise to the Microbusiness Weak Customer Response AEC (and the resulting detriment), ie that microbusiness customers have limited awareness of, and interest in, their ability to switch energy supplier and that microbusiness customers face actual and perceived barriers to accessing and assessing information.

Parties' views on the prompts to microbusiness customers on default contracts remedy

- 17.221 We consider that the core issues concerning the remedy and its design are similar between the microbusiness segments and the domestic retail energy markets. Therefore, for the purposes of this remedy, we have taken into consideration the parties' views in relation to a similar remedy outlined for the domestic retail markets (see details in Section 13) (including parties'

views concerning the application of the remedy to prepayment customers) and applied their views to the microbusiness segments.

17.222 In their responses to the Remedies Notice, and subsequent submissions,¹¹¹ parties were generally supportive of measures to promote engagement among microbusiness customers. In their responses to the provisional decision on remedies in relation to this remedy concerning the micro-business segments, parties were broadly consistent with their responses in relation to the similar remedy in the domestic markets. However:

- (a) Some suppliers raised concerns about potential data protection issues for non-domestic customers whose data could be considered personal data. Scottish Power gave the example of a sole trader that traded in the individual's name, and corporate entities where the data could often include the full name and address of a director.
- (b) SSE told us that this remedy was unnecessary for microbusiness segments because it considered these segments to be highly competitive with high customer engagement.
- (c) Smartest Energy considered that microbusiness customers of independent suppliers were engaged. It therefore recommended that independent suppliers should be excluded from the scope of this remedy. It added that it would avoid independent suppliers incurring costs. Utilita also raised concerns about the costs of the Database remedy.

17.223 In relation to the first comment above in paragraph 17.222(a), the design of this remedy takes into account the compliance with data protection legislation (see paragraph 17.232).

17.224 In relation to SSE's submission in paragraph 17.222(b), see paragraphs 17.179 and 17.180 for evidence concerning the high proportion of customers on default contracts and the high prices of default contracts, which strongly suggests a level of disengagement and that customers on default contracts could benefit by switching to lower priced acquisition and retention contracts. In addition, the Database remedy will only concern 'disengaged customers'. So even if there was a high level of engagement in the microbusiness segments (as suggested by SSE), there would still be some disengaged customers, whom our remedy will target.

¹¹¹ See Appendix 17.3.

17.225 Finally in relation to Smartest Energy's and Utilita's comment in paragraph 17.222(c), the Database remedy will only capture disengaged customers, irrespective of the scale of the supplier. So suppliers with a high proportion of active microbusiness customers will not be significantly affected by this remedy. Also, a significant proportion of the costs of the Database remedy will be borne by Ofgem.

Design considerations

17.226 The key elements of the design of this remedy are set out below. We note that some of these elements will be similar to those of the equivalent remedy outlined for domestic customers and, accordingly, we cross-refer to these elements where relevant.

17.227 We have considered the following matters in the design of this remedy:

- (a) what approach should be taken to prompt engagement;
- (b) who should the remedy target;
- (c) what data protection issues should be addressed and how;
- (d) what should be the role of Ofgem and suppliers in implementing the remedy; and
- (e) how the remedy should be implemented.

- *What approach should be taken to prompt engagement*

17.228 We recognise that microbusiness customers on default contracts already receive certain information from suppliers.¹¹² However, as noted for the equivalent remedy outlined for domestic customers, the incentives of a supplier contacting its own Disengaged Microbusiness Customers and alerting them of their ability to switch are quite different from rival suppliers contacting such customers. As discussed above, we recommend an Ofgem-led programme that will identify, test and implement measures to promote engagement.

17.229 We consider that the disclosure to rival retail energy suppliers of the details of the Disengaged Microbusiness Customers who have not opted out will further contribute to prompting engagement. In particular, we consider that rival suppliers will have an incentive to contact these customers to try to win

¹¹² SLC 7A.

their custom. Hence, the remedy will encourage existing suppliers and/or new entrants to compete more intensively for the Disengaged Microbusiness Customers who have not opted out.

- *Who should be targeted by the remedy*

17.230 As indicated in paragraph 17.179 above, a little less than half of microbusiness customers were on default contracts in 2013. Moreover, the median term of the default contract was greater than one year.

17.231 We consider that instances when microbusiness customers roll on to default contracts and choose not to move contract immediately could be explained by a number of factors other than pure disengagement with the markets. However, we also consider microbusiness customers on default contracts for three or more years (with the same supplier) are more likely to be on such contracts due to a certain level of disengagement. We are therefore of the view that the remedy should apply to all microbusiness customers on default contracts for three or more years.

- *What data protection issues should be addressed and how*

17.232 To the extent that this remedy involves the processing of personal data, it has been designed so as to take into account discussions between the CMA and the ICO, and to be compliant with the following relevant UK and EU data protection legislation: (i) the Data Protection Act 1998 (the 'DPA'); (ii) the EU Directive 95/46/EC¹¹³ (the 'Data Protection Directive'); (iii) the Privacy and Electronic Communications Regulations 2003 (the 'PECR'); and (iv) the new EU General Data Protection Regulation ('GDPR')¹¹⁴ (collectively, the 'Data Protection Regime'). Hence, any data protection considerations concerning the domestic database remedy (see Section 13) will also be treated as applicable to this remedy and will be reflected in the implementation of this remedy.

¹¹³ Directive 95/46/EC of the European Parliament and of the Council of 24 October 1995 on the protection of individuals with regard to the processing of personal data and on the free movement of such data, OJ L 281, 23/11/1995.

¹¹⁴ Regulation (EU) 2016/679 of 27 April 2016 on the protection of natural persons with regard to the processing of personal data and on the free movement of such data, and repealing Directive 95/46/EC (General Data Protection Regulation). The Data Protection Directive and applies from May 2018.

- *What should be the roles of Ofgem and suppliers in implementing and testing the Database*

17.233 Under this remedy, suppliers will be required (pursuant to a CMA order) to send a letter to their Disengaged Microbusiness Customers (the Opt-out Letter). The Opt-out Letter will:

- (a) inform the Disengaged Microbusiness Customers of the CMA's order requiring suppliers to disclose certain details, ie the microbusiness customer's full name, billing (or registered) address, consumption address, current supplier, meter type, name of their current contract, annual energy consumption, and MPAN/MPRN to Ofgem;
- (b) inform the Disengaged Microbusiness Customers of how their data will be used by Ofgem and rival suppliers;
- (c) allow the Disengaged Microbusiness Customers the possibility to opt-out of having such data passed to Ofgem. It will also inform them of their right to opt-out of Ofgem and rival suppliers using their information in this way at any point and the procedure for doing so; and
- (d) be subject to the CMA's and Ofgem's approval before it is sent to the Disengaged Microbusiness Customers, to ensure that it clearly explains the proposed disclosure including how the customer's data will be used, the reasons for this, and the mechanisms for opting out.

17.234 Suppliers will also be required (pursuant to a CMA order) to disclose the data concerning the Disengaged Microbusiness Customers who have not opted out (the 'Microbusiness Customer Data') to Ofgem (in the format prescribed by Ofgem).

17.235 We recommend that Ofgem develops, operates and maintains a secure cloud database to hold the Microbusiness Customer Data (in an accessible format). Ofgem will be the data controller: it could use external IT/database experts to develop this database. Once the database is created, Ofgem will operate, control and maintain it.¹¹⁵ We recommend that Ofgem adopt publically recognised standards for data security in the arrangements for gathering, assembling and storing the Microbusiness Customer Data, and in providing access to it.

17.236 We consider that Ofgem, as the industry regulator, is best placed to collect and disclose the Microbusiness Customer Data to rival suppliers. This is

¹¹⁵ Ofgem is not precluded from contracting with a suitably qualified third party data processor to operate and maintain the Database securely.

because we consider that Ofgem can represent the interests of the Disengaged Microbusiness Customers fairly. In this regard, the incentives of energy suppliers to control and share the Microbusiness Customer Data with each other may not align with the interests of the Disengaged Microbusiness Customers.

17.237 We recommend that Ofgem test both the operation of the Database (prior to its roll-out) and aspects of the marketing correspondence (eg content and frequency) sent by rival suppliers to the Disengaged Microbusiness Customers who have not opted out. We also recommend that Ofgem monitors the impact of the database with a view to maximise its effectiveness (see Section 13).

17.238 Under this remedy, suppliers will also be required, through a CMA order, to provide Ofgem with updated information, in the format prescribed of any new or existing Disengaged Microbusiness Customers who have not opted out on a regular basis. The regularity will be specified by Ofgem. This will enable Ofgem to remove the details of microbusiness customers that have moved off default contracts, and to include the details of microbusiness customers that have become eligible to be on the Database. We suggest that the Database is updated on a monthly basis, unless there are good operational reasons for doing otherwise. Additionally, before the details of any eligible microbusiness customers are added to the Database, they will first be notified of the disclosure process through the Opt-out Letter (see Section 13 for further details).

17.239 We also recommend that Ofgem put in place safeguards to mitigate any prejudice to the rights and interests of the data subjects (see Section 13).

17.240 Rival suppliers will be allowed to prompt the Disengaged Microbusiness Customers who have not opted out by sending them marketing correspondence by letter (see Section 13).

- *How the remedy should be implemented*

17.241 We will implement this remedy through:

- (a) a CMA order (and amendments to suppliers' standard licence conditions) that will require suppliers to:

- (i) send Opt-out Letters¹¹⁶ to the Disengaged Microbusiness Customers;
 - (ii) disclose the Microbusiness Customer Data to Ofgem in the format prescribed by Ofgem; and
 - (iii) provide Ofgem with updated Microbusiness Customer Data on a regular basis, as specified by Ofgem.
- (b) a recommendation to Ofgem to:
- (i) create, operate and maintain a secure cloud database for the purposes of holding the Microbusiness Customer Data;
 - (ii) hold the Microbusiness Customer Data;
 - (iii) test the operation of the Database (prior to its roll-out);
 - (iv) put in place safeguards to mitigate any prejudice to the rights and interests of the data subjects;
 - (v) provide access to the Microbusiness Customer Data to any rival supplier subject to such safeguards;
 - (vi) test aspects of the marketing letters to prompt the Disengaged Microbusiness Customers who have not opted out; and
 - (vii) monitor the impact of the Database with a view to maximising its effectiveness.

Assessment of effectiveness of the remedy

17.242 As we explain below, our view is that the remedy will be effective in achieving its aims of enabling rival energy suppliers to identify and market to the Disengaged Microbusiness Customers, and prompting Disengaged Microbusiness Customers to engage. Accordingly, the remedy will be effective in partly addressing two of the features giving rise to the Microbusiness Weak Customer Response AEC. These two features are that customers have limited awareness of, and interest in, their ability to switch supplier; and that customers face actual and perceived barriers to assessing and accessing information.

¹¹⁶ As defined in the domestic Database remedy.

17.243 In evaluating the effectiveness of the remedy, we have considered the following factors:

- (a) the effectiveness of the key design elements of the remedy.
- (b) the extent to which the remedy will be capable of effective implementation, monitoring and enforcement.
- (c) the timescale over which the remedy will be expected to take effect.
- (d) compliance with existing or expected laws or regulations.

- *Effectiveness of the key design elements*

17.244 We consider that the following key design elements of the remedy will, in combination, assist the remedy be effective in achieving its aim. In particular:

- (a) rival suppliers will be able to easily identify the Disengaged Microbusiness Domestic Customers;
- (b) Ofgem's role in testing, operating, controlling, maintaining the Database, and in providing access to it will ensure that the Database is set up and administered fairly in the interests of microbusiness customers;
- (c) the Database will be readily accessible to rival suppliers upon request (subject to the appropriate safeguards) and will include data that is accurate and up to date. The remedy provides for the Microbusiness Customer Data to be updated on a regular basis; and
- (d) rival suppliers that have an incentive to compete for and be able to provide the Disengaged Microbusiness Customers (that have not opted out) with personalised information. Suppliers will know certain customer details such as the current supplier, contract type and annual consumption.

- *Implementation, monitoring compliance and enforcement*

17.245 In determining whether the remedy will be effective, we have considered the operation and implementation of the remedy.

17.246 As regards the implementation of the remedy, our order on suppliers will place specific requirements on suppliers. Our recommendation to Ofgem will provide an indicative list of the types of issues that Ofgem should address with regards to the implementation of this remedy.

17.247 As regards monitoring compliance with the remedy, we note that the CMA will be responsible for monitoring compliance. This is because part of this remedy will be implemented through a CMA order. In addition, by introducing a new licence condition that will be consistent with the CMA's order, Ofgem will also be under a duty to perform a monitoring role and can require the provision of information from suppliers concerning potential breaches of a licence condition. Moreover, as the sector regulator, Ofgem will be well placed to receive any allegations of misuse of the Microbusiness Customer Data by a rival supplier and will be able to take action under the agreements put in place concerning access to and use of the Microbusiness Customer Data, or under a licence condition.

- *Timescales for the remedy*

17.248 As regards the timescales for implementation, following the publication of this report, the CMA will start drafting and consulting on an order requiring suppliers to send the Opt-out Letter to their Disengaged Microbusiness Customers. During this period, we also expect Ofgem to begin developing the Database and associated agreements. Following publication of the CMA's Final order, we will require suppliers to send the Opt-out Letter to all Disengaged Microbusiness Customers by mid-2017. We will also require suppliers to pass the Microbusiness Customer Data to Ofgem by October 2017 at the latest. Therefore, we expect rival suppliers to start accessing the Database, and contacting the Disengaged Microbusiness Customers who have not opted out from the beginning of 2018. The Database will then be updated regularly from the beginning of 2018.

17.249 In evaluating the effectiveness of the remedy, we have also considered the timescale over which we expect the Microbusiness Weak Customer Response AEC to endure, and the timescale over which the remedy will likely take effect. We consider that the detriment would persist, absent the remedy. We also note that the impact of future market developments, including the roll-out of smart meters, is somewhat uncertain. Therefore, we have decided that the remedy will not be subject to a sunset clause. However, we expect Ofgem to keep the operation and impact of the Database under review and report on its impact after five years.

- *Consistency and compliance with existing or expected laws or regulations*

17.250 As indicated in paragraph 17.232 above, we have taken account of our discussions with the ICO, and the remedy will be compliant with the Data Protection Regime.

Assessment of proportionality of the remedy

17.251 In this section we set out our assessment of whether the Database remedy will be proportionate.

- *Effective in achieving its aim*

17.252 For the reasons set out above, we consider that the remedy will be effective in achieving its aim of enabling rival retail energy suppliers to identify Disengaged Microbusiness Customers who have not opted out. Accordingly, it will be effective in partly addressing two of the features giving rise to the Microbusiness Weak Customer Response AEC (and the resulting detriment).

- *No more onerous than needed to achieve its aim*

17.253 Consistent with our approach in the domestic markets, we also consider that the remedy will be no more onerous than needed to achieve its aim. In particular, we have considered very carefully the limitations on the data that suppliers will be required to disclose, the requirements of microbusiness customers, the frequency with which suppliers will be required to update the Database, and the procedures to disclose and access the Database. We consider that the remedy will be no more onerous than needed to achieve its aim. With regard to the data that suppliers will be required to disclose, it is our view that the Microbusiness Customer Data will be sufficient for rival suppliers to be able to identify and contact the Disengaged Microbusiness Customers who have not opted out, and to provide these customers with personalised information on the savings they could make by switching.

17.254 With regard to the microbusiness customers for whom suppliers will be required to disclose information, we consider that an approach targeted specifically at the Disengaged Microbusiness Customers will be more proportionate, than a similar remedy directed at all microbusiness customers on default contracts or those that have been on default contracts for a shorter duration than three years. In particular, our judgement is that if microbusiness customers were to actively engage in the market every three years, it is likely that will be sufficient to exert an effective competitive constraint on suppliers.

17.255 Finally, Ofgem will have discretion to determine the frequency with which suppliers will be required to update the Database. However, we suggest that the Database be updated on a monthly basis unless there are good operational reasons for doing otherwise. We expect that the process of extracting, formatting and disclosing the Microbusiness Customer Data will be moderately costly for suppliers. We also consider that frequent updating

will reduce the risk of rival suppliers contacting microbusiness customers who had recently switched away from a default contract, based on out-of-date information.

- *Least onerous if there were a choice between several effective measures*

17.256 We have considered whether there may be alternative designs of this remedy to achieve the same aim that are less onerous. For the reasons noted above, we consider that the remedy, as designed, appropriately balances the need for the remedy to be effective, and proportionate, in terms of the proportion of suppliers' existing customer base to which the remedy will apply (ie customers on a default tariff for three or more years).

- *Would not produce disadvantages disproportionate to the aim*

17.257 Consistent with our approach in the domestic markets, we have concluded that the remedy will not produce adverse effects that will be disproportionate to its aim. In this regard, we estimate that the costs of extending the Database remedy concerning domestic customers to disengaged customers in the microbusiness segments will be similar in nature and in scale on a per customer basis to those identified in Section 13 for the domestic markets.

- *Any relevant customer benefits that may be lost*

17.258 We do not consider any relevant customer benefits will be lost as a result of the disclosure of details of the Disengaged Microbusiness Customers to Ofgem and rival suppliers subject to the Use Restrictions. As noted above, the remedy will have several detailed design mechanisms to mitigate the risk of customers receiving unwanted correspondence that could disengage them further. Instead, the remedy will provide Disengaged Microbusiness Customers with relevant information, encourage them to engage and switch to cheaper acquisition and retention contracts.

- *Ofgem's statutory duties*

17.259 As discussed in Section 13, we consider that the remedy is consistent with Ofgem's principal objective of promoting the interests of existing and future customers.

Remedies relating to the Microbusiness Weak Customer Response AEC not being pursued

TPI information disclosure remedy

17.260 One of the features of the retail energy markets identified giving rise to the Microbusiness Weak Customer Response AEC was that customers faced actual and perceived barriers to accessing and assessing information arising from certain aspects of these markets. The aspects contributing to the feature were a general lack of price transparency and the role of TPIs.¹¹⁷

17.261 In relation to the role of TPIs, we observed that trust in TPIs was likely to have been reduced in the microbusiness segments due to:

- (a) alleged TPI malpractice; and
- (b) customers not necessarily being aware of TPIs' incentives (for example, commissions that TPIs receive) not to give customers the best possible deal.¹¹⁸

17.262 In the Remedies Notice, we proposed certain measures that would require the introduction of rules regarding the information that TPIs would have to provide to microbusiness customers. The possible remedy would have required TPIs to disclose the following information to microbusiness customers:

- (a) The extent to which they cover the whole of the market, eg by highlighting those suppliers with which they have and do not have agreements.
- (b) How they are paid for their services, eg by commission from energy suppliers.
- (c) Whether they will provide the customer with the cheapest quote (or cheapest quotes) among those firms with which the TPI has an agreement to supply customers, or whether only a selection of quotes will be provided.¹¹⁹

¹¹⁷ TPIs are intermediaries in the supply chain between the energy supplier and the retail microbusiness customer. However, in some circumstances, these can include online TPIs (eg PCWs) and offline TPIs (eg brokers). References to TPIs in this section relate specifically to brokers.

¹¹⁸ Appendix 16.1.

¹¹⁹ [Remedies Notice](#), paragraph 77.

Parties' views on the TPI information disclosure remedy

- 17.263 In the Remedies Notice, we invited views on a number of questions on the possible remedy. The key questions that we asked were whether this possible remedy could be effective in improving transparency over TPI incentives; and whether this possible remedy should be implemented in addition to Ofgem's draft Code of Practice (CoP).¹²⁰
- 17.264 In their responses to the Remedies Notice, all of the Six Large Energy Firms and certain of the independent suppliers welcomed a remedy to improve transparency over TPIs and they supported Ofgem's draft CoP. However, some suppliers such as EDF Energy and RWE were in favour of direct regulation of TPIs via a licensing regime.¹²¹ The FSB also supported Ofgem's draft CoP, and said that the CMA should consider Ofgem's draft CoP when designing the remedy. The FSB supported greater transparency regarding TPIs. All TPIs, which responded to the Remedies Notice, were also in favour of Ofgem's draft CoP, except for the UIA, a TPI, which has its own code of practice. In relation to whether the TPI information disclosure remedy should be implemented in addition to Ofgem's draft CoP, most parties said that either one or the other (but not both) should be implemented, with most favouring Ofgem's draft CoP.¹²²
- 17.265 In their responses to the provisional decision on remedies, some parties such as Centrica,¹²³ E.ON, and the Federation of Small Businesses suggested that the CMA recommend Ofgem to implement the CoP. Scottish Power considered that it was important that the CMA's final report left open the possibility for Ofgem to take the matter forward including consideration of a TPI CoP. RWE said that it considered TPIs to be a more important sales channel than indicated in Ofgem's survey, and it also suggested formal regulation of TPIs.

Our position on the TPI information disclosure remedy

- 17.266 We have decided not to pursue the TPI information disclosure remedy. Our view is that the price transparency remedy will address in part, aspects of the feature of actual and perceived barriers to accessing and assessing information that we have found gives rise to the Microbusiness Weak Customer Response AEC in particular, concerning the general lack of price

¹²⁰ Remedies Notice, paragraph 80.

¹²¹ EDF Energy said that even though it supported Ofgem's CoP, it saw it as an interim measure until a direct licensing regime was established.

¹²² See Appendix 17.4 for further details on parties' views.

¹²³ Centrica further suggested the CMA specify a time frame for its implementation of within 12 months, and that minimum requirements on transparency be recommended, particularly around commission payments.

transparency. It will also enhance TPIs' roles (in particular PCWs' roles) in helping microbusiness customers to access and assess information to help them engage (see paragraphs 17.23 to 17.26 above). In addition, we note that we have received inconclusive evidence regarding alleged TPI malpractice, in particular as regards microbusinesses. In addition, Ofgem is considering implementing its draft CoP, which seeks to address similar areas to those outlined under this possible remedy.

- *The price transparency remedy*

17.267 We also note that the price transparency remedy will also constrain TPI conduct (ie potential or alleged malpractice), which was the second aspect that contributed to the feature. The price transparency remedy will reduce search costs and will facilitate the development of PCWs (see paragraphs 17.23 to 17.26 above). This will enable microbusiness customers to effectively assess and verify online whether the prices they were quoted by TPIs were reasonable. This will act as a competitive constraint on TPIs, which will be incentivised to offer competitive quotes to microbusiness customers.

- *Evidence base for alleged TPI malpractice*

17.268 We have received inconclusive evidence regarding alleged TPI malpractice in the supply of energy to SMEs and in particular microbusiness customers. It is therefore unclear whether this is a significant concern for microbusiness customers.

17.269 The evidence we received was primarily drawn from Ofgem surveys on SMEs' concerns with TPIs, which showed mixed and inconclusive results:

(a) Ofgem's survey results showed overall negative perceptions of TPIs among SME customers. However, the majority (81%¹²⁴) of customers (SMEs including microbusiness customers), which used brokers, were satisfied with them.¹²⁵

(b) The same survey showed that just 5%¹²⁶ of SMEs that have used a broker reported that they were charged for the broker's services.

¹²⁴ We note that a recent update puts this figure at 82%. See BMG Research (May 2016), *Micro and Small Business Engagement in Energy Markets* (report for Ofgem).

¹²⁵ BMG Research (2015), *Micro and Small Business Engagement in Energy Markets* (report for Ofgem).

¹²⁶ We note that a recent update puts this figure at 8%. See BMG Research (May 2016), *Micro and Small Business Engagement in Energy Markets* (report for Ofgem).

However, of those SMEs recall being charged, 92% were aware of the level of the charge before using the broker's services.¹²⁷

(c) A Cornwall Energy Report (2011) pointed out that TPIs might be presenting not the most advantageous offers to SMEs because suppliers were skewing commission payments towards the deals they wanted to sell.¹²⁸ This suggests that the root cause of alleged TPI malpractice may not be TPIs, which may be responding to incentives from suppliers.

17.270 Some parties stated that alleged TPI malpractice was an issue with a few TPIs and that this did not represent most TPIs, which performed a useful function in the markets. For example, Energy UK told us that concerns regarding TPI malpractice applied to a minority of TPIs. Furthermore, surveys for Ofgem such as those conducted by BMG indicated issues (eg sales pressure tactics) among some TPIs, not most TPIs.¹²⁹

17.271 Third, a recent survey done for Ofgem showed that only 11% of microbusiness customers procured their current energy contract with the help of a broker,¹³⁰ thus demonstrating limited TPI penetration in the microbusiness segments. The survey noted that microbusiness customers were more likely to contact suppliers directly to procure energy, rather than procure energy through a TPI.¹³¹ A recent research report also noted that 28% of micro and small businesses said that brokers and suppliers were their 'main source of information'.¹³² We noted that low TPI penetration among microbusiness customers could partly be driven by the financial incentives of TPIs, which may prefer to focus on larger businesses from which they can earn more commission.¹³³ We also noted that the low TPI penetration is irrespective of the 28% of businesses that considered TPIs to be the main source of information.

¹²⁷ BMG Research (2015), *Micro and Small Business Engagement in Energy Markets* (report for Ofgem).

¹²⁸ Cornwall Energy (2011), *Brokerage services for micro-business energy consumers* (report for Consumer Focus), p14.

¹²⁹ BMG Research (2015), *Micro and Small Business Engagement in Energy Markets* (report for Ofgem).

¹³⁰ Appendix 16.1, paragraph 99, sourced from The Research Perspective and Element Energy (2013), *Quantitative research into non-domestic consumer engagement in, and experience of, the energy market* (report for Ofgem), p31.

¹³¹ Appendix 16.1, paragraph 99, sourced from The Research Perspective and Element Energy (2013), *Quantitative research into non-domestic consumer engagement in, and experience of, the energy market* (report for Ofgem), p31.

¹³² BMG Research (May 2016), *Micro and Small Business Engagement in Energy Markets* (report for Ofgem).

¹³³ Appendix 16.1, paragraph 104.

- *Ofgem's draft Code of Practice*

17.272 We have also noted that Ofgem is considering implementing its draft CoP. Having discussed further with Ofgem around its intentions concerning its draft CoP, we consider that it has a clear intention to take its draft CoP forward and introduce it, following a consultation process with the industry.¹³⁴

17.273 In its response to the Remedies Notice, Ofgem told us that the measures described in the TPI information disclosure remedy (see above) were currently included in its draft CoP. Ofgem considered it would not be appropriate for it to duplicate regulation by implementing these aspects of the CoP alongside a remedy which addresses the same areas.¹³⁵

17.274 We also note that Ofgem's draft CoP applies across retail supply to SMEs. Hence, to the extent its draft CoP were to address concerns pertaining to the SME markets, we are of the view that Ofgem's draft CoP will effectively target such concerns.

17.275 Given the inconclusive evidence and the extent to which any concerns regarding TPI malpractice or mistrust are specific to the microbusiness segments, we consider that such concerns would more effectively be monitored¹³⁶ and addressed by an Ofgem CoP concerning all SMEs.

Price cap remedy – protecting customers that are unable to engage to exploit the benefits of competition

17.276 We have considered whether a price cap would be an appropriate remedy to protect microbusinesses that are unable to engage. We have decided not to implement a price cap on the grounds that it would be a disproportionate measure. This is on the basis that we consider that the package of remedies (see paragraphs 17.300 to 17.317 below) will adequately address the Microbusiness Weak Customer Response AEC and/or associated detriment. We also note that the microbusiness segments are heterogeneous¹³⁷ and there is considerable variation in consumption levels among different microbusinesses. These factors would significantly increase the complexity of implementing, monitoring and enforcing any price cap remedy in the microbusiness segments and its associated costs to suppliers.

¹³⁴ Discussed with Ofgem on 24 November 2015.

¹³⁵ [Ofgem response to the Remedies Notice](#).

¹³⁶ In its response to the Remedies Notice, Ofgem told us that there were approximately 1,200 TPIs engaged with suppliers and considerably more that operated through aggregators. According to Ofgem, many TPIs operating in the microbusiness space were 'one man bands'.

¹³⁷ Section 16.

Creating the framework for effective competition

Settlement reform remedy

- 17.277 The remedies relating to gas and electricity settlement, discussed in Section 12 above in relation to domestic customers, will also apply to microbusiness customers.
- 17.278 The remedy concerning electricity settlement will move non-domestic customers (including microbusiness customers) in profile classes 1 to 4¹³⁸ into half-hourly settlement. However, we note that there are currently no firm plans to move domestic and microbusiness customers to half-hourly settlement. Nevertheless, once the changes are completed, it will affect almost all (90% or more) microbusiness electricity customers. In particular, Ofgem told us that its data suggested that 88%¹³⁹ of non-domestic electricity customers would be covered by looking at profile classes 3 and 4. It estimated also that 6% of non-domestic customers were in profile classes 5 to 8, though there were also a small number of microbusiness customers in profile classes 1 and 2.¹⁴⁰
- 17.279 In Section 12, we reported evidence on the potential for demand-side response in the domestic retail markets and in particular we noted that according to one study shiftable electricity demand (see Section 12) could be as high as 10 GW by 2025. Similar studies have been conducted for the SMEs sector.¹⁴¹ They tend to suggest that the potential for demand-side responses might be of the order of 2 GW.¹⁴²
- 17.280 We discuss our decision on remedies in relation to both gas and electricity settlement, including aims, parties' views, design, effectiveness and proportionality of the remedy in Section 12.

¹³⁸ Profile class 1 – domestic unrestricted customers. Profile class 2 – domestic Economy 7 customers. Profile class 3 – non-domestic unrestricted customers. Profile class 4 – non-domestic Economy 7 customers. For more information of the use of profile classes in settlement see Elexon (2013), [Load Profiles and their use in Electricity Settlement](#).

¹³⁹ This would suggest the proportion of microbusiness customers affected by the changes would be higher than 88%, which affects all non-domestic customers.

¹⁴⁰ Email from Ofgem dated 15 September 2015. Note that Ofgem cited these proportions using Elexon and Xoserve, June 2015 data.

¹⁴¹ See Baringa (2013), Smart Metering Load Shift Analysis; and Baringa and Element Energy (2012), [Electricity System Analysis – future system benefits from selected DSR scenarios, Final report pack](#).

¹⁴² See Baringa and Element Energy (2012), [Electricity System Analysis – future system benefits from selected DSR scenarios, Final report pack](#), p43.

Proposed package of remedies to address the Microbusiness Weak Customer Response AEC: effectiveness and proportionality

17.281 We have discussed the rationale for each element of the package of remedies in the subsections above. In this subsection, we explain how the elements in the package of remedies will work together to be effective and proportionate in addressing the Microbusiness Weak Customer Response AEC and/or the resulting customer detriment.

Effectiveness of the package of remedies

- *How the package of remedies will address the Microbusiness Weak Customer Response AEC and/or resulting customer detriment*

17.282 We conclude that the package of remedies will be effective in addressing the features giving rise to the Microbusiness Weak Customer Response AEC and associated detriment.

17.283 As regards the feature that microbusiness customers face actual and perceived barriers to accessing and assessing information, the price transparency remedy will require suppliers to disclose online the prices of all their available acquisition and retention contracts to those microbusiness customers suffering most detriment from the lack of price transparency, namely those in the Relevant Segment. This remedy contrasts with the current practice, where most contracts are individually negotiated between microbusiness customers and suppliers, in the context of many prices not being disclosed online.

17.284 The remedy may reduce the need for and the levels of negotiated contracts, by reducing microbusiness customers' search costs, and increasing the efficiency of switching. Also, this remedy will facilitate the development of PCWs in the microbusiness segments, thereby enhancing the ability and incentives of TPIs to promote customer engagement, and increasing the level of trust in TPIs. These changes will reduce the search costs, increase price transparency and as a result reduce the actual and perceived barriers that microbusiness customers currently face in accessing and assessing information regarding contract prices.

17.285 The remedies concerning the Ofgem-led programme (see paragraph 17.177) and the Database remedy (see paragraph 17.216) will also address the actual and perceived barriers to accessing and assessing information, and hence enable microbusiness customers to switch from default contracts onto lower-priced acquisition and retention contracts.

17.286 We also consider that the Database remedy will address, in part, the feature that microbusiness customers have limited awareness of, and interest in, their ability to switch energy supplier.

17.287 As regards the third feature concerning microbusiness customers on auto-rollover contracts, the auto-rollover remedy will address this feature. Microbusiness customers will no longer face certain restrictions that constrain their ability to switch contract or supplier. In addition, we note that the inclusion of termination fees in OOC and deemed contracts also acts as a barrier to switching. We therefore consider that the removal of termination fees for OOC and evergreen contracts will increase the ability of those microbusiness customers to switch supplier or contract.

17.288 By addressing each of the three features, we consider that our package of remedies will be effective in addressing the Microbusiness Weak Customer Response AEC. The package of remedies will also address the customer detriment by reducing the energy costs for microbusiness customers that switch from relatively higher priced default contracts on to relatively lower priced acquisition and retention contracts.

17.289 We have therefore concluded that our package of remedies will be effective in addressing, in large part, the Microbusiness Weak Customer Response AEC, and the resulting customer detriment.

- *Other aspects of the effectiveness of our package of remedies*

17.290 Based on our assessment of the effectiveness of each remedy contained within our package of remedies, we consider that the package of the four remedies as a whole (see paragraphs 17.283 to 17.289 above) will be capable of effective implementation, monitoring compliance and enforcement within reasonable timescales.

17.291 As regards monitoring compliance with the remedies package, we note that we note that both the CMA and Ofgem will be responsible for monitoring compliance with the price transparency remedy, the auto-rollover remedy and the Database remedy, as these remedies will be implemented through an order, and amendments to suppliers' licence conditions. Accordingly, we consider that monitoring compliance with the remedies package will be straightforward.

17.292 As regards enforcement, the CMA will be able to directly enforce against any breach of the order and Ofgem will be able to enforce against any breach of new licence conditions, without making an application to the court (as compared to a breach of the order, for which a court application is required).

- *Timescale for the remedies package*

17.293 In evaluating the effectiveness of the remedies package, we have considered the timescale over which the remedies will be likely to take effect.

17.294 We concluded that the package of remedies will have a beneficial impact in addressing the Microbusiness Weak Customer Response AEC soon after its implementation. However, the success over the medium to long term of the price transparency and auto-rollover remedies will depend upon increased microbusiness customer awareness that all prices are being disclosed and that customers no longer face restrictions on auto-rollover contracts. To this effect, we note that microbusiness customers could be made aware of the benefits of these remedies through the Database remedy and the Ofgem-led programme. Additionally, PCWs will have a greater incentive to advertise their services to microbusiness customers, which would in turn increase customer awareness.

17.295 Therefore, we have concluded that the package of remedies will be capable of effective implementation within a reasonable timescale.

- *Coherence of the package of remedies*

17.296 We have considered whether there would be synergies between the various remedies contained within our package of remedies. We note that none of the individual remedies will work against the aims of the other remedies that we are introducing to address the features that give rise to the Microbusiness Weak Customer Response AEC.

17.297 For example, the Database remedy will prompt disengaged microbusiness customers to switch; the price transparency remedy will facilitate switching by allowing microbusiness customers to discover competitive prices more easily; as will the Ofgem-led programme, which will also enable them to access clear information that will facilitate switching; and the auto-rollover remedy will no longer constrain them from switching. We therefore consider that these individual remedies will mutually reinforce each other.

17.298 We have therefore concluded that our remedies represent a coherent package, whose elements will be mutually reinforcing.

Proportionality of the package of remedies

17.299 We note that the proportionality of the package of remedies has been built into its design. We have considered issues such as less onerous alternatives, costs and the adverse consequences of the package of

remedies. We have discussed the proportionality of each individual remedy above.

17.300 In this subsection, we explain how the package of remedies will be proportionate to address the Microbusiness Weak Customer Response AEC and/or associated detriment. We have done so by considering whether the remedies package will:¹⁴³

- (a) be effective in achieving its legitimate aim;
- (b) be no more onerous than needed to achieve its aim;
- (c) be the least onerous if there is a choice between several effective remedies; and
- (d) not produce disadvantages that are disproportionate to the aim.

- *Effective in achieving its aim*

17.301 We conclude that our package of remedies will be effective in directly addressing aspects of the features that give rise to the Microbusiness Weak Customer Response AEC or the AEC itself and/or its resulting customer detriment (see paragraphs 17.282 to 17.289 above).

- *No more onerous than necessary to achieve its aim*

17.302 In order to assess whether the package will be no more onerous than necessary, we have considered:

- (a) whether each of the remedies within the package of remedies will be required to remedy the Microbusiness Weak Customer Response AEC and/or associated detriment; and
- (b) whether the design of each remedy within the package of remedies will be no more onerous than it needed to be.

17.303 Based on our assessment of how the various remedies within the package will contribute to addressing the Microbusiness Weak Customer Response AEC and/or associated detriment, it is our view that each remedy will make a distinct and material contribution to the overall effectiveness of the remedies

¹⁴³ CC3, paragraph 344, citing the principles established in the *Fedesa* case, Case C-331/88, *The Queen v Minister of Agriculture, Fisheries and Food and Secretary of State for Health, ex parte: Fedesa and others*, [1990] ECR I-4023, paragraph 13.

package. Even though some of the remedies will have overlapping aims/purposes, no single remedy could be a substitute for any other.

- 17.304 While we consider that each remedy will play an important role in addressing the Microbusiness Weak Customer Response AEC and/or associated detriment, we expect each remedy's contribution to the overall impact of the package to vary. For example, the price transparency remedy will be key to unlocking competition on price, and the other remedies will be helpful in making sure that microbusiness customers will then be aware, willing and able to take advantage of that increased price transparency by finding cheaper available contracts, and therefore enabling them to switch to those contracts.
- 17.305 This is because the price transparency remedy in our view, has the potential to transform the microbusiness segments of the retail supply markets from individually negotiated contracts, specifically with opaque prices, into one with transparent price disclosures.
- 17.306 Based on our assessment above, we conclude that it will be necessary to include each of the remedies in our package in order to achieve a comprehensive solution to the Microbusiness Weak Customer Response AEC and/or associated detriment.
- 17.307 When reaching our decision on remedy design, we have sought to avoid imposing costs and restrictions on parties that go beyond what will be needed to achieve an effective remedy. For example, in relation to the price transparency remedy, our approach to the Relevant Segment will rule out the requirement for suppliers to develop complex and costly online quotation tools concerning the largest microbusiness customers. Similarly, the option to disclose prices via PCWs will present a cost-effective option for smaller suppliers. In relation to the auto-rollover remedy concerning existing auto-rollover contracts, we have decided that an implementation period of up to 12 months following the publication of the final report will be reasonable to allow suppliers adequate time to adjust their business practices and manage risks.
- 17.308 Based on the above, we have conclude that our package of remedies will be no more onerous than necessary in order to address the Microbusiness Weak Customer Response AEC and/or resulting customer detriment.

- *Least onerous if there were a choice of effective remedies*

17.309 For the reasons given above, we do not consider that there are other less onerous remedies that would be effective in remedying the AEC and/or associated detriment we have identified.

17.310 First, we consider that the online means of price disclosure under the price transparency remedy is likely to be the most cost-effective and least restrictive way of reaching the target microbusiness customer audience, compared to other means such as online price lists or letters. In addition, we note that our concerns regarding termination fees on fixed-term auto-rollover contracts, could not be addressed in any way other than how we have outlined in the remedy.

17.311 We have also considered whether other possible remedies not within our package of remedies could address the Microbusiness Weak Customer Response AEC and/or associated detriment. These included remedies that were put to us by parties such as certain parties' preferences for no action over the auto-rollover remedy. We note that such alternative remedies would be of limited or no effectiveness, and would not address the Microbusiness Weak Customer Response AEC or associated detriment. We were not able to identify an alternative package of remedies that would be both less onerous and effective in addressing the Microbusiness Weak Customer Response AEC and/or associated detriment.

17.312 We therefore conclude that our package of remedies will be the least costly and least restrictive solution.

- *Does not produce adverse effects and costs that are disproportionate to the aim*

17.313 We have considered whether the package of remedies – or any specific remedy within it – would produce adverse effects that could be disproportionate to their individual aims of remedying the Microbusiness Weak Customer Response AEC and/or associated detriment. Specifically, we considered whether the benefits of the remedies package as a whole would exceed the overall costs of the package. We summarise below our estimates of the cost of each remedy in the package:

- (a) We estimate that the price transparency remedy will likely impose costs on the Six Large Energy Firms of approximately £750,000; and on all 30 suppliers (including the Six Large Energy Firms) these costs could amount to approximately £4.5 million if they all opted for the more expensive online quotation tool option (see paragraph 17.99 above).

- (b) We do not expect the auto-rollover remedy to impose any consequential costs on suppliers, as we expect them to be able to change their risk management (see paragraphs 17.162 to 17.169 above).
- (c) We estimate that the costs of extending the Ofgem-led programme remedy to the microbusiness segments will be similar in nature and scale (on a per customer basis) to those identified in Section 13 for the domestic markets. We note that the Ofgem-led programme will be proportionate given the scale of the detriment, and any potential costs to suppliers will be subject to Ofgem's obligation to consider the proportionality of any testing.
- (d) We note that the costs of extending the Database remedy to the microbusiness segments will be similar in nature and scale (on a per customer basis) to those identified in Section 13 for the domestic markets.¹⁴⁴

17.314 In light of the above, we consider that the total costs associated with the remedies package as a whole are unlikely to exceed around £750,000 for the Six Large Energy Firms. For the approximately 30 suppliers in the market, the costs of this remedy on suppliers are unlikely to exceed £4.5 million. However, we note that these figures are likely to be an upper bound of the cost estimates because we expect several suppliers to choose the third party online platform option, which will be significantly more cost-effective, to comply with the price transparency remedy.

17.315 By comparison, we consider that there is substantial scope for price reductions and that the package of remedies will still be proportionate even if it is more costly to implement than we have estimated, if it leads to a reduction in prices for microbusiness customers. This is because even if it is small we have estimated that the Six Large Energy Firms generated profits in excess of the cost of capital from microbusiness customers of £183 million.

17.316 With regards to the Six Large Energy Firms, the package of remedies will need to result in a very small 0.03%¹⁴⁵ reduction in prices for the benefits to customers to exceed the costs of the package. By comparison, we consider that prices for the microbusiness customers of the Six Large Energy Firms

¹⁴⁴ This position is consistent with the domestic retail markets, which contributes a far greater share of revenues than the microbusiness segments.

¹⁴⁵ This is the same calculation as used to assess the proportionality for the price transparency remedy and relates to the microbusiness customers of the Six Large Energy Firms.

could have been on average 5% lower between FY 2007 to FY 2014 in a better-functioning market.¹⁴⁶

17.317 We have therefore concluded that the benefits of the remedies package for all microbusiness customers are likely to substantially exceed the costs that it will impose on all suppliers in the microbusiness segments. Consequently, the remedies package will unlikely give rise to adverse effects that are disproportionate to its legitimate aim.

¹⁴⁶ Section 16, paragraph 16.153.

18. Governance of the regulatory framework: AECs and detriment

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Introduction

- 18.1 Efficient and robust rules and regulations are fundamental to the well-functioning of energy markets. Because of the technical nature of electricity and gas production and distribution, energy markets are highly regulated, and the nature of competition in these markets is shaped by the design of the regulatory regime to a much greater extent than in most other markets.
- 18.2 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 sections we have observed that this framework has had a profound effect on the nature of competition in wholesale and retail energy markets. While we have found several areas in which the regulatory framework appears to be working well, such as certain aspects of wholesale electricity market design, we have also identified a number of specific aspects of the regulatory framework that lead to AECs in wholesale and retail energy markets, such as the introduction of the simpler choices component of the RMR rules, the settlement systems for gas and electricity and the absence of locational charging for transmission losses.
- 18.3 The regulatory framework has had a material effect in driving outcomes for energy consumers. 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.

- 18.4 Government policies – particularly those designed to reduce harmful greenhouse gas emissions – are having an increasing impact on energy prices and bills. On the basis of current announced plans, climate and energy policies as a whole are expected to amount to 37% of the retail price of electricity paid by households in 2020. Further, some policies – such as the roll-out of smart meters – are expected to improve energy efficiency and hence reduce energy bills. Given the central role that government policies are expected to play in determining energy bills in the future, we believe it is vital that policy decisions are robust, and informed by a transparent analysis of their impacts on consumers.
- 18.5 In this section, we consider whether there are features of the energy markets relating to the structure and governance of the regulatory framework that give rise to an AEC. We consider two aspects of this question:
- (a) First, 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, whether the current system of industry code governance delivers timely change that is needed to support competition, innovation and wider policy objectives.

Broader regulatory framework

- 18.6 We have identified in this report some specific regulations and policies that we consider 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 component of the RMR rules. We also noted 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.
- 18.7 In this section, we identify 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 – which 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.

18.8 Specifically, for the reasons set out below, we believe that:

- (a) The allocation of powers, roles and objectives between DECC, Ofgem and the industry does not ensure that decisions are consistently made in the interests of customers in the long term, and sometimes leads to inefficiencies in the implementation of policies, in particular because:
 - (i) Ofgem's objectives and duties, as amended by the Energy Act 2010 (EA10), are unclear and may hinder the achievement of customers' best interests wherever appropriate through effective competition; and
 - (ii) the relationship between Ofgem and DECC is suboptimal, regarding both policy design, where Ofgem does not have a clear role in expressing views on policy proposals, and policy implementation, where there is a lack of coordination between DECC, Ofgem and the industry.
- (b) The level of analysis and transparency underpinning decision making is either insufficient or ineffectively communicated, including as a result of:
 - (i) a lack of effective communication on the forecast and actual impact of government and regulatory policies over energy prices and bills; and
 - (ii) insufficiently clear and relevant financial information concerning generation and retail profitability available to support decision making.

Allocation of powers, roles and responsibilities between DECC, Ofgem and the industry

Ofgem's duties and objectives

18.9 We consider that a lack of clarity around Ofgem's objectives and duties has increased the likelihood of Ofgem taking decisions that are not in the best interest of consumers. Examples of such decisions (discussed in more detail elsewhere in this report) 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 rules, which we have found has reduced retail suppliers’ ability to innovate in designing tariff structures to meet customer demand and softened competition between suppliers and PCWs.
- 18.10 Ofgem’s objectives and duties are set out in section 4AA of the GA86 and in section 3A of the EA89 (see Appendix 18.3). These two sections are focused on the principal objective of protecting the interests of existing and future consumers, although recognising the existence of multiple subsidiary duties and objectives underpinning the principal objective.
- 18.11 However, Ofgem has expressed concerns¹ with regard to its current objectives and duties, noting that its competition duty had been progressively downrated relative to other duties over the last ten years.
- 18.12 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.
- 18.13 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

¹ 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.’ See [Ofgem response to the updated issues statement](#).

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.

18.14 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.

18.15 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 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 policies towards improving competition, for our conclusions and remedies to be reconciled with the structure of its duties.

- *Parties' views*

18.16 Most parties broadly agreed that changes made by the EA10 to Ofgem's principal objective and duties may constrain Ofgem's ability to promote competition and to carry out efficient trade-offs between competing objectives, and that a revision of Ofgem's statutory objectives and duties was necessary (or at least they acknowledged that it would be beneficial) to assist Ofgem in regulating the energy markets.² Centrica noted that such a revision should help to refocus energy regulation on competitive market principles which would better serve the interests of consumers, whilst at the same time reducing the risk of interventions that would not benefit competition. Further, Centrica said that it had observed a shift in Ofgem's regulatory approach, away from the promotion of effective competitive markets as the primary way of furthering the interests of consumers. Several respondents said that competition should be the principal mechanism by which Ofgem achieved its duties.

² See for instance ESB; Genserv; Good Energy; InterGen; Energy UK; First Utility; Spark Energy; EDF Energy; RWE; Centrica; SSE; Scottish Power.

- 18.17 However, Citizens Advice/Citizens Advice Scotland said that no evidence had been presented to substantiate the argument that changes to Ofgem's statutory duties made in the EA10 had constrained its ability to promote competition or had either positively or negatively affected subsequent regulatory decisions.
- 18.18 Other respondents argued that the role of promoting competition had not been materially diminished by the EA10, given that the current hierarchy of duties did not preclude Ofgem from promoting competition (Northern Powergrid, Ovo Energy).
- *Our assessment*
- 18.19 Under the GA86 and EA89, Ofgem decides how to pursue its principal objective, provided that its principal objective is achieved 'wherever appropriate by promoting effective competition'.
- 18.20 The EA10, amending the GA86 and EA89, 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 is now part of the paragraph setting out the general duties as to how Ofgem is to carry out its functions.
- 18.21 Moreover, the EA10 introduced a further procedural 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. This requirement is as follows:
- (1C) Before deciding to carry out functions under this Part in a particular manner with a view to promoting competition as mentioned in subsection (1B), the Secretary of State or the Authority shall consider—

(a) to what extent the interests referred to in subsection (1) of consumers would be protected by that manner of carrying out those functions; and

(b) whether there is any other manner (whether or not it would promote competition as mentioned in subsection (1B)) in which the Secretary of State or the Authority (as the case may be) could carry out those functions which would better protect those interests.

- 18.22 We note that, before the EA10, the words ‘wherever possible by promoting effective competition’ gave a margin of appreciation as to when it is appropriate for Ofgem to pursue its principal objective by promoting effective competition but it was without any caveat the primary route (‘wherever possible’). The additional requirement referred to in paragraph 18.21 above qualifies the words ‘wherever possible by promoting effective competition’ in a way that may constrain Ofgem’s margin of appreciation and indeed lead to some confusion as to a conflict between competition on the one hand, and ‘consumer protection’ or similar concepts on the other. For instance, the repositioning of these words, and the added caveat as described above, suggests that less emphasis should be placed by Ofgem on competition when pursuing consumers’ interests.
- 18.23 Our interpretation of this qualification to Ofgem’s objectives and duties is therefore that, this additional requirement referred to in paragraph 18.21, coupled with the repositioning of the words ‘wherever appropriate by promoting effective competition ...’, is likely to constrain Ofgem’s ability to promote competition or lead to confusion as to its role in promoting competition.
- 18.24 The Parliamentary debate shows that an underlying rationale of the EA10 reform to Ofgem objectives and duties was a concern that, in general, Ofgem pursued consumers’ interests exclusively through competition, and did not sufficiently consider whether other measures would have been more appropriate in the short term. For instance, Ed Miliband (MP) described the aim of the draft Bill for the EA10 as being to ‘change Ofgem’s remit to reflect the fact ... that relying on competition alone is insufficient to provide the consumer protection that we need.’³ In a similar vein, Lord Hunt interpreted the impact of this reform as making ‘it clear that, where consumer interests

³ House of Commons debate, 24 November 2009.

are threatened, Ofgem must consider measures other than the promotion of competition in order to rectify the situation.⁴

- 18.25 We consider that Ofgem's duty to pursue its principal objective by 'wherever appropriate promoting effective competition' (if left in those terms) grants it an appropriate level of discretion to determine on a case-by-case basis whether promoting consumers' interests is best achieved through competition or by other means, and what procedural steps need to be taken for that purpose.
- 18.26 Therefore, in our view, the introduction of paragraph 1C in sections 4AA of the GA86 and 3A of the EA89 has created an unnecessary actual or perceived constraint on Ofgem's discretion in this context.
- 18.27 To the extent 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), 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.
- 18.28 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 is to be considered to be unclear and in need of clarification.

Suboptimal relationship between DECC and Ofgem on policy design and implementation

- 18.29 The regulatory framework governing energy markets comprises a combination of regulatory instruments available to different decision makers. Policy reforms may be implemented by measures taken by DECC (mainly through legislation), Ofgem (mainly through licence conditions) and the industry (through code self-regulation).
- 18.30 In principle, DECC is responsible for setting policy objectives and developing policy. This includes for instance the responsibility for setting targets relating to the structure and pace of decarbonisation, for establishing acceptable

⁴ Second reading at the House of Lords, 23 March 2010.

parameters of security of supply, and for identifying social policy priorities. However, in view of its powers, duties and objectives, Ofgem inevitably also takes decisions which develop certain areas of policy, and go beyond mere implementation. And, as noted above, certain reforms that have substantial impacts on competition and the delivery of policy objectives are carried out through code changes (half-hourly settlement, transmission losses, cash-out reforms), in which industry has a key governance role.

18.31 This multi-layered structure of regulation in part reflects the complex nature of the sector and the need to make effective use of resources and expertise where they can be found. We also recognise that the role of the industry in code governance arrangements is influenced by the desire to protect private investors' interests from regulatory instability. However, we are concerned that:

- (a) this fragmentation of responsibility increases the risk of policy decisions being taken that are inconsistent, conflicting, or based on insufficient analysis. It also increases the difficulty both industry parties and other stakeholders have in navigating the regulatory framework (we discuss this concern below); and
- (b) the combination of roles and responsibilities leads to some parties – notably industry participants – having a role in decision-making but facing incentives that are not always aligned with those of consumers (this concern is mainly addressed in our separate discussion on the governance of industry codes).⁵

18.32 In this section we assess whether the quality of policy decision-making and implementation is undermined by dysfunctional relationships between DECC, Ofgem and the industry. Within this context, we consider first whether the coincidence of DECC's and Ofgem's roles risks undermining the perception of Ofgem as an independent and authoritative regulator, contributing to some of the poor outcomes we have observed. We then assess whether, in view of the complementarity of DECC, Ofgem and industry roles, a lack of coordination between them may lead to ineffective outcomes.

⁵ In relation to the incentives of industry participants, we note that these often differ between firms, leading to lengthy and costly regulatory processes and delays in decision-making. Examples of this include the long-running deliberations over whether to introduce locational charges for transmission losses over the past 25 years, which we documented in our provisional findings report.

- *Independence and the overlap of DECC and Ofgem's roles*

- 18.33 We note that Ofgem's decisions to implement both SLC 25A and the RMR rules – neither of which we consider to have been in customers' interests – 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.
- 18.34 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.'⁶ In relation to the RMR rules, 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 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.'⁷
- 18.35 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. Within this context, the coincidence of DECC and Ofgem's actions is likely to create the perception of a lack of independence on the part of Ofgem.
- 18.36 In our view, it is essential to the well-functioning of the regulatory framework that Ofgem be an effective, independent and authoritative regulator – and be generally perceived as being so. 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.
- 18.37 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. Government is effectively

⁶ [Energy policy: future challenges: Government Response to the Committee's First Report of Session 2008-09 – Business and Enterprise Committee.](#)

⁷ DECC (17 May 2013), [Ensuring a better deal for consumers: Government response to consultation on DECC's discussion document](#), paragraph 2.9.

constraining its own discretion – committing not to interfere – by delegating authority over certain decisions to an independent, expert authority that will make decisions according to a clear set of criteria established in advance. The expectation is that this will reduce ex ante estimates of the risks of investment and hence the return on investment investors will require. The benefits arising from a reduced cost of capital should in turn be passed through to customers.

- 18.38 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 with respect to generation and supply markets. In view of its powers, duties and objectives, Ofgem inevitably takes decisions which go beyond mere implementation and into policy development. An important question that we have considered concerns the appropriate nature and extent of Ofgem's independence in pursuing such activities.
- 18.39 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);⁸
 - (b) pursuant to its ability to drive primary legislation, to cause Ofgem's statutory duties and objectives to be altered (subject to compliance with EU legislation which sets out a minimum set of powers and resources);
 - (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;⁹
 - (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.¹⁰

⁸ Schedule 1 of the Utilities Act 2000.

⁹ Section 34(3)(b) of GA86 and section 47(2)(b) of EA89.

¹⁰ Section 34(3)(a) of GA86 and section 47(2)(a) of EA89.

- 18.40 In summary, DECC has a number of tools that it can use to influence Ofgem's actions. However, there are no clear formal processes for Ofgem and DECC to discuss transparently the merits of policy design, in particular allowing Ofgem to set out its views on particular DECC policy proposals, so that stakeholders can understand why a particular decision is being made and the potential costs and benefits. Similarly, there is no clear process to discuss transparently (and consult upon) strategies for the implementation of DECC's policies.
- 18.41 It is not realistic to expect 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 is likely to lead to a lack of robustness in regulatory decision-making. This lack of transparency also increases the legal uncertainty about the design and implementation of new policies.
- 18.42 We are concerned that, in the absence of such formal processes, DECC is more likely to pursue the option (see paragraph 18.39(c) above) of exerting 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 – is likely to harm transparency and the independence of regulation, undermine trust and transparency and ultimately lead to inefficient decision making.
- 18.43 We believe that the absence of mechanisms by which Ofgem is required to publicly express its views on policy proposals increases the risk of decisions being taken in the absence of relevant information, therefore undermining rational debate and regulatory stability, as well as the perception of Ofgem's independence.
- *Ineffective coordination on policy design and implementation*
- 18.44 As noted above, 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). Under current arrangements, we are concerned that ineffective coordination between stakeholders leads to greater risks of negative outcomes for consumers.

- 18.45 In Annex A to Appendix 18.2 we describe several 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.
- 18.46 The decision to move to 17-day switching and P272 (half-hour settlement for certain categories of customer) were both seen as 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, it is likely that it could have implemented more efficiently the necessary changes to allow faster switching and half-hourly settlement for profile 5–8 customers.
- 18.47 A third illustration of suboptimal coordination between DECC's and Ofgem's regulatory interventions relates to the EBSCR reform carried out shortly after DECC's introduction of a Capacity Market. In this case, Ofgem's intervention to reform imbalance prices, although covering a different aspect of the market, interacted with the Capacity Market, in that both measures originally sought to remedy the widespread perception that the prevailing market and regulatory regime provided insufficient incentives to invest in capacity (the 'missing money' problem).¹¹ We 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 reformed imbalance prices) and potentially 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.
- 18.48 Another recent example of inefficient coordination, this time between Ofgem and the industry (within the context of a code modification), is the implementation of Project Nexus. In view of the delays in implementing this modification proposal, Ofgem decided to 'step in' and take an 'overall sponsorship role for Project Nexus' in March 2016. Having done so, Ofgem has found a lack of coordination between separate IT projects (carried out by Xoserve but also by each individual shipper, transporter and supplier) required in order to deliver Project Nexus. As a result of this, we understand that the implementation date of 1 October 2016 is unlikely to be achieved, as

¹¹ See Section 5.

it would carry the potential risk of severe problems in the gas settlement process in the event it were to be implemented on 1 October 2016.

- 18.49 This example, which relates to a key reform of the gas settlement process (see our analysis in Section 8 above, and the AEC that we have found) is an important illustration of the need for greater coordination and project management with respect to the implementation of policies through codes, and the key role that Ofgem can play within this context.
- 18.50 We are also surprised to note some decisions that appear to us to be fundamental to ensuring effective competition appear to be only loosely governed under the industry codes, and not to have involved any formal role for Ofgem. For example, in relation to competition for customers on prepayment meters we understand, based on the relevant provisions set out in the Supply Point Administration Agreement,¹² and parties' submissions, that there are no formal mechanisms in place to monitor the allocation of gas tariff pages and to govern the distribution of tariff pages between suppliers. This is of particular concern since the lack of access to gas tariff pages has been one of the factors inhibiting new entry into, and growth within, the prepayment segments, to the detriment of customers. Given the importance of gas tariff codes in entering, and growing within, both the gas and electricity prepayment segments, we consider it essential that Ofgem should control their allocation.
- 18.51 In summary, we note that the delineation between the powers and roles of DECC, Ofgem and the industry can be blurred. Within this context, we noted a mechanism introduced by the Energy Act 2013 – the Strategy and Policy Statement – by which DECC can provide more clarity about the respective roles of Ofgem and government. This is in an attempt to ensure that policy and regulation will be consistent and coherent.
- 18.52 A draft Strategy and Policy Statement was published in August 2014, but DECC has not yet exercised its power to designate that document. In principle, this document is to be reviewed every five years by DECC, in order to reflect changes in policies.¹³
- 18.53 The aim of the Strategy and Policy Statement is to ensure that policy and regulation will be consistent and coherent in the energy markets. For this purpose, the Strategy and Policy Statement should clearly set out:

¹² Schedule 25 to the Supply Point Administration Agreement.

¹³ It may also be reviewed in certain specific circumstances, for example after a general election, if Ofgem notifies DECC that a policy outcome contained in the Strategy and Policy Statement is not realistically achievable, or after a significant change in the government's energy policy.

- (a) the government's strategic policy priorities;
- (b) the policy outcomes to be achieved as a result of the implementation of that policy; and
- (c) the roles and responsibilities of those involved in implementation of that policy.

18.54 The EA13 further provides that Ofgem, in response to the Strategy and Policy Statement, must publish:

- (a) a forward plan for each financial year, which sets out its strategy for furthering the policy outcomes set out in the Strategy and Policy Statement; and
- (b) an annual report which must, in particular, include Ofgem's assessment of:
 - (i) how it has contributed to the delivery of the policy outcomes contained in the Strategy and Policy Statement; and
 - (ii) if it has failed to do any of the things mentioned in its forward plan for that year.

18.55 In our view, the Strategy and Policy Statement will be a useful instrument to provide additional clarity to stakeholders about policy priorities and the roles and responsibilities of DECC, Ofgem and the industry in achieving these. This would be a useful overarching framework for both Ofgem and the industry (eg within the context of self-governance) that should facilitate consistent regulatory interventions. We therefore recommend that government designate the Strategy and Policy Statement as soon as practicable.

18.56 However, we note that, by its nature, the Strategy and Policy Statement is unlikely to contain detailed provisions as to the implementation of specific policies. We are concerned, therefore, that, even if published, it will not effectively address some of the concerns outlined above (see paragraphs 18.44 to 18.50), specifically the lack of coordination between DECC and Ofgem with respect to the implementation of policies.

18.57 We believe, therefore, that the Strategy and Policy Statement is not sufficient, on its own, to address the concerns identified above, and mitigate the risk of situations in which a lack of coordination between DECC and Ofgem leads to adverse outcomes.

Lack of clear and trusted analysis underpinning decision making and implementation

- 18.58 As noted above, government policies and regulations have had a fundamental influence on the nature of competition in energy markets and have had a significant impact on energy bills. Such impacts are expected to increase in the future. To ensure that energy policies and regulations serve customers' needs, it is vital that policy decisions (and the public debate surrounding them) are informed by robust analyses of their likely impacts.
- 18.59 In this section we set out our view that, because of the magnitude of their impact and their complexity, interventions in the energy markets will typically require a particularly detailed level of analysis. We note in particular the challenges of pursuing competing policy objectives and in particular the absence of robust information concerning the profitability of large, vertically integrated, energy firms.
- 18.60 We then explain our view that:
- (a) analysis and communication of the impact of government and regulatory policies on energy prices and bills (including assessment of the trade-offs made within and between policies) is insufficient; and
 - (b) there is a lack of relevant financial information, which is needed to provide clear and trusted assessment of outcomes in the GB energy markets, including an analysis of the forecast and actual impacts of regulation, and the trade-offs between policies.

Intrinsic complexity of the energy markets

- *Impact of policy decisions on prices and bills*

- 18.61 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. Government policies – particularly those designed to reduce harmful greenhouse gas emissions – are having an increasing impact on energy prices and bills (on the basis of current announced plans, the cost of such policies will amount to 37% of the retail price of electricity paid by households in 2020).
- 18.62 This dramatic increase in prices, combined with a lack of clear understanding of the factors (including government policies) driving the movement in prices, has caused public and political concern. This is likely

one of the high level contributory factors that led to our investigation and might also explain, at least in part, the adoption of certain decisions which in our view did not deliver positive outcomes for competition and consumers (see above, for instance the simpler choices component of the RMR rules and SLC 25A). We believe that better analysis regarding the state of the energy markets and the impact of the regulatory framework, on bills (including the trade-offs between different objectives) will positively influence the public debate and increase the robustness of the policy decision making process.

- 18.63 In relation to trade-offs between policy objectives, 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.
- 18.64 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.
- 18.65 In this report we have identified some policies that appear not to have achieved an efficient trade-off between these objectives. We consider that a lack of independent scrutiny of such policies is one of the factors that increases the risks of suboptimal policy design in the future.
- 18.66 For instance, in Sections 5 and 6 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 (potentially bringing forward investment by a short period of time) at a considerable cost against another objective (a 1% increase in electricity bills for a number of years).
- 18.67 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.¹⁴

- 18.68 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.
- 18.69 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 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 gas consumption, further subsidies are provided through the Renewable Heat Incentive to move away from gas heating towards renewable heating.
- 18.70 We are aware that there is a clear distributional rationale for subsidising VAT on energy consumption, since, as noted in Section 8, 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.¹⁵
- 18.71 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. In our view this emphasises the importance of clear, objective analysis to inform the public debate.
- 18.72 More generally, we note that the different measures that Government can put in place to reduce emissions vary considerably in terms of the cost they impose on customers, from measures that reduce overall costs to those that add considerably to them.¹⁶ Such differences would suggest that there may be scope for a more efficient trade-off between policy objectives.

¹⁴ Institute for Fiscal Studies (2013), *Energy use policies and carbon pricing in the UK*.

¹⁵ 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*.

¹⁶ Such differences can be presented in the form of what is generally called a 'Marginal Abatement Cost Curve'. See, for example, page 157 of [Annex B: Carbon budgets analytical annex](#).

- *Outcomes in the market in terms of firms' profitability*

- 18.73 We consider that trusted and transparent information on revenues, costs and the profits earned by energy firms is necessary to inform the public debate and reduce the risk of errors in policymaking, by providing clearer information about whether and where intervention is required. This is also likely to improve confidence in the regulator on the part of policymakers and the general public, which itself would improve the stability of the regulatory regime.
- 18.74 The absence of such trusted and transparent information is a material problem, undermining regulatory stability. Parliamentary select 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.
- 18.75 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.
- 18.76 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.
- 18.77 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.

- 18.78 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.
- 18.79 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.

Communication on the state of the markets forecast and actual impact of government and regulatory policies over energy prices and bills

- *Parties' views*

- 18.80 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:

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.

18.81 Parties responding to the provisional findings¹⁷ expressed widespread agreement with the CMA's provisional finding that there is a lack of effective communication of the ex ante and ex post impacts of policies and the trade-offs between different policy objectives, which gives rise to an AEC. The parties agreed that a clear communication of policy impacts ex ante and ex post, and of the interactions and trade-offs between forthcoming and existing policies, was essential to public debate about energy prices and effective future policy-making.

18.82 Similarly, in their responses to our provisional findings, parties supported our view that there are some shortcomings in DECC's analysis, including the lack of a cumulative evaluation of policies and independent scrutiny. While some parties were aware that DECC published ex ante impact assessments on all new individual policies, they pointed out that impact assessments focused only on the specific impacts of the policy under consideration and that there was little consideration of interactions with other policies. One party noted the recent move towards the retrospective evaluation of policies and said that this complemented impact assessments, although it observed that the number of policies selected for review might be limited due to the resources involved. Parties also commented on the need to ensure that analysis conducted by policymaking institutions was subject to challenge or scrutiny by an independent, external body. We note that some stakeholders were unaware that all of DECC's impact assessments are currently scrutinised by the Regulatory Policy Committee.

- *Current level of scrutiny*

18.83 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

¹⁷ Respondents included the Six Large Energy Firms, several small suppliers (Ecotricity, Opus Energy, First Utility) and consumer groups. The suppliers' trade body, Energy UK, stated that it looked forward to working with the CMA on its suggestions.

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.¹⁸
- (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.

18.84 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.

18.85 Our view however is that analysis of these issues is insufficient and not adequately trusted, which undermines the quality of the public debate and policy decision-making.

18.86 In particular, 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.

18.87 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 as well as the impact of renewable subsidy mechanisms) 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 properly identified.

¹⁸ NAO (27 June 2013), [Early contracts for renewable electricity](#).

18.88 We have assessed the existing level of scrutiny, both of individual policies and of the aggregate impact of the regulatory framework.

- *Assessment of individual policies*

18.89 As regards the assessment of individual policies that currently takes place, initiatives from government are subject to an impact assessment at the proposal stage.¹⁹ DECC typically produces an impact assessment in respect of each policy proposal which it seeks to introduce, prior to implementation. Assessments are carried out on an individual basis. Although a template is followed to ensure consistency of approach, this does not allow for comparison across policies or any kind of cumulative evaluation, as each assessment focuses on an individual policy in isolation, and against a case-specific baseline.

18.90 Trade-offs between policy objectives are typically considered as part of the impact assessment. For example, although a particular policy proposal may focus primarily on one policy objective (such as reducing emissions), the effect on other objectives is generally also considered as part of the cost-benefit analysis, either in monetised form, or otherwise quantified or, where neither is possible, as a qualitative assessment. Distributional implications (notably impacts on energy bills and prices) are also generally included.

18.91 Impact assessments carried out by government are subject to independent scrutiny by the Regulatory Policy Committee. The Regulatory Policy Committee is an independent advisory body the remit of which is to ensure that decisions are made on the basis of a robust, evidence-based policymaking process. The role of the Regulatory Policy Committee is to deliver external scrutiny of regulatory and deregulatory proposals put forward by government to ensure that the evidence and analysis presented in impact assessments are fit for purpose. It does not comment on the merits of policy proposals; its opinions are expressed as a red/amber/green rating, with a red-rated 'not-fit-for-purpose' opinion denoting not a flawed policy, but that the evidence as presented in the impact assessment is inadequate. All impact assessments must be assessed as 'fit for purpose' by the Regulatory Policy Committee.²⁰ The process permits the re-submission of impact assessments where these are not initially given a green rating. DECC has a strong track-record of producing 'fit for purpose' Regulatory Policy Committee assessments; since the Regulatory Policy Committee was

¹⁹ See [The Green Book](#) and [Better Regulation Framework Manual](#).

²⁰ They are then cleared by the Reducing Regulation sub-committee.

established in 2011, it has assessed 85% of DECC's impact assessments as fit for purpose.²¹

- 18.92 According to central government guidance, as enshrined in the so-called *Green Book*²² and *Magenta Book*,²³ policies should be reviewed in the context of a policy cycle, according to which they should not only be subject to ex ante appraisal but to ex post evaluation. In practice, evaluation has been carried out less systematically than appraisal.
- 18.93 Going forward, as a result of the *Better Regulation Framework Manual*, policies that impose a regulatory burden on businesses will be exposed to a post-implementation review. Review clauses should impose a statutory duty to carry out post-implementation reviews of the measure in a specified timescale, usually within five years of it coming into force. Review clauses are mandatory for all measures that regulate business (including both domestic and EU-derived measures).²⁴
- 18.94 The purpose of a review is to establish whether, and to what extent, the measure has achieved its original objectives. For that purpose, government shall publish a report of its review, including a post-implementation review impact assessment, and must obtain approval from the Regulatory Policy Committee. In particular, the review must address the following three questions, with a view to concluding whether the measure should be removed, renewed without any changes or amended: (i) are the policy objectives that led to the introduction of the measure still valid and relevant? (ii) if the objectives are still valid and relevant, is regulation still the best way of achieving those objectives, compared to the possible alternatives? (iii) if regulation is still justified, can the existing measure be improved?
- 18.95 DECC is currently in the process of identifying matters for priority evaluation.
- *Assessment of the aggregate impact of a package of policies*
- 18.96 There is already extensive information and analysis in the public domain in relation to energy policy (see above). For example, the Committee on Climate Change has a remit to report to government on emissions reductions, including assessment of the impacts of policies aimed at tackling

²¹ Impact assessments are also subject to peer review by other government departments; however, this is a more informal process and the reviews are focused primarily on the likely impacts of policies on the area of business for which those departments are responsible.

²² HM Treasury, *The Green Book: Appraisal and Evaluation in Central Government*.

²³ HM Treasury (April 2011), *The Magenta Book: Guidance for Evaluation*.

²⁴ Certain exceptions exist, for example time-limited measures that are subject to an existing 'sunset' clause which causes them to expire within one year of coming into force (sunset clauses provide for automatic expiry of the measure on a specified date).

climate change on energy bills and prices. DECC produces an annual report on the estimated impacts of energy and climate change policies on energy prices and bills, and National Grid has a statutory obligation to report on gas security of supply. The National Audit Office has a remit to report on the value for money of government expenditure and policies.

- 18.97 Ofgem carries out analysis on a wide range of areas, including security of supply²⁵ and energy prices and profits, and publishes various indicators designed to track, among other things, the profitability and the customer service performance of individual suppliers (see in this respect our proposed remedy on financial reporting below). We note also that Ofgem has committed to report annually on the retail energy markets, which has led to the publication in September 2015 of the first Retail Energy Market report.
- 18.98 The purpose of these publications is to ‘foster understanding, trust and confidence’ among stakeholders by publishing more information about the markets Ofgem regulates. They seek to track the contribution of the retail and wholesale markets – including the way in which Ofgem regulates them – in achieving the outcomes for consumers set out in its strategy. However, Ofgem does not scrutinise in this context government policies, which is an essential element of understanding the GB energy markets.
- 18.99 Despite the range of the analyses available, none takes an holistic approach and provides a picture of the overall impact of the regulatory framework on the GB energy markets; instead, different institutions tend to focus on specific policy objectives (eg the Committee on Climate Change on reducing emissions, National Grid on security of supply, Ofgem on the functioning of the markets).
- 18.100 While we understand this reflects the remit of each of these institutions, the segmentation of this analysis hampers in our view the objective to ‘foster understanding, trust and confidence among stakeholders’ in policy regulation and energy markets, and undermines a balanced and objective assessment of policy trade-offs.
- 18.101 Analysis has been done within government in the past setting out the aggregate impact of a broad range of climate change and energy policies in terms of social costs and benefits,²⁶ but this analysis has not been systematically updated (or at least communicated to an external audience).

²⁵ Ofgem (June 2014), *Electricity Capacity Assessment 2014*.

²⁶ See, for example, the Analytical Annex to the *UK Low Carbon Transition Plan, 2009*.

18.102 Another concern relating to the existing analysis available in the public domain relates to the lack of independent scrutiny (or apparent lack of independent scrutiny) in relation to certain aspects of energy policies. For example, where policies are evaluated by the policymaking body (eg DECC's assessment of the impacts of energy and climate change policies on energy prices and bills), there is a risk of engendering at least a perception of confirmation bias. Independent assessment is therefore important in order to evaluate existing policies and to ensure effective policymaking in the future. Trusted analysis is also crucial to inform the public debate on energy. Without such trust, effective debate is undermined.

- *Our assessment*

18.103 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, notably some elements of taxation. However, it is our view, for the reasons identified above (paragraphs 18.61 to 18.79), that some of the results are not communicated effectively and clearly to a broader audience, in particular interactions between policies and policy trade-offs within policies. The existence of disparate analyses, focusing on individual policies and/or on different policy objectives, creates considerable challenges for stakeholders to get access to, and link, all the available analysis. It might also lead to inconsistencies and confusion, as observed by some parties in their responses, and contribute to an overall lack of transparency of, and trust in, such analysis, which in turn, inhibits productive debate and effective policymaking.

18.104 For the reasons set out above, we believe that the quality of policy decision making and implementation (and more broadly, of the public debate) is undermined by a lack of shared understanding of the energy markets, in particular of the impact of policies on bills. We therefore consider that a more authoritative and independent assessment of the energy markets is necessary.

18.105 As noted above (see paragraphs 18.73 to 18.79), the lack of clear and trusted financial information about revenues, costs and the profits earned by energy firms are a key concern in this respect. We discuss below why we believe that the level of financial information concerning generation and supply activities that is currently available is not sufficiently clear and relevant to provide a trusted analysis of the energy markets.

Insufficiently clear and relevant financial information concerning generation and retail supply activities

18.106 As noted in Appendix 18.1,²⁷ Ofgem has taken several measures since 2008 to get a better understanding of costs, profits and profitability. In particular, it has decided to set up two financial reporting regimes, ie an ex post accounting regime under which the Six Large Energy Firms report their generation and retail supply profits for the previous financial year and an ex ante regime under which Ofgem estimates the margin that a typical large supplier could make over the following 12 months.

- *The current situation: ex post reporting regime*

18.107 Following the Energy Supply Probe in 2008/09, Ofgem has required the Six Large Energy Firms to publish separate profit and loss accounts for gas and electricity retail supply and generation ('segmental statements') annually. Specifically, pursuant to sections 16B and 19A²⁸ of the gas and electricity supply standard licence conditions respectively, Relevant Licensees (as defined in the standard licence conditions²⁹) are required to prepare and publish on their website a consolidated segmental statement³⁰ in respect of information relating to the revenues, costs and profits of their activities in the generation and supply of electricity and the supply of gas and electricity to any premises.

18.108 The evolution of the current ex-post reporting regime, from when it was first proposed by Ofgem in 2008 to the current position, is described in Appendix 18.1.³¹ We note that Ofgem has put considerable effort into setting up and improving this financial reporting obligation since its introduction in September 2010,³² and that this has influenced how some of the Six Large Energy Firms report their financial results. For example, some of the Six Large Energy Firms have adopted market-based transfer charging

²⁷ See Appendix 18.1, Financial transparency, Ofgem's initiatives to obtain further financial information.

²⁸ The current requirements under this reporting regime are set out in Standard Condition 16B of [Electricity Generation Licences](#) (p53) and Standard Condition 19A of the [Electricity](#) (p104) and [Gas Supply Licences](#) (p100). These licence requirements are supplemented by [Ofgem's reporting guidelines](#).

²⁹ Relevant Licensee means the holder of a supply licence if (a) it supplies, or it and any of its affiliates jointly supply: i. electricity to more than 250,000 domestic customers; or ii. gas to more than 250,000 domestic customers; or iii. electricity to more than 250,000 non-domestic customers; or iv. gas to more than 250,000 non-domestic customers, respectively; and (b) it or any of its affiliates is a holder of an electricity generation licence.

³⁰ We note that the term 'consolidated' in 'consolidated segmental statements' is unhelpful in the context of this regulatory reporting regime. This is because the purpose of the regime is to provide **segmental** rather than **consolidated** financial information.

³¹ See Appendix 18.1, Financial transparency, Use of Ofgem's powers to require segmental accounting information.

³² Ofgem (2010), [Update on Energy supply probe remedy: publication of segmental generation and supply accounts by energy companies](#).

practices.³³ We consider this to be an important positive development in terms of furthering the transparency of firms' financial performance.

18.109 The key elements of the current regulatory reporting regime (ie as reflected in the 2014 segmental statements) are that:

- (a) the profit and loss accounts are segmented by broad generation technology and broad retail customer type, in line with each of the Six Large Energy Firms' organisational structure;
- (b) no balance sheets are provided;
- (c) wholesale energy revenues and costs are measured diversely³⁴ (and therefore not comparably³⁵ across firms);³⁶
- (d) figures are prepared on a (modified) historical cost accounting basis;
- (e) there are no prior year comparatives;³⁷ and
- (f) the profit and loss accounts are audited and published in the form mandated by Ofgem.

18.110 Every year Ofgem publishes a document comparing and contrasting revenues, costs and profits across firms and across time, together with some commentary.³⁸

- *The current situation: ex ante reporting regime*

18.111 As noted in paragraph 18.106, in addition to the ex post regime described above, Ofgem has also developed an ex ante tool whereby, using a range of inputs, it regularly forecasts the expected evolution of retail supply margins over the following 12-month period for a typical large energy firm. This form of reporting was designed to show the impact on domestic prices of changes in input costs, most notably wholesale energy costs. Ofgem expected such forward-looking reporting to be relevant to the assessment of a competitive

³³ By *market based transfer pricing practices* we mean that transfer charges reflect the costs actually incurred by the firm, generally a mix of standard wholesale products traded on the open market and bespoke products.

³⁴ By *diversely* we mean that firms measure costs (and revenues for generation) using prices struck over a wide range in points of time for both their standard and bespoke purchases.

³⁵ We discuss the qualitative characteristic of financial information that is comparability in Appendix 19.1.

³⁶ See Appendix 18.1, Financial transparency, Annex A, Review of wholesale energy costs.

³⁷ Since their inception in respect of the 2009 financial year, each of the Six Large Energy Firms' published segmental statements provided results for the current period only even though each of the Six Large Energy Firms had also been active in the immediately preceding prior period in both generation and retail supply.

³⁸ For example, [the revenues, costs and profits of the large energy companies in 2013](#). For 2014 this analysis was included in Ofgem's [Retail and Wholesale Market Reports](#).

supplier's cost base. It was also intended to show whether suppliers' margins were increasing or not, in particular margins on the SVT tariffs, which account for around 70% of all domestic customers in Great Britain.

18.112 This initiative became known as the Supply Market Indicator (SMI). In May 2015, Ofgem suspended the SMI ahead of a review of the information it collected and published so that it could provide greater transparency about the market to inform the energy debate.³⁹

18.113 In its most recent form the SMI sought to compare the expected annual bill under the SVT of a typical large firm for a domestic customer with typical medium energy consumption against the costs⁴⁰ that Ofgem forecast that such a retail supplier would need to incur in order to supply that typical customer. Having established the forecast bill total (based on SVT prices) and associated costs, Ofgem then inferred a retail supply margin that this typical firm might be expected to earn in the following 12 months. For the wholesale energy cost element of this calculation, Ofgem estimated the cost it expected a firm typical of the Six Large Energy Firms to have actually incurred based on an 18-month stylised hedging strategy.⁴¹

- *Parties' views*

18.114 In our provisional findings, we set out the view that the Six Large Energy Firms' current ex post reporting systems were unable to provide the market-orientated financial information that regulators and policymakers required. We stated that the lack of a regulatory requirement for clear and relevant financial reporting had, in our view, contributed to a lack of financial transparency in the information available to Ofgem, and this had contributed to our then provisional Governance AEC.

18.115 As regards the lack of relevant financial information, we received a range of responses from the Six Large Energy Firms, other retail suppliers and generators, consumer advocates and academics regarding this possible financial reporting remedy. Whilst the consumer advocates and academics expressed their support for our findings and proposed remedy, most of the Six Large Energy Firms told us that they considered the existing reporting

³⁹ [Ofgem announces review of markets data.](#)

⁴⁰ Note that Ofgem did not attempt to forecast all costs that a retail supplier would need to incur, rather only the costs that would be accounted for in each Six Large Energy Firm's profit and loss account for retail supply. Such an approach would, for example, omit the costs of servicing working and other operational capital.

⁴¹ In 2008 as part of its Supply Probe work, Ofgem researched how the Six Large Energy Firms actually purchased wholesale energy. On the basis of its findings Ofgem used a strategy where costs are based on firms starting to purchase energy 18 months ahead of the time of delivery as its central assumption to track the relationship between wholesale costs and the domestic retail prices of the Six Large Energy Firms. See paragraphs 1.10 & 1.13 of [Ofgem's Methodology for Supply Market Report](#), 31 January 2012.

set up already provided a good level of financial transparency. In addition, SSE submitted that we had not provided any evidence to support our contention that there had been a linkage between Ofgem's lack of access to particular types of financial information on the one hand and poor policy interventions on Ofgem's part on the other.

- *Impact of the lack of clear and relevant information concerning generation and retail markets*

18.116 As discussed earlier in paragraphs 18.83 to 18.105, we are concerned by a lack of shared understanding of the evolution of GB energy markets. Concerns have been raised regularly since the liberalisation of the GB energy markets with respect to the evolution, and competitiveness, of domestic retail prices. These were caused, among other things, by a lack of clarity as to whether, and to what extent:

- (a) domestic retail prices were tracking changes in wholesale energy prices, as one might expect in competitive retail markets;
- (b) social and environmental policy decisions made by government were driving changes in retail prices;
- (c) energy firms had made excessive profits at the expense of certain categories of customers; and
- (d) differences in the prices charged by individual suppliers to different groups of customers (eg by payment methodology, tariff types) were objectively justified by differences in the cost of supply.

18.117 As discussed above, Ofgem has put in place financial reporting mechanisms seeking to acquire financial information that it believed would help it to address these concerns in an authoritative manner. For instance, it developed the SMI in response to a government request⁴² to help address concerns such as the so-called 'rockets and feathers effect'⁴³ and the consolidated ex post reporting regime in response to wider concerns (as those expressed by Parliamentary select committees, consumer groups, policy think tanks, Ofgem and political parties, among others, about the potential link between firms' profitability and prices, see paragraphs 18.74 to 18.78 above). The design of both reporting regimes has also been

⁴² [HM Treasury Pre-budget report November 2008](#), paragraph 7.69.

⁴³ That is the circumstance that increases in wholesale prices are reflected promptly and sharply in retail prices while decreases in wholesale prices are passed through to retail prices over a longer period of time.

influenced by the desire to help shed light on the impact of policy decisions on prices and profitability respectively.

18.118 The concerns we set out in paragraph 18.116 were part of the wider context at the time of Ofgem's decision to make a market investigation reference in respect of the energy markets. The inability to provide a cogent explanation for these concerns, and in particular for the dramatic increase in retail prices since 2004 has given rise to speculation as to the existence (and level) of energy firms' excessive profits, and as to the potential causes of such excessive profits (eg rockets and feathers effects, vertical integration, profits hidden within trading activities). There is also a lack of clarity of the net impact of environmental policies, not least because interventions to support these policies take place at more than one stage of the energy value chain.

18.119 In our view the current financial reporting measures put in place by Ofgem have at best only partially addressed the concerns identified above, failing to offer a robust basis to assess the state of the markets.

- *Key deficiencies in the current ex post financial reporting regime*

18.120 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, it is critically important that financial information is specified in a way that allows the user to discern performance in all (relevant) stages of the value chain and the impact of firms' use of forward markets for wholesale energy. In this respect, we have identified four key deficiencies in the current financial reporting regime.

- *Under the current reporting obligation firms' activities are separated along firm-specific divisional lines rather than relevant market lines*

18.121 The Six Large Energy Firms are all large businesses active in a number of different geographical markets (including the GB energy markets). We have found in their current financial reporting to Ofgem that the activities which each of the Six Large Energy Firms groups into its generation and retail supply divisions differ across the Six Large Energy Firms. This reflects their different choices about the best way to organise themselves internally across their value chain (ie divisional lines), and not necessarily the different markets in which they compete (ie market lines).⁴⁴ However, our view is that

⁴⁴ By this we mean that each of the Six Large Energy Firms makes its own choice on what it considers to be the most effective organisational set-up for its organisation as a whole. However, we do not see each of the Six Large Energy Firms to be competing in different product markets as regards GB generation and retail supply.

Ofgem needs financial information based on defined markets, rather than on firms' operating divisions, in order to be able to assess the state of competition in these markets.

18.122 More specifically, one shortcoming of the current regime relates to the approach to accounting for wholesale energy. For some of the Six Large Energy Firms, transfer charges across market boundaries are not always based on market prices for products available in the market at the time of the purchase or sale.

18.123 The lack of a requirement to prepare financial information on a market-orientated basis also undermines Ofgem's ability to compare financial reporting across firms since different firms take different approaches. This, in turn, makes it more difficult to provide a clear view as to what extent, for example, any retail price increases are driven by increased levels of profitability on the part of firms acting in retail supply or generation markets.

- *Firms are not required to provide a balance sheet as well as profit and loss account*

18.124 We also note that the Six Large Energy Firms are not currently required to provide a balance sheet for either their generation or their retail operations. As a result, Ofgem cannot undertake an analysis of the profitability of the Six Large Energy Firms' generation and supply activities, which would involve calculating the return on capital earned by such firms and comparing that return to a benchmark 'normal' rate of return.⁴⁵ When undertaking our profitability analysis within the context of this investigation, we also found that not all of the Six Large Energy Firms were able to provide robust balance sheet information, even at a broad market level. Thus any assessment of firms' performance is currently limited to that of profits. However, the level of profits does not by itself indicate whether there might be an issue with how a market is operating because it does not take into account the amount of capital employed that has been required to achieve those profits.

18.125 This is a particularly important issue for generation, as it is a very capital-intensive activity, but also applies to retail supply.

18.126 In Appendix 9.13, we set out our consideration of retail profit margins and the use of comparator firms as a means of benchmarking a competitive profit

⁴⁵ Currently Ofgem can compare margins across the Six Large Energy Firms (albeit not necessarily on market lines). However, an assessment of margins (or profits) does not enable an assessment of profitability because the latter requires all costs of supply to be taken into account, including those that relate to balance sheet items.

margin. We note that this is the approach that Ofgem has adopted as a means to assess profitability. When we sought to make comparisons between the margins earned in different customer segments, the Six Large Energy Firms submitted that we should take account of differences in risk and capital employed across these segments.

- 18.127 Our work in this area of margin assessment demonstrates the difficulties in identifying a suitable benchmark given the differences in capital intensity, risk profile and cost structure across firms. Selection of appropriate benchmarks for this purpose involves making a subjective overall assessment.
- 18.128 These observations highlight the benefits of a ROCE approach to evaluating profitability. This approach takes into account the level of capital employed by firms in an industry and the risks incurred in investing in an industry in a transparent way. The absence of a balance sheet prevents Ofgem from systematically taking into account capital intensity, and the associated risks,⁴⁶ in its profitability assessment.
- *Wholesale energy costs for retail supply are not disaggregated in a manner that allows Ofgem to understand the level of profitability of the Six Large Energy Firms' retail activities on a relevant and comparable basis*
- 18.129 The cost of wholesale energy is the single largest cost item in the profit and loss account for retail suppliers. However, the amounts reported for wholesale energy in firms' profit and loss accounts reflect each firm's purchasing strategy regarding both the timing⁴⁷ and choice of wholesale product. As wholesale energy prices can trend upwards or downwards over time, the level of reported costs, even for standard wholesale products, can be heavily influenced by the timing of purchases. Likewise, bespoke purchases delivered in the current period may well reflect prices negotiated some time ago and as part of a broader, multi-period agreement. However, the current financial reporting requirements do not allow for an assessment of the cost of wholesale energy to suppliers on a comparable basis across firms, nor do they allow for an assessment of the profitability of retail activities once the specific hedging strategy of the firms has been controlled for, ie excluding windfall losses or gains arising from trading activities.⁴⁸

⁴⁶ Through the assessment of the cost of capital for the capital employed in the business.

⁴⁷ ie how far ahead of the delivery period a firm agrees to purchase wholesale energy.

⁴⁸ This information is necessary to disaggregate out-turn financial performance between (a) a firm's performance as a prudent retail supplier operating in a competitive market, and (b) its performance as a purchaser of wholesale energy.

- *The absence of prior year comparatives*

18.130 Access to financial information that is prepared on a different basis from one reporting period to the next limits its usefulness in discerning trends. Greater comparability from one period to the next would help Ofgem and other stakeholders to better identify and understand similarities in, and differences between, financial performance for each firm from one period to the next.⁴⁹

- *Key weakness in the ex ante SMI regime*

18.131 From the perspective of the public policy debate and wider regulation, it is important that any reporting tool designed to help assess the competitiveness or otherwise of current prices, ie the prices of tariffs currently on sale, is based on an assessment of relevant costs.

18.132 There is a read-across between the issue we identify above in relation to ex post accounting information and the calculation of wholesale energy costs within the SMI. We observe that the measure of wholesale energy costs within the SMI is one that reflects a forecast of costs that would be historically incurred. Our view is that historically incurred costs are not the relevant basis on which Ofgem could infer trends in the strength of the competitive pressure on retail prices including the SVT over time. Retail prices would instead reflect the opportunity cost of energy.^{50 51}

- *Our assessment*

18.133 In summary, we have identified four key deficiencies in the existing ex-post regulatory financial reporting obligation:

- (a) Some firms' activities are separated along firm-specific divisional lines rather than relevant market lines.
- (b) Firms are not required to provide a balance sheet as well as profit and loss account.

⁴⁹ We discuss the issue of comparability more fully in Appendix 19.1.

⁵⁰ We discuss 'opportunity cost' in Section 19, *Design Consideration C: Disaggregation of wholesale energy costs for retail supply between standardised opportunity cost and residual elements*.

⁵¹ We note that the concern about the relationship between cost and price of retail energy has not been limited to wholesale energy costs. Stakeholders seeking to promote the interests of consumers have also had the desire to be confident that changes in retail prices attributed to changes in level of network costs and the cost to retail suppliers meeting environmental and social obligations, were also reflective of the cost of provision. The difference between wholesale energy on the one hand, and network and environmental and social costs on the other, is that there has been no consensus across all stakeholders about how to measure the cost of wholesale energy for these purposes.

(c) Wholesale energy costs for retail supply are not disaggregated in a manner that allows Ofgem to understand, for the purposes of its regulatory functions, the level of profitability of the Six Large Energy Firms' retail activities on a comparable basis.

(d) Firms are not required to provide prior period comparatives.

18.134 We believe that these deficiencies have contributed to a lack of shared understanding of market trends and of the nature of competition, which has contributed to the overarching feature that we have identified, ie a lack of robustness and transparency in regulatory decision-making.

18.135 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 conclude, rather, that the problem arises from a lack of relevant and consistent accounting across each part of the relevant value chain. In parallel, there has been a lack of stakeholder confidence in, and understanding of, the information provided under this financial reporting obligation, particularly around transfer charging, which may have exacerbated the issues set out above.⁵²

18.136 We also identified a weakness in Ofgem's currently suspended retail price monitoring tool, the SMI, namely that wholesale energy costs are based on a forecast of historically incurred costs, and not a measure that would be expected to inform prices in a competitive market.

18.137 We disagree with SSE's view that there is no evidence to support there being a link between the financial information that has been available to Ofgem and poor policy interventions on its part. We acknowledge that it is not possible to pin this link individually to any of the policy interventions implemented by government or by Ofgem since 2008. In our view, however, Ofgem's lack of access to suitably specified financial information means it is unable to provide a clear and robust analysis of market trends, prices and profitability. This in turn contributes to a climate where, under the influence of the public and political debate, ill-advised changes to the regulatory regime have been implemented, some of which, we have found, give rise to AECs.

⁵² Transfer charging can be used to transfer profits from one part of the value chain (eg retail supply) to another one (trading or generation). If these other parts of the value chain are either not subject to reporting requirements (eg trading) or make losses (eg generation), then the true extent of profitability can be disguised. Such a concern was evident in, for example, the questioning by the Energy and Climate Change Committee of the Six Large Energy Firms in 2013. See transcript [Energy Prices, Profits and Poverty](#), 29 July 2013.

- 18.138 For instance, we found that some decisions taken by Ofgem over the last few years (eg SLC 25A and the simpler choices component of the RMR rules), which in our view were not based on robust analysis, have had adverse effects on consumers. Both measures were taken in the wake of the Energy Supply Probe, which found that the market was not working in the best interests of consumers⁵³ but failed to provide a clear narrative in respect of increases in retail prices and energy firms' profitability.⁵⁴ Secondly, SSE's view takes no account of the risk that certain regulatory steps which may have properly and effectively addressed market failures were not taken (or even considered) because of a lack of clear and robust understanding of the state of the markets. A regulator's ability to undertake properly informed analysis is self-evidently an important element of effective regulation.
- 18.139 In our view, had clearer and more relevant information been available to Ofgem, it would have been in a position to provide a more robust analysis of the markets which would have led to more robust decisions being taken in the best interests of consumers.
- 18.140 The reason why these concerns continue to arise is primarily because Ofgem has not sufficiently specified the content of the outputs to be reported. In relation to ex post financial reporting, the Six Large Energy Firms have in practice been given latitude to report their performance (profit and loss account only) largely in line with what they chose to report for statutory reporting purposes, rather than with the aim of seeking to address public policy concerns such as those identified in paragraph 18.116. This is what we mean by the lack of a regulatory requirement for clear and relevant financial reporting concerning generation and retail profitability.
- 18.141 In our view, financial information should be specified on a market lines basis so as to give a clear indication of the financial outcome of competition that is comparable across firms. This in turn would help provide insight on the intensity of competition in the relevant market. This analysis, in conjunction with other relevant evidence, would help Ofgem to provide a trusted assessment of the state of the markets, including by providing a clear explanation of the factors having an impact on prices and bills. Our view in

⁵³ [Ofgem Energy Supply Probe](#).

⁵⁴ Noting that the Six Large Energy Firms' generation activities at that time appeared to be profitable, the relevant select committee recommended that Ofgem conducted further work to understand where the profits were being made in the value chain. See [House of Commons - Business and Enterprise Committee: Energy prices, fuel poverty and Ofgem](#), paragraph 56. The Energy Supply Probe did not find excess profits because assessment of suppliers' profitability was difficult. See [Ofgem Energy Supply Probe - Initial Findings Report](#), paragraphs 8.2–8.4 and conclusions after paragraph 8.79.

this matter has been grounded in own experience of using the Six Large Energy Firms' financial information as the starting point for our profitability and other analysis as set out in Appendix 18.1.⁵⁵

- 18.142 Within the context of this energy market investigation, we have sought to provide a coherent representation of the functioning of the energy markets. As a result, we have identified a number of AECs, and the features that give rise to them, but have also tried to clear the air of speculations which, in the light of all our analysis, do not reflect reality. For the purpose of addressing concerns such as those set out in paragraph 18.116, we decided that the financial information available to Ofgem was insufficiently clear and relevant and therefore decided to require in some respects differently specified and additional information from relevant parties.
- 18.143 As set out above, Ofgem's inability to address concerns about the Six Large Energy Firms' profitability with the information they currently obtain, not least those stemming from perceptions of there being a 'rockets and feathers' effect in relation to movements in wholesale prices, was a significant driver of the set of circumstances which ultimately led to those Ofgem policy interventions which in Section 9 we concluded have led to AECs.
- 18.144 Our view is that the deficiencies we have identified in the current reporting regimes all contribute to a lack of transparency in the costs, revenues and capital employed (and hence profitability) in retail and generation markets. This lack of transparency has directly led to Ofgem making this market investigation reference, and were it to continue, would hinder its ability to act effectively in the future.

Our conclusions on the broader regulatory and institutional framework

- 18.145 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.
- 18.146 In relation to its regulatory interventions, 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 (or at least cause some confusion as to the place in the legislative hierarchy regarding) Ofgem's ability to pursue its principal objective 'wherever possible by promoting effective

⁵⁵ See Appendix 18.1, Financial transparency, Our diagnosis of the Six Large Energy Firms' accounting information.

competition'. This in our view is likely to increase the risk of Ofgem carrying out inefficient trade-offs between competing objectives, which in turn would lead to regulatory decisions that adversely impact competition.

- 18.147 We have also noted that the overlap of roles between DECC and Ofgem has led in the past, and if left unchanged is likely to lead again, to inconsistent interventions and 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 is likely to harm transparency, the independence of regulation, and consumers' confidence in the regulatory and policy decisions that are taken. This in turn is likely to undermine the robustness of policy decision making and implementation.
- 18.148 In relation to the impact of government policies, we have considered whether there is a lack of independent and authoritative assessment of the costs and benefits of different proposed and existing policies, including the trade-offs between different policy objectives, and/or a lack of information and analysis regarding the energy markets on which to base robust decisions. While we noted that there are already several independent institutions that scrutinise these costs and benefits, we consider that clearer communication around these issues is necessary to increase the transparency of the information already available. This would improve the quality of the public debate and policy decision-making.
- 18.149 Lastly, 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 in turn prevents Ofgem from providing a clear and trusted analysis of the energy markets. In our view market-orientated financial information is necessary to ensure the robustness of the decision making process.
- 18.150 Our conclusion is therefore that a combination of features of the wholesale and retail energy markets in Great Britain give rise to an AEC (the Governance 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) Ofgem's statutory objectives and duties which, in certain circumstances, may constrain its ability to promote effective competition.

- (b) The absence of a formal mechanism through which disagreements between DECC and Ofgem over policy decision-making and implementation can be addressed transparently.
- (c) The lack of effective communication on the forecast and actual impact of government and regulatory policies over energy prices and bills.
- (d) The lack of a regulatory requirement for clear and relevant financial reporting concerning generation and retail profitability.

The governance of industry codes

18.151 Regulation of a number of aspects of the energy markets is governed by industry codes, which are managed by industry participants themselves. Whereas, at the time of privatisation, there were two codes covering largely technical matters, there are now 11 codes, comprising over 10,000 pages of rules that cover a range of commercial and policy areas. We are concerned that, where these rules affect competition and customers, Ofgem has insufficient ability to influence decision making, giving undue influence to established industry participants whose interests are not aligned with those of customers.

18.152 In this section we set out these concerns in more detail, in particular, 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.⁵⁶ 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.
- (c) We assess whether the current code governance and modification arrangements fail 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 processes.

The current system of codes

18.153 The functioning of the governance framework for codes has a significant impact on consumers' interests and competition. Since privatisation, and as

⁵⁶ This section draws on Appendix 18.2, which provides further detail on the current system of code governance.

the GB energy markets have undergone the process of liberalisation, the role of codes within the wider regulatory framework has evolved dramatically.

18.154 Originally, codes were mainly a tool for setting out common technical rules and standards for the upstream part of the sector.⁵⁷ Under the current regime, codes perform two additional critical functions: firstly, they enable the implementation of high-level policy objectives such as security of supply; and, secondly, they underpin dynamic competition within the retail energy markets.

Overview of codes

18.155 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).

18.156 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.

⁵⁷ The two industry codes set up at the time of privatisation, the Grid Code and the Distribution Code (defined in Appendix 18.2 as the 'technical codes') were intended to provide technical rules relating to the upstream part of the sector.

18.157 For gas, the codes include:

- (a) Uniform Network Code;
- (b) Independent Gas Transporter Uniform Network Code; and
- (c) Supply Point Administration Agreement.

Ofgem and DECC's powers to modify and enforce industry codes

18.158 Ofgem and the relevant legislation 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.

18.159 Ofgem, in effect, has established the substantive provisions of the industry codes as a domain of limited industry self-regulation within the wider regulatory framework.

18.160 Ofgem has the general power to modify standard licence conditions⁵⁸ but does not have an equivalent power to directly modify industry codes.⁵⁹ While in principle it could alter licence conditions to then require or effect a change in the codes, this is not the approach taken. 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, and it may be the 'effective progenitor' of code modifications (either by way of a Significant Code Review (SCR) or less formally).

18.161 In general, DECC's ability to influence the industry codes is concentrated in its power to designate the initial version of each industry code. On occasion, DECC has directed amendments to certain codes under legislation enacted for that purpose.⁶⁰ Through the choice of this arrangement, Ofgem and

⁵⁸ Section 23 of GA86 and section 11A of EA89.

⁵⁹ This statement is subject to one exception, found in section 36C of GA86, which gives Ofgem the power to modify the Uniform Network Code for the purpose of implementing modifications related to gas security of supply.

⁶⁰ For example, the Secretary of State for Energy directed amendments to the BSC in relation to the EMR under powers contained in the Energy Act 2013.

DECC have signalled that industry will be responsible for driving the ongoing substantive development of the industry codes in most cases.

18.162 The detailed governance and modification arrangements for each industry code are set out in the codes themselves. Ofgem has set out a formal structure that industry must 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.⁶¹ 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.

Complexity and number of codes

18.163 As noted above, codes are critical for the functioning of the regulatory framework. However, they are also largely responsible for the complexity of that system. Indeed, following the introduction of eight⁶² codes since privatisation, the codes now include 10,000 pages of legally binding rules. The sheer complexity of this system may increase the risk of certain inefficiencies⁶³ and introduces substantial costs which might disincentivise both Ofgem and certain industry participants from engaging efficiently with the code governance framework.

⁶¹ 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.

⁶² In Appendix 18.2 we note the following codes as having been introduced since privatisation (they are collectively referred to as the 'commercial codes'): for gas, the Uniform Network Code, the independent Gas Transporters' Uniform Network Code and Supply Point Administration Agreement; and, for electricity, the Balancing and Settlement Code, the Connection and Use of System Code, the Master Registration Agreement, the System operator – Transmission owner Code and the Distribution Connection and Use of System Agreement. We note that this list does not encompass two further codes that are outside the scope of this report: the Green Deal Arrangements Agreement and the Smart Energy Code.

⁶³ For instance, the complexity of the system increases the risk that analysis to assess the benefits of a particular modification proposal is duplicated due to a lack of coordination between stakeholders (which typically results in Ofgem using its 'send back' powers to require a code panel to carry out further analysis, causing further delays).

- 18.164 The complexity of codes and the related governance arrangements creates significant compliance costs for industry participants. These costs are likely to discourage parties from fully engaging with consultations and other relevant processes. This is a particular concern due to the fact that these costs will weigh most heavily on smaller parties, which are a major potential source of pro-competitive innovation.
- 18.165 We solicited views from parties on whether the fragmentation of industry codes relating to the electricity market⁶⁴ 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.

Parties' views

- 18.166 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.⁶⁵ The consolidation of substantive provisions into one single code (as for gas) would have limited benefits.
- 18.167 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 modification proposals have consequential impact on other codes ('cross-code modifications').
- 18.168 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,⁶⁶ which helps new suppliers to enter the electricity supply market. Indeed, under this regime, entrants may partner with an existing

⁶⁴ Compared to the gas market, where the bulk of code regulation is carried out through the Uniform Network Code.

⁶⁵ The views of parties are set out in more detail in Appendix 18.2.

⁶⁶ Ofgem introduced the Licence Lite option by modifying electricity supply standard licence condition 11.3. See Ofgem's [Licence Lite guidance document](#).

larger supplier as an alternate form of compliance with certain of the industry codes (specifically the MRA, DCUSA and BSC).

- 18.169 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).
- 18.170 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 Energy⁶⁷ 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 guidelines⁶⁸).

Our assessment of the general scheme of industry codes regulation

- 18.171 The general scheme of industry codes regulation is the basis for a decentralised system of governance. Each of the industry codes has bespoke governance and modification arrangements. Although differences across codes may be justified, 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.
- 18.172 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.⁶⁹ We believe that these initiatives are helpful and note that Ofgem has recently adopted final proposals following the third phase of its Code Governance Review which include changes that will lead to further harmonisation.

⁶⁷ [Cornwall Report on Credit and collateral in the GB energy markets](#).

⁶⁸ See Ofgem’s [Best practice guidelines for gas and electricity network operator credit cover](#).

⁶⁹ These are described in Annex C – Overview of principles set out in the Code Administration Code of Practice of Appendix 18.2.

- 18.173 Overall, it appears to us that, to some extent, the complexity of codes reflects the complexity of the industry and the technical and commercial relationships between market players. We recognise however 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 18.2.
- 18.174 As regards the specific issue relating to collateral requirements under industry codes, we note that a number of recent modification proposals⁷⁰ 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.⁷¹ Finally, we note that collateral requirements under energy codes are significantly smaller than those under energy trading contracts. For these reasons, we have found that this issue does not constitute, or contribute to, an AEC.

Code governance and modification arrangements

- 18.175 The GB energy sector 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 technological and policy developments.
- 18.176 While, as noted above, we believe the current system of industry-led regulation is appropriate for the purpose of regulating many aspects of the regulatory framework, there are risks attached to industry-led regulation, in particular in circumstances in which the industry has conflicting interests or where the industry lacks sufficient incentives to carry out changes. If industry-led regulation fails to ensure that industry codes keep pace with market developments and wider policy objectives, then it is possible that

⁷⁰ 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.

⁷¹ 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).

these industry codes become a barrier to pro-competitive change and/or innovation.

18.177 Our central concern is that inefficiencies in the process, combined with the limited ability of Ofgem to influence the development and implementation processes when appropriate, 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 governance and modification arrangements that might be implicated in some of the problems we highlight.

Case studies

18.178 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.

18.179 Annex A to Appendix 18.2 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 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.

18.180 We found that each one of these case studies provides some important insights into difficulties in the code modification process. We concentrated 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.

18.181 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.

- 18.182 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.
- 18.183 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.
- 18.184 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 Annex A to Appendix 18.2). 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.
- 18.185 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.

- 18.186 What is clear, however, is that, with respect to Project Nexus, a more efficient implementation process could, and should, have been put in place at the outset. As noted above, in view of the delays in implementing this modification proposal, Ofgem decided to 'step in' and take an 'overall sponsorship role for Project Nexus' in March 2016. Having done so, Ofgem has found a lack of coordination between separate IT projects (carried out by Xoserve but also by each individual shipper, transporter and supplier) which must all interoperate to deliver Project Nexus. As a result of this, we understand that the implementation date of 1 October 2016 is unlikely to be achieved, as it would carry the risk of problems in the gas settlement process with adverse consequences for energy customers if implemented by that date. This in our view demonstrates that more effective project management (in which Ofgem would have a role) is necessary within the context of complex implementation processes that require interaction between multiple parties.
- 18.187 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 18.2 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.
- 18.188 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 Uniform Network Code 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 53 months to date, and is not yet completed.
- 18.189 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'.

18.190 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.

Ofgem's Code Governance Review

18.191 As discussed in more detail in Appendix 18.2, Ofgem has been active in trying to solve some of the issues identified above. Within the context of its Code Governance Review, 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.

18.192 In order to address these two deficiencies, Ofgem has decided to implement – in three phases (2010, 2013 and 2016) – a package of measures seeking to improve the governance and modification arrangements of the industry codes. The measures introduced by the first two phases of that process include:

- (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.

- 18.193 In its proposals for the third phase of the Code Governance Review, which are yet to be implemented, Ofgem has proposed measures to introduce new variants of the existing SCR process that will give it greater control over the development phase of the process. It has also proposed establishing the self-governance procedure as the default 'modification route' for modification proposals. In addition, the final proposals under the third phase of the Code Governance Review include measures to increase the accountability of code administrators and for code administrators to have additional responsibilities around the management of modification proposals and the development of forward work plans. Finally, code administrators will also be responsible for developing a coordinated cross-code impacts identification process for modification proposals.
- 18.194 Ofgem has recently expressed its concerns that the Code Governance Review measures have not fully addressed the systemic issues which it first identified in 2007 and, as a result, it is considering that wider institutional reform, beyond the mere strengthening of the Code Governance Review measures, is required. In its final proposals following the third phase of the Code Governance Review, it explicitly noted that these proposals were incremental improvements that would help code administrators and the wider industry to prepare for the more fundamental changes proposed by the CMA in its provisional decision on remedies. We also note that 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. It has also posed to us, in response to our provisional findings, 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.

The code governance arrangements

- 18.195 Three main entities form part of the governance framework for the industry codes: Ofgem, code panels (which are comprised mainly of industry participants) and the code administrators. Together, those entities are responsible for the functioning of the code system and ensuring that the codes keep pace with wider industry developments. Appendix 18.2 provides a description of the current governance arrangements and modification processes. Our assessment of the current roles and functions that each of those three main entities perform within the code governance arrangements is set out below.

- *Ofgem*

18.196 Under the current regime, Ofgem has two main functions in relation to delivering code changes that impact on consumers' interests and/or competition: first, to review (and, where appropriate, approve – it must approve unless there is a negative impact) all material code changes (its 'gatekeeper' function); and, second, to deliver complex or cross-cutting code changes through a SCR when the ordinary industry-led process has failed to do so (its 'gap-filling' function⁷²). Ofgem does not currently have direct responsibilities (other than as derive from fulfilling its statutory duties) to manage codes and typically only interacts with them in the limited contexts described above.

18.197 We support Ofgem's gatekeeper role. Ofgem is uniquely qualified to perform this function due to the strict legal requirements which protect its independence. Ofgem's obligation to consider its wider statutory duties and objectives in deciding on code changes also helps to ensure that the codes regime is adequately 'joined up' with the wider regulatory framework.

18.198 Analysed as a package, however, we consider that there are several interrelated issues with Ofgem's current functions and role in relation to codes including a lack of role clarity, the absence of a truly strategic role, and a lack of adequate discretion to intervene in the codes regime.

18.199 The particular configuration of Ofgem's functions has led it to intervene in the codes regime in a reactive and somewhat ad hoc manner. For instance, the code changes that Ofgem reviews as part of its gatekeeper function are almost solely⁷³ the product of industry initiative. Similarly, Ofgem has, in the past, not seemed to be willing to exercise its gap-filling function until it is clear that the ordinary industry-led process has failed to address an issue or is incapable of doing so. From an external perspective, this makes it hard to understand whether or how interventions are consistent with a single codes agenda and, as a result, the extent to which Ofgem and the industry are responsible for system-level developments.

18.200 As a separate matter, we are concerned that Ofgem has not sufficiently sought to develop its resources, expertise, powers and involvement in the code governance framework in a manner commensurate with the increased importance of that framework to competition and consumers' interests.

⁷² Ofgem does also, on occasion, act as the 'effective progenitor' of a modification by liaising with the industry on an informal basis.

⁷³ The exception to this rule would be code changes initiated following the SCR process, which has occurred infrequently in practice.

18.201 In summary, our concerns with respect to Ofgem's role in the current regime are the following:

- (a) In the absence of comprehensive wider strategic expectations or objectives set by Ofgem in those contexts, industry participants are not given strategic signals which they can use to guide their allocation of resources across the portfolio of pending and ongoing code changes, which increases the risk that they allocate their resources inefficiently in the light of Ofgem's expectations, which may lead to delays in modifications processes and, ultimately, the delivery of code changes beneficial to consumers' interests and/or competition.
- (b) Ofgem's functions do not drive it to grapple with important system-level issues such as whether there is inefficient duplication across codes and whether the substantive scope of the codes is appropriate, undermining its ability to assess the impact of the wider regulatory framework.⁷⁴
- (c) Ofgem's ability to intervene in the code regime is limited to either providing informal input through its attendance at code panel meetings and responses to relevant consultation documents, or to exercising its SCR powers to influence the initiation and prioritisation of code changes. While the former tends to be of low impact, the SCR process is an inflexible and resource-intensive⁷⁵ tool that is only appropriate to address the most significant and complex code issues (the same can be said of seeking to amend codes via licence changes). This leaves Ofgem without the discretion to opt to intervene in an intermediate capacity in situations in which its input may be highly beneficial (eg scoping of analysis).

- *Code panels*

18.202 Each industry code mandates the establishment of an internal management board (in this context termed a 'code panel'). In practice, the code panel takes key decisions concerning the development and recommendation of modification proposals.

18.203 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.⁷⁶ Our view is that the current

⁷⁴ An example of the issues that may result from the current arrangement is the inefficient governance of the distribution of gas tariff pages, as noted above.

⁷⁵ One indication of this fact is that the SCR processes so far have taken much longer to complete (40 months on average) than Ofgem's anticipated time frame (18 months).

⁷⁶ Appendix 18.2.

representation of industry participants on code panels, in the light of the nature of each code, achieves a fair balance.

18.204 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.⁷⁷ 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, it is essential that the governance structure of each industry codes contains adequate mechanisms 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, the principal mechanism in place for that purpose is the code administrator.

- *Code bodies (code administrators and delivery bodies)*

18.205 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 18.2).

18.206 We are concerned that, in the context of some codes, code administrators do not play a sufficient role in supporting the code governance arrangements. Currently, the core role that code administrators perform is secretarial in nature.⁷⁸ Some code administrators seem to have limited resources and expertise to assist the industry and Ofgem beyond a secretarial role. This is particularly problematic given the need of smaller code parties for support to engage with codes, due to their complexity, in particular in the contexts of submitting and progressing modification proposals. Therefore, we consider that there is scope to expand the role of

⁷⁷ See Appendix 18.2 for a further discussion of this issue.

⁷⁸ We note that in 2010 Ofgem's Code Governance Review introduced a secondary role for code administrators to act as 'critical friend' for the purpose of facilitating industry participants' engagement in the governance and modification arrangements. We note further that while some code administrators perform an additional range of substantive functions, including, for instance, the performance of analysis, we note that such work tends to be undertaken on an ad hoc basis rather than as part of a clearly defined role.

code administrators to take on project management responsibilities that do not sit naturally with Ofgem, given its role of economic regulator.

- 18.207 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).
- 18.208 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.
- 18.209 The above factors have led us to believe that additional supporting mechanisms are needed to ensure that code administrators are appropriately incentivised to perform to a consistent standard and with the right set of objectives. We consider that combining clear accountabilities for code administrators with an expanded manager role for those entities would help to ensure that there is a clear 'owner' of day-to-day responsibilities linked to the delivery of code changes (see Appendix 18.2).

Code modification arrangements

- 18.210 The code modification arrangements 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.

18.211 Following the first two phases of Ofgem’s Code Governance Review, a modification proposal could be progressed through one of the three following ‘modification procedures:’

- (a) the ordinary modification process;
- (b) the SCR; or
- (c) the self-governance process.

18.212 Each of the modification processes 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.

18.213 Table 18.1 provides an overview of the participation by different stakeholders in the various stages of the three modification procedures.

Table 18.1: Alternative processes for modifying codes

<i>Modification procedure</i>	<i>Modification stage</i>			
	<i>Initiation*</i>	<i>Development</i>	<i>Decision</i>	<i>Implementation</i>
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.

18.214 We discuss below our assessment of the functioning of each of the three main modification ‘routes’.

Ordinary modification and SCR processes

18.215 As noted above, under the current ordinary modification process, each modification proposal must pass through four sequential stages: initiation, development, approval and implementation. The development stage can be further broken down into several essential functions, including: prioritisation

of modification proposals, the performance of analysis, project management (which is also an essential function in the context of the implementation stage) and the drafting of the modification report (and the legal text).

18.216 Modification proposals initiated through the SCR process must also pass through the four main stages described above. However, in addition to those stages, the SCR process inserts prior to the initiation stage an Ofgem-led analysis stage which includes an exploratory assessment of the underlying issues.

- *Initiation*

18.217 Within the context of the SCR process, and unlike for the ordinary process (where the proposal is made by a panel member – though on occasion this is elicited by informal liaison by Ofgem), Ofgem provides early scoping of issues, performs analysis of the area of regulation that requires a code modification, and can also control a limited number of procedural elements. However, after Ofgem has performed its analysis, the modification proposal must then be raised by an industry participant (pursuant to an Ofgem-issued direction) and go through all the stages of the ordinary procedure.

18.218 For the purposes of the ordinary modification process, 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.

- *Development*

18.219 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.

18.220 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.

- 18.221 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.
- 18.222 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.
- 18.223 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 18.2)
- 18.224 The case studies discussed above and in Appendix 18.2 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.
- 18.225 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.
- 18.226 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).

18.227 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 Uniform Network Code, 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.

18.228 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.

18.229 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.

- *Decision*

18.230 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.

- *Implementation*

18.231 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.

18.232 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).

18.233 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.

18.234 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.

18.235 We note that a number of measures are in place to facilitate cross-code modification measures (see Appendix 18.2). 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 assessment*

18.236 In light of our findings above, analysis of stakeholders' capacity and parties' responses, we consider that the following aspects of the current ordinary and

SCR processes are a cause of inefficiency, which in turn lead to delays in the delivery of code changes:

- (a) The absence of 'strategic principles' for identifying and prioritising code changes that are necessary to keep pace with regulatory developments and other policy objectives.
- (b) Insufficient coordination between Ofgem and industry.
- (c) The excessive length of the typical SCR process that in practice has disincentivised Ofgem from initiating an SCR in all appropriate instances.
- (d) Insufficient project management of the development and implementation stages of strategically important or complex modification proposals.
- (e) Ofgem's limited ability to influence, and hold accountable, entities responsible for the development and implementation of code changes.
- (f) The lack of a central entity capable of identifying, and coordinating the development of, cross-code changes.
 - o *Absence of strategic principles for identifying code changes*

18.237 The lack of such principles means that there is no mechanism to distinguish between the roughly 70% of code changes that pass through the ordinary process, ie those code changes that meet a basic definition of materiality. As the possible spectrum of materiality in this context is extremely broad, the absence of overarching principles within the current system increases the likelihood that stakeholders allocate their (scarce) resources inefficiently and in an inconsistent manner across codes.

18.238 We note that under the current regime Ofgem can only provide industry with signals as to its overarching code development objectives and priorities through the use of its SCR powers. However, in our view, Ofgem's utilisation of the SCR process can only provide such signals in an ad hoc, piecemeal fashion, and puts a lot of pressure on Ofgem's resources due to the requirement to carry out extensive analysis. This type of involvement may be appropriate for the most important (and exceptional) modification proposals, eg those initiated through the SCR process. Our concern is that, short of using the resource-intensive SCR process (see below), Ofgem has no other mechanism to assess the materiality of modification proposals and adapt the level of its involvement in the development of any given modification proposal.

18.239 The combination of this restricted choice framework and the sheer number of modification proposals that go through the ordinary process means that, in practice, Ofgem usually does not get involved in the development of ordinary modification proposals until a recommendation is made by a code panel. This is a concern because any substantive involvement by Ofgem at this stage is likely to cause avoidable delay in the process. Therefore, we consider that the current regime is missing a mechanism that establishes an overarching, cross-code framework for assessing the materiality of code changes, and for adapting accordingly the level of resources and (early) involvement from Ofgem.

- *Insufficient coordination between Ofgem and industry*

18.240 Ofgem has been forced to use its send back powers on several occasions following a recommendation made by a code panel at the end of the industry-led development stage. In each instance, we consider such action by Ofgem to be an indication that it was not satisfied with the scope or depth of the analysis carried out by the industry. This suggests that there is a general lack of oversight by Ofgem over the analysis performed by modification work groups, which, in turn, may lead to the duplication of analysis and therefore to additional costs and delays. Currently, Ofgem can only influence the development stage formally through its SCR powers, which, as noted above, is a resource-intensive process that is not likely to be an appropriate option in most cases. Whilst Ofgem could engage informally with the industry, the frequent use of its send back powers indicates that Ofgem has insufficient ability and/or incentives to engage early in the development stage in order to improve the scoping of analysis.

- *The excessive length of the typical SCR process that prevents Ofgem from initiating an SCR in all appropriate instances*

18.241 We have noted three main issues with the current SCR process:

- (a) firstly, the SCR processes so far have taken much longer to complete (40 months on average) than Ofgem's anticipated timeframe (18 months);
- (b) secondly, Ofgem lacks the ability to drive forward SCRs that become 'stuck' during the industry-led stages (eg by mandating timetables); and
- (c) thirdly, Ofgem has only exercised its SCR powers on four occasions since it established the process in 2010, which has forced several significant modification proposals (eg Project Nexus and half-hourly settlement) to pass through the ordinary process, with the result that

they have not been adequately resourced or project managed, which has ultimately caused delays in the delivery of those modification proposals.

18.242 We have also identified that Ofgem does not have significant expertise or resource to devote to codes issues and, as a result, it is constrained from utilising the SCR process efficiently. This is because, in its current format, each SCR process is rigidly resource-intensive: once Ofgem launches an SCR, it in effect commits to perform the 'SCR gate' consultation, which takes six weeks, as well as all required analysis to enable it to provide the industry with meaningful SCR directions, which according to its own published guidance will typically take around a year.

- *Insufficient project management of the development and implementation stages of strategically important or complex modification proposals*

18.243 Across the case studies, we observed several instances in which avoidable delays occurred during the development and implementation stages as a result of insufficiently robust project management. Code panels have some power to provide oversight (eg by approving the terms of reference for modification work groups), but they are (perceived as) insufficiently independent from the industry to be relied upon to provide robust project management. Code administrators, meanwhile, do perform a limited form of project management (eg by drafting the terms of reference and providing secretarial support), but are constrained by their lack of formal powers to compel other code parties and, with few exceptions, by their resources. We note that some code administrators may have insufficient incentives and/or ability to project manage modification proposals.

18.244 In the context of some codes, project management of modification proposals by the code administrator is made possible due to the existence of a project assurance framework or a contractual arrangement between the code administrator and the relevant code parties. In those circumstances, the project assurance framework or contractual arrangement generally creates an obligation on the code administrator to carry out project management functions while obliging the relevant code parties to facilitate the code administrators' fulfilment of that obligation. However, and as noted above, for several codes there are no such arrangements in place. In any event, the use of project assurance frameworks or contractual arrangements has limitations because it does not grant Ofgem the ability to hold any party directly accountable for its performance.

18.245 We also recognise that, to a degree, centralised project management is hampered by the inherently fragmented nature of the implementation

process. This is due to the fact that each code party (ie system owner) is individually responsible for transposing the legal text of a modification proposal into its own relevant systems.

- *Ofgem's limited ability to influence, and hold accountable, entities responsible for the development and implementation of code changes*

18.246 Outside of the context of the initial stage of the SCR process, in which Ofgem directly oversees progress, development and implementation is left to the code panels, individual code parties and code administrators, with Ofgem's role limited to its gatekeeper function. Given this arrangement, we view it as a particular cause for concern that Ofgem can hold neither code panels nor code administrators accountable for their performance in this context.

18.247 Code panels and code administrators are essentially unlicensed private entities, with the result that Ofgem has limited powers to direct them and to sanction them for failing to progress or implement code changes on a timely basis. In relation to code panels, Ofgem could in theory seek to hold licensed employers of code panel members responsible, though in practice this course of action would be fraught with difficulty. We also recognise that an additional complicating factor in relation to code administrators is that there is no common approach to funding or contracting code administration services.

18.248 A separate cause for concern is that Ofgem does not seem to be willing, in certain circumstances, to hold individual code parties accountable for failing to implement approved modification proposals in a timely manner. An illustration of this issue emerged in the context of the implementation of Project Nexus, where the lack of established protocol and the sheer number of implicated code parties appeared to deter Ofgem from taking enforcement action against non-performing parties. However, we note that RWE npower has raised a modification proposal seeking to establish an accountability mechanism within the Uniform Network Code (ie which does not require Ofgem enforcement) for the purpose of incentivising code parties to complete implementation of Project Nexus by the proposed deadline.

18.249 We have not formed a view on this particular modification proposal, but consider it necessary to ensure that code parties have sufficient incentives to implement approved changes in a timely manner. We believe that the industry and code administrators may have a role in identifying circumstances where additional resources (eg the appointment of an external project manager) are required to ensure timely implementation. We also believe that mechanisms should be in place to monitor code parties'

compliance with their obligations, in order to facilitate Ofgem enforcement where necessary.

- *The lack of a central entity capable of identifying, and coordinating the development of, cross-code changes*

18.250 Under the current arrangements, the two principal mechanisms in place to ensure the coordination of cross-code changes are the SCR process and the non-binding obligations placed on code administrators by Principles 1 and 13 of the CACoP to contact one another to identify cross-code impacts. We note that each of these mechanisms is ad hoc by nature; and that the two mechanisms together do not combine to provide a centralised, systematic approach to coordination. Moreover, the current system places primary responsibility for identifying cross-code impacts on Ofgem and code administrators, and does not utilise industry participants' greater expertise to perform this function.

Self-governance

18.251 As noted above, as part of its Code Governance Review reforms, Ofgem introduced the self-governance scheme to streamline the delivery of code changes deemed non-material to the industry, consumers' interests and/or competition. Under the self-governance scheme, eligible code changes pass through the same four stages as under the ordinary modification process with the sole distinction being that the code panel does not have to submit the change to Ofgem for review before approving it for implementation.⁷⁹

18.252 There are two main efficiency gains related to the existence of the self-governance scheme: firstly, there are straightforward efficiencies achieved from truncating the process for these changes; and, secondly, it enables Ofgem to allocate its own resource more efficiently, ie by focusing its resource on the evaluation of material code changes.

18.253 A 2015 Ofgem-run survey indicates that 30% of all modification proposals are now processed through either the fast-track or regular self-governance procedure. In our view, this indicates that the introduction of the self-governance scheme has already resulted in significant efficiency gains across the codes regime. However, we consider that there remains scope for further efficiency gains to be achieved as a result of increased usage of that scheme.

⁷⁹ Ofgem has the ability to overturn a code panel decision to qualify a modification proposal as eligible for self-governance.

- 18.254 As a basis for the above claim, we note Ofgem’s analysis of all code changes processed from May 2014 to May 2015, which concluded that the usage rate of self-governance during that period could have been as high as 50% if each of the code panels had interpreted the materiality criterion in line with Ofgem’s understanding of that concept. Ofgem has stated that the discrepancy it has identified between the actual and possible usage rate is likely due to code panels taking an overly conservative approach in making such determinations, which is likely caused by the code panels’ lack of familiarity with the process.
- 18.255 In our view, maximising the sensible usage of the self-governance regime is an important part of improving the overall efficiency of the codes regime. In accordance with Ofgem’s own analysis, we expect that this objective will be achieved partly as a natural result of code panels gaining experience with the self-governance process over time. However, we consider that Ofgem could accelerate the process by which code panels arrive at the ‘correct’ approach to interpreting the materiality criterion by publishing guidance on this subject. Ofgem should seek input from each of the code panels and code administrators in developing this guidance to ensure that the proposed guidance is of practical use to those entities. Therefore, Ofgem should publish guidance, developed in the manner described above, on how the materiality criterion should be interpreted for the purposes of self-governance.⁸⁰
- 18.256 As a separate matter, we note that as part of its Code Governance Review phase 3 final proposals, Ofgem has proposed making the self-governance process the default option to process any given code change that is not the subject of an SCR. This change would effectively reverse the evaluation undertaken to determine whether a modification proposal is eligible for self-governance. Rather than setting out reasons for why a particular modification proposal is not material (and thus eligible for self-governance in the current system), code panels would instead have to reach a decision that a particular modification proposal is material in order for it to become eligible to be processed through the ordinary modification process.
- 18.257 In our view, this change could help to overcome the current conservative approach adopted by code panels in interpreting the materiality criterion. However, we recognise that there is a risk of code panels taking an equally conservative approach in relation to submitting code changes for the ordinary modification process and that, as a result, the usage rate of the self-

⁸⁰ We note that as part of Ofgem’s ongoing Code Governance Review it is consulting on an initial proposal to require code panels and code administrators to produce guidance on how they will interpret the materiality criterion.

governance could be (significantly) higher than the 50% that Ofgem considers appropriate. This, in effect, would excessively restrict Ofgem's role in code governance, which we consider inappropriate. Therefore, regardless of which modification 'route' is established as the default option, we believe that Ofgem should provide guidance on how to interpret the materiality criterion in order to achieve an efficient usage rate for self-governance and monitor compliance with that guidance.

- *Our assessment*

18.258 We consider that the self-governance scheme has improved the overall efficiency of the code regime. However, for the reasons set out above, we believe that Ofgem should publish, following appropriate consultation of the industry, a new guidance document on the interpretation of the materiality criterion within the context of the self-governance process.

Our conclusion on code governance and modification arrangements

18.259 The functioning of the governance framework for codes has a significant impact on consumers' interests and competition. Since privatisation, and as the GB energy markets have undergone the process of liberalisation, the role of codes within the wider regulatory framework has evolved dramatically. Originally, codes were mainly a tool for setting out common technical rules and standards for the upstream part of the sector (see paragraph 18.154 above). Under the current regime, codes perform two additional critical functions: firstly, they enable the implementation of high-level policy objectives such as security of supply; and, secondly, they underpin dynamic competition within the retail energy markets by ensuring a level playing field between new entrants and incumbent businesses.

18.260 Codes are therefore critical for the functioning of the regulatory framework, but they are also largely responsible for the complexity of that system. Indeed, following the introduction of eight codes since privatisation, the codes now include 10,000 pages of legally binding rules. The sheer complexity of this system may increase the risk of certain inefficiencies and introduces substantial costs which might disincentivise both Ofgem and the industry from engaging efficiently with the code governance framework (see paragraph 18.163 above).

18.261 First, and most straightforwardly, the complexity of codes and the related governance arrangements creates significant compliance costs for industry participants. These costs are likely to discourage parties from fully engaging with consultations and other relevant processes. This is a particular concern

due to the fact that these costs will weigh most heavily on smaller parties, which are a major potential source of pro-competitive innovation.

- 18.262 Second, this complexity may also be a hindrance to effective regulatory actions and enforcement by Ofgem.
- 18.263 We believe that Ofgem has taken important steps to prevent or mitigate these risks through its Code Governance Review. 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) seems to have facilitated a more efficient allocation of time and resources between the industry and public bodies.
- 18.264 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.
- 18.265 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.
- 18.266 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 mechanisms available to Ofgem to accelerate and/or streamline the process.
- 18.267 The complexity of the code regime may also be the cause of a reluctance on the part of Ofgem to intervene in areas that are governed primarily by codes (as shown for instance by the small number of SCRs launched by Ofgem since it established that process).⁸¹ We are further concerned that

⁸¹ See Appendix 10.4.

complexity may, in certain circumstances, increase the risk of circumvention and render enforcement more difficult.

- 18.268 Another related issue is that, in performing its current role within the code governance arrangements, Ofgem does not provide the industry with adequate signals as to its expectations for the strategic development of the codes. As a result, the industry are not able to efficiently allocate their resources to progress the ongoing portfolio of code modifications in accordance with those expectations.
- 18.269 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, the issues arising from the current governance arrangements are 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.
- 18.270 These inefficiencies, in our view, dampen pro-competitive innovation, and lead to the code regime failing to keep pace with market developments and wider policy objectives.
- 18.271 In light of the above, we have 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 (the Codes AEC) through limiting innovation and causing the energy markets to fail to keep pace with regulatory developments and other policy objectives. In particular, we are concerned that this AEC has the impact of limiting pro-competitive change. The underlying features of this AEC 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.

Assessment of the detriment arising from the Governance AEC and Codes AEC

- 18.272 The AECs we have identified in this section relate to the processes, structures and institutions involved in regulatory decision-making in the energy sector. They – and the features contributing to them – are systemic in nature, having an impact across all of the energy markets that we have investigated. Further, given rapid changes in the regulatory and technological environment, their effects are likely to be felt not just in past

regulatory decisions that have harmed customers but in the risk of future decisions that are not in customers' best interests. It is our view, therefore, that, while the detriment arising from these AECs is, by its nature, difficult to quantify, it is likely to be very substantial.

- 18.273 First, the costs of energy policies – the transfers and subsidies put in place to achieve government policy objectives such as reducing greenhouse gas emissions – will comprise an increasing proportion of customers' energy bills. On the basis of current announced plans, DECC estimates that climate and energy policies will add 37% to the retail price of electricity paid by households in 2020.
- 18.274 To take one example of policies that are expected to add to energy prices, the government is set to invest billions of pounds in decarbonising electricity generation over the next few years. The spending cap under the Levy Control Framework – which covers the Renewables Obligation, feed-in tariffs and CfDs – began at £3.3 billion for the period 2014/15 and will rise to £7.6 billion for the period 2020/21. With such large sums of money at stake, suboptimal regulatory design can lead to substantial consumer detriment.
- 18.275 For instance, we found that the cost of supporting an early form of CfDs (under the FIDeR framework) allocated outside the context of a competitive auction is £250–£310 million per year higher than it likely would have been had the FIDeR projects been awarded CfDs at the auction clearing price – a detriment equivalent to 1% of all customers' electricity bills (see Sections 5 and 6).
- 18.276 Second, because of the technical reality of electricity and gas consumption and production, energy markets are highly regulated, and the nature of competition in these markets is shaped by the design of the regulatory regime to a much greater extent than in most other markets.
- 18.277 This is particularly the case for wholesale markets, which currently comprise around 50% of the costs faced by electricity and gas customers. In our report, we also noted evidence of a detriment arising from the absence of charges for transmission losses. Our analysis of this detriment, based on NERA's work for the CMA (see above in Section 5), suggests that the absence of locational charges for transmission losses will lead to a cost of between £134 million and £190 million over the period 2017 to 2026.
- 18.278 While in other respects we found the wholesale gas and electricity markets to be operating at a broadly efficient level, the nature and size of technological and regulatory changes expected over the next few years is such that it is vital that the regulatory framework is sufficiently robust to

ensure that competition and customers' interests are protected in the future. And in retail energy markets, many of the competition problems that we have identified – the settlement systems for gas and electricity, which fail to give suppliers the right incentives and the introduction of the simpler choices component of the RMR rules, which has stifled innovation – are regulatory in nature, reflecting specific provisions in legislation, licence conditions and industry codes.

18.279 Within this context, we have noted that a lack of robust evidence and the fragmentation of responsibility between stakeholders (DECC, Ofgem and industry) have led to suboptimal outcomes. Our concern is that the existing institutional and regulatory arrangements in the GB energy markets may lead to future decisions that themselves have adverse effects on competition. While it is not possible to quantify the potential detriment of future decisions which may arise as a result of the current institutional arrangements, the outcomes discussed above provide an indicator of the likelihood and substantial magnitude of this potential detriment.

19. Remedies relating to the governance of the regulatory framework

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Introduction

19.1 Both the Governance AEC and the Codes AEC highlighted what we consider to be inefficiencies in the structure and governance of the regulatory framework for the GB energy markets. In this section, we set out a package of remedies which, by addressing these two AECs we have identified, will help to ensure that regulatory and policy decisions in the future are robust, efficient and timely, and driven by a concern for the interests of current and future energy consumers, wherever appropriate through competition. Our package is based on a ‘reset’ of the current regulatory framework, involving a recalibration of the powers, roles and objectives of Ofgem, DECC and industry participants.

- 19.2 Ofgem will be at the heart of this new regulatory framework, with a simpler and clearer focus on competition and the interests of consumers, an additional role to scrutinise and comment on government policies, greater access to relevant financial information from the industry and greater powers to drive through changes to industry codes when these are needed to meet broader policy objectives and in the interests of energy consumers and competition.
- 19.3 This section sets out:
- (a) our strategic approach to designing remedies to address these AECs;
 - (b) a detailed assessment of the remedies that we are proposing to implement in relation to the governance of the regulatory framework (ie the Governance Remedies);
 - (c) an assessment of the effectiveness and proportionality of the Governance Remedies as a package;
 - (d) a detailed assessment of the remedies that we are proposing to implement in relation to the governance of industry codes (ie the Code Remedies); and
 - (e) an assessment of the effectiveness and proportionality of the Code Remedies as a package.

Strategic approach to remedies design

Overarching aim and principles

- 19.4 The overarching aim of the remedies that we are considering in this context is to improve the capacity of the regulatory framework to deliver good outcomes for all energy customers (by remedying as far as possible, the AECs identified). These remedies seek to achieve that aim either by reducing the risk of policies being developed that are not in customers' best interests or by facilitating the development of policies that are in their best interests.
- 19.5 To meet this objective, we have decided to implement a range of remedies relating to the roles of regulatory institutions and the relationships between them, the design of key regulatory processes and the provision of information to inform policy decision-making. The remedies relate to five specific areas:
- (a) Ofgem's statutory duties and objectives;

- (b) the relationship between DECC and Ofgem;
 - (c) the analysis of the impacts of policy and regulation;
 - (d) the regime for financial reporting; and
 - (e) the governance of the industry codes.
- 19.6 While the remedies are varied, affecting the full range of regulatory instruments and processes (legislation, licence conditions and industry codes), it is possible to group them under two overarching principles:
- (a) well-defined powers, roles and objectives aligned with the best interests of customers; and
 - (b) robust analysis underpinning decision-making and improving transparency.
- 19.7 In the rest of this section, we explore aspects of our remedies concerning the Governance AEC, the Codes AEC, or both, under each of these principles before summarising our revised regulatory framework.

Well-defined powers, responsibilities and objectives aligned with the interests of customers

- 19.8 As noted above, the regulatory framework governing energy markets comprises a combination of regulatory instruments, each with different decision makers, ie DECC (mainly through legislation), Ofgem (mainly through licence conditions) and the industry (through industry-led regulation of codes). This multi-layered structure of regulation in part reflects the complex nature of the sector and the need to leverage resources and expertise where they can be found. We also recognise that the role of industry in code governance arrangements is influenced by the desire to protect private investors' interests from regulatory instability.
- 19.9 We accept that each stakeholder has a role to play in designing and policing the regulatory framework of the energy markets, and that the delineation between these powers, roles and objectives may not always be clear-cut. However, we found that the current allocation of roles and responsibilities between stakeholders is currently inefficient and increases the risk of decisions being taken that are not in the best interests of energy customers.
- 19.10 Our remedies seek to address these concerns through three related measures:

- (a) a recalibration of the current regulatory framework to create clear and consistent powers, roles and objectives for decision makers at the various levels of regulation, aligned with the best interests of customers;
- (b) a reinforcement of the role of an independent and authoritative regulator; and
- (c) a clear assignment of responsibilities and transparent, coordinated implementation.

Clear and consistent roles and objectives, aligned with the best interests of customers

19.11 We have identified concerns relating to a lack of clear and consistent roles and objectives that are aligned with the best interests of energy customers. With respect to the Codes AEC, our remedies seek to address these features by giving greater power and responsibility to Ofgem to influence the code modification processes, to ensure that the decisions that are taken are fully aligned with the interests of customers. The remedies include (for more details see paragraphs 19.295 to 19.395):

- (a) new responsibilities for Ofgem to produce a strategic direction and a set of strategic work plans for code modifications;
- (b) new responsibilities for Ofgem and new powers for licensed code administrators to initiate and prioritise code changes for the purposes of delivering this strategic direction; and
- (c) the creation of a backstop executive power to allow Ofgem to ‘call in’ an ongoing strategically important code modification.

19.12 In relation to the Governance AEC, we have found that Ofgem’s statutory objectives and duties could be considered to be unclear and in need of clarification (see Section 18). One of our remedies (see paragraphs 19.33 to 19.53) seeks to address this feature by removing from Ofgem’s statutory objectives and duties unnecessary constraints that may prevent it from pursuing its primary objective of meeting the needs of current and future consumers wherever appropriate by promoting competition.

An independent and authoritative regulator

19.13 As the above discussion suggests, our remedies will give greater powers and responsibilities to Ofgem, particularly in relation to code governance. In light of this we consider it particularly important that Ofgem is both independent in practice and perceived to be independent from both

government and the industry.¹ It is also key that Ofgem be regarded as authoritative, and able to answer the range of questions stakeholders may have about the effectiveness of competition and regulation in energy markets.

- 19.14 We noted in Section 18 above that two of Ofgem's most important decisions in recent years (neither of which we consider to be fully in customers' best interests)² 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, and that the coincidence of DECC and Ofgem's actions risked creating the perception of a lack of independence on the part of Ofgem.
- 19.15 To bolster the perception of Ofgem's independence (and potentially actual independence), we propose to introduce a remedy to address in part the Governance AEC that would empower and require Ofgem to comment transparently on DECC policy proposals, expressing its views publicly on the relative merits and potential impacts of such proposals. We believe that this would be in the interests both of transparency and of confidence in Ofgem as an independent body. We also consider that our remedies to require Ofgem to publish periodic assessments of the impacts of government policies (discussed below in paragraphs 19.132 to 19.143) would bolster its perception by stakeholders as an independent, authoritative regulator.
- 19.16 We are aware that certain of Ofgem's decisions have been the subject of some criticism in recent years – and indeed we have found that some of its decisions give rise to AECs. However, we believe that, with the powers, roles and objectives created by our remedies and with the current leadership it has in place, it can reinforce its position as an independent, authoritative regulator, trusted by – but independent of – both government and the industry and acting in the interests of current and future energy consumers, wherever appropriate through effective competition.

Clear ownership of policies and transparent, coordinated implementation

- 19.17 We believe that the absence of mechanisms to coordinate government policy objectives, Ofgem's current statutory objectives and duties, and the objectives and processes enshrined in industry codes, is likely to lead to inconsistent approaches being taken to policy development, increasing the

¹ See below paragraph 19.60.

² The introduction of the simpler choices component of the RMR reforms in 2013 and of SLC 25A in 2009, prohibiting regional price discrimination.

risks of policies and regulations being developed that are not in customers' best interests.

- 19.18 The obvious risk of this fragmentation of decision-making power is a lack of coordination in decision-making and implementation, leading to incoherent outcomes. In this report, we have identified a few instances in which the implementation of policy goals was delayed or suboptimal due to a lack of coordination between DECC, Ofgem and the industry (see paragraphs 19.91 to 19.110). We therefore believe it is essential to improve the clarity of both the overarching policy objectives for the regulatory framework and to ensure that all stakeholders are given clear direction as to the implementation of these policy objectives.
- 19.19 We believe that policy objectives should be clearly stated by DECC (following consultation with Ofgem and the industry). In turn, mechanisms should be in place in order to ensure that these objectives are reflected in the decision-making processes, and that their achievement is regularly assessed. We acknowledge that steps have already been taken in this respect (with DECC having now the power to designate a Strategy and Policy Statement), but believe that further actions need to be taken.
- 19.20 In particular, through our remedies concerning the Governance AEC and the Codes AEC, we seek to increase coordination and transparency of interactions between the different governance levels of the regulatory framework. We expect DECC to take responsibility for the full implementation of its policy decisions, by ensuring that all the necessary analysis and implementation steps are being taken by the appropriate stakeholders (including modification to licences or industry codes where necessary). Similarly, Ofgem should actively and transparently make its expertise available to DECC, and should be held ultimately responsible for the outcomes arising from regulation through standard licence conditions and industry codes (including ensuring that the scope of industry-led regulation and the supervision of it is appropriate).
- 19.21 More specifically, our remedies concerning the Governance AEC and the Codes AEC provide, among other things, for:
- (a) mechanisms facilitating coordination (such as action plans and joint statements) where interventions from different stakeholders are required to achieve a particular objective, with a view to avoiding delayed or sub-optimal implementation;
 - (b) mechanisms empowering Ofgem to comment transparently on DECC policies, with a view to contributing their expertise; and

- (c) an efficient process, for which Ofgem is ultimately responsible, to deliver in a timely manner industry code changes which are in line with broader policy objectives.

Robust analysis underpinning decision-making and improving transparency

- 19.22 To ensure that energy regulations serve customers' needs, it is vital that policy decisions are informed by robust analyses of their likely impacts. We believe that, because of the magnitude of their impact and their complexity, interventions in the energy markets will require a particularly detailed level of analysis.
- 19.23 For the reasons set out in Section 18, we believe that negative outcomes for customers have arisen from past regulatory interventions due to difficulties in assessing the impact of the policies and regulations on energy prices and bills, ineffective collaboration between stakeholders in cases of disagreements over policy decision-making and implementation, a lack of clarity in the statutory duties applicable, and a lack of relevant financial information. We believe that the risk of poor outcomes will be reduced (and the features giving rise to the Governance AEC addressed, at least in part) by setting up mechanisms that:
- (a) facilitate transparent exchanges between DECC and Ofgem over policy decision-making and implementation, so as to address disagreements and facilitate consultation with the industry;
 - (b) ensure robust and authoritative analysis of the overall impact of the regulatory framework, taking into consideration the aggregate costs and impacts of policies on the various policy objectives; and
 - (c) ensure that decision-making is based on relevant financial information.
- 19.24 Through our remedial action concerning the Governance AEC we also seek to ensure that mechanisms be put in place with a view to monitoring the markets on an ongoing basis, and in particular with a view to:
- (a) conducting and communicating effectively a robust and authoritative analysis of the overall impact of the energy regulatory framework on different policy objectives, notably decarbonisation, security of supply and affordable prices; and
 - (b) facilitating a clear and transparent understanding of key market outcomes (we noted in Sections 2 and 18 above that there has been in recent years a lack of shared understanding about key elements of the

evidence base such as the price and bill impacts of policy objectives and of energy firms' profitability).

- 19.25 In addition, we believe that the ex post review of individual policies, as required by the *Better Regulation Framework Manual*³ is essential in this area. These changes would allow DECC and Ofgem to identify areas where interventions are required, either by removing/amending previous interventions or by adjusting proposed policies in order to prevent overlaps or conflicts between interventions.
- 19.26 In order to better understand the interaction between interventions taken by different stakeholders, and to facilitate assessment of their cumulative impacts, we also believe it is appropriate to ensure that the frameworks for analysis used over time and across decisions are consistent and easily comparable. Transparent discussions between DECC, Ofgem and the industry would, in our view, facilitate such consistency. In particular, as discussed in more detail below, we have decided to recommend the following with a view to addressing, in part, the features giving rise to the Governance AEC:
- (a) Setting up a clear process for Ofgem to comment publicly on draft primary and secondary legislation that is relevant to its statutory objectives and duties and which has a material impact on GB energy markets.
 - (b) Pursuant to the principles set out in the *Better Regulatory Framework Manual*, DECC should review regularly the impact of its policies; the level of scrutiny should depend on the impact of each policy on business and consumers.
 - (c) Ofgem should publish annually a state of the market report which would provide analysis regarding issues such as:
 - (i) the evolution of energy prices and bills over time;
 - (ii) the profitability of key players in the markets;⁴
 - (iii) the social costs and benefits of policies;

³ See *Better Regulation Framework Manual: Practical Guidance for UK Government Officials* (latest version March 2015, currently being updated).

⁴ Specifically those firms which are required to comply with the regulatory accounting reporting obligation (see paragraph 19.158).

- (iv) the impact of initiatives relating to decarbonisation and security of supply;
- (v) the trade-offs between policy objectives resulting from the extant regulatory framework; and
- (vi) the trends for the forthcoming year.

19.27 In order to support these three remedies, we have decided to recommend that Ofgem:

- (a) enhance the existing regulatory reporting obligation pursuant to which certain firms must submit financial reports to Ofgem; and
- (b) create a new internal unit within Ofgem (eg an office of the chief economist), which would build expertise across the different areas of the energy markets with a view to performing some of the tasks above.

Reset of the regulatory framework

19.28 The Governance Remedies and the Codes Remedies are individually incremental but in combination represent a substantial reform package. They represent a 'reset' of the regulatory framework governing the energy sector, clarifying and recalibrating the powers, roles and objectives of Ofgem, DECC and the industry to help ensure that regulatory and policy decisions in the future are robust, efficient and timely, and driven by a concern for the best interests of current and future energy consumers.

19.29 Ofgem will be at the heart of this new regulatory framework, with a simpler and clearer focus on the interests of energy consumers (and on enhancing competition wherever appropriate in furthering consumers' interests), an additional role to scrutinise and comment on government policies, greater access to relevant financial information from industry and greater responsibility to drive through changes to industry codes when these are needed to meet broader policy objectives and are in the interests of energy consumers and competition.

19.30 We believe that the two overarching principles informing our remedies package are mutually reinforcing. For example, the roles given to Ofgem to comment on and scrutinise the impacts of government policies on the one hand, and undertake greater scrutiny of companies' financial returns on the other, will help both to:

- (a) improve the robustness of the decision-making process, the quality of regulatory decisions and transparency in public debates about energy; and
- (b) bolster the perception of Ofgem as an authoritative, trusted and independent regulator, consistent with the greater responsibilities it will have in relation to code governance and reform.

19.31 We also consider that our reforms are fully consistent with the government's *Principles for Economic Regulation*⁵ and its *Better Regulation Framework Manual*. In particular, our remedies should ensure that new policy proposals and existing policies and regulations are subject to robust scrutiny in terms of their costs and benefits. Further, our remedies to the code governance process and mechanisms to improve coordination between DECC and Ofgem should serve to streamline and rationalise the policymaking process.

19.32 We are aware that industry-led regulation of codes is sometimes considered a 'light-touch' approach to regulation. However, in our view, the existing model of industry-led code modifications has often led to burdensome and time-consuming processes that have served to impede pro-competitive change. We believe that by giving Ofgem greater powers and responsibilities to pro-actively intervene where necessary to help deliver agreed policy goals that benefit energy consumers, our reforms will substantially reduce regulatory burdens.

Governance of the overarching framework

Revision of Ofgem's statutory duties and objectives

19.33 We have noted that one of the features giving rise to a lack of robustness and transparency in regulatory decision-making is Ofgem's statutory objectives and duties which, in certain circumstances, may constrain its ability to promote effective competition. In particular, we noted that Ofgem considered that its duty to pursue its principal objective by 'wherever appropriate promoting effective competition' had been progressively downrated relative to its other duties over the last ten years.

19.34 Ofgem's perception that its duty to promote competition has been downrated is a significant cause for concern, as it implies that Ofgem's ability to promote competition may be constrained.

⁵ BIS (April 2011), [Principles for Economic Regulation](#).

19.35 We therefore recommend that Ofgem's statutory objectives and duties be revised.

Aim of the remedy

19.36 The aim of this remedy is to clarify Ofgem's statutory objectives and duties in order to remove any constraint (actual or perceived) on Ofgem's ability to pursue its principal objective (protecting the interests of existing and future energy consumers) by promoting effective competition. The change would increase the robustness and transparency of Ofgem's regulatory interventions and, in turn, contribute to remedying the Governance AEC.

Parties' views

19.37 Most parties broadly agreed with our proposed remedy. In response to our Remedies Notice, Centrica went one step further, suggesting not only to remove Ofgem's current duty to consider means other than competition before proceeding with a course of action, but also to include in Ofgem's statutory objectives and duties a requirement to 'seek to further the Principal Objective wherever possible by promoting competition' (rather than 'wherever appropriate', as is currently the case).

19.38 Citizens Advice opposed our proposed remedy, as it considered the evidence to support the Governance AEC finding and remedy to be extremely weak and the remedy to be therefore unnecessary. This was because Citizens Advice considered that Ofgem was not precluded from pursuing an intervention promoting competition where it considered it to be the most appropriate course of action. It also noted that any change to the regulator's principal statutory duty created stakeholder uncertainty on how this might affect its future decisions. It also said it would be at best inadvisable, and at worst inappropriate, to seek to redraft primary legislation through market investigations as it was a matter for Parliament to define a regulator's statutory duties, and not a matter for either the CMA or the regulator itself. Smartest Energy said that a regulator should be clear on its principal objective and thought should be given to this before legislation was amended.

19.39 A few other consumer bodies (ie Which?, National Energy Action) expressed concern in relation to this proposed remedy. In particular, in response to our Remedies Notice, Which? welcomed the proposed remedy but stated that a revision of Ofgem's statutory objectives and duties should not lead to a 'downgrading of Ofgem's duty to protect consumers'. Some respondents (Northern Powergrid, Ovo Energy) noted that statutory change was not necessary to enable Ofgem to promote competition. However, Ovo Energy

stated that Ofgem should have ‘a greater focus on competition matters from a principle-based approach’.

Design considerations

19.40 We have noted that Ofgem’s statutory objectives and duties were amended by the EA10 (see Appendix 10.1) which, among other things, inserted in both current sections 4AA of the GA86 and 3A of the EA89 a new paragraph 1C as follows:

(1C) Before deciding to carry out functions under this Part in a particular manner with a view to promoting competition as mentioned in subsection (1B), the Secretary of State or the Authority shall consider—

(a) to what extent the interests referred to in subsection (1) of consumers would be protected by that manner of carrying out those functions; and

(b) whether there is any other manner (whether or not it would promote competition as mentioned in subsection (1B)) in which the Secretary of State or the Authority (as the case may be) could carry out those functions which would better protect those interests.

19.41 We have found that this new paragraph may constrain (or at least create the perception of constraining) Ofgem’s margin of appreciation as to deciding the most appropriate manner to achieve energy consumers’ best interests, and that this constraint is a feature of the energy markets that contributes, in combination with other features, to an AEC through an overarching feature of lack of robustness and transparency in regulatory decision making.

19.42 While we note Citizens Advice’s comment that Ofgem is not precluded from promoting competition, this new paragraph creates for the reasons set out in paragraphs 18.26 and 18.27 an unnecessary constraint on such action by Ofgem.

19.43 Therefore, we have decided to recommend that DECC initiate a legislative process in order to delete paragraph 1C from both sections 4AA of the GA86 and 3A of the EA89.

19.44 For the avoidance of doubt, the purpose of this remedy is not to constrain Ofgem’s ability to carry out its functions in the manner which it considers is most likely to further its principal statutory objective. We acknowledge that in certain circumstances the best way of energy protecting consumers’

interests may be achieved by a means other than through competition. We therefore do not believe, as some parties have suggested, that competition should be given explicit priority as the preferred mechanism by which Ofgem should seek to achieve its principal statutory objective, and this is reflected in our decision to recommend a return to a form of wording closer to the one pre-EA10. It is our view that the wording ‘wherever appropriate by promoting effective competition’ puts sufficient emphasis on the role of competition within this context, and any further emphasis might unnecessarily constrain (or even preclude) Ofgem’s ability to pursue its principal statutory objective by means other than competition.

- 19.45 Most respondents to our provisional findings report and provisional decision on remedies have either supported this approach or at least acknowledged that there would be some benefits in clarifying the role of competition, relative to other types of regulatory interventions, in pursuing energy consumers’ best interests. We have noted however concerns from consumer advocacy organisations about the need to preserve the option for Ofgem to promote the best interests of energy consumers through other means where appropriate.
- 19.46 As a consequence, subject to the deletion of paragraph 1C from sections 4AA of the GA86 and 3A of the EA89, we are not recommending any further amendment to Ofgem’s principal statutory objective and duties (and in particular to the words ‘wherever appropriate by promoting effective competition’) which would seek to reinforce the emphasis (but not an exclusive focus) on competition. Such an amendment is, in our view, not necessary and may, on the contrary, cause further confusion. As noted above, it is Ofgem’s role to identify the best way in which to carry out its functions in order to achieve its statutory principal objective, and to decide which steps it needs to take in order to reach a view on this.
- 19.47 In practice, as this remedy is not time-sensitive, in our view, it is not necessary to initiate a legislative process for the purpose of this remedy only. Instead, a provision to that end can be included within the next draft energy act (or any relevant omnibus bill). We have noted government’s commitment, in the Budget 2016⁶ and in its response to our provisional decision on remedies, to implement this remedy.

⁶ Paragraph 7.53 of the [Budget 2016](#): ‘The government intends to amend the statutory duties of Ofgem to ensure that wherever appropriate it considers competition levers first. This work will take into account the conclusions of the Competition and Markets Authority (CMA)’s Energy Market Investigation.’

Assessment of effectiveness

- 19.48 Pursuant to our guidelines, we assess below the effectiveness of this remedy, and in particular:
- (a) whether this remedy is effective in contributing to the achievement of the aims of our remedial action;
 - (b) whether this remedy is capable of effective implementation; and
 - (c) the timescale over which this remedy will take effect.
- 19.49 By removing from Ofgem's principal statutory objective a requirement to consider, before promoting competition, whether there is any other manner in which it could carry out its functions, this remedy will in our view be effective in removing unnecessary procedural and substantive constraints on Ofgem's ability to pursue its principal statutory objective. The amended statutory objectives and duties, reverting to the previous balance set by the words 'wherever appropriate by promoting effective competition', will put an appropriate emphasis on Ofgem's duties to promote competition (see in particular paragraph 19.46 above). This, in turn, will address one of the features giving rise to the Governance AEC.
- 19.50 This remedy is to be implemented through a change in legislation. For the reasons set out in paragraph 19.47, and in particular government's commitment set out in the Budget 2016 to implement this remedy, we consider that this remedy is capable of effective and timely implementation by way of a legislative change to be initiated by the government.

Assessment of proportionality

- 19.51 For the reasons, set out above, we believe that this remedy will be effective in achieving its aim.
- 19.52 For the reasons set out above (see in particular paragraph 19.46), we believe that this remedy is no more onerous than necessary to achieve its aim. We have not identified other remedies that would be effective. We have noted Citizens Advice's comment that a change in legislation may create uncertainty for stakeholders. We believe however that this remedy, by reversing an unnecessary change made by the EA10 to Ofgem's statutory duties and objectives, would reduce, rather than increase, regulatory uncertainty for stakeholders. This view is supported by the majority of parties' views in response to our provisional decision on remedies (see paragraph 19.37 above).

19.53 The cost of the legislative process as envisaged in paragraph 19.47 above will be very low.

Improving coordination between Ofgem and DECC on policy design and implementation

19.54 Responsibility for setting up the legal framework and regulating the GB energy markets is shared between different public bodies (principally DECC and Ofgem) and the industry itself (with respect to the industry-led regulation of codes). In some cases, the implementation of a particular energy policy requires a combination of measures taken by DECC (mainly through legislation), Ofgem (mainly through licence conditions) and the industry (through the amendment of codes). In our report, we have identified concerns relating to the overlap of DECC's and Ofgem's functions and the interaction between measures adopted independently by DECC and Ofgem (see Section 16 above). Similar issues relating to industry codes are addressed separately below.

19.55 We note that it is always possible that DECC and Ofgem will disagree on how to address a particular area of policy, but consider that where such disagreements do occur, it would be preferable if there were a mechanism through which such disagreements could be surfaced transparently and that such a mechanism would mitigate any perception of a lack of independence on the part of Ofgem.

19.56 We have also noted cases⁷ in which the implementation of policy goals has been delayed (or sub-optimally implemented as a result of inconsistencies between regulations) due to a lack of coordination between DECC, Ofgem and the industry. We believe that there should be mechanisms in place to mitigate these risks.

19.57 We concluded in Section 18 that these shortcomings were a feature of the GB energy markets that contributed to the Governance AEC.

19.58 To address these issues, we have decided for the reasons set out below to recommend a remedy consisting of two mechanisms to increase the transparency and effectiveness of the relationship between DECC and Ofgem, ie:

⁷ See, for instance, 17-day switching and half-hourly settlement as examples of delayed implementation. DECC's capacity market reform and Ofgem's EBSCR code modification provides an example of insufficient consideration of the interplay between different policies.

- (a) a mechanism requiring Ofgem to set out its views on relevant policy proposals that have a material impact on GB energy markets; and
- (b) a mechanism designed to increase the transparency of the policy implementation process and the roles of key participants.

Aim of the remedy

- 19.59 The remedy seeks to facilitate rational debate between DECC, Ofgem and the industry in order to promote regulatory stability. We expect the benefits to be twofold. This remedy will, on the one hand, enhance the robustness and transparency of DECC's and Ofgem's decisions and, on the other hand, reduce the risk of inefficient implementation of policy decisions.
- 19.60 We also note, for the reasons set out in Section 18, that preserving Ofgem's independence, both actual and perceived, is essential to the well-functioning of the energy markets.

Parties' views

- 19.61 Many parties welcomed the CMA's assessment of the issues arising from the overlap of DECC's and Ofgem's roles and most supported both remedial mechanisms proposed in the provisional decision on remedies.
- *Views on Ofgem being able to comment on DECC policies*
- 19.62 Ten parties expressed support for this remedy.⁸ Most respondents suggested a fairly broad remit.
- 19.63 Other parties (Flow Energy, Ecotricity and National Energy Action) also suggested that Ofgem should be able to comment on a wide range of DECC's policies. Citizens Advice⁹ and E.ON,¹⁰ however, proposed a narrower scope, suggesting that Ofgem's comments should be confined to issues relating to the delivery of policies. Indeed, E.ON noted that the government has a democratic mandate and that it should not be for an independent regulator to challenge the broad aspects of policies. Citizens Advice noted that any opinion offered by Ofgem to government should only carry the status of advice and should not be binding. RWE felt that Ofgem should have the right and duty to submit comments to DECC in the context

⁸ Centrica, the Centre for Competition Policy, Citizens Advice, Drax, Elexon, First Utility, Ofgem, SSE, Tempus Energy and Utilita.

⁹ See Citizens Advice response to provisional decision on remedies.

¹⁰ See E.ON response to Remedies Notice.

of an impact appraisal of policies that were likely to affect competition.¹¹ EDF Energy argued that this right/duty should relate to Ofgem's statutory duties.¹²

19.64 Centrica suggested that this remedial mechanism should require Ofgem to undertake robust quantified impact assessments of all proposed policies that will have a material impact on the operation of the market, the activities of market participants and ultimately on energy customers. Scottish Power submitted that this remedial mechanism was unnecessary as Ofgem already had the powers to publish opinions. It noted that it was appropriate for Ofgem to express views where a DECC policy had a bearing on Ofgem's regulatory functions, but that this should not be a mandatory requirement. Scottish Power and Utilita also noted that although Ofgem's views should normally be made public in the interest of transparency, this should not preclude informal dialogue between Ofgem and DECC while such policies were being formulated.¹³ E.ON and Flow Energy suggested that DECC should have to respond to any Ofgem comments on policy.

- *Views on the relationship between DECC and Ofgem*

19.65 Although an earlier remedy we proposed at provisional findings – to set up a formal mechanism for Ofgem to seek direction from DECC – received limited support (and in some circumstances would conflict with the EU legal requirements of independence of national regulatory authorities in the gas and electricity markets), most respondents acknowledged the need for greater transparency in the relationship between DECC and Ofgem and the benefits of increasing clarity regarding their respective roles. SSE suggested that 'introducing a formal mechanism for DECC/Ofgem policy reconciliation would increase transparency and improve the quality of public debate and policy decision-making'. Centrica expressed broad support for remedies which 'clarify roles and responsibilities, and improve the transparency of regulatory decision making.' Centrica noted that DECC's responsibility for setting overall energy policy and Ofgem's role in overseeing and maintaining competitive markets and the regulatory framework had been blurred at times.

19.66 Other parties and stakeholders expressed support for a clear separation of Ofgem's and DECC's roles (Energy UK, ESB, University of Exeter, Changeworks, CBI and the Highland and Islands Housing Association). In

¹¹ See RWE response to Remedies Notice.

¹² See EDF Energy response to Remedies Notice.

¹³ See Scottish Power response to Remedies Notice, paragraph 17.4 and Utilita response to provisional decision on remedies.

this respect, Ovo Energy¹⁴ stated that it would support anything that promoted greater regulatory and policy certainty. Scottish Power was not supportive of a remedy in the form proposed because it considered it might reduce the independence of the regulator. It also argued that the precise timing and history of any government influence over certain Ofgem decisions in the past (in respect of SLC 25A and the RMR tariff rules) was unclear and the remedies proposed by the CMA would be unlikely to have prevented it.

19.67 Five parties referred to the Strategy and Policy Statement as an existing mechanism that could help to establish clearer boundaries between DECC and Ofgem. These parties included Ofgem, which stated that the Strategy and Policy Statement was ‘one important route for providing more clarity over our respective roles’. EDF Energy argued that although a Strategy and Policy Statement had yet to be formally adopted by the government, it could provide an ‘opportunity to promote regulatory certainty and increase alignment between the Government’s energy policy objectives and the way in which Ofgem regulates the sector’.¹⁵ Similarly, the University of Exeter suggested it would be helpful for ‘the Government to resurrect the discussion surrounding its Strategy and Policy Statement’ because ‘the process of setting out key relationships and responsibilities between DECC and Ofgem would provide a useful framework.’ For Citizens Advice/Citizens Advice Scotland, the Strategy and Policy Statement’s effectiveness in this respect would be limited because it would likely only contain high-level rather than detailed content on policy design and would only be infrequently updated, resulting in content gaps.

19.68 Some parties made more general comments about the value of introducing some form of document setting out the roles of DECC and Ofgem in the energy markets. Gazprom said it would support a framework which would set out details as to their respective responsibilities for the development of policies, the cost/benefit analysis undertaken and how disputes between those organisations would be arbitrated. First Utility suggested that such documents could take the form of a Memorandum of Understanding ‘covering how Ofgem and DECC will work within their respective remits and where these meet, setting out best practice for handling this.’

¹⁴ See Ovo Energy response to provisional findings and Remedies Notice, p32.

¹⁵ See EDF Energy response to Remedies Notice (August 2015), paragraph 17.7.

Ofgem's duty to comment on draft primary and secondary legislation relating to the GB energy markets regulatory framework

- 19.69 Under the current regulatory framework,¹⁶ Ofgem has a duty, when expedient or requested by government, to give information, advice and assistance with respect to any matter in respect of any its statutory functions under the GA86 or EA89. Moreover, it has the power to publish any advice or information if it appears to Ofgem that such publication would promote the interests of consumers. This effectively enables Ofgem to comment on any government draft statutory instrument, and to respond to any public consultation, when it considers it relevant to any of its functions.
- 19.70 Ofgem and DECC have put to us that, in practice, Ofgem provides such advice or information in relation to draft policy instruments on an ad hoc basis by means of private letters at staff level. It is, however, unusual for Ofgem to publish these letters, or even to provide a summary of the interactions between Ofgem and DECC. In our view, the absence of an established practice by which Ofgem publishes views on DECC's policy proposals (and of any Ofgem statement providing a framework for such publications), is not in the interests of transparency and an informed public debate.
- 19.71 Further, because such public statements are rare, there is a risk that, if Ofgem wished to make public comments on a particular proposal in the future, the significance of any concerns that it raised would be overstated in the public debate. In turn, awareness of this risk may effectively cause Ofgem's officials to err on the side of caution by keeping both technical and substantive comments private.
- 19.72 In order to increase transparency in policy making – and help underpin Ofgem's independence – we believe Ofgem should publicly comment on relevant draft legislation and policy proposals in a systematic way. In particular, where relevant, Ofgem should highlight the potential impacts of policy proposals, and expose any challenges or technical difficulties relating to implementation where such proposals relate to Ofgem's own remit/areas of action in the sector. By publishing such views (referred to hereafter as Opinions), it will openly contribute its technical expertise to the design of policy initiatives with a view to making the decision process more robust. It will also open a transparent discussion between DECC and Ofgem, which can help to air differences and, by doing so, highlight areas potentially requiring further analysis or future reviews. The publication of such Opinions

¹⁶ See, in particular, sections 34 & 35 of the GA86 and 47 & 48 of the EA89.

will serve to ensure a more coherent regulatory process, and reduce the risk of suboptimal policy implementation due to a lack of coordination.

- *Scope of Opinions*

- 19.73 Parties have made several suggestions as to the circumstances in which it would be appropriate for Ofgem to comment publicly on draft policies. We would expect Ofgem to comment publicly on the expected impacts of policy initiatives that are relevant to Ofgem's statutory objectives and duties.
- 19.74 Moreover, in order to keep this mechanism workable, it is in our view appropriate to have some form of materiality threshold, ie limiting Ofgem's duty to comment on draft legislation and policy proposals that are likely to have a substantial impact on GB energy markets. We note that this may include policies developed by government departments other than DECC. For instance, fiscal measures developed by HM Treasury (eg the carbon price floor or changes to downstream taxes) may have significant implications on GB energy markets and therefore on Ofgem's future activities.
- 19.75 We therefore expect the scope of these Opinions to vary depending on the nature of the draft policies, and consider it appropriate for Ofgem to have discretion to determine the level of detail to include in each Opinion, dependent on not only materiality, but also the relative expertise of the Departments concerned and the statutory remit of each.
- 19.76 These Opinions should complement (and be informed by) the ongoing analysis of aggregate impacts of regulation on the energy markets that would be performed by Ofgem (see paragraphs 19.111 to 19.154 below). Indeed, such analysis will provide insight on the cumulative impact of various government policies on the GB energy markets, and on existing trends (eg the evolution of prices and energy companies' profits over time).
- 19.77 In view of the technical nature of Ofgem's role in this context, we expect Opinions to broadly cover the following issues:
- (a) the impact of draft legislation on each of the three key policy objectives of decarbonisation, security of supply and affordability;
 - (b) the interaction between draft legislation and the existing regulatory framework (including licences and industry codes);
 - (c) any necessary steps required to implement draft legislation (including changes to licences or industry codes); and

(d) the likely overall effectiveness of draft legislation in achieving the government's stated objectives (and expected net benefits).

19.78 This remedy does not preclude Ofgem from having iterative confidential interactions with government departments at any stage of the formulation of a policy, nor does it impose a duty on Ofgem to disclose a detailed account of such interactions.

- *Timing for the publication of Ofgem's Opinion*

19.79 As per the scope of the Opinions, we consider it appropriate for Ofgem to have discretion to determine the appropriate time to publish such Opinions, subject to a general principle that the Opinion should be published in time for Parliament and/or government to take the Opinion into consideration before reaching a decision. Moreover, where a draft piece of legislation is subject to a consultation process, the appropriate time for Ofgem to publish an Opinion would be in the early stage of this consultation, in order to allow stakeholders to reflect on it before they formally respond within the relevant consultation period.

- *Response from DECC*

19.80 We consider that DECC should seek to address material concerns raised by Ofgem in an Opinion within the context of its own appraisal of the policy proposal (eg within the context of an impact assessment) and, where the proposal is subject to a consultation, in the government's response to it.

- *Implementation of this remedy*

19.81 As noted above, Ofgem has wide-ranging powers to publish any advice or information if it appears to Ofgem that such publication would promote the best interests of energy consumers.¹⁷ In our view, these powers enable Ofgem to publish Opinions as set out above. However, for this remedy to be effective, the publication of such Opinions needs to be established as common practice. For the reasons set out below, we believe that it is appropriate to recommend a legislative change in order to establish this common practice. Specifically, our recommendation to DECC is to amend section 35 of the GA86 and section 48 of the EA89 in order to include a duty on Ofgem to publish an Opinion on all draft legislation and policy proposals which are relevant to Ofgem's statutory duties and objectives and which are likely to have a material impact on GB energy markets; the exact scope,

¹⁷ See in particular sections 34 & 35 of the GA86 and 47 & 48 of the EA89.

level of details and timing of the Opinion would be left to Ofgem to determine, taking into consideration the specific circumstances of each case and the principle of proportionality.

19.82 Until the entry into force of this legislative change, we recommend Ofgem to use its existing powers to implement this remedy to the extent possible.

- *Considerations relating to the effectiveness of this remedy*

19.83 We consider that the publication by Ofgem of Opinions will significantly improve the transparency of Ofgem's assessment of the impacts of contemplated legislation, and of the interaction between such contemplated legislation and the existing regulatory framework. Increased transparency would, in our view, improve the quality of the policy development process, in particular by making the rationale for interventions clearer, by exposing the views of different parties and by reinforcing the perception of Ofgem's independence and credibility. More specifically, it would create opportunities to air any disagreements between DECC and Ofgem, and highlight areas of policy interventions that require particular attention within the context of their appraisal and/or ongoing review.

19.84 We therefore believe that this remedy would contribute to addressing in part the Governance AEC, in particular by addressing the feature concerning the absence of a formal mechanism through which disagreements between DECC and Ofgem over policy decision-making and implementation can be addressed transparently.

19.85 As noted above in paragraph 19.70, Ofgem already has the power to publish views on draft legislation and we therefore recommend that Ofgem implements this remedy as soon as possible following our final report by issuing an Opinion on all draft legislation and policy proposals which are relevant to Ofgem's statutory duties and objectives and which are likely to have a material impact on GB energy markets. However, we believe that the creation of an established practice, so as to avoid the risk identified in paragraph 19.71 above, would reinforce the effectiveness of this remedy in the longer term. To create such an established practice, and provide stronger incentives to Ofgem, we consider it appropriate to recommend that DECC amend section 35 of the GA86 and section 48 of the EA89.

19.86 Such a legislative change, however, would not be time sensitive, so that it is not necessary in our view to initiate a legislative process for the purpose of this remedy only. Instead, a provision to that end can be included within the next draft energy act (or any relevant omnibus bill).

- *Considerations relating to the proportionality of this remedy*

- 19.87 The implementation costs arising from this remedy would be very low and, for the reasons set out in paragraphs 19.85 and 19.86, no more onerous than necessary to achieve its aim.
- 19.88 As noted in paragraph 19.85, we considered an alternative, less intrusive remedy, consisting in a recommendation to Ofgem, but concluded that it would not be as effective in the long term.
- 19.89 We consider that the incremental costs for Ofgem to publish Opinions would be low considering that it already reviews and provides views (albeit seldom publically) on draft legislation. These incremental costs should be substantially outweighed by the benefits arising from the increased robustness and transparency of the decision-making process. For instance, as highlighted in paragraphs 18.43 to 18.57 of Section 18, a lack of coordination and transparency between Ofgem and DECC has led to sub-optimal outcomes in the past (eg both Ofgem and DECC seeking to remedy the same ‘missing money’ problem) – the prevention of which justifies and outweighs the concomitant costs.
- 19.90 This remedy would also leave significant leeway for Ofgem to have iterative confidential interactions with DECC, and to determine the timing and content of Opinions. This would allow Ofgem to assist DECC throughout the policy formulation process, and to allocate its resources efficiently. For these reasons, we believe that this remedy would not produce disadvantages which are disproportionate to its aim.

Mechanisms designed to clarify the role and responsibilities of DECC, Ofgem and the industry, and to allow an efficient delivery of policy objectives

- 19.91 In our report, we have identified a number of situations in which implementation of policy goals had been delayed or suboptimal (eg incomplete) due to a lack of coordination between DECC, Ofgem and the industry. We gave two types of examples of these inefficiencies:
- (a) The failure to implement, in a timely manner, all the regulatory changes that were required for a policy initiative to be effective (for instance a change to standard licence conditions or to an industry code which are required in practice to give full effect to a statutory instrument). A delayed (or imperfect) implementation can be caused either by a failure to identify the need for consequential changes, or poor management of the implementation process that leads to inconsistencies and/or delays (see discussion above, and in Appendix 18.2, of Project Nexus, 17-day

switching and half-hourly settlement, where DECC decided not to adopt certain provisions by way of statutory instrument, with the result that certain changes imposed by DECC were not sufficiently supported by implementing measures).

(b) A lack of understanding of the interplay between parallel ongoing changes. An example of this relates to Ofgem's EBSCR carried out shortly after DECC's proposals for the introduction of a Capacity Market.

19.92 To a certain extent, these issues can be mitigated by introducing a duty for Ofgem to comment on DECC's policies so as to give Ofgem the opportunity to raise concerns relating to the implementation of a policy change (eg relation to consequential changes, or the interplay between DECC's policy proposals and other regulations).

19.93 However, we are concerned that such a mechanism on its own will not be fully effective in achieving the objective set out above, and in particular will not be effective in addressing the lack of coordination between DECC and Ofgem (eg in the case of 17-day switching).

19.94 An attempt to clarify the respective powers, roles and objectives of Ofgem and DECC, and improve the coordination of their actions, led to the introduction, by the Energy Act 2013, of a mechanism – the Strategy and Policy Statement – by which DECC can provide more clarity about the respective roles of Ofgem and government (see paragraphs 18.53 and 18.54). For the reasons set out above, we believe that it is necessary to complement the Strategy and Policy Statement with mechanisms that would improve such coordination. Such mechanisms would apply to specific policies, the implementation of which is complex and requires multiple changes to the existing regulatory framework.

- *Mechanisms to increase the transparency of the policy implementation process*

19.95 We note that joint initiatives have been undertaken in the past by DECC and Ofgem in order to increase the transparency and coordination of their actions. These include, for instance:

(a) DECC's and Ofgem's joint consultation and implementation programme regarding smart metering;¹⁸

¹⁸ See Ofgem and DECC (July 2010), [Smart metering implementation programme: Prospectus](#).

- (b) a Memorandum of Understanding¹⁹ between DECC and Ofgem relating to the contingency plans that would apply in the event of the financial distress of an energy network company; and
 - (c) DECC's and Ofgem's joint action plans setting out a number of commitments by DECC and Ofgem to help independent energy suppliers to enter and grow in their target markets.²⁰
- 19.96 DECC and Ofgem have also put to us that they interact regularly for the purpose of discussing policy implementation. However, the outcome of these interactions has not been transparent and therefore not open to consultation. In our view, a transparent and coordinated approach between DECC and Ofgem to implement policies should be frequent and follow consistent patterns.
- 19.97 We also note that any joint statements between DECC and Ofgem need to be sufficiently detailed to ensure that they cover all the consequential changes and effects that are required to achieve the expected net benefits of a policy, as identified in the relevant impact assessments.
- 19.98 An example of a failure to do this is provided by DECC's and Ofgem's joint consultation and implementation programme regarding smart metering, and in particular its supporting document 'Regulatory and Commercial Framework'.²¹ These documents address various aspects of the roll-out of smart meters, but only briefly discuss whether amending the settlement periods (ie a move towards mandatory or optional half-hourly settlement) was required for the emergence of time-of-use tariffs. There was no clarity provided as to what action should be taken to achieve the desired outcome and who should be responsible.
- 19.99 Since 'load shifting' was a material aspect of the case in favour of the roll-out of smart meters in DECC's impact assessment, as highlighted in our report, we consider that DECC and Ofgem should have agreed on a set of concrete actions to ensure that such benefits would be delivered, including clear responsibilities for taking forward proposals for settlement reform. Further, as any such change was likely to require one or more code modifications as well as a change in commercial practices, DECC and Ofgem should have considered more carefully parties' incentives and hence whether the

¹⁹ See [Memorandum of Understanding between the Gas and Electricity Markets Authority, the Department of Energy and Climate Change and Her Majesty's Treasury](#).

²⁰ DECC and Ofgem (August 2013), [Government and Ofgem Action Plan: Challenger Businesses \(Independent Energy Suppliers\)](#).

²¹ Ofgem (July 2010), [Smart Metering Implementation Programme: Regulatory and Commercial Framework](#).

required change would be likely to be delivered through an industry-led process.

19.100 We believe that DECC and Ofgem should publish detailed joint statements in circumstances where the implementation of a DECC policy objective is likely to necessitate, in order to achieve its stated objective, parallel or consequential Ofgem interventions (eg through a licence change) or one or more code modifications.²² The level of detail of this implementation strategy should depend on the nature and complexity of the policy and its consequential implementation. However, we would expect these joint statements to cover broadly the following main areas:

- (a) an action plan setting out the list of regulatory interventions (including code changes), and the relevant entity in charge of designing and/or approving such interventions, that are necessary in order to implement the policy;
- (b) an estimated timetable for the completion of each necessary intervention; and
- (c) where appropriate, a list of relevant considerations that will be taken into account in designing each regulatory intervention.

19.101 Publishing detailed joint statements would facilitate the engagement of stakeholders, as these would have more clarity about the actual implications of the proposed action plan. They would therefore be in a better position to contribute their knowledge and expertise of the most legal and technical details of the industry, and to comment on DECC's and Ofgem's expectations regarding code modifications.

19.102 This in turn should be an effective way to raise, earlier in the implementation process, possible legal or technical issues to be addressed, and to gain an understanding of the likely effects of the relevant reform. It follows that these joint statements must be consulted upon before concluding the appraisal of the policy.

19.103 This process would also give more legal certainty to parties about the likely pace and technical implications of a given policy, allowing them to roll out the necessary internal changes (eg IT).

²² Better coordination between Ofgem and the industry is also required where Ofgem's regulatory interventions require amendments to the industry codes. This issue is discussed in below, where we propose a greater role in setting up a strategic vision for code governance, including the areas of codes that Ofgem consider needs to be amended.

19.104 As noted above, some policy changes may require code modification proposals to be raised by the industry. It is important therefore to ensure that DECC's strategic vision and policy objectives (as set out in the Strategy and Policy Statement) are reflected in the code governance arrangements. This remedy, which is focused on the relationship between DECC and Ofgem, therefore works synergistically with our remedies in relation to code governance, and in particular the need for Ofgem to develop a strategic plan for code modifications. We address this issue in our discussion of the Code Remedies (see paragraphs 19.295 to 19.421 below).

19.105 For the avoidance of doubt, nothing in this joint statement should prejudice the outcome of any future appraisal, nor constrain Ofgem (or DECC) in the way in which it exerts its functions in a manner that it considers is best calculated at the time to further its principal statutory objective.

19.106 Taking all the above factors into account, we have therefore decided to recommend that DECC designates a Strategy and Policy Statement, setting out its policy objectives, the respective roles of DECC and Ofgem in meeting these policy objectives, and principles governing the interaction between DECC and Ofgem. We have also decided to recommend that, where appropriate, DECC and Ofgem publish joint statements setting out a detailed plan of action for the implementation of specific policies, with clear responsibilities assigned between them.

- *Consideration relating to the effectiveness of this remedy*

19.107 This remedy will, in our view, help to provide transparency to stakeholders about the complete process of policy development and implementation, from the high-level objectives of government policies to the assessment and approval of the implementation measures needed to achieve these objectives. It follows that public bodies, as well as private entities within the context of consultations, will be in a better position to identify inconsistencies between contemplated regulatory interventions and the existing legal and regulatory framework, including consequential changes that might be required across licences conditions and industry codes. This, in turn, should lead to better project management of the process of designing, assessing and implementing policies. We therefore believe that it will contribute to addressing the Governance AEC, in particular by addressing the feature concerning the absence of a formal mechanism through which disagreements between DECC and Ofgem over policy decision-making and implementation can be addressed transparently.

19.108 We note, however, that this remedy focuses on the allocation of responsibilities. It will then be the responsibility of each stakeholder (DECC,

Ofgem and, within the context of codes modifications, the industry under Ofgem's supervision) to develop and implement the regulatory actions set out in the joint statement. Within that context, our remedy requiring Ofgem to publish Opinions on relevant draft legislation (see above) will further contribute to addressing this feature that gives to the Governance AEC.

19.109 As noted above in paragraph 19.95, DECC and Ofgem have in the past taken initiatives consistent with our remedy. No change in legislation is required and the remedy can be implemented by DECC and Ofgem immediately. We are therefore confident that this remedy is capable of effective and timely implementation. We note in this respect that DECC and Ofgem have expressed support for this remedy.

- *Consideration relating to the proportionality of this remedy*

19.110 This remedy will, in our view, be effective in achieving its aim. For the reasons set out in paragraph 19.109, we believe that this remedy is no more onerous than necessary and the least onerous of those remedies that we have considered to be effective. The incremental costs of this remedy, ie setting out clear plans and consulting on the steps that DECC deems necessary to implement certain policies, would be low and only incurred in a limited number of circumstances set out in paragraph 19.100 above. In those circumstances, it would only increase the transparency around work already carried out to a large extent by DECC and Ofgem. Similarly, as regards the designation of the Strategy and Policy Statement, this remedy should not add any further costs that were not already contemplated by the Energy Act 2013. We believe that any such costs would be substantially outweighed by the benefits arising from the increased robustness and transparency of the decision-making process.

Transparent analysis of impacts of policy and regulation

19.111 In this report, we have noted aspects of the structure and governance of the regulatory framework that have both contributed to the development of policies which are not in the best interests of consumers, and hindered the development of policies which are in the best interests of energy consumers. In particular, we found that the lack of effective communication on the forecast and actual impact of government and regulatory policies on energy prices and bills is one of the features contributing to an overarching feature of a lack of robustness and transparency in regulatory decision-making. In turn, this increases the risk of poor policy decisions which have an adverse impact on competition and the interests of energy consumers.

Aim of the remedy

19.112 The aim of this remedy can be seen as comprising two elements:

- (a) providing a clear and trusted assessment of the GB energy markets and regulation, including an analysis of the forecast and actual impacts and trade-offs resulting from energy policies that have been implemented (including updating forecasted impacts) and an overview of commercial trends in the GB energy markets; and
- (b) improving the communication of that analysis in order to inform public debate and policymaking.

Parties' views

- *Views on the existing analysis*

19.113 Parties were broadly supportive of our proposed remedy. Several parties' responses to our Remedies Notice flagged that there is a need for the ex ante and ex post assessment of policy impacts and trade-offs to be presented in a holistic way, and in a format which the public is able to understand. They suggested that this should include the likely impact of policies on bills, presented on a 'pence per unit' basis, to enable comparison against current rates paid by customers across the GB energy markets, and a simple explanation of suppliers' costs and how they might vary. As well as highlighting the omissions in the analysis currently available, parties identified various issues concerning the quality of that analysis, including:

- (a) a lack of transparency, particularly in relation to the underlying assumptions relied upon;²³
- (b) inconsistency, either with information subsequently published or as compared with information provided by other institutions, which impacts adversely on efficient decision-making concerning investment (particularly when coupled with the transparency issue, noted above);²⁴ and

²³ One party cited as an example the impact assessment for DECC's original proposals for an Energy Companies Obligation (ECO) which, in its view, lacked transparency around the assumptions as to customer contributions in relation to Green Deal financing plans taken out by consumers. This made it hard to identify any confirmation bias in DECC's assessment. The assumptions as to contributions subsequently turned out to have been inaccurate, with the result that the projected cost of ECO to consumers was underestimated.

²⁴ Examples cited included the figures published by the Office for Budget Responsibility relating to low carbon generation at the time of the summer 2015 budget were projected to be over £2 billion higher in 2019/20 than had been estimated at the time of the March 2015 budget.

(c) the use of counterfactuals, whereby DECC presents the benefits of a policy as compared with a counterfactual where no action is taken (rather than a counterfactual where another policy approach is adopted), or which incorporates changes in bills resulting from causes other than the policy intervention, creating confusion.

- *Views on who should perform the role set out in the proposed remedy*

19.114 A number of parties also felt that the information already in the public domain was tainted by a lack of independence on the part of the publishing organisation. They noted that there were unclear incentives to provide objective analysis and that this undermined trust and public confidence in the information: parties observed that there was an incentive for DECC to exercise confirmation bias, as the body responsible for developing policy, but that there was also a risk of confirmation bias by Ofgem,²⁵ and that Ofgem had previously shown a tendency to bow to political pressure, despite its formal independence. It was clear from parties' responses that they identified a need for an independent body to perform the role of disseminating reliable information, in a form accessible to all stakeholders, which sets out clearly and credibly the impact of policies and trade-offs across different policy objectives. Some parties specified, for example, that this information should be produced on a regular basis, or that it should have a common structure.

19.115 On that basis, a few parties were strongly in favour of a new institution being established in order to perform the new role set out in this remedy. RWE submitted that there was a need for a new institution with responsibilities separate to those of DECC and Ofgem. Under its proposed approach: DECC and Ofgem would retain responsibility for setting out estimates of the impact of policies and the role of the new institution would be to provide its independent view, identifying where it takes a different view in relation to such impacts and explaining the origin and nature of the differences as appropriate.

19.116 However, the majority of respondents were neutral or supported the function being performed by Ofgem, as a body independent from government. The need for independence was given as the reason why DECC would not be the appropriate body to perform this function. Parties acknowledged that extending the remit of existing organisations to encompass this function was likely to be easier than creating a new institution for this purpose and that Ofgem had the appropriate skills and resources to conduct the analysis and communicate its analysis to consumers (subject to the proper exercise of its

²⁵ The impact assessments produced for the RMR rules were cited as an example of this.

independence). They noted that Ofgem also had access to a substantial amount of market data and regulatory reporting, by virtue of its existing functions, which could be fed into its analysis (this might include, potentially, the additional financial reporting envisaged below).

- 19.117 Where there were aspects of the analysis which fell outside Ofgem's area of competence, Ofgem could seek input from other bodies operating within the same regulatory space such as the Committee on Climate Change, which already produced reports on the impact of meeting carbon budgets on energy bills. Ofgem's role in relation to regulatory reporting (see our remedy on financial reporting below) would also promote efficiencies, as the creation of a new body might result in an additional regulatory reporting burden being placed on industry participants. One party also commented that the body performing the role would need to have sufficient authority that its conclusions would contribute to improving policy.
- 19.118 Whether the role was housed within an existing institution or a new institution set up, the overall point made by parties was made that a clear delineation of responsibilities was essential.

Design considerations

- 19.119 Assessments seeking to improve all stakeholders' understanding of the impacts of energy policies (and therefore contribute to increasing the robustness of regulatory decision-making) may be considered to vary along two dimensions. First, the assessment may take place at two different stages in the policy development cycle:
- (a) The assessment of draft legislation or regulatory interventions before adoption (*ex ante*). *Ex ante* appraisal enables policymakers to consider the benefits of a proposed policy as against the costs before deciding whether or not to go ahead with its introduction.
 - (b) The ongoing assessment (*ex post*) of the impact of the regulatory framework on the GB energy markets. *Ex post* evaluation of the impacts allows policymakers to reflect on the extent to which policies have achieved their objective, permitting lessons to be learned and facilitating improved future policymaking.
- 19.120 Second, assessments vary according to the extent to which they cover individual policies or packages of several policies. Broadly speaking, assessments can be considered to fall within one of two categories, addressing either:

- (a) the impact of individual policies, ie the appraisal of draft legislation (ex ante), which enables the costs and benefits of the policy to be fully explored, and the review post-implementation of existing legislation, which facilitates the evaluation of the policy's effectiveness; or
- (b) the aggregated impact of a package of energy policies on the GB energy markets, which provides a clear picture of the interplay between policies, the trade-offs within policies and their influence on the GB energy markets.

19.121 The table below shows the different types of assessment against these two dimensions.

Table 19.1: Overview of policy assessments

	Impact of individual policy	Cumulative impact of policies
Ex ante assessment	Impact assessments/policy appraisals	Projected impact of package of policies
Ex post assessment (evaluation)	Evaluation of individual policies	Evaluation of package of policies/ongoing monitoring

19.122 In the paragraphs below, we consider the existing level of assessment available and then propose changes that, building on the existing framework, will contribute to remedying the Governance AEC.

Scope of remedy

19.123 As stated above, the aim of this remedy is to provide a clear and trusted assessment of the impact of policy interventions in the energy markets and to improve the communication of that analysis to all stakeholders (including policymakers, industry, media and public audience), with a view to informing public debate and assisting in the effective formulation of energy policy.

19.124 In order to achieve the aim of the remedies package, we consider below the changes that, in our view, should be made in the following areas

- (a) the assessment of the forecast impacts of individual policies by government (ex ante policy appraisal);
- (b) the assessment of the actual impacts of individual policies by government (ex post evaluation); and

- (c) the independent assessment of the aggregate impact of a broad package of climate change and energy policies (both ex ante and ex post).

19.125 We also consider how to ensure the effective communication of the above assessments to a wider audience. The overall objective is to inform public debate in this area and assist in the effective formulation of energy policy.

- *Assessment of the forecast impacts of individual policies – appraisal by government*

19.126 As already mentioned, government initiatives are typically subject to an impact assessment at the proposal stage, which in turn is subject to independent scrutiny from the Regulatory Policy Committee.

19.127 The format of such impact assessments requires that the policy objectives, the expected impacts and any alternate policy options considered are all set out in detail and a cost-benefit analysis carried out. The assessment is then subjected to the independent scrutiny of the Regulatory Policy Committee, which performs a quality assurance role, for example by conducting a sensitivity analysis of the impact assessment or picking up on any assumptions based on out-of-date data.²⁶

19.128 Our view is that DECC's processes are fit for purpose and that some of the remedies that form part of the wider package of Governance Remedies (ie Ofgem's publication of Opinions on draft legislation and Ofgem's evaluation of the broad range of policies governing GB energy markets) will facilitate in the future government's appraisal of draft legislation.

- *Assessment of the actual impacts of individual policies – evaluation by government*

19.129 As regards the review post-implementation of individual policies, we believe that the requirement, introduced by the *Better Regulation Framework Manual*, for government to carry out reviews of its policies will provide valuable insights to policymakers. The evidence for this review will be based on actual impact, rather than forecast impact. A comparison between actual impacts and forecast impacts might also assist government in future appraisal processes.

²⁶ Some parties commented on the quality of this analysis, around the lack of transparency in relation to assumptions underpinning the analysis, the inconsistencies with information published by other institutions, and the use of confusing counterfactuals. We believe that these comments should be addressed to DECC directly.

19.130 One potential issue may be the amount of resources which DECC chooses to dedicate to this exercise: the *Better Regulation Framework Manual* permits a range of approaches, from a full review for high-impact measures to a light-touch, desktop exercise;²⁷ however, the *Better Regulation Framework Manual* makes clear that, where the policy being reviewed has an impact of more than £50 million, a substantial review is expected. While it is too early to assess the effectiveness of post-implementation reviews by government of individual policies as envisaged by the *Better Regulation Framework Manual*, we are satisfied that the role of the Regulatory Policy Committee provides a check and balance on the quality of these reviews and thus do not propose any changes to this process at this point.

19.131 We fully support the requirement under the *Better Regulation Framework Manual* to carry out a regular review of individual policies and believe it will contribute to increasing the robustness of the decision-making process. In our view, for the reasons set out above, evaluation by the government of its own policies must be complemented by a regular, independent evaluation of the broad range of policies governing the GB energy markets. We therefore believe that the remedy set out below will facilitate the government's evaluations of individual policies.

- *Independent evaluation of the broad range of policies governing GB energy markets – state of the market assessment*

19.132 As already outlined, various institutions carry out analyses of broad policy areas (see paragraph 11.48 of the provisional findings report). In our view, however, these analyses should be communicated more effectively to a wider audience, in particular in relation to the interactions between policies and policy trade-offs within policies (eg concerning the trilemma). Also, meaningful ex post evaluation of policy impacts and trade-offs is, in our view, currently hampered by a lack of information concerning how wholesale energy costs, network costs, policy costs and profits contribute to changes in retail prices (and in energy companies' profitability).

19.133 Having regard to all of the above, we believe that there is a need for a more effective assessment of the cumulative policy impacts on the GB energy markets. In our view, a holistic and thorough review of the effects of energy policies on GB energy markets has the potential to inform public debate and improve future policymaking in this area. A key facet of this review would be the clarification of generation and retail profitability and the contribution to

²⁷ *Better Regulation Framework Manual: Practical Guidance for UK Government Officials* (March 2015, currently being updated), paragraph 1.8.19.

price increases made by wholesale energy costs, network costs, profit costs (and similar). As noted above, we have found that this lack of financial transparency is one of the features that has hindered robust and transparent regulatory decision-making, giving rise to the Governance AEC. The changes to financial reporting of revenues, costs and profits by generators and suppliers implemented as part of the remedy relating to financial reporting (see below) will contribute directly to an assessment of the state of the GB energy markets which is fit for purpose.

- 19.134 A more effective assessment of the cumulative policy impacts on the GB energy markets should provide both an ex post evaluation of actual impacts of climate change and energy policies as well as a projection of the forecast impact of these policies, taking into consideration structural changes in the foreseeable future (eg delayed implementation of legislation, changes in generation portfolio).
- 19.135 Parties' responses supported a proposal for an independent body to perform the role of disseminating reliable information, in a form accessible to all stakeholders, which sets out clearly and credibly the impact of policies and trade-offs across the different limbs of the trilemma. Having reviewed parties' submissions, we consider that Ofgem is the appropriate independent authority to conduct this 'state of the market' assessment. Within this context, we agree with Citizens Advice's suggestion that Ofgem should scrutinise the policy costs and assessments carried out by government and other stakeholders.
- 19.136 This new role for Ofgem is compatible with its existing statutory remit and would require it, as the sector regulator, to draw on its extensive knowledge of the markets. As noted by one of the responding parties, where Ofgem is not well placed to comment (eg on some aspects of climate change, as its remit extends only to gas and electricity, and not to all relevant areas such as transport and agriculture), it can draw on the analysis of other institutions, eg the Committee on Climate Change. Giving this role of publishing cross-policy impacts and trade-offs to Ofgem would also create efficiencies due to the existing regulatory reporting regime, which affords it access to significant amounts of industry data; these would be maximised by our remedy relating to financial reporting (see paragraphs below).
- 19.137 For the above reasons, we think that Ofgem is well-placed to perform the role due to its status as an independent, non-departmental public body. However, in order to strengthen its independence and remove any risk (actual or perceived) of confirmation bias, we have decided to recommend the creation of a new unit within Ofgem (eg an office of the chief economist), distinct from the policy teams within the organisation. Such an office of the

chief economist would be tasked with producing the state of the markets assessment on behalf of Ofgem.

19.138 Due to the complexity of the subject area, achieving a comprehensive and holistic assessment of the actual impacts of policies in the energy sector, and the trade-offs between different policy objectives, would be challenging. DECC highlighted in particular the difficulties involved in translating wholesale prices into retail prices due to the individual hedging strategies adopted by energy companies and the impact these have on the way in which savings are passed on to consumers. Although there will undoubtedly be challenges inherent in producing a holistic and wide-ranging assessment, Ofgem's sector knowledge and understanding of the energy markets nonetheless make it best-placed to address these. Also, centralising expertise within an Office of the Chief Economist could help overall understanding of the impact of a wide range of climate and energy policies, and increase consistency over time and across areas in the economic evaluation of policies.

19.139 As stated above, we envisage that Ofgem's assessment will set out policy initiatives implemented across the energy sector during the review period and provide analysis on, at least, the following areas:

- how energy prices and bills have evolved over the period of the review and what has contributed to this, including the cost of regulation;
- a periodically updated assessment of the social costs and benefits of climate and energy policies;
- the profitability of energy firms, and in particular the Six Large Energy Firms, on the basis of the data acquired as a result of the financial reporting remedy set out below in paragraphs 19.155 to 19.294;
- the impact of initiatives to reduce carbon emissions, including a tracker to measure progress against decarbonisation targets;
- the effectiveness of measures introduced to maintain security of energy supply and progress against targets;
- the interplay between these two areas (ie energy security of supply and decarbonisation) and the affordability of prices (trilemma trade-offs); and
- relevant trends and drivers for the forthcoming year, such as forecasts as to the likely direction of wholesale costs.

- 19.140 We envisage that this assessment would be published once per year, in line with Ofgem's commitment to report annually on retail markets. This would also be consistent with the publication of certain other annual reports addressing discrete aspects of the energy markets and which would inform Ofgem in carrying out this task. (This includes, for instance, Ofgem's electricity capacity assessment, DECC's annual report on the estimated impacts of energy and climate change policies on energy prices and bills, and the Committee on Climate Change's annual report.)
- 19.141 Parties commented on the scope of this state of the market report. We noted that the Federation of Small Businesses considered that Ofgem should go much further, particularly around key issues such as energy efficiency, smart meter uptake, energy management, performance of the TPI industry, complaints and the prevalence of tariff conditions like security deposits. uSwitch suggested that the state of the market report include switching targets that would be tracked in Ofgem's state of the market report. Citizens Advice argued that publishing dates should be fixed and published in advance to reduce the risk that the report be moved around to accommodate other of Ofgem's priorities. On the other hand, Scottish Power felt that this remedy would be resource intensive and should be tightly focused. It expressed concerns that a requirement to consider the social costs and benefit of policies, and the impact of initiatives relating to decarbonisation and security of supply could take Ofgem into new areas which would divert scarce resources and potentially duplicate activity already undertaken by DECC or other bodies. Scottish Power, as well as Stephen Littlechild et al, suggested that it would be more proportionate to have less frequent reporting.
- 19.142 We believe that Ofgem is better placed to determine the exact scope and format of this assessment, which may need to change over time. We have therefore decided not to be overly prescriptive in this regard. We believe, however, that in order to address the feature that we have identified, Ofgem should report annually on certain key aspects of the energy markets. This is consistent with Ofgem's own commitment to report annually on retail markets. We accept, however, that Ofgem may consider it appropriate not to carry out certain in-depth analysis of the markets, beyond the high-level scope outlined in paragraph 19.140, on an annual basis.
- 19.143 We envisage that the audience for the assessment will include stakeholders of all kinds, such as government, industry participants, media contacts and consumers. The different sections of the audience will have different expectations and requirements. As explored above, there is a need for government and the industry to understand the detailed analysis which can

then inform debate and the development of policy, whereas the media and consumers require a more accessible digest (eg in the form of an executive summary, which could be supported by media briefings). We envisage that Ofgem would be well placed to decide how to leverage its existing channels in order to communicate its findings to all of these stakeholders in the most appropriate manner. We have therefore decided not to be prescriptive in this regard.

- *Considerations relating to effectiveness*

19.144 As noted above (see paragraph 19.120), appraisals and evaluations of policies should focus on two key aspects:

(a) the impact of individual policies; and

(b) the aggregated impact of energy policies on the GB energy markets.

19.145 We consider that the existing level of assessment of the aggregated impact of energy policies is insufficient and contributes to the Governance AEC (and in particular concerning the feature of a lack of effective communication on the forecasted and actual impact of government and regulatory policies over energy prices and bills). We have therefore decided to recommend Ofgem to carry out such an assessment annually. We believe that Ofgem has the level of independence and expertise to provide robust and trusted analysis to all stakeholders.

19.146 To reinforce the effectiveness of this remedy, we have also decided to recommend that Ofgem establish an internal unit with relevant cross-cutting expertise (eg an office of the chief economist). We noted that Ofgem created earlier this year a new 'Improving Regulation' division, which is headed by Ofgem's chief economist. We have not taken a view as to whether this division should be the basis for the new internal unit we are recommending, as we consider it unnecessary to intervene in detailed matters of Ofgem's and GEMA's internal organisation and governance arrangements. As noted above, our key concern is to ensure that this analysis is carried out with sufficient levels of independence (including from other divisions within Ofgem and GEMA which may be responsible for certain interventions under scrutiny) and cross-cutting expertise (so as to be able to provide a holistic assessment).

19.147 As this new unit would essentially draw on existing resources and expertise, it could therefore be achieved in a relatively short time. Some recent initiatives taken by Ofgem show, in our view, that it is already committed to carry out analysis of this nature that may foster understanding, trust and

confidence among stakeholders. We therefore believe that this remedy is capable of timely and effective implementation.

19.148 We consider that a state of the market report produced by Ofgem would also facilitate DECC's appraisal and evaluation of policies. Similarly, our recommendation to Ofgem to publish Opinions on draft legislation (see paragraphs 19.69 to 19.90 above) will facilitate DECC's appraisal of individual policies.

19.149 We believe that the benefits that would arise from a trusted and independent assessment of the markets would provide benefits to the decision-making process and public debate.

19.150 For these reasons, we believe that this remedy would contribute to addressing the Governance AEC by providing clear and trusted expert assessment of the GB energy markets and regulation, and improving the communication of that analysis in order to inform public debate and policymaking.

- *Considerations relating to proportionality*

19.151 In terms of the state of the market report, the main costs of this remedy would be related to the recruitment and staffing costs attached to establishing a new unit (eg Office of the Chief Economist) within Ofgem. The level of these costs might be comparable to the costs incurred during the development of the state of the market report produced by Ofgem prior to the market investigation reference being made to the CMA, although these would be reduced by economies of scale and increased productivity over time. Also, as some of these analyses are already being carried out within Ofgem (although not in a centralised way), only the incremental costs should be considered. In any event, we believe that such costs would be largely outweighed by the benefits arising from the remedy.

19.152 In terms of the analysis of individual policies in accordance with the *Better Regulation Framework Manual*, the proposed approach (of supporting the innovation brought by it, including reviews of policies) does not attract any costs over and above what is currently planned.

19.153 For these reasons, we believe that our remedy is no more onerous than necessary to achieve its aim.

19.154 We considered (and consulted upon) the possibility of creating a new institution to perform the role of producing the state of the market report. The sole advantage of this proposal would have been that a new institution would be

fully independent from policy development. However, the disadvantages of this approach included the significant additional costs it would incur, diseconomies of scale and issues around credibility/visibility in an already crowded space. As set out above, the majority of parties supported using an existing body rather than creating a new body. Although it has a role in policy development, Ofgem is independent of government and our remedy provides for an additional degree of independence through the establishment of a separate office within Ofgem to take on the new function. We therefore believe that our remedy is the least intrusive of the remedies we have considered that is effective.

Regime for financial reporting

Introduction

19.155 We have found that the lack of a regulatory requirement for clear and relevant financial reporting concerning generation and retail supply profitability is a feature of the GB gas and electricity markets that, in combination with other features set out in Section 18, gives rise to the Governance AEC. This remedy seeks to address weaknesses in the current reporting regime so that Ofgem will be better placed in the future to make decisions using relevant information on the revenues, costs and capital employed (and hence profitability) of the principal firms active in these markets.

19.156 We believe that this remedy will provide Ofgem with information that will allow it to provide a clear and trusted assessment of the GB energy markets (see above our remedy relating to the annual publication of a state of the market report by Ofgem). This information will also be relevant in preparing Opinions (see remedy above) on government's draft policy proposals that are likely to have a material impact on GB energy markets. This, in turn, will inform the public debate and enhance government's ability to design and implement appropriate policies.

- *Ofgem's current ex post reporting regime for the Six Large Energy Firms*

19.157 Each year Ofgem obtains profit and loss accounts ('segmental statements') for certain firms' generation and retail supply activities (the Relevant Licensees). We describe in more detail these reporting requirements in Section 18.

19.158 We note that currently only the Six Large Energy Firms qualify as Relevant Licensees and therefore, in the section below, we discuss this remedy with

reference to the Six Large Energy Firms. For the reasons set out in Appendix 19.1, we are not recommending that Ofgem change this definition.

- *Ofgem's ex ante reporting tool*

19.159 As set out in Section 18, Ofgem developed alongside the ex post reporting regime a price monitoring tool in which it sought to track the relationship between costs and domestic prices. This initiative became known as the Supply Market Indicator (SMI). In May 2015, Ofgem suspended the SMI.

- *Aim of the remedial action and envisaged outcome*

19.160 The aim of this remedy is to improve Ofgem's decision making in both the short and long term. The immediate aim of this remedy is to ensure that Ofgem regularly obtains financial information from the Six Large Energy Firms that will enable it to undertake robust analysis of the firms' outturn profitability in both the generation and retail supply markets.

19.161 In addition, given that the actual profitability of an energy firm for its retail supply activities in any one period is strongly influenced by the timing and mix of wholesale energy products purchased by that firm, our remedy will help Ofgem assess retail supply profitability on a basis that is comparable across firms in this respect and that, at the same time, will give a better indication of the intensity of competition in retail supply markets than outturn profitability.

19.162 As segmental financial statements appear only once per year, typically several months after the end of the accounting year (which, in the case of SSE, is three months later than the other Six Large Energy Firms²⁸), Ofgem needs a more timely, if less complete, tool to monitor the trend in the relationship between wholesale costs (ie wholesale energy, network costs and social and environmental costs) and prices. An additional aim of this remedy is, therefore, to help Ofgem develop an ex ante price monitoring tool which would provide a more robust comparison of costs to prices.

19.163 These three analyses, in conjunction with other relevant evidence, will then allow Ofgem to provide a trusted assessment of the state of competition in GB generation and retail supply markets, and in turn lead to better policy decisions being made.

²⁸ See discussion of SSE's year end in Appendix 19.1, paragraphs 78–80.

19.164 Ofgem and other stakeholders, as set out in Appendix 19.1,²⁹ raised wider concerns over current segmental reporting, beyond Ofgem's ability to perform such analysis. It is therefore also important that stakeholders have confidence that, regardless of the organisational structure of each of the Six Large Energy Firms, the financial information produced is relevant, complete, understandable and comparable across each of the Six Large Energy Firms. Likewise stakeholders need to have confidence in any price monitoring. Achieving this outcome, which is important to achieve a shared understanding of the markets, is therefore also an aim of this remedy.

Parties' views

19.165 A proposed reporting remedy was set out in our Remedies Notice and further developed in our provisional decision on remedies. In this section we have focused on stakeholders' comments on these proposals that specifically address its design, effectiveness and proportionality.

19.166 We have included a thematic summary of stakeholders' responses regarding the remedy as well as a summary of responses on a stakeholder-by-stakeholder basis in Annexes A and B to Appendix 19.1. We address responses in the discussion below and in Appendix 19.1.

Design considerations: ex post reporting regime

19.167 We have identified four key deficiencies in the existing regulatory financial reporting obligation:

- (a) some firms' activities are separated along firm-specific divisional lines rather than relevant market lines;
- (b) firms are not required to provide balance sheets alongside profit and loss accounts;
- (c) wholesale energy costs for retail supply are not disaggregated in a manner that allows Ofgem to understand, for the purposes of its regulatory functions, the level of profitability of the Six Large Energy Firms' retail supply activities on a comparable basis; and
- (d) firms are not required to provide prior period comparatives.

19.168 In this section, we set out the enhancements we are recommending to address each of these deficiencies. These enhancements will, in our view,

²⁹ See Annexes A and B to Appendix 19.1.

ensure that Ofgem receives on a regular basis 'clear and relevant financial information' regarding the Six Large Energy Firms, and therefore will contribute to remedying the Governance AEC. Later in this section we set out how we will implement this remedy.

- *A: Separation of firms' activities along market rather than divisional lines*

19.169 We noted that the lack of a requirement to provide financial information on market lines (rather than on divisional lines) has undermined Ofgem's ability to assess the state of competition in the energy markets.

19.170 We therefore recommend that Ofgem require the Six Large Energy Firms to report financial information relating to their activities along market lines. This would also have the effect of considerably enhancing cross-firm comparability.

19.171 Several stakeholders, including all of the Six Large Energy Firms, told us that regulatory reporting requirements should not in any way constrain their ability to run their businesses in the way that best fitted their commercial interests. Our view is that the reporting of financial information on market lines would not preclude the Six Large Energy Firms from maintaining their own divisional structures (including for the purpose of their annual reports). However, those of the Six Large Energy Firms that chose to base their accounting along divisional lines which did not align with market lines would be required, under this remedy, to produce a separate set of accounts for regulatory reporting purposes only.

19.172 Reporting along market lines for the purpose of our remedy entails the following principles:

- (a) The Six Large Energy Firms should report all activities that relate to a particular market (as defined for that purpose by Ofgem) regardless of how these activities are allocated for statutory or internal reporting purposes.
- (b) Reporting in relation to each relevant market should be done on a stand-alone basis, taking into account (as per (c) and (d) below) those goods and services a firm in one market provides to itself (ie intra-group) in another (transfer charging).
- (c) Transfer charging (for the purpose of (b)) should be based on goods and services actually provided between these markets. Goods and services transacted freely between one independent party active in one market

and another independent party active in another market provides evidence that these goods and services are market products.

(d) Transfer prices should be based on the prevailing prices for that good or service as per (c) as at the time of sale or purchase.

19.173 In Appendix 19.1³⁰ we elaborate on these principles and on the principles for identifying relevant markets and segments within markets.

19.174 We also recommend that Ofgem require the Six Large Energy Firms to use only standard wholesale products, and not bespoke products, as the basis for any transfer charging between the different markets in respect of internal supply.³¹ We believe that such a measure will help ensure that transfer charging is seen to be robust, reliable, consistent over time, and comparable between the Six Large Energy Firms.

- *B: Provision of balance sheets alongside profit and loss accounts*

19.175 The Six Large Energy Firms are not currently required to prepare balance sheets alongside their profit and loss accounts either for generation or retail supply and therefore any assessment of firms' performance is currently limited to that of profits (which is a less relevant tool than profitability, ie return on capital, to assess the state of the market).

19.176 We therefore recommend that Ofgem require the Six Large Energy Firms to prepare balance sheets at least to cover all generation and retail supply markets separately. This should be done along market lines (for the reason set out in paragraph 19.169). The profit and loss account would need to tie in with the balance sheet, the profit in the former reconciling³² with the change in net assets in the latter.^{33,34} Providing a balance sheet on such a basis will enhance the integrity of the profit and loss account by helping to ensure that no items are missing and that revenues and costs in the profit and loss account are consistent with values given in the balance sheet.

³⁰ See Appendix 19.1, *Principles relevant to identifying which markets should be reported on*.

³¹ Where internal supply simply reflect the costs externally incurred by the firm, eg where a product is purchased in the market by one division and then transferred to another division, the external purchase price could be used. If the firm purchases a bespoke product from a third party, the price paid represents a market price.

³² The reconciling items would relate to transactions with owners, such as dividend payments.

³³ See *Profits determined on the basis of comprehensive income*, paragraphs 52–54, within Appendix 9.9 (Profitability approach).

³⁴ This requirement would not involve a fundamental change of approach to current reporting for the profit and loss account, rather it might mean that certain profit and loss items, which are currently treated as reconciling items between these profit and loss statements and the segmental statements for statutory reporting, would need to be reported on the face of the profit and loss account. See Appendix 19.1, paragraph 36.

19.177 Some of the Six Large Energy Firms have submitted that preparing balance sheets without also revaluing assets to their current value would not assist Ofgem.³⁵ We disagree. The purpose of this requirement is to provide the information Ofgem needs as a starting point to undertake and interpret the Six Large Energy Firms' profitability in the different relevant markets. This does not preclude Ofgem needing, on occasion, to make adjustments to that information. Indeed, we recognise that Ofgem may need to update certain assets or liability values to undertake and interpret its profitability analysis. Preparing balance sheets as per our remedy will provide Ofgem with balance sheets that are complete and internally consistent with suppliers' profit and loss accounts, which will be a considerable advantage when undertaking a profitability assessment.

19.178 RWE questioned the relevance of non-operational items such as goodwill, deferred tax and loan balances to the balance sheet.³⁶ It also told us that it was not possible to split out cash.³⁷ Centrica made a similar point in relation to tax and interest from the perspective of the profit and loss account.³⁸ In line with the approach we have adopted in our ROCE analysis, we have always intended the scope of the balance sheet and profit and loss to be limited to operating revenues, costs and capital employed. Such an approach abstracts from the financing and tax structures adopted by individual firms (and the goodwill balances held by them), thereby avoiding the issues that RWE and Centrica described.

- *C: Disaggregation of wholesale energy costs for retail supply between standardised opportunity cost and residual elements*

19.179 The cost of wholesale energy is the single largest cost item in the profit and loss account for retail suppliers. However, there is currently no mechanism to assess the cost of wholesale energy to suppliers on a comparable basis, ie excluding windfall losses or gains arising from trading activities.

19.180 For the reasons set out in Section 18, we consider that there is a compelling need for the development of a common measure of wholesale energy costs that can be applied across the Six Large Energy Firms. This would make the relationship between wholesale and retail prices more transparent and therefore lead to a greater understanding of the nature of competition in the retail supply markets.

³⁵ Appendix 19.1, Annex B, paragraph 15.

³⁶ Appendix 19.1, Annex A, paragraph 67.

³⁷ Appendix 19.1, Annex A, paragraph 64.

³⁸ Appendix 19.1, Annex A, paragraph 48.

- 19.181 We initially proposed to assess the cost of wholesale energy used within retail supply solely on the basis of market prices for standard wholesale products.³⁹ The Six Large Energy Firms pointed out certain limitations of such an approach and the alternative ‘spot’ pricing scenario analysis we had previously carried out.⁴⁰ They submitted that the former did not necessarily reflect their actual purchase costs and that the latter reflected an imprudent approach to purchasing which would substantially increase the likelihood of a supplier becoming insolvent, if wholesale costs were to rise sharply.⁴¹ We therefore revised this aspect of this remedy by proposing that actual wholesale energy costs be disaggregated between an opportunity cost and a residual element.
- 19.182 Some of the Six Large Energy Firms expressed concerns about certain aspects of our revised proposal as set out in the provisional decision on remedies by which firms’ actual purchase costs would be disaggregated between an opportunity cost and a residual element. While Scottish Power told us that our proposal for standard fixed-term products broadly reflected a prudent purchasing strategy, it, EDF Energy, Centrica, RWE and SSE all told us that, in relation to their SVT, purchasing in line with contractual commitments to customers was not consistent with the actions of a prudent retail supplier, who would want to purchase over a more extended period. These same firms were also concerned about how residual costs would be interpreted and communicated to a wider audience. E.ON was concerned that we ran the risk that these reporting requirements would inappropriately influence their commercial hedging behaviours and strategies,⁴² a view shared by all the other Six Large Energy Firms.
- 19.183 Ofgem, however, supported our proposal to require the Six Large Energy Firms to provide standardised information about their wholesale costs but also highlighted the risk of confusion from the Six Large Energy Firms publishing two measures of wholesale energy costs. Citizens Advice told us that stakeholders must be able to understand both the purchase opportunity cost and residual cost elements. The Six Large Energy Firms also raised concerns about the scope for confusion and how this could in turn undermine trust in the reliability of this information. EDF Energy told us that some commentators could misinterpret residual costs as being the result of

³⁹ This is the first variant of the accounting approach to costing wholesale energy as discussed in paragraphs 10.249–10.255 in the provisional decision on remedies.

⁴⁰ Provisional findings report, [Appendix 10.5](#), Annex B (Wholesale spot scenario analysis).

⁴¹ Appendix 19.1, Annex B, paragraphs 8–12.

⁴² Appendix 19.1, Annex A, paragraph 24.

speculative activity, even though, in its view, the reverse in fact would be true.

- *The logic for our remedy concerning the costing of wholesale energy costs for retail supply*

19.184 Businesses tend only to commit to deliver goods or services at a future point in time for an agreed price if they are also able to purchase their major inputs for meeting this commitment at the same time. Such an approach affords businesses a degree of confidence about the profit margins they will eventually earn.⁴³ This is particularly the case when the prices of certain major inputs can fluctuate significantly (and unexpectedly) between the point of agreeing the sale and delivering the goods or services.

19.185 We have observed that energy firms also tend to adopt this approach. For example, we understand that generators only sell forward for an agreed price if at the same time they are also able to secure the fuel and carbon allowances required for a given price. Similarly, when agreeing a contract to supply in retail supply markets on a fixed-term fixed-rate basis, retail suppliers tend to seek at the same time to purchase forward at a given price in the wholesale markets the energy they expect to supply over the term of the contract.

19.186 The extent to which suppliers are able to purchase wholesale energy forward therefore influences the range of retail supply tariffs that firms are willing to offer their customers. Centrica stressed this aspect of the operation of the retail supply markets to us.⁴⁴ Retail suppliers may be reluctant to supply customers under a particular tariff at a given price unless they can at the same time purchase the wholesale energy they expect to supply at that given price in forward markets, at least on an approximate basis.

19.187 By purchasing forward when taking on a commitment to supply their customers on a particular tariff at a given price, retail suppliers minimise their exposure to subsequent movements in wholesale energy costs without resorting to costly insurance products. By not purchasing ahead of taking on a commitment to supply retail customers, suppliers would also avoid the risk of paying more for wholesale energy than they could expect to recover in highly competitive retail supply markets.

⁴³ We note that this practice is called hedging. We, however, tend to avoid the use of the term hedging because it can relate to purchasing wholesale energy for transactions a firm forecasts that it will enter into, rather than ones that it has contractually entered into. As we explain later, we make a distinction between these two types of 'hedging'.

⁴⁴ Appendix 19.1, Annex B, paragraph 10.

19.188 We describe the cost of purchasing in line with this approach set out in the paragraph above as the purchase ‘opportunity cost’, rather than a historical or current (‘spot’) cost. At the point at which a retail supplier commits to supply its customer on a particular tariff at a given price, we might expect a retail supplier to purchase forward its expected wholesale energy requirements in order to be confident that it will in due course be able to meet its obligations in relation to its customers.⁴⁵ Under this approach, the (expected) cost of pursuing the opportunity to supply an individual customer is therefore the prevailing wholesale market price at the point of taking on the commitment to supply, ie the date of the contract between the retail supplier and customer.⁴⁶ This amount represents the cost of the other commercial opportunities foregone by the retail supplier.^{47,48}

19.189 Costs calculated on this purchase opportunity cost basis would at the same time reflect the costs of purchasing wholesale energy that one might expect to observe in competitive markets.⁴⁹ In such a retail market, suppliers who had not purchased key inputs ahead of having a guaranteed profitable outlet for them, would be compelled to factor into their prices the prevailing cost of satisfying the obligation to supply.

19.190 Reporting on the basis of incurred cost (or an approximation thereof) as the Six Large Energy Firms currently do in their segmental statements is likely to cause a problem when interpreting profitability because reported performance will reflect a mix of (a) a firm’s performance acting as a prudent retail supplier, and (b) the outcome of the way in which that firm has actually purchased its wholesale energy, the latter of which, as explained below, will typically not be directly relevant for assessing the nature of competition in the retail supply markets.

⁴⁵ A retail supplier could, of course, choose not to purchase at this point and rely on near time and spot markets. However, such a retail supplier would be taking on the risk of adverse price movements that could threaten it with bankruptcy. Historically such an approach has not been sustainable over the longer term. See paragraph 10.253 of the provisional decision on remedies and footnote 76. This footnote refers to Appendix 3, *Exits from the supply markets since 2000 (to 2006)*, of Supplementary evidence submitted by Energywatch to the Select Committee on Business and Enterprise, dated 28 July 2008.

⁴⁶ We note that there is a further element to the opportunity cost, the incremental cost of meeting *actual* demand rather than *expected* demand (as described above), that is explained further in paragraphs 50 to 52 of Appendix 19.1.

⁴⁷ While, in principle, such a firm could sell on any energy it had already purchased, it would remain under an obligation to supply the customers it had previously contracted with. So, were the firm to sell on this energy in practice, it would then have to purchase the requisite amount of wholesale energy once again at the subsequently prevailing price. The firm would, therefore, leave itself exposed to unexpected movements in wholesale energy prices between the point at which it sold the energy it had originally bought and the point at which it purchased the energy for the second time.

⁴⁸ See also graph titled ‘Not laughing’ in article titled ‘*The Energy Business*’, *The Economist* (13 February 2016) as an example of the use of opportunity cost. In this graph the total cost that a retail supplier would expect to incur to supply a customer using the prices for standard wholesale products prevailing at each point in time is estimated over a series of successive points in time.

⁴⁹ See footnote to paragraph 19.187 on our use of the highly competitive market standard in this context.

19.191 We, therefore, recommend that Ofgem requires the Six Large Energy Firms to disaggregate their actual wholesale energy purchase costs for their retail supply businesses between an opportunity cost calculated on a standardised basis and a residual amount. Implementing this recommendation would require the introduction of a reporting rule that involves standardising the point ahead of delivery at which it is deemed that the Six Large Energy Firms take on the commitment to supply.

- *Application to different types of tariffs*

19.192 In the case of fixed-term contracts, this standardised point would be the point at which each of the Six Large Energy Firms becomes contractually committed to supply energy on a particular tariff at a given price for the volumes that the customer will demand. For example, for a one-year fixed-term fixed-rate tariff, this point would currently be roughly two weeks before the start of the 12-month delivery period.

19.193 In the case of evergreen contracts, some retail suppliers may wish to offer a degree of price smoothing on their variable tariffs by changing prices less frequently than the maximum frequency allowed under the contract with their customer or in accordance with the notice period mandated by the regulator for price changes.⁵⁰ These suppliers may in practice seek to purchase the volumes they expect to supply at the smoothed price somewhat further ahead of delivery than the point at which they become contractually committed to supply their customers at a given price.

19.194 The proposed treatment of evergreen contracts in our provisional decision on remedies was broadly in line with their contractual form (see footnote 50), notwithstanding the practice by some suppliers to offer a degree of price smoothing, namely, to treat evergreen contracts such as the SVT as a one month fix.

19.195 As noted in paragraph 19.182, all of the Six Large Energy Firms set out concerns with this proposed treatment, many highlighting the price volatility that the absence of such smoothing practice might imply. These parties argued that this volatility was not desired by their customers, and in addition created risk for their businesses. RWE highlighted that price volatility at one month ahead was large and similar in magnitude to the volatility that would

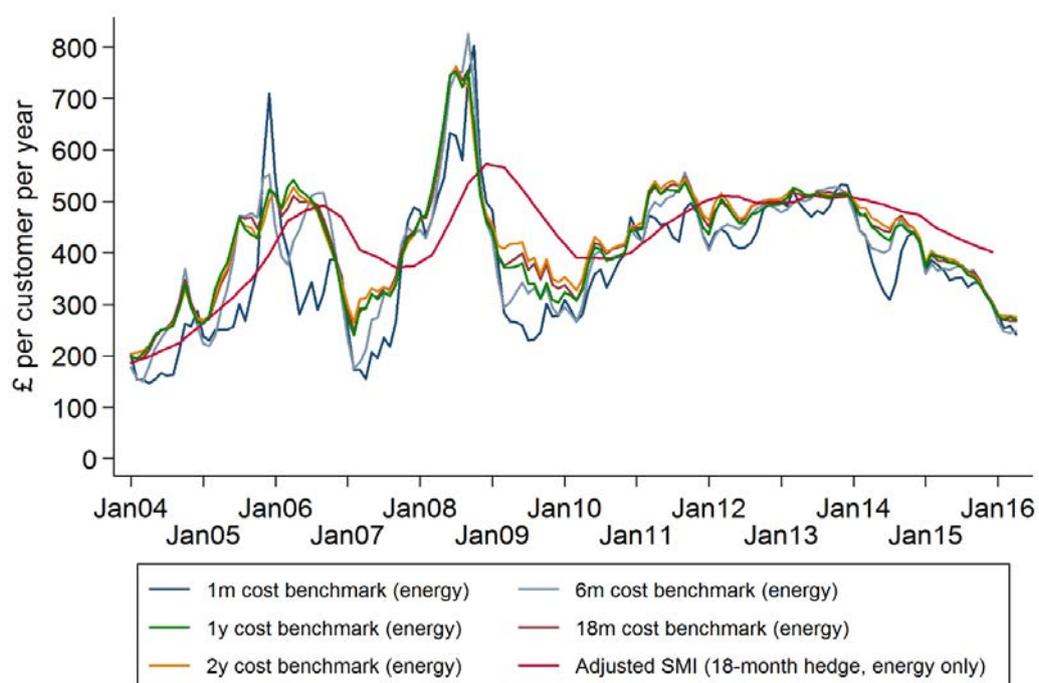
⁵⁰ Retail suppliers are free to change the price of their evergreen variable tariffs such as the SVT as often as they like subject to the domestic customers' ability to terminate the evergreen contract after giving a maximum notice period of 28 days (SLC 24.6). See Standard Condition 24.6 of the [Electricity](#) (p209) and [Gas Supply Licences](#) (p191).

affect a strategy based on purchasing at spot prices, an approach we had rejected.

19.196 In light of these comments, we have reconsidered this aspect of our proposal. We remain of the view that a rateable purchasing strategy (ie purchasing gradually in advance over an extended period), as Scottish Power submitted, is not relevant for assessing competitive outcomes, even for evergreen products such as the SVT. This is because such an approach implies, regardless of intervening changes in wholesale energy prices, that historically incurred costs form part of a competitive cost base.

19.197 We therefore limited our reconsideration to the forward timeframe over which we would expect suppliers seeking to supply a smoothed price SVT to purchase forward their customers' expected demand. We looked at a number of different potential forward timeframe cost benchmarks as represented in the figure below. The SMI benchmark is also shown to illustrate its smoothed nature.

Figure 19.1: Cost benchmarks for different forward timeframes for a dual fuel, typical consumption customer*



Based on typical domestic consumption of 3200kwh/year for electricity and 13500kwh/year for gas
Energy costs only

Source: CMA analysis of data collected from Ofgem and ICIS
*Based on Ofgem TDCV for gas and electricity.

19.198 We note that from Figure 19.1 that the six-month ahead forward timeframe measure has been less volatile than that of the one-month forward timeframe measure, and that the 6- and 12-month ahead measures have tended to move together at times of both rising and falling energy prices.

19.199 Therefore, for evergreen contracts such as the SVT, we have decided to use as a standardised point six months ahead of delivery, rather than one month as proposed in our provisional decision on remedies.⁵¹ On the one hand, we agree that SVT pricing should not be expected to reflect volatile changes from seasonal weather norms that can be reflected in the one-month ahead standard. We also note that customers may value a degree of shorter-term price smoothing and, where this is the case, purchasing a month ahead would represent an imprudent strategy on the part of the supplier. On the other hand, standardising the point of purchase at one year ahead risks treating the SVT as though it was the same as a one-year fixed-term fixed-rate product.

19.200 We note that historically SVT prices have moved every six to nine months. Therefore, we consider it reasonable to expect SVT prices offering a degree of price smoothing to be recalibrated on average every six months or so. For this reason we consider this to be the most suitable timescale over which to standardise the point at which suppliers would be expected, for the purpose of these calculations, to purchase wholesale energy.

19.201 As a result of making this modification to the point at which SVT energy costs would be standardised, an estimate of the incremental purchase cost of supplying energy on this smoothed basis will be systematically included in the measure of the purchase opportunity cost.

- *Products to be used to estimate costs on a standardised basis*

19.202 We recommend that Ofgem require the Six Large Energy Firms to calculate the opportunity cost of their wholesale energy purchases on this standardised basis using standard wholesale products. This is for two main reasons. Firstly, this approach will strip out any variations in cost arising from the use of non-standard products. Standard products are products which guarantee the supply of a stipulated quantity of energy over a stipulated period whereas non-standard products feature other potential benefits or disadvantages, which effectively means they are bundled products.⁵² Secondly the prices for the standard wholesale products are the result of a

⁵¹ See Appendix 19.1, paragraph 60 for further detail of the recommended treatment of evergreen tariffs such as the SVT tariff for the purpose of calculating purchase opportunity costs.

⁵² For example, long-term gas contracts can feature the option to buy more in one period to meet exceptional demand at the price stipulated in the contract at the expense of being able to buy less in another future period. This is a valuable 'swing' option to a retailer supplier who otherwise might have to buy extra energy at an elevated spot price reflecting the exceptional demand at that point in time. Another example is that a purchaser of intermittent energy, like wind, takes on the added cost of addressing any shortfalls/excesses between what the wind farm was predicted to supply and what it actually did supply.

market process that we have found to be competitive and are readily observable and verifiable.

19.203 As noted in our provisional decision on remedies, the requirement to report wholesale energy costs disaggregated on a standardised basis should not be interpreted as an obligation to purchase wholesale energy in this standardised way. The Six Large Energy Firms, however, submitted⁵³ that a standardised approach to costing might drive standardisation in purchasing behaviour across the Six Large Energy Firms, thereby adversely influencing the range of tariffs available and the keenness of pricing. We do not, however, agree that a standardised approach to reporting these costs would inevitably push energy suppliers to adopt that same approach in carrying out their actual energy purchases. Suppliers will have the freedom to purchase using the timescales and wholesale products they judge best as is currently the case.

- *Residual wholesale energy costs*

19.204 There will be some actual costs that retail suppliers have incurred that are not captured within this measure of the purchase opportunity cost. For the purpose of this report, we defined this as the 'residual cost'. In the case of fixed-term contracts, this residual cost will reflect the cost to the retail supplier of 'holding positions' in the wholesale energy markets. Such cost may arise either from purchasing wholesale energy in advance of the point at which it becomes contractually committed to supply it or, having taken on a contractual commitment to supply, the firm holding an open position before it contracts for its expected wholesale energy needs closer to the point of delivery. (However, we note that, for the reasons set out in paragraphs 19.194 to 19.201, with respect to evergreen tariffs, we have used a deemed, rather than contractual, position.) In this way, the residual cost will reconcile the purchase opportunity cost with the actual cost incurred.

19.205 To ensure the integrity of the financial statements, it is important that both the opportunity and residual cost elements of wholesale energy purchases are identified in the profit and loss account. Otherwise retail suppliers would not be able to fully account on the face of the profit and loss account for all of the wholesale energy they have actually purchased in order to supply their customers, and thereby report the profits they had actually made from supplying their customers in the period.

⁵³ For example as described by E.ON in paragraph 19.182.

- *Interpretation of purchase opportunity cost and residual cost*

19.206 As set out in paragraph 19.183, many respondents to the provisional decision on remedies raised concerns about how analysis based on this disaggregation of wholesale energy costs would be interpreted. We expect that as a result of the more granular information on wholesale energy costs reported to it by each of the Six Large Energy Firms, Ofgem should be in the position to disaggregate outturn financial performance for each of the Six Large Energy Firms between (a) its performance as a prudent retail supplier operating in a competitive market, and (b) its performance as a purchaser of wholesale energy. We would also expect Ofgem to provide an interpretation of the Six Large Energy Firms' performance disaggregated on this basis to allow stakeholders to place this information in context

19.207 We recommend that Ofgem implement a methodology that estimates the opportunity cost of their wholesale energy purchases on a standardised basis for each type of tariff, including evergreen tariffs such as the SVT, either by incorporating it into a standard licence condition or into guidance that is directly linked to the condition. We set out further details in Appendix 19.1 of how such a methodology could be implemented.

- *D: Prior period comparatives*

19.208 Ofgem's decisions involve making judgements based on evidence, including judgements relating to the financial performance of the Six Large Energy Firms. Consequently, financial information about one of the Six Large Energy Firms is more useful if it can be compared with similar financial information about the other Six Large Energy Firms and over time.

19.209 Currently the Six Large Energy Firms are required to report their profit and loss figures only for the current period. This has meant, historically, that whenever the Six Large Energy Firms changed their accounting policies or basis of transfer charging from one period to the next, then there was no mechanism to systematically make sure that figures for all prior years were restated, and that the firm appropriately described the changes in the basis of preparation.

19.210 We therefore recommend that Ofgem require that the financial statements provided to it (ie both the profit and loss account and the balance sheet) should include prior period comparatives based on the same accounting rules.

19.211 This will enable Ofgem to undertake and interpret profitability analysis confident that for two adjacent periods the information has been presented

on a comparable basis. In the published profit and loss accounts and balance sheets the Six Large Energy Firms would provide comparative figures.

19.212 Most of the Six Large Energy Firms told us they were content to provide prior year comparatives, although some noted that the accompanying explanations would make the statements longer. E.ON told us that information should only be required from the following year in which a new or amended reporting requirement had been implemented. This was because it would not have collected the information in the normal course of business and it might prove difficult to acquire this information retrospectively.⁵⁴ EDF Energy made a similar point. We understand this concern. We consider that Ofgem should give firms subject to reporting obligations sufficient advance notice of changes that allows them to prospectively collect the requisite underlying data to prepare prior year comparatives. This approach is in line with best accounting standard setting practice.

19.213 In Appendix 19.1⁵⁵ we discuss in further detail the importance of comparability in financial information. We explain in that appendix how other elements of our reporting remedy would contribute to greater comparability of the segmental financial information for generation and retail supply across each of the Six Large Energy Firms than has previously been the case.

Design considerations: ex ante reporting tool

19.214 As a complement to accounting information, it is possible to produce forward-looking (ex ante) financial information. This information substitutes, for example, a forecast bill for a typical consumer on a typical tariff for outturn revenues and a forecast of the cost of supplying that customer for outturn costs.

19.215 Citizens Advice told us that we should not focus exclusively on ex post financial reporting and there was also a need for current analysis/forward-looking projection of the costs of retail supply which would help consumers understand the drivers of price rise or price cut. Citizens Advice was therefore concerned about the prospect of a protracted suspension to the SMI⁵⁶ and urged that we recommend that Ofgem reinstate the SMI.⁵⁷

19.216 In November 2015 Ofgem took us through the different options that it was considering as part of its review of the SMI, in light of the new suite of retail

⁵⁴ Appendix 19.1, Annex A, paragraph 25.

⁵⁵ *Comparability*, paragraphs 66–80

⁵⁶ Appendix 19.1, Annex B, paragraphs 35 & 146.

⁵⁷ Appendix 19.1, Annex A, paragraph 11.

supply market indicators that it had recently launched. It told us that it had been often been viewed as a live version of the Six Large Energy Firms' segmental statements. As a result, however, the credibility of the SMI forecasts had been undermined. This was because, after allowing for the adjustments Ofgem had made to take account of the fact the former (the segmental statements) was an outturn and the latter (the SMI) was a forecast, the SMI predictions had begun to diverge significantly from the Six Large Energy Firms' outturn profits.

19.217 In our analysis we have identified a deficiency in Ofgem's currently suspended retail price monitoring tool, the SMI.⁵⁸ This is that wholesale energy costs are based on a forecast of historically incurred costs, and not a measure that would be expected to inform prices in a competitive market.

19.218 We agree with Citizens Advice that Ofgem, as a complement to the ex post accounting information, should have access to a tool to help more timely monitoring of market developments affecting retail pricing such as those described in paragraph 19.214. However, such a tool needs to address the wholesale cost design deficiency. We therefore recommend to Ofgem that, in its consideration of the future form of its price monitoring tool, it consider and address the design deficiency that we have identified.

19.219 In this section we set out the feature that we recommend Ofgem reflect within a revised price monitoring tool.

- *Measuring wholesale energy costs on an ex ante basis*

19.220 Ofgem used an 18-month rateable hedging strategy to determine wholesale energy costs within the SMI. However, in our view, such a measure reflects a forecast of costs that the energy suppliers would actually incur, not those that would be expected to inform prices in a well-functioning market. In this regard, the purchase opportunity cost approach can also be used to estimate wholesale energy costs at any one point on an expected basis.⁵⁹ The difference between this estimate and the forecast of costs that energy suppliers would actually incur is a measure of the windfall 'trading' gains or losses that the supplier would record at the point of delivery (assuming volume expectations are met). This latter element is not relevant to an assessment of the competitiveness of prices.

⁵⁸ Paragraph 18.138.

⁵⁹ In the paragraphs above we have described this approach applied on an outturn basis (ie the purchase opportunity cost of the firm meeting actual demand in the historical period) because the ex post financial reporting regime deals with outturn financial statements.

19.221 We therefore consider that the purchase opportunity cost would provide a helpful, and better, basis against which the Six Large Energy Firms might explain movements in the pricing of their tariffs with regard to changes in wholesale energy prices, rather than using a forecast of the costs as per the approach used by Ofgem's SMI (ie what Ofgem would expect the Six Large Energy Firms to incur were they each to be consistently implementing an 18-month rateable hedging strategy for the SVTs they offer).

19.222 Therefore we recommend that Ofgem take appropriate steps, in its ongoing work to develop a price monitoring regime, in order to ensure that such regime measures wholesale energy purchases on a relevant basis, such as the opportunity cost.

- *Implementation considerations*

- *Publication*

19.223 This issue primarily affects the ex post reporting regime as any price monitoring tool's cost base will be not be based on firm-specific information. Currently Ofgem requires the Six Large Energy Firms to publish their segmental statements in full. Only a limited amount of more granular analysis is routinely provided to Ofgem.

19.224 The Six Large Energy Firms told us that some of the ex post accounting information they were already required to publish was borderline commercially confidential and therefore damaging to the competitive process, and that our proposals went much further, especially in relation to wholesale energy costs. Were the financial information covered by our remedy to be published in full, the extent of their concerns would increase substantially.

19.225 Our starting point is that, in the interests of transparency, all regulatory reporting information should be published. We consider that such transparency is important for rebuilding trust in the energy sector. In particular:

- (a) We recommend that Ofgem require the Six Large Energy Firms to publish financial statements prepared along market lines (and not on a firm-specific divisional basis as is currently the case) with prior year comparatives.
- (b) We also recommend that Ofgem require the Six Large Energy Firms to publish balance sheet information, prepared along the market lines as

set out in paragraphs 19.175 to 19.178 and with prior year comparatives, at a minimum for generation and retail supply separately.

- (c) The Six Large Energy Firms currently publish their wholesale energy purchase costs for retail supply on a historical cost basis disaggregated between their domestic and non-domestic customers for both electricity and gas. For the purposes of the remedy we recommend that Ofgem require the Six Large Energy Firms to disaggregate their wholesale energy purchase costs between the estimated purchase opportunity cost and residual cost elements on the face of the published profit and loss account at market level. In the notes to the segmental statements, we recommend that Ofgem require the Six Large Energy Firms to set out the purchase opportunity cost elements, but not the residual cost elements, by broad tariff type.⁶⁰ Prior year comparatives would be provided in all cases.

19.226 The extent of disclosure entailed in the above is broadly the same as in the current situation. Whilst publication of purchase opportunity costs would be a new requirement, these costs reflect a standardised purchasing strategy, not necessarily one that any individual firm adopts. As a result, we consider publication of purchase opportunity costs would not jeopardize commercial confidentiality.

19.227 We do, however, recognise that there is a balance to be struck in furthering the interests of consumers between full transparency, protecting the competitive process and respecting commercial confidentiality. Ofgem should be well placed to make those judgements as it develops and modifies the ex post reporting regime in future.

- *Implementation mechanism for enhancements to existing ex post reporting remedy*

19.228 In both our Remedies Notice and provisional decision on remedies we proposed that any ex post reporting remedy would be introduced by way of a recommendation to Ofgem rather than by way of order. Either approach could in principle be possible: either Ofgem can modify the relevant licence conditions or we could issue an order that the Six Large Energy Firms report in a certain way.

19.229 A revised reporting regime would be a key tool for Ofgem to ensure that it receives the relevant information it needs to perform its statutory functions,

⁶⁰ We note that the cost of complying with this requirement relates to the cost of calculating the estimate of the purchase opportunity cost by broad tariff type, and not the cost of publishing this information.

and take decisions that are in the best interests of existing and future energy consumers. Our remedy therefore identifies how certain – highly relevant – financial information should be reported and suggests that at least generation and retail supply be covered. We have decided not to recommend in any more detail the precise formats for the segmental financial statements. These are decisions that Ofgem is best placed to take.

19.230 The financial remedy is also likely to need to be updated on a regular basis, a role that would naturally fall to Ofgem. Ofgem may develop its own proposals to enhance the reporting regime, and we believe it would be efficient to manage any such enhancements as part of a single implementation programme. Ownership by Ofgem is also critical to the longer-term success of the financial reporting project.

19.231 We have therefore decided to implement the enhancements to the existing financial reporting regime by way of a recommendation to Ofgem. Ofgem and all the Six Large Energy Firms supported this approach to implementation.

Considerations relating to effectiveness

19.232 This remedy seeks to revise the current ex post financial reporting regime by way of a recommendation to Ofgem to introduce licence conditions for each of the Six Large Energy Firms to require them to:

- (a) report their generation and retail supply activities along market lines;
- (b) report balance sheets as well as profit and loss accounts for these activities;
- (c) disaggregate wholesale energy costs for retail supply across broad tariff types between a standardised purchase opportunity cost and a residual element; and
- (d) report prior year figures prepared on the same basis as current period figures.

19.233 This remedy also seeks to ensure that, in its consideration of a revised retail price monitoring tool, Ofgem produces forecasts that measure wholesale energy costs on an opportunity cost basis.

- *Envisaged outcome from revised ex post reporting regime*

19.234 With this re-specified information, Ofgem would be in a better position than it currently is to assess and interpret the profitability in generation and retail supply markets of any of the Six Large Energy Firms.

19.235 For retail supply markets only there would be a mechanism to identify each of the Six Large Energy Firms' wholesale energy purchase cost on a common, standardised basis.⁶¹ As a result, Ofgem would be able to:

- (a) assess the actual profitability of each of the Six Large Energy Firms, given the purchasing decisions it has made (which includes the incremental impact on profit of each of the Six Large Energy Firms entering transactions on the basis of expected customer behaviour at a portfolio level); and
- (b) use such profitability assessment to inform a judgement on whether retail supply competition is working effectively, by stripping out the impact of individual firms' purchasing strategies and isolate that profitability that would have been reported had the Six Large Energy Firms, in respect of wholesale energy purchases only, purchased their wholesale energy on an opportunity cost basis.

19.236 We now consider the effectiveness of this remedy as a whole in terms of the objectives we set out above.

- *Effectiveness in providing relevant financial information to Ofgem*

19.237 We consider that the ex post financial information generated under this remedy will provide a robust starting point for Ofgem to undertake and interpret profitability analysis. This analysis will then allow Ofgem, in conjunction with relevant other evidence, to assess the state of competition in the markets, identify issues and then take appropriate decisions.

19.238 The first and third proposed measures set out in paragraph 19.232 will at the same time greatly enhance the cross-firm comparability of the financial information and the fourth measure will enhance comparability from one period to the next. Many stakeholders articulated their criticism of the existing reporting regime in terms of the lack of comparability of the financial information produced under it.

⁶¹ This mechanism is not needed for generation markets because firms generally seek to lock-in their net margin at the point at which they commit to generating output. See paragraph 19.185.

19.239 We consider that an appropriately re-specified price monitoring tool would enable Ofgem to track the relationship between expected costs and retail prices as these evolve over time.

19.240 With clear and relevant financial information, Ofgem will also be in a much better position to more effectively:

- (a) investigate developments within markets;
- (b) monitor the effectiveness of existing remedies and implement any new remedies; and
- (c) evaluate policy impacts on bills.

19.241 This information will also contribute to Ofgem's ability to carry out an independent evaluation of the broad range of policies governing GB energy markets, as contemplated by other parts of these Governance Remedies.

- *Effectiveness in enhancing stakeholder confidence in the segmental financial information produced by the Six Large Energy Firms*

19.242 By strengthening the principles under which the Six Large Energy Firms prepare their segmental accounts for retail supply and generation on a market lines basis, the revised reporting regime should provide the comparability and financial accountability of the Six Large Energy Firms that stakeholders have called for.

19.243 We have observed in paragraphs 19.23 and 19.24 that there is a lack of shared understanding of the factors that have led to price increases, and that it is possible that the public debate is poorly informed about the factors driving such price increases. We consider our remedy for the Six Large Energy Firms to disaggregate their wholesale energy costs by broad tariff type between that element that a prudent retail supplier would incur in a well-functioning market and the remainder would provide a better basis for public debate and understanding. Adopting the same approach to measuring wholesale energy costs that a prudent retail supplier would incur within a revised price monitoring tool would further the same aim.

Considerations relating to proportionality

19.244 We now consider the proportionality of our proposals as a whole in terms of the relevant considerations as set out below.

- *Effective in achieving its legitimate aim*

19.245 As explained above, each of the four enhancements to the existing ex post financial reporting regime and each of the two enhancements to Ofgem's price monitoring tool are designed to enhance Ofgem's ability to perform its functions effectively. As a result, we consider that each enhancement (individually and collectively) will be effective in achieving this aim by addressing the feature of a lack of a regulatory requirement for clear and relevant financial reporting concerning generation and retail supply profitability, which in turn should increase Ofgem's ability to carry out its functions effectively. The information produced under the remedy is also designed to improve public understanding of the Six Large Energy Firms' financial performance in generation and retail supply and the link between costs and retail prices, and therefore help Ofgem providing clear and trusted analysis to other stakeholders (including DECC). This in turn should increase the robustness and transparency in regulatory decision-making.

- *No more onerous than needed to achieve its aim*

19.246 Each enhancement is designed to improve the relevance of either the ex post or ex ante financial information available to Ofgem. This can only be achieved through some sort of financial reporting remedy. We have recognised that there will be a financial cost to the Six Large Energy Firms of complying with the new ex post reporting requirements. However, in limiting our recommendation to those markets in greatest need of this level of transparency (generation and retail supply), and not recommending that Ofgem adopts the new reporting enhancements more broadly (to additional markets) or more narrowly (to granular segments) we believe the ex post reporting remedy is no more onerous than necessary to achieve its aim. In addition, as noted in paragraphs 25 to 28 in Appendix 19.1, we have decided neither to order the Six Large Energy Firms to report separately on their activities in trading markets nor to recommend that Ofgem require those firms to do so.

- *The least onerous if there is a choice between several effective measures*

19.247 Each enhancement is in response to a clearly identified reporting deficiency, ie a lack of a particular design feature of the current reporting regime. As a result we set out a single solution to remedy the lack of each design feature, ie a reporting regime with the design feature. We have reached our remedy having completed detailed analysis of the Six Large Energy Firms' businesses, and having taken into account their representations, we have

designed the remedy so that each of the enhancements is no more onerous than needed to remedy the identified deficiency.

- *Does not produce disadvantages which are disproportionate to the aim*

19.248 In the following paragraphs, we consider the likely costs of implementation for each design enhancement before considering the benefits in a holistic way.

19.249 Costs of implementation will be incurred in part by Ofgem, but principally by the firms subject to this remedy, namely the Six Large Energy Firms. Some costs would be one-off and some would be ongoing. There may also be changes in the information that would need to be audited. The starting point for analysis is the cost to the Six Large Energy Firms of ongoing compliance with the current segmental reporting framework (including Ofgem's SMI) and the administrative costs to Ofgem of setting and revising reporting requirements. The cost of imposing this remedy is the incremental costs brought about by the enhancements to the existing reporting regime.

- *Assessment of costs: separation of firms' activities on market rather than divisional lines*

19.250 Most of the Six Large Energy Firms are now in a position to report broadly along market lines. For retail supply in particular, the Six Large Energy Firms either report wholesale energy at the cost to the firm or as a transfer charge into retail supply on the basis of standard wholesale products available at the time of purchase.⁶² Departures from the principle of reporting along market lines arise chiefly because some of the Six Large Energy Firms have transferred some activities intrinsic to their role as retail suppliers or generators in GB into their trading divisions. As a result, the associated transfer charges are not along market lines. Where this is the case, there will be a need for such firms to modify their transfer charging approach only for regulatory reporting purposes.

19.251 Our view is that one of the Six Large Energy Firms with the most to do in this area is likely to be E.ON. Hitherto E.ON has reported its generation activities on a (non-market) toll generator basis and its retail supply activities as though E.ON is always able to purchase shaped wholesale energy products. However, E.ON is in the process of separating its energy operations into two separate companies⁶³ and, as a result, will need to revise its systems

⁶² See Appendix 18.1, Annex A, Wholesale energy costs.

⁶³ Appendix 19.1, Annex B, paragraph 89.

accordingly. RWE has a separate issue in that, although it ultimately reports its generation activities on a full function basis, it achieves this outcome by transferring across the net profit or loss on optimising its generation fleet as initially accounted for within its trading division. As a result, RWE is currently unable to present all revenues and costs as they would be reported by a stand-alone full-function generator.

19.252 In order to assess the broad likely impact of these measures, we have looked at what one of the Six Large Energy Firms, SSE, which up to 2013/14, had reported its generation activities on a toll generator basis and its retail supply activities on a non-market prices basis for wholesale energy, has recently done (for its 2014/15 financial year) in order to overhaul the basis of its transfer charging. SSE told us that this investment was part of a wider investment to monitor and manage the risks it took on when buying and selling commodities for generation and retail supply. SSE had spent £[redacted] of a [redacted] wider investment on a reporting module which had enabled it to report its generation and retail supply activities on the basis of how they would have interacted with the external market had they not been part of an integrated group.⁶⁴

19.253 The costs of implementation will naturally be quite specific to each of the Six Large Energy Firms and their individual circumstances. Nonetheless, it is the case that most of the Six Large Energy Firms either do, or have the capability to, report along market lines.

- *Assessment of costs: provision of balance sheet*

19.254 Similarly, the costs of implementing this design enhancement will depend on whether firms already do or have the capability to report along market lines. Therefore there should be little incremental cost, at least so far as concerns reporting at a pan-generation or pan-retail supply basis for the firms who already do/can report along market lines.

19.255 However, as discussed in paragraphs 18.123 and 18.124 9 in Section 18, one issue we found when conducting our profitability analysis was that not all of the Six Large Energy Firms' working capital balances (debtors and creditors) for their retail supply operating divisions reflected their external payment terms and as a consequence these balances were not stated along market lines. Some of the Six Large Energy Firms then asked us to restate these balances in our profitability analysis. These Six Large Energy Firms would therefore need to restate these balances to reflect external payment

⁶⁴ Appendix 19.1, Annex B, paragraph 48.

terms in order to comply as the difference between the two would be material to an assessment of their total capital employed. We would not expect there to be a material cost associated with this restatement.

- *Assessment of costs: disaggregation of wholesale energy costs for retail supply between standardised opportunity cost and residual elements*

19.256 The cost of obtaining this disaggregation relates to gathering the necessary input information, doing the calculations and obtaining assurance on these calculations through a suitable audit opinion. Although not prepared for the same purpose, this activity is broadly comparable to the activity Ofgem undertook in order to estimate wholesale energy costs for the currently suspended SMI.⁶⁵ Our remedy, however, requires a two-stage calculation⁶⁶ to identify opportunity purchase costs on a standardised basis and such costs to be disaggregated by broad tariff type. In their responses to this proposal as set out in the provisional decision on remedies, Centrica, EDF Energy and SSE all submitted that the costs in this regard could be of the order of £500,000 to £1 million, with Centrica and EDF Energy attributing this range to enhanced annual operating costs whilst SSE attributed this range to the one-off cost of enhancing its internal reporting systems.

19.257 We accept that this process will result in some extra cost to be incurred in order to perform these calculations, and that these costs will be incurred by the Six Large Energy Firms. We consider that much of this cost will relate to one-off costs to set up the capability to disaggregate wholesale energy costs in this way (ie as described by SSE), rather than ongoing implementation costs. However, there is also a material cost to consumers and suppliers in Ofgem not having the information to enable it to better address questions regarding the strength of the linkage between movements in wholesale and retail energy prices (especially in relation to SVT) and the associated impact on firms' profitability. Without this particular enhancement Ofgem will not be in a position to address these questions. The lack of market orientated financial information, including isolating the 'trading' element of retail supply, has led in the past to, and increases the risk in future of, a lack of clear and trusted understanding of the energy markets shared by all stakeholders. Such information is necessary to ensure that decisions are taken on a robust basis.

⁶⁵ Albeit it the SMI's coverage relates to domestic customers only, whereas this enhancement to the reporting of wholesale energy costs would cover all retail customers, ie SME and I&C too.

⁶⁶ See Appendix 19.1, paragraphs 50–52.

- *Assessment of costs: prior period comparatives*

19.258 Firms constantly strive to maintain and improve the quality of their financial reporting. From time to time this may result in changes in the basis of preparation. The cost of implementation is therefore the cost of restating the prior period figures and procuring an audit opinion that extends to prior year comparatives.

19.259 The Six Large Energy Firms will incur costs in restating their prior year comparatives whenever they materially change the basis of preparation for their segmental statements. This will depend on how often they need to make material changes. This approach is universal practice in statutory reporting and is what firms would seek to do for internal management purposes. For changes that Ofgem mandates, implementation costs should be minimised by it giving sufficient notice.

- *Assessment of benefits of remedy*

19.260 With the enhanced information that would be produced under this proposal Ofgem would be much better placed to undertake and interpret the Six Large Energy Firms' profitability. With a suitably specified price monitoring tool, Ofgem would be much better placed to comment on trends in retail prices. Ultimately this will enable Ofgem to make better decisions in its role as regulator. It will also put Ofgem in a stronger position to address stakeholder concerns about profitability as well as perform the analysis to support its full range of responsibilities. This would minimise the risk of undue pressures being placed on Ofgem by other stakeholders and thereby help avoid the risk of ill-advised interventions either on the part of Ofgem or other (government) bodies.

- *Assessment of proportionality of remedy*

19.261 It is challenging to quantify the benefits expected to arise from this proposal. However, we believe these benefits, which are expected to arise from better policy making in the future, are likely to be considerable for the reasons set out at the beginning of this section. We note in particular that Ofgem's perceived (or actual) inability to resolve the recurring debates over the Six Large Energy Firms' profitability was one of the factors that contributed to the reference for this market investigation.

19.262 We also note that the costs are those that need to be incurred to ensure that all of the Six Large Energy Firms, not just those which currently possess the relevant reporting capability, are properly financially accountable for their generation and retail supply activities.

19.263 We therefore consider that the benefits are likely to greatly exceed the associated costs. This financial reporting remedy is, fundamentally, about providing Ofgem with information essential to it being able to perform its functions effectively and it being seen to do so.

Assessment of the remedy against the relevant statutory functions of Ofgem

19.264 Where the CMA is considering whether to modify the licence conditions of licensed energy companies for the purposes of remedying an AEC, in deciding whether such action would be reasonable and practicable, the CMA must 'have regard' to the relevant statutory functions of Ofgem.⁶⁷

19.265 Ofgem's relevant statutory functions are set out in Part 1 of GA86 and Part 1 of EA89, both as amended by the EA10, and include (among other things) granting generation and supply licences, promoting efficiency and economy on the part of persons authorised by licences, and to secure a diverse and viable long-term energy supply.

19.266 Ofgem's principal objective in carrying out such functions is to protect the best interests of existing and future energy consumers.⁶⁸ In reaching a decision to make a recommendation that Ofgem modify a licence condition, we must therefore assess the remedy against Ofgem's principal statutory objective, as set out above.

19.267 In paragraph 18.152, we noted that the lack of robustness in decision-making and implementation increased the risk of poor policy decisions which have an adverse impact on competition. We have also identified within the context of this investigation regulatory interventions which have had an adverse impact on the interest of existing and future consumers (see, for instance, the simpler choices component of the RMR rules, SLC 25A).

19.268 As part of our own application of the legal framework requiring us to decide upon remedies that are effective and proportionate,⁶⁹ we have noted that this remedy would contribute to increasing the robustness of the policy decision-

⁶⁷ Section 168 of the 2002 Act and paragraph 347 of [CC3](#).

⁶⁸ See, among others, section 3A and section 6B of the EA89.

⁶⁹ These objectives include, among other things, a requirement on the national regulator to take all reasonable measures for a competitive, secure and environmentally sustainable internal market in electricity within the European Community, and ensuring appropriate conditions for (i) the effective and reliable operation of electricity networks, taking into account long-term objectives; (ii) developing competitive and properly functioning regional markets within the European Union; (iii) eliminating restrictions on trade in electricity between member states; (iv) eliminating restrictions on trade in electricity between member states; (v) facilitating access to the network for new generation capacity; (vi) ensuring that system operators and system users are granted appropriate incentives, in both the short and the long term, to increase efficiencies in system performance and foster market integration; (vii) ensuring that customers benefit through the efficient functioning of their national market; and (viii) helping to achieve high standards of universal and public service in electricity supply, contributing to the protection of vulnerable customers.

making and implementation. It will provide Ofgem with financial information relevant to carrying out its functions effectively, including by providing clear and trusted analysis to other stakeholders (including DECC).

19.269 We consider therefore that this remedy (and each of the cumulative elements within it), by reinforcing the robustness of the decision-making process, and reducing the risk of poor regulatory interventions by Ofgem or DECC, will be in the best interests of existing and future energy consumers and is therefore reasonable and practicable in light of Ofgem's statutory functions.

Governance Remedies package: effectiveness and proportionality

Assessment of effectiveness

Introduction

19.270 We identified an overarching feature of a lack of robustness and transparency in regulatory decision-making giving rise to the Governance AEC. This feature is underpinned by four features, relating to the decision-making process:

- (a) the lack of a regulatory requirement for clear and relevant financial reporting concerning generation and retail supply 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.

19.271 The Governance Remedies are complementary as they each seek to improve DECC's and Ofgem's decision-making and implementation processes by addressing, in whole or in part, one or more of the underlying features set out above. We assess below:

- (a) whether this remedies package is effective in achieving the overarching aims of our remedial action;
- (b) whether this remedies package is capable of effective implementation; and

(c) the timescale over which the remedial measures will take effect.

Assessment against aims of the Governance Remedies

- *Robust analysis underpinning decision-making and improving transparency*

19.272 For the reasons set out above, in order to ensure that robust analysis is carried out and made available to all stakeholders, therefore informing the policy debate and the decision-making process, we decided to recommend the following:

- (a) DECC to initiate a legislative change so as to set up a clear and established process for Ofgem to comment publicly, by publishing Opinions, on all draft legislation and policy proposals which are relevant to Ofgem's statutory objectives and which are likely to have a material impact on GB energy markets; pursuant to this remedy, and for the reasons set out above, Ofgem would be in a better position to openly contribute its technical expertise to the design of policy initiatives with a view to making the decision-making process more robust and transparent.
- (b) Ofgem to publish annually a state of the market report which would provide analysis regarding issues such as (i) the evolution of energy prices and bills over time, (ii) the profitability of key players in the markets (eg the Six Large Energy Firms), (iii) the social costs and benefits of policies, (iv) the impact of initiatives relating to decarbonisation and security of supply, (v) the trilemma trade-offs, and (vi) the trends for the forthcoming year.
- (c) Ofgem to enhance the existing financial reporting obligation so as to ensure that in their reporting the Six Large Energy Firms:
 - (i) separate their activities on market rather than divisional lines;
 - (ii) provide a balance sheet as well as profit and loss account;
 - (iii) disaggregate their wholesale energy costs for retail supply between standardised opportunity cost and residual elements; and
 - (iv) provide the previous period as a comparative using the same accounting rules.
- (d) Ofgem to take appropriate steps, in its ongoing work to develop a price monitoring regime, in order to ensure that such regime measures

wholesale energy purchases on a relevant basis, such as the opportunity cost.

- 19.273 In order to support these three remedies, we decided to recommend that Ofgem create a new unit (eg an office of the chief economist) within Ofgem, which will build expertise across the different areas of the energy markets with a view to publishing annually a state of the market report as set out above.
- 19.274 We believe that the implementation of these remedies, in combination with the existing current processes, will improve DECC's decision-making. Our remedy relating to Ofgem's role in giving Opinions on draft legislation will contribute to the robustness of DECC's impact assessments, and to the consistency of approach over time and between stakeholders in carrying out analysis. Also, DECC's assessment of contemplated or existing policy interventions will, in our view, be greatly facilitated by the existence of an ongoing analysis of the market by Ofgem, which can provide a shared understanding of market trends and of the nature of competition. In particular, this will allow DECC to consider more easily the aggregate impacts of the regulatory framework on, and the trade-offs between, different policy objectives.
- 19.275 A better designed financial reporting obligation on the Six Large Energy Firms will address specifically the first underlying feature we have identified in our provisional findings. It will allow Ofgem to carry out more robust and detailed analysis on certain key aspects of the markets, making Ofgem's state of the market reports and Opinions more authoritative.
- 19.276 The creation of a new body internal to Ofgem, such as an Office of the Chief Economist, with cross-cutting expertise, will in our view facilitate Ofgem's exercise of its new functions summarised above, and in turn the effectiveness of our remedial action in improving the robustness of the analysis underpinning the decision-making process.
- *Well-defined powers, roles and objectives aligned with the interests of customers*
- 19.277 Many initiatives have been taken in the past in an attempt to clarify policy objectives and the respective powers, roles and objectives of Ofgem and DECC, in particular the initiative for DECC to publish a Strategy and Policy Statement every five years. We strongly support the use of this mechanism and expect Ofgem to take this Strategy and Policy Statement into consideration in setting out annual work plans for its work and for industry code governance (as regards codes, see below paragraphs 19.342 to

19.348). However, we are concerned that this might be insufficient to address issues arising out of Ofgem's statutory objectives and duties (as per the second underlying feature we identified in our provisional findings) and from the implementation of policy (as per the fourth underlying feature we identified in our provisional findings).

19.278 In order to ensure that the powers, responsibilities and objectives of stakeholders are well defined, we have decided to recommend that:

- (a) DECC introduces a plan for a new law which would include a provision deleting paragraph 1C from both sections 4AA of the GA86 and section 3A of the EA89;
- (b) in circumstances where the implementation of a DECC policy objective is likely to necessitate, in order to achieve its stated objective, parallel or consequential Ofgem interventions (eg through a licence change) or a code modification, DECC and Ofgem publish detailed joint statements setting out:
 - (i) an action plan setting out the list of regulatory interventions (including code changes), and the relevant entity in charge of designing and/or approving such interventions, that are necessary in order to implement the policy;
 - (ii) an estimated timetable for the completion of each necessary intervention; and
 - (iii) where appropriate, a list of relevant considerations that will be taken into account in designing each regulatory intervention.

19.279 As noted above in paragraph 19.48, the recommended changes would remove unnecessary constraints from Ofgem's statutory objectives and duties which increase the risk of suboptimal decision-making.

19.280 As noted above in paragraph 19.107, clear and transparent plans regarding decision-making and implementation of specific policies would, in our view, increase transparency about the complete process of decision-making, therefore putting stakeholders in a better position to identify inconsistencies between contemplated regulatory interventions and the existing legal framework, including consequential changes that might be required across licence conditions and industry codes. This in turn should lead to better project management of the process of designing, assessing and implementing policies.

19.281 As noted below, our remedies relating to code governance contain a recommendation to Ofgem to provide a strategic direction to the industry and to reflect these strategic objectives in annual work plans set out for each code.

19.282 Together, these remedies will, in our view, ensure that at each governance level of the regulatory framework interventions that follow consistent objectives are pursued, and will facilitate the coordination between these interventions so as to achieve swift and effective implementation.

The remedies are capable of effective implementation and timeliness

19.283 The remedies that we have explored in this section seek to improve certain aspects of Ofgem's and DECC's decision-making and implementation processes. In doing so, we are seeking to bolster the ability of those organisations to regulate the energy markets efficiently, and therefore to reduce the risk of the detriment that we have observed continuing. However, the responsibility of any future intervention, and the quality of such decisions, rests ultimately with DECC, Ofgem and, in the context of code governance, the industry. While better processes reduce the risk of suboptimal interventions, it is in our view essential that stakeholders comply not only with the letter of our remedies, but also with the broader spirit, and the overarching principles that underpin them. In practical terms, this means that the effectiveness of our remedial actions will depend to a large extent on the support from stakeholders, and in particular support from DECC and Ofgem.

19.284 As noted in our guidelines, before making a recommendation to another public body, the CMA will form a view as to the likelihood that the recommendation will be acted upon. In reaching this view, the CMA must have regard both to the stated policy of the body to which the recommendation is to be directed and to the possibility that that stated policy may change, either in light of the CMA's recommendation or subsequent events (and if so, over what time period).⁷⁰

19.285 In this section we have noted that the government's *Green Book* and *Better Regulation Framework Manual* have put significant emphasis on the need for robust economic assessment of policy initiatives. We have also noted that Ofgem considers that monitoring markets forms a crucial part of its role.⁷¹ We believe that our remedies package is not only consistent with these policies but would support them in seeking to achieve better results, and

⁷⁰ CC3, paragraph 331.

⁷¹ See, for instance, Ofgem, *Wholesale Energy Markets in 2015*, paragraph 1.1.

ultimately better decision-making. Finally, we note that the government has made a commitment to give a public response to any recommendation made to it within 90 days of the publication of a CMA report.⁷²

19.286 In their responses to our provisional decision on remedies, both DECC and Ofgem confirmed their support for these remedies. We note in particular that, in the Budget 2016, the government announced its intention to initiate the legislative changes required in order to implement the CMA's proposed recommendations. We are therefore confident that DECC and Ofgem will act upon these recommendations in a timely way.

Assessment of proportionality

19.287 For the reasons set out above, we believe that the remedies package as a whole will help to increase the robustness and transparency in regulatory decision-making. Each of the remedies will contribute to this aim by helping to address one of the four features that give rise to the Governance AEC.

19.288 The first feature is addressed by our recommendation to enhance the existing financial reporting obligation set out in the standard licence conditions.

19.289 The second feature (lack of effective communication on the forecasted and actual impact of government and regulatory policies over energy prices and bills) is addressed by our remedies that seek to reinforce the level of analysis carried out by DECC, before and after implementation of primary and secondary legislation, and by Ofgem on an ongoing basis (as summarised above).

19.290 The third feature (Ofgem's statutory objectives and duties) is addressed by our recommendation to clarify Ofgem's principal statutory objective.

19.291 The fourth feature (absence of a formal mechanism through which disagreements between DECC and Ofgem over policy decision-making and implementation can be addressed transparently) is addressed by the remedies that seek to improve coordination between Ofgem and DECC on policy design and implementation.

19.292 We believe that this remedies package is no more onerous than necessary and the least onerous package of remedies that is capable of addressing the Governance AEC effectively. Each of the remedies within this package individually contributes to addressing the overarching feature that gives rise

⁷² See [CC3](#), paragraph 95.

to the Governance AEC by increasing the robustness of policy decision-making and implementation. These should not therefore be seen as alternative but as complementary remedies.

19.293 For the reasons set out above, we consider that this remedies package would only incur low implementation costs. Some remedies would create some limited additional burden on DECC's and Ofgem's resource. However, for the reasons set out above, we would expect these costs to be low as Ofgem and DECC are already required to carry out similar actions, and to be partially netted off by efficiency gains arising from an improved process. While we have noted that our financial reporting remedy should only have limited impact on the Six Large Energy Firms that already report on market lines, we have also acknowledged above that some of them would have to modify their transfer charging approach for regulatory reporting purposes.

19.294 However, in the light of the substantial impact of the regulatory framework and other public interventions in the GB energy markets, amounting to several billions each year, and the concrete risk of inefficient outcomes arising from such interventions (as identified in our provisional findings), we consider that the costs of our remedies package are justified by their aim and expected benefits.

Codes governance

Introduction and relevant context

19.295 We have found that a combination of features of the wholesale and retail gas and electricity markets in GB relating to industry code governance gives rise to the Codes AEC through limiting innovation and causing the energy markets to fail to keep pace with regulatory developments and other policy objectives. In particular, we believe that the Codes AEC has the impact of limiting pro-competitive change. The underlying features of the Codes AEC are the following:

(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.

19.296 We are concerned that Ofgem has not sufficiently sought to develop its expertise, powers and involvement in the code governance framework in a manner commensurate with the increased importance of that framework to competition and consumers' interests.

Aims of our remedial action

- 19.297 The aim of our remedial action is to ensure that regulation set in codes keeps pace with technical and commercial developments in the GB energy markets and promotes effective competition in a manner consistent with DECC's and Ofgem's strategic objectives and policies. The remedies package should recalibrate the roles and incentives of Ofgem and code administrators while maintaining involvement by industry participants – which is required given the technical nature of many code provisions – for the purpose of driving forward the delivery of code changes that affect competition and consumers' interests. This, in turn, should facilitate the longer-term development of the code governance framework under the supervision of Ofgem, which is ultimately responsible for the overall regulation of the energy markets.
- 19.298 To achieve that aim, our remedies seek to clarify Ofgem's responsibility for the establishment and delivery of a strategic direction for codes, and to revisit code administrators' roles in supporting the industry and Ofgem in their respective functions. As regards Ofgem, these remedies aim to increase its ability to engage more proactively with the code regime to fulfil its responsibilities, in particular to ensure that modification proposals are prioritised by stakeholders to support DECC's and Ofgem's strategic objectives, and that the analysis supporting recommendations from code panels is sufficient for Ofgem to take a decision. To facilitate such engagement, these remedies create additional discretionary mechanisms through which Ofgem can input into modification processes and discuss cross-cutting issues.
- 19.299 In similar fashion, the remedies package should recalibrate the powers and incentives of the code administrators so that they are able to support Ofgem's and DECC's strategic objectives by ensuring the timely development and delivery of modification proposals. In particular, this remedies package seeks to ensure that code administrators' incentives are consistently aligned with those of energy customers and that their performance is monitored by Ofgem and improved over time.
- 19.300 Taken together, the changes described above should balance the powers and responsibilities allocated to the relevant stakeholders efficiently, taking into account the:
- (a) resources and expertise of each stakeholder group, as well as their independence from commercial interests (ie ability to act in the interests of consumers); and

- (b) relative importance of each modification proposal and the need to prioritise scarce resources (eg focus Ofgem's attention on material modification proposals).

Potential longer-term aims

- 19.301 The expansion of the codes regime is largely responsible for the current complexity of the regulatory framework governing energy markets.
- 19.302 This complexity may also be a hindrance to effective regulatory actions and enforcement by Ofgem. In the past, the complexity of the codes regime may have been the cause of a reluctance on the part of Ofgem to intervene in areas which are governed primarily by codes (as shown for instance by the small number of Significant Code Reviews launched by Ofgem since it established that process⁷³). We are further concerned that complexity may, in certain circumstances, increase the risk of circumvention and render enforcement more difficult.
- 19.303 Exacerbating the complexity of the code system is the presence of a network of decentralised specialist entities that each govern a separate aspect of the codes regime. In general, we observe that it can be difficult to coordinate decentralised entities that by their nature act pursuant to code-specific objectives and the interests of different sets of stakeholders. This difficulty increases the risk that the delivery of cross-cutting pro-competitive code changes is delayed.⁷⁴
- 19.304 Both government and Ofgem have stated policies seeking to reduce the overall burden of the regulatory framework on the industry. Our analysis and respondents' submissions indicate that there is broad agreement that the current complexity of the codes regime greatly increases regulatory compliance costs, impedes effective monitoring and regulatory decision-making and, in some cases, the delivery of pro-competitive innovations. We consider, therefore, that there is widespread appetite for reforms that would tackle this system-level issue of complexity. However, under the current regime no single stakeholder has the necessary combination of expertise, capacity and incentive to drive forward the reform process.
- 19.305 We believe that some of the remedies that we are considering would support DECC and Ofgem in this task of broader reform. Alongside those changes, this remedies package would establish processes that will prompt and

⁷³ See Appendix 18.2.

⁷⁴ For example, Ofgem has put to us that the delays in the delivery of BSC MP 272 were partly attributable to the absence of adequate coordination mechanisms that could ensure the identification of necessary consequential modification proposals to other codes.

facilitate the gradual streamlining of the code regime. We expect Ofgem to keep reviewing the code governance regime and use these processes when appropriate so as to ensure that the regime is fit to handle pending system-level challenges including, for instance, the need to transpose the EU network codes.

19.306 In the light of the above, this remedies package should put in place a regulatory framework that creates appropriate incentives and fora for stakeholders to address the system-level issues related to complexity and consider the benefits of consolidation in the long term as well as to align the decisions taken with Ofgem's statutory objectives.

Parties' views

General comments

19.307 A number of parties (Drax, ESB, Northern Powergrid, Genserv) have put to us that Ofgem's ongoing Code Governance Review, which seeks to implement incremental changes to the current governance arrangements, represents the best method to address the Codes AEC. Therefore, they have submitted that the CMA should refrain from implementing any of its remedies in this area in order to allow the Code Governance Review process to run its course.

19.308 In contrast, Ofgem has proposed a remedy that represents a structural change to the current code governance regime.⁷⁵ Indeed, it proposes the creation of a new single code body in charge of managing all aspects of the commercial codes. In its final proposals document following the third phase of the Code Governance Review,⁷⁶ Ofgem noted that these changes would 'prepare for the more fundamental changes proposed by the CMA'. Several of the Six Large Energy Firms (Centrica, SSE) have also argued in favour of some form of centralisation of code management, though their suggestions envision a central body that would be more limited in scope, such as one entitled to set a 'strategic direction' for code development, project manage the change process or set, oversee and consult on improvements to the market rules.

⁷⁵ See Ofgem response to provisional findings.

⁷⁶ [Code Governance Review \(Phase 3\): Final Proposals](#), 31 March 2016.

Views on Ofgem taking a strategic role within the code governance framework, setting a strategic direction for code development and leading the development of strategic work plans

- 19.309 A majority of respondents agreed with the proposal for Ofgem to take up a more strategic role within the code governance framework, set a strategic direction for code development and lead the development of strategic work plans.
- 19.310 EDF Energy supported the recommendation for Ofgem to publish a strategic direction but highlighted the importance of sufficient consultation with stakeholders.
- 19.311 Centrica stated that the strategic direction would be helpful as long as it was not unduly prescriptive in a way that could pre-judge the detailed industry arrangements required to put them into effect. It also noted that the development of the strategic direction should involve input from the Chief Economist's office (see paragraph 19.137 above). RWE said that there should be transparency around how Ofgem makes decisions regarding the strategic direction. It also considered that the strategic direction should cover a sufficiently broad time horizon to give parties time to organise their capital investment, resources and systems capacity. The MRA Executive Committee proposed that the expertise of the code panels and code administrators would be a valuable input to Ofgem in developing the strategic direction.
- 19.312 EDF Energy stated that it did not believe that the development of code-specific work plans would necessarily result in incremental value (and, instead, suggested that Ofgem should have greater oversight of the performance of code panels and to make a comparative assessment of their performance against their duties). First Utility stated that we must be careful to consider the cost implications of the development of the strategic work plans various code bodies, including on the code administrators.

Views on the creation of a consultative board

- 19.313 Respondents were broadly supportive of the creation of a consultative board, with some raising specific issues around its design. For instance, Electralink noted that it would be important to ensure that there is fair representation of small and new players within the board's composition. Centrica stated that Ofgem should have a duty to have regard to the consultative board's decisions and that the consultative board's composition should include an external specialist in management the management of complex energy industry change programmes.

19.314 Scottish Power stated that care should be taken to ensure that the consultative board is not duplicative of existing change overview boards which already exist in the context of certain codes. It also noted that the consultative board could have a role in carrying out ex post evaluations of implemented modification proposals, as a means to provide Ofgem with information that it could use to develop more effective strategic directions.

Views on the proposal for Ofgem to take, and for code administrators to have, the powers to initiate and prioritise code modifications

19.315 Respondents were mostly supportive of the proposal for Ofgem to take, and for code administrators to have, the powers to initiate and prioritise code modifications.

19.316 Some respondents (EDF Energy, Drax, Citizens Advice) stated that Ofgem did not need to take powers to initiate and prioritise modification proposals because it already had sufficient powers to intervene in the code modification arrangements through the SCR process.

19.317 The MRA Executive Committee stated that there may be consequential impacts of Ofgem raising code modifications, which code parties are likely to be more able to identify due to the nature of their role. Hence, industry consultation is vital. Utilita noted that under our proposal, in circumstances in which Ofgem proposed the modification and set the priorities based on its preferred approach, it would have concerns that Ofgem also holding the oversight function would be inappropriate. This would remove one of the checks and balances currently available. Some parties (Scottish Power, RWE, E.ON) suggested that Ofgem could address this type of concern by introducing clear rules and principles that indicates how it would exercise these powers.

19.318 Centrica raised the concern that this remedy should be matched by an extension to the normal rights of appeal 'on the merits' – since these are only triggered when Ofgem overturns a code panel recommendation and that is unlikely to apply in this case.

19.319 Some parties (RWE and First Utility) raised the concern that code administrators did not have adequate resources or expertise to exercise the powers that would be introduced under this remedy. EDF Energy raised a similar concern that code administrators are not necessarily the experts in the drivers for a code modification or its impact on the market so would require clear oversight from Ofgem if they were given these powers. First Utility also raised concerns, including that code administrators would face conflicts of interest and perverse incentives when deciding whether to

exercise the proposed powers. RWE raised the concern that if code administrators initiated modification proposals that were perceived negatively by the industry then their independence would be questioned and trust in them would diminish.

- 19.320 In light of the proposed powers for Ofgem and code administrators to prioritise modification proposals, E.ON stated that it would be necessary to consider how the parallel process of deprioritising modification proposals should be handled. It also noted that code panels currently did not have the ability to reject modification proposals on the ground that they were not a priority. First Utility stated that there should be safeguards to ensure that deprioritised but material modification proposals are progressed in a timely fashion.

Views on Ofgem having the power to exercise a 'call-in' power

- 19.321 Respondents were broadly supportive of this remedy. Several respondents asserted that Ofgem's exercise of the call-in power should be subject to sufficiently robust procedural safeguards. To this end, some respondents (EDF Energy, SSE, Scottish Power, Smartest Energy) requested that the 'exceptional circumstances' that would meet the threshold for Ofgem to exercise the call-in power be clearly and narrowly defined. Other respondents (Centrica, Scottish Power) asserted that parties should have a merits-based appeal right to challenge code modification proposals produced as result of Ofgem's exercise of the call-in power.
- 19.322 Some respondents (Scottish Power, First Utility) considered that the proposed call-in power would not be an effective substitute for the current SCR process, as the SCR process was not designed as a back-stop.

Views on the licensing of code bodies (code administrators and delivery bodies)

- 19.323 By licensing the activities of code administrators and code change delivery, this remedy aims to give Ofgem the power to efficiently monitor performance of the relevant code bodies, by issuing directions to them and imposing sanctions on them, when appropriate. A secondary aim of this remedy is to further the harmonisation of the governance and modification arrangements across codes.
- 19.324 The majority of respondents agreed with the aim of this remedy. In general, respondents (Ofgem, EDF Energy, Centrica, RWE, E.ON, ESB, [redacted], Co-operative Energy, Ecotricity) agreed that providing Ofgem with greater means to oversee code administrators would have a positive impact by

harmonising arrangements and raising standards and service offerings. Ofgem submitted that licensing would enable the accountability of code administrators to be redirected towards it for the purpose of delivering positive outcomes for consumers. Three (out of four total which responded) of the code administrators (Elexon, Electralink, Gemserv) agreed with the general objective of the remedy. Elexon expressed concern that the proposed licensing approach had the potential to increase cost and complexity, and could inhibit innovation.

- 19.325 RWE agreed that the creation of a separate licensable activity for code administration would address concerns where there are conflicts of interest by transferring code administration to an independent body.
- 19.326 Scottish Power and Ecotricity posed the concern that this change would enable Ofgem to act through the code administrators in a way that would undermine both the code administrators' independence and the principle of industry code ownership.
- 19.327 Respondents provided a wide range of views in relation to the best method to achieve the aim of this remedy. Some respondents chose to emphasise the potential downsides to a licensing regime for code administrators. The main criticisms raised by respondents were that it would be costly to implement (SSE, Gemserv), complicated to operate (SSE, ESB), that it would offer little benefit (ENGIE) and that it would introduce unnecessary bureaucracy into the system (Total).
- 19.328 Several respondents (RWE, SSE) raised the concern that there was no clear definition of the scope of 'code administration services' or 'code delivery bodies' for the purposes of the licence and considered that it would be challenging to arrive at such a definition in the required legislation (without inadvertently also encompassing legal and accountancy services). In relation to the content of the conditions attaching to the licence, the MRA Executive Committee raised the concern that it would be difficult for Ofgem to measure certain outputs for code administrators, such as the requirement to act as a 'critical friend.'
- 19.329 A number of respondents (SSE, Scottish Power, Drax, ESB, Elexon, Energy UK) argued that strengthening the CACoP (see our provisional findings report, paragraph 11.127) would be a more proportionate and effective method to provide Ofgem with a sufficient level of oversight over code administrators. Similarly, First Utility as well as two of the code administrators (Elexon, Gemserv) stated that using contractual arrangements or existing oversight arrangements (such as those already

provided for in certain industry codes such as the BSC) would be a more proportionate way to achieve the aim of this remedies package.

19.330 Some respondents focused on the separate issue of whether a mandatory tendering regime for all code administration (and delivery) services should be considered as complementary or an alternative to the licensing regime. Ofgem and most of the Six Large Energy Firms (RWE, EDF Energy, SSE, Scottish Power) were open to the idea of a competitive tender regime as an additional means to ensure that code administrators meet the necessary requirements for independence, expertise and resource capacity. Centrica argued that cost was not the only factor that should be taken into account when selecting code administrators and that experience and expertise were equally if not more important factors in this context. Gemserv felt that the main aim of this remedy should be to introduce 'full code administration contestability' and that a tender regime was a better means to achieve that aim than a licensing regime. Elexon stated that a clearer steer should be provided as to the funding arrangements that would be considered appropriate for supporting impartiality and the delivery of Ofgem and code panel functions under the licensing regime. Gemserv noted that it agreed with the CMA that there was a lack of a uniform approach to funding, and that it was vital that the process toward licensing includes establishing a consistent funding approach to provide a level playing field.

19.331 Some respondents raised concerns around the ability to implement this remedy within a reasonable timeframe. Centrica suggested that one means to mitigate such concerns would be to introduce a voluntary 'code of practice' which could become the basis for the new code administrators' licence conditions.

Design considerations

19.332 We recognise upfront that a material proportion of modification proposals appear to be processed efficiently by the existing industry-led governance arrangements. In particular, we note that the scheme of self-governance, which Ofgem introduced in 2010 to provide a streamlined process for modification proposals deemed by the relevant code panel to be immaterial,⁷⁷ appears to have led to quick approval and implementation of such proposals, and we have not received submissions that this process has been used inappropriately.⁷⁸ We consider that Ofgem's proposal to make the

⁷⁷ See Section 18, paragraph 18.252.

⁷⁸ However, as noted in Section 18, paragraphs 18.200–18.202, we consider that compared to the industry and code administrators, Ofgem has limited knowledge of certain code provisions and in particular those provisions that have not been the subject of an SCR process or submitted to Ofgem by a code panel. We are concerned

self-governance process the default modification route will expand the efficient usage of that scheme and that. As a means to further improve the efficient usage of that process, Ofgem could publish guidance on how the code panels should interpret the key materiality criterion (see Section 18, paragraphs 18.252 to 18.258 for a further assessment of the self-governance procedures).

- 19.333 We are also mindful that, to the extent practicable, our remedies package should not exacerbate the regulatory burden on the industry and the system-level issue of complexity.
- 19.334 In addition, we note that Ofgem has recently published its Code Governance Review phase 3 final proposals.⁷⁹ Ofgem has stated the design of its final proposals is intended to deliver incremental improvements to the code governance framework which can help to prepare that framework for the wider reforms forming part of the Codes Remedies package.
- 19.335 In light of the above and of the Codes AEC, we have sought to narrow the scope of our remedies package to those areas of the code governance framework where we have found that the current arrangements have a negative and material impact on consumers' interests and/or competition. In general, the design of our remedies seeks to improve the efficiency of those arrangements by adjusting the high-level incentives and roles of the relevant stakeholders rather than by tinkering with procedural details.
- 19.336 The remedies set out below would entail a more proactive role for Ofgem in those situations in which modification proposals are being considered that are likely to have a significant impact on consumers' interests and/or competition. While in the shorter term this would take the form of more formal engagement from Ofgem with respect to such modification proposals, including directly 'calling them in' where necessary (see paragraphs 19.374 to 19.378 below), we expect that over time its involvement will increasingly take the form of influencing the activities of licensed code bodies and industry participants.
- 19.337 We recognise that several of the measures included within this remedies package represent a significant reform to the current code governance arrangements which are capable of full implementation only in the medium

that this may also include provisions that may potentially lead to competition issues – such as provisions relating to the allocation of gas tariff pages (see Section 18, paragraph 18.50). As the regulator in charge of pursuing the best interests of existing and future consumers, it is in our view essential that Ofgem has an adequate understanding of the substantive provisions of codes, a clear direction for code governance and the ability to influence the initiation and development of code changes.

⁷⁹ [Code Governance Review \(Phase 3\): Final Proposals](#), 31 March 2016.

term. We also recognise that, as a result, there is likely to be a transition period as those measures are put in place and stakeholders gain familiarity with new roles, functions and processes. Therefore, we expect the relationship, and the balance of powers, roles and objectives, between Ofgem and code administrators to evolve over time. We have sought to smooth this process of transition by setting out how we expect Ofgem to assist code administrators to develop their understanding of their expanded role under this remedies package. In addition, we consider that the incremental measures which Ofgem has proposed as part of its ongoing Code Governance Review will aid the process of transition.

19.338 Taking into account the above, parties' submissions and the reasons set out in Appendix 19.2, we recommend to DECC and Ofgem the following remedies package.

Clarification and recalibration of Ofgem's and code administrators' respective roles and functions in relation to codes

19.339 Our revised remedies package shifts Ofgem's role in this context so that it is centred on a core responsibility to oversee the strategic development of the codes. To ensure that Ofgem has adequate support to fulfil this new responsibility, our remedies package seeks to expand the role of code administrators so that they can progressively take on more of the day-to-day project management of modification proposals.

19.340 We note that the high-level adjustments described above retain the close involvement of industry in the development of codes. This approach reflects our analysis and parties' submissions, both of which indicate that robust ongoing engagement by the industry is an essential ingredient of a well-functioning code governance framework due to the technical nature of code provisions.⁸⁰ However, we consider it equally essential that Ofgem, as the regulator in charge of pursuing the best interests of existing and future consumers, remain ultimately responsible for the overall regulation of the energy markets, and therefore for the well-functioning of the codes governance arrangements.

19.341 Our general approach to designing this revised remedies package has been to provide Ofgem (and code administrators) with appropriate tools to fulfil the responsibilities set out in our recommendations without prescribing the precise means by which those respective responsibilities should be fulfilled.

⁸⁰ We note that it would be difficult and inefficient to replicate within Ofgem the required level of knowledge and expertise currently held by the industry (see also Appendix 19.2).

In particular, Ofgem should consider on an ongoing basis whether the tools set out in this remedies package create the most efficient balance of powers, roles and objectives between the relevant stakeholders as the sector evolves.

New responsibility for Ofgem to produce a strategic direction

- 19.342 We believe that Ofgem should publish a strategic direction in which it sets out its expectations for the strategic development of the codes (the 'strategic direction'). This form of strategic direction would enable Ofgem to translate DECC's Strategy and Policy Statement (see Section 18, paragraphs 18.53 and 18.54 above) into appropriate signals as to how it expects high-level policy decisions to be implemented via code changes (including the expected timeframes for implementation of such changes). In addition, Ofgem could use the strategic direction to give the industry a steer in relation to its expectations for EU level and other wider market changes. Ofgem should ensure that the steer covers at least the medium term (three to five years) in order to give industry participants an understanding of the volume, nature and proximity of all relevant future changes so as to be able to organise their respective resources appropriately.
- 19.343 Given our wider goal of ensuring an efficiently joined up system of regulation of the energy markets (see paragraphs 19.19 to 19.20 above), we consider that this strategic direction should be developed and published alongside Ofgem's annual report in response to the Strategy and Policy Statement (which when designated will set out the government's high-level policy goals for energy). In the process of developing this document, Ofgem should consult the code panels, code administrators and code parties to ensure that the strategic direction is capable of providing a meaningful steer to those stakeholders and of forming a basis for the strategic work plans (see paragraphs 19.346 to 19.348 below) and that Ofgem understands the potential resource implications of its strategic direction on the industry. Ofgem should also consider whether incorporating input from the analysis carried out pursuant to our other Governance Remedies as part of the process of developing the strategic direction would provide incremental value.
- 19.344 In terms of impacts, we consider that a strategic direction for codes should identify areas requiring code changes and provide a systematic framework for Ofgem's and code administrators' exercise of their powers to initiate and prioritise modification proposals that have a significant impact on consumers' interests and/or competition ('strategically important modification proposals'). On a general basis, the strategic direction would provide code panels with a

helpful metric against which they could more efficiently allocate capacity across the portfolio of code changes. Further, the strategic direction would also improve the ability of code panels to interpret what should be considered as 'material' for the purpose of determining which modification proposals should be eligible for self-governance.

- 19.345 Ofgem would be able to implement this remedy simply by publishing guidance stating that it intends to carry out this function. As it develops the strategic direction, Ofgem should coordinate with DECC to ensure that the strategic direction and Strategy and Policy Statement are appropriately joined up in terms of their content. In addition, Ofgem should correspond with the relevant stakeholders and issue directions, if necessary, to ensure that it receives their input in developing the strategic direction. Ofgem should also consider whether to supplement the strategic direction through more frequent briefings or updates.

New responsibility for Ofgem to lead the production of a set of strategic work plans

- 19.346 We consider that Ofgem could provide considerable incremental value if it developed, in collaboration with the relevant code bodies, a series of documents that set out the changes that it expects are needed to deliver the strategic direction for each code. For that purpose, we propose that Ofgem should develop a series of code-specific 'strategic work plans.'
- 19.347 As such, each strategic work plan would contain an indicative list of areas requiring change to implement the strategic direction (ie strategically important modification proposals). These work plans would help to identify key pinch points, risks and dependencies over the relevant time horizon. We consider that Ofgem should establish a development process that ties into the development of the strategic direction and which uses the input of each code panel and code administrator to a degree commensurate with the expertise and capacity of those entities. Ofgem should also consider whether there is incremental value in producing a consolidated cross-code strategic work plan.
- 19.348 Ofgem could implement this remedy by publishing guidance on its website about the form and purpose of the strategic work plans. Ofgem should correspond with the relevant stakeholders and issue directions, if necessary, to ensure that it receives their input in developing the strategic work plans.

Creation of a 'consultative board' to serve as a forum for addressing cross-cutting code issues

- 19.349 This remedy involves a recommendation to Ofgem to create a standing forum (the 'consultative board') that would function primarily as a stakeholder management tool. The purpose of the consultative board would be to serve as a flexible forum at which Ofgem and other stakeholders could discuss and consider a range of cross-cutting issues such as matters linked to the development and delivery of Ofgem's strategic direction, best practice considerations and the system-level functioning of the code regime.
- 19.350 We recognise that Ofgem already has the ability to attend and input at the various meetings held by the individual code panels. However, following our analysis and parties' submissions, we consider that those fora tend to focus by their nature on code-specific issues and do not foster the discussion of cross-cutting issues such as those described above. Therefore, in our view, an additional complementary forum dedicated to the discussion of such issues at which all industry stakeholders could participate would create incremental value.
- 19.351 We consider that the first capacity in which a consultative board would be beneficial relates to the strategic direction and work plans, as it would provide a forum for Ofgem, code administrators and the industry to discuss the development of these documents and ensure consistency across codes.
- 19.352 A second capacity in which the consultative board could be beneficial is that it could improve the efficiency and provide additional oversight of (strategically important) modification proposals. Centrica suggested that a single 'design authority', taking the role played today by code administrators, would be able to better coordinate cross-code change, resolve areas of contention, prioritise, and generally help project manage proposals such that they are delivered more promptly than today. While we do not propose the creation of an authority with formal powers to (partially) replace code administrators, we believe that the consultative board would provide support to Ofgem, code administrators and the industry so as to improve their respective abilities to contribute to the delivery of strategically important modification proposals and improve the overall quality of project management. An illustrative range of functions that the consultative board could perform in this context includes the following:
- (a) In relation to the scoping of analysis: providing a formal venue for Ofgem to contribute its initial views on the terms of reference of work groups.

- (b) In relation to the performance of analysis: improving the quality of analysis by ensuring that work groups are composed of members with the relevant expertise and, where appropriate, making additional resources available for the purpose of obtaining such expertise⁸¹ as well as reviewing discrete pieces of analysis performed during the development stage (following a request by the relevant code administrator).
- (c) In relation to cross-code changes: helping the code administrators to perform their functions, in particular in relation to identifying cross-code impacts.

19.353 A third capacity in which the consultative board could be beneficial is that it could serve as a forum in which stakeholders could consider and tackle long-term system-level issues, such as revisiting the scope of the codes, governance arrangements or the general complexity of the codes regime (eg by harmonising certain processes).

19.354 We do not consider it necessary to prescribe in our recommendation to Ofgem rules relating to the composition and governance of this board, or to the frequency of the meetings. We would expect the consultative board to be composed of a comprehensive range of stakeholders, including code administrators and parties to each industry code, with Ofgem serving as chair. Ofgem should also consider how to best ensure that the views of small and new entrants are well represented on the consultative board. While we can see the value of including an external specialist in project management within the consultative board's composition, we consider this to be a matter best left for Ofgem and the industry to determine.

19.355 While Ofgem should seek cross-industry input, it should not design the consultative board's compositional structure in a way that may lead to significant costs or additional resource constraints for some or all industry participants. We note that the consultative board would not be a separate entity with its own powers and would thus only be able to act pursuant to the exercise of Ofgem's, code administrators' and industry's respective powers.

19.356 We note that the governance frameworks of some industry codes already contain entities designed to consider the strategic approach to code changes. In proposing the consultative board, we do not intend to create additional bureaucracy or complexity within the code governance framework.

⁸¹ In certain circumstances, Ofgem (or another stakeholder) may consider it beneficial to have additional analysis performed which goes beyond the relevant code's objectives (and thus would not be analysis included within the remit of the relevant work group or budgeted by the relevant code panel).

Therefore, in implementing this remedy, Ofgem should seek to ensure that the overlaps between the consultative board and existing code-specific strategic bodies are minimised.

Ofgem to undertake periodic wholesale reviews of the code regime

- 19.357 Over time, Ofgem is likely to improve its understanding of strategic and cross-cutting code issues through its involvement in the development of the strategic direction and work plans as well as through engagement with stakeholders within the consultative board. We consider that Ofgem could capture the value of that understanding by undertaking wholesale reviews of the codes regime on a periodic basis. Ofgem could then use the findings of those reviews as a basis for making changes aimed at improve the efficiency of the regime, such as consolidating certain codes or reallocating powers and responsibilities between stakeholders.

New powers for code administrators to initiate and prioritise code changes for the purpose of delivering Ofgem's strategic direction

- 19.358 As noted above, we consider that there is scope for code administrators to perform certain key project management functions for modification proposals, where such project management is appropriate in the light of the complexity of the task and/or the substantive impact that the proposal may have on consumers' interests and competition. In principle, and for the reasons set out in Section 18 and Appendix 18.2, we consider that code administrators could perform these functions by virtue of their expertise in the relevant code processes and their quasi-independent status.
- 19.359 This remedy involves a recommendation to Ofgem to grant code administrators the powers to initiate and prioritise code changes which, in their view, either are necessary to deliver the strategic direction or capable of improving the efficiency of the code governance or modification arrangements.
- 19.360 The first aspect of this power would enable code administrators to fulfil their project management role more effectively by enabling them to increase the resources devoted to the development of changes that they consider to be complex or cross-cutting. Ofgem, as part of its implementation of this remedy, should provide some form of guidance to explain when it would be appropriate to overrule code administrators' use of this power (eg through a binding direction).
- 19.361 The second aspect of this power would lead to better utilisation of code administrators' expertise in code governance and modification processes

and would thus improve the efficiency of the modification arrangements. In exercising the power to prioritise a particular modification proposal, code administrators should actively consider how to manage the consequential effects on the timeframes of other modification proposals in order to ensure that they are still progressed in a timely manner.

- 19.362 As code administrators would be subject to a licence pursuant to our remedies package, Ofgem would be in a position to monitor code administrators' performance of these functions and, as the case may be, issue formal directions so as to influence their behaviour as appropriate.
- 19.363 In the short term, we recognise the concern raised by some parties that the ability of certain code administrators to exercise these powers to initiate and prioritise modification proposals may be hampered by capacity constraints (see paragraph 19.319 above). However, we expect these constraints to diminish over time as code administrators are able to develop their expertise and resources. In the long term, we would expect the code administrators to progressively take more responsibility from the industry in terms of the management of code processes and the performance of analysis, under the joint supervision of Ofgem and industry.
- 19.364 Some parties (see above paragraph 19.317) suggested that, to ensure that code administrators' and Ofgem's exercise of these powers is coordinated, Ofgem and the code administrators should jointly develop and publish a guidance document which explains how these powers will be exercised in practice. While we recognise that this may provide some useful clarity to the industry on this issue, we are also concerned that it may unnecessarily restrict the use of these powers. We believe that Ofgem is better placed to decide how to address these concerns, and whether guidance on the use of these powers is appropriate.

Ofgem to initiate and prioritise code changes for the purpose of delivering its strategic direction

- 19.365 This remedy involves a recommendation to Ofgem to take powers to initiate and prioritise code changes which, in its view, are necessary to deliver the strategic direction.
- 19.366 Ofgem's initiation of a code change under this power would trigger an obligation for the relevant stakeholders (eg the relevant code administrator and code panel) to develop and submit an end-to-end project management plan (including both the development and implementation stages) to Ofgem. The relevant code administrator would then have an ongoing responsibility to

report to the consultative board on the delivery of that project management plan.

- 19.367 Ofgem would have the option but not the obligation to contribute to the delivery of that plan, for instance, by agreeing to take responsibility for performing a discrete piece of the required analysis. This would grant Ofgem the discretion to tailor its input into the process in a way proportionate to the materiality of the relevant code change and reflective of its own ongoing capacity.
- 19.368 We note that some parties have argued that Ofgem's exercise of such a power to initiate modification proposals should be subject to a merits-based appeal right (see paragraph 19.318 above). However, we do not view that providing such an appeal right in this context would be appropriate, as it would unnecessarily constrain Ofgem's ability to take the initiative to drive forward strategic change, which would undermine the very purpose of Ofgem taking this power. Any challenge on the substance of the modification proposal should be made within the context of the existing modification process (and pursuant to the existing appeal rights concerning Ofgem's decision to approve or reject a modification proposal).
- 19.369 Ofgem would also have the complementary ability to designate as strategically important any ongoing modification proposal initiated by another stakeholder (see paragraph 19.317 above). The modification process to develop any modification proposals so designated would be subject to the same enhanced project management process described above.
- 19.370 To implement this remedy, Ofgem would need to modify the relevant licence conditions to set out the process for it to raise modification proposals under each of the codes.⁸²
- 19.371 This remedy grants Ofgem the ability to provide input directly into specific aspects of the modification processes to ensure the timely and effective delivery of its strategic direction. However, we are keen to ensure that Ofgem does not find it necessary to expend a significant proportion of its resource in this way, as this outcome would contradict our aim of focusing Ofgem's role on strategic level input. Therefore, we expect that such granular interventions into the modification processes may sometimes take the form of directions issued to code panels and code administrators, rather than actual formal interventions. In certain circumstances, Ofgem should proactively consider whether it is appropriate to commission an independent

⁸² Under most codes, Ofgem is only entitled to raise modification proposals for the purpose of ensuring the consistency of the GB codes regime with EU legislation.

third party to provide additional project management, for instance to facilitate the implementation of complex or cross-cutting code changes.

- 19.372 The table below provides a visual overview of the modification routes that would be followed by all code changes that do not qualify for self-governance (as noted above, the self-governance procedures would not be affected by our remedies). However, the actual level of involvement of code administrators and Ofgem would vary from case to case, depending on the complexity and materiality of the modification proposal. For instance, we would expect that changes which are unlikely to have a significant impact on consumers' interests and/or competition to follow a similar process to the current ordinary procedure, with limited or no involvement by the consultative board or Ofgem (other than for the approval or rejection of the modification proposal).
- 19.373 On the contrary, we expect that 'strategically important' modification proposals would be prioritised by code administrators and code panels for the purpose of delivering Ofgem's strategic direction. As a result, such modification proposals will be subject to closer oversight by the consultative board (in particular when cross-code changes are involved), stronger project management by code administrators and possibly direct contributions to the performance of analysis from Ofgem and/or third party experts appointed for that purpose by Ofgem following discussions at the consultative board (again, the level of each of these actions would depend on the complexity and materiality of the relevant modification proposal).

Table 19.2: The end-to-end functions required to deliver a modification proposal

Function	Performing entity
Initiation	Either industry, code administrators or Ofgem
Prioritisation	If appropriate, code administrators or Ofgem
Creation of work groups (setting remit, selecting members etc)	Code administrators, if appropriate with oversight by consultative board (Ofgem)
Performance of analysis	Industry with possible intervention from code administrators/Ofgem
Project management	Code administrators (with additional formal powers as set out in licence)
Drafting legal text	Industry, with support from code administrators and, if appropriate oversight by consultative board (Ofgem)
Approval	Ofgem
Implementation	Industry/delivery bodies, with possibility of project management by code administrators or third party appointed by Ofgem

Creation of a backstop executive ‘call in’ power

19.374 This remedy involves a recommendation to Ofgem to intervene to ‘call in’ an ongoing strategically important modification proposal in the event of the occurrence of certain exceptional circumstances.

19.375 Ofgem’s exercise of this power would transfer all procedural and substantive control in relation to the modification proposal at issue from the industry and relevant code administrator to Ofgem. Ofgem would then be in a position either to carry out the remaining required functions itself or to appoint third party experts to do so on its behalf. To maximise the deterrent effect of this power, and ensure that it does not become a means for the industry to exploit Ofgem’s resources, we consider that Ofgem should pass on any consequential costs it incurs following the exercise of the call-in power to the relevant licensees. We note, however, that any such decision by Ofgem to exercise the call-in power and impose costs in the way envisioned above would need to be subject to robust procedural and judicial safeguards. In particular, we consider that materially affected parties should be granted a merits-based appeal right to challenge Ofgem’s exercise of this power. In addition, Ofgem should incorporate adequate consultation of the industry into the development process for any modification proposal that it has ‘called in’. This contrasts to our view concerning the exercise by Ofgem of the

power to initiate modification proposals which, as a mere step within the context of the industry-led modification process, we consider merits a lesser degree of judicial scrutiny than this call-in power. This is because the call-in power may lead to material changes to codes with limited input from the industry (compared to an ordinary industry-led process) and therefore requires a merits-based appeal consistent with the existing appeal process for changes to licence conditions.

19.376 For the purposes of ensuring a transparent system of regulation, we consider that either DECC in legislation or Ofgem in guidance should provide some definition of what constitutes ‘exceptional circumstances’ in this context. Though we consider that defining exceptional circumstances is a matter for Ofgem’s discretion, we expect that it would include at least the following two scenarios. Firstly, Ofgem could consider it inappropriate, as a matter of principle, for certain code changes to be dealt with primarily by means of self-regulation due to the significance of their impact on consumers’ interests and/or competition.⁸³ In such cases, it would not be sufficient for Ofgem to influence discrete steps of the modification process (as envisaged in our remedy through the consultative board). Secondly, there may be instances in which Ofgem determines that the ordinary industry-led process has failed to deliver a strategically important modification proposal in a timely manner. To implement this change, as a baseline Ofgem would need to publish guidance indicating the factors that it would take into account in determining when to utilise the call-in power.

19.377 Legislative measures would be needed to implement this remedy. We therefore recommend that DECC initiate a legislative process with a view to granting Ofgem an open-ended power to make code changes in the special circumstances identified above.

19.378 We consider that this remedy, together with the remedy for Ofgem to take powers to initiate and prioritise strategically important modification proposals (see paragraph 19.365 to 19.373 above), would form an effective alternative to Ofgem’s current ability to initiate the SCR process (for a further assessment of Ofgem’s SCR powers see Section 18, paragraphs 18.216 to 18.251 and Appendix 18.2).

⁸³ Possible examples could include provisions that are necessary to achieve the benefits of a strategic policy such as half-hourly settlement, which is needed to support the roll-out of smart meters or measures intended to ensure gas security of supply.

Supporting remedy: DECC to make the provision of code administration (and delivery) services a licensable activity

- 19.379 This remedy involves a recommendation to DECC to make the provision of code administration (and delivery) services a licensable activity. The purpose of this remedy is for Ofgem to have appropriate sight of all relevant code development issues so that it can exercise its discretion to intervene in the most effective manner. To achieve this objective it is necessary to establish a clearer role for code bodies by licensing those entities and codifying their powers and responsibilities.
- 19.380 Ofgem put to us that it considered licensing to be the cornerstone of the new framework which would be put in place by this remedies package. It recognised that the current mechanisms in place which allowed it to incentivise the behaviour of code administrators were insufficient⁸⁴ and also inconsistent across codes. By contrast, it considered that licensing represented an effective means to introduce new accountabilities of code administrators towards consumers via Ofgem. Ofgem noted that this shift was needed because there was no entity within the current code governance arrangements that was responsible for balancing the interests of the industry against those of consumers and/or competition. Moreover, it saw licensing as a means to allow universal requirements and/or incentives to be applied to the behaviour of code administrators.
- 19.381 For code bodies to evolve most effectively into ‘code managers’, Ofgem should refrain from micro-managing their behaviour, to the extent possible. This is important to ensure that those entities do not become reliant on formal directions from Ofgem to determine the most appropriate method to fulfil their codified duties. However, we recognise that in the transition period Ofgem may need to make use of such directions in order to incentivise appropriate behaviours for code administrators. Given the current differences in the governance arrangements across the codes, we do not believe that it is appropriate to provide a precise definition of ‘code administration (and delivery) services’ for the purposes of the licence. However, we note that the objective of this remedy is to ensure that code bodies act in the interests of competition and consumers and that Ofgem is capable of monitoring the performance of all code bodies that administer and/or project manage modification proposals. Where appropriate, we also expect Ofgem to be able to intervene to address non-performance. In light of that objective, we consider that, for the purposes of the licence remedy, the

⁸⁴ In particular, Ofgem considered that licensing would have helped to avoid the issues that arose in several of the case studies described in the appendix to this section, including the half-hourly settlement, Nexus and Gas SCR case studies.

classification of 'code administration (and delivery) services' should include most of the required activities listed in Table 19.2 above. We believe, however, that DECC and Ofgem are in a better position to define precisely the scope of licensable activities, and to update it as the relationship between Ofgem and these licences evolve over time. For the avoidance of doubt, we note that under this construction, both code administrators and code-specific delivery bodies would need to be licensed following the implementation of this remedy.

19.382 Following our analysis and our review of parties' submissions (including Ofgem's), we consider that the licence remedy for code administration services should include (but not be limited to) the following standard conditions:⁸⁵

- (a) requirement to carry out its functions having regard to the objectives of the relevant industry codes, Ofgem's strategic direction and Ofgem's principal objective and duties;⁸⁶
- (b) effective coordination with Ofgem in relation to developing the cross-codes strategic work plan and the relevant code specific strategic work plan;
- (c) effective coordination with other code bodies in relation to delivering code changes with cross code impacts;
- (d) timely delivery of code changes set out in the strategic work plans;
- (e) effective project management of all modification proposals, including, in particular, appropriate consultation of all relevant code parties;
- (f) transparent provision and presentation of all relevant information including, in particular, through a clear and helpful website;
- (g) effective performance of the 'critical friend' role (see Section 18, footnote 77 to paragraph 18.207 and Appendix 18.2);
- (h) minimisation of delivery costs; and
- (i) appropriate reporting of cross-cutting governance issues to Ofgem.

⁸⁵ We note that it is for Ofgem to determine the extent to which these conditions would apply to delivery bodies which do not actively engage in the administration or project management of modification proposals.

⁸⁶ We consider this to be appropriate since Ofgem will carry out its gatekeeper functions in respect of all modification proposals with a view to pursuing its principal objective and duties.

- 19.383 We recommend that Ofgem take the above as a starting point for setting up the initial standard licence conditions, and develops these over time. Ofgem should also consider whether to insert additional special conditions into the licences of those code administrators that perform distinct functions in the context of certain codes.
- 19.384 We consider that licensing code administrators and delivery bodies in the manner contemplated above would be a transparent and effective means of incentivising those entities to take up their new role in supporting Ofgem to deliver the strategic direction in a timely and efficient manner.
- 19.385 We also consider that licensing would create a direct accountability mechanism which should address the concerns raised by some parties that code administrators will face conflicts of interest and perverse incentives when deciding whether to exercise the new powers to initiate and prioritise modification proposals under this remedies package (see paragraphs 19.317 and 19.358).
- 19.386 We note the concern raised by some parties that performance against the conditions set out above may be difficult to measure in practice (see comments in paragraph 19.328 above). We consider that this is a matter that is most appropriately determined by Ofgem; we also note that Ofgem has considered how to address this issue as part of its Code Governance Review phase 3 final proposals.
- 19.387 An important additional benefit of licensing code bodies is that this change would enable Ofgem to open up the market for code administration (and delivery) services to full competition. Several parties (including Ofgem, see paragraph 19.330 above) submitted to us that the establishment of a competitive tendering regime for the code administration (and delivery) licences would help to ensure the effectiveness of this remedy. We agree with this position as we expect that effective competition within the market for code administration (and delivery) services would lead to some consolidation as the tendering process would enable efficient entities to take on additional powers, roles and objectives. This outcome would go some way to fulfilling our remedies package's long-term objective of streamlining the codes regime. Therefore, in our view, Ofgem should introduce in due course a competitive tendering regime for the licences required following the implementation of this remedy. We consider that it is for Ofgem to determine the specifics of the most appropriate time and how precisely to establish a tendering regime, as considered above. This should be a relevant consideration for DECC and Ofgem in setting up the licence regime.

- 19.388 We have considered whether, as an alternative, a package of measures centred only on a competitive tendering regime and not including any form of licence for code administration (and delivery) services would be capable of achieving the aim of this remedy. However, the first issue that we note in relation to the alternative package described above is that Ofgem would potentially face change-control issues. Ofgem put to us that it would have to agree with contracted parties any changes to contractual terms. This could make it difficult to impose new obligations on code bodies which they did not consider to be in their interest. This could lead to delays and inefficiencies. In addition, Ofgem considered that if it had separate contracts with each code body it could be difficult to coordinate changes as it would have to negotiate changes separately, as each party may have a distinct position. Over time, this arrangement would also create a risk that it would lead to a divergence in code body powers, roles and objectives rather than the convergence which is considered necessary.
- 19.389 The second issue with the package considered above is that Ofgem's only enforcement option would be to initiate court proceedings which may prove to be costly, lengthy and, in some cases, unsuccessful. Ofgem put to us that, in the possible context of litigation to enforce a breach of contract terms against a code body, it would face particular difficulties in proving that it had suffered loss and in quantifying that loss. In addition, we also note that contractual arrangements are already relied upon to provide adequate performance incentives for code administrators in the context of certain codes, such as the BSC. We note further that our case studies illustrate that those arrangements have not prevented strategically significant code changes progressed through the modification arrangements of those codes from experiencing delays (eg the EBSCR). Therefore, we consider that a system which utilises contractual arrangements may not adequately incentivise code administrators' behaviour to perform at the level needed for those entities to play a greater role in the code governance framework, as contemplated under this remedies package.
- 19.390 Another alternative to our licensing remedy that we have considered is to strengthen the CACoP. We recognise that the CACoP has successfully incentivised code administrators to take on additional roles such as that of 'critical friend', the performance of which has facilitated engagement by smaller parties. However, Ofgem put to us that the CACoP provided limited means to facilitate innovation or to provide code administrators with reputational incentives to disseminate best practice across codes. In addition, Ofgem considered that, as the requirement to appoint a code administrator was placed on the 'code owner', performance drivers under the CACoP mechanism were indirect and primarily industry-facing. Therefore,

we do not consider that strengthening the CACoP would provide adequate incentives for code bodies to perform the expanded role envisaged under this remedy package effectively.

- 19.391 In implementing this remedy, Ofgem should consider whether it is appropriate to modify the licence conditions of certain code parties as an additional means to incentivise the behaviour of code bodies that would be licensed following implementation of this remedy (ie those code parties which are responsible for funding code administrators and which may seek to influence their actions). RWE also suggested that distinct arrangements might need to be put in place to ensure that this remedy incentivised National Grid's behaviour appropriately, due to its dual administrative and commercial capacities. We agree with this suggestion and recommend that Ofgem considers this matter as part of its implementation plan.
- 19.392 We expect Ofgem to consider how it will approach the transition to a licensing regime as it works up its implementation plan. In particular, we expect that Ofgem would consider whether it would be efficient to pilot certain licence conditions by putting in place arrangements that code administrators would follow on a voluntary basis.
- 19.393 A separate practical issue that should be considered by Ofgem in implementing this remedy is whether the licensing regime may conflict with the funding arrangements for certain code administrators (in particular, those which currently operate on a not-for-profit basis) and, if so, whether it is necessary to introduce a uniform funding arrangement for code administrators. We believe that rationalising the funding arrangements of code administrators would enable Ofgem to introduce a common mechanism whereby it could sanction code administrators directly for non-performance of licence conditions. We note in this context that Scottish Power suggested that, in order to support such a mechanism, related organisations should transfer resources to code administrators and/or that code administrators should be required to hold a certain level of capital. We note further that Gemserv stated that code contestability must be considered in line with licensing such that sanctions may not apply under the licence until after full code contestability is realised. We recommend that Ofgem perform analysis to determine the optimal funding arrangements for licensed code administrators and considers what mechanisms would be necessary and effective to ensure the accountability of code administrators to itself.
- 19.394 We note that EDF Energy suggested a series of additional reforms, such as the standardisation of relevant websites that could be implemented in the short term before the introduction of the licence under this remedy in order to start making code bodies more accountable. We consider that those reforms

would provide incremental value and would help to ensure an efficient transition to a licensing regime but, given their incremental nature, they would be more appropriately taken forward by Ofgem as part of its ongoing Code Governance Review.

Summary of the Codes Remedies package

19.395 In summary, we consider that the package of Codes Remedies consisting of the following key elements would be effective in remedying the Codes AEC:

- (a) In relation to its approach to intervening within the code regime, the following recommendations to Ofgem:
 - (i) to publish a cross-cutting strategic direction for code development;
 - (ii) to oversee the annual development of code-specific work plans for the purpose of ensuring the delivery of the strategic direction;
 - (iii) to establish and administer a consultative board in order to bring stakeholders together for the purpose of discussing and addressing cross-cutting issues;
 - (iv) to take powers to initiate and prioritise modification proposals that, in its view, are necessary for the delivery of the strategic direction;
 - (v) in exceptional circumstances, to intervene to take substantive and procedural control of an ongoing strategically important modification proposal; and
 - (vi) to modify licence conditions to grant each code administrator the power to initiate and prioritise modification proposals that, in its view, are necessary for the delivery of the strategic direction or to improve the efficiency of the governance arrangements.

We expect Ofgem to implement these recommendations by way of amendments to the relevant standard licence conditions, and/or by ensuring that appropriate industry code modifications are developed and implemented, so as to set up the necessary processes and mechanisms for it to carry out these functions. In addition, we expect that in relation to several of the above recommendations Ofgem will publish guidance setting out how it intends to implement them.

- (b) A recommendation to DECC that it should enact legislation to grant Ofgem the power to modify codes in certain exceptional circumstances.

- (c) A recommendation to DECC that it should require a licence for the provision of code administration (and delivery) services and, in the process of designing the associated licence conditions, ensure that such licence conditions are appropriately targeted to incentivise code administrators to take on the expanded role envisaged under this remedies package and minimise the regulatory burden on those entities.

Effectiveness of this remedies package

- 19.396 In terms of impacts, we consider that our remedies package will increase the efficiency and robustness of the code modification processes, by giving Ofgem appropriate tools to influence the development and delivery of strategically important modification proposals.
- 19.397 The strategic direction, and associated work plans, should identify areas requiring code changes and provide a systematic framework for Ofgem's and code administrators' exercise of their powers to initiate and prioritise strategically important modification proposals.
- 19.398 Code administrators (and delivery bodies), as licensed bodies with better defined powers and responsibilities, and appropriate funding, will be able to step into the modification processes where appropriate to support Ofgem and code panels in their respective functions.
- 19.399 The consultative board will provide parties with a forum to surface cross-cutting or complex issues related to the development or implementation of code changes at an early stage, thus lessening the risk that such issues result in delays. Similarly, it will create a framework for Ofgem to engage proactively and at an early stage with strategically important modification proposals, so as to ensure that the analysis carried out during the development stage is appropriate. The consultative board will, among other things, discuss the appointment of third party experts for the purpose of carrying out detailed analysis or managing the implementation process (although we would expect that, over time, these roles would be progressively taken over by code administrators). In addition, it will contribute to giving Ofgem a better grasp of the code regime, with respect to its substantive scope, which in turn will facilitate the broader policy objective, set out above, of promoting a streamlined and predictable regulatory framework.
- 19.400 Together, the measures described above should contribute to ensuring that the code regime is capable of keeping pace with wider technical and policy developments, including, for instance, the pending challenge of transposing the EU network codes.

- 19.401 We have also considered whether to include in our remedies package further measures such as those proposed by Ofgem in its response to our provisional findings (see paragraph 19.308). We note that one of the objectives of Ofgem's proposed measures is to consolidate and simplify the codes regime (or at least the provisions relating to retail markets), which would be governed by a single entity.
- 19.402 While we accept that this would have some benefits, by reducing the complexity of certain code processes and costs for industry parties, we consider that designing our remedies package in such a way as to achieve that objective directly would go beyond addressing the Codes AEC. In particular, it would require merging certain (parts of) industry codes, as well as creating a new body which would centralise a number of functions carried out by different stakeholders. We also note that it would only be feasible to make these changes in the much longer term and following significant institutional change that would entail significant implementation costs. Taking into account the above, we have deliberately designed our remedies package in a way that is effective in addressing the Codes AEC within a reasonable time frame (see paragraph 19.403 below), which also supports Ofgem's long-term objective.
- 19.403 We expect our remedies package to show results in the short and medium term. The measures within our remedies package that involve a recommendation to Ofgem could be implemented and take effect within a relatively short period, once Ofgem has had a chance to develop the details of these measures and consult stakeholders, as appropriate. We note that, as DECC must follow the normal legislative process in order to create a new licence for code administration (and delivery) services, the licensing remedy will likely be implemented and take effect in the medium term. We expect that Ofgem would award licences to each of the current code administrators (and delivery bodies) and then consider whether it would be appropriate to initiate a competitive tender for those licences.
- 19.404 A number of the remedies considered within this package involve recommendations to Ofgem to change its approach to intervening in the codes regime. We consider that there is a high likelihood that Ofgem would implement our recommendations on the basis of its submissions to us and the consistent thrust of its ongoing work on the Code Governance Review. We note that Ofgem has the ability to modify the relevant standard licence conditions to alter the role of code administrators and it has done so in order to implement the proposals of its Code Governance Review. We note further that DECC has the power to create new licences for designated activities

within the energy sector and recently exercised this power in September 2013 to establish a new licence for smart meter communication services.

19.405 For the reasons set out above, we consider that the Codes Remedies package is effective in targeting the features of the Codes AEC, and is capable of effective implementation within a reasonable time frame.

Assessment of proportionality

19.406 We have assessed whether the Codes Remedies package is proportionate on the basis of our guidelines. Specifically, our assessment has considered whether our remedies package:

- (a) is effective in achieving its legitimate aim;
- (b) is no more onerous than needed to achieve its aim;
- (c) is the least onerous if there is a choice between several effective measures; and
- (d) produces adverse effects which are disproportionate to the aim.

19.407 For the reasons set out above we have concluded that the package of Codes Remedies is effective in its legitimate aim of remedying the Codes AEC.

19.408 In reaching our decision on remedy design, we have sought to avoid imposing costs and restrictions on parties that go beyond what is needed to achieve an effective remedy.

19.409 The measures of our Codes Remedies package that impact Ofgem leave it a wide margin of discretion over the precise nature of its involvement within the codes regime. This enables Ofgem to take a proportionate approach, allocating its resources only to those projects where its interventions are needed or appropriate, due to the complexity or materiality of the modification proposal in question.

19.410 We have also sought to ensure that our Codes Remedies package retains close industry involvement in codes and, in turn, does not unnecessarily disrupt legal certainty in this area of regulation. We believe that our remedies package maintains a key role for the industry, while increasing transparency and facilitating formal and informal engagement between the industry, Ofgem and code bodies.

19.411 We also consider that our approach to licensing code administration (and delivery) services should minimise the regulatory costs for affected entities.

In particular, we note that our licensing remedy recommends the use of clear outputs-based conditions rather than prescriptive rules as a means to incentivise those entities toward desired behaviour. We note further that code administrators are already incentivised to perform some of the outputs-based licence conditions due to their inclusion in the (non-binding) requirements set out in the CACoP.

19.412 We do, however, recognise that there are costs associated with a licensing regime: for example, code bodies will likely need to invest some resource into understanding their licence conditions and the associated incentives (for example, by establishing compliance or regulatory teams). However, Ofgem put to us that there were a number of considerations which together indicated that the costs described above should be more than compensated by the related benefits to consumers. For instance, it considered that the introduction of compliance teams within code administrators would better enable those entities to act upon the relevant requirements and incentives, to the benefit of competition and consumers. Another consideration was that a large proportion of the costs involved in licensing were likely to be redistributive from Ofgem to the code bodies. Ofgem noted that it would consider any reallocation of costs from one industry sector to another as part of any changes to funding arrangements.

19.413 We also note that, pursuant to our remedies package, Ofgem would perform a periodic review of the codes regime for the purpose of assessing its functioning. In particular, this mechanism would enable Ofgem to review the appropriateness of the allocation of powers, roles and objectives across the various stakeholders put in place by this remedies package. This mechanism increases the flexibility of this remedies package and lessens the risk that it will lead to a governance framework that is unnecessarily onerous for any of the main stakeholders.

19.414 We also considered other possible ways of addressing the Codes AEC. These included measures that we had put forward ourselves for consideration and some alternative measures that were put to us by parties in response to the Remedies Notice.

19.415 We found that each of the following alternative measures were less effective and/or more costly than the remedies package set out above:

- (a) a set of measures centred on a grant to Ofgem of stronger powers to make changes directly to codes, for the reasons given in paragraphs 10 to 13 of Appendix 19.2;

- (b) an alternate approach to driving the behaviour of code administrators, under a contractual tendering regime, for the reasons given in paragraph 19.388 above;
- (c) an alternate approach to driving the behaviour of code administrators, under a strengthened CACoP, for the reasons given in paragraph 19.390 above; and
- (d) Ofgem's proposal to create a single code entity, for the reasons given in paragraph 19.402 above.

19.416 Finally, we considered whether the remedies package – or any specific measure within it – was likely to produce adverse effects which were disproportionate to the aim of remedying the Codes AEC.

19.417 Our remedies package would require Ofgem to invest more resources in monitoring and supervising code changes that are likely to have a significant impact on consumers' interests and/or competition. However, we consider that by focusing Ofgem's role on strategic determinations, and influencing code administrators and code panels, the associated costs should be limited, and certainly significantly less burdensome than those which Ofgem currently expends under the SCR process. We also expect that the strategic signals provided by Ofgem to the industry through its new functions will lead to significant efficiency gains as parties are able to better allocate their resources across the portfolio of pending and ongoing code changes.

19.418 Our remedies package also contains powers for Ofgem to direct some or all aspects of a given modification procedure (in particular under the call-in power). However, we expect that these powers will be used only in exceptional circumstances, if at all, and thus should not lead to significant costs for Ofgem. We also expect that the existence of these powers will act as an incentive on the industry to comply with Ofgem's directions.

19.419 While code administrators (or at least, some of them) would need additional resources to perform their expanded role efficiently (and, if appropriate, to appoint third party experts to carry out additional analysis or perform certain functions to ensure that a certain modification proposal is developed and implemented efficiently), these costs are a form of centralisation of costs. Therefore, they are likely to lead to certain economies of scale and/or scope, for example by avoiding duplication or repetition of analysis (for instance, in circumstances where Ofgem would use its send-back power as a result of unsatisfactory analysis being submitted to it as part of a code panel recommendation).

19.420 We believe that better project management would reduce the time frames of complex modification proposals and, in turn, reduce the costs borne by industry as a result of engaging with the code modification processes. These benefits would, in our view, offset to a significant extent the additional costs incurred by code administrators and other delivery bodies. The net cost is therefore justified by the benefits arising from a better overall code governance framework.

19.421 We also note that, as the majority of this Codes Remedies package will be implemented by means of recommendations to Ofgem, it is therefore ultimately for Ofgem to ensure that its interventions to implement this remedies package are not disproportionate to the expected benefits.

20. Decision on AECs and remedies

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Decision on AECs

20.1 As described in paragraph 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. 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.¹

20.2 In this section, we summarise the AECs we have identified, and the features of the energy markets in Great Britain giving rise to each of these AECs.

¹ Section 134(2) of the 2002 Act.

Locational Pricing AEC

- 20.3 In Section 5, we have 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 (the 'Locational Pricing 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.

CfDs AEC

- 20.4 In Section 5, we have also found that the mechanisms for allocating CfDs are a feature of the wholesale electricity market in Great Britain giving rise to an AEC (the 'CfDs 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.

Domestic Weak Customer Response AEC

- 20.5 In Section 9, we have 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 response² which, in turn, gives suppliers a position of unilateral market power concerning their

² We refer to weak customer response as an overarching feature as synonymous with it being a source for an AEC ([CC3](#), paragraph 170).

inactive customer base which they are able to exploit through their pricing policies or otherwise (the 'Domestic Weak Customer Response AEC'). 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. We note that these features differ in intensity across different meter types.

20.6 More particularly, in relation to domestic customers on all meter types 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.

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. In addition, the fact that the regulations governing energy supply ensure that domestic customers generally receive continuous supply of gas and electricity implies that there is no natural trigger point for engagement, which may depress levels of engagement relative to other sectors.

- (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 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 perceived barriers to switching, such as where they 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.

20.7 We have found that prepayment customers and standard credit customers overall are less engaged than direct debit customers, particularly in terms of whether they have ever considered switching or are likely to consider switching in the next three years, and, for prepayment customers, their awareness of their ability to switch.

20.8 In addition, we have found that there are additional aspects of the prepayment and restricted meter segments that contribute to the features that customers face actual and perceived barriers to accessing and assessing information, and that customers face actual and perceived barriers to switching supplier, for prepayment customers and customers on restricted meters.

20.9 We have found that prepayment customers face:

(a) higher actual and perceived barriers to accessing and assessing information about switching arising, in particular, from relatively low access to the internet and confidence in using PCWs; and

(b) higher actual and perceived barriers to switching arising, in particular, from:

(i) the need to change meter to switch to a wider range of tariffs (and the obstacles associated with this requirement such as perceptions of the complexity of the meter replacement process); and

(ii) restrictions arising from the Debt Assignment Protocol hindering indebted prepayment customers' ability to switch supplier.

20.10 We have found that customers on restricted meters face:

- (a) higher actual and perceived barriers to accessing and assessing information arising, in particular, from a general lack of price transparency concerning the tariffs that are available to them, which results from restricted meter tariffs not being supported by PCWs or suppliers' online search tools; and
- (b) higher actual and perceived barriers to switching arising from:
 - (i) the requirement imposed by suppliers on certain restricted meter customers to replace their meters with a single-rate or Economy 7 meter, which may be at a cost to the customer, to be able to switch to a wider range of tariffs;
 - (ii) the fact that a restricted meter replacement might involve some rewiring in the home; and
 - (iii) the fact that a restricted meter replacement (particularly to a single-rate meter) may entail a loss of functionality to the customer, and possibly higher tariffs in the future, with no option of reverting back to their old meter.

20.11 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 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.

The Prepayment AEC

20.12 In Section 9, we have found that a combination of features of the prepayment meter segments give rise to an AEC through reducing suppliers ability and/or incentives to compete to acquire prepayment customers, and to innovate by offering tariff structures that meet customers' demand (the 'Prepayment AEC'). These features are:

- (a) technical constraints that limit the ability of all suppliers, and in particular new entrants, to compete to acquire prepayment customers, and to innovate by offering tariff structures that meet demand from prepayment customers who do not have a smart meter. These technical constraints are exacerbated by certain aspects of the simpler choices component of the RMR rules; and

- (b) softened incentives on all suppliers, and in particular new entrants, to compete to acquire prepayment customers due to:
 - (i) actual and perceived higher costs to engage with, and acquire, prepayment customers compared with other customers; and
 - (ii) a low prospect of successfully completing the switch of indebted customers, who represent about 7 to 10% of prepayment customers.

The RMR AEC

20.13 For the reasons given in Section 9, in relation to the regulatory framework governing the markets for domestic and/or SME retail gas and electricity supply, we have found that certain aspects of 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) are 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 compete and innovate in designing tariffs and discounts to meet customer demand, and by softening competition between suppliers and PCWs (the ‘RMR AEC’).

The Gas Settlement AEC

20.14 For the reasons given in Sections 9 and 16, 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 (the ‘Gas Settlement AEC’).

The Electricity Settlement AEC

20.15 For the reasons given in Sections 9 and 16, 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 (the ‘Electricity Settlement AEC’).

The Microbusiness Weak Customer Response AEC

20.16 For the reasons given in Section 16, we have 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 microbusinesses³ 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 otherwise (the 'Microbusiness Weak Customer Response AEC'). 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.

20.17 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.
- (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-

³ We refer to weak customer response as an overarching feature as synonymous with it being a source for an AEC ([CC3](#), paragraph 170).

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 contracts (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).

The Governance AEC

20.18 In Section 18 we have 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 (the 'Governance AEC'). More particularly, these features are as follows:

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

- (b) the absence of a formal mechanism through which disagreements between DECC and Ofgem over policy decision-making and implementation can be addressed transparently;
- (c) the lack of effective communication on the forecast and actual impact of government and regulatory policies over energy prices and bills; and
- (d) the lack of a regulatory requirement for clear and relevant financial reporting concerning generation and retail profitability.

The Codes AEC

20.19 In Section 18, we have 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 (the 'Codes AEC'). In particular, we are concerned that this AEC has the impact of limiting pro-competitive change. The underlying 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.

20.20 We have therefore 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, 9, 16 and 18 of this final report.

Decision on remedies

20.21 In this section we summarise our remedies to address the AECs identified above, and the resulting detriment.

Remedies concerning the Locational Pricing AEC

20.22 The remedies package to address the Locational Pricing AEC, and the resulting detriment is as follows:

- (a) An order on National Grid (the Locational Pricing Order) (and amendments to National Grid's licence conditions) that will require National Grid to:
 - (i) ensure that, at all times, imbalance charges (and specifically the estimated volumes of imbalance) are calculated such as to be locationally sensitive to transmission losses;
 - (ii) ensure that the imbalance charges are calculated, as of 1 April 2018, on the basis of the principles set out in the order;
 - (iii) assume responsibility for the calculation of the transmission loss factors if the BSCCo and/or any other agent appointed for that purpose fails to perform its duties within this context; and
 - (iv) raise a code modification proposal to modify the BSC in line with P229.
- (b) A recommendation to Ofgem to support National Grid by taking necessary steps that might facilitate the effective and timely implementation of the Locational Pricing Order.
- (c) A recommendation to Ofgem and to the industry to assess alternative solutions to the remedy as implemented based on full marginal pricing and, if and when appropriate, consider whether to develop and implement a further code modification based on the most effective solution.

Remedies concerning the CfDs AEC

20.23 The remedies package to address the CfDs AEC, and the resulting detriment is as follows:

- (a) A recommendation to DECC to undertake, and disclose the outcome of, a clear and thorough impact assessment before awarding any CfD outside the CfD auction mechanism.
- (b) A recommendation to DECC to undertake and consult on a clear and thorough assessment of the appropriate allocation of technologies and CfD budgets between pots.

Remedies concerning the Domestic Weak Customer Response AEC and the Prepayment AEC

20.24 The remedies to address part of the Domestic Weak Customer Response AEC and part of the Prepayment AEC, and the resulting detriment are as follows:

- (a) A recommendation to Ofgem to establish an ongoing programme (the 'Ofgem-led programme') to identify, test (through randomised controlled trials, where appropriate) and implement (for example, through appropriate changes to gas and electricity suppliers' standard licence conditions) measures to provide domestic customers with different or additional information with the aim of promoting engagement in the domestic retail energy markets, including a recommendation to develop and test proposals (including through randomised controlled trials, where appropriate) concerning the following priority list of measures:
 - (i) changes to the information in domestic bills and how this is presented;
 - (ii) changes to information provided to customers on cheaper tariffs available across the markets;
 - (iii) changes to the specific messaging that domestic customers receive in bills once they move, or are moved, on to an SVT and/or other default tariffs; and
 - (iv) changes to the name of the default tariffs.
- (b) A recommendation to Ofgem to modify gas and electricity suppliers' standard licence conditions to introduce (following a consultation) an obligation on suppliers to participate in the Ofgem-led programme.
- (c) An order on gas and electricity suppliers (and amendments to suppliers' standard licence conditions) requiring the disclosure to Ofgem of (i) certain details⁴ (the Domestic Customer Data) of their domestic customers who have been on one of their standard variable tariffs (or any other default tariff) for three or more years (the Disengaged Domestic Customers), and (ii) updated Domestic Customer Data on a

⁴ This will be the customer's full name, billing address, consumption address, current supplier, meter type (eg unrestricted, Economy 7 etc), name of their current tariff, annual energy consumption, MPAN/MPRN and, as regards a customer on a restricted meter, certain additional consumption data by specified time periods and details of the customer's standing charges and volume rates. For the avoidance of doubt, the Domestic Customer Data will exclude details relating to any Disengaged Domestic Customer that opted out following receipt of an Opt-out Letter.

regular basis for the purposes of a creating, operating and maintaining a secure cloud database containing the Domestic Customer Data, and allowing rival suppliers to access and use the data for the purpose of postal marketing. The order will also require suppliers, prior to disclosing the Domestic Customer Data to Ofgem, to send a prescribed letter to each Disengaged Domestic Customer, explaining the proposed use of the customer's details, and including an opt-out mechanism for the domestic customer, at any time, to object to and prevent the proposed disclosure and use of their details.

- (d) A recommendation to Ofgem to (i) create, operate and maintain a secure cloud database for the purposes of holding the Domestic Customer Data and to adopt a publically recognised standard for data security in the arrangement for gathering, assembling, and storing the Domestic Customer Data and in providing access to it; (ii) hold the Domestic Customer Data; (iii) test the operation of the database (prior to its roll-out); (iv) put in place safeguards to mitigate any prejudice to the rights and interests of the data subjects; (v) provide access to the Domestic Customer Data to any rival supplier subject to such safeguards; (vi) test aspects of the marketing letters to prompt the Disengaged Domestic Customers who have not opted-out; and (vii) monitor the impact of the database with a view to maximising its effectiveness.
- (e) An order on the code administrator or governing body with authority to grant access to the ECOES database to give PCWs (and other TPIs providing similar services) access upon request to the ECOES database on reasonable terms and subject to satisfaction of reasonable access conditions.
- (f) An order on gas transporters to give PCWs (and other TPIs providing similar services) access upon request to the SCOGES database on reasonable terms and subject to satisfaction of reasonable access conditions, and to make any necessary amendments to the Uniform Network Code.
- (g) A recommendation to DECC to make the following changes to the current specifications of Midata phase two:
 - (i) That participation in Midata should be mandatory for all gas and electricity suppliers.
 - (ii) That the scope of Midata should be expanded to include the following data fields: meter type, Warm Home Discount Indicator,

consumption data and time-of-use for those customers on Economy 7 meters or other time of use tariffs.

- (iii) That TPIs should be given the ability to seek customer consent on the frequency with which they can access the customer's data through Midata; should be required to present at least two options to a customer when seeking consent to access Midata (including one option for access on an annual or ongoing basis, and another option for access on a specified frequency); and should be given the ability to send updated tariff comparison information based on any subsequent access granted to a customer's Midata.
- (h) An order on gas and electricity suppliers with more than 50,000 domestic customers (and amendments to suppliers' standard licence conditions) (i) requiring such suppliers to make all their single-rate electricity tariffs available to all (existing and new) domestic electricity customers on restricted meters,⁵ and (ii) prohibiting such suppliers from making their single-rate electricity tariffs available to domestic electricity customers on restricted meters conditional upon the replacement of their existing meter.
- (i) An order on gas and electricity suppliers (and amendments to suppliers' standard licence conditions) requiring suppliers to (i) remind their domestic electricity customers on restricted meters, in their regular communications with them, that they have the option to switch supplier or to switch to a single-rate tariff without having to change their meter or incur replacement costs, (ii) provide their domestic electricity customers on restricted meters contact details for Citizens Advice in their regular communications with them, (iii) provide their domestic electricity customers on restricted meters certain information⁶ upon request, and (iv) provide, on a timely basis, Citizens Advice with the information it may reasonably require concerning customers on restricted meters in the format specified by Citizens Advice.
- (j) A recommendation to Citizens Advice to become a recognised provider of information and support to domestic electricity customers on restricted meters.
- (k) An order on gas and electricity suppliers (and amendments to suppliers' standard licence conditions) requiring suppliers to ensure that the annual

⁵ Excluding Economy 7 meters.

⁶ I.e, total consumption, consumption by register, meter type, tariff type and MPAN number.

bills paid by prepayment customers do not exceed a specified cap, for a period until the end of 2020.

Remedies concerning the Prepayment AEC

20.25 The remedies to address part of the Prepayment AEC, and the resulting detriment are as follows:

- (a) A recommendation to Ofgem to:
 - (i) modify suppliers' standard licence conditions to introduce an exception to SLC 22B.7(b) so as to allow a supplier to set prices to customers on dumb prepayment meters without applying regional cost variations which are applied to other payment methods within the same core tariff;
 - (ii) deprioritise potential enforcement action pending the modification of SLC 22B.7(b) against any supplier that sets prices to prepayment customers without applying regional cost variations which are applied to other payment methods within the same core tariff;
 - (iii) take responsibility for the efficient allocation of gas tariff pages; and
 - (iv) take appropriate steps to ensure that changes to the Debt Assignment Protocol are implemented by the end of 2016, and in particular in areas relating to objection letters, complex debt and issues relating to multiple registrations; including setting out clear objectives and a timetable with appropriate milestones, supervising progress against such objectives and milestones, and to take all steps, if and when necessary, to ensure delivery of these changes.
- (b) The acceptance of undertakings from the Six Large Energy Firms (or, absent such undertakings, a recommendation that Ofgem introduces a new licence condition in suppliers' standard licence conditions) including the following three components:
 - (i) a cap on the number of gas tariff pages that any supplier can hold (at 12);
 - (ii) an obligation for suppliers to provide relevant information for Ofgem to monitor the allocation of the gas tariff codes; and
 - (iii) a condition that allows Ofgem to mandate the transfer of one or more gas tariff pages to another supplier.

Remedies principally concerning the RMR AEC

20.26 The remedies to address the RMR AEC and the resulting detriment, as well as part of the Prepayment AEC and the Domestic Weak Customer Response AEC, and the resulting detriment are as follows:

(a) A recommendation to Ofgem to:

(i) modify gas and electricity suppliers' standard licence conditions to:

- remove the following conditions (the 'Conditions'):
 - the ban on complex tariff structures (SLC 22A.3 (a) and (b));
 - the four-tariff rule (SLC 22B.2 (a) and (b));
 - the restrictions on the offer of discounts (SLCs 22B.3-6 and 22B.24-28);
 - the restrictions on the offer of bundled products (SLCs 22B.9-16 and 22B.24-28);
 - the restrictions on the offer of reward points (SLCs 22B.17-23 and 22B.24-28); and
 - the requirement to make all tariffs available to new/existing customers (SLC 22B.30 and 22B.31);
- make any consequential standard licence condition amendments in light of the restrictions we are recommending being removed; and
- introduce an additional standard of conduct into SLC 25C that will require suppliers to have regard in the design of tariffs to the ease with which customers can compare value-for-money with other tariffs they offer; and

(ii) remove the Whole of the Market Requirement in the Confidence Code and introduce a requirement for PCWs accredited under the Confidence Code to be transparent over the market coverage they provide to energy customers.

Remedies concerning the Gas Settlement AEC

20.27 The remedies package to address the Gas Settlement AEC, and the resulting detriment is as follows:

- (a) A recommendation to Ofgem to:
- (i) ensure implementation of Project Nexus by 1 February 2017 (or as soon as possible after that date, once Ofgem is satisfied that IT systems are ready for an effective implementation of Project Nexus and do not pose risks to final customers) by monitoring closely the progress made by through its role as a chair of the three governance groups;
 - (ii) if appropriate, in order to ensure the effective implementation of Project Nexus, amend the implementation process for Project Nexus (eg by requiring relevant parties to carry out further testing), and set a new suitable implementation date for Project Nexus; and
 - (iii) take further measures where appropriate to achieve this objective (for instance if a party fails to meet agreed milestones or causes a further deferral of the implementation date).
- (b) With respect to all non-daily metered supply points in Great Britain with a dumb meter, an order on gas suppliers (and amendments to gas suppliers' standard licence conditions) to submit valid meter readings (as defined in the Uniform Network Code) to Xoserve as soon as they become available, and at least once per year.
- (c) With respect to all non-daily metered supply points with a smart or advanced meter, an order on gas suppliers (and amendments to the suppliers' standard licence conditions) to submit valid meter readings (as defined in the Uniform Network Code) to Xoserve at least once per month (unless for reasons of malfunction or related issues it was not possible to take such a meter reading).
- (d) A recommendation to Ofgem to take appropriate steps to ensure that a performance assurance framework is established within a year of the CMA's final report.

Remedies concerning the Electricity Settlement AEC

20.28 The remedies package to address the Electricity Settlement AEC, and the resulting detriment is as follows:

- (a) A recommendation to Ofgem to:
- (i) conduct a full cost-benefit analysis of the move to mandatory half-hourly settlement, including analysis of costs, benefits and distributional implications as well as mitigating measures;

- (ii) start the process of gathering evidence for the analysis as soon as practicable;
 - (iii) consider the cost-effectiveness of alternative design options for half-hourly settlement such as a centralised entity responsible for data collection and aggregation;
 - (iv) consider options for reducing the costs of elective half-hourly settlement, including (i) whether any of these options are likely to delay or accelerate the adoption of mandatory half-hourly settlement; and (ii) any challenges that may arise or benefits that may accrue from the existence of two settlement systems, including in particular the possibility of gaming/cherry picking behaviour; and
 - (v) consult, as part of the implementation of half-hourly settlement, on a proposed modification to the provisions of SLC 47 that prohibit suppliers from collecting consumption data with greater granularity than daily unless a customer has given explicit consent to do so.
- (b) A recommendation to DECC to consider whether it is appropriate to remove any other potential barrier for suppliers to collecting consumption data with greater granularity than daily for the purpose of implementing mandatory half-hourly settlement in the context of the review of the Data Access and Privacy frameworks.
- (c) A recommendation to both DECC and Ofgem that they publish and consult jointly on a plan setting out:
- (i) the aim of the reform for half-hourly settlement;
 - (ii) a list of proposed regulatory interventions (including code changes), and the relevant entity in charge of designing and/or approving such interventions, that are necessary in order to implement the half-hourly settlement reform;
 - (iii) an estimated timetable for the completion of each necessary intervention; and
 - (iv) where appropriate, a list of relevant considerations that will be taken into account in designing each regulatory intervention.

Remedies concerning the Microbusiness Weak Customer Response AEC

20.29 The remedies package to address the Microbusiness Weak Customer Response AEC, and the resulting detriment is as follows:

- (a) An order on gas and electricity suppliers (and amendments to suppliers' standard licence conditions):
- (i) requiring suppliers to disclose the prices of all available acquisition and retention contracts to non-domestic customers falling within a defined category either through an online quotation tool made available on their websites, or through one or more third party online platforms (and including a web link on their own website to direct non-domestic customers to such third party online platform(s));
 - (ii) requiring suppliers to disclose the prices of all their out of contract and deemed contracts on their websites;
 - (iii) prohibiting the inclusion of conditions in their existing and future auto-rollover contracts with microbusiness customers that:
 - prohibit the microbusiness customer from giving a termination notice up to the last day of the initial fixed-term period;
 - prohibit the microbusiness customer from giving a termination notice up to the last day of the fixed-term roll-over period; and
 - impose a termination fee and/or no-exit clause for the roll-over period;
 - (iv) prohibiting the transfer of microbusiness customers that have given a termination notice during the rollover period of an auto-rollover contract to a higher priced contract during the notice period; and
 - (v) prohibiting the inclusion of a condition in their existing and future out-of-contract, and evergreen contracts with microbusiness customers that include termination fees.
- (b) A recommendation to Ofgem to make any necessary consequential amendments to suppliers' standard licence conditions.
- (c) A recommendation to Ofgem to establish an ongoing programme to identify, test (through randomised controlled trials, where appropriate) and implement measures to provide microbusiness customers with different or additional information to promote them to engage in the SME retail energy markets.
- (d) An order on gas and electricity suppliers (and amendments to suppliers' standard licence conditions) requiring the disclosure to Ofgem of: (i)

certain details⁷ of their microbusiness customers that have been on a default contract for three or more years (the ‘Microbusiness Customer Data’); and (ii) updated Microbusiness Customer Data on a regular basis for the purposes of creating, operating and maintaining a secure cloud database containing the Microbusiness Customer Data for the purpose of postal marketing. The order will also require suppliers, prior to disclosing the Microbusiness Customer Data to Ofgem, to send a prescribed letter to each Disengaged Microbusiness Customer, explaining the proposed use of the customer’s details, and including an opt-out mechanism for the microbusiness customer, at any time, to object to and prevent the proposed disclosure and use of their details.

- (e) A recommendation to Ofgem to (i) create, operate and maintain a secure cloud database for the purposes of holding the Microbusiness Customer Data; (ii) hold the Microbusiness Customer Data; (iii) test the operation of the database (prior to its roll-out); (iv) put in place safeguards to mitigate any prejudice to the rights and interests of the data subjects; (v) provide access to the Microbusiness Customer Data by any rival supplier subject to such safeguards; (vi) test aspects of the marketing letters to prompt the Disengaged Domestic Customers who have not opted-out; and (vii) monitor the impact of the database with a view to maximising its effectiveness.

Remedies concerning the Governance AEC

20.30 The remedies package to address the Governance AEC and/or the associated detriment is as follows:

- (a) A recommendation to DECC to initiate a legislative programme with a view to:
 - (i) deleting paragraph 1C from both sections 4AA of the Gas Act 1986 and 3A of the Electricity Act 1989; and
 - (ii) set up a clear and established process for Ofgem to comment publicly, by publishing opinions, on all draft legislation and policy proposals which are relevant to Ofgem’s statutory objectives and which are likely to have a material impact on the GB energy markets.

⁷ This will be the microbusiness customer’s business name, billing address, consumption address, current supplier, name of their current contract, annual energy consumption, and MPAN/MPRN.

- (b) A recommendation to DECC and Ofgem to publish detailed joint statements concerning proposed DECC policy objectives that are likely to necessitate parallel, or consequential, Ofgem interventions, setting out (i) an action plan for the regulatory interventions needed and responsibility for these, (ii) an estimated timetable, and (iii) where appropriate, a list of relevant considerations in designing the policy.
- (c) A recommendation to Ofgem to:
- (i) publish annually a state of the market report (the 'State of the Market Report') which will provide analysis regarding issues such as (i) the evolution of energy prices and bills over time, (ii) the profitability of key players in the markets (eg the Six Large Energy Firms), (iii) the social costs and benefits of policies, (iv) the impact of initiatives relating to decarbonisation and security of supply, (v) the trilemma trade-offs, and (vi) the trends for the forthcoming year;
 - (ii) create a new unit (eg an office of the chief economist) within Ofgem, which will build expertise across the different areas of the energy markets with a view to publish annually a state of the market report;
 - (iii) modify the licence conditions of the Six Large Energy Firms' generation and supply licences by introducing requirements to:
 - report their generation and retail supply activities on market rather than divisional lines;
 - report a balance sheet as well as profit and loss account separately for their generation and retail supply activities;
 - disaggregate their wholesale energy costs for retail supply between a standardised purchase opportunity cost and residual elements; and
 - report prior year figures prepared on the same basis; and
 - (iv) take appropriate steps, in its ongoing work to develop a price monitoring regime, in order to ensure that such regime measures wholesale energy purchases on a relevant basis, such as the opportunity cost.

Remedies concerning the Codes AEC

20.31 The remedies package to address the Codes AEC and/or the associated detriment is as follows:

- (a) A recommendation to Ofgem to:
- (i) publish a cross-cutting strategic direction for code development (the 'Strategic Direction');
 - (ii) oversee the annual development of code-specific work plans for the purpose of ensuring the delivery of the Strategic Direction;
 - (iii) establish and administer a consultative board in order to bring stakeholders together for the purpose of discussing and addressing cross-cutting issues;
 - (iv) initiate and prioritise modification proposals that, in its view, are necessary for the delivery of the Strategic Direction;
 - (v) in exceptional circumstances, intervene to take substantive and procedural control of an ongoing strategically important modification proposal, as appropriate; and
 - (vi) modify the licence conditions of code administrators to introduce the ability for the administrator to initiate and prioritise modification proposals that, in its view, are necessary for the delivery of the Strategic Direction or to improve the efficiency of governance arrangements.
- (b) A recommendation to DECC to initiate a legislative programme with a view to:
- (i) giving Ofgem the power to modify industry codes in certain exceptional circumstances; and
 - (ii) making the provision of code administration (and delivery) services activities that are licensed by Ofgem and specifying that such licence conditions will include appropriate targets to incentivise code administrators to take on an expanded role to be able to deliver pursuant to the Strategic Direction.

Statement of dissent of Professor Martin Cave

1. I agree with the analysis of energy markets set out in this report, and with the bulk of its remedies. But I respectfully disagree with my colleagues over an important aspect of the remedies adopted for the domestic retail energy market.¹ I do not oppose the proposed remedies, but I do not think they go far enough.
2. The harm which is presently inflicted on households in this market (£2 billion in 2015, or an average of £75 for every British household) is very severe, and in my opinion how far and how fast that harm is reduced is the key indicator of the success of the household market remedies. But the remedies proposed for the large majority of households will take some time to come into effect, and are in any case untried and untested. This makes it risky to rely on them. That is why I believe they must be supplemented by a wider price control designed to give household customers adequate and timely protection from very high current levels of overcharging.
3. The point about risk is illustrated by the report's information remedies, designed to combat disengagement. A significant source of evidence on the effectiveness of such remedies lies in our experience of them over the past three years or more. We have seen a variety of measures covering such things as bill formats and customer prompts, barrages of publicity adverse to energy companies, concerning the level of their charges, and very large amounts of column inches, TV advertising and other advice devoted to explaining how to switch supplier. Yet none of these developments has made a dent in the proportion of customers of the six large energy firms (about seven out of ten) which remains on the standard variable tariff (SVT). This is despite the fact that the SVT is currently more than £300 per year more expensive than the competitive benchmark for a dual fuel customer.
4. The report considers several additional remedies or forthcoming developments which bear on engagement. These include: a data base remedy, the roll-out of smart meters, and the Ofgem-led programme. But the evidence on the likely effect of the new measures is conjectural or limited. It would be very good news if they did work speedily, but I am far from confident that they will.
5. I believe that this point is illustrated by the fact that, while the report contains a quantified estimate of the decline in detriment associated with the pre-paid meter price cap, it is unable to make a similar forecast for non-price cap

¹ These remedies comprise a set of pro-competitive and pro-engagement measures affecting all customers and a cap on the price to be charged to the minority of households with a particular form of prepay meter.

protected customers.² These customers are exposed to the prospect of excessive prices on a scale which might amount to many billions of pounds of harm over the next four years, and quite likely thereafter as well.

6. A natural supplement to the above measures is the application of a wider non-renewable price cap for a short period – say two years. This approach has the potential to give all SVT households some reliable and speedy relief from the very high charges they are currently facing. This combination would be consistent with the CMA’s Guidelines for market investigations.³
7. The majority of the Group believes in an ‘either/or approach’ to competitive and regulatory measures (excluding the ‘middle’ option of applying both) on the ground that the two sets of measures would work against one another,⁴ whereas I am not persuaded the conflict between the two approaches is irreconcilable. This is a question which ultimately has to be resolved not theoretically but on the basis of experience and other empirical evidence. I observe that in other liberalised sectors, and in energy in Great Britain and more recently in several Australian states, both remedies were used in tandem, and then the caps were successfully removed - precisely because customer engagement was judged to have developed under an appropriately designed price control.⁵
8. My proposed wider price cap remedy attempts to achieve this goal of interim protection and promotion of engagement. Thus:
 - it reliably resets the charges paid by about 16 million SVT households, removing a significant part of the 2015 detriment of £2 billion, whereas the prepay meter cap addresses only one fifth of it;
 - a safe-guard (above-cost) element enables the designer of the cap to be confident in achieving a desired level of detriment reduction, but also allows variation in the intrusiveness of the cap, and permits its level to be set to provide appropriate incentives to switch to a cheaper tariff;

² Compare Appendix 11.1: Assessment of the impact of domestic retail remedies on detriment, paragraphs 61 & 72.

³ These state at paragraph 337: ‘Some remedy options may have an almost immediate impact, while the effects of others will be delayed. In such instances the [CMA] may select a remedy package combining both types of measure taking into account both when each measure would take effect and how long it would endure.’ And at paragraph 333: ‘While generally preferring to address the causes of the AEC [adverse effect on competition], the [CMA] will consider introducing measures which mitigate the harm to customers created by competition problems, for example if other measures are not available, or as an interim solution while other measures take effect.’

⁴ See Section 11, paragraphs 87 & 89.

⁵ See S Littlechild (2003), ‘Wholesale spot price pass-through,’ *Journal of Regulatory Economics*, 23, pp88 & 89; Australian Energy Market Commission, [Final report: 2014 Retail Competition Review](#).

- the short duration of the cap (two years or so) reduces the risk that it will become unworkable as a result of unforeseen events;
 - its non-renewable nature ensures that a separate regulatory or legislative process has to be agreed and implemented for it to be extended in time;
 - it puts cost pressure on the larger suppliers to become more efficient;
 - its protective power should outlast the cap, as customer resistance and other factors will prevent energy companies from immediately re-establishing the same level of over-charging as before;
 - it protects vulnerable customers;
 - it defaults after two years to reliance on the other remedies, which by that time may emerge from their 'untried and untested' status and have a better chance of success.
9. If after an interval competition fails to develop on this platform, then new legislation or regulation should be introduced to drive out excessive retail pricing on a more permanent basis.
10. I consider that this approach represents a viable strategy for retrieving the situation in a market for an essential service which is presently working very badly for most British households.