Decision Appendix

Default Tariff Cap: Decision	
Appendix 5 – Policy and network costs	
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In accordance with the Domestic Gas and Electricity (Tariff Cap) Act 2018, we are implementing the default tariff cap to come into effect from 01 January 2019. This supplementary appendix sets out our decision and the detailed methodology in relation to policy and network costs.

Please see the default tariff cap – decision overview document for an accessible summary of the complete methodology.

Document map

Figure 1 below provides a map of the documents published as part of the decision on the implementation of the default tariff cap.

Figure 1: Default tariff cap – decision document map

Policy decision documents

Default tariff cap – decision overview document

Supplementary Appendices

Cap level

Appendix 1 - Benchmark methodology

Appendix 2 - Cap level analysis and headroom

Appendix 3 - Updating the cap methodology

Specific categories of cost

Appendix 4 – Wholesale

Appendix 5 – Policy and network costs

Appendix 6 – Operating costs

Appendix 7 – Smart metering costs

Appendix 8 – Payment method uplift

Appendix 9 - EBIT

Additional

Appendix 10 – Exemptions

Appendix 11 – Final impact assessment

Associated licence condition documents

Notices

Notice of modification of electricity and gas Standard Licence Conditions

Final notice of baseline values

Statement to terminate SLC 28AA

Annexes

Annex 2 – Wholesale cost allowance methodology

Annex 3 – Network cost allowance methodology elec

Annex 3 – Network cost allowance methodology gas

Annex 4 – Policy cost allowance methodology

Annex 5 – Smart metering net cost change methodology

Supplementary workbook to Annex 2, 3 and 4 – Demand and losses

Initial level of the cap

Default tariff cap – 01 January 2019 – 31 March 2019

Model – default tariff cap level

Contents

1. Introduction

Overview

1.1. In this appendix, we explain our decisions on our approach to estimating the costs that suppliers incur in relation to:

a) their obligations under different environmental and social programmes (policy costs)

b) charges from the gas and electricity network companies (network charges)

as part of our our bottom-up assessment of costs when setting the default tariff cap.

Policy costs

1.2. Energy suppliers are subject to a number of environmental and social obligations, designed to achieve a variety of different policy goals. In most cases, these obligations result in additional costs to suppliers, which are then passed on to gas and electricity customers via their energy bills.

1.3. There are currently six schemes in operation which directly result in additional expenditure by domestic suppliers:

- policies supporting low carbon and renewable energy, including the Renewables Obligation (RO), Contracts for Difference (CfD), and Feed-in Tariffs (FIT)
- delivering energy efficiency measures under the Energy Company Obligation (ECO) scheme
- Warm Home Discount (WHD) rebates paid to fuel poor customers
- Assistance for Areas with High Electricity Distribution Costs (AAHEDC, previously known as the Hydro Benefit Scheme) which aims to reduce electricity prices in areas of high distribution costs (currently Northern Scotland).

1.4. A description of all of the schemes can be found in Appendix 2 – Cap level analysis and headroom of our default tariff cap working paper.[1]

1.5. In addition, suppliers must also make payments to fund the Capacity Market (CM) scheme, designed to ensure security of supply. As discussed in Appendix 1 – Benchmark methodology, we consider that these are best categorised as wholesale energy costs, and therefore discuss these costs in Appendix 4 - Wholesale.

[1] https://www.ofgem.gov.uk/system/files/docs/2018/04/working_paper_4_-_environment_and_social_obligation_costs.pdf

1.6. In Chapter 2, we set out the methodology that we have used to estimate the costs of each of these schemes when setting the level of the default tariff cap. Based on this methodology, we estimate that the total costs of these schemes was equal to approximately £117 for a domestic dual fuel customer with typical consumption in 2017/18 (for a customer with a single rate electricity meter).

1.7. We set out the key issues raised in response to our statutory consultation,[2] and our views on these issues. We discuss:

- our approach to estimating the costs of ECO3, and particularly the impact of the new taper mechanism
- the treatment of the value of deemed exports when estimating the costs of the FIT scheme
- how the impact of the exemption for Energy Intensive Industries (EIIs) from the costs of some schemes is captured in the way we set the cap, and
- a small number of detailed points relating to our approach to AAHEDC and WHD.

Network charges

1.8. Suppliers are charged for the costs of building, maintaining and operating the energy network and system infrastructure used to deliver energy to their customers. Because networks are largely monopoly businesses, we regulate the prices that the network companies are able to charge by controlling the companies' allowed revenues. The network charges suppliers pay, vary, depending on where their customers live, what type of electricity meter they have and how much energy they use.

1.9. Different charges apply for the high voltage/high pressure transmission networks (which take electricity and gas around Great Britain) and the lower voltage/lower pressure distribution networks (which connect customers to the national transmission networks).

1.10. In Chapter 3, we describe how we estimate these costs when setting the level of the default tariff cap. Based on this approach, we estimate that network charges amounted to a total of approximately £258 for a domestic dual fuel customer with typical consumption in 2017/18 (for a customer with a single-rate electricity meter). This is based on a simple average across GB regions – our estimate varies from £234 in the region with the lowest network charges and up to £298 in the region with the highest.

1.11. In Chapter 3, we set out the key issues raised in response to our statutory consultation, and our views on these issues. We discuss:

- the need to take into account the impact of group correction factors when calculating suppliers' costs

[2] https://www.ofgem.gov.uk/system/files/docs/2018/09/appendix_5_-_policy_and_network_costs.pdf

- our approach to estimating the costs of Balancing Services Use of System (BSUoS) charges, and

- the impact on costs of the gas volumes used in settlement.

1.12. Note that while we have discussed the second and third of these issues alongside our discussion of network charges, they also affect other categories of suppliers' costs.

Related publications

1.13. Ofgem (2018), Default tariff cap working paper – setting the level of the cap. https://www.ofgem.gov.uk/publications-and-updates/default-tariff-cap-working-paper-setting-level-cap

1.14. Ofgem (2018), Default tariff cap working paper – treatment of environmental and social obligation costs under the default tariff cap. https://www.ofgem.gov.uk/system/files/docs/2018/04/working_paper_4_-_environment_and_social_obligation_costs.pdf

1.15. Ofgem (2018), Default Tariff Cap: Policy Consultation. Appendix 7 – Policy and network costs. https://www.ofgem.gov.uk/system/files/docs/2018/05/appendix_7_-_policy_and_network_costs.pdf

1.16. Ofgem (2018), Default Tariff Cap: Statutory Consultation. Appendix 5 – Policy and network costs. https://www.ofgem.gov.uk/system/files/docs/2018/09/appendix_5_-_policy_and_network_costs.pdf

2. Policy costs

We first describe the methodology used to estimate the costs of suppliers' environmental and social obligations ('policy costs') when setting the level of the default tariff cap. We then describe the key issues raised in response to our statutory consultation, and our views on each of these issues.

Methodology

2.1. Our approach to estimating policy costs for the purposes of setting the default tariff cap is as follows:

- We estimate policy costs using administration data (ie official forecasts or data from scheme administrators, rather than information collected from the suppliers themselves), and wherever possible rely on publically available information to do so. This increases transparency around how the level of the cap is being set.
- In general, we set the cap to reflect forecasted policy costs specifically in the given six month price cap period, to allow the cap to be cost reflective and reduce the risk of distorting competition in the wider market. However, in the case of CfDs, we base our cost estimates on an annualised view of the costs of the scheme, to avoid the risk of the cap systematically varying between winter and summer as a result of seasonal trends in wholesale prices.
- We set the policy cost allowance to reflect the costs that we would expect a fully-obligated supplier in steady state to incur (ie where their obligation reflects their market share in the relevant period). This means that suppliers that are not obligated under ECO and WHD schemes will incur costs beneath the level allowed in the cap.
- Scheme costs that a supplier is exposed to, vary in proportion to the amount of electricity used (for ECO, electricity or gas), with the exception of the WHD, where a supplier's obligation depends on the number of customers. This is reflected in how we set and update the level of the cap at nil and typical consumption.
- Where necessary, charges to suppliers are uplifted by forecasts of losses on the electricity networks, to reflect the true cost associated with a given supplier obligation.[3] We will update our estimates of losses annually in February (as part of the cap update process) with the latest forecasts published by the distribution network companies and Elexon for the coming year. Full details of how we have calculated losses is provided in the Demand and losses workbook published on our website.

2.2. Table A5.1 provides a summary of each scheme, and the specific approach we take to estimate the costs to suppliers for the purpose of setting the level of the cap. Full

[3] Distribution losses are based on the distribution network operators' forecasts as per their charging statements, for each region and period. Transmission losses are based on the expected transmission loss multipliers as published by Elexon for each region. To derive the final values, we weight the loss multipliers by demand in different settlement periods.

details – including links to sources and details of the calculations - are set out in Annex 4 to the licence condition 28AD, published on our website alongside this document.[4]

Table A5.1: **Summary of our approach to estimating policy costs**

Description	Approach to estimating supplier costs
Renewables obliation Under the RO, suppliers have an obligation to source an increasing amount of electricity from renewable sources. Suppliers can meet their obligation by presenting certificates bought from generators or making payments into a buy-out fund.	We estimate the cost of the RO scheme using the buy-out price as a proxy of the cost of a ROC faced by a supplier. This buy-out price is multiplied by the obligation level (ROCS/MWh supplied), to obtain a £/MWh cost of the scheme. For the period April to September, we use the previous years' buy-out price and combine it with the most recent Office of Budget Responsibility (OBR) forecast of annual Retail Price Index (RPI) for the previous calendar year. This is due to the final buy-out price not being published until mid Febuary, after the level of the cap is published in early February.
Contracts for Difference CfDs are designed to give greater certainty and stability of revenues to low-carbon electricity generators. The payments to generators are funded via a compulsory levy on all electricity suppliers.	For CfDs, the allowance is based on a weighted average of quarterly interim levy rates as published by the Low Carbon Contract Company (LCCC) for the year running April to March, uplifted to reflect the estimate of maximum allowable green excluded electricity. To this, we add the operational cost levy as published by the LCCC. We then uplift to reflect costs per MWh of electricity *supplied* using our estimate of regional transmission and distribution losses for single rate and multi-register electricity customers.
Feed in Tariffs Under the FIT scheme, owners of small-scale low-carbon generation receive payments for electricity they generate. To fund the scheme all suppliers are required to pay into a levelisation fund.	For FITs, the allowance is based on the latest OBR estimates of total scheme costs, divided by a forecast of total supply volumes for the given scheme year from BEIS. Total supply volumes excludes the capped amount of green excluded electricity – and will also exclude forecast EII volumes on confirmation from BEIS that the costs of the scheme will no longer apply to these customers.
Energy Company Obligation Under ECO, suppliers have an obligation to meet targets for installing energy efficiency measures to eligible domestic consumers. Only domestic suppliers above a given threshold are required to participate in the scheme.	For ECO, the allowance is based on BEIS' forecast of the annualised cost of the scheme, taken from the most recent impact assessment, divided by our latest estimates of the supply volumes used to calculate suppliers' obligations (or the final values, where available). Currently only the supply volumes of fully obligated suppliers (ie those above the 1,400GWh of gas and 500GWh electricity thresholds) are used. From April 2019, the way obligations are calculated will change, meaning that the obligation per MWh will vary between all suppliers, depending on their total supply volumes (due to the deduction of a set supplier allowance). To reflect this, we will from this period onwards calculate average ECO costs by dividing annualised scheme costs by the total supply volumes of *all* obligated suppliers.
Warm Home Discount Under WHD, suppliers provide support to customers at risk of fuel poverty through a rebate of £140 to eligible customers. Only domestic suppliers above a given threshold are required to participate in the scheme.	For WHD, the allowance is based on target spending for the scheme year, divided by our latest estimates of the customer numbers of obligated suppliers (or the final values, where available). We exclude the part of core group spending accounted for by voluntary suppliers.
AAHEDC The scheme reduces prices for domestic consumers in areas with high electricity distribution network costs.	For AAHEDC, the allowance is based on the final charges as published by National Grid (in July) and the previous year's charge increased using RPI when the final charge is not available (in February). This is uplifted using our estimate of distribution losses.

[4] www.ofgem.gov.uk/publications-and-updates/default-tariff-cap-decision-overview

2.3. Table A5.2 sets out our estimates of the costs in relation to each scheme in 2017/18, calculated using the above methodology.

Table A5.2: **Estimates of scheme costs in 2017/18 (GB average)**

Scheme	Electricity (single rate) (£)		Electricity (multi-register)(£)		Gas (£)	
	Nil	TDCV	Nil	TDCV	Nil	TDCV
RO	n/a	57.79	n/a	78.29	n/a	n/a
CfD	n/a	8.33	n/a	11.49	n/a	n/a
FIT	n/a	14.39	n/a	19.51	n/a	n/a
ECO	n/a	9.43	n/a	12.77	n/a	12.41
WHD	6.70	6.70	6.70	6.70	6.70	6.70
AAHEDC	n/a	0.78	n/a	1.06	n/a	n/a
Total	**6.70**	**97.42**	**6.70**	**129.82**	**6.70**	**19.11**

Source: Ofgem calculations based on data from BEIS and scheme administrators.
Notes:
1. The figures reflect a weighted average of our estimates of scheme costs as would have been forecast for periods starting April 2017 and October 2017. For electricity, we assume that 57% of consumption takes place in winter for single rate and 61% for multi-register. For gas, we assume that 75% of consumption takes place in winter.
2. Typical Domestic Consumption Values (TDCV) are 3.1MWh per year for electricity (single register), 4.2MWh per year for electricity (multi-register) and 12.0MWh per year for gas.[5]
3. The only difference compared to the values published in September relate to ECO, which we have corrected to reflect revised information on the supply volumes of obligated suppliers for phase one of ECO3. This increases the allowance for ECO by approximately £0.06 per customer.

2.4. These estimates reflect the charges to suppliers under each of the schemes. However, it is important to note that they will not reflect the full impact of the schemes on customer bills – or the overall cost of each scheme to customers. This is because this will depend on the wider impacts of the schemes on, for example, wholesale prices (in the case of RO and CfDs), energy efficiency (in the case of ECO), and network charges (in the case of AAHEDC).

Key issues raised in response to our statutory consultation

2.5. In response to our statutory consultation, stakeholder comments on policy costs were mostly limited to a small number of detailed points seeking clarification of our proposed methodology. The most substantive comments related to concerns about our approach to estimating the costs of ECO and FIT. We set out below the key arguments raised, as well as our responses.

Our estimates of the costs of the ECO scheme

2.6. Two stakeholders raised concerns regarding how the cap methodology reflected the updated supplier allowance approach used by BEIS in ECO3. Both stakeholders argued that due to the change to the tapering approach used in assessing supliers' obligations, further costs would be borne by large suppliers. They explained that the supplier allowance approach would penalise the larger non-exempt suppliers. Another

[5] See the TDCV page on our website for further details: https://www.ofgem.gov.uk/gas/retail-market/monitoring-data-and-statistics/typical-domestic-consumption-values

stakeholder highlighted concern that the use of gross supply volumes instead of obligated supply volumes is not sustainable throughout the duration of the default tariff cap.

2.7. We recognise the adoption of a supplier allowance approach by BEIS implies that suppliers' obligation under the scheme will now increase with their size. However, while this means that larger suppliers will have a larger obligation, these suppliers are also expected to benefit from economies of scale in ECO delivery which should offset these additional costs - for example, the fixed administration costs associated with the scheme will be spread across a higher number of customers. Our approach means that we are, in effect, basing the costs on the average supplier in the market. We consider this a more appropriate approach than, for example, using the obligation of the largest supplier, which would overstate the cost of the scheme to the market as a whole, and so would not be consistent with our aim of protecting customers on default tariffs from excessive prices.

2.8. Another stakeholder raised concerns that smaller suppliers who are fully obligated are disadvantaged compared to both large suppliers and small non-obligated suppliers. However, given the objective of the Act, we retain the view that the allowance for the costs of ECO should be set to reflect the costs of a supplier operating at efficient scale. We also noted that mid-tier suppliers may enjoy other cost advantages compared to the large incumbent suppliers (see Appendix 6 – Operating costs).

2.9. One stakeholder highlighted that suppliers with decreasing market share will not be able to fully recover their costs, because lagged supply volumes are used to calculate the size of supplier obligation. We note that the converse effect exists for a growing supplier, for which our methodology may overstate the cost of the scheme. In our view, basing the allowance on a supplier in steady state (neither growing nor shrinking) best balances these risks – ensuring that the cap reflects the costs of a company at efficient scale, not losing market share.

2.10. Another stakeholder raised concerns that the ECO3 impact assessment could understate the costs of obligated suppliers, due to the risk of a delivery delay (which could drive up supply chain costs) and because of the introduction of a new quality mark standard. While we agree that there is some uncertainty as to the cost of the ECO scheme, we consider that the BEIS impact assessment provides the most reliable view of the forecast costs of the scheme available. Were a more recent impact assessment published, we would use any updated forecast to set the allowance for ECO. We have taken into account the general uncertainty affecting forecasts of policy costs in how we have set the overall level of the cap, as discussed in Appendix 2 – Cap level analysis and headroom.

2.11. One stakeholder asked for clarification of the ECO methodology set out in Annex 4 to the licence condition. We can confirm that for the first cap period (running from 1 January to 31 March 2019), our methodology takes into account the supply volumes of 'fully' obligated suppliers only. From the second period onwards the methodology reflects the revised supplier allowance approach. We have added notes to the model to clarify this point. The stakeholder also highlighted a formula error in the annex which meant that the model would not correctly calculate the costs of the ECO scheme for future periods according to the described methodology. We have updated these cells accordingly.

FITs

2.12. One stakeholder argued that because the OBR forecasts of FIT costs were net of the expected value of deemed exports, they would understate the cost of the scheme. It argued that this was the case because suppliers are billed assuming that there are no deemed exports, and while in theory there may be industry benefit from exports, this is entirely theoretical and difficult to track. It said that inflating the forecast cost of the scheme to exclude the assumed benefit of deemed exports would increase the allowance by £0.28/MWh.

2.13. While the benefit to any supplier associated with deemed exports is uncertain (depending on the volume of exports that took place, and when they occurred), and would be different for different suppliers, we do not agree that this benefit is "entirely theoretical". A supplier will benefit from being allocated lower volumes in settlement where its customers have exported electricity in a given period.

2.14. Given this, we have not changed our approach to estimating the costs of the FIT scheme for the purposes of setting the level of the default tariff cap. We have, however, had regard to the uncertain value of these benefits (alongside wider uncertainties affecting the OBR forecasts of FIT costs) in making our decision on how the overall level of the cap should be set, given the uncertainties affecting different cost components, as discussed in Appendix 2 – Cap level analysis and headroom.

Energy Intensive Industries (EIIs)

2.15. Two suppliers raised the point that BEIS are consulting on the widening of the exemptions for EII. These changes may impact the costs that domestic suppliers incur in relation to the RO, CfDs and potentially FITs.

2.16. The impact on costs of the existing exemption for EII customers from the RO and CfDs is captured in our existing methodology, and if a decision is taken to lower the threshold (ie widening the group of business consumers that the exemption applies to) then this will flow through to our estimates directly via the RO obligation level updates published by BEIS and the Interim Levy Rate forecasts published by the LCCC.

2.17. In relation to the FITs scheme, as set out in our statutory consultation, where it is confirmed that the exemption for EIIs is to be extended to FITs, we will capture this in the supply volume forecasts used to calculate the total cost of the scheme when updating the level of the cap.

AAHEDC

2.18. One stakeholder argued that the AAHEDC forecast for the summer period fails to take into account the correction factor used by National Grid to account for revenue over- or under- recovery in the previous year. While true, the value of the correction factor is not known when the level of the cap is updated in February. Given this, we consider inflating the previous year's charge by RPI to be the most suitable way of calculating the forecast level of the tariff for the summer period (as RPI is used to inflate the assistance and administration amount each charging year).

WHD

2.19. One supplier questioned the attribution of WHD scheme costs to both gas and electricity, stating that it is levied on electricity only. However, while rebates are paid via electricity bills, each suppliers' obligation is calculated with reference to their share of the domestic gas and electricity market.

2.20. One supplier said that the estimate of the total target spending under the WHD should be updated to reflect the revised obligation level communicated to suppliers in September 2018. We noted that there had been an increase in the WHD overall obligation of £3 million for 2018/19 (equating to an increase in the cost per dual fuel customer of approximately 13 pence). There have also been a number of other updates to third party inputs to our policy cost calculations that have been released since our statutory consultation (for example, significant downwards revisions to the LCCC forecasts of the interim levy rate, and changes to the OBR inflation forecasts).

2.21. We considerd that the overall impact of using these updated forecasts would be to reduce the level of the cap by a small amount. However, we considered that doing so would risk introducing inconsistency with the approach taken when setting other inputs used to calculate the level of the cap for the first period. Given this, we decided not to update any of these inputs using information published in the period since our statutory consultation.

3. Network costs

We describe the methodology we use to estimate the costs suppliers incur in relation to gas and electricity network charges. We then describe the key issues raised in response to our statutory consultation, and our views.

Methodology

3.1. To estimate network charges, we combine information on charges (taken from the network companies' charging statements) with assumptions about demand and losses to estimate the costs to a supplier for each customer type for a given charging year. The methodology for each category of network charge is described in Table A5.3. Full details of our calculations can be found in Annex 3 to licence condition SLC28AD.

Table A5.3: Summary of our approach to estimating network charges

Category	Approach to estimating supplier costs
Gas transmission and distribution	Gas distribution charges in each Local Distribution Zone (LDZ) are set annually for the period April to March by the gas distribution companies. Gas transmission charges are set by National Grid twice a year, in spring and autumn. For both transmission and distribution, the charges comprise a set of pence/kWh commodity charges and pence/kWh/day capacity charges: • To estimate total capacity charges per customer in each LDZ, we combine our assumed level of annual domestic consumption per customer with information on regional load factors (published by Xoserve) to produce an estimate of peak daily load. This is then multiplied by capacity charges as reported in the most recent charging statements. For transmission, we weight NTS exit capacity charge across exit zones using flat target capacity in order to derive a weighted average charge for each LDZ . • For commodity charges, we multiply assumed annual domestic consumption per customer with the published charges (for transmission, the transportation owner and system operator commodity charges published by National Grid and, for distribution, the LDZ system commodity charges published by the gas distribution companies). Finally, we calculate a weighted average of the charges for the LDZs overlapping each electricity distribution region (we use electricity regions for the purposes of setting regional variants of the default tariff cap).
Electricity transmission	Electricity transmission charges are set annually by National Grid for the period April to March. They constitute an energy consumption tariff (p/kWh), which we multiply by an estimate of the proportion of annual consumption that takes place during peak times (4pm-7pm, estimated using seasonally normal profile data provided by Elexon, as set out in the demand and losses model published on our website) to estimate charges per customer. We scale up to account for regional distribution losses, estimated using the methodology described in paragraph 2.1.
Electricity distribution	Charges for each region are set by the electricity distribution companies 15 months in advance of the charging period (which runs from April to March). They comprise a unit rate paid per kWh, and a fixed daily charge, which we combine with annual consumption and the number of days in the year respectively to derive an annual estimate of the cost per customer. Different charges apply to customers with single- and multi-register meters.
Balancing Services	Balancing Services Use of System (BSUoS) charges cover the cost of services used to balance the electricity system, and internal system operator operating costs. Under the cap, these charges are passed through on a lagged basis – specifically, following the methodology used in the prepayment price cap, a weighted average of BSUoS charges in £/MWh in each settlement period across the preceding calendar year (in February) and preceding year running from 1 July to 30 June (in August) is calculated. This charge is then uplifted by forecast losses, calculated according to the methodology described in paragraph 2.1, before being multiplied by annual domestic consumption.

3.2. Table A5.4 sets out our estimates of network charges in 2017/18, calculated according to this methodology.

Table A5.4: **Estimates of network charges in 2017/18**

Scheme	Electricity (single register)		Electricity (multi register)		Gas	
	Nil	TDCV	Nil	TDCV	Nil	TDCV
Transmission	n/a	37.27	n/a	40.08	n/a	8.81
Distribution	16.43	89.84	16.43	89.99	n/a	113.65
Balancing Services	n/a	8.35	n/a	11.34		
Network costs, total	**16.43**	**135.46**	**16.43**	**141.41**	**n/a**	**122.46**

Source: Ofgem calculations based on data from BEIS and scheme administrators.
Notes:
1. The figures reflect a weighted average of our estimates of scheme costs as would have been forecast for periods starting April 2017 and October 2017. For electricity, we assume that 57% of consumption takes place in winter for single rate and 61% for multi-register. For gas, we assume that 75% of consumption takes place in winter.
2. Typical Domestic Consumption Values (TDCV) are 3.1MWh per year for electricity (single register), 4.2MWh per year for electricity (multi-register) and 12.0MWh per year for gas.

Key issues raised in response to our statutory consultation

3.3. Only a small number of comments were raised in relation to network charges in response to our statutory consultation.

Grid Supply Point (GSP) Group Correction Factors

3.4. One stakeholder stated that an allowance for GSP group correction factors (GCFs) should be included in the cap. Based on a historic assessment, it argued that if a GCF is greater than one, there is need for an allowance against wholesale electricity and BSUoS costs. They suggested a 0.5% allowance should be included against wholesale electricity costs, a 5% allowance against capacity market costs, a 4% allowance against TNUoS costs and a 0.3% allowance against BSUoS costs.

3.5. Looking at weighted average GCFs across regions and the most common standard settlement configurations for profile classes 1 and 2, we estimate an average GCF of around 1.0007 in 2016/17 and 1.0013 in 2017/18. This is significantly lower than that suggested by the stakeholder – amounting to less than £0.50 per electricity customer.

3.6. We note that there is considerable uncertainty around the scale and direction of GCFs in advance, and - as set out in our statutory consultation - we are not aware of any forecasts that are available which could be used. In general, we'd expect these factors to tend towards one on average. Given this, and the relatively low materiality, we do not capture the impact of GCFs in our models. We have taken any potential residual impact into account as a cost uncertainty when making our decision on how the overall level of the cap should be set relative to our efficient benchmark, as discussed in Appendix 2 – Cap level analysis and headroom.

BSUoS

3.7. One stakeholder highlighted a rising trend in BSUoS costs in recent years and claimed this is likely to continue in future. They stated that this growth means costs are unlikely to be fully recovered under our lagged approach to setting the BSUoS allowance. They recommended that £0.12/MWh be applied to the network costs methodology, to reflect the historic trend.

3.8. While BSUoS costs have increased in the past, we note that there is significant uncertainty about the future value of BSUoS charges. In particular, while we recognise there are factors that could apply upward pressure on BSUoS charges, such as increasing intermittent generation, there are also factors that could apply downward pressure, such as healthier capacity margins or network reinforcement. For example, the Western HVDC link or inititives such as the Trans European Replacement Reserves Exchange (TERRE), are both factors that could cause BSUoS costs to fall.

3.9. Given this uncertainty, we do not consider that the accuracy of our estimated BSUoS charges would be improved by uprating them in line with historic trends. We have, however, taken this uncertainty into account when making our decision on how the overall level of the cap should be set relative to our efficient benchmark, as discussed in Appendix 2 – Cap level analysis and headroom.

Use of typical domestic consumption values, rather than annual quantities, for gas

3.10. One stakeholder highlighted that gas transportation costs are set based on annual quantity (AQ), and so there is a risk that Ofgem's calculations would underestimate costs if TDCV demand is less than customer AQ. Similarly, another stakeholder argued that the historical AQ process results in inaccurate gas allocation, such that allocated volumes do not fully translate into customer billed volumes. While this is due to improve under Project Nexus, it will take time for this issue to be resolved.

3.11. Because the level of the cap scales with a customer's consumption (ie creates an implied maximum unit rate for a simple tariff), rather than being based specifically on typical demand, we do not agree that our approach will cause us to underestimate costs where AQs depart from typical consumption. We also note that under Nexus, suppliers are able to submit more meter reads to increase the accuracy of the volumes allocated to them in settlement, and while this will be subject to some lag, the final reconciliation will be against actual metered volumes. Given this, we did not consider that changes to the design of the cap were required in relation to either of these issues.