Appendix 8.6: Gas and electricity settlement and metering

Contents

Page

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 then briefly describe 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

[1] We note that current work on standardising arrangements across Europe indicates that settlement for electricity is likely to move 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.

system (eg Project Nexus[4] for gas, half-hourly (HH) settlement for electricity). 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 settling 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.

[4] The planned upgrade of the gas settlement system.

Gas settlement

The gas settlement process

5. Xoserve is responsible for ensuring that the gas transportation and energy balancing charges invoiced to the 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], 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

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

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

[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.

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 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 makes 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 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] 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,

[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.

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 cost each year, based on analysis of its own imbalance costs.

Other observations

23. 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

24. The reform of the gas settlement arrangements (through UNC modification), which was expected to become operational from 1 October 2015, has now

been delayed.[9] 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.

25. 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.[10] However, as with the current arrangements, there were no governance or control arrangements proposed to govern all market 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).

26. Scottish Power proposed the introduction of a performance assurance framework (PAF) post-Project Nexus delivery to solve these remaining issues. It 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.

27. However, Scottish Power did not consider that the current governance arrangements provided market participants with sufficient incentives to introduce a mechanism such as a PAF to complement Project Nexus, and it did not feel that it had any power to influence the decisions in the current gas governance model.[11] Scottish Power proposed that Ofgem work with the

[9] Ofgem (2015), Open Letter: Project Nexus implementation.
[10] As long as a reading is taken within the settlement window, which is currently three to four years.
[11] Scottish Power explains that the current gas governance model comprises central systems for allocation, settlement, supply point administration and billing for which Xoserve, as the transporters' agent, and the Joint Office of Gas Transporters, which runs the industry codes administration process, are responsible. Xoserve, the Joint Office of Gas Transporters and the Supply Point Administration Agreement make up the gas governance model.

industry to reach an understanding of what was causing the inability to attribute a certain volume of gas to any user and to develop solutions which would reduce the size of this problem. It further stated that there was an opportunity to have an optimum dual-fuel governance solution and framework that would bring the two fuels together and reduce costs and complexity for the industry. Scottish Power has asked Ofgem to consider this under its Smarter Markets Programme.

Respondents' views on gas settlement and Project Nexus

28. 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.

(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. It was currently working on developing a performance assurance regime to help address such concerns. As yet, it is not clear what form such a regime might take.

(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.

29. However, SSE was not convinced that the PAF would be necessary. It considered that the nature of the new settlements system created an incentive on shippers to obtain accurate readings and this incentive was reinforced by suppliers' interests in ensuring that sustained falls in the annual consumption of domestic customers are accurately recorded.

30. In relation to unidentified gas, SSE agreed that the introduction of a revised settlement regime under Project Nexus in October 2015 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.

Our assessment of gas settlement and Project Nexus

31. We consider that Project Nexus will address some of the inefficiencies in the gas settlement process identified above. We also note that its implementation has been slow and some players might have been adversely affected by these delays.

32. We are aware that Ofgem is investigating the current AQ process, including the possibility of gaming. We also understand that this may inform Ofgem's view on, amongst other things, whether a PAF should be introduced and what form it should take. Several UNC modification proposals on performance assurance are currently being developed and Ofgem will await their progress before deciding what, if any, further steps towards the establishment of a PAF may be required.

33. In relation to the allocation of unidentified gas between LSPs and SSPs, we note that Ofgem has recently (9 April 2015) approved UNC 473. This modification will replace the existing RbD methodology and reinstate the AUGE arrangements. The AUGE would 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 sectors. The allocation will be determined by class of settlement rather than whether the supply point is categorised as DM, LSP and SSP.

34. Overall, we consider that even after Nexus has been implemented the possibility for gaming the system (ie AQ) and inaccuracies in cost allocation might remain.

35. Under Nexus a party has the opportunity for monthly rather than annual updates of the AQs. But it might still gain financially, in terms of reduced imbalance and settlement costs, from its ability to delay updates, particularly if this would lead to an upward revision of an AQ. Further, the incentive for a party to place a higher priority on adjusting AQs down reduces that particular party's settlement costs, but would increase the cost of settlement for all other parties due to the unidentified gas mechanism. Incentives for suppliers to encourage demand-responsiveness in their customers are also dampened.

Electricity settlement

The electricity settlement process

36. 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.[12]

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

38. 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.[13] 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 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.

39. 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

40. Market participants put to us that the length[14] 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[15].

---

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

41. 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, create additional barriers to entry and cause inefficiencies.

Profile settlement for electricity distorts incentives to suppliers

42. 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.

43. 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.

44. Tempus submitted that incumbent suppliers might resist the move to HH 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.

45. Ofgem submitted to us that incumbent suppliers may also resist moving to HH 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

46. 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.

47. 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.

48. Both Centrica and First Utility noted the current work being undertaken by industry[16] 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.

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

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

51. 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.

52. 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

53. 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 HH 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).

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

54. 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 HH 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 HH 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.

55. 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 HH data would match the profiled demand shape so closely that HH 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.

Our assessment of electricity settlement

56. We consider that the current industry-led work on reducing the normal settlement timetable should address some of the concerns we expressed above on the length of the settlement process

57. The roll-out of smart meters and the availability of HH settlement for all customers could overcome some of the concerns regarding profile settlement. We consider this further in the next section.

Smarter energy markets

58. 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 42 to 45.

Smart meters overview

59. 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.[17]

60. The roll-out of smart meters is a major national programme.[18] The Department of Energy and Climate Change's (DECC) current implementation programme aims at the installation of smart meters within all domestic and smaller non-domestic premises in Great Britain by the end of 2020.[19] Households will also be provided with an in-home display. This device will provide up-to-date information about the value and volume of gas and/or electricity used.

61. The aim is that 53 million smart meters will be installed in domestic properties and non-domestic premises. The latest official estimates project discounted costs of nearly £11 billion and associated discounted benefits of £17 billion.[20] A brief summary of the DECC impact assessment is set out in Annex C.

62. In addition to other benefits,[21] smart meters have the ability to record HH consumption data which could enable HH electricity settlement for all customers based on actual rather than estimated consumption.

63. 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

---

[17] 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.
[18] It is also a requirement within EU law, under the 2009 Directive concerning common rules for the internal market in electricity and the Directive concerning common rules for the internal market in natural gas.
[19] The initial milestone date of end 2019 set in legislation was pushed back by DECC in May 2013 following advice from bidders for DCC service provider contracts, and from the energy industry, that more time was needed for the design, build and test phases of their programmes (DECC (2013), *Smart Meters Programme*).
[20] DECC (2014), *Smart meter roll-out for the domestic and small and medium non-domestic sectors (GB) (Impact Assessment)*.
[21] 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.

to reach the final allocation of charges associated with a particular settlement period. HH 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.

Benefits from smart meters and half-hourly settlement

64. Ofgem highlighted in its Smarter Markets Programme published on 31 July 2012 that the roll-out of smart metering provided an opportunity significantly to improve the quality of electricity settlement.[22] In particular, the improved access to metering data facilitated by smart metering can enable the use of accurate and timely electricity consumption data in settlement. It also provides a suitable juncture to improve the efficiency of the current design of settlement arrangements, for example reducing the time taken to finalise the allocation of charges.

65. Benefits of using smart metering data in settlement as identified by Ofgem included:[23]

- more accurate and timely allocation of costs: Improvements in the way the costs of consumption are attributed across individual industry parties should help promote competition between suppliers.

- potential for new products and services: Using more granular data in settlement can strengthen the link between actual consumption and energy charges, leading to sharper price signals for market participants. Combined with the functionality of smart metering, reform could therefore encourage the development of new products and services, including offerings such as time of use (TOU) tariffs that reward customers for shifting consumption away from peak periods.

- streamlined processes leading to cost savings, for example through improving or removing profiling and estimation processes as well as reducing the time taken to finalise the allocation of charges. The latter may have particular benefits for smaller suppliers through reduced collateral requirements.

[22] Ofgem (2012), *Promoting Smarter Energy Markets: A Work Programme*.
[23] Ofgem (2014), *Electricity Settlement Reform: moving to half-hourly settlement* provides a more recent overview of the benefits of HH settlement.

Product innovation and demand-side response

66. Smart meters make time-varying and other sophisticated types of tariffs possible by recording the time when electricity is used, and by allowing two-way communications. However, if HH settlement is not available, the incentive to develop new products and services will be reduced. Since suppliers will still be settled on the basis of the profiles, the incentive to offer tariffs which reflect the cost of providing the electricity will be reduced. Suppliers will also have reduced incentives to encourage customers to move their consumption out of the peak periods.

67. This section describes how innovative tariffs can incentivise demand-side response (DSR) or load shifting, which can potentially bring significant benefits to the electricity system and consumers.

68. DSR is defined by Ofgem as 'customers responding to a signal to change the amount of energy they consume from the grid at a particular time'.[24] There are three main types of tariff that can incentivise DSR/load shifting:

- Static time of use (STOU) tariffs use different prices depending on the time of day in order to incentivise customers to shift their energy consumption from peak to off-peak times, in doing so flattening the load demand curve. STOU tariffs have fixed price structures, which do not vary according to real-time network conditions. An example of their simplest expression is the Economy 7 tariff in the UK.

- Dynamic TOU tariffs offer customers variable prices depending on network conditions – for example, during a period of plentiful wind, customers may receive an alert that electricity will be cheaper for the next few hours. Types of dynamic TOU include critical peak pricing, where an alert of a higher price is given usually one day in advance, for a pre-established number of days a year, and a critical peak rebate, where the customer is offered a rebate to reduce their energy consumption at peak time.

- Automated TOU tariffs are tariffs that also include automation, for example through remote control of appliances by a third party, or through programmable appliances, and may be driven by price or non-price factors (such as network conditions). Although automated TOU tariffs may have

[24] Ofgem (2013), *Creating the Right Environment for Demand-Side Response: Next Steps*.

the largest potential for DSR, consumers' willingness to use such automated tariffs has not yet been fully tested.[25]

69. Already many larger industrial and commercial energy users, and some households, take part in schemes where the price of electricity changes depending on when it is used. Some domestic electricity customers (13%) in the UK are already on some form of TOU tariff (mainly Economy 7).[26] DECC expects 0.4% of total demand to be shifted away from peak times as a result of STOU starting from 2016, increasing to around 0.9% by 2030.

70. The potential benefits of reducing the strain on the system at peak times and shifting usage to when there is spare capacity could include[27]:

- less need to switch on expensive and carbon-intensive backup power plants at peak times;
- less need to build new power plants;
- less need to reinforce or extend existing distribution networks;
- better outage management and use of small-scale, intermittent renewable energy sources such as wind farms; and
- more efficient balancing of the grid on local and national levels.

71. DECC estimates that benefits from TOU for domestic customers might range from £453 to £1,621 million over the period 2013 to 2030 (PV), with a central estimate of the order of £900 million (PV) over the same period.[28] It is also considering the scope for DSR, including domestic load shifting in the domestic sector and its report will be published in the summer.

---

[25] DECC (2014), *Smart meter roll-out for the domestic and small and medium non-domestic sectors (GB) (Impact Assessment)*.
[26] Consumer Focus (2012), *From Devotees to The Disengaged – A Summary of Research into Energy Consumers' Experiences of Time of Use Tariffs and Consumer Focus's Recommendations*. Economy 7 meters are two-rate or multi-rate meters, such that electricity consumed at certain times of day will be cheaper than at other times a day. The 13% figure is from a 2012 Consumer Focus Omnibus Survey. Consumer Focus also obtained figures from ELEXON which indicated that 19.5% of electricity customers in GB have a meter capable of supporting a TOU tariff. One explanation for the disparity between the two figures may be that some consumers are not aware that they have a TOU tariff.
[27] In its response to the gas and electricity settlement and metering working paper, EDF Energy pointed to some evidence from the Low Carbon Network Funding trials which show that STOU tariffs for domestic customers have not impacted winter peaks to the same extent as the rest of the year and so believes that the benefits from STOU will be reduced.
[28] See DECC (2014), *Smart meter roll-out for the domestic and small and medium non-domestic sectors (GB) (Impact Assessment)*.

Potential obstacles to achieving demand-side response benefits

72. In addition to the lack of HH 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 third party intermediaries to smart metering data.

Retail Market Review

73. 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.

74. 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.

75. 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.

76. 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.

77. 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.

78. 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.

79. 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).[29] 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

80. It seems likely that significant reforms to market arrangements would be needed to maximise the system-wide benefits of DSR. Ofgem, however, does not believe that launching a significant market reform process to improve the allocation of DSR[30] across the system should be a priority.[31] Rather, Ofgem is undertaking work to set out a strategy for facilitating the use of new sources of flexibility, including DSR, across the value chain. The strategy will detail what Ofgem intends to do and, if necessary, when it expects regulatory changes to happen. Ofgem will publish the strategy in summer 2015.[32]

Third party access to data

81. It has been put to us that the combination of smart metering data (and in particularly HH data) with an individual's address or name would constitute personal data for the purposes of data protection law. At an HH level this data could potentially be used to infer views about an individual's lifestyle. Licence conditions 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 HH 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 HH consumption data.[33]

82. 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

---

[29] DECC and Ofgem (2014), *Government and Ofgem Action Plan: Challenger Businesses (independent energy suppliers)*.
[30] This would involve developing new market models to allow consumer interaction with DSR.
[31] Ofgem (2013), *Creating the Right Environment for Demand-Side Response: Next Steps*.
[32] Ofgem (2015), *Open letter: facilitating efficient use of flexibility sources in the GB electricity system*.
[33] DECC (2012), *Smart Metering Implementation Programme data access and privacy: consultation document*.

important with the introduction of TOU tariffs as TPIs cannot offer these tariffs unless they have access to HH customer data.

83. Some respondents 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.

Industry progress toward half-hourly settlement for all profile classes

Cost–benefit analysis of profile classes 1–4

84. In 2011 ELEXON undertook a cost–benefit analysis for mandating HH settlement for profile classes 1–4.[34] The conclusions from the consultation were as follows:

   (a) There was overall support for the principle of HH settlement. However, the majority of respondents felt that it was too early to consider mandating HH 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 HH 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 HH settlement, so a firm conclusion was not possible.

85. ELEXON is undertaking further work to ensure there are no barriers to suppliers electing to settle meters on a HH basis and that the NHH arrangements continue to work effectively during the smart metering roll-out.

Half-hourly settlement for profile classes 5–8

86. 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-

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

domestic customers) using their HH consumption data.[35] This was to prepare for the obligation on suppliers to provide customers in profile classes 5–8 with an advanced meter capable of recording HH consumption data by 6 April 2014. There was, however, no requirement to settle these customers on an HH 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 HH settlements for profile classes 5–8 as of 1 April 2016.[36,37]

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

87. At present, however, no proposal has been raised to modify the BSC in order to mandate the use of HH 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 HH consumption data. Therefore, in April 2014, it set out plans for examining how this could be achieved.[38] Since then, with support from an expert group consisting of market participants and the government, it has developed options for reforming the existing settlement process so that it can accommodate profile class 1–4 customers in a cost-effective way. It has also explored the options for transitioning to settlement using HH consumption data, including timing. At the conclusion of this work, in February 2015, Ofgem published a letter[39] stating that next steps for the settlement project would be set out in the context of its demand-side flexibility strategy, which is due to be published in summer 2015.In principle, National Grid also supports a move to HH settlement. In its response to the ELEXON consultation, it said:

> Given the scale of the energy challenge ahead NG believe they need to ensure the benefits of smart technologies are realised as soon as possible and would welcome the proposal to mandate Half Hourly settlement for BSC Customers in Profile Classes 1–4 as soon as is feasibly possible. They see this as crucial in developing time of use tariffs to end consumers.[40]

---

[35] Modification proposal P272: Mandatory half hourly settlement for profile classes 5–8.
[36] Ofgem (2014), *Balancing and Settlement Code (BSC) P272: Mandatory half-hourly settlement for profile classes 5–8* (decision document).
[37]This appears to be delayed. A new proposal for migrating Profile 5–8 customers to HH by 1 April 2016 has been proposed by RWE.
[38] Ofgem (2014), *Electricity settlement reform – moving to half-hourly settlement (launch statement)*.
[39] Ofgem (2015), *Update on electricity settlement project* (letter to interested parties, 28 January 2015).
[40] ELEXON (2011), *Profile class 1–4: mandating HH settlement cost benefit analysis*.

88. We understand that although it is in theory possible to have domestic customers settled on an HH basis under the current system, it is a complicated process to move a meter from NHH settlement to HH settlement.

Respondents' views on smart energy markets

89. A number of parties have submitted to us that while they see benefits in HH 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 HH settlement in the long term once the smart metering roll-out is complete or largely complete. It considered that a move to universal mandatory HH settlement today would introduce unnecessary risks disproportionate to the benefits.

(b) Scottish Power agreed that a move to HH 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 HH 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 HH 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. It believed that Ofgem is correct to link development work on HH settlement with its DSR project, since this should allow this trade-off to be made in an informed way.

(c) Ofgem also considered that HH 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 HH 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 HH 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 HH

settlement Until then, it added, it believes that the material costs of HH settlement would vastly outweigh the benefits realised by those with smart meters. Further, it noted that the volume of data that HH 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.

90. Some respondents considered that some of the benefits of smart meters, including innovative tariffs, can already be realised even in the absence of HH settlement.

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

(b) RWE said that for small, medium and large businesses, elective HH settlement is possible, and hence there is no requirement for mandating it. It believed that elective HH settlement will achieve the change and that this should only be made mandatory if progress is insufficient until at least 2020. RWE opposed the P272 modification of the BSC which, according to them, would have imposed additional costs on consumers by forcing mandatory HH settlement too quickly.

(c) 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.

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

91. 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 HH 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 HH 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

(e) E.ON considered that the barriers for suppliers to choose to settle their customers on a HH 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 mid-2016) signalled that progress is being made in this area but that benefits will not be visible for a number of years.

(f) 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 HH 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.

(g) 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 NHH and HH meters in electricity.

Further, Utilita noted [✂].

(h) 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.

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

(a) Reform of the existing process for using HH 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 HH data.

(b) The approach to transitioning customers to settlement using HH data. Settling all customers using HH 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 HH 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.

Our assessment of smart energy markets

93. We have concerns that the delays to HH settlement reforms and the lack of competition between DCAs companies might distort suppliers' incentives to offer innovative products to customers.

94. Specifically, the lack of concrete proposals to modify the regulatory framework for profile 1–4 customers and the uncertainty over the role of DCAs might delay the realisation of potential benefits from smart meters (ie reductions in wholesale energy costs and avoided network costs).

95. We note that Ofgem would set out its plan for HH settlement as part of its demand-side flexibility strategy, which is due to be published in summer 2015.

96. We believe that the absence of HH settlement may further distort incentives and competition in a number of ways – notably, if HH settlement at non-discriminatory prices is not available to suppliers, it will mean that suppliers are not incentivised to encourage their customers to change their consumption patterns (as suppliers will be charged in accordance with the profile patterns). This may in turn distort suppliers' incentives to innovate and bring in new products and services such as TOU tariffs, which reward customers for shifting consumption away from peak periods. Since peak-load shifting has the potential to reduce costs to the electricity sector substantially, this risks increasing costs to the sector and hence the price paid by customers overall.

97. There are a number of other factors which may also prevent the introduction of innovative products and the attainment of demand-side response. We identify the Retail Market Review tariff rule, the need for market reform and the ability of third party intermediaries to access HH data as other potential areas of concern.

Potential inefficiencies in gas and electricity supplier switching processes

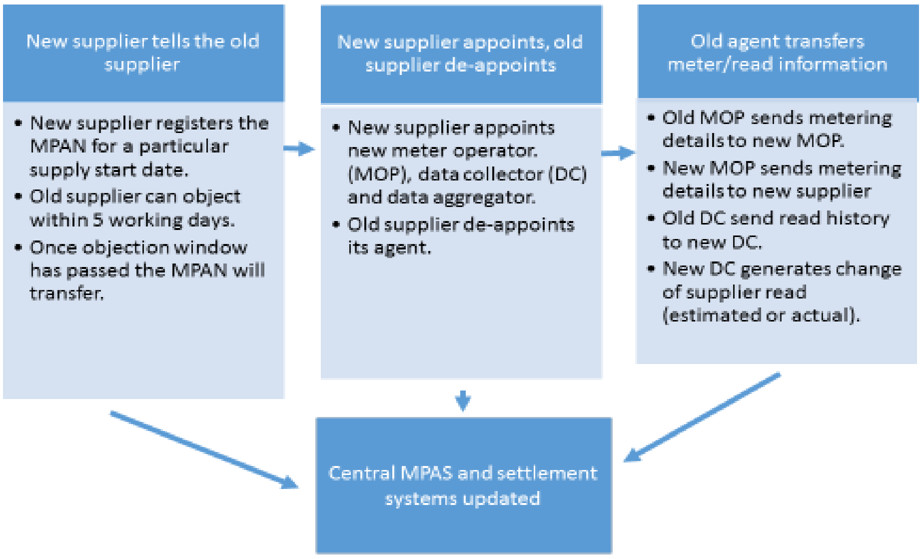
The switching processes

98. 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.[41] 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.[42] 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.

99. Changes introduced at the end of 2014 have reduced switching timescales from five weeks to approximately 17 days for domestic customers.[43] 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).[44]

[41] 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.
[42] Ofgem (2015), *Moving to reliable next-day switching*.
[43] 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).
[44] Ofgem, *Enforcing three week switching* (letter to interested parties, 3 December 2013).

The electricity registration process



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

100. On 9 April 2014, Ofgem published a statutory consultation on licence modifications to enforce three-day 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.

101. Ofgem has recently announced its decision to introduce reliable next-day switching by 2019. This will build on the new arrangements introduced to support smart metering.[45] It is proposed that the Data Communications Company (DCC) will provide a central registration service which will facilitate the change of supplier process for all gas and electricity supply points. This 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, and Ofgem is therefore currently of the view that it should use its 'Significant Code Review'[46] process.[47]

Erroneous transfers

102. Erroneous transfers (ETs) occur when a customer has their supplier switched without their consent, which can cause confusion and distress, and damage

---

[45] Ofgem (2015) *Moving to reliable next-day switching*.
[46] See Appendix 2.1: Legal and regulatory framework for an overview.
[47] Ofgem (2014) *Moving to reliable next-day switching*.

customers' perception of the retail energy market.[48] Resolving ETs and returning the customer to their previous supplier is also costly for both suppliers.

103. Ofgem evidence[49] 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,[50] 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 time. The remainder were linked to the way in which contracts were sold to customers.

104. 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.

105. On 4 July 2014, Ofgem published a decision letter on measures to prevent ETs.[51] 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.

106. 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.[52]

---

[48] Ofgem, *Preventing erroneous transfers* (letter to interested parties, 3 December 2013).
[49] 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*.
[50] 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.
[51] Ofgem (2014), *Decision letter on enforcing three week switching and preventing erroneous transfers*.
[52] Ofgem (2012), *Promoting Smarter Energy Markets: A Work Programme*.

Respondents' views on switching processes and erroneous transfers

107. 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.

108. 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 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-day 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.

109. 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.

Distortions in the switching process arising from uncertified meters

110. Both gas and electricity meters must be certified periodically, the responsibility for this falling on the supplier. However, there is some chance that a customer who has switched finds themselves with an uncertified meter. We consider the possible supplier incentives and consumer harms that this can lead to.

111. First Utility has submitted to us its concerns regarding the number of customers with uncertified electricity meters it gains from other suppliers through switching. It estimates that, in 2014, it gained approximately [✂] customers with uncertified meters. This has caused First Utility to incur additional costs in terms of certification or meter replacement when the previous suppliers must have ensured the meter was either re-certified or exchanged. In addition to the costs of dealing with uncertified meters, First Utility noted that the customer is inconvenienced, having to arrange for an engineer visit. In their view, this situation risks causing the customer to regret having switched and adds to the perceived 'hassle factor' of switching.

112. Furthermore, First Utility pointed out that a similar situation arises for gas, where gas suppliers must ensure that meters are inspected every two years. We note that British Gas has been granted a derogation from this obligation. As a result, British Gas can instead inspect meters every five years. First Utility believes that this derogation creates a number of distortions:

(a) British Gas has a lower cost base as a result;

(b) there is a 60% chance that meters taken on from British Gas are already beyond their inspection date; and

(c) all other suppliers have to inspect the meters that British Gas would, had the derogation not been in place, have inspected themselves.

Our assessment of switching processes, erroneous transfers and uncertified meters

113. We believe that Ofgem's changes to standard licence conditions to enforce three-week switching and prevent erroneous transfers may have addressed the issues we identified. We do not have data yet to assess whether these changes have been effective.

114. We would welcome views from third parties in relation to these concerns, and whether they might have a negative impact on competition through distorting the allocation of costs between suppliers. For example, costs that should have been incurred by the supplier losing a customer to another supplier may be transferred to the supplier that is gaining the customer, which has no

possibility of recovering those from the previous supplier. Further, suppliers who are gaining a large percentage of new customers (relative to their existing customer base) might be disproportionally impacted.

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

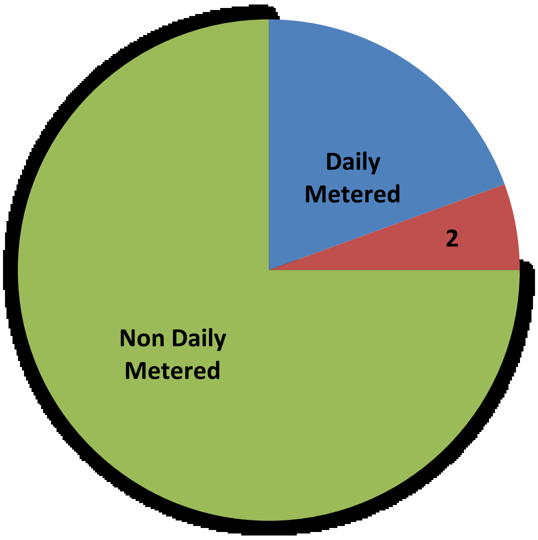
   - LSPs, ie meter points that have an annual consumption between 73,200 and 58.6 million kWh. LSPs can be further subdivided into those with annually read meters (73,200 to 293,000 kWh) and monthly read meters (293,000 to 58.6 million kWh).

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*.

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. It is currently predicted that the system will be operational in October 2015, in line with changes to UNC rules.

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 HH 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 HH consumption, and have meters that may only be read once or twice a year (ie NHH meters). To settle half-hourly for these customers, it is necessary to

[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*.

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

6. Using sample data, load profiles are created that estimate the HH 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.

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

[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*.

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).

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).