IMPACTS OF RECOVERING BALANCING SERVICES COSTS WITH AN EX ANTE FIXED CHARGE

August 2021

CONTENTS

1 INTRODUCTION

Balancing Services Use of System (BSUoS) charges are the means by which the Electricity System Operator (ESO) recovers the costs associated with balancing the electricity transmission system. They are made up of several elements including constraint costs, frequency response services, provision of reserve, the costs of actions taken in the Balancing Mechanism and the ESO's internal costs.

In November 2018, Ofgem asked the ESO to launch the Balancing Services Charges Task Force to examine potential reforms to BSUoS charges. The task force concluded that BSUoS should be treated as a cost recovery charge and recommended that:

- BSUoS should be recovered from "Final Demand" i.e. it should no longer be recovered from generation in line with other supply sources;
- that the charges should be fixed in advance with a combined notice period of 14-15 months; and
- ESO should manage the forecast risk associated with fixing the charge.[1]

Ofgem accepted that the task force made a good case for reform but highlighted the need for more work to quantify the costs and benefits. The industry is now developing options in line with the task force recommendations through the code modification process:

- CMP308 – Removal of BSUoS charges from generation and recovering all costs from final demand.
- CMP361 – Introduction of an ex ante fixed BSUoS tariff.

Ofgem has commissioned Frontier Economics and Lane Clark and Peacock (LCP) to carry out analysis of the impacts of the potential reforms to inform Ofgem's assessment of the options in this process.

This report is focused on the analysis of the impacts of CMP361 and follows on from our previous report on the impacts of CMP308.[2] For the purposes of assessing the impacts of CMP361, we assume that CMP308 is implemented and therefore this report describes the incremental impacts of recovering all BSUoS costs from final demand with an ex ante fixed charge relative to an ex post floating charge. We do not assess the impacts of CMP361 in the absence of CMP308 being implemented.

We carry out the assessment in three stages:

- **Stage 1: System and consumer impact analysis** – we examine the implications of the reform, and in particular the fixing of BSUoS costs for all

[1] First task force report http://www.chargingfutures.com/media/1348/balancing-services-charges-task-force-final-report.pdf; Second task force report http://www.chargingfutures.com/media/1477/second-balancing-services-charges-task-force-final-report.pdf

[2] Available here: https://www.ofgem.gov.uk/publications/reform-bsuos-charges-analysis-proposal-remove-bsuos-generation

periods of a season, for the total costs[3] of operating the electricity system and costs to consumers up to 2040. This assessment is based on system modelling using the Envision model.

- **Stage 2: Bill impact analysis –** we assess the potential impact on bills for a number of different representative domestic, commercial and industrial user archetypes, consistent with those that we developed for Ofgem as part of our earlier analysis for the Targeted Charging Review (TCR). This is presented as a dynamic impact. This means that it accounts for the direct impact of the change in BSUoS incidence on different end users and the impact of consequential changes in other market charges identified in our system modelling.
- **Stage 3**: **Risk premia analysis –** we assess the benefit from the reallocation of forecasting risk to the ESO under a range of options for different lengths of fixed and notice periods. The Second Balancing Services Charges Task Force concluded that a total fixed and notice period of 14-15 months was a reasonable compromise between the ESO and suppliers/customers but did not conclude on an appropriate split between the fixed period and the notice period. Given this we consider three options that align directly with the Task Force's conclusions. We also consider one further option to illustrate the impact of longer fixed and notice periods. The options we consider are:
  - 12 month notice, 3 month fixed (12N - 3F)
  - 9 month notice, 6 month fixed (9N - 6F)
  - 3 month notice, 12 month fixed (3N - 12F)
  - 12 month notice, 12 month fixed (12N - 12F)

We note that throughout this quantitative analysis we have had to make numerous simplifications and assumptions. For example, when assessing future system or customer costs, assumptions are required on factors such as commodity prices and renewables build out. Where we believe that assumptions are key to understanding the results in this report, we have set out the basis for our analysis. Similarly, impacts for different user archetypes will be a function of a number of user specific factors, particularly for larger customers, which it is not possible to capture in the bill impact analysis and therefore, modelled impacts should only be considered illustrative to provide the broad direction of the expected impacts.

Finally, in relation to the analysis in this report, it is our view that quantitative modelling does not constitute a full impact assessment, and thus should not be the sole (or in many cases even principal) basis for determining whether particular modifications to a charging regime are appropriate. We consider that a qualitative assessment against clear criteria for efficient, equitable and practical charging is of critical importance.

This report is structured as follows:

[3] In common with our analysis of the Targeted Charging Review, we have not sought to quantify explicitly network costs, as to do so would rely on too many assumptions regarding the location of changes in use to render the analysis meaningful.

- In **Section 2**, we set out the quantitative modelling of the system and consumer impacts using Envision.
- In **Section 3**, we set out the quantitative assessment of the dynamic distributional impacts for different types of users.
- In **Section 4**, we set out our approach to the quantitative assessment of the impact on risk premia of reallocating BSUoS forecast risk to the ESO.
- In **Section 5**, we present the results of our risk premia analysis.
- In **Section 6**, we summarise the overall implications of our three analytical elements.
- Finally, in **Section 7** we set some key limitations of our analysis.

2 MODELLING OF WIDER SYSTEM AND CONSUMER IMPACTS

In this section, we look at the potential impact that recovering BSUoS using an ex ante fixed £/MWh charge could have on the wider system, and understand the impacts that this might have on aggregate consumer welfare.

2.1 Methodology and Assumptions

Moving to a fixed BSUoS charge will not directly affect the vast majority of generation because we assume that CMP308, removing BSUoS from generation, has been implemented in the counterfactual for this analysis. This means that direct impacts only affect behind the meter generation (BTMG), and therefore the impacts are very small. Nonetheless the displacement of other generation by BTMG can result in changes in system and consumer costs. We have modelled the impacts of this change using LCP's Envision Model.[4]

Note that there may also be impacts due to demand that responds to price signals - for example, demand being reduced or shifted during overnight periods with high BSUoS charges – but this is not captured in the modelling.

2.2 Modelling scenarios

In the modelling, we compare:

- a Counterfactual scenario where BSUoS is fully recovered from suppliers on a variable £/MWh basis. This is equivalent to the Factual scenario used in our analysis of CMP308.[5] This places all generation sources that are not behind the meter (including interconnection) on a "level playing field", in terms of not being exposed to BSUoS. However, BTMG continues to benefit from reducing supplier BSUoS exposure,[6] and this benefit is larger than under current charging arrangements (roughly double in size).
- a Factual scenario where BSUoS is fully recovered from suppliers on a fixed £/MWh basis. The average BSUoS charges from the counterfactual model run have been used as an input for these fixed charges. The key difference from the counterfactual scenario is the impact on the dispatch of different types of BTMG, as the "shape" to BSUoS hourly £/MWh charges is removed. Whilst, CMP361 is considering a range of fixed periods, for system modelling purposes we assumed a 6 month fixed period.

The analysis is conducted using National Grid's FES 2020 Consumer Transformation (CT) market background, which provides assumptions for

4 For more details on LCP's EnVision model see Section 2.1 of our report on Wider System and Distributional Impacts of Recovering Balancing Services Costs from Demand. Available at: https://www.ofgem.gov.uk/publications/reform-bsuos-charges-analysis-proposal-remove-bsuos-generation

5 Available here: https://www.ofgem.gov.uk/publications/reform-bsuos-charges-analysis-proposal-remove-bsuos-generation

6 Note that CMP333, implemented in April 2021, changed supplier charging to a gross basis (instead of net of embedded generation). However, BTMG is still able to reduce a supplier's BSUoS exposure for a particular site.

projections of commodity prices, demand, low-carbon build and interconnector build.

These core modelling scenarios are summarised in Figure 1

Figure 1 Core Modelling scenario runs

Scenario	FES 2020 Background	BSUoS assumption
Counterfactual	CT	Fully recovered from suppliers on a variable £/MWh basis set ex post.
Factual	CT	Fully recovered from suppliers on an ex ante fixed £/MWh basis

Source: Frontier/LCP

2.3 Key modelling assumptions

In this section, we explain the key assumptions used in our modelling.

2.3.1 Market background assumptions

Assumptions for commodity prices, demand and the build-out of low-carbon and interconnection are taken from the FES 2020. See Annex B for more detail.

The build-out of Capacity Market technologies, including CCGTs, gas peaking plant and battery storage are modelled endogenously through the simulation of the capacity auctions. The cost assumptions used for these technologies, including capital expenditure (capex), operating expenditure (opex) and hurdle rates are taken from BEIS' 2020 electricity generation cost projections.

For the purposes of our system cost analysis, we do not quantify the network cost impacts as they are highly sensitive to changes in the assumed build locations of new plant.

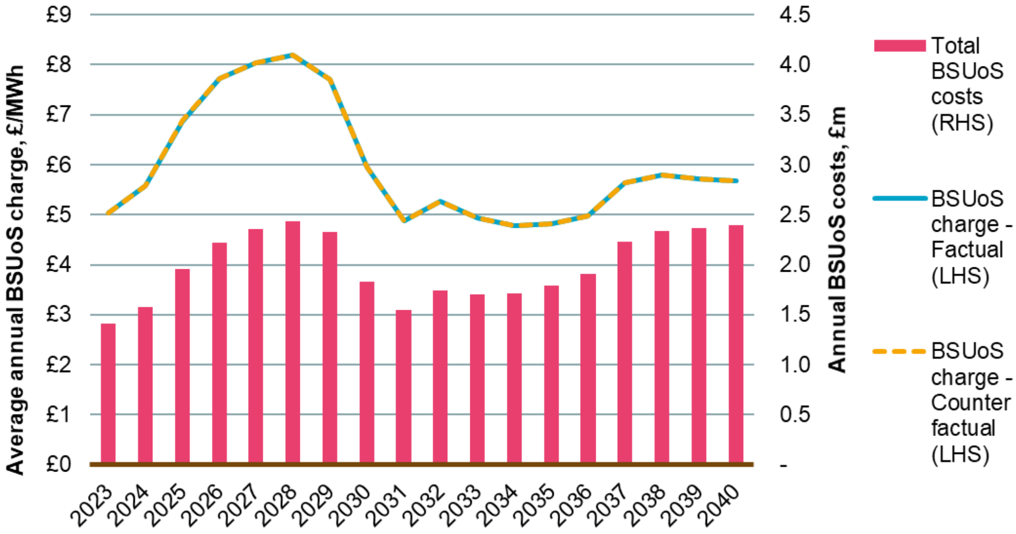
2.3.2 BSUoS assumptions

Our annual BSUoS cost projections have been developed based on three components:

- Thermal constraint costs, based on annual projections provided by NG ESO.
- Non-thermal constraint costs based on same profile, but assuming that thermal rises from 40% of total constraints costs to 75% over the 2022-2026 period.
- Other BSUoS costs based on current levels, scaled in line with total demand in real terms.

The charges used in the two scenario runs are shown below.

Figure 2 Per MWh BSUoS charges in the two scenario runs (volume-weighted) and total BSUoS costs



Source: Frontier/LCP

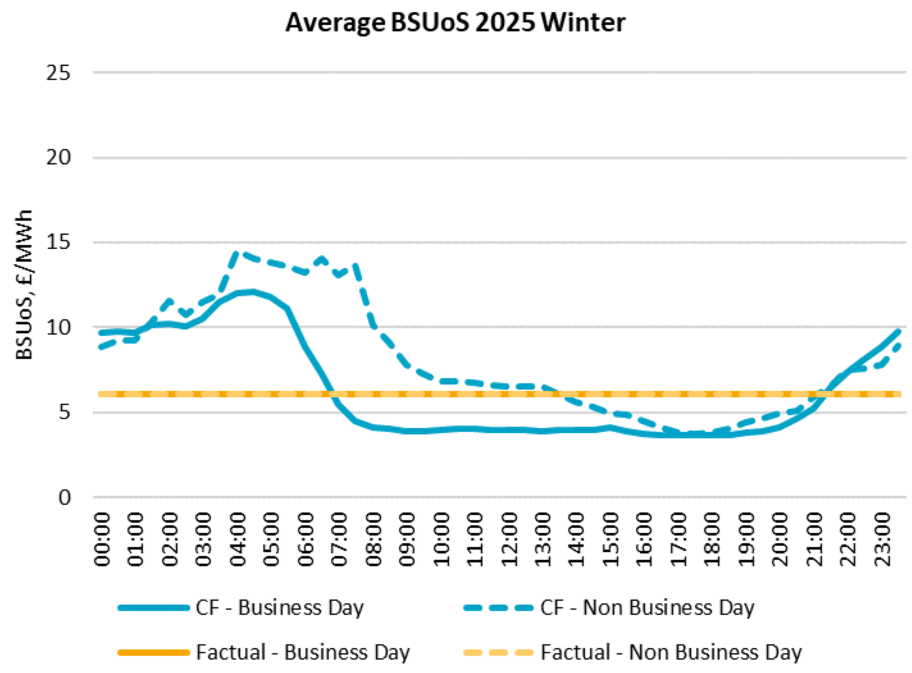
Average annual BSUoS charges in the two scenarios are almost identical, as the total costs gathered are assumed to remain unchanged, and there are just some small differences in the charging base due to the behaviour of BTMG. The charges peak at around £8/MWh in 2028, and flatten from 2030 onwards at around £5/MWh to £6/MWh.

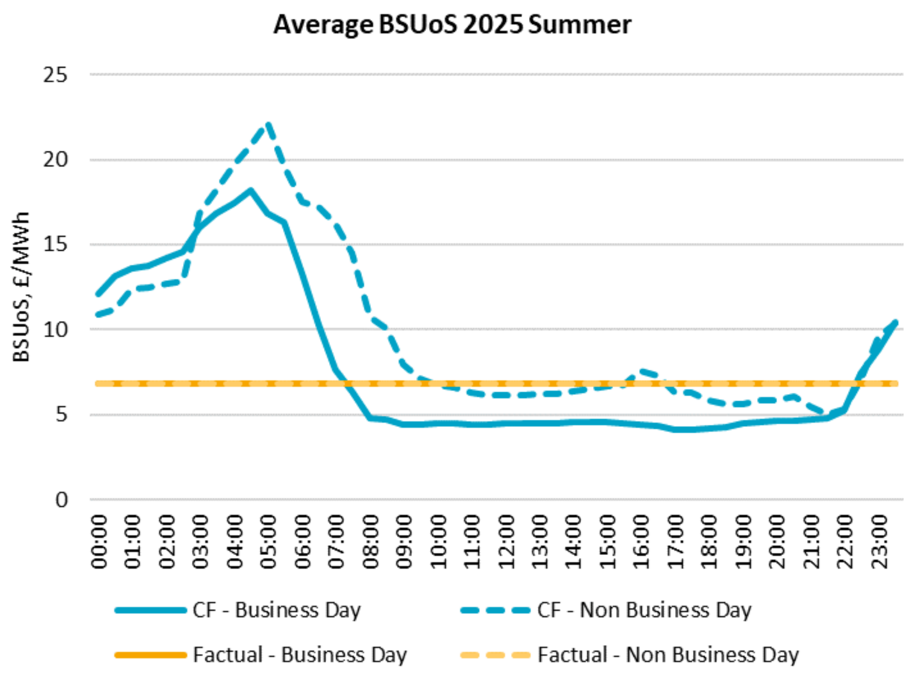
In addition to the annual projections, we also estimate how BSUoS charges vary within the year. BSUoS charges, particularly constraint costs, tend to be much higher during periods of high renewable and must-run output, and low demand. During these periods, expensive actions need to be taken to resolve constraints on the system, including turning down wind and turning up thermal generation.

To estimate this, we have established a relationship between BSUoS charges and residual demand (demand net of must-run and intermittent generation), based on historical data, with high BSUoS charges corresponding to low levels of residual demand. This relationship is adjusted in each future year (in particular, the variable component of BSUoS, corresponding to constraint costs), to ensure the average BSUoS charges across the year align with the annual projections shown above, while still maintaining hourly shapes that vary with residual demand.

The average BSUoS charges by period assumed for two example seasons in 2025 are shown below.

Figure 3 BSUoS charges by period for 2025





Source: Frontier/LCP

Due to the different approaches in recovering the BSUoS costs, the charge profiles between the two scenarios are very different. While the Factual case has flat values across all days within the seasons, the Counterfactual has higher charges on non-business days and overnight, as these are the periods with lower overall demand and so higher constraints costs due to intermittent generation. Both scenarios have higher per MWh charges in summer than winter, also due to the lower overall demand and a higher proportion of intermittent generation.

2.4 Modelling results

Capacity breakdown

The modelling did not show any difference in the capacity mix between the Counterfactual and Factual scenarios. The impacts on generators are limited to the “shape” of BSUoS charges for BTMG, meaning there is little impact on the market as a whole.

Generation breakdown

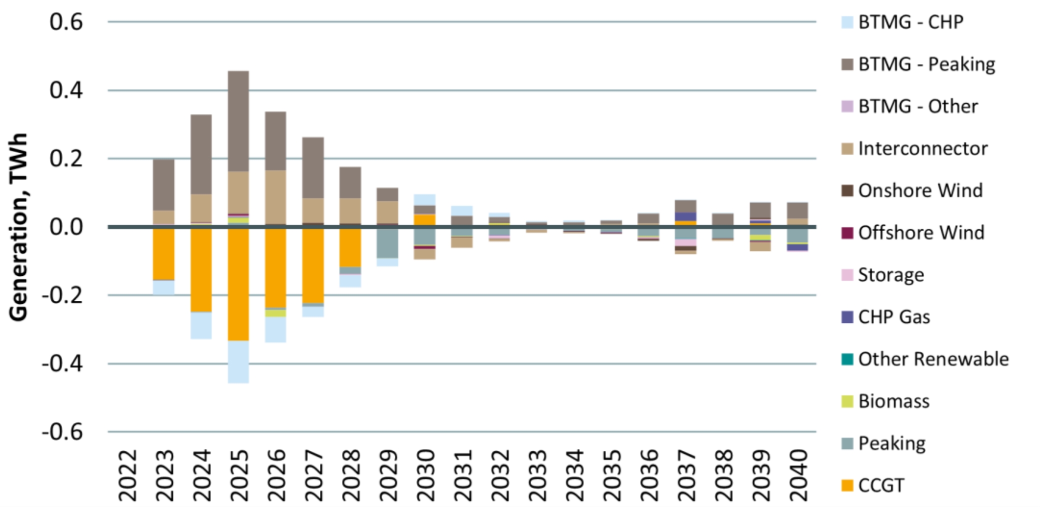
Figure 4 below shows the change in generation between the Counterfactual and Factual scenarios.

Overall, the impacts are relatively small, with less than 0.5TWh of overall impact in any given year, and much less than this in later years.

The largest increase in generation comes from behind-the-meter (BTM) gas peaking generation. This generation benefits from the higher fixed BSUoS charges during the peak demand periods when it typically runs. Offsetting this are decreases in CCGT and front-of-the-meter peaking generation, which are not directly impacted by the change in BSUoS charge shape, but are displaced by the BTM peaking generation. BTM gas CHP generation decreases, as it loses the benefits of high BSUoS charges during off-peak overnight periods (with BTM gas CHP often running close to baseload). This reduction is offset by an increase in Interconnectors, which (like CCGT) are not directly affected but displace the lower generation from BTM gas CHP in the factual scenario. Other BTMG (such as wind and solar) is largely unaffected, as it is economic for these technologies to run under both scenarios.

The impacts are lower in later years, partly due to lower BSUoS charges, but mostly due to there being fewer periods when dispatchable BTMG is close enough to being the marginal generator that the change in BSUoS can influence its dispatch.[7]

Figure 4 Generation (Factual – Counterfactual)



[7] The change in BSUoS is sufficiently large in some periods that even if dispatchable BTMG is not the marginal plant it capable of being pushed in or out of merit.

Source: Frontier/LCP

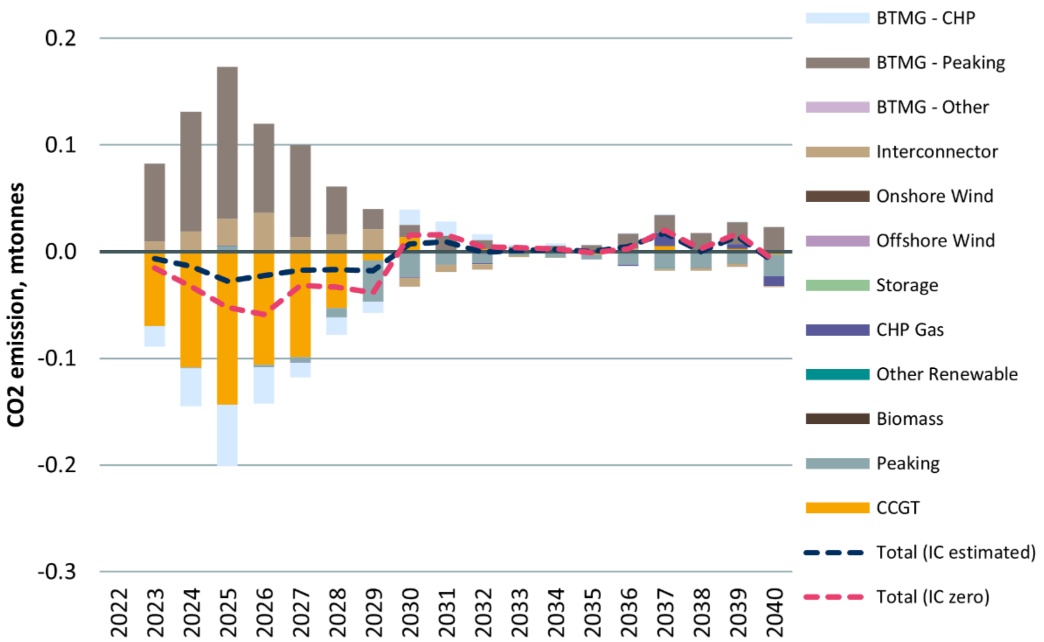
CO_2 Emissions

Figure 5 below shows the difference in annual CO_2 emissions between the Counterfactual and Factual scenarios.

The technology impacts are similar to those for generation, with an increase in emissions from BTM peaking generation and a decrease in emissions from BTM gas CHP, offset by decreases in CCGT and increases in interconnection.

Overall, with interconnector flows treated as zero-emission, total carbon emissions decrease in most years. However, the impacts are reduced if the emissions associated with IC flows are estimated.[8]

Figure 5 CO_2 Emissions (Factual – Counterfactual)



Source: Frontier/LCP

System Costs

Figure 6 below shows the change in modelled system costs between the Counterfactual and Factual scenarios.

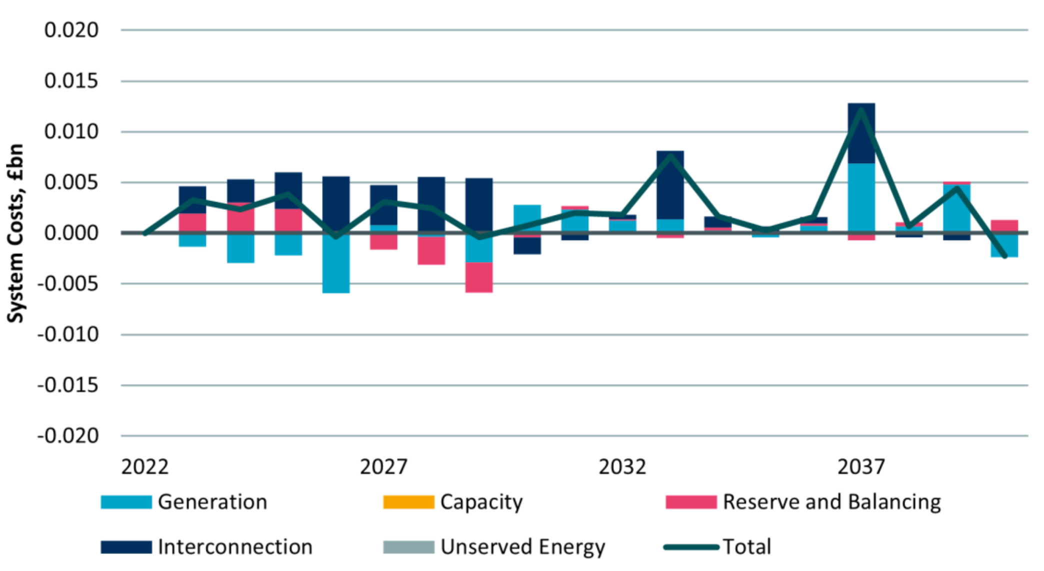
The modelling shows an increase in system costs in the factual scenario of about £30m (2022-2040 NPV, using a 3.5% social discount rate). This system cost increase is very small in the overall context of the system, and can largely be regarded as negligible and within the margin of error (in terms of both uncertainty in input assumptions and modelling accuracy).

The increase in costs is a result of less efficient dispatch due to the distortion created by the increased BSUoS benefit for BTMG in some periods. The inefficiency caused by an increase in distortion during peak periods (and hence

[8] Estimated in the modelling based on assuming the interconnector flows have the same carbon intensity as the nearest domestic generator within the GB merit order.

increase in BTM peaking generation who benefit from a fixed charge), outweighs the benefit from lowering the distortion in off-peak / overnight periods.

Figure 6 System Cost (Factual – Counterfactual)



Source: Frontier/LCP

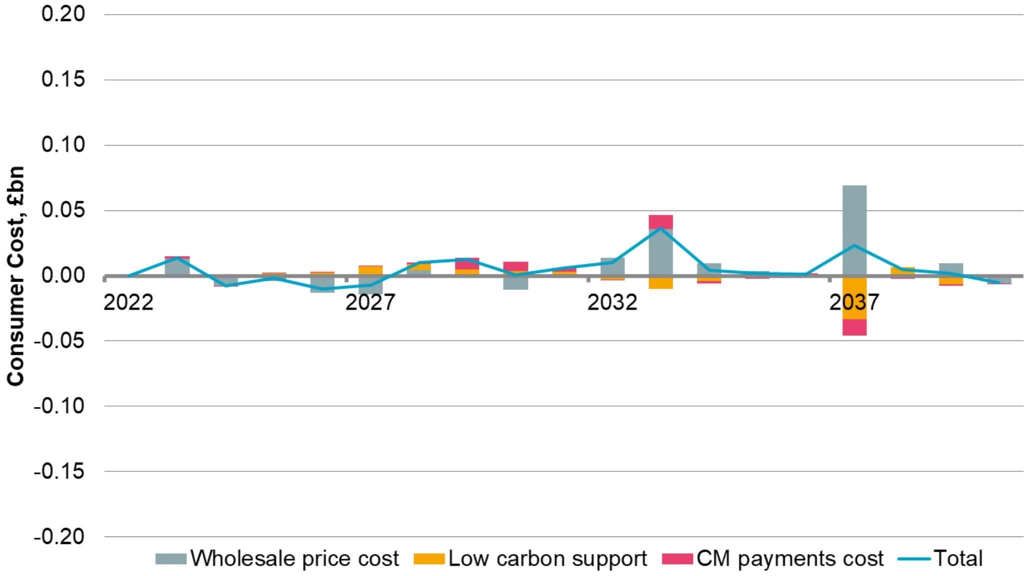
Consumer Cost

Figure 7 below shows the change in modelled consumer costs between the Counterfactual and Factual scenarios.

The proposed reform results in an increase in consumer costs of £60m (2022-2040 NPV, 3.5% discount rate). This consumer cost increase is very small in the overall context of the system, and can largely be regarded as negligible and likely to be well within the margin of error (in terms of both uncertainty in input assumptions and modelling accuracy).

The most significant impacts are from wholesale price costs, due to periods where the dispatch of BTMG affects the overall market price. We have assumed that there is no net impact on consumers overall due to BSUoS costs. This is because we have assumed the fixed charges in the factual scenario are set such that they recover the same total amount as the variable charges in the counterfactual.

Figure 7 Consumer Cost (Factual – Counterfactual)



Source: Frontier/LCP

2.4.1 Overview of system modelling results

Based on the system modelling results set out in this section, the moving of BSUoS from a variable charge to a fixed charge (in both cases fully recovered from suppliers) results in a small increase in overall system and consumer costs. These increases are very small in the context of the overall system, and we would expect these to be well within the margin of error for modelling of this type.

The tables below summarise the change in the system and consumer costs estimated in the system modelling between the Counterfactual and Factual scenarios over the 2022 to 2040 period.

Figure 8 Total Cost Change, 2022-2040, £2020 real

FES scenario	System cost (£bn)	Consumer cost (£bn)
Consumer Transformation	+0.04	+0.09

Source: Frontier/LCP

Figure 9 NPV of Total Cost Change, 3.5%, 2022-2040, £2020 real

FES scenario	System cost NPV (£bn)	Consumer cost NPV (£bn)
Consumer Transformation	+0.03	+0.06

Source: Frontier/LCP

3 DISTRIBUTIONAL IMPACTS

In this section, we estimate the bill impacts of moving from a counterfactual with a variable, half-hourly BSUoS charge (that fully recovers BSUoS costs from demand) to a fixed ex ante charge (that fully recovers BSUoS costs from demand) on 14 illustrative customer profiles.

For this analysis, we apply the same methodology that we outlined in our recent report on the Wider System and Distributional impacts of Recovering Balancing Services Costs from Demand.[9] We also assess the impacts for the same user groups we considered in our previous analysis. More detail on the methodology can be found in section 3.1 of our previous report and more detail on the user groups can be found in section 3.2 of our previous report.

We assume that overall costs are not affected by the change and hence over the course of a fix period, total BSUoS will be unchanged. However, introducing a fixed charge will mean moving from a charge that has daily shape to one that is flat across the day (as shown in Figure 3 above). In the counterfactual, BSUoS costs in £/MWh terms are typically around 3 times as large during their night time peak (approximately 3 am to 6 am) as they are in most day time hours. Therefore, the introduction of a fixed charge will have the impact of reducing night-time BSUoS costs significantly, whilst increasing costs during the day. As a result, those customers that consume a large share of their electricity overnight benefit from a reduced cost whilst those whose consumption is mainly during the day see an increase.

Figure 10 shows the consumption of our 14 illustrative customer profiles and the share of their consumption that falls between 11 pm and 7 am, when BSUoS charges are highest in the counterfactual.

[9] Available here: https://www.ofgem.gov.uk/publications/reform-bsuos-charges-analysis-proposal-remove-bsuos-generation

Figure 10 Net demand and overnight consumption share for each consumer archetype[10]

User group	Annual net demand (kWh)	Share of overnight consumption*
1. Domestic – Low consumption	1,800	21%
2. Domestic – Medium consumption	2,900	13%
3. Domestic – High consumption	4,300	16%
4. Domestic – High Economy 7	7,100	25%
5a. Domestic – Medium Solar PV	2,055	36%
5b. Domestic – Medium Solar PV with storage	1,148	43%
6. Domestic – Medium Electric vehicles	4,170	34%
7. Domestic – Heat pumps	5,447	21%
8. Commercial – Low consumption	10,000	9%
9. Commercial – High with onsite generation/storage	8,312	16%
10. Commercial – High without onsite generation/storage	25,000	10%
11. Commercial – Light industrial HV-connected	5,000,000	25%
12. Industrial – EHV-connected without onsite generation/demand management	50,000,000	33%
13. Industrial – T-connected without onsite generation/demand management	100,000,000	33%

Source: LCP / Frontier

*Note: * overnight consumption is defined as consumption in the period 11 pm to 7 am*

User groups 1-7 represent domestic users, which in aggregate account for around 35% of total consumption, whilst user groups 8-13 represent non-domestic users, which in aggregate account for around 65% of consumption. See Figure 28 below

The percentage of overnight consumption can vary from 43% in the case of Domestic customers with Solar PV and storage, down to 9% in the case of small commercials.[11]

3.1 User Group Impacts

Figure 11 to Figure 14 below show the annual bill impacts for our 14 customer profiles using a six month fixed period as the example.[12] Detailed results providing the breakdown of annual bill impacts by cost item are presented separately for each user group type:

- Domestic customers;

10 For more detail on the customer archetypes, please see Frontier Economics (2021) Wider System and Distributional Impacts of Recovering Balancing Services Costs from Demand, in particular Annex A. Accessible here: https://www.ofgem.gov.uk/sites/default/files/2021-07/CMP308_Wider%20System%20and%20Distributional%20Impacts%20of%20Recovering%20Balancing%20Services%20Costs%20from%20Demand_FINAL%20STC%20300621.pdf

11 A flat profile has 33% of consumption in the 11pm to 7am period.

12 Shorter or longer fixed periods would also remove the daily shape in BSUoS observed in the counterfactual. Therefore, these results are likely to be representative of the impacts even if longer or shorter fixed periods were modelled.

- Domestic customers with low carbon technologies;
- Commercial customers; and
- Industrial customers.

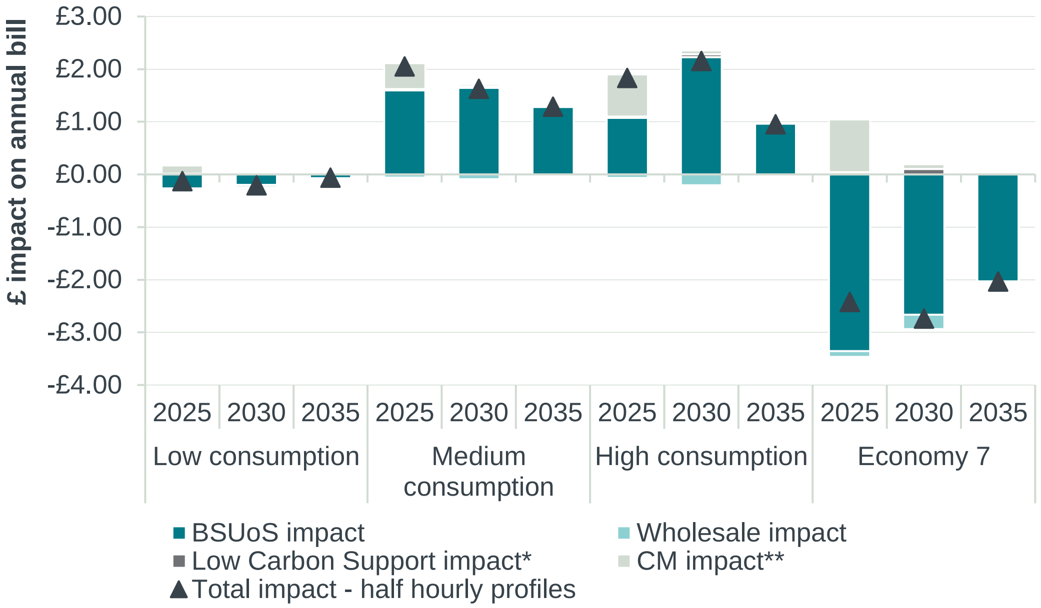
The principal impact is driven by the changes in BSUoS incidence described above, although there are some smaller impacts from changes to the capacity markets and wholesale prices. The overall impact is signified by the black triangle.

In Section 3.1.5 we provide an aggregated summary of the impacts for each customer profile on a £/MWh basis to allow for a side by side comparison of the customer profiles controlling for the wide disparity in annual consumption between them.

3.1.1 Domestic customers

Figure 11 shows the modelled impact on typical domestic customers without low carbon technologies.

Figure 11 Annual bill impact – domestic customers



Source: Frontier/LCP
Note: For customers with low consumption, the modelling shows a net decrease in bills equivalent to 1%-2% of their counterfactual BSUoS costs. For customers with medium and high consumption, the net impact is an increase in bills equivalent to 5%-11% of their counterfactual BSUoS costs. The net impact for Economy 7 customers is a decrease in bills equivalent to 5%-6% of their counterfactual BSUoS costs.

Overall the impacts on these customer groups are small. On average, over 2025-2035 relative to a counterfactual of implementing only CMP308, our modelling suggests that BSUoS costs will:

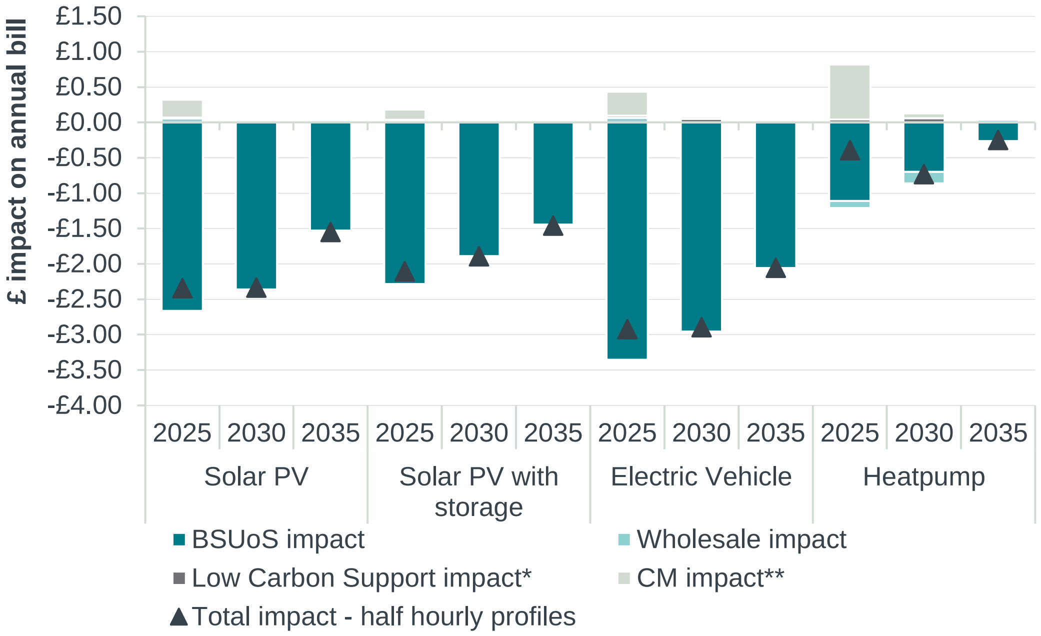
- Reduce by £0.13 per annum for low consuming customers (£0.07/MWh);
- Increase by £1.66 per annum for medium consuming customers (£0.57/MWh);
- Increase by £1.65 per annum for high consuming customers (£0.38/MWh); and
- Reduce by £2.40 per annum for Economy 7 customers (£0.34/MWh).

Economy 7 customers benefit relative to the other groups because a higher proportion of their consumption is at night time.

3.1.2 Domestic customers with low carbon technologies

Figure 12 shows the modelled impact on domestic customers with low carbon technologies.

Figure 12 Annual bill impact – Domestic customers with low carbon technology



Source: Frontier/LCP

Note: For domestic customers with Solar PV, the modelling shows a net decrease in bills equivalent to 13% -16% of their counterfactual BSUoS costs. For customers with Solar PV and storage, the net impact is a decrease in bills equivalent to c. 20% of their counterfactual BSUoS costs. For customers with Electric Vehicles, the net impact is a decrease in bills equivalent to c. 10% of their counterfactual BSUoS costs. The net impact for domestic customers with heatpumps is a reduction in bills equivalent to 1%-2% of their counterfactual BSUoS costs.

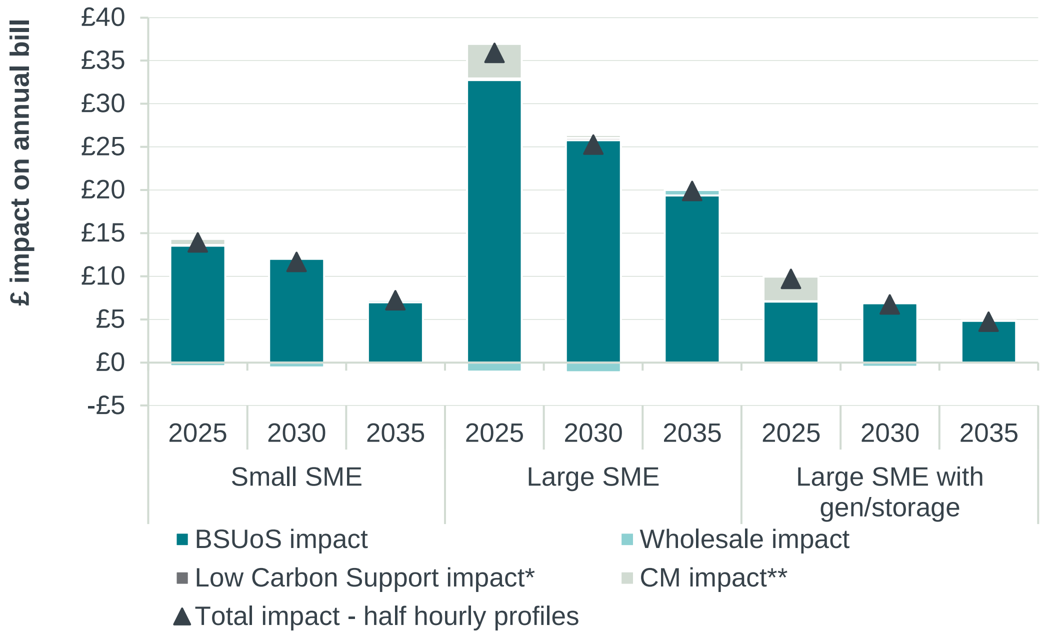
The low carbon technologies push a higher proportion of these customers' consumption towards night time, either by increasing night time consumption (in the case of EVs and heat pumps) or reducing day time consumption (in the case of solar PV). Therefore all of these customers benefit more from a fixed BSUoS rate relative to the counterfactual. Taking the average from 2025-2035, our modelling suggests that annual BSUoS costs reduce by:

- £2.08 for Solar PV customers without storage (£1.01/MWh);
- £1.82 for Solar PV customers with storage (£1.58/MWh);
- £2.62 for Electric Vehicles customers (£0.63/MWh); and
- £0.46 for Heat Pumps customers (£0.08/MWh).

3.1.3 Commercial customers

Figure 13 shows the modelled impact on commercial customers.

Figure 13 Annual bill impact - Commercials



Source: Frontier/LCP

Note: For small SME customers, the modelling shows a net increase in costs equivalent to 18% -26% of their counterfactual BSUoS costs. For Large SME customers, the net impact is an increase in bills equivalent to 20% - 26% of their counterfactual BSUoS costs. For Large SME customers with generation/storage, the net impact is an increase in bills equivalent to 13% - 20% of their counterfactual BSUoS costs.

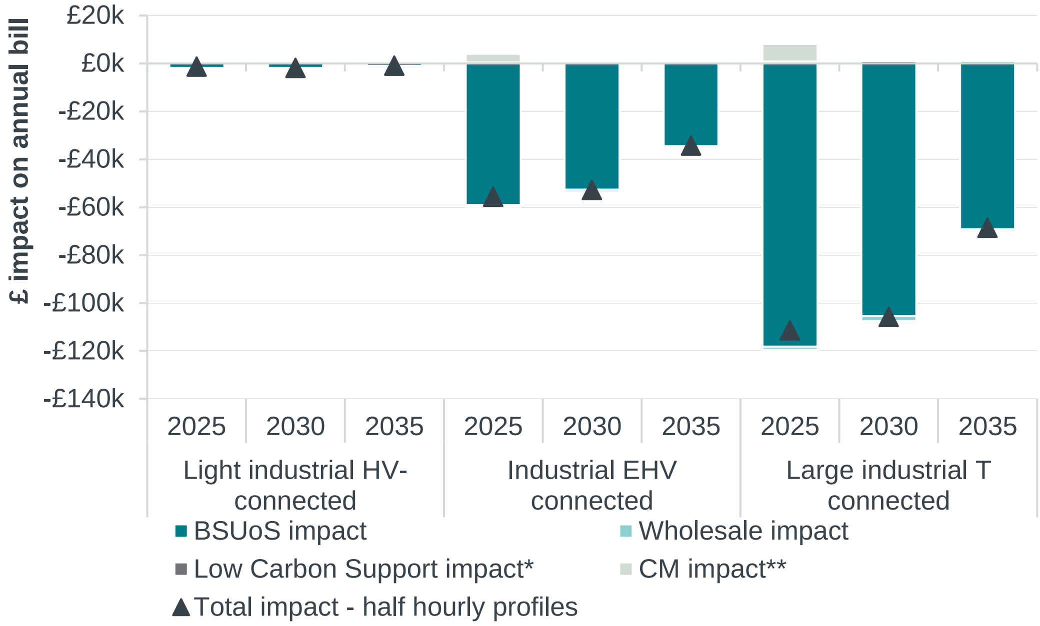
Commercial customers' consumption is far higher during the day, and as a result, these groups would face higher overall costs as a result of BSUoS costs moving from being predominantly at night time – where they avoid it – to being spread evenly throughout the day. Taking the average from 2025-2035, our modelling suggests that annual BSUoS costs will increase by:

- £10.93 for Small SME customers (£1.09/MWh);
- £27.01 for Large SME customers (£1.09/MWh); and
- £7.06 for Large SME customers with onsite generation and storage (£0.85/MWh).

3.1.4 Industrial customers

Figure 14 shows the modelled impact on large industrials.

Figure 14 Annual Bill impact - Industrials



Source: Frontier/LCP

Note: For light industrial HV-connected customers, the modelling shows a net decrease in bills equivalent to 4% - 6% of their counterfactual BSUoS costs. For Industrial EHV-connected customers, the net impact is a decrease in bills equivalent to 12% - 15% of their counterfactual BSUoS costs. For Large industrial T-connected customers, the net impact is a decrease in bills equivalent to 12% - 15% of their counterfactual BSUoS costs.

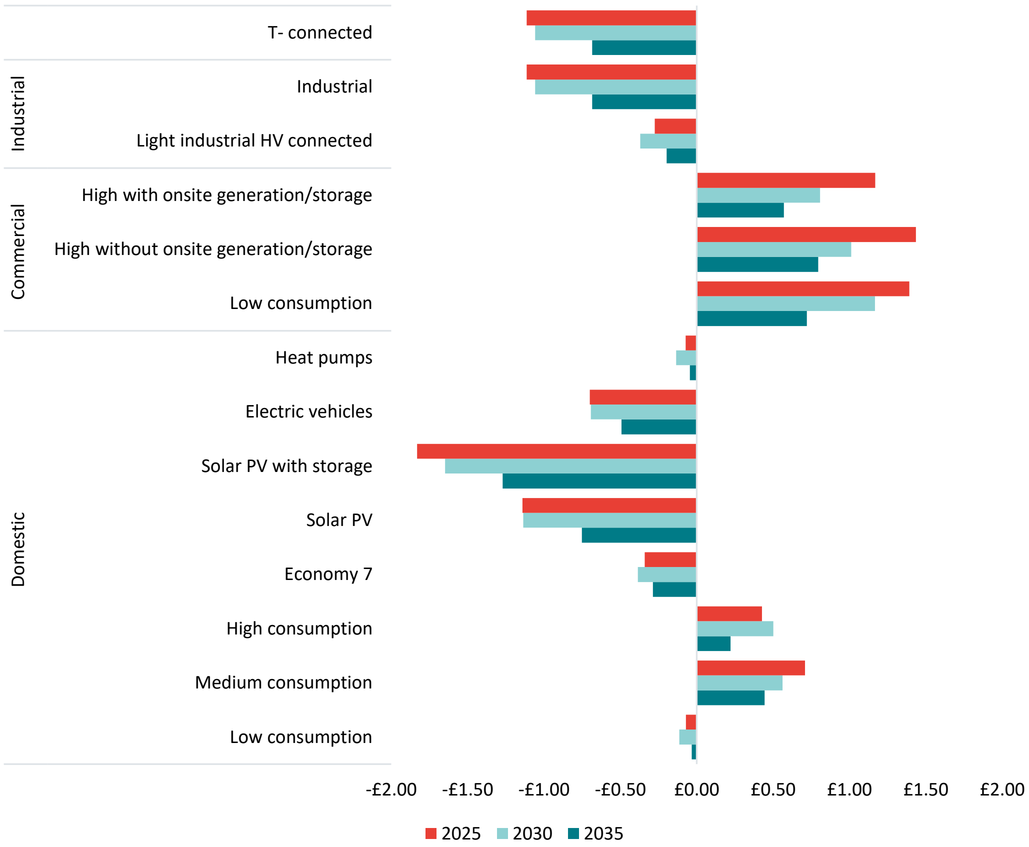
Their consumption is skewed more towards the night time than the average profile, especially in the case of EHV and T Connected customers, for whom we assume a flat profile. As a result, taking the average from 2025-2035, our modelling suggests that annual BSUoS costs will reduce by:

- £1,405 for Light industrial HV-Connected customers ((£0.28/MWh);
- £47,609 for Large, EHV-connected customers without onsite generation (£0.95/MWh); and
- £95,219 for Large, T-connected customers without onsite generation (£0.95/MWh).

3.1.5 Summary

Figure 15 below details the modelled impact of a shift to fixed BSUoS charges in £/MWh terms.

Figure 15 Impact of introducing 6 month fix by customer group (£/MWh)



Source: Frontier/LCP

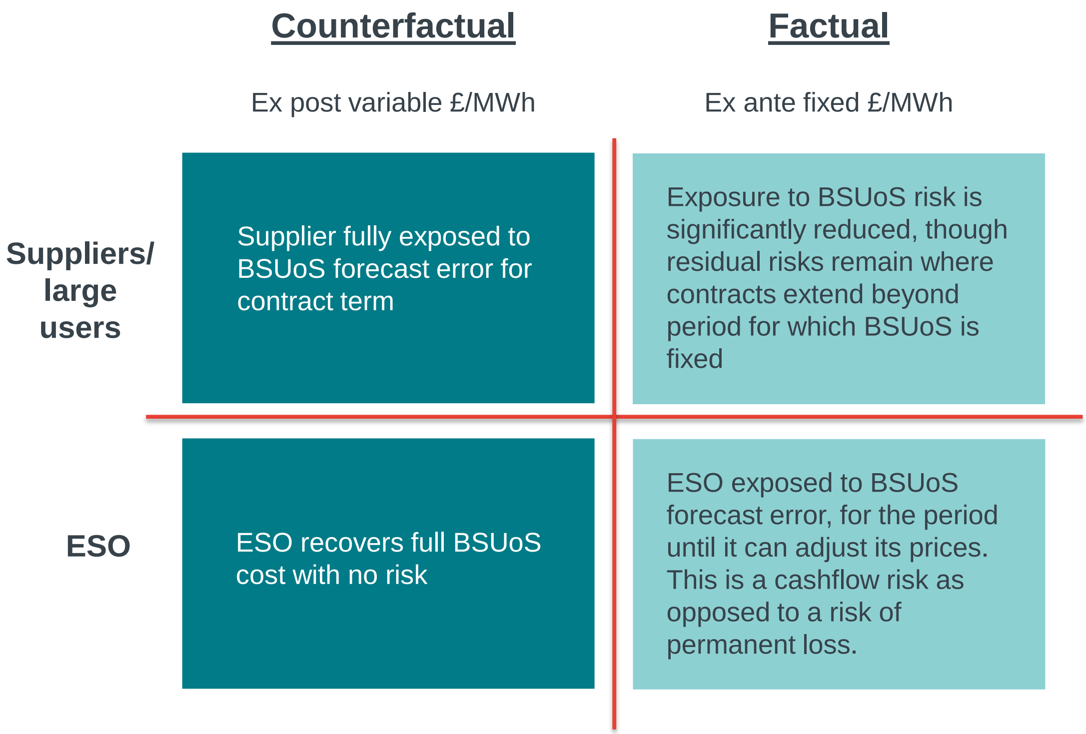
Due to their relatively high day time consumption, commercial customers without onsite generation and storage see the largest increases in their bills of up to £1.44/MWh in 2025. Conversely, domestic customers with solar PV and storage see a reduction of £1.83/MWh in their overall costs. Industrial customers with flat load profiles also see a reduction in BSUoS costs, although this is smaller in £/MWh terms.

4 RISK PREMIA ANALYSIS: APPROACH

On the basis of CMP308 alone, BSUoS would be fully recovered from demand by a variable charge set ex post. Therefore, all BSUoS forecasting risk will sit with suppliers (or end users if they agree passthrough contracts with their suppliers). Under CMP361 BSUoS would be fixed in advance for suppliers and end users. This would allow suppliers to more accurately price in BSUoS costs into customer contracts. The BSUoS forecasting risk would shift to the ESO, resulting in cashflow risk management costs for the ESO that ultimately need to be recovered from customers.

This reallocation of risk is illustrated in Figure 16 below.

Figure 16: BSUoS forecast risk in the Factual and Counterfactual



Source: Frontier/LCP

Our analysis seeks to estimate the benefit from the reallocation of forecasting risk to the ESO under a range of options for different lengths of fixed and notice periods.

The Second Balancing Services Charges Task Force concluded that a total fixed and notice period of 14-15 months was a reasonable compromise between the ESO and suppliers/customers but did not conclude on an appropriate split between the fixed period and the notice period.[13] Given this, we consider three options that align directly with the Task Force's conclusions. We also consider one further option to illustrate the impact of longer fixed and notice periods. The options we consider are:

[13] http://www.chargingfutures.com/media/1477/second-balancing-services-charges-task-force-final-report.pdf , bottom of page 35

- 12 month notice, 3 month fixed (12N - 3F)
- 9 month notice, 6 month fixed (9N - 6F)
- 3 month notice, 12 month fixed (3N - 12F)
- 12 month notice, 12 month fixed (12N - 12F)

The estimated impact is calculated as the difference in risk management costs (risk premia incurred or charged by suppliers and the ESO) between the factual and the counterfactual scenarios. In order to estimate this, the analysis needs to assess the size of BSUoS forecast error risk, and supplier and ESO costs of managing BSUoS forecast error risk in the counterfactual and factual scenarios.

In the counterfactual, suppliers set prices for contracts for fixed periods of time and bear BSUoS forecast error risk, as they do with many other costs which are uncertain at the point at which they agree prices. Therefore, as with any other risk, suppliers must have sufficient capital available to ensure that they can continue their business if this loss occurs. Holding this risk capital represents a cost for suppliers because it means that the capital cannot be deployed productively elsewhere in their business or elsewhere in the economy.

If the risk does materialise (i.e. if a supplier did under forecast actual BSUoS for a period) then the supplier will suffer a hit to profitability for that period. Since suppliers operate in a competitive market, there are no contractual or regulatory mechanisms that ensure the profitability hit can be recovered in future periods. However, providing that BSUoS forecasting is unbiased then the profitability hit in one period will be offset by gains in other periods where BSUoS costs are actually lower than forecast. Therefore, the risk capital is only required until the BSUoS forecast risk crystalises.

In the factual scenarios, suppliers still bear some BSUoS forecast risk (e.g. in relation to long contracts that run beyond the end of the currently announced fixed period). However, much of the risk is passed to the ESO because the ESO will have set a fixed BSUoS charge, but a volatile BSUoS cost base.[14] Therefore, in the factual the ESO needs some risk capital to ensure that its business can continue if BSUoS costs turn out to be higher than forecast. Regulation of the ESO's activity should enable the ESO to recover any BSUoS under recovery by adjusting charges in future periods. As a result, whilst suppliers are more likely to provide risk capital via equity, the ESO is more likely to be able to fund risk capital with debt (i.e. treat the risk as purely a cashflow risk). Regulation of the ESO should allow it to recover the efficient cost of holding risk capital. Therefore, the total costs faced by suppliers linked to BSUoS forecast error risk can be calculated as the sum of direct supplier costs and ESO costs.

We set out the detail of the approach taken to quantify risk management costs in the factual and counterfactual scenario under six steps:

- First, we analyse historical BSUoS data to understand historical variability in BSUoS costs.

[14] The ESO will also face a small uncertainty over the BSUoS revenues it will collect because although the charge is fixed the volumes that it is collected on are subject to uncertainty. However, the uncertainty over volumes is very significantly less than the uncertainty over BSUoS costs.

- Second, we generate a distribution of forecast error calibrated using historical BSUoS outturn data.
- Third, we define some assumptions relating to the way in which suppliers and ESO might hold capital to manage forecast error risk.
- Fourth, we estimate the risk capital required by the ESO and suppliers under different fixed and notice period options in the counterfactual and factual scenarios.
- Fifth, we determine the cost of capital that suppliers and the ESO will incur for the risk capital that they hold.
- Finally, we aggregate the cost of risk capital for suppliers and ESO to understand the total industry cost taking into account the mix of contracts at the industry level.

4.1 Approach Steps

4.1.1 Analysis of historical BSUoS data

Ideally, we would have considered the forecast error implied by *historical* forecasts and historical outturn BSUoS. While we note that the ESO had previously produced a number of forecasts,[15] these forecasts were not produced with the objective of setting an ex-ante BSUoS charge. Therefore, comparing these historical forecasts to historical outturn BSUoS would not be appropriate for estimating future BSUoS forecast error risk. This position was confirmed in our discussions with the ESO.

As a first step, we therefore analysed historical BSUoS data to understand the variability of outturn BSUoS to date. We received preliminary analysis conducted by the ESO regarding BSUoS variability, and considered the same data for our analysis. The historical data provided to us include daily outturn BSUoS costs and volumes, covering the period 1st of April 2015 - 28th of February 2021.[16] We exclude the data covering 2020 and 2021 to abstract from the effects of Covid-19,[17] and deflated the data using the RPI measure of inflation to make BSUoS costs over time more comparable.

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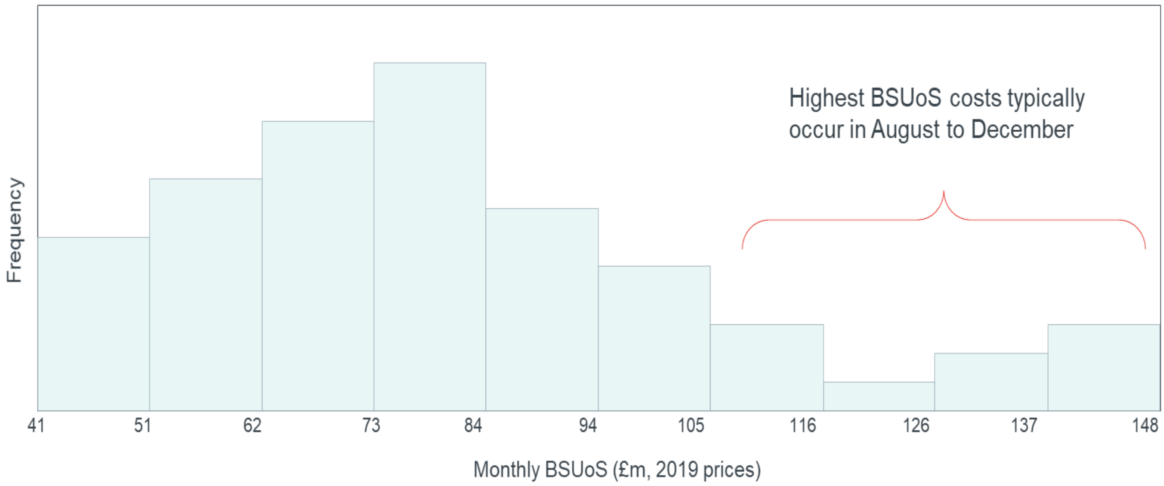
15 For example, we note that there are a number of historical forecasts available including a monthly forecast which has been produced since 2014, accessed here https://data.nationalgrideso.com/balancing/monthly-balancing-services-use-of-system-bsuos-forecast-reports?from=0#resources

16 We note that half-hourly historical outturn BSUoS charges in £/MWh terms are accessible here, and these are available from 2001: https://www.nationalgrideso.com/industry-information/charging/balancing-services-use-system-bsuos-charges. Our analysis of this data indicates a change in the structure of the data in FY2014/15. Furthermore, we note that this data is published on a legacy version of the ESO's website, and the underlying methodology for this data is not clear. For these reasons, we have chosen to consider the dataset provided by the ESO for our analysis.

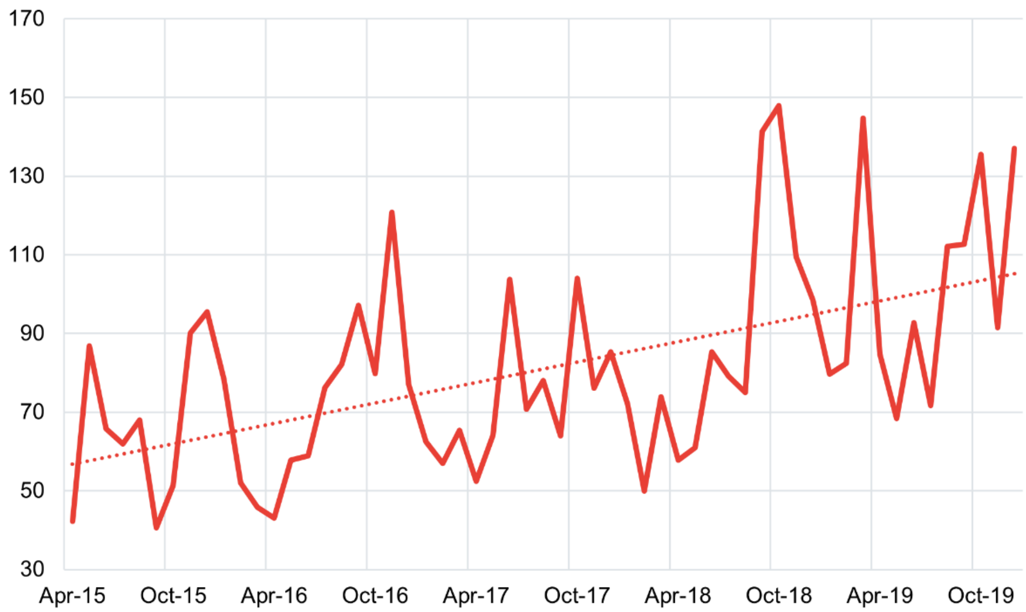
17 Ofgem noted that the period from March to July 2020 has seen balancing costs which are 39% higher than the ESO expected. See for example: https://www.ofgem.gov.uk/publications/open-letter-our-review-high-balancing-costs-during-spring-and-summer-2020

Figure 17: Histogram of monthly BSUoS costs (£m, Jun'19 prices)



Source: Frontier/LCP analysis of NG ESO data

Figure 18: Monthly BSUoS charges (£m, Jun'19 prices)



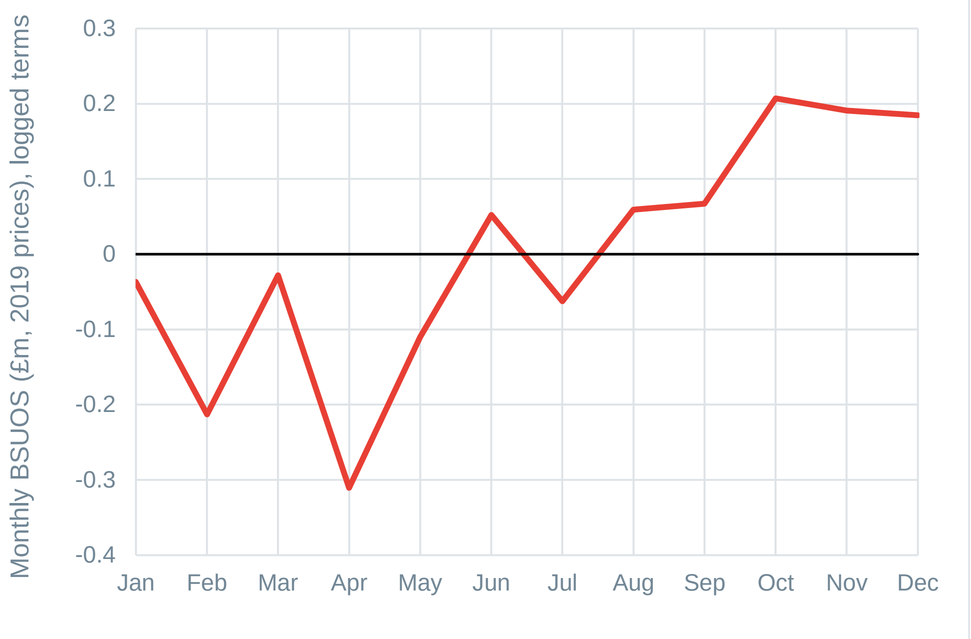
Source: Frontier/LCP analysis of NG ESO data

The historical data show that:

- BSUoS costs have a significant positive skew, i.e. there is a reasonable probability of outcomes where outturn BSUoS is positive and the distribution has a 'long tail' on the right
- high BSUoS costs generally occur between August and December inclusive and
- BSUoS costs have increased over time.

Given the upward trend in BSUoS, a further step is needed to confirm whether BSUoS is consistently higher in the months of August – December. We compared the data to a simple time trend and checked whether the residuals were greater than zero for these months.[18] Figure 19 shows the residuals by month, and it is clear that the residuals are consistently above zero in the months of August to December inclusive, and consistently below zero for the other months. This indicates a seasonal pattern in BSUoS costs, even after we account for the general upward trend in BSUoS observed in Figure 18.

Figure 19: Average residuals (by month) of a linear regression with time trend, taking logged values of monthly BSUoS charges



Source: Frontier/LCP analysis of NG ESO data

Note: We have considered the log transformation of BSUoS data for the regression analysis as the distribution of BSUoS costs was approximately lognormal. Transforming the BSUoS data for the regression analysis ensures that the assumptions of the OLS model are not violated.

In addition to the seasonality of the BSUoS costs, we also note that there is some degree of serial correlation in historic BSUoS i.e. if BSUoS costs are high in the current month, it is likely to be high in the subsequent month. The same observations can be made for the months with low BSUoS costs.

These findings inform the next step of our analysis.

4.1.2 Generating a distribution of BSUoS forecast error

In this step, we specify a Monte Carlo simulation (MCS) and use it to produce distributions of BSUoS forecast error for each of the contract lengths we consider under the counterfactual and factual scenarios.

The MCS was calibrated with three assumptions:

- First, the monthly variability of BSUoS forecast error;
- Second, serial correlation of BSUoS forecast error across months; and

[18] Residuals are defined as the outturn BSUoS less the predicted values from the linear regression

- Third, the forecast mean level of BSUoS at a point in time. In this case, we consider the forecast BSUoS in 2025 in the FS1 scenario.[19]

Calibration of the MCS for variability and serial correlation in BSUoS forecast error

To estimate the monthly variability in BSUoS forecast error,[20] we specified a simple BSUoS forecasting model based on a time trend and a seasonal dummy, which partially explains BSUoS over time. The regression was specified as follows:

$$Log(BSUoS) = constant + \beta_1(time\ trend) + \beta_2(seasonality\ dummy) + error$$

Where:

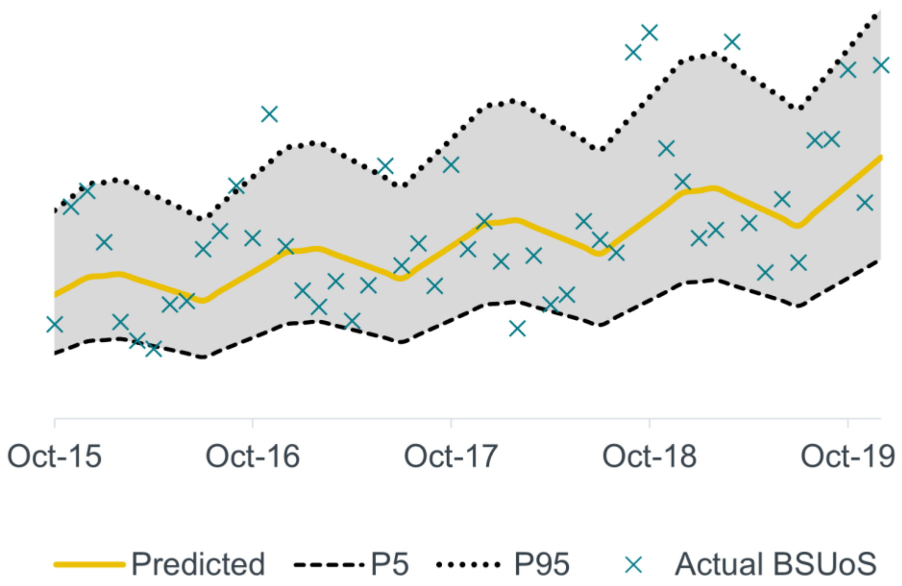
Time trend	a variable that indexes each month (increasing with months)
Seasonality dummy	a variable that is equal to 1 if the month is August - December inclusive, otherwise zero

Using this monthly prediction model allowed us to arrive at an initial estimate of BSUoS forecasting error. We considered the variance of the residuals (i.e. the difference between the outturn BSUoS and predicted values using our simple model). We were able to estimate the range of forecast error at the P5 and P95 level (i.e. the forecast error all but the most extreme 10% of the observations of actual BSUoS cost). This is represented in a stylised fashion in Figure 20.

[19] This is the factual scenario from our CMP308 analysis that applies CMP308 individually and does not include the impact of CMP361.

[20] We consider monthly and weekly models, but selected the monthly models for ease of aggregation to annual values. We did not observe a large difference in the regression performance of the weekly and monthly models.

Figure 20: Stylized representation of a simple explanatory model of BSUoS



Source: Frontier/LCP

We then factored in the observed serial correlation in historic BSUoS by considering the correlation of the lagged residuals, i.e. we estimate the level of serial correlation *after* accounting for the trend of increasing BSUoS over time, and seasonality of BSUoS costs. This is necessary as the Monte Carlo process is used to simulate forecast errors over different lengths of time (e.g. over 1 year, 2 years etc.). Failing to take into account serial correlation would have resulted in an *under-estimate* of BSUoS variability and thus an under-estimate of the risk that parties have to bear, since it would treat the individual months as independent uncorrelated events.

Based on this, we estimate that the monthly standard deviation of BSUoS forecast error is 23%[21] of the mean BSUoS and the corresponding degree of serial correlation in BSUoS forecast error is 11%.[22] In absolute terms, the monthly standard deviation in our model is 23% multiplied by the mean estimate for BSUoS of £163m per month (£1.96bn per annum), which we derive from LCP's 2025 forecast under Consumer Transformation.

MCS of BSUoS forecast error

Based on these estimates, we then use an MCS to simulate the forecast error distribution for various durations of exposure. For example, in the counterfactual, if a supplier signs a 1-year fixed contract with a final demand customer, the supplier will face 1 years' worth of BSUoS forecast error risk. In this particular case, the MCS simulates each of the relevant 12 months 10,000 times, and these are aggregated into a 1-year distribution of BSUoS forecast error risk accounting for serial correlation.

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[21] We considered a monthly prediction model. The 23% relates to the standard deviation of the regression residuals, which are also expressed on a monthly basis

[22] The first-order autocorrelation coefficient is 0.11

Over longer time periods, the £m variation in BSUoS is larger in absolute terms but reduces when expressed as a percentage over the mean BSUoS cost as shown in Figure 21. This is because, although we assume some serial correlation, high costs during some months may be cancelled out by low costs during others.

Figure 21 Modelled BSUoS mean and P95 values over different timescales

Exposure length	Mean	P95	Difference	Percent difference
1 month	£163,464,048	£232,672,453	£69,208,405	42%
3 month	£490,395,650	£613,618,349	£123,222,698	25%
6 month	£980,791,690	£1,153,098,681	£172,306,992	18%
1 year	£1,961,584,072	£2,206,605,491	£245,021,419	12%
2 year	£3,923,173,008	£4,263,784,922	£340,611,913	9%
3 year	£5,884,757,518	£6,304,112,627	£419,355,109	7%

Source: *Frontier/LCP*

Note: *The mean value of BSUoS scales linearly with time. Whilst the difference between the mean and P95 value increases for longer time periods, it decreases as a percentage of the mean.*

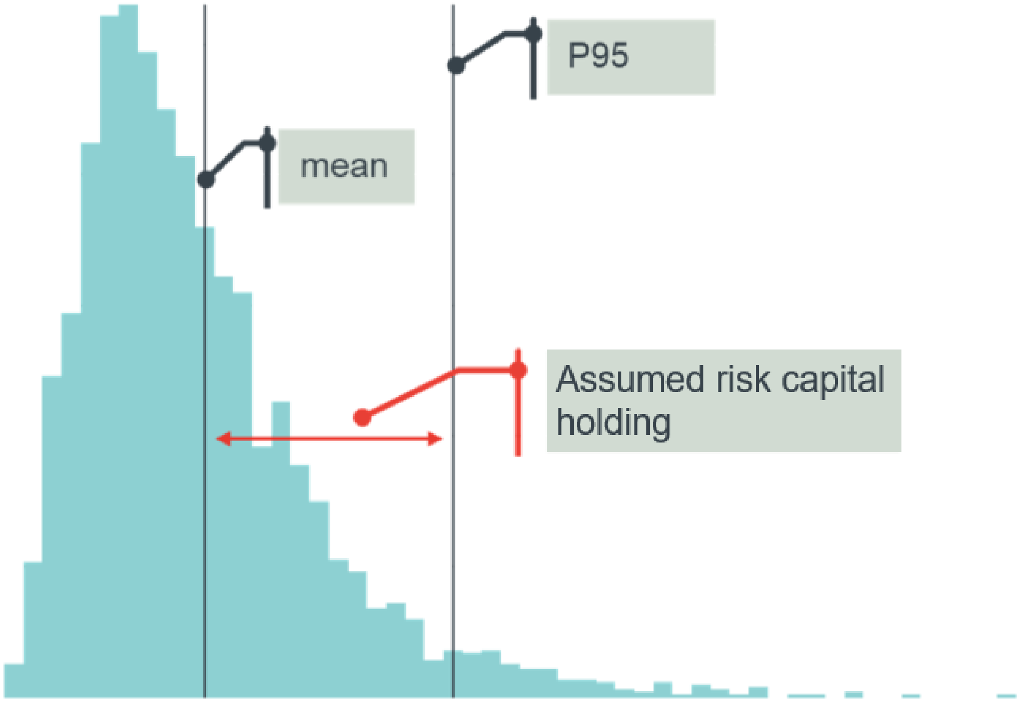
4.1.3 Assumptions in relation to risk management capital

We make three key assumptions as to the way ESO and suppliers hold capital to manage forecast error risk:

- First, we assume they are risk neutral in respect of the exposure provided that they have secured enough capital to meet their risk management strategy;
- Second, we assume that parties hold capital equal to the difference between their estimate of mean BSUoS and the point on the forecast error distribution set by their risk management strategy;
- Third, we assume that parties will hold sufficient capital to guard against all but the worst 5% of potential outcomes (i.e. at a P95 level). This is illustrated in the figure below. We note that in principle, it is possible to select other points on the distribution (e.g. P75 or P99 etc.), and that this choice affects the absolute level of costs and benefits derived from the quantitative analysis (although not the overall direction of the net benefits).[23]

[23] This would scale the final benefits up (if a P99 value is taken) or down (if a P75 value is taken)

Figure 22: Illustrative example of the assumed risk capital holding



Source: Frontier/LCP

It is worth noting that the level of risk capital holding will change over time for both suppliers and the ESO. For example, if a supplier has agreed a one year contract in the counterfactual, it will initially face one year's worth of BSUoS forecast error exposure, and must hold capital to cover all but the worst 5% of outcomes over the course of this year. However, after three months have passed, the outcome of these months is certain, and the supplier will only need to hold risk capital for the remaining nine months of the contract. The capital requirements will continue to fall until, after 11 months of the contract, the supplier will only require capital for one month's worth of exposure.

We assume that as time progresses, parties only hold capital to cover the uncertain future.

4.1.4 Estimating the risk capital required

The value at risk for the ESO and suppliers, and hence their capital requirements, varies substantially by scenario. For the ESO, there is no risk in the counterfactual while the risk in the four factual scenarios, varies depending on both the fix and notice period and the length of time since the most recent announcement.

For suppliers, the risk in the counterfactual varies depending on the length of the contracts agreed with end customers, and the amount of time remaining on that contract. In the factual scenarios, the risk depends further on:

- The length of the fix and notice period.
- The length of the contract agreed.

- The time of year it was agreed in relation to the fix and notice periods.

Risk capital in the counterfactual

We have assumed that in the counterfactual, the ESO faces no risk whatsoever, since it is able to fully recoup BSUoS costs from suppliers using an ex post charge.

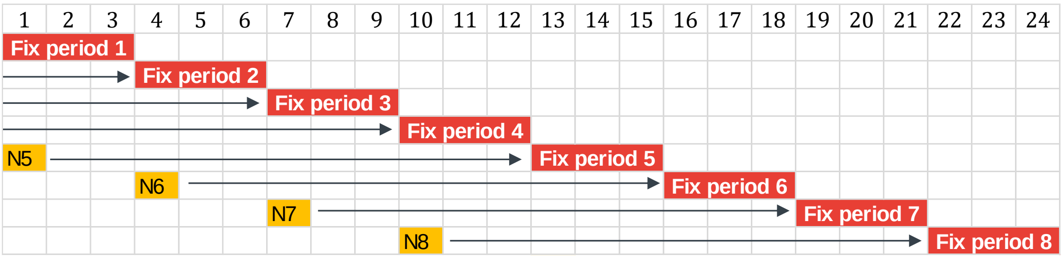
In contrast, we assume that suppliers are exposed to the risk of forecast error over the length of their contracts, and carry risk capital to cover this. Rather than modelling a mixed portfolio of contracts, we assess separately the risk of suppliers assuming they hold 6 month, 12 month, 24 month and 36 month contracts.

ESO capital in the factual

Under the different factual scenarios, the ESO must announce BSUoS charges on an ex ante basis and will face risk because the true BSUoS costs may differ from its forecast.

The ESO's capital requirements in the factual scenarios depend on the length of the fix and notice period and on the time since the most recent announcement. Figure 23 illustrates the timings of announcements that the ESO must make under the 12 month notice and three month fix factual scenario.

Figure 23 Timetable of announcements – 12 month notice; 3 month fix



Source: Frontier/LCP

At the start of month 1, four fixed charge levels have already been announced. The ESO announces the charges for fix period 5 and from that point on is exposed to the potential variance in BSUoS costs from this forecast during period 5 (months 13, 14 and 15). Therefore, in total the ESO faces uncertain costs over a 15 month period (the total of fix periods 1 to 5), and has to hold enough capital to cover the difference between the P95 value of BSUoS over 15 months and the mean value (which is covered by the charges set for these periods).

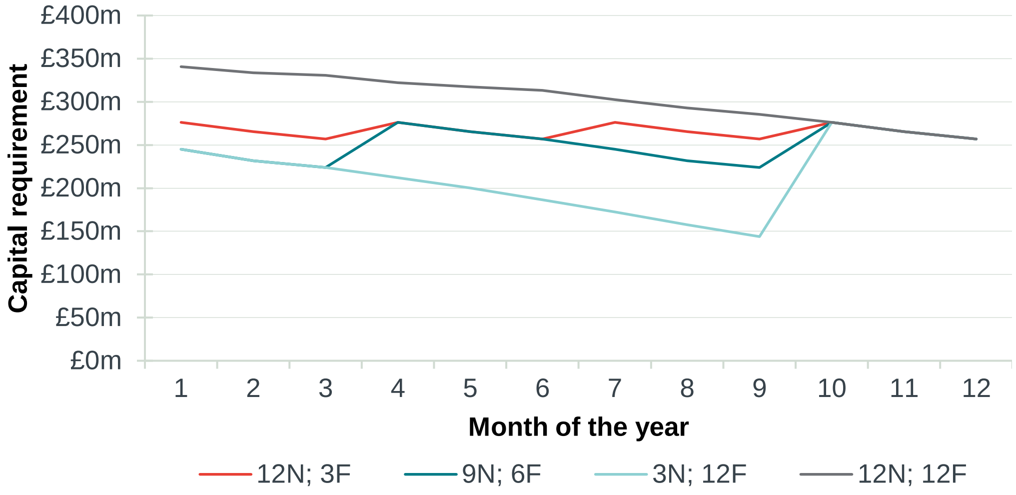
In month 2, the value of month 1's BSUoS costs is known and as a result the risk capital requirements reduce to 14 months: the remaining two months of fix period 1, plus all the uncertainty resulting from fix periods 2 – 5.[24] Similarly, in month 3, exposure reduces to 13 months. However, in month 4 the ESO announces fix period 6, taking its exposure back up to 15 months.

A similar logic applies to the ESO under the other factual scenarios. Figure 24 shows how the ESO's risk capital requirements vary for each of the four factual scenarios. In each case, the peak capital requirements are determined by the sum of the fix and notice periods, but with longer fix periods, there is a greater time

[24] Note that we are assuming that the ESO's fixed ex ante charges will be an unbiased forecast of true BSUoS. Therefore although BSUoS costs in month 1 may, in the event, be either above or below this forecast, leading to either under- or over-recovery, on average this value will be zero, and hence the ESO will be able to reduce the risk capital it must have access to.

between announcements and hence a bigger reduction in capital requirements in the interim.

Figure 24 ESO capital requirements – four factual scenarios



Source: Frontier/LCP

Note: The capital requirements in each period are the result of the period of uncertainty faced by the ESO (as described above), and the modelled variation in BSUoS over that time period. For example, in month 1 under the 12 month notice, 3 month fix scenario, the ESO faces uncertainty for the following 15 months. Their capital requirement will be the difference between the mean BSUoS cost over 15 months (£2.45bn) and the P95 BSUoS cost over this period (£2.73bn)

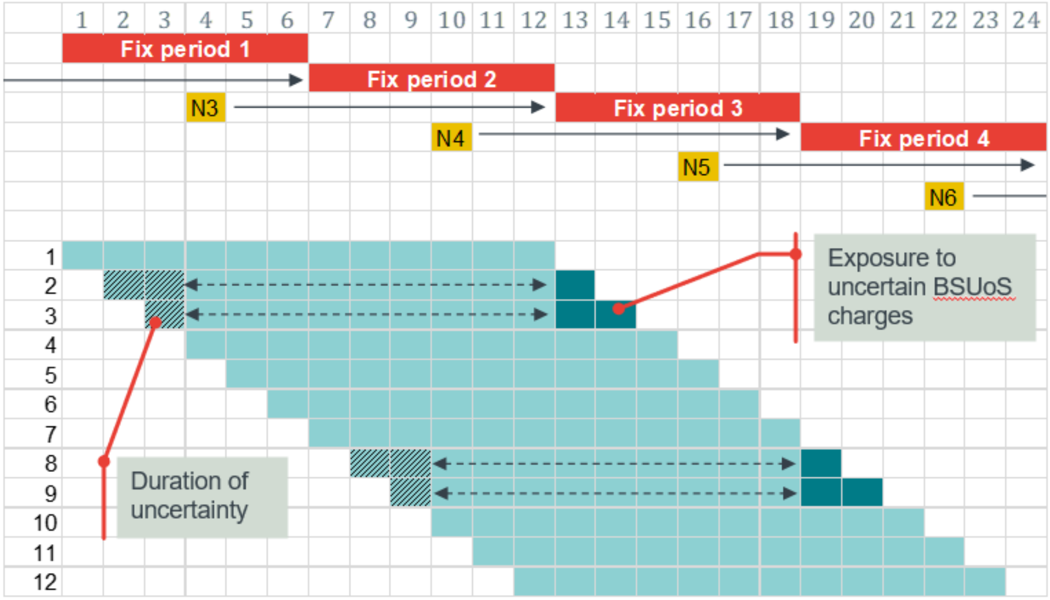
Supplier risk capital in the factual

To estimate suppliers' risk capital requirements there are some additional levels of complexity for each factual scenario. This is because:

- Suppliers sign contracts with different lengths; and
- Suppliers agree contracts with their customers throughout the year. Contracts may be agreed immediately after the ESO has announced the next fix period, shortly before the next announcement, or anywhere in between. This affects the uncertainty the supplier faces at the point the contract starts, as well as when this uncertainty is resolved.

Figure 25 below illustrates the uncertainty faced by suppliers under the 9 month notice, 6 month fix scenario and how it varies depending on when the contract starts, assuming that the supplier signs 12 month contracts with customers.

Figure 25 Supplier risk by contracted month



Source: Frontier/LCP

For 12 month contracts starting at the start of month 1, the supplier faces no risk because the contract will span fix periods 1 and 2, the BSUoS charges of which have already been announced. Therefore, the supplier can simply price the exact costs that the ESO has announced into their contracts with customers.

However, in the case of contracts starting in month 2, the final month of the contract will fall into fix period 3 which hasn't been announced at the point of agreeing the contract. Whilst the supplier will know their BSUoS cost for the first 11 months of the contract they will face uncertainty over BSUoS costs for the final month of the contract. In a similar way, contracts starting in month 3 will face uncertainty over two months of BSUoS costs. Periods for which there is uncertainty are shown by the striped squares in the figure.

The uncertainty that suppliers face with respect to BSUoS charges in fix period 3 come from two sources.

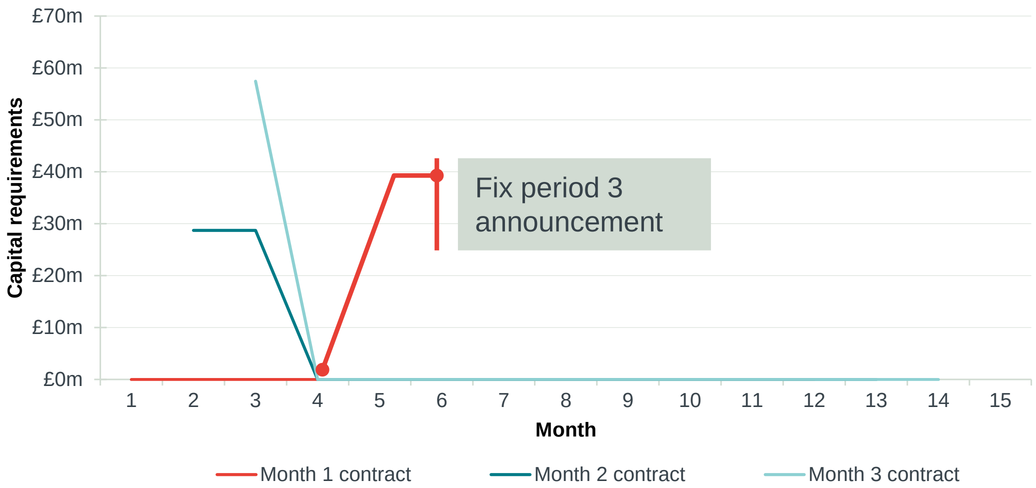
First, the ESO's fix period 3 charge depends on its forecast for true BSUoS costs during this period. Hence one form of uncertainty relates to the fact that the ESO's forecast, which it will announce in month 4, may differ from the supplier's expectation of this forecast. For the purpose of the analysis, we assume that the risk from this uncertainty is zero. Whilst in practice, this risk will not be zero, it should be considerably closer to zero than the risk for suppliers of forecasting actual BSUoS under the counterfactual.[25] Furthermore, if the ESO were to publish the methodology it would apply or provide regular forward guidance on likely BSUoS charges then suppliers should be able to make a good estimate of the forecast the ESO will make.

[25] In the counterfactual suppliers must estimate outturn BSUoS. Thus they are exposed to the full variability of the distribution of possible BSUoS costs. In the factual scenario, suppliers no longer need to forecast actual BSUoS costs, rather they must forecast the ESO's forecast of BSUoS costs. The ESO's forecast will be based on the expected value of BSUoS, which is effectively the mean of the distribution of possible BSUoS. Statistically, estimating the mean of a distribution is subject to significantly less error than forecasting actual outturn which is effectively a single random draw from the distribution.

Second, the fix period 3 charge also depends on the size of the 'K factor' which the ESO applies to adjust future charges to unwind any over or under recovery from previous fixed periods. We assume that the K factor that will apply when fix period 3 is announced will seek to unwind any cumulative over or under recovery that has accrued since the last notice of charges was issued six months previously. Hence the uncertainty relates to the variation in BSUoS risk over a six month period, which we model using our Monte Carlo framework.

We therefore assume that a supplier will hold enough capital to cover itself for the P95 forecast error related to fix period 3, multiplied by the fraction of the fix period to which it is exposed (contracts starting in month 1 will be exposed to 1/6th of fix period 3, while those starting in month 3 are exposed to 2/6ths). A supplier will only hold this until the announcement of fix period 3 in month 4, after which the fix period 3 charge is known with certainty. The resultant capital requirements are shown in Figure 26.

Figure 26 Capital requirements over time – 9 month notice, 6 month fix scenario – one year contracts agreed in months 1, 2 and 3



Source: Frontier/LCP

We assume that suppliers will conclude contracts evenly throughout the year. For example, in this scenario we account for both the eight months in which suppliers can agree a contract with no BSUoS risk whatsoever, and the four months where there is some risk as described above. We follow an equivalent logic for the other factual scenarios and for the different contract lengths we consider.

4.1.5 Determining the appropriate cost of capital

Companies will need to hold some capital to manage their exposure to BSUoS forecast error risk. Since this capital could have been used elsewhere in their business, this represents an opportunity cost that should be valued at an appropriate cost of capital for those companies.

For suppliers, we note that Ofgem has previously stated a nominal WACC range of 8.5% - 20%, and has suggested that the industry weighted average (given suppliers' market shares) is 9.6% per annum nominal.[26,27] The low end of the range represents large suppliers, and the high end of the range is derived from the cost of capital of small suppliers. We have considered the industry average of 9.6% in our analysis as we are estimating an industry-wide risk impact; however, we note that the cost of risk capital may differ significantly across different suppliers.

In 2015, the CMA found that the cost of equity range for retail supply was between 9.3% - 11.5% in analysis which was focussed on the Big Six energy suppliers.[28] Since Ofgem's more recent analysis implies a weighted average WACC which is within the CMA's cost of equity range for larger suppliers,[29] we use this value in our analysis.

For the ESO, we have valued the risk capital at 1.8%, which is an estimate of the ESO's short-term borrowing cost. As a sensitivity, we have also considered the ESO's regulatory cost of capital of 5.4%, as stated in the ESO's RIIO-2 Final Determination and corresponding Price Control Financial Model (PCFM).[30] We include the ESO's regulatory cost of capital as a sensitivity to illustrate a scenario where the ESO may face a cashflow shortfall beyond the level which can be financed with a debt facility. In this case, we assume an equity injection may be needed (in other words, the potential shortfall may be financed with a combination of ESO debt and equity). However, we note that this may be conservative, as unlike suppliers, the ESO has a regulatory guarantee of full BSUoS cost recovery and therefore will not face a permanent risk of loss as a result of BSUoS forecast error.

In our quantitative analysis, we consider the average cost of capital for suppliers of 9.6% and the ESO's borrowing cost of 1.8%. We also present a sensitivity based on the ESO's regulatory WACC of 5.4% combined with the average retail sector WACC of 9.6%.

4.1.6 Aggregating to a total industry cost based on mix of supply contracts

For each fixed and notice option considered in the assessment, we model the cost of holding capital for different lengths of supply contracts individually (as if all final demand were supplied with a given length of contract).

The last step in our calculations involves weighting the resulting costs per contract length by the prevalence of each type of contract length in the market in order to estimate the total cost of managing BSUoS forecast error faced by the industry.[31]

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[26] https://www.ofgem.gov.uk/sites/default/files/docs/2021/03/cmp2_consultation_final.pdf footnote 22

[27] We use a nominal cost of capital, as risk management costs are assumed to represent 'in-year' opex to parties

[28] See Appendix 9.12, CMA (2015) Final Report - Energy Market Investigation

[29] Consistent with the possibility that risk capital for suppliers is principally provided by equity

[30] We note that the ESO's RIIO-2 PCFM contains a 5-year SONIA forecast covering the RIIO-2 price control. For our analysis, we consider the average of the forecasted SONIA to formulate a point estimate.

[31] We consider the same mix of contracts in both the factual and counterfactual scenarios.

Customer types and contribution to final demand

Final energy customers consist of both domestic and non-domestic customers. Over the last decade, non-domestic customers have consistently contributed c. 65% of final energy demand, as shown in Figure 27 below.

Figure 27 GB Domestic and non-domestic electricity consumption

Year	Electricity consumption (TWh)		Contribution (%)	
	Non-domestic	Domestic	Non-domestic	Domestic
2010	205.6	115.7	64%	36%
2011	201.8	108.6	65%	35%
2012	199.5	111.8	64%	36%
2013	199.1	110.4	64%	36%
2014	190.6	105.0	64%	36%
2015	191.4	104.8	65%	35%
2016	191.5	105.1	65%	35%
2017	189.8	102.5	65%	35%
2018	190.9	102.1	65%	35%
2019	186.9	100.9	65%	35%

Source: Tab 5.1.2, Digest of UK Energy Statistics (2020); Sub-national electricity consumption in Northern Ireland (2020)

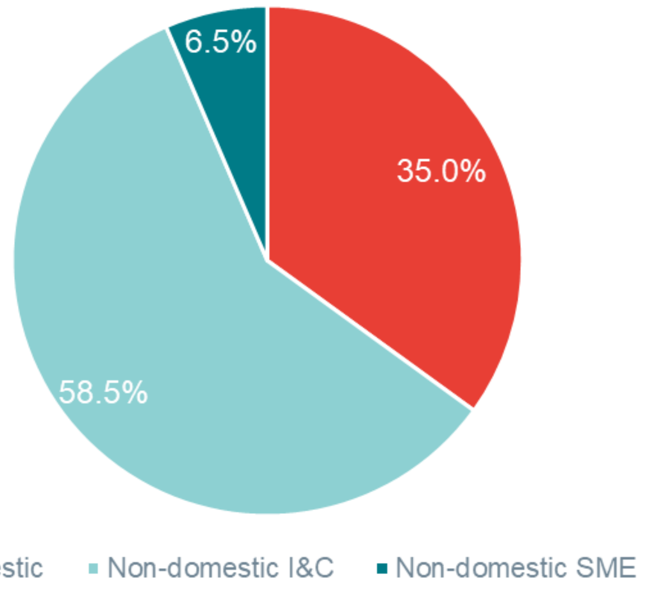
Note: With regards to the DUKES data, we have assumed that the Non-domestic sector covers "Industrial" and "Other", as the "Other" category includes energy consumption from Public administration, transport, agricultural and commercial sectors. See note (4) of Table 5.1.2.

The non-domestic segment can be further segmented into Small/Medium Enterprises ("**SME**") and Industrial and Commercial ("**I&C**") customers. While we understand that I&C customers are much larger, there are significant data limitations with regards to the relative size of the SME and I&C subsectors. Industry engagement and our own research suggest that the I&C sector contributes the majority of electricity consumption in the non-domestic sector, about 90%.[32]

For the purpose of our analysis, we assume that the breakdown of total energy consumption is as follows.

[32] Industry engagement suggests that SME customers contribute about 7% of non-domestic demand. The ND-NEED database prepared by BEIS (accessible here: https://www.gov.uk/government/statistics/non-domestic-national-energy-efficiency-data-framework-nd-need-2021) suggests that SME consumption in 2019 was 24TWh, which is c. 12% of total non-domestic consumption in that year (24 / 191.7 = 12%). In this case, we consider that SME customers have the meter Profile Classes 3 and 4, which is consistent with Ofgem's classification of small business customers in its annual Retail Market Reviews. Given the uncertainty in the data, we have assumed a contribution of 10% by the SME sector for our analysis.

Figure 28 Breakdown of final consumption by customer type



Source: BEIS, Industry engagement and Frontier analysis

Contract breakdown in the domestic segment

We received information from Ofgem regarding the breakdown of tariff types in the domestic sector. The incidence of tariff types and the corresponding modelling assumptions on contract lengths are shown in the table below.

Figure 29 Incidence of contracts by length in the domestic segment

Modelling assumption	Tariff type	Number of customer accounts	% contribution
Modelled as 6-month fixed contracts	Non-standard variable	324,537	1%
	Default tariff <3 years	10,037,333	36%
	Default tariff >3 years	6,892,529	25%
Modelled as 12-month fixed contracts	0-12 month fixed	6,572,754	24%
Modelled as 24-month fixed contracts	13-24 month fixed	3,002,112	11%
Modelled as 3-year fixed contracts	>24 month fixed	1,073,923	4%

Source: Ofgem, Tariff RFI submitted by domestic suppliers, data as of April 2021

Note: In using this data we have assumed that the number of customer accounts are a good representation of volumes consumed.

Default tariffs and non-standard variable tariffs can, strictly speaking, be adjusted at any time and are not subject any fixed periods. However, in practice, suppliers do not tend to adjust prices for these tariffs more often than every 6 months as there are significant costs associated with changing prices. Furthermore, these tariffs are currently subject to the Default Tariff Cap, which is updated every 6 months.[33] Therefore, for simplicity, we model these default and non-standard variable tariffs as 6-month fixed contracts.

Contract breakdown in the non-domestic SME sector

Less data is available on contract lengths for the non-domestic sector. We received data from Ofgem regarding the breakdown of supply by contract length in the microbusiness sector. We note that microbusinesses account for c. 90% of the SME segment.[34] As data was not available for the remaining 10% of the SME segment, we assume the contract breakdown for the microbusiness sector applies to the wider SME segment.[35]

The data we received from Ofgem, along with our modelling assumption, is shown in the table below.

Figure 30 Incidence of contracts by duration in the microbusiness sub-segment

Modelling assumption	Tariff type	% supplied volumes
Modelled as 6-month fixed contracts	no fixed term	12%
Modelled as 12-month fixed contracts	1 year	2%
Modelled as 24-month fixed contracts	2 years	38%
Modelled as 3-year fixed contracts	3+ years	48%

Source: Ofgem

Our modelling assumption for each of the annual contracts (1, 2 and 3+ years) is relatively straightforward. However, for tariffs with no fixed term, we had to make a more subjective assumption. This category of tariffs consists of:

- ***Roll-over contracts***: A contract where suppliers can extend or apply a new Fixed Term Tariff without the customer's assent
- ***Deemed contracts***: A deemed contract normally applies if a customer moves into new business premise and doesn't agree a contract with their energy supplier.
- ***Out of contract supply***: An arrangement where a supply contract has ended but a supplier continues to provide energy to a customer's premises. Under this arrangement, the rates payable after the conclusion of a fixed term would have been specified under the original supply contract.
- ***Evergreen contracts***: A type of contract which has an indefinite length but is neither a deemed nor out of contract arrangement.

Based on the logic applied in relation to domestic default tariffs, we model all of these contracts as 6-month fixed contracts.

[33] https://www.ofgem.gov.uk/publications/default-tariff-cap-level-1-april-2021-30-september-2021

[34] Ofgem. 90% share is computed on the basis of the number of meter points.

[35] Even if the remaining 10% of SME customers had one type of contract, it would only change the percentages presented by only 5% - 8%. In addition, SME consumption only accounts for 6.5% of total final energy consumption, so the uncertainty arising from the data limitation is less than 1% (6.5% x 5% = 0.3% or 6.5% x 8% = 0.6%).

Contract breakdown in the I&C sector

Through industry engagement, we received an indication of the split of I&C contract lengths as shown in the table below.

Figure 31 Incidence of contracts by duration in the I&C sub-segment

Modelling assumption	Contract type	Approximate % supplied volumes
Modelled as 1-year fixed contracts	Passthrough	~80%
	Up to 13 month fixed	~10%
Modelled as 2-year fixed contracts	14 - 26 month fixed	~8%
Modelled as 3-year fixed contracts	27 month + fixed	~2%

Source: Frontier analysis, industry engagement

We note a significant proportion of large customers (generally industrial and extra-high voltage customers) will have passthrough supply contracts. Under these contracts, I&C business customers (not energy suppliers) are liable for BSUoS variability. For these customers, an ex-ante fixed charge would therefore benefit the final customer itself (rather than the supplier) as they would face less exposure from BSUoS forecast error.

The implications for a final customer of reduced exposure to BSUoS variability and forecast error will depend on factors that will vary according to the characteristics of the relevant final product markets (e.g. supply contracts with own customers, the importance of energy in cost structure). As a pragmatic solution, absent information about this heterogeneous group of customers, we model I&C passthrough volumes as 1-year fixed contracts. This is preferable to excluding them from the analysis, as this would understate the impact of the change, but we note that in reality, contracting practices of this group may vary significantly. We discuss this further in section 7.3.5.

Based on our analysis and the information we received, the breakdown of contracts in the non-domestic sector is as follows.

Figure 32 Incidence of contracts by duration in the non-domestic segment

Tariff type	SME	I&C	Total
6-month fixed	1%	0%	1%
1-year fixed	0%	81%	81%
2-year fixed	4%	7%	11%
3-year fixed	5%	2%	7%
Total	**10%**	**90%**	**100%**

Source: Frontier analysis

Industry level contract breakdown

The last step in formulating an assumption for the breakdown of consumption by contract length is to combine the domestic and non-domestic contract breakdowns. We noted in Figure 27 that the domestic and non-domestic sector contribute 35% and 65% of final consumption respectively. The estimated breakdown of final consumption by contract length is shown in the table below.

Figure 33 Breakdown of final consumption by contract length

Contract length	Unweighted		Weighted		Overall
	Domestic	Non-domestic	Domestic	Non-domestic	
6-month fixed	61%	1%	21%	1%	22%
1-year fixed	24%	81%	8%	53%	61%
2-year fixed	15%	11%	5%	7%	12%
3-year fixed	0%	7%	0%	4%	4%
Total	100%	100%	35%	65%	100%

Source: Frontier analysis

5 RISK PREMIA ANALYSIS: RESULTS

In this section, we present the impact of the four factual scenarios in terms of risk exposure and cost of risk capital. These impacts vary depending on the length of the contract that suppliers agree, and sections 5.1 to 5.1.4 detail what the impact would be if the whole industry were operating under each of the individual contract lengths that we consider. In each case we assume the ESO's cost of capital is 1.8%, and that the average cost of capital for suppliers is 9.6%.

In section 5.1.5, we aggregate these results based on the mix of contracts described in section 4.1.6, to give an overall view of the benefits for the industry given our assumptions on the average contracting practices. We also present two sensitivities. The first sensitivity we present is based on the ESO facing a higher cost of capital (5.4%) to finance its cashflow risk exposure based on its RIIO-2 WACC. The second sensitivity we present is based on all parties taking a more cautious approach to risk management and securing enough capital to cover P99 BSUoS costs.

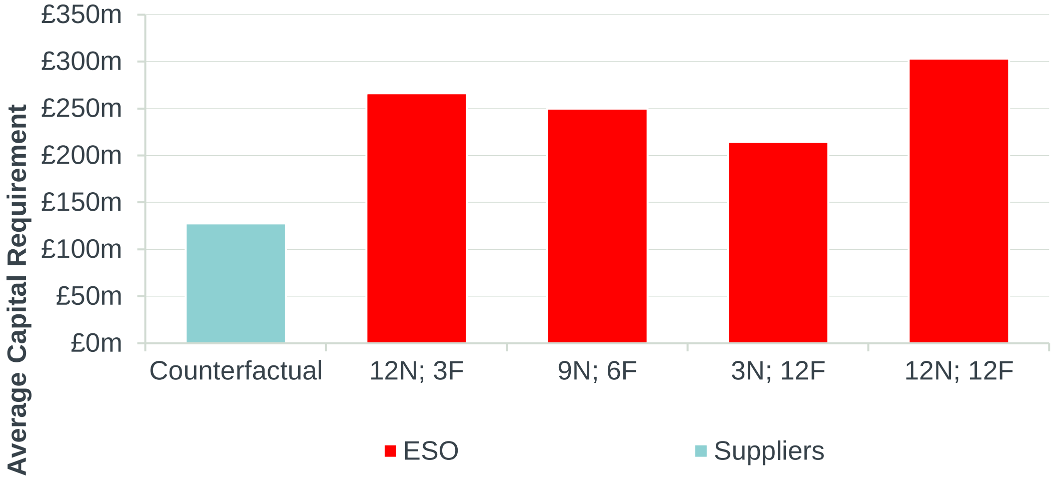
We then draw out some of the implications of the analysis, as well as noting some important limitations.

5.1 Results

5.1.1 Variable contracts (modelled as 6 month fixed)

Figure 34 shows the average capital requirements for the ESO and suppliers in the counterfactual and the four factual scenarios, assuming that the whole industry contracts for power on variable or 6 month contracts.

Figure 34 Average capital requirements – 6 month contracts



Source: Frontier/LCP

In the counterfactual, suppliers must initially hold enough capital to cover potential BSUoS forecast error over a six month period. At an industry level we model this to be £172m. However, as the 6 month period unfolds, this capital requirement is reduced as uncertainty reduces, meaning that the average capital requirement is £128m. Suppliers face no BSUoS forecasting risk in any of the factual scenarios.

The ESO faces no risk in the counterfactual.

In the factual scenarios, its peak capital requirements are determined by the sum of the fix and notice periods:

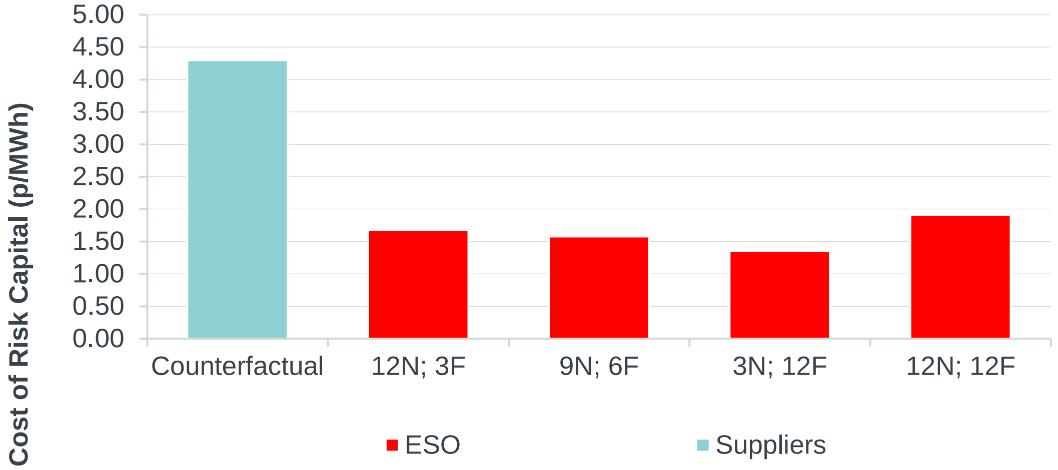
- Under the first 3 factual scenarios (with a combined fix and notice period of 15 months) the ESO must hold enough capital, on the day of announcing a fix period, to cover itself for 15 months of BSUoS forecast error - this amounts to £276m.
- Under the 12 month notice, 12 month fix scenario, the ESO must hold enough capital on the day of announcing a fix period to cover itself for 24 months of BSUoS forecast error - this amounts to £341m.

However, as shown in Figure 24, this capital requirement unwinds somewhat before the announcement of the next fix period. As a result the average capital requirements are:

- £266m under the 12 month notice, 3 month fix scenario;
- £250m under the 9 month notice, 6 month fix scenario;
- £214m under the 3 month notice, 12 month fix scenario; and
- £303m under the 12 month notice, 12 month fix scenario.

Figure 35 compares the cost of this risk capital assuming that suppliers' cost of capital is 9.6% and the ESO's cost of capital is 1.8%. In the counterfactual, suppliers face a cost of 4.3p/MWh. The cost to the ESO varies across the factual scenarios from 1.4p/MWh in the 3 month notice, 12 month fix scenario, to 1.9p/MWh in the 12 month notice, 12 month fix scenario.

Figure 35 Cost of risk capital (p/MWh) – 6 month contracts



Source: Frontier/LCP

Figure 36 shows the total cost of the risk capital, when scaled to industry level by multiplying by total demand of 285TWh.[36] The economic cost falls from £12.3m in the counterfactual to £4-6m in the factual, resulting in benefits for the modelled year of around £7-8m depending on the scenario.

The factual scenario with the highest benefit assuming 6 month contracting would be one with a 3 month notice, 12 month fix. A 12 month notice, 12 month fix scenario would be the least beneficial of the factual scenarios with benefits of £6.8m. This is because it would increase the amount of capital that the ESO would need to hold whilst delivering no further benefits for suppliers, who have no risk in any of the factual scenarios.

Figure 36 Cost of risk capital (£m) by scenario – 6 month contracts

	ESO cost	Supplier cost	Total cost	*Benefit*
Counterfactual	-	£12.3m	£12.3m	
12N; 3F	£4.8m	-	£4.8m	*£7.5m*
9N; 6F	£4.5m	-	£4.5m	*£7.8m*
3N; 12F	£3.9m	-	£3.9m	*£8.4m*
12N; 12F	£5.5m	-	£5.5m	*£6.8m*

Source: Frontier/LCP

5.1.2 1 year fix contracts

Figure 37 shows the average capital requirements for the ESO and suppliers in the counterfactual and the four factual scenarios, assuming that the whole industry contracts for power on one year contracts.

In the counterfactual, suppliers must initially hold enough capital to cover the potential variation in BSUoS over a one year period, which is £245m at an industry level. However, this capital requirement reduces over time, meaning that the average capital requirement is £172m.

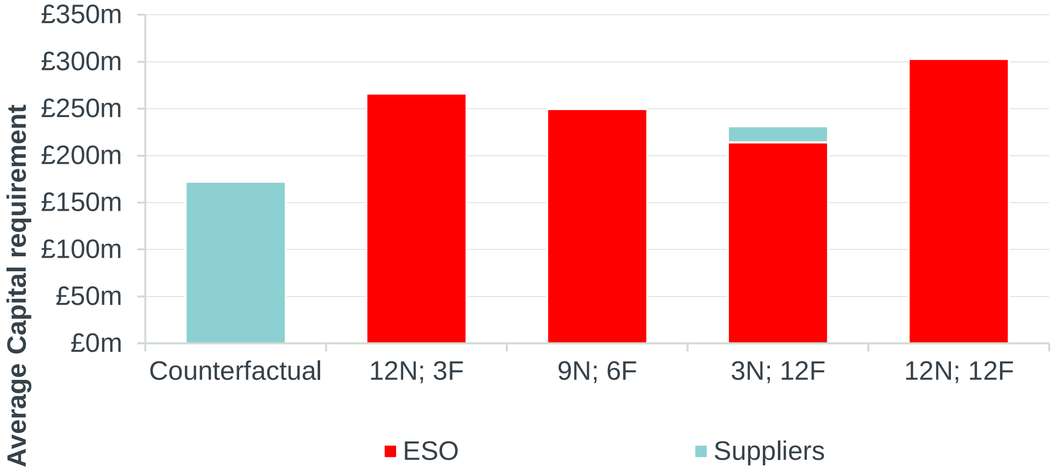
In the factual scenarios, average capital requirements for the ESO are unchanged by the length of the contract suppliers use, and hence these figures are the same as those shown in Figure 34 and described in Section 5.1.

For suppliers, the 12 month notice, three month fix and 12 month notice, 12 month fix factual scenarios would remove all risk since, no matter when in the year the (one year) contract is signed, the supplier will have full knowledge in advance of the BSUoS charges they will face.[37] In contrast, capital requirements under the nine month notice, six month fix scenario are on average £1.6m, and under the 3 month notice, 12 month fix are on average £17m.

[36] Demand of 285TWh is forecast for 2025 under the consumer transformation scenario. This figure is based on grid demand and is therefore net of BTMG.

[37] This follows from our assumption that contracts commence at the point they are signed.

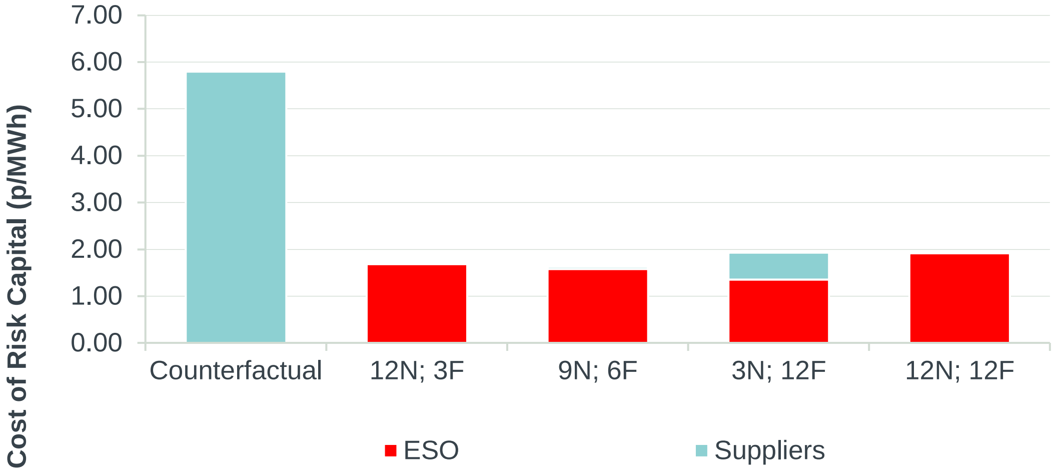
Figure 37 Average capital requirements – 1 year fix contracts



Source: Frontier/LCP

Figure 38 compares the cost of risk capital, assuming that suppliers' cost of capital is 9.6% and the ESO's Cost of Capital is 1.8%. In the counterfactual, suppliers face a cost of 5.8p/MWh. In the factual, they would charge, on average less than 1p/MWh in both the nine month notice, six month fix and three month notice, 12 month fix scenarios and nothing at all in the other two factual scenarios.

Figure 38 Cost of risk capital (p/MWh) – 1 year fix contracts



Source: Frontier/LCP

Figure 39 shows the total cost of risk capital under the different counterfactual and factual scenarios. Benefits are similar (between £11m and £12m) across all 4 factual scenarios, since those factual scenarios which eliminate supplier risk, also increase the ESO's capital requirements offsetting this benefit. The nine month notice, six month fix scenario sees the highest benefit of £11.9m, whilst the scenario with the lowest benefit is the three month notice, 12 month fix (£11.0m).

Figure 39 Cost of risk capital (£m) – 1 year contracts

	ESO cost	Supplier cost	Total cost	*Benefit*
Counterfactual	-	£16.5m	**£16.5m**	
12N; 3F	£4.8m	-	**£4.8m**	*£11.7m*
9N; 6F	£4.5m	£0.2m	**£4.7m**	*£11.9m*
3N; 12F	£3.9m	£1.6m	**£5.5m**	*£11.0m*
12N; 12F	£5.5m	-	**£5.5m**	*£11.1m*

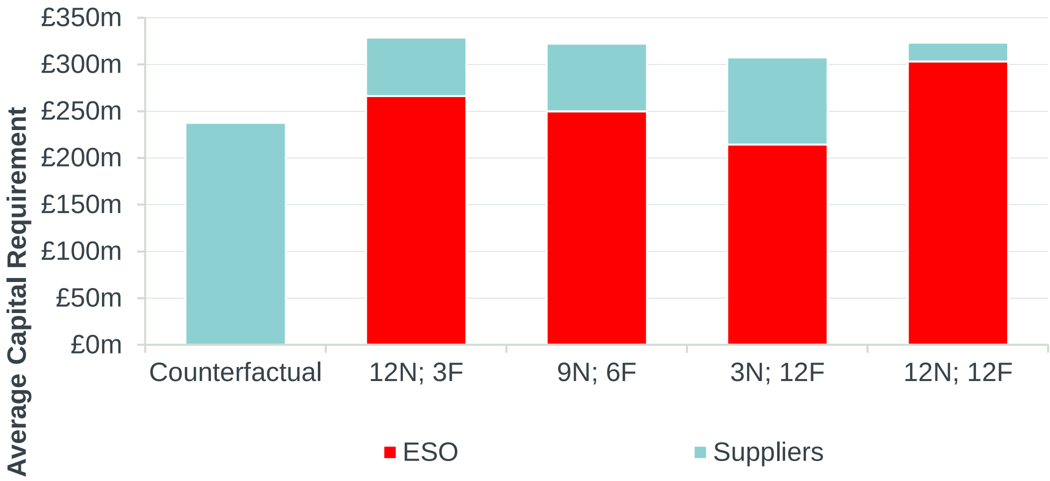
Source: Frontier/LCP

5.1.3 2 year fix contracts

Figure 40 shows the average capital requirements for the ESO and suppliers in the counterfactual and the four factual scenarios, assuming that the whole industry are on two year contracts.

Average capital requirements for the ESO are unchanged by the length of the contract suppliers use, and hence these figures are the same as those shown in Figure 34 and described in Section 5.1.

Figure 40 Average capital requirements – 2 year fix contracts



Source: Frontier/LCP

In the counterfactual, suppliers' capital requirements of £238m reflect the fact that they must initially reserve for two years' worth of BSUoS forecast error, unwinding over time. Suppliers face some BSUoS forecasting risk under all of the factual scenarios, though this is substantially less (£20m) for the longer 12 month notice, 12 month fix scenario than it is for the three shorter scenarios (which vary from £63m to £93m).

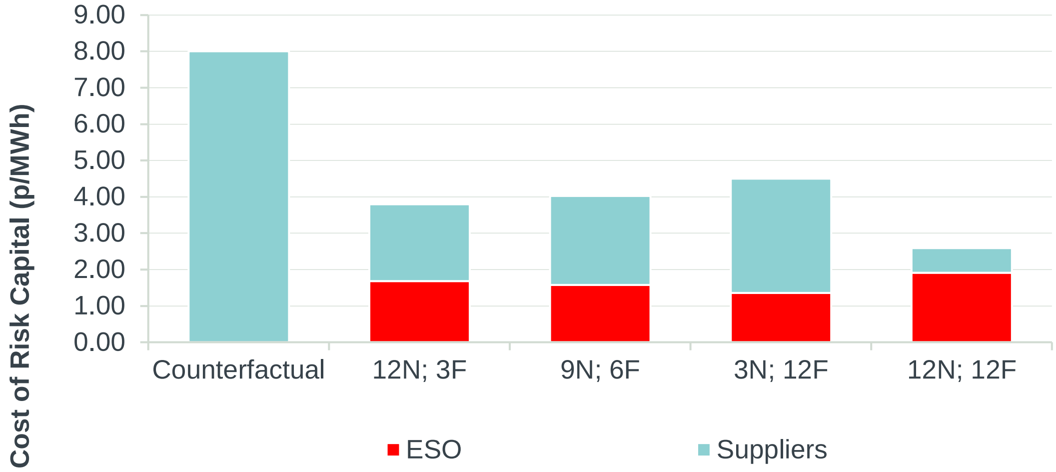
Average capital requirements for the ESO are unchanged by the length of the contract suppliers use, and hence these figures are the same as those shown in Figure 34 and described in Section 5.1.

Figure 41 compares the cost of risk capital assuming the ESO's cost of capital is 1.8%. The overall costs are lowest in the 12 month notice, 12 month fix scenario.

Although the ESO's cost is slightly higher in this scenario than the others, this is more than offset by lower supplier costs.

Figure 42 shows that the factual scenario with the largest benefit (£15.4m), is the 12 month notice, 12 month fix scenario. The 3 month notice, 12 month fix scenario has the lowest benefit of £10.0m.

Figure 41 Cost of risk capital (p/MWh) – 2 year fix contracts



Source: Frontier/LCP

Figure 42 Cost of risk capital (£m) – 2 year contracts

	ESO cost	Supplier cost	Total cost	*Benefit*
Counterfactual	-	£22.8m	**£22.8m**	
12N; 3F	£4.8m	£6.0m	**£10.8m**	*£12.0m*
9N; 6F	£4.5m	£7.0m	**£11.5m**	*£11.3m*
3N; 12F	£3.9m	£9.0m	**£12.8m**	*£10.0m*
12N; 12F	£5.5m	£1.9m	**£7.4m**	*£15.4m*

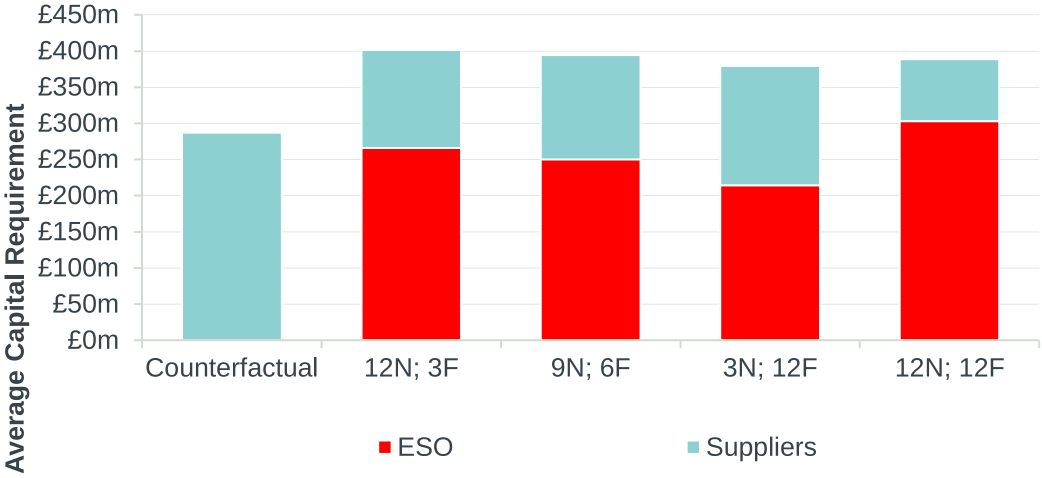
Source: Frontier/LCP

5.1.4 3 year fix contracts

Figure 43 shows the average capital requirements for the ESO and suppliers in the counterfactual and the four factual scenarios, assuming that the whole industry are on three year contracts.

Average capital requirements for the ESO are unchanged by the length of the contract suppliers use, and hence these figures are the same as those shown in Figure 34 and described in Section 5.1.

Figure 43 Average capital requirements – 3 year fix contracts



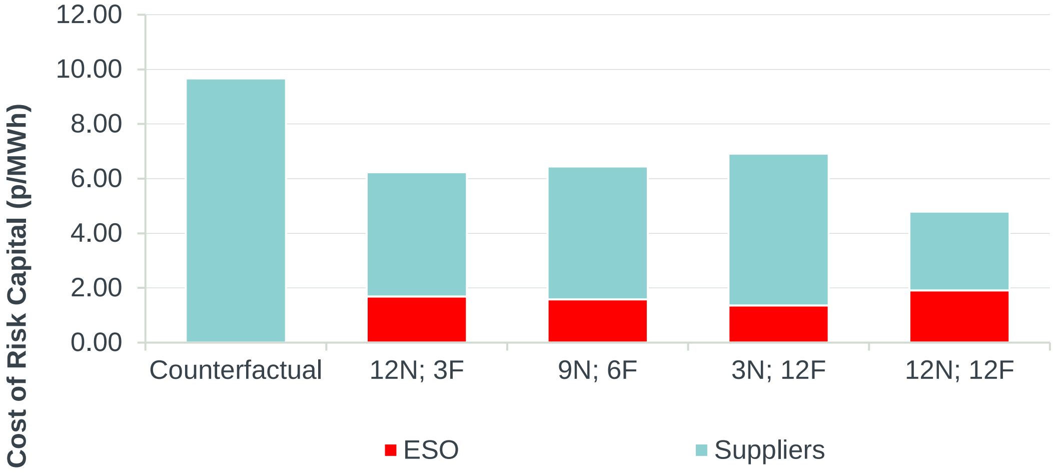
Source: Frontier/LCP

In the counterfactual, suppliers' capital requirements of £286m reflect the fact that they must initially hold capital to cover three years' worth of BSUoS forecast error, with capital holding requirements unwinding over time. Suppliers face substantial BSUoS risk under all of the factual scenarios. The average capital requirement is lowest for the longer 12 month notice, 12 month fix scenario (£85m) since this gives suppliers certainty over a larger proportion of their contract. Under the other factual scenarios, capital requirements vary from £135m - £165m.

Average capital requirements for the ESO are unchanged by the length of the contract suppliers use, and hence these figures are the same as those shown in Figure 34 and described in Section 5.1.

Figure 44 shows the overall cost. These are lowest in the 12 month notice, 12 month fix scenario. Figure 45 shows that this scenario has the largest benefit of £13.9m, significantly larger than the other scenarios, whose benefits range from £.7.9m to £9.8m. These benefits are lower across the board than under two year contracts because there still remains a significant supplier risk under all the factual scenarios.

Figure 44 Cost of risk capital (p/MWh) – 3 year fix contracts



Source: Frontier/LCP

Figure 45 Cost of risk capital (£m) – 3 year contracts

	ESO cost	Supplier cost	Total cost	*Benefit*
Counterfactual	-	£27.6m	**£27.6m**	
12N; 3F	£4.8m	£13.0m	**£17.8m**	*£9.8m*
9N; 6F	£4.5m	£13.9m	**£18.4m**	*£9.2m*
3N; 12F	£3.9m	£15.8m	**£19.7m**	*£7.9m*
12N; 12F	£5.5m	£8.2m	**£13.7m**	*£13.9m*

Source: Frontier/LCP

5.1.5 Average industry impact

In this section, we present the modelled benefits if we assume that suppliers have a mix of contract lengths. Figure 46 shows the average capital requirements for the ESO and suppliers assuming this mix of contracts. Since we assume that 83% of contracts are six month or one year fixes, supplier capital requirements are small in all of the factual scenarios.

Figure 46 Average capital requirements – industry mix of contracts

Source: Frontier/LCP

Figure 47 shows the industry benefits under each of the contract lengths considered and the average industry impact assuming a portfolio of contract lengths. Benefits are very similar across the four scenarios, with the three month notice, 12 month fix scenario showing the lowest benefits, and the nine month notice, six month fix and 12 month notice, 12 month fix scenarios show the highest.

Figure 47 Industry benefits by scenario and contract length

	6 month contracts	1 year contracts	2 year contracts	3 year contracts	Weighted average
12N; 3F	£7.5m	£11.7m	£12.0m	£9.8m	**£10.7m**
9N; 6F	£7.8m	£11.9m	£11.3m	£9.2m	**£10.8m**
3N; 12F	£8.4m	£11.0m	£10.0m	£7.9m	**£10.2m**
12N; 12F	£6.8m	£11.1m	£15.4m	£13.9m	**£10.8m**

Source: Frontier/LCP

We note that the results are likely to be sensitive to the weighting of contracts. For example, under two and three year contracts, the scenario which shows the most benefits is the 12 month notice, 12 month fix, whereas for six month contracts this scenario shows the least benefits.

Sensitivity: Higher ESO cost of risk capital

As a sensitivity, we considered the benefits of the policy if the ESO faced a higher cost of risk capital. For this sensitivity, we assumed that the ESO faced a cost of capital of 5.4%, equal to its regulatory WACC. This reflects a downside scenario where the shortfalls due to forecasting error may need to be financed with some equity.

Under this sensitivity, the benefits to suppliers are the same, but the factual scenarios result in larger costs for the ESO. As a result, the overall benefits of the proposed change are significantly reduced, and in the case of the 12 month notice, 12 month fix scenario, are slightly negative (-0.1m). Benefits are highest under the three month notice, 12 month fix scenario as the ESO's average risk capital requirements are lowest in this scenario.

Figure 48 Industry benefits by scenario and contract length – Higher ESO cost of capital assumption

	6 month contracts	1 year contracts	2 year contracts	3 year contracts	Weighted Average
12N; 3F	-£2.1m	£2.2m	£2.4m	£0.2m	£1.2m
9N; 6F	-£1.2m	£2.9m	£2.3m	£0.2m	£1.8m
3N; 12F	£0.7m	£3.3m	£2.3m	£0.1m	£2.5m
12N; 12F	-£4.1m	£0.2m	£4.5m	£3.0m	-£0.1m

Source: *Frontier/LCP*

Sensitivity: Parties hold capital for P99 risk

As another sensitivity, we also modelled each of the scenarios assuming that both the ESO and suppliers will hold enough capital to cover all but the worst 1% of forecasting outcomes (i.e. the P99 value of BSUoS forecast error). This increases capital requirements by around 50% relative to our central (P95) assumption, although the exact proportion varies slightly with the length of BSUoS exposure.[38] Since this increase applies both to the ESO's costs and that of suppliers, the result is a scaling up of benefits for each scenario.

Benefits range from £15.0m for the three month notice, 12 month fix scenario, up to £16.0m for the 12 month notice, 12 month fix scenario.

Figure 49 Industry benefits by scenario and contract length – P99 capital assumption

	6 month contracts	1 year contracts	2 year contracts	3 year contracts	Weighted average
12N; 3F	£11.3m	£17.5m	£17.4m	£13.9m	**£15.9m**
9N; 6F	£11.7m	£17.6m	£16.4m	£12.9m	**£15.9m**
3N; 12F	£12.6m	£16.3m	£14.4m	£11.1m	**£15.0m**
12N; 12F	£10.4m	£16.5m	£22.5m	£19.9m	**£16.0m**

Source: *Frontier/LCP*

5.2 Implications of the risk premia analysis

A number of implications can be drawn from the analysis presented above.

First, clear benefits arise when the sum of the notice and fixed period are moderately greater than a particular contract length. All the factual scenarios considered show clear benefits from reduced risk premia if the ESO is able to fund its risk capital through short term debt, and all 15 month combinations of fixed and notice periods still show benefits even if the ESO has a relatively high cost for the

[38] Our modelling assumes that monthly BSUoS is lognormally distributed. However, due to central limit theorem, combining these months to obtain a full year's distribution (e.g. for a 12 month fix scenario), creates a distribution that is closer to a normal distribution. As a result, the percentage difference between the P99 and P95 values is larger for 1 month of exposure than it is for 1 year.

capital it must hold. This is because supplier risks are transferred to the ESO which has a lower cost of capital.[39]

These benefits will accrue either directly to end users who are on passthrough contracts or to electricity suppliers where fixed contracts have been agreed. Assuming that the retail energy market is competitive, these supplier benefits, can be expected to be passed through to consumers. Therefore, these estimated benefits can be considered as both system benefits and consumer benefits.

Second, however, it is not unambiguously clear which of the factual scenarios considered is likely to be the most beneficial.

If the most prevalent supply contracts are longer than the sum of the notice and fixed period then the benefits start to narrow significantly, because more residual forecast error risk is left with suppliers. If the sum of the fixed and notice periods is significantly greater than prevalent contract lengths then benefits can also decline, because the ESO is taking on more risk exposure in the factual scenario (with a longer fixed and notice period) than suppliers are in the counterfactual.

The true mix of contracts in the market matters (and we note that this may change over time, including in relation to changes in the regulatory framework). There is uncertainty over the current portfolio of contracts, and in particular, how passthrough contracts (which account for a significant share of total volumes) are treated.[40] Varying assumptions on the average contract mix in the industry will change the factual scenario which appears to deliver the highest benefits. And if passthrough contracts were modelled as 2 year fixed contracts, the longer notice and fixed period option (12 month notice and 12 month fixed) would deliver the greatest benefits.

The option which delivers the greatest benefits also depends on the actual cost to the ESO of holding the necessary risk capital. If the ESO can finance the risk capital through a debt facility, then longer notice periods may be more beneficial, because they remove more supplier risk. In contrast, if the ESO has to rely on some equity funding (or higher debt with costs that approach the ESO's regulated WACC) then for a given set of supplier contract lengths, shorter notice periods appear to show greater benefits.[41]

Overall the differences in net benefits estimated for the different factual scenarios are small. Combined with the uncertainty associated with key inputs to the analysis, this means that it is difficult to draw a strong recommendation from this analysis of which of the factual options may be the best.

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[39] We have valued the risk capital of suppliers and ESO using cost of capital information available from Ofgem to ensure that the costs to parties are evaluated on a consistent basis. However, in practice, we note that there could be a number of alternative ways the ESO can be funded to manage cashflow risk. We note that the ESO currently receives an additional allowance on top of its regulated cost of capital to cover various other risks. In order to manage these risks, the ESO may procure a working capital facility (WCF) to manage intertemporal cash imbalances. In the RIIO-2 Final Determination, the ESO was allowed around £5m p.a. to manage these risks and cover WCF costs. We note that the ESO costs from CMP361 estimated by our analysis are of a similar magnitude to this allowance, and the same regulatory treatment could be applied to manage additional ESO risk arising from the implementation from CMP361. See page 73-74 of Ofgem (2021) RIIO-2 Final Determinations – Electricity System Operator (REVISED)

[40] See for example the discussion at 4.1.6 of this report.

[41] The ESO's regulatory WACC assumes a gearing level of 55%. Table 11, Ofgem (2021) RIIO-2 Final Determinations – Electricity System Operator (REVISED)

6 OVERALL IMPLICATIONS

The wider system and consumer cost analysis shows a small cost for the system (£30m) and consumers (£60m) over the period 2022-2040.[42] These modelled costs arise from marginal changes in the behaviour of behind the meter generators. However, in the context of the total costs to consumers and the energy system, these modelled costs can be considered negligible and well within the margin of error of the accuracy of the EnVision modelling and the uncertainty in the input assumptions. Therefore, absent a strong *a priori* reason to expect there to be system and consumer costs from implementing a fixed BSUoS charge, these results can reasonably be considered to be equivalent to zero modelled system and consumer impacts.

The main distributional impact of introducing a fixed BSUoS charge announced with a notice period is the unwinding of the distributional impacts that would be introduced by CMP308.[43] Broadly speaking, those user groups that would see an increase (decrease) in bills from the introduction of CMP308 in isolation see a decrease (increases) in bills from the subsequent introduction of CMP361. The offsetting is not perfect but considering those users in each user group category that are most affected by CMP308 alone the mitigation is significant.

Figure 50 Illustration of the offsetting impact of CMP361 on CMP308 distributional impacts

User Group Type	User Group	CMP308 Impact (£/MWh)	CMP361 Impact (£/MWh)	Net impact (£/MWh)
Domestic (no LCT*)	High consuming E7	+£0.43	-£0.34	+£0.09
Domestic (with LCT)	Domestic with solar PV and storage	+£1.09	-£1.58	-£0.49
Commercial	Large commercial with onsite generation and storage	-£0.59	+£0.85	+£0.26
Industrial	EHV or T-connected user	+£0.87	-£0.95	-£0.08

Source: *Frontier/LCP*

Note: *Results are shown for the Consumer Transformation scenario only and only for the dynamic impacts include the effects of wholesale prices, low carbon support payments and capacity market costs*
** Low Carbon Technologies*

The risk premia analysis shows a clear customer benefit from introducing a fixed BSUoS charge announced with a notice period. This results from a transfer of forecasting risk from suppliers to the ESO, which has a lower cost of capital and hence charges less for bearing this risk.

Although not strictly comparable to the system and consumer costs estimated in the wider system and consumer cost analysis, a simple comparison shows that the benefits are of a similar scale. The estimated annual risk premia benefit for the sample year of 2025 is £10.2-10.8m based on an ESO cost of capital of 1.8%. If this benefit was achieved each year in the period 2022-2040 (the assessment

[42] Figures are on an NPV basis with a discount rate of 3.5%

[43] For more details of the distributional impacts of CMP308 see our previous report available here: https://www.ofgem.gov.uk/publications/reform-bsuos-charges-analysis-proposal-remove-bsuos-generation

period for the system cost analysis) then the NPV of the benefit would be £140-148m.[44] However, if the ESO has a high cost of cashflow risk capital, then the annual benefit, of the 15 month combinations of fixed and notice periods is £1.2-2.5m and the corresponding simple NPV estimate is only £16-34m.

Overall it seems likely that there is a good case for the implementation of some form of fixed BSUoS charge announced with a notice period.

- The system modelling does not suggest that there are significant system or consumer costs of doing so;
- It would substantially mitigate distributional concerns that may arise from the implementation of CMP308 in isolation; and
- There are clear and material benefits from a transfer of forecasting risk.

However, the quantitative evidence alone does not suggest that there is a strong frontrunner among the options analysed in this report. Indeed, it suggests that the differences in benefits among the options may be relatively small.

[44] Assuming a 3.5% discount rate.

7 LIMITATIONS OF THE ANALYSIS

The modelling presented in this report can help to inform the nature, direction and broad magnitude of potential effects of the modifications being considered. However, the modelling outputs we present are dependent on assumptions on a number of inherently uncertain input variables (e.g. fuel prices, demand). Such outputs are best used to complement a more principles-based assessment of the likelihood of modifications better facilitating objectives.

It will be important that sound economic principles form the basis of the final decision in relation to any changes to BSUoS charging arrangements. Such principles relate to economic efficiency, fairness and practical considerations. Charging in a manner consistent with such principles should help ensure an optimum outcome for society as a whole.

7.1 Limitations of the wider system modelling

The wider system modelling results contained in this report are produced by LCP's dispatch model of the GB power market. The report contains modelled outcomes from 2022 to 2040 under assumptions provided by Ofgem or obtained from publicly available sources where possible.

The results presented in this report are dependent on the assumptions used and the modelling methodology applied. Long-term forecasts are subject to significant uncertainty and actual market outcomes may differ materially from the forecasts presented.

In particular:

- The scenarios presented do not take into account all changes that could potentially occur in the power market. More extreme market outcomes than those presented are therefore possible.
- The relationship between the cost of generation and prevailing market prices has been assessed based on historical data and current forward power prices. To the extent that this relationship changes over time, results could vary.
- The modelling results are based on all market participants having a common view on future market outcomes. To the extent that views vary between market participants the results could be considerably different to those presented in this report.
- The modelling makes use of a power plant database maintained by LCP which is based on publicly available information where possible. Assumptions on individual plant characteristics have been estimated where required.
- We do not take into account the effect that future changes to the market structure or arrangements may have on the behaviour of market participants.

A further challenge with this type of modelling is that relatively small changes in inputs can result in relatively large changes in outputs, due to "cliff-edge" effects. For example, a small change in charges can be enough to tip the economics of an investment decision for a large new build project from going ahead to not going ahead. When evaluating larger changes to assumptions, these effects tend to get smoothed out, but for smaller changes it can reduce the stability of the modelling and adds an additional area of uncertainty to the modelling results. We have made efforts to minimise the impact of these effects, for example the renewable build is locked down between scenarios as per the “background” FES scenario. However, caution should be taken in interpreting relatively small system impacts calculated over the 2022-2040 time horizon. Given the nature of the modelling small positive or negative system impacts could reasonably be interpretated as not being significantly different from there being no clear impact.

7.2 Limitations of the Distributional analysis

The bill impact analysis has been developed based on data from publicly available sources and requests from network owners. The data available to us does not allow the estimation of the exact charges that could be expected if the options are implemented. We have had to make numerous simplifications and assumptions. The user groups are designed to represent a reasonable spread of different levels and shapes of consumption, but they are not representative of all consumers. We also note that we do not consider any evolution in demand patterns between 2025 and 2040 e.g. due to technological improvements related to the LCTs assessed or new tariff arrangements which incentivise different consumption behaviour. As a result, the charges and bill impacts estimated should only be considered illustrative to provide the broad direction of the expected impacts.

The bill impact analysis should only be considered illustrative to provide the broad direction of the expected impacts of the changes in customer costs modelled by Envision for different types of consumers. The user groups are designed to represent a reasonable spread of different levels and shapes of consumption, but they are not representative of all consumers.

7.3 Limitations of the Risk Premia analysis

The risk premia analysis is intended to inform the benefits case associated with the different fixed and notice periods being considered for CMP361 and to aid with decision making. The modelling of risk, risk management and risk management costs is complicated and inherently uncertain. We also note that some other assessments of similar proposals have estimated higher supplier risk premia for BSUoS risk in the counterfactual than our analysis.[45] To the extent that supplier counterfactual costs are greater than we have estimated, this would increase the benefits associated with reallocation of risk from suppliers to the ESO.

We have developed an analytical framework that allows the issues to be considered in a consistent manner and in significant detail. However, it has still been necessary to make a number of assumptions and simplifications for the analysis to be tractable and informative.

[45] For example analysis of CMP250 estimates a counterfactual supplier risk premia for the industry in excess of £80m where as our estimate is less than £20m. See paragraph 2.163 of: https://www.nationalgrideso.com/document/106876/download

The use of assumptions and simplifications of the real world in the analysis introduce limitations into the work that should be noted when drawing conclusions. We draw out the key limitations below.

7.3.1 Data limitations associated with BSUoS forecast error risk

As noted in Section 4.1, we were not able to observe relevant BSUoS forecast errors directly. We therefore generated a distribution of forecast errors from historical data and a simple forecasting model. This means that our estimates of the potential for BSUoS forecasting error are based on historical conditions (although we attempted to account for observed structural breaks and exceptional events such as the Covid-19 pandemic by only considering the period 2015 – 2019).[46] This historical variability may not be a reasonable guide to future variability, if factors such as the wholesale market structure or the type of balancing services that are procured change in future.

We note that the ESO has made its own estimates of the BSUoS variability in future periods which indicates a greater level of variability than we have estimated in our analysis.[47] To the extent that the true underlying variability of BSUoS in the future is greater than that which we have estimated this will tend to increase the size of the benefits estimated in our analysis. This is because a greater degree of variability would imply a greater degree of risk transfer from suppliers to the ESO.

7.3.2 Limitations associated with the forecasting dynamics included in this analysis

We adopted a very simple approach to BSUoS forecasting in order to generate our estimates of potential forecast error. We also assumed that the ESO and suppliers have the same ability to forecast BSUoS, and that they are able to produce unbiased forecasts of BSUoS.

In practice, the ESO may have more information regarding the likely evolution of BSUoS costs. If the ESO is indeed better than suppliers are minimising BSUoS forecast error, all else equal, we would expect the estimated benefit of CMP361 to be larger across all the options assessed. This is because the ESO's better forecasting ability should lower its risk management costs. Under the assessment framework described in this report, the ESO's better forecasting ability would result in a smaller average exposure for the ESO, reducing costs in the factual scenarios.

We note that there are discussions regarding the ESO publishing regular forward guidance on BSUoS forecasts as part of the implementation of CMP361. There are likely to be benefits from the ESO publishing either its methodology or regular forward guidance. This could reduce supplier risks by aligning expectations of charges for fixed periods that have not been announced yet and would support consistency with our framework which assumes that all parties liable for BSUoS

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[46] There was a structural break in the data around 2014-15, and we note that the ESO had also considered data from 2015 onwards in their preliminary assessment.

[47] See ESO response to Frontier Economics Draft Analysis. Available here: https://www.nationalgrideso.com/document/202856/download

have the same forecasting ability. However, we do not seek to quantify any benefit associated with this potential action by the ESO.

We assume that (over the timescales relevant for the analysis) the accuracy of forecasts does not depend on the forecast horizon. There is some indication that parties may be able to forecast more accurately over more modest time horizons than over long timer horizons. For practical reasons, we cannot account for such potential changes in forecast accuracy over time in our analysis.

We note that to the extent that one party (e.g. the ESO) faces greater uncertainty over longer term BSUoS forecasts, the same should be true for other parties (e.g. suppliers). Therefore, if forecast uncertainty increases for longer time horizons this will generally increase the quantified benefits of the options where the fixed and notice period is moderately longer than mean supplier contract length. This is because higher BSUoS variability amplifies the impact of the difference in supplier and ESO capital costs. However, options where the ESO takes on fixed and notice periods that are significantly longer than average supplier contract lengths may see reduced benefits as the additional forecast risk would be a burden on the ESO with no benefit from avoiding the risk for suppliers.

7.3.3 Risk aversion and risk management strategies of individual parties

In applying common risk management strategies for both ESO and suppliers, our analysis does not account for individual parties' differences in risk management strategies. However, we note that this is a necessary design solution to allow us to assess the counterfactual and factual costs for the ESO and Suppliers on a consistent basis. We note that, in reality, different parties will have different forecasting methods, risk aversion, and risk management strategies.

We also note that BSUoS forecast errors may be correlated with other risks held by suppliers and the ESO, but for the purposes of this analysis, we have ignored such correlations.

7.3.4 Limitations regarding the valuation of risk capital

In our discussions with ESO and the CMP361 working group, some parties noted that the cost of capital may change as the scale of risk exposure changes over time. It was not possible to directly account for the detailed financing arrangements faced by individual parties. We have considered a weighted sector average for suppliers and a sensitivity on risk capital costs for the ESO. Different assumptions on the cost of capital for the ESO and for suppliers would impact the conclusions of the analysis.

7.3.5 Limitations regarding contracting assumptions

We make five key assumptions regarding the contracting structure that exists in the retail market for electricity. We assume that:

- Contracts start in the month that they are agreed;

- Passthrough tariffs can pragmatically be proxied for by modelling one year fixed tariffs;
- The prevalence of contract types for SMEs can reasonably be proxied for by Ofgem’s data on contract types for microbusinesses;
- The information we have received through some limited industry engagement on the prevalence of contract types for I&C customers is representative of the I&C sector as a whole; and
- The prevalence of different types of contracts is unaffected by the potential introduction of CMP361 and is therefore the same in the counterfactual and factual scenarios.

These assumptions are necessary given data limitations and the need to make the analysis tractable. However, we recognise that they mean that there are some limitations with the analysis.

Contracts start in the month they are agreed

Assuming contracts are agreed in the month that they start is a necessary simplification for our analysis. However, we are aware that, particularly in the non-domestic sector, contracts may be agreed some time prior to their effective term. Based on industry engagement, we understand that some contracts may be agreed many months ahead of supply commencing and that a lead time of two to four months would not be unusual. For fixed price contracts this would affect the benefits that we have calculated.[48] However, we also note that the majority of non-domestic supplier volumes are contracted on a passthrough basis.

Long lead times on contracts will reduce the benefits to suppliers from shorter combinations of fixed and notice periods because for a given contract length, a lead time means that more of the contract may be in a period when the BSUoS charges have yet to be announced. This suggest that the benefits estimated for longer combinations of fixed and notices periods may be more robust.

Passthrough contracts proxied for by one year fixed contracts

A significant portion of non-domestic supply volumes (typically large industrial or extra high voltage customers) are contracted for on a passthrough basis. This means that energy suppliers do not hold BSUoS forecast error risk in the counterfactual. Rather it is held by the electricity user.

We do not have information on the sales contracting approach of large industrial or extra high voltage electricity customers and if we did it is likely to be very varied as these are businesses that will operate in a wide variety of final product markets. Pragmatically we model the risk to passthrough customers as a one year fixed price contract to make sure that we capture the potential benefit associated with this significant supply volume. However, we recognise that there is significant uncertainty associated with this assumption and therefore what benefits end users may achieve. However, we are confident that, in principle, large end users should

[48] We note that long lead times for electricity supply contracts do not affect our calculation of benefits if the supply contracts are passthrough contracts. This is because the BSUoS forecast error risk in passthrough contracts sits with the electricity user at all times. Thus when the contract is agreed with the electricity supplier does not matter as it does not transfer risk at that point.

benefit from reduced volatility in BSUoS pricing in a similar manner to electricity suppliers.

Microbusiness contracting is representative of all SMEs

As a result of data limitations, we assume that microbusiness contracting is representative of contracting for all SMEs. This is a necessary simplification.

I&C contracting data is representative

As discussed in section 4.1.6, we received an indication of the split of I&C contract lengths via industry engagement over the course of this project. The information was not compiled via a full survey of the I&C segment. We have no specific reason to believe the unrepresentative of the broader market segment. However, we cannot be sure that data we received is representative of the actual contract mix in the I&C sector. Therefore, the actual contract mix in the I&C sector may differ from the mix presented in this report.

In light of the data limitations on contracting arrangements in the I&C segment, we consider that using the information that we have been able to gather is a reasonable and pragmatic approach.

Contracting practices unaffected by proposals

We have gathered information and made assumptions on current contracting practice in the electricity market. We assume that this approach applies in both the factual and counterfactual scenarios. In principle contract lengths and timings could be adjusted by suppliers to maximise the benefits they can realise from announced BSUoS charges. However, BSUoS charges account for only a small portion of the total electricity bill, and so while it is a simplification, we think it is reasonable to assume that contracting practices do not change significantly between the factual and counterfactual.

7.3.6 Independent assessment of distributional and risk premia impacts

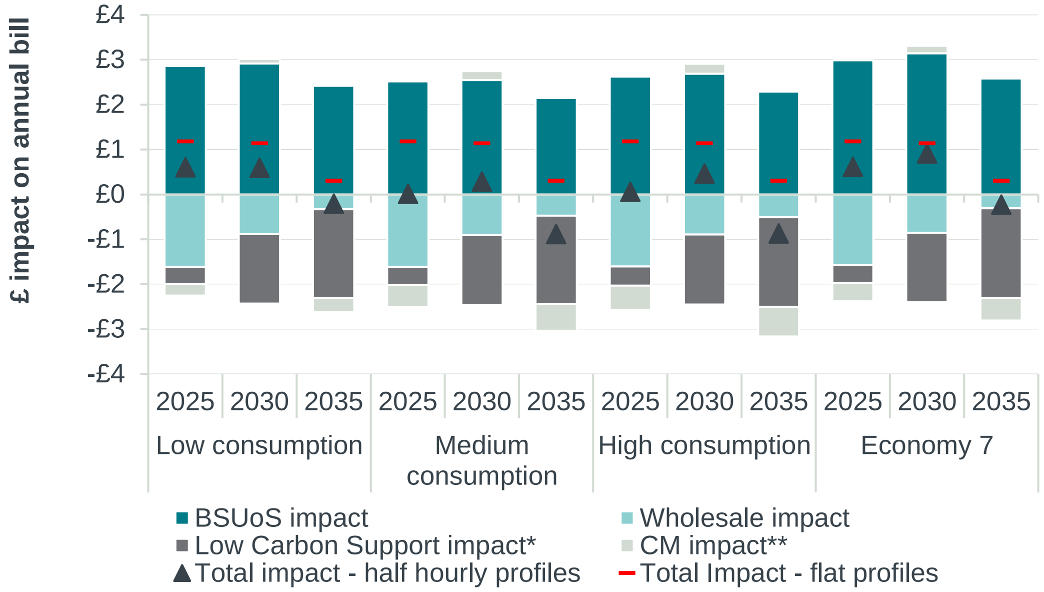
Finally, we note that the risk premia analysis in Section 4 has been carried out independently of the distributional analysis carried out in Section 3.

- The distributional analysis shows that commercial customers with on-site generation and storage may see an *increase* in BSUoS costs, while domestic and industrial customers are likely to see a reduction.
- On the other hand, the risk premia analysis shows that CMP361 is likely to benefit the industry overall in terms of lower risk management costs.

As such, we note that there may be some offsetting effects of CMP361 for some commercial customers, and that domestic and industrial customers are likely to benefit. Our results do not present the combined impact.

ANNEX A £/MWH DISTRIBUTIONAL CHARTS

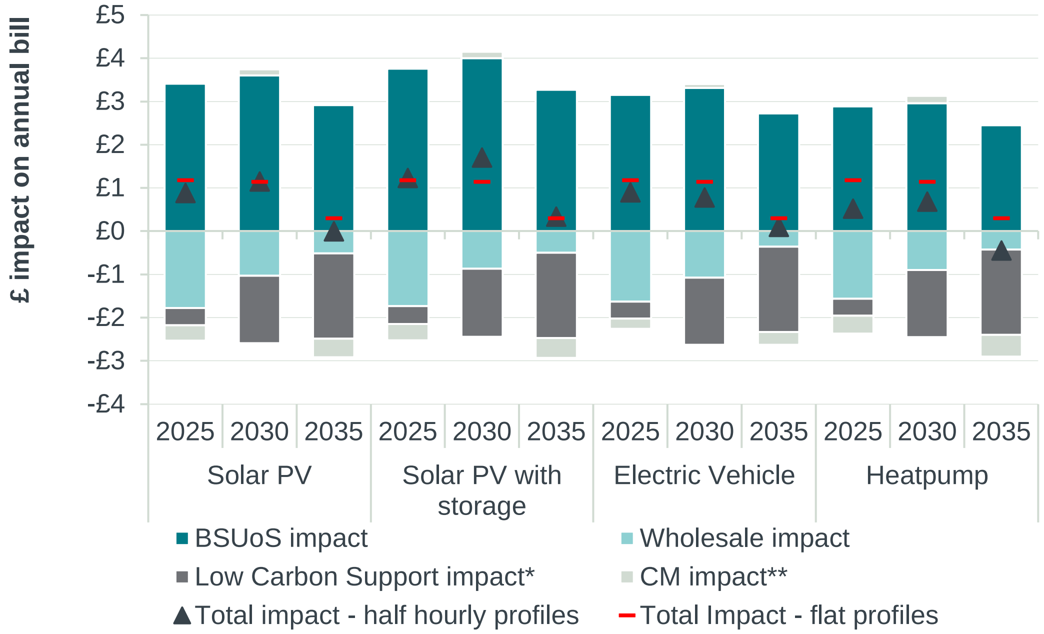
Figure 51 Consumer transformation – Annual £/MWh impact – Domestic



Source: Frontier Economics analysis

*Note: *Low Carbon Support includes Contracts for Difference and Renewables Obligation Certificates payments.*
***Capacity Market modelling volatile- we have therefore taken the 5 year average of the forecast (e.g. 2025 is an average of the forecasts from 2023 – 2027 inclusive*

Figure 52 Consumer Transformation – Annual £/MWh impact – Domestic with low carbon technologies

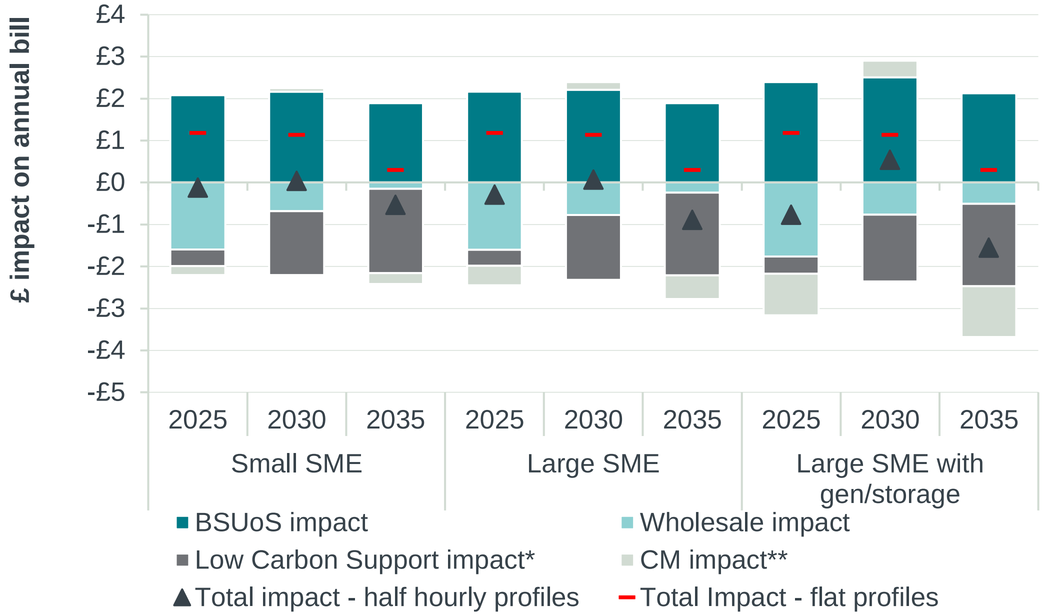


Source: Frontier Economics analysis

*Note: *Low Carbon Support includes Contracts for Difference and Renewables Obligation Certificates payments.*

***Capacity Market modelling volatile- we have therefore taken the 5 year average of the forecast (e.g. 2025 is an average of the forecasts from 2023 – 2027 inclusive)*

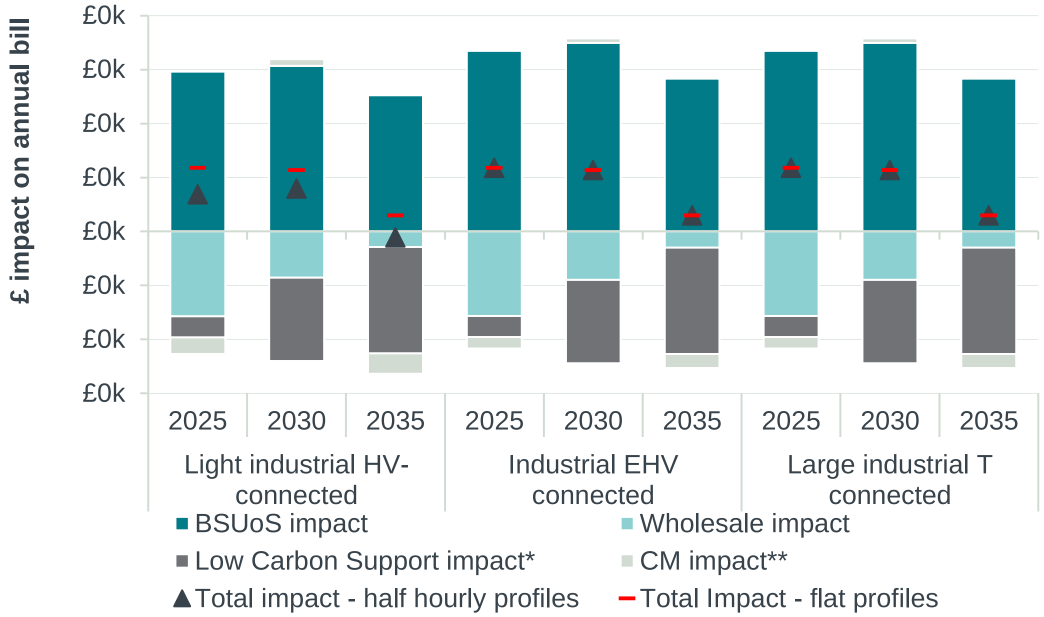
Figure 53 Consumer Transformation – Annual £/MWh impact – SMEs



Source: *Frontier Economics analysis*

Note: **Low Carbon Support includes Contracts for Difference and Renewables Obligation Certificates payments.*
***Capacity Market modelling volatile- we have therefore taken the 5 year average of the forecast (e.g. 2025 is an average of the forecasts from 2023 – 2027 inclusive)*

Figure 54 Consumer Transformation – Annual £/MWh impact – Industrials



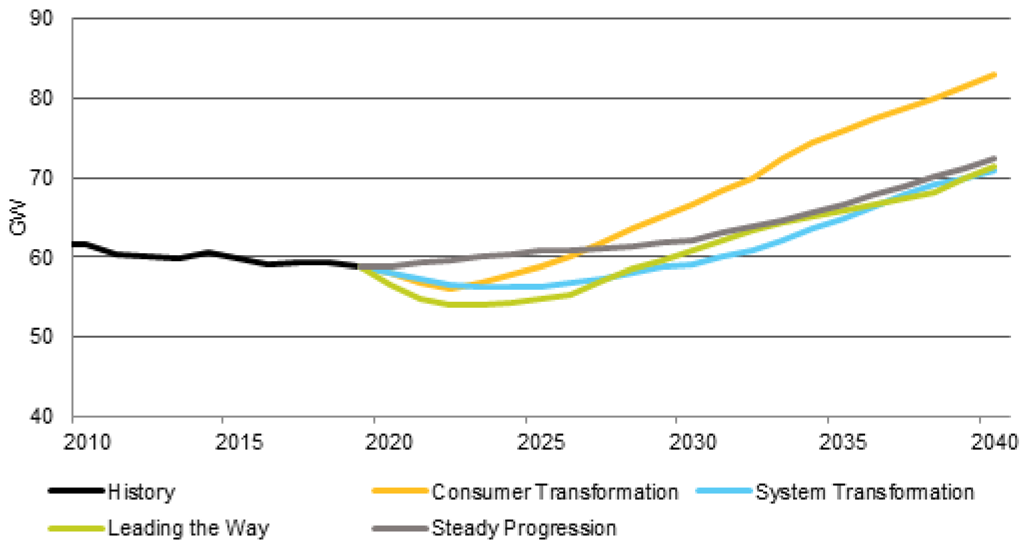
Source: *Frontier Economics analysis*

Note: **Low Carbon Support includes Contracts for Difference and Renewables Obligation Certificates payments.*
***Capacity Market modelling volatile- we have therefore taken the 5 year average of the forecast (e.g. 2025 is an average of the forecasts from 2023 – 2027 inclusive)*

ANNEX B ADDITIONAL SYSTEM MODELLING ASSUMPTIONS

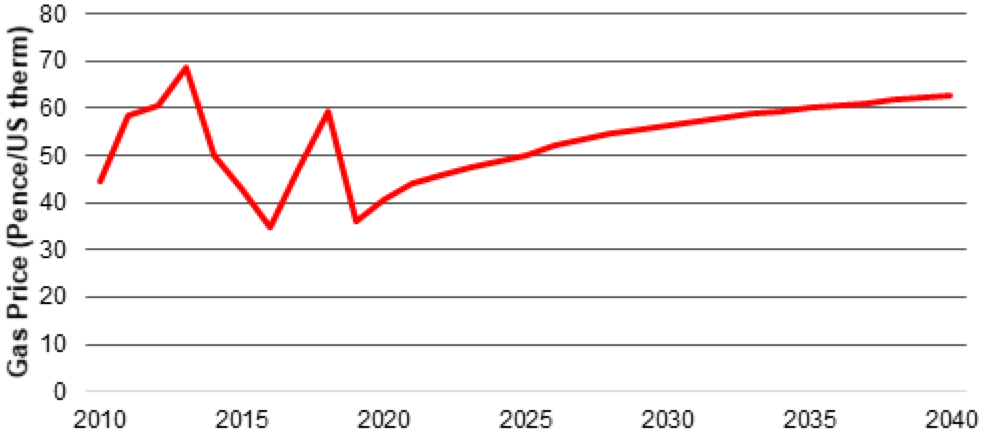
B.1.1 Demand Assumptions

National Grid FES 2020 – Peak Demand, GW

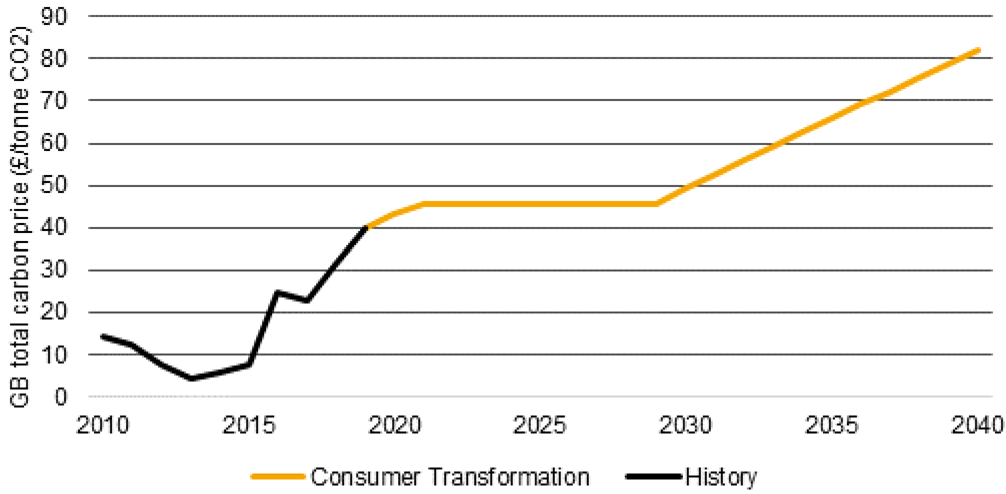


B.1.2 Commodity Prices

National Grid FES 2020 – Base Case Gas Price, p/th

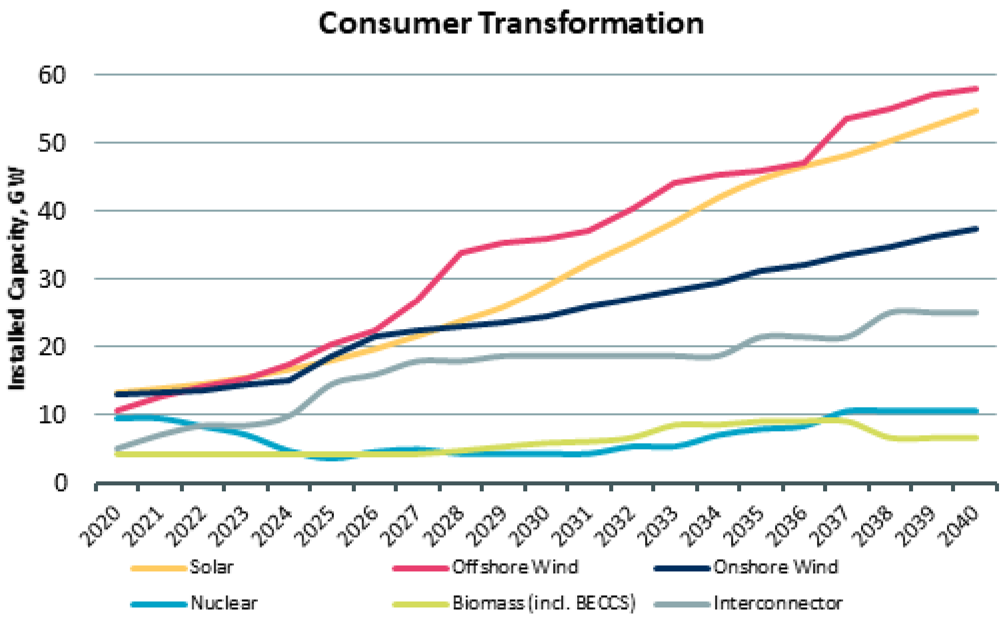


National Grid FES 2020 – Base Case Total Carbon Price, £/t



B.1.3 Low carbon build projections

Projections of post-2020 low carbon build, based on Steady Progression and Consumer Transformation FES 2020 scenarios.



ANNEX C INTERNATIONAL COMPARISONS

Ofgem asked us to conduct a light touch international review of how balancing services costs are recovered internationally. We set out the findings of this review below.

The key finding from our review is that there is wide variation in how the costs of different system services linked to system operation and balancing are recovered internationally. Figure 55 on the next page shows the variation in how system service and congestion management costs are recovered across 29 European jurisdictions. Many of these charges are recovered through transmission tariffs (TRM-T) in a number of countries and balancing energy is often recovered through charges on balance responsible parties (BRPs). However, different services that contribute to system stability and balancing can be recovered through different mechanisms and in some jurisdictions, certain services that contributed to system stability charges are not paid for by the TSO but are required to be provided free of charge by generators.

This wide variety of approaches to the recovery of ancillary services and congestion management costs highlights the challenges with making meaningful comparisons of which parties are responsible for cost forecast error. Despite these comparability challenges, we have tried to ascertain if there are examples of charges that are set to recover similar costs to BSUoS being set on ex ante or ex post bases. We provide the details we are aware of in the text below.

In the Netherlands, the TSO, TenneT, is responsible for forecasting the costs of purchasing Primary Reserve, control and emergency power and recovery facilities. The regulator (ACM) assessed that the TSO should be capable of making unbiased forecasts of these costs but accepted that the costs will be subject to considerable uncertainty. TenneT is provided an ex ante allowance for these costs and then there is a subsequent reconciliation which allows TenneT to recover a portion of the forecast error in future periods.[49]

We understand that in Austria the regulator includes planned fixed costs of reserve capacity in the annual determination of TSO network tariffs. These costs are then subject to an ex post rolling up of out turn and planned costs that are recoverable in future network tariffs. In contrast, we understand that in Germany the recovery of the fixed costs of procuring reserve capacity are treated as non-controllable costs and enter network charges with a time lag and are therefore effectively recovered ex post.

We note that in principle, the difference between ex post and ex ante can be blurred if there is a true up with a lag. If balancing and system charges are set on an ex ante basis but the forecast of ex ante costs is set equal to actual costs in some previous period (without any adjustment), this is equivalent to the charges being set ex post but with a lag.

[49] See Paragraphs 133-158 (in Dutch) of: https://www.acm.nl/sites/default/files/documents/2019-01/herstel-methodebesluit-systeemtaken-tennet-2017-2021.pdf

Figure 55 Recovery of system services and congestion management costs in various jurisdictions

Jurisdiction	Frequency containment reserve	Frequency restoration reserve	Replacement reserve	Reactive support and voltage control	Black start capability	Balancing energy	Congestion management
Austria	Other charge	Both TRM-T and other charges	N/A	TRM-T	TRM-T	Imbalance settlement / BRPs	TRM-T
Belgium	TRM-T	TRM-T	N/A	TRM-T	TRM-T	Imbalance settlement / BRPs	TRM-T
Bulgaria	TRM-T	TRM-T	TRM-T	TRM-T	TRM-T	Imbalance settlement / BRPs	Not recovered by any tariffs or charges levied on grid users
Croatia	Provided by generators on a mandatory basis without compensation by the TSO	Partially TRM-T	N/A	TRM-T	TRM-T	Imbalance settlement / BRPs	TRM-T
Cyprus	Other charge	Other charge	Other charge	Other charge	Other charge	Other charge	Not recovered by any tariffs or charges levied on grid users
Czech Republic	Other charge	Other charge	Other charge	Other charge	Other charge	Imbalance settlement / BRPs	TRM-T
Denmark	Other charge	Other charge	N/A	Other charge	Other charge	Imbalance settlement / BRPs	Other charge
Estonia	Frequency is held by Russian TSO free of charge	Frequency is held by Russian TSO free of charge	TRM-T	Both TRM-T and other charges	TRM-T	Imbalance settlement / BRPs	Included in the commodity price

Jurisdiction	Frequency containment reserve	Frequency restoration reserve	Replacement reserve	Reactive support and voltage control	Black start capability	Balancing energy	Congestion management
Finland	Both TRM-T and other charges	Both TRM-T and other charges	N/A	TRM-T	TRM-T	Imbalance settlement / BRPs	TRM-T
France	TRM-T	TRM-T	TRM-T	TRM-T	Provided by generators on a mandatory basis without compensation by the TSO	Imbalance settlement / BRPs	TRM-T
Germany	TRM-T	TRM-T	N/A	TRM-T	TRM-T	Imbalance settlement / BRPs	TRM-T
Greece	Other charge	Other charge	Other charge	Other charge	Provided by generators on a mandatory basis without compensation by the TSO	Other charge	Other Charge
Hungary	TRM-T	TRM-T	N/A	TRM-T	TRM-T	Partially recovered by TRM-T	TRM-T
Ireland	TRM-T	TRM-T	TRM-T	TRM-T	TRM-T	Other charge	Other Charge
Italy	Provided by generators on a mandatory basis without compensation by the TSO	Other charge	Other charge	Provided by generators on a mandatory basis without compensation by the TSO	Other charge	Partially recovered by other charge	Between zone congestion is in the commodity price. Intra-zonal congestion is recovered by a specific charge
Latvia	TRM-T	TRM-T	TRM-T	TRM-T	TRM-T	Imbalance settlement / BRPs	TRM-T
Lithuania	Other charge	Other charge	Other charge	Other charge	Other charge	Other charge	TRM-T

Jurisdiction	Frequency containment reserve	Frequency restoration reserve	Replacement reserve	Reactive support and voltage control	Black start capability	Balancing energy	Congestion management
Luxembourg	TRM-T	TRM-T	N/A	TRM-T	TRM-T	Imbalance settlement / BRPs	TRM-T
The Netherlands	TRM-T	TRM-T	N/A	TRM-T	TRM-T	Imbalance settlement / BRPs	TRM-T
Norway	TRM-T	TRM-T	TRM-T	TRM-T	Not recovered by any charge levied on grid users	Imbalance settlement / BRPs	TRM-T
Poland	TRM-T	TRM-T	TRM-T	TRM-T	TRM-T	Imbalance settlement / BRPs	TRM-T
Portugal	Provided by generators on a mandatory basis without compensation by the TSO	Not recovered by any charge levied on grid users	Not recovered by any charge levied on grid users	Other charge	Other charge	Imbalance settlement / BRPs	Other Charge
Romania	Provided by generators on a mandatory basis without compensation by the TSO	System services charge	Other charge	Other charge	Provided by generators on a mandatory basis without compensation by the TSO	Imbalance settlement / BRPs	TRM-T
Slovak Republic	Other charge	Other charge	Other charge	Other charge	Other charge	Other charge	Not recovered by any tariffs or charges levied on grid users
Slovenia	TRM-T	TRM-T	N/A	TRM-T	TRM-T	Imbalance settlement / BRPs	TRM-T
Spain	Included in the commodity price	Included in the commodity price	Included in the commodity price	Included in the commodity price	Included in the commodity price	Not recovered by any charge levied on grid users	Included in the commodity price

Jurisdiction	Frequency containment reserve	Frequency restoration reserve	Replacement reserve	Reactive support and voltage control	Black start capability	Balancing energy	Congestion management
Sweden	TRM-T	Other charge	Other charge	TRM-T	both TRM-T and other charges	Imbalance settlement / BRPs	TRM-T
UK (Great Britain)	Other charge (BSUoS)	Other charge (BSUoS)	Other charge (BSUoS)	Other charge (BSUoS)	Other charge ((BSUoS)	Imbalance settlement / BRPs	Other Charge
UK (Northern Ireland)	TRM-T	TRM-T	TRM-T	TRM-T	TRM-T	Market Operator charges (imperfections Charge)	Other Charge

Source: *https://documents.acer.europa.eu/Official_documents/Acts_of_the_Agency/Publication/ACER%20Practice%20report%20on%20transmission%20tariff%20methodologies%20in%20Europe.pdf*

Note: Reproduced from Tables 12 and 13 www.frontier-economics.com