Appendix 8.6: Gas and electricity settlement and metering

Contents

Introduction

1. In this appendix we consider the settlement of gas and electricity. Settlement is the process by which suppliers' contracted positions are matched with their customers' consumption ex post. Any shortfall or excess supply is charged/refunded to the supplier accordingly. It is generally known how much electricity or gas has been put into the system but it is more difficult to determine how much each customer has used, in particular when meters are not read with the same frequency as that with which the supply of electricity and gas is settled.

2. Currently gas is settled daily and electricity is settled every half hour[1] (a settlement period). To estimate how much customers have used in these settlement periods a number of assumptions are made (as described in Annexes A and B below). Xoserve[2] undertakes gas settlement and ELEXON[3] is responsible for electricity settlement.

3. We briefly describe below the settlement systems for both gas and electricity and the potential inefficiencies that may currently exist, and then look at the progress the industry has made to improve the efficiency of the current system (eg Project Nexus[4] for gas, half-hourly (HH) settlement for electricity).

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[1] We note that current work on standardising arrangements across Europe indicates that settlement for electricity might move in the future to 15 minute granularity.
[2] Xoserve was founded on 1 May 2005, and is an integral part of gas distribution in Great Britain. It delivers gas transportation transaction services on behalf of all major transporters and provides a single point of interface between gas transporters and gas shippers.
[3] ELEXON ensures the smooth operation of the wholesale electricity markets. It compares how much electricity generators and suppliers said they would produce or consume with actual volumes. It then works out a price for the difference and transfers funds accordingly.
[4] The planned upgrade of the gas settlement system.

We then consider the extent to which the use of smart meter data could make the settlement processes more efficient as well as some more general benefits for competition that can be expected from the roll-out of smart meters. Finally, we describe potential inefficiencies in gas and electricity supplier switching processes. A more detailed outline of the settlement processes is set out for gas in Annex A and for electricity in Annex B.

4. Costs associated with settlement and metering are indirect and – together with other indirect costs such as billing, customer service, bad debt, acquisitions, sales and marketing – account for around 15% of the total retail cost of gas and electricity.

Gas settlement

The gas settlement process

5. Xoserve is responsible for ensuring that the gas transportation and energy balancing charges invoiced to more than 100 gas shippers and traders who use the transporters' transmission and distribution networks are in line with Uniform Network Code and accurately reflect the underlying data. It invoices around £4 billion a year on behalf of the transporters, generating 45 million charge items on approximately 24,000 invoices. 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. For this purpose, it forecasts non-daily metered (NDM) gas usage by analysing factors such as the expected peaks and troughs in demand caused by the weather. Xoserve, in consultation with UNC signatories, develops annual profiles of gas consumption, which is an essential part of the processes in providing the gas transporters' charges to gas shippers for their usage of the network. Data is gathered by Xoserve from 4,200 customer volunteers (plus samples taken by Networks) spread across Great Britain, who have an automated meter reading unit attached to their gas meter. These units gather daily gas consumption data. A detailed outline of the settlement process for gas is set out in Annex A, which also outlines the anticipated changes under Project Nexus.

Potential inefficiencies surrounding the gas settlement process

6. Gas settlement is based on daily positions. However, for customers who do not have their meter read on a daily basis (the vast majority of customers)[5],

[5] These are domestic customers and small and medium-sized enterprises. For further details, see Annex A.

their consumptions 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. Total NDM gas in each Local Distribution Zone (LDZ) is allocated to all NDM supply points using industry agreed usage profiles that take account of differing customer 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 eventually spread between shippers based on their market share of smaller supply points in each LDZ. This process is called Reconciliation by Difference (RbD).

7. The main concerns that were put to us in relation to the gas settlement process were as follows:

   (a) The infrequent updating of the AQ can result in shippers being faced with charges for gas that are inaccurate. This in turn provides inaccurate price signals to suppliers, which distort 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.

   (c) The lack of reconciliation on the basis of actual consumption results in an inefficient allocation of unidentified gas, which fails to provide the correct incentives to suppliers and may represent a barrier to entry.

8. Collectively, according to Scottish Power, the various issues around gas settlement have led to differences of around 6% between the amount of gas it is deemed to have purchased in respect of a domestic customer and the amount actually delivered.

9. Utilita submitted to us that in the in gas year 2012/13 it was over-allocated gas by around 13% in kWh terms, but 16% in wholesale cost. It also noted that in a large portfolio, or a portfolio with a small percentage of prepayment customers, inefficiencies in gas settlement will not make a great deal of difference. But that in a portfolio such as its own it might lead to significant over allocation of gas by as much as 25% in some winter months.

Infrequent updates of the annual quantity

10. Several suppliers highlighted that the infrequent updating of the AQ can mean that for a significant period of time shippers are faced with incorrect charges for the meter point based on historical usage that is not reflective of more recent actual consumption; this could be for a period of a year or longer in some cases.[6] Xoserve has highlighted that the most common cause of infrequent updates to AQs is the lack of adequate valid meter read history. Meter read provision is the responsibility of the shipper.

11. If a supplier is attracting customers who are willing to cut their consumption in response to a price signal, through a smart meter for example, then there can be a significant delay before the resultant reductions are reflected in the supplier's costs. This could provide a disincentive for the supplier to introduce innovative products or services or to encourage energy savings.

12. Ovo Energy, for example, said that:

    "In gas, if we wanted to encourage our customers to use less energy, we bill them for fewer units of energy, but we settle not based on how much they use but based on how much they were estimated to use for the year, the AQ. There is far too infrequent settlement to actual meter readings. So if we ever are successful enough to convince customers to use less energy, it is going to cause us problems in the short-term. Project Nexus should help improve this situation and it appears a welcome change."

13. Utilita found that for suppliers with an average mix of customers, the errors in AQ were expected to even out over the customer base, but that suppliers whose customer base was skewed towards certain categories of customer could face a disadvantage.

14. Centrica also noted that the current system has historically led to prepayment meter customers being over-allocated costs. Its analysis suggested that prepayment meter customers use less energy than credit customers. However, it considered that this issue has been recently resolved through the introduction of a new 'prepayment meter profile' reflecting the different consumption pattern.

15. Utilita said that the weather-adjustment in the new prepayment meter profile still resulted in inaccurate allocation to prepayment meters, as the underlying

[6] The AQ value is set annually during the AQ review period, which commences around March and concludes in September. Where there is adequate meter read history, Networks will propose new AQ values. SSPs' proposed AQs may only be further amended by shippers during the AQ review if meter reads (that are at least six months and one day apart) demonstrate that the AQ has varied by more than +/- 5% from values proposed by networks.

profile was very similar to the credit meter profile and the cold weather adjustments overestimated the demand increase of customers with these meters (because they are the same as for credit metered customers). Further, Utilita considered, that the inaccurate profile used for prepayment customers has resulted in a transfer of cost from credit to prepayment customers, and consequently contributed to higher market retail prices for prepayment customers.

16. First Utility also highlighted that, when a supplier took on a contract for a new-build property, a positive AQ was provided for that property. However, if no one entered that property, the supplier was still charged on the basis of the AQ for the property, so that it would face a charge but collect no revenue from the property.

Lack of reconciliation allows gaming of the annual quantity

17. Scottish Power had concerns over the absence of mechanisms to reconcile estimated gas consumption with actual gas consumption similar to the mechanisms that are currently in place for electricity. This made it difficult to have confidence in the integrity of the gas settlement process.

18. In particular the rules and requirements regarding the annual updating of AQs could be perceived as ambiguous and this means that gas shippers have the possibility of a gaming opportunity if they are less assiduous in updating AQs that are increasing than those that are falling.[7]

19. Utilita highlighted this issue by stating that the annual AQ review process was an opportunity to swing the sums in one's favour. If a supplier is able to swing the sums in its favour, it can reduce its own gas costs and increase everybody else's. Utilita stated that if a supplier had a number of AQs that were underestimated and others that were overestimated, then obviously it would start by appealing against the ones that were overestimated, making a 'mockery of the whole system'.

Lack of reconciliation and allocation of unidentified gas

20. Scottish Power also identified a risk of significant cross-subsidy between domestic small supply points (SSPs) and non-domestic large supply points (LSPs). The cross-subsidy arises because under RbD there is a presumption that the costs of unidentified gas (estimated at £119 million for 2015/16)[8]

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[7] In such a case the shipper concerned would have an average AQ across its portfolio which underestimated consumption, so that part of its gas settlement and transportation costs would be met by its rivals.
[8] See '16 January 2015 Final 2014 AUG Table for 2015_16' on the Joint Office of Gas Transporters website.

should be allocated to SSPs unless there is evidence to the contrary. An independent technical expert known as the Allocation of Unidentified Gas Expert (AUGE) has been appointed by the gas transporters to allocate unidentified gas and to set the rates to be levied. As a result of the AUGE's work some of the unidentified gas is now allocated to LSPs.

21. Scottish Power argued, however, that the combination of the continued presumption that the costs of unidentified gas should be allocated to SSPs and the general lack of robust data on actual gas consumption made it likely that costs which should be attributable to LSPs were allocated to SSPs. Should a (non-daily) LSP meter not be read within the four-year cut-off period, or should the relevant AQ not be updated, the error will be permanently allocated to SSPs. Furthermore Scottish Power considered that the AUGE process did not provide a fully comprehensive view of market error or an appropriate bottom-up approach to allocating that error to market sectors/players.

22. Centrica indicated that the SSP sector may be being over-allocated approximately £90 million for the cost of unidentified gas each year, based on analysis of its own imbalance costs.

23. We discuss some of the causes of unidentified gas in Section 9 of this report.

Other observations

24. Centrica highlighted some additional concerns with the current settlement system for gas:

(a) It reported that, since 2008, 127 errors had been reported with the accuracy of offtake meters (meters recording the volume of gas entering the system), with all but two errors involving the offtake meter under recording the amount of gas entering the system. Whilst 85% of these errors were classified as 'low' impact errors, 5% were deemed as being 'high' impact and resulting in millions of pounds of unrecovered gas charges retrospectively being collected by the Gas Transporters (GTs). In total, these 126 errors had resulted in nearly 5.5TWh of gas entering the system unrecorded.

(b) It said that in one single error, at an offtake meter at Aberdeen, the meter failed to record 3.2TWh of gas over more than a year before detection. Payment for this gas was subsequently demanded by the GTs three years later, with costs allocated based on the market share of volume at the time of the error.

(c) It considered that, at the moment, suppliers are wholly reliant on the GTs identifying, reporting and remedying these issues themselves. Further, it believed, given the rate at which these errors occur, and the length of time between the error occurring and being identified, that this process is not working sufficiently well today.

Project Nexus

25. The industry has attempted to address some of the above-mentioned issues through a reform of the gas settlement arrangements (by raising an UNC modification). This reform, referred to as Project Nexus, was expected to become operational from 1 October 2015. It has subsequently been delayed to 1 October 2016.[9] However, we understand from Ofgem that this new implementation date will not be met due to concerns around the robustness of the implementation of the reform into IT systems, and therefore the risk of adverse impacts on consumers.[10]

26. These UNC changes are referred to as 'Project Nexus' modifications. When implemented the changes will include:

(a) reconciliation at all individual meter points;

(b) the opportunity for monthly rather than annual update of the AQs (also referred to as rolling AQ);

(c) the possibility for 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.

27. We note that elements of the retrospective adjustment arrangements, *(d)* above, have been deferred to October 2017[11].

28. It is also expected that Project Nexus will enable settlement using increased volumes of read data from smart meters. Scottish Power noted that Project Nexus would introduce a rolling AQ and reconcile all meter points to meter readings.[12] However, as with the current arrangements, there were no governance or control arrangements proposed to govern all market

[9] Ofgem (2015), Open Letter: Project Nexus implementation.
[10] Ofgem is currently consulting on a new implementation date in order to allow additional testing of relevant IT systems to be carried out before full implementation of Project Nexus.
[11] 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] As long as a reading is taken within the settlement window, which is currently three to four years.

participants. As a result there would continue to be uncertainty around the integrity of the data elements that drive settlement costs (for example the frequency and accuracy of meter readings, which would impact on the rolling AQs).

29. We understand that several proposals for the establishment of a performance assurance framework (PAF) have come forward and that Ofgem has approved UNC 506V, which sets out a process for establishing a performance assurance framework within the context of the Uniform Network Code[13].

30. Scottish Power proposed that suppliers' data and AQ update performance would have to be controlled by mandatory rules, as is already done for meter reading submission to electricity settlements. If the scope of the PAF included sufficient controls to assure settlement accuracy, this would reduce the volume of unidentified gas and therefore the risk of cross-subsidy from domestic to non-domestic markets.

Respondents' views on gas settlement and Project Nexus

31. Most respondents (EDF Energy, RWE, SSE, Scottish Power, Utilita, First Utility, E.ON) to our working paper agreed with the concerns we had identified in relation to the gas settlement process and the majority believed these would be addressed by the implementation of Project Nexus. However, some considered that some distortions will persist post-Nexus:

   (a) Scottish Power considered that issues around the quality of industry data and the resulting risk of cross-subsidy between SSPs and LSPs would not be addressed without a comprehensive and independent Performance Assurance regime (PAF).

   (b) First Utility also believed that the lack of a PAF resulted in little incentive for gas shippers and suppliers to maintain and exchange data in an accurate and timely manner, eg when executing the change of supply process. It proposed to model a gas PAF on the current Error and Failure Resolution arrangements, in support of the Balancing and Settlement Code (BSC). Moreover, it considered that incentives for shippers to place a higher priority on adjusting AQs down and delaying adjusting AQs up would still be present after Nexus was implemented. This resulted from AQs being updated more frequently (monthly) than at present but not completely reflecting actual consumption.

[13] Uniform Network Code (UNC) 506V/506AV: Gas Performance Assurance Framework and Governance Arrangements.

(c) Ofgem submitted to us that individual supply point reconciliation, would mitigate, but not entirely remove, the possibility of gaming AQ amendments since parties might still gain financially by withholding reads.

(d) Centrica also agreed that the risk of abuse in some areas and inaccuracies in cost allocation would remain post-Nexus and for these reasons it supports efforts to introduce a PAF for gas settlement.

(e) EDF Energy also expressed support for a PAF and noted that there were three modifications currently in development.

32. In relation to unidentified gas, SSE agreed that the introduction of a revised settlement regime under Project Nexus would address some concerns regarding the disproportionate level of unallocated gas costs currently borne by domestic suppliers. However, it believed there was further work to be done to address the underlying issue of unidentified gas. It considered that that gas imbalance was caused by a variety of factors which were not fully accounted for: incorrect shrinkage and temperature calculations in the national systems; a more significant level of theft than is nationally assumed; unregistered sites; and other physical occurrences, such as venting and leakage.

Electricity settlement

The electricity settlement process

33. The rules for electricity settlement are set out in the BSC. ELEXON administers the BSC and provides and procures the services needed to implement it.[14]

34. A detailed outline of the settlement process for electricity is set out in Annex B.

35. Electricity is settled in half-hour (HH) periods; however, the majority of customers' meters record energy over longer periods (typically months to a year) and are therefore read only once or twice a year.[15] This makes it more difficult for a supplier to match its contracted position with actual consumption. To settle these customers, it is necessary to estimate their electricity consumption for each half hour of the day. This involves grouping customers into one of eight profile classes and using these load profiles to allocate energy used to each half-hour period. The settlement of electricity over a

[14] ELEXON is currently fully owned by National Grid. See the 'What we do' page of ELEXON's website.
[15] ELEXON (2013), *The Electricity Trading Arrangements: a beginner's guide*.

period will be accurate; however, the timing of when in the day this electricity was consumed will be estimated in line with the load profile.

36. Full settlement involves a number of rounds of reconciliation as more accurate data becomes available, and it usually concludes 14 months after the electricity was consumed (final reconciliation).

Potential inefficiencies surrounding the electricity settlement process.

Length of the settlement and reconciliation process creates uncertainty of costs and revenues for suppliers

37. Market participants put to us that the length[16] of the settlement runs creates significant uncertainty and risk for suppliers, who may face significant changes in their energy charges over the settlement period. As set out in Annex B, following each half-hour supply period there are five settlement runs and final reconciliation is not until 292 days after the electricity has been supplied. The accuracy of settlement improves over time but does not reach 90% until 156 days after the supply date[17].

38. This means that suppliers have to set aside capital to cover any potential shortfall. In addition collateral is required by the BSC (and managed by ELEXON) to cover an estimate of the suppliers' imbalance charges which fall due after 29 days following each settlement run. These costs may represent an extra burden on suppliers, creating additional barriers to entry and cause inefficiencies.

Profile settlement for electricity distorts incentives to suppliers

39. The use of load profiling to estimate each supplier's demand fails to charge suppliers for the true cost of their customers' consumption. This could mean that suppliers are not incentivised to encourage their customers to change their consumption patterns, as the supplier will be charged in accordance with their customer's profile. This in turn may distort suppliers' incentives to introduce new innovative products (see paragraphs 65 to 69). The roll-out of smart meters provides an opportunity to address this concern.

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[16] We note that work looking at reducing the normal settlement from 14 to 7 months is currently being undertaken by industry. See report to BSC Panel, 234_16 *Reducing Settlement timescales*.
[17] Electricity suppliers are required to meet standards for the volume of energy settled using actual readings. Current industry performance is that approximately 90% of the energy is settled using actual meter readings by the third reconciliation (around 156 days after the supply date).

40. Secondly, as a result of this system, suppliers are ex ante forecasting profile demand rather than the demand expected from the characteristics of their customer base, which creates inefficiencies if the realised demand is different.

41. Tempus submitted that incumbent suppliers might resist the move to half-hourly settlement because it would place the onus of managing imbalance risk onto them. The current arrangement (ie profile settlement) transfers the cost of imbalance away from the supplier onto the system operator and ultimately customers. Actual management of imbalance (rather than simply passing costs to customers) in a half-hourly settled world would be better for customers but not for incumbent suppliers, who would need to create processes and business models to manage the risk.

42. Ofgem submitted to us that incumbent suppliers may also resist moving to half-hourly settlement because of the significant cost of upgrading IT systems.

Respondents' views on electricity settlement

Length of the settlement and reconciliation process creates uncertainty of costs and revenues for suppliers

43. In principle some suppliers (Centrica and First Utility) would welcome a reduction in settlement timescales. Centrica agreed that the length of the electricity settlement and reconciliation process creates uncertainty of costs and revenues for suppliers.

44. However, they warned that if, the process today was simply shortened so that final settlement occurred after twelve months, costs may be allocated on a less accurate set of meter readings.

45. Both Centrica and First Utility noted the current work being undertaken by industry[18] to reduce the normal settlement timetable from 14 to 7 months and express support for this proposal in principle. First Utility also noted that any greater a reduction to less than 148 working days would not allow suppliers enough time to resolve some of the more difficult issues that arise as a result of change of supply processes combined with poor meter read historic data.

46. Centrica also said that the ultimate solution in relation to settlement is linked to efforts to increase the frequency and quality of meter read submissions. It believed that the most pro-competition and cost effective solution would be to

[18]The Profiling and Settlement Review Group has explored reducing the normal settlement timetable from 14 to 7 months. See details on ELEXON's website.

deliver shorter settlement and reconciliation periods alongside the smart meter program.

47. Utilita reported that 97% of its electricity customers, most with a smart meter, are already settled on actual data within three months.

48. Other suppliers (Scottish Power and SSE), however, did not consider the length of the settlement process to be a significant problem and SSE strongly disagreed with the suggestion that the settlement process itself creates an undue barrier to entry.

49. Scottish Power also noted that the uncertainty in final settlement outcomes are reduced to a very low level well before the end of the process. It thought that it would be premature to consider any reduction in timescales ahead of the completion of Ofgem's smarter meters work.

Profile settlement for electricity distorts incentives to suppliers

50. Centrica agreed that the use of profiles to allocate costs could distort the incentives on suppliers to innovate and bring in new products. It therefore supported the principle of moving towards half-hourly settlement for all meters. However, it noted that suppliers are able to offer a range of time of use tariffs today (it acknowledged, though, that these are generally static and not dynamic time of use tariffs and are unlikely to be sufficient to encourage significant demand-side response).

51. SSE, instead, regarded the current use of demand profiles in electricity settlement as adequate, and did not believe that the cost of managing imbalance was higher as a result of this approach. However, once the roll-out of smart meters is suitably advanced, it would welcome a move towards half-hourly settlement for all profile classes (data access permitting). It considered that improved efficiency of significantly reduced settlement runs would be a benefit to all market participants. It considered that lessons learned from the introduction of half-hourly settlement for profile classes 5–8 should help to expedite the process of assessing and implementing the necessary code modifications for profile classes 1–4 in due course.

52. Further, SSE considered that our working paper had not made the case that any difference in imbalance costs due to the current use of profiled settlement is significant. In fact, SSE would expect that the shape required to be balanced based on half-hourly data would match the profiled demand shape so closely that half-hourly settlement would not result in materially different imbalance costs for suppliers. Although the industry is evolving towards smarter markets, it considered that the existing processes to deliver

incremental change are appropriate and have been effective in, as far as possible, eliminating inefficiencies in the settlements process.

Smarter energy markets

53. In this section we discuss the impact that smart metering might have in the coming years on gas and electricity settlement, in particular in relation to the inefficiencies identified for electricity in paragraphs 39 to 42.

Smart meters overview

54. A smart meter is a gas or electricity meter that is capable of two-way communication. It measures energy consumption in the same way as a traditional meter, but has a communication capability that allows data to be read remotely and displayed on a device within the home, or transmitted securely externally.[19]

55. The roll-out of smart meters is discussed in further detail in Appendix 8.4.

56. In addition to other benefits,[20] smart meters have the ability to record half-hourly consumption data which could enable half-hourly electricity settlement for all customers based on actual rather than estimated consumption.

57. As described above, and in Annex B, the existing electricity settlement arrangements rely on complex processes to estimate consumption in each settlement period for the majority of customers according to certain profiles. Only the largest customers (by volume of consumption) are settled using an actual meter reading for each settlement period. It can take up to 28 months to reach the final allocation of charges associated with a particular settlement period. Half-hourly settlement has the potential to reduce settlement costs and timescales, lower credit requirements and enable the introduction of new tariffs that incentivise customers to shift consumption away from peak periods. More accurate information on consumption may also give rise to network benefits in the form of more stable network charging and improved network planning and management.

58. We discussed in Section 12 how the introduction of half-hourly settlement may contribute (or be necessary) for the delivery of certain potential benefits arising from smart meters.

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[19] Ofgem (2011), *Smart metering – What it Means for Britain's Homes*. A GB gas or electricity smart meter is a device which meets the requirements placed by the Smart Metering Equipment Technical Specifications.
[20] Smart meters will, for example, eliminate estimated bills, enable remote meter readings and reduce call centre charges. Smart meters may also enable 24-hour switching and a sharp reduction in erroneous transfers.

Potential obstacles to achieving demand-side response benefits

59. In addition to the lack of half-hourly settlement, other potential obstacles highlighted by parties to achieving the DSR benefits, and therefore increased competition, include the Retail Market Review (RMR) rules, the need for significant market reform and the access by suppliers and third party intermediaries to smart metering data.

Retail Market Review

60. The RMR rules on the four-tariff limit were identified by some suppliers as an obstacle to tariff innovation and achieving the benefits of DSR.

61. E.ON called for the removal of RMR restrictions by around 2017 in the light of the roll-out of smart meters. It said that the prescriptive nature and complexity of the RMR rules were likely to stifle and restrict future innovation, from both existing suppliers and new entrants.

62. RWE said that the RMR tariff simplification would not suit the level of innovation in tariff structure desired from smart meter implementation. RWE said that this was an example of how 'the myriad regulatory measures' are uncoordinated with one another or are not aligned to energy policy.

63. Ovo Energy said that the RMR tariff restrictions were inappropriately short-sighted. Ovo Energy argued that there was a risk that RMR could stifle the transformation of energy pricing (resulting from the roll-out of smart meters and community energy projects) by limiting the number of tariffs that would leverage these developments for the benefit of consumers.

64. Scottish Power said that RMR made tariff innovation much harder as suppliers no longer had the space to 'test and learn' with new tariff concepts.

65. SSE also had concerns with the RMR product bundling restriction, claiming that this had reduced the scope for innovation within the industry – and that this was particularly concerning given the potential that the roll-out of smart meters would otherwise create for such innovation. SSE said that it was now much harder for suppliers to offer benefits such as discounts from non-energy add-ons (such as boiler care), which previously facilitated and encouraged competition within the market.

66. Ofgem has clarified that the RMR rules allow suppliers to offer up to four core tariffs per metering category at any time. There are four TOU metering categories, meaning that a supplier can potentially offer up to 16 distinct TOU

tariffs (four for each metering category).[21] In addition, the RMR rules allow for derogations from the four core tariff rule, and Ofgem has already granted a number of derogations to allow suppliers to introduce additional tariffs targeted towards social outcomes, vulnerable consumers, and innovative schemes. Where there is substantial evidence that compliance with RMR rules would result in unintended consequences for consumers, Ofgem is open to granting new derogations and is looking at ways to improve the derogations process.

Absence of market reforms supporting demand-side response

67. It is likely that significant reforms to market arrangements would be needed to maximise the system-wide benefits of DSR

68. Ofgem and DECC are working together to develop a smarter, more flexible electricity system. This includes considering shorter term policy options, including removing regulatory barriers to DSR[22].

Access to smart metering data

69. It has been put to us that the combination of smart metering data (and in particularly half-hourly data) with an individual's address or name would constitute personal data for the purposes of data protection law. At a half-hourly level this data could potentially be used to infer views about an individual's lifestyle. Licence conditions[23] reflect this concern and allow suppliers access to monthly (or 'less granular', ie less frequent) consumption data for billing and other regulatory purposes without needing consent. When collecting half-hourly data, there will be a clear opt-out for daily collection of data, and an opt-in will be required for use of the most detailed half-hourly consumption data.[24]

70. Suppliers have submitted that this opt-in clause effectively precludes half-hourly settlement and is a major barrier to the development of static and dynamic time-of-use tariffs.

71. Some respondents also raised concerns with the CMA about the conditions under which third parties (eg price comparison websites) will be permitted to access smart meter data files when a customer is considering a switch.

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[21] DECC and Ofgem (2014), *Government and Ofgem Action Plan: Challenger Businesses (independent energy suppliers)*.
[22] DECC (2015). Towards a Smart Energy System.
[23] SLC 47 ,
[24] DECC (2012), *Smart Metering Implementation Programme data access and privacy: consultation document*.

72. It has been put to us that third party access to the consumption data is necessary for third party intermediaries (TPIs), such as price comparison websites, to continue to compete and provide switching services for customers with smart meters. TPIs need to be able to give an accurate estimation of charges under available tariffs. This issue is particularly important with the introduction of TOU tariffs as TPIs cannot offer these tariffs unless they have access to half-hourly customer data. Industry progress toward half-hourly settlement for all profile classes

Cost–benefit analysis of profile classes 1–4

73. In 2011 ELEXON undertook a cost–benefit analysis for mandating half-hourly settlement for profile classes 1–4.[25] The conclusions from the consultation were as follows:

(a) There was overall support for the principle of half-hourly settlement. However, the majority of respondents felt that it was too early to consider mandating half-hourly settlement for the 29 million metering systems in profile classes 1–4, as the structure of the smart roll-out and the scope of the DCC were not clear.

(b) The majority of respondents were unable to quantify the costs to their company from such a mandate as the future business process could not be defined in sufficient detail at that stage; therefore it was not possible to carry out a full cost–benefit analysis as there was too much uncertainty around the smart metering solution and particularly the scope of the DCC.

(c) The majority of respondents felt that there could be benefits in using half-hourly data in settlements, particularly in terms of data accuracy and in relation to customers on TOU tariffs. However it was not clear that these benefits would outweigh the costs of mandating half-hourly settlement, so a firm conclusion was not possible.

74. We are not aware of any other cost-benefit analysis of half-hourly settlement for profile classes 1-4In 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.

Half-hourly settlement for profile classes 5–8

[25] ELEXON (2011) *Profile class 1–4: mandating HH settlement cost benefit analysis*.

75. On 20 May 2011 Smartest Energy raised a proposal (P272) to amend the BSC to require suppliers to settle customers in profile classes 5–8 (larger non-domestic customers) using their half-hourly consumption data.[26] This was to prepare for the obligation on suppliers to provide customers in profile classes 5–8 with an advanced meter capable of recording half-hourly consumption data by 6 April 2014. There was, however, no requirement to settle these customers on a half-hourly basis and the Smartest Energy proposal addressed this. An alternative to the original proposal, ie P272 Alternative, was approved on 1 August 2014. As a consequence, the BSC mandates the use of half-hourly settlements for profile classes 5–8 as of 1 April 2017.[27,28]

No current modifications for half-hourly settlement for profile classes 1–4

76. At present, however, no proposal has been raised to modify the BSC in order to mandate the use of half-hourly data for settlement for customers in profile classes 1–4. Ofgem is of the view that it is in the interest of customers in profile classes 1–4 to be settled against half-hourly consumption data. It has recently agreed (in a letter published on 17 December 2015) to take forward a project to reform the electricity settlement arrangements in Great Britain. 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. We comment on these proposals by DECC and Ofgem in Section 12 of this report.

Respondents' views on smart energy markets

77. A number of parties have submitted to us that while they see benefits in half-hourly settlement, they consider that the costs are likely to be disproportionally high until the majority of customers have a smart meter.

   (a) RWE said that there is merit in moving to mandatory half-hourly settlement in the long term once the smart metering roll-out is complete or largely complete. It considered that a move to universal mandatory half-hourly settlement today would introduce unnecessary risks disproportionate to the benefits.

[26] Modification proposal P272: Mandatory half hourly settlement for profile classes 5–8.
[27] Ofgem (2014), *Balancing and Settlement Code (BSC) P272: Mandatory half-hourly settlement for profile classes 5–8* (decision document).
[28] We understand that Ofgem approved P322 Alternative, which extends the implementation date of P272 to 1 April 2017. See Ofgem (2015), Ofgem response to the BSC Panel's request for an extension to the Implementation Date of Balancing and Settlement Code Modification P272: Mandatory Half-Hourly Settlement for Profile Classes 5-8

(b) Scottish Power agreed that a move to half-hourly settlement of profile class 1–4 meters will be important for realising the full benefits of smart electricity meters in terms of DSR and TOU tariffs. It considered that without half-hourly settlement, changes in consumer consumption patterns away from periods of peak price will not be reflected in a supplier's wholesale costs and there will be little incentive to offer TOU tariffs to incentivise such behaviour. However, whilst it believed the move to half-hourly settlement was important, it said it is likely to be a complex and lengthy process, with extensive changes required to industry systems and processes. It considered that a balance needed to be struck between moving too quickly, which could incur additional system costs, and moving too slowly which could result in some benefits being delayed.

(c) Ofgem also considered that half-hourly settlement for domestic electricity customers cannot be implemented before smart meters are in place. So the benefits of this reform cannot be fully realised until after smart meter roll-out.

(d) SSE would welcome a move towards half-hourly settlement for all profile classes (data access permitting), once the roll-out of smart meters is suitably advanced.

(e) Centrica considered that aggregate benefits associated with half-hourly settlement will become significant after 2018, when both 60% of domestic customers will have a smart meter, and when customers may start to demand the dynamic time-of-use tariffs that realise the benefits of half-hourly settlement Until then, it added, it believes that the material costs of half-hourly settlement would vastly outweigh the benefits realised by those with smart meters. Further, it noted that the volume of data that half-hourly settlement would require means upgrades to both suppliers and industry systems of a similar size and scale to those currently being undertaken in the gas industry through Project Nexus.

78. Some respondents considered that some of the benefits of smart meters, including innovative tariffs, can already be realised even in the absence of half-hourly settlement.

(a) Centrica noted that innovative products are already being offered without half-hourly settlement (eg Free Saturdays) and that current customer demand creates the opportunity for launching innovative tariffs.

(b) SSE considered that the markets are currently suitably developed so that opportunities already exist for DSR in the non-domestic markets. As the markets develop there may be scope for DSR to expand into the domestic

markets and microbusiness segment/SME markets as well. SSE said it did not believe that the current limited nature of DSR in the Great Britain markets represents an adverse effect in competition.

(c) Ofgem agreed that is already possible for suppliers to settle their customers half-hourly. But considered that elective half-hourly settlement might not happen on large scale given the complexity and the upfront cost of migrating a customer to half-hourly settlement. It added that it is more costly for sites to be settled half-hourly compared to non-half-hourly on an ongoing basis.

79. Other parties, instead, believed that a number of barriers are preventing/will prevent the realisation of benefits from smart meters. Most respondents mentioned the RMR rules that restrict the number of tariffs each supplier can offer.

RMR rules act as a barrier to innovation

(a) Centrica considered that the barrier to the development of innovative products are not the lack of half-hourly settlement, but the four tariff rule which complicates the way in which innovative products can be offered.

(b) EDF Energy also agreed that the four tariff rule might be a barrier to customers making full use of TOU pricing with the introduction of smart meters. It supported alternative means of simplifying tariffs, for example by unit rate pricing. Moreover EDF Energy identified a number of developments that need to take place to realise the full benefit of smart meters, including decisions on whether half-hourly data collection and aggregation is centralised or left for suppliers to appoint their own data collector/data aggregator competitively.

(c) RWE also considered that the four tariff rule has an impact on suppliers' ability to provide innovative products. Further it pointed out that the possibility for derogation proposed by Ofgem is not enough to encourage mass migration to TOU products.

(d) SSE believed that the current approach under which suppliers are able to apply for a derogation is too restrictive and inefficient and creates an unnecessary barrier to innovation of smart TOU tariffs.

Other barriers

(a) E.ON considered that the barriers for suppliers to choose to settle their customers on a half-hourly basis have started to be addressed by Ofgem

and the industry as part of the BSC Modification Proposal 272. It believed that removal of these barriers and the delayed deployment of smart meters (the DCC will now not go live until August 2016) signalled that progress is being made in this area but that benefits will not be visible for a number of years.

(b) Good Energy was supportive of the view that smart meters create a real opportunity to engage customers with their energy use. But it noted that there are a number of barriers to reaching that potential fully. Firstly, it considered that the fixed cost of the smart metering programme, that independent suppliers will have to implement, is acting as a substantial barrier to entry. The programme has the potential in the short term to significantly reduce the number of independent suppliers in the markets as only those with strong balance sheets may be able to see the programme through. Good Energy added that many independent suppliers are either in denial of the costs or are worrying how they will raise the capital to meet the challenge. Even if this was solved (eg by turning the roll-out into a network-led operation), it then considered that Ofgem's current restrictions through RMR need to be removed and the ability of suppliers to innovate encouraged. Finally, it said that many of the benefits require the industry to move to half-hourly settlements. At the moment this is a costly change, on top of the cost of the roll-out. Ofgem is also proposing next-day switching reforms, which adds further additional cost.

(c) Utilita put to us that in electricity, while in theory the approach of submitting sub-daily data could be utilised now, the administrative charges levied by Data Aggregator Companies (DACs) and ELEXON for the different metering types precludes this on cost grounds.

Specifically for profile 1–4 customers, Utilita said that [✂].

Utilita considered that the strict regulatory standards DCAs have to comply with and the significant uncertainty on the roll-out of smart meters (including implications for the future role of DCAs) prevents other competitors from entering these markets and hence allow the existing DCAs to charge such high fees. It therefore suggests that more cost reflective charging should be considered across the board for both non half-hourly and HH meters in electricity.

Further, Utilita noted [✂].

(d) RWE said that uncertainties in relation to data privacy and security rules act as a deterrent to investment in systems and that this in turn affects

offering TOU and other tariffs that that benefit individual customers and society as a whole.

80. In relation to half-hourly settlement for profile 1–4 customers, Ofgem identified three further issues that need to be considered before mandatory half-hourly settlement for profile 1–4 can be introduced:

(a) Reform of the existing process for using half-hourly data in settlement. This process was designed for a small number of large business customers. Optimising it to accommodate millions of domestic and smaller business customers can help to bring down the costs of using half-hourly data.

(b) The approach to transitioning customers to settlement using half-hourly data. Settling all customers using half-hourly data would be a significant undertaking for the industry, requiring major changes to processes and systems. Rules may be needed to deliver an orderly transition that protects the interests of consumers.

(c) Assessment of the impact of using half-hourly data in settlement. The costs and benefits, as well as distributional impacts, have not been quantified and hence are not fully understood at this time. The impact on other parts of the regulatory framework also needs to be considered, particularly the interactions with the data privacy rules in the supply licence.

Potential inefficiencies in gas and electricity supplier switching processes

The switching processes

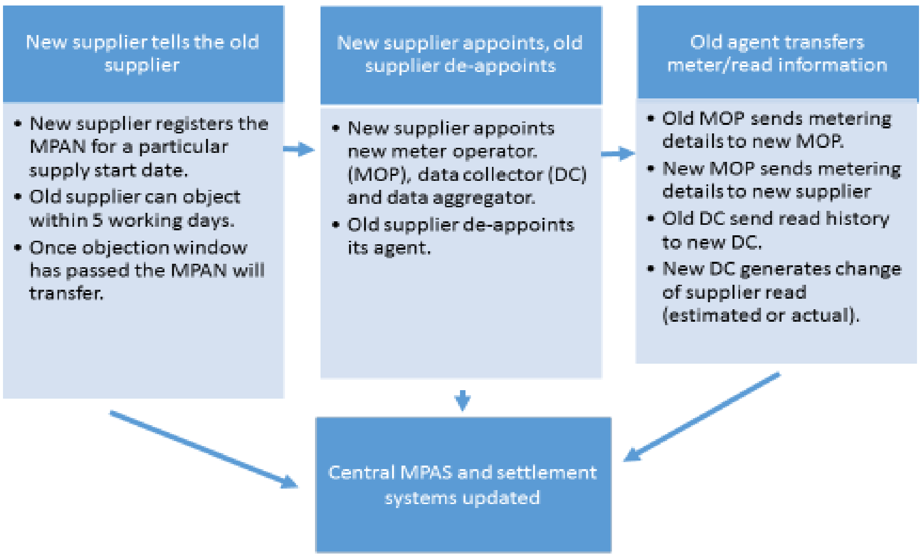
81. When a customer decides to switch supplier the current change of supplier processes involve a number of pieces of data being exchanged between the incumbent supplier and newly appointed metering agent.[29] The electricity switching process, in particular, is very complex, as illustrated in Figure 1 below. This complexity can lead to delays, errors and costs. This, in turn, may have an impact on customer confidence and the propensity to switch. Ofgem has recognised this in its recent decision on fast and reliable switching.[30] 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

[29] 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.
[30] Ofgem (2015), *Moving to reliable next-day switching*.

realised by enabling faster switching with less complexity and scope for errors.

82. Changes introduced at the end of 2014 have reduced switching timescales from five weeks to approximately 17 days for domestic customers.[31] This means that a customer can switch three days after their cooling-off period ends. 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).[32]

Figure 1: The electricity registration process



Source: Adapted Cornwall Energy.
Note: MPAN – metering point administration number; MPAS – Meter Point Administration Service.

83. On 9 April 2014, Ofgem published a statutory consultation on licence modifications to enforce three-week switching (after taking into account the 14-day cooling-off period). This was implemented at the end of 2014.The change means that the registration process can begin within the cooling-off period, and should a customer decide to cancel their new contract, a withdrawal notice can submitted to halt the switch.

84. 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.[33] Ofgem recently published its decision to modify the

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[31] This consists of a 14-day cooling-off period followed by three weeks for the switching process. In December 2014, according to Ofgem, the system average time to complete a switch in the domestic market was down to 16 days in electricity (from 18 days in June and September 2014) and 19 in gas (from 24 days in June and 23 days in September 2014).
[32] Ofgem, *Enforcing three week switching* (letter to interested parties, 3 December 2013).
[33] Ofgem (2015) *Moving to reliable next-day switching*.

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.[34] This will 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.

85. 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.[35] 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 Appendix 9.4) 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.[36]

Erroneous transfers

86. Erroneous transfers (ETs) 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 market.[37] Resolving ETs and returning the customer to their previous supplier is also costly for both suppliers.

87. Ofgem evidence[38] 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 ETs. This equates to around 66,000 switches per annum,[39] most of which could have been avoided. For the domestic gas and non-half-hourly (NHH) settled electricity customers affected in 2014, 76% of ETs for gas and 77% for electricity happened because the wrong metering point was selected and 18 % for electricity and 17% for electricity because the incumbent supplier did not process the customer's cancellation request in

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[34] Ofgem (2016) DCC's role in developing a Centralised Registration Service.
[35] DECC (2015), Draft Measures: Fast and reliable switching and Half-hourly settlement power(s), p10, paragraph 42.
[36] ibid, p10, paragraph 47.
[37] Ofgem, *Preventing erroneous transfers* (letter to interested parties, 3 December 2013).
[38] Ofgem's own analysis, based on data provided by large domestic suppliers for the period Q1 2012 to Q1 2013, showed that the proportion of domestic switches taking longer than three weeks was over 20% in electricity and over 80% in gas. See: Ofgem (3 December 2013), *Enforcing three week switching*.
[39] The Ofgem data refers to the Six Large Energy Firms and Utility Warehouse. Assuming the figures are representative of the industry as a whole and applying them to the total number of switches for 2014 gives 66,000 ETs for 2014.

time. The remainder were linked to the way in which contracts were sold to customers.

88. Smaller suppliers highlighted that ETs 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.

89. On 4 July 2014, Ofgem published a decision letter on measures to prevent ETs.[40] It decided to amend standard licence conditions to require suppliers to take all reasonable steps to prevent ETs. It also introduced a new defined term of 'valid contract' as being one that has been entered into by the customer, relating to the premises of the customer that intended to be switched to the new supplier. These changes were implemented in September 2014.

90. Going forward, smart meter data could further help lower the number of ETs and could provide significant improvements in the current arrangements. With the data being held by the DCC, it is expected that the number of ETs 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.[41]

Respondents' views on switching processes and erroneous transfers

91. EDF Energy said that it supports Ofgem's work on faster switching, and the implementation of a centralised registration service that will simplify and harmonise the switching processes for gas and electricity. It considered that this will improve switching times and reduce errors. It called for two-day switching to be considered as an alternative option to next day switching if it delivers better overall value for customers due to reduced implementation and running costs. However it expressed concerns on how the data being held by the Data Communications Company (DCC) will help to reduce ETs. It considered that helping the industry address data quality issues will reduce the number of erroneous transfers.

92. First Utility and SSE also considered that that more emphasis should be put on reducing erroneous transfers rather than on faster switching.

(a) First Utility said that poor industry data (eg address data) is the underlying cause of change of supply process problems, including erroneous

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[40] Ofgem (2014), *Decision letter on enforcing three week switching and preventing erroneous transfers*.
[41] Ofgem (2012), *Promoting Smarter Energy Markets: A Work Programme*.

transfers, and leads to all suppliers having to introduce additional internal processes to manage missing and incorrect data. It thought that Error and Resolution arrangements that exist for the BSC should be extended to other industry codes. Further, it said that under the current arrangements poor gas and electricity address data are to be copied into the Data Communications Company.

(b) SSE said that it welcomed the recent move to three-week switching (after the cooling-off period) and that improvements to the switching process should help to further improve customer engagement. But it considers that the greatest emphasis could most usefully be placed on tackling the root causes of erroneous transfers.

93. Utilita submitted to us that next-day switching would introduce further inefficiencies into the switching process due to fallout within cooling off periods. It also believed it would also introduce significant costs in terms of system changes, balancing and credit costs to the industry through inability to demand forecast accurately and manage volume risk. It said that the potential higher imbalance costs and associated additional credit support do not appear to have been factored into Ofgem's Impact Assessment. It believed that these impacts would be more keenly felt by those with smaller, more dynamic portfolios. A 5 or 7 day timeline could, in its view, meet most customers' desires for quicker switching with minimal system and balancing risk and cost.

94. Distortions in the switching process arising from meter certification and Centrica's exemption from gas and electricity inspections Suppliers are responsible for installing and maintaining gas and electricity meters and for the roll-out of smart meters. We identified two potential competition problems which might create distortions in the switching process and reduce suppliers' incentives to acquire new customers:

(a) the Centrica exemption from gas and electricity meter inspections for health and safety purposes; and

(b) the regime governing the certification of electricity meters to ensure their accuracy.

95. In this section we address both of these issues.

- *The Centrica exemption*

96. Domestic gas and electricity meters must be inspected for health and safety reasons every two years by the supplier.[42] Centrica, the company with the largest number of domestic gas and electricity customers, was able to assure Ofgem and Health and Safety Executive (HSE) that its processes of inspection were sufficiently robust, that there was an increase in expenditure to check for theft, and that two yearly inspections would lower the benefits of the smart rollout, therefore it should be allowed an exemption from this requirement. Instead, it would have to inspect meters only every five years.

97. One party, First Utility[43], pointed out to us that this meant that it became disproportionately likely that a switcher from Centrica would have a meter that had not been inspected in the last two years, and therefore that the obligation would fall immediately on the new supplier to inspect the meter. We believe that increasing the cost of acquiring Centrica customers thus reduced competition for them.

98. We accepted the logic of this argument in our provisional findings report and invited views in relation to such concerns. Ofgem has now put in place a general exemption for all suppliers that has come into force on 1 April 2016.[44] We therefore decided that there was no further need to consider these concerns.

- *Meter certification*

99. Electricity meters must be certified[45] as being accurate on a regular basis in a process that is overseen by The National Measurements and Regulation Office (NMRO). The NMRO collects data on certification rates from the 12 largest suppliers[46] on an annual basis.

100. Meters of a given design tend to lose accuracy at a similar rate, and therefore it is economic to test only a sample of meters of each design. Suppliers have had the obligation to ensure that 100% of each meter class has been certified as being accurate.

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[42] The Gas Supply Standard Licence Condition (SLC) and Electricity Supply SLC 12 place an obligation on gas suppliers and electricity suppliers respectively to take all reasonable steps to inspect their customers' meters at least once every two years unless the Authority otherwise consents.
[43] First Utility Response to Working Paper on Gas and Electricity Settlement and Metering.
[44] Ofgem has decided to repeal the two-yearly meter inspection licence conditions in gas and electricity in their entirety. See Ofgem (February 2016), *Decision on reforming suppliers' meter inspection obligations*.
[45] The requirement for suppliers to have up-to-date certificates ensuring the accuracy of all electricity meters is set out in Schedule 7 to the Electricity Act 1987.
[46] The Six Large Energy Firms and six largest smaller suppliers.

101. However, since it would be costly and impractical to maintain a 100% certification rate[47] (there are currently 27 million electricity meters), the NMRO has not historically taken further action if a supplier's certification rates are in the high 90%s. As of December 2014 all of the Six Large Energy Firms had certification rates above 95%, and the average figure for the smaller suppliers monitored by the NMRO was 93%.

102. One party, First Utility, has pointed out to us that this mechanism for ensuring meter accuracy suffers two problems: it is wasteful and it creates an economy of scale for larger suppliers. The waste comes from the fact that an obligation is placed on each supplier, which in statistical terms could lead to too much testing or to action that avoids the testing – like replacing meters that still function well.[48] The economy of scale is that for rare meter types, a large supplier might have a sufficient number to be able to satisfy the testing requirement at a relatively low cost. However, a small supplier, with very few such meters, finds that each addition of an uncommon meter type puts it in breach of its certification requirement. It therefore finds that the only economic way to comply is to install a new meter as the default choice when it wins over a customer with an uncommon meter.

103. Centrica said[49] that it did not agree that the issue of uncertified meters was necessarily creating a barrier to switching as a supplier would not know the certification status of the meter when it acquired a site, and as such it could not be a factor in their decision about whether to acquire a site. Centrica also said[50] that the problem was relatively minor with just 3% of its electricity meter population being uncertified.

104. Centrica also said,[51] however, that the problem meant that meter certification costs were not always properly allocated, which meant that suppliers faced strong financial disincentives to exchange an uncertified meter for a new traditional meter. This was a particular problem where a smart meter could not yet be installed.

105. Having considered submissions, we agree that the certification regime treats large and small suppliers differentially and that it runs the risk of imposing unnecessary costs through the replacement of meters that still function well. We understand that DECC has also recognised the problem and has

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[47] This is also to avoid traditional-for-traditional meter exchanges prior to smart meter roll-out.
[48] Further during the period of smart meters roll-out, the current system might also lead to high volumes of traditional to traditional meter replacements and result in additional costs.
[49] Centrica response to provisional findings, paragraph 98.
[50] Centrica response to provisional findings, paragraph 99.
[51] Centrica response to provisional findings, paragraphs 100 & 101.

developed, in collaboration with industry (the Smart Metering Governance Group), a plan which seeks to address both of these issues.[52] In particular, the plan proposes prioritising sample testing of the meter types that are the most common in Great Britain's meter population. This policy should maximise, subject to the samples passing the tests, the proportion of the meters that will have their certification life extended.

106. The Six Large Energy Firms and one independent supplier have chosen to participate and will be sharing the costs of these tests.

107. The proposed cost-sharing arrangement should address most of the externality arising from the current regime, since the Six Large Energy Firms have the largest absolute number of electricity meters, and are expected to benefit most from the certification extension. However, since the smaller suppliers, except one, are not part of this agreement, they will be able to free-ride, as the extensions will also apply to their meters of the same types.

108. We note that the policy might not address the problem of uncertified meters of less popular types. The incentives for suppliers to apply for extension of these meter types may not be sufficient, and these meters will remain uncertified, or will have to be exchanged. This will lead to costs to suppliers who have or who are gaining such customers. The scale of this problem will depend on the distribution of meter types.

109. Nevertheless, we believe that the impact on competition, to the extent that there is any, is likely to be small and that the current plan constitutes a substantial improvement to the regime. We therefore decided that there was no further need to consider these concerns.

[52] DECC submission to the CMA, 15 February 2016.

Annex A: The gas settlement process[53]

1. There are two types of metering arrangements that are applied to GB gas customers depending on their annual consumption. Consumption is provided to gas transporters on a daily basis for daily metered (DM) customers, ie very large gas customers with an annual consumption over 58.6 million kWh (for whom daily metering is a mandatory requirement) and other large sites which are voluntarily daily metered. All other customers are non-daily metered (NDM). These are further divided into:

   - SSPs, ie meter points that have an annual consumption of not more than 73,200 kWh (typically domestic customers and smaller business premises); and

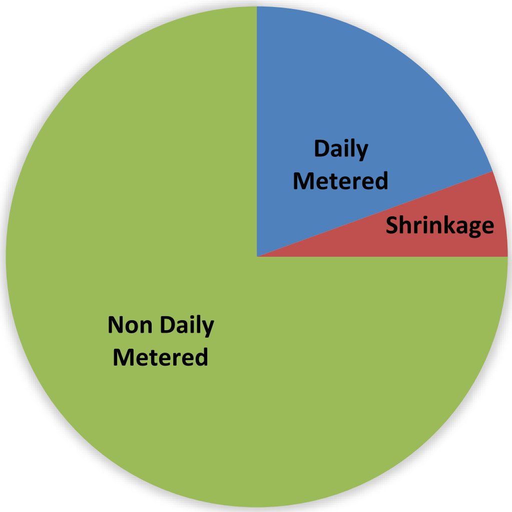
   - LSPs, ie meter points that have an annual consumption between 73,200 and 58.6 million kWh. LSPs can be further subdivided into those with annually read meters (73,200 to 293,000 kWh) and monthly read meters (293,000 to 58.6 million kWh).

2. Every NDM supply point has an AQ – the expected annual consumption of the supply point based on the metered volumes and adjusted to seasonal normal weather conditions. The AQ value is set annually during the AQ review period, which commences around March and concludes in September. An SSP's proposed AQs may only be adjusted during the AQ review if meter reads (that are at least six months and one day apart) demonstrate that actual consumption has varied by more than +/–5% from the current AQ. LSPs may have their AQ adjusted during the year by appeal; shippers are currently unable to adjust AQ values of SSPs outside the review period with the exception that a limited number of SSPs' AQs can be reviewed outside the review period, if the adjusted value is not within 20% of the current AQ value, and in addition differs by at least 4,000 kWh.

3. The AQ value is used for demand attribution by Xoserve to apportion gas to shippers for the purposes of balancing.

[53] This description is taken with slight alteration from Cornwall Energy (2014), *Project Nexus: a Cornwall Energy primer*.

Figure 2: Total daily local distribution zone volume



Source: Cornwall Energy.

4. The supply offtake quantity (SOQ) is the maximum expected daily consumption at a supply point and provides a measure of the peak daily load. The SOQ is arithmetically linked to the AQ. The SOQ is calculated for all NDM sites on the basis of their end user category (a profile of how the customer type is deemed to consume gas) and load factor, and is used for calculation of transportation rates and charges.

5. The total demand entering a local distribution zone is measured daily. The DM consumption is known from meter readings, and shrinkage is the agreed (pursuant to UNC) value for gas 'lost' in the system. Once these two values have been removed then the remaining consumption volume belongs to NDM sites (see figure above). This is then apportioned between NDM sites for each shipper through the demand attribution process. This process uses the end user categories (EUCs), a series of annual load profiles based on the AQ and winter annual ratio (for LSPs where monthly meter reads are available), and the daily adjustment factors, a set of profiles that determine the weather sensitivity of the EUC.

6. When meter reads are submitted for LSPs there is conciliation between the allocated consumption arising from the demand attribution process and the actual consumption. For SSPs, their consumption is reconciled through the RbD process, whereby the LSP meter point reconciliations are spread across the SSPs in the relevant LDZ, and are apportioned to each shipper's SSP portfolio based on their market share, calculated from the AQs.

Project Nexus

7. The introduction of new gas settlement rules is a major component of Project Nexus. The new UNC rules have been developed following extensive industry consultation going back to 2008, resulting in a suite of UNC Modifications to be given effect through a major IT system replacement. The major changes will include:

   (a) four settlement products ('classes') for shippers to choose between – time-critical daily metered (DM), non-time-critical DM, batched daily and periodic meter readings;

   (b) individual meter point reconciliation for all classes of meter point;

   (c) RbD will be removed requiring replacement with apportionment of unidentified gas across all classes of site;

   (d) monthly recalculation of AQs for all meters where a valid read has been successfully submitted by the shipper within the month;

   (e) retrospective adjustment when meter/read data is updated and the shipper wishes previous erroneously submitted data to be overwritten; and

   (f) the possibility for gas transporters to use the same systems and processes as other gas transporters.

8. Once this system is in place it will enable use of larger volumes of smart meter data for settlement purposes.

Annex B: The electricity settlement process[54]

1. When more electricity is generated than consumed, or vice versa, it can result in system frequency falling or rising to an unmanageable degree (an imbalance). As electricity cannot easily be stored on a large scale, it is important that suppliers have incentives to match the amount of energy they buy with the amount used by their customers. They are therefore charged for the difference between the volume of energy that they buy (contracted position) and what their customers consume (metered position). The process for comparing contracted and metered positions, and determining the charges to be paid for any imbalance, is called settlement. This process is set out in the BSC and is performed for every half hour (known as a settlement period).

2. For each settlement period, market participants can trade up to one hour before real time. National Grid Electricity Transmission, in its role as the system operator, then compares the volume of energy scheduled to be brought onto the system with its forecast of demand. If necessary, it will take action to manage any residual difference between supply and demand.

3. The Supplier Volume Allocation arrangements set out the rules for determining how much each supplier's customers use in each settlement period. The information generated through this process is used in settlement to charge suppliers for any mismatch between contracted and metered positions. It is also used to allocate other charges, such as those suppliers pay for using the transmission and distribution networks and those relating to government programmes designed to increase the use of low-carbon technologies.

4. Under the current arrangements set out in the BSC, a small number of customers (0.4%) must be settled against their actual half-hourly consumption because their average maximum demand exceeds 100 kW in defined circumstances. These account for just over 40% of total energy consumption. A supplier can also elect to settle half-hourly any customer with an appropriate meter. However, in practice very few sites are voluntarily settled half-hourly at present.

5. Historically, most customers have not had meters capable of recording half-hourly consumption, and have meters that may only be read once or twice a year (ie non- half-hourly meters). To settle half-hourly for these customers, it

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[54] The description of settlement is taken from Ofgem (2014), *Electricity Settlement – moving to half hourly settlement* and ELEXON (2013), *The Electricity Trading Arrangements: a Beginner's Guide*.

is necessary to estimate consumption. This involves grouping customers into one of eight profile classes.[55]

6. Using sample data, load profiles are created that estimate the half-hourly consumption 'shape' of the average customer in each profile class. These load profiles are used to allocate energy used to each half-hour period. The settlement of electricity over a period will be accurate; however, the timing of when in the day this electricity was consumed will be estimated in line with the load profile.

7. Settlement involves a number of rounds of reconciliation (known as settlement runs) as more accurate data becomes available, and can take up to 14 months after the electricity was consumed. If there is a dispute this can take a further 14 months to resolve. The table below provides an approximation of how long after the electricity was supplied each run is carried out (this is known as the settlement date). Parties either pay or are paid for their imbalances resulting from these runs.

8. After the initial settlement (SF) run and all later runs, invoices are generated and sent out to all parties. The payment date for the SF run (and all later runs) is always 29 calendar days after the settlement date in question.

Table 1: Settlement timescales and Supplier Volume Allocation performance targets

Settlement run	*Working days*	*NHH performance target (%)*	*HH performance target (%)*
Initial settlement (SF)	+16		99
First reconciliation (R1)	+39	30	99
Second reconciliation (R2)	+84	60	99
Third reconciliation (R3)	+154	80	99
Final reconciliation (RF)	+292	97	99

Source: ELEXON.

9. As shown in the table above, nearly all energy settled using half-hourly meters should have accurate data before SF but the vast majority of energy settled using non-half-hourly meters will be based on estimates, as those meters will not have been read before SF. The non-half-hourly energy volumes are estimated and entered into settlement. As time passes, the actual volumes will

[55] 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.
Profile class 5 – non-domestic Maximum Demand customers with a peak load factor of less than 20%.
Profile class 6 – non-domestic Maximum Demand customers with a peak load factor of between 20% and 30%.
Profile class 7 – non-domestic Maximum Demand customers with a peak load factor of between 30% and 40%.
Profile class 8 – non-domestic Maximum Demand customers with a peak load factor of over 40%.
For more information of the use of profile classes in settlement see ELEXON (2013), *Load profiles and their use in electricity settlement*.

start to come in and replace the estimates. This results in a more accurate picture of settlement at each settlement run.

10. After the initial settlement run there are four further runs, known as reconciliation runs (R1, R2, R3 and RF), which provide a continually clearer picture of settlement at spaced dates after the settlement date. The target is for all suppliers to settle 97% of their energy on actual metered data by RF.

11. If any volumes at RF are still under dispute then another run can be carried out when the corrected data has been received (a Dispute Final (DF) run). Any BSC party can raise a dispute but it is the decision of the Trading Disputes Committee as to whether data is corrected and whether a DF run goes ahead.

Annex C: The costs and benefits of smart meter roll-out

1. This annex summarises part of the DECC January 2014 impact assessment of smart meter roll-out for the domestic and small and medium non-domestic sectors. It focuses on the high-level costs and benefits and the potential impacts on competition from smart meters.

DECC impact assessment

2. In January 2014 DECC published its latest cost–benefit assessment of the smart meter roll-out.[56] Its 'central estimate' case shows a positive net present value of £6.2 billion. Sensitivity analysis produces a range of £1.4 billion to £11.4 billion. The biggest benefits accrue from supplier cost savings and energy savings to consumers, while the biggest costs relate to the capital and operating expenses of the meters and in-home displays, their installation and the communications equipment.

3. Supplier benefits will include savings on avoided site visits, reduced call centre traffic related to estimated bills, improved theft detection and debt management. Consumers are expected to use near-real-time information on energy consumption to make energy savings.

4. DECC assumes that the costs to energy suppliers of rolling out smart meters will be recovered through higher energy tariffs. These higher tariffs will be offset by reduced energy consumption and the expectation that competition will lead to energy suppliers passing cost savings to consumers. DECC estimates that initially, energy bills will increase on average around £6 a year for each household after taking account of savings, before turning into a bill saving from 2017. By 2020, once the roll-out is complete, it is expected that household energy bills will average £26 lower a year than would be the case in the absence of full smart meter roll-out. By 2030 the saving is expected to be around £43 a year.

[56] DECC (2014) *Smart meter roll-out for the domestic and small and medium non-domestic sectors (GB)* (impact assessment).

Table 2: Total discounted costs and benefits of smart meter roll-out

	£bn
Benefits	
Supplier cost savings	8.30
Energy savings	5.70
UK-wide benefits (carbon)	1.30
Network benefits	0.95
Peak load shifting	0.90
Total	17.10
Costs	
Meters and in-home displays	4.60
Installation	1.80
Communication hubs and DCC services	2.50
Supplier and other participant costs	0.80
Other costs	1.30
Total	10.90

Source: DECC (2014) *Smart meter roll-out for the domestic and small and medium non-domestic sectors (GB)* (Impact Assessment).
Note: Figures do not sum exactly due to rounding.

5. Of the £6.2 billion net present value, DECC estimates that £4.3 billion accrues to the domestic sector, and £1.9 billion to the non-domestic sector. However some of the costs are hard to distribute and have been allocated to the domestic sector given the relative roll-out sizes. DECC acknowledges that this could understate the domestic benefit relative to the non-domestic benefit, although the size of the overall net benefit is unaffected.

Potential impact on competition between suppliers

6. Although benefits from increased competition have not been monetised as part of the DECC impact assessment, there is an expectation that the roll-out will increase competition within energy supply markets for the following reasons:[57]

   (a) Smart meter reads providing accurate and reliable data flows will support easier and quicker switching between suppliers.

   (b) Information on energy consumption provided to consumers via displays will enable them to seek out better tariff deals, switch suppliers and therefore drive prices down.

   (c) Improved availability of information should create opportunities for energy services companies to enter the domestic and smaller business markets; and for other services to be developed, for example new tariff packages.

[57] DECC (2014), *Smart meter roll-out for the domestic and small and medium non-domestic sectors (GB)* (Impact Assessment).