DISTRIBUTIONAL AND WIDER SYSTEM IMPACTS OF REFORM TO RESIDUAL CHARGES

November 2018

CONTENTS

1 INTRODUCTION

In 2017 Ofgem launched the Targeted Charging Review (TCR), which is a Significant Code Review (SCR) with the objective to review and reform the network charging arrangements related to the recovery of fixed costs of the electricity transmission and distribution networks. The TCR is primarily motivated by a concern that the current framework for residual charging may drive inefficient behaviours from some network users, and result in adverse impacts on others.

The TCR builds on the Embedded Benefit Review and the assessment of CMP 264/265 relating to the charging arrangements for distribution connected generation, specifically to remove the potential for avoidance of transmission use of system (TNUoS) cost recovery charges on load through the use of distribution connected generation. The TCR builds on the same principle, but is an assessment of cost recovery charges across a broader set of network users i.e. all types of load including those sites with onsite generation or behind the meter generation (BTMG), and more network charges i.e. including distribution use of system charges (DUoS).

In November 2017 Ofgem published an update to the TCR setting out its initial views on proposed reforms to residual charges and how it proposes to go forward with its assessment of options. In this working paper Ofgem set out that based on their initial assessment they are minded to levy residual charges on demand, rather than generation. They also set out four high-level options which it considered worth further assessment for the structure of charges.

- Fixed charges (per user): based on a fixed rate per user, which varies in a clearly defined way e.g. such as user profile classes, line loss factor classes or measurement classes.
- Ex-ante capacity demand (per kW) charge: based on a network user’s physical connected capacity or a lower agreed capacity charge.
- Ex-post demand capacity charge (per kW): based on a number of metered peaks in individual users’ demand.
- Gross volumetric consumption charge (per kWh): based on the totality of a network user’s electricity consumption, including consumption of electricity generated on-site. This option should be primarily explored with respect to non-domestic consumers (given practical and other considerations in relation to residential consumers).

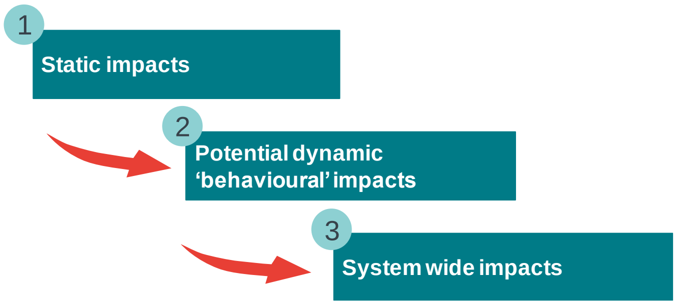
Ofgem has also suggested that there could be hybrid options which are based on some combination of the four options above. The choice of these options was motivated by the fact that, to varying degrees, they each reduce the ability of network users to avoid the charges by way of demand reduction or the dispatch of onsite generation. There are also a wider set of implications to consider from the changes. Ofgem is keen to balance improvements in the level of distortions from the charging options with considerations of fairness and proportionality and practicality.

Ofgem has engaged Frontier and LCP to provide an independent assessment of some key aspects of the options it is considering. The options we consider in this report are based on the high-level options set out by Ofgem in their consultation. In the first instance, we assess what we term ‘basic options’, i.e. the most basic interpretation of Ofgem’s high-level TCR options. We then consider a further five options which Ofgem set out following consideration of the initial ‘basic’ results.

This report is intended to support the wider assessment work of the options being carried out by Ofgem, and is focused on the potential distributional and wider system impacts of the options, i.e. are the changes likely to reduce or increase the costs of operating the system. Consequently, this report does not contain all of the analysis being considered by Ofgem in coming to its decision, and as a result does not contain an explicit recommendation as to which option(s) should be preferred. In particular, we reiterate our previously expressed view that quantitative modelling should not be the sole (or in many cases even principal) basis for determining whether particular modifications to a charging regime are appropriate, and that a qualitative assessment against clear criteria is of critical importance.

Specifically, our approach investigates the potential impacts in three key areas as highlighted in Figure 1.

Figure 1 Potential impacts considered



Source: Frontier Economics

- **Static bill impact analysis** – In the first phase of the work we assess the potential direct impact on bills. This is a static analysis, by which we mean we are assessing the impacts holding physical behaviour constant. This is intended to provide Ofgem with an understanding of the potential distributional impacts of the proposed changes. In other words, we identify the types of users and types of consumption patterns that are likely to pay less as a result of the changes and those that are likely to pay more. We illustrate these impacts by modelling the effect of the different charges on a range of different representative domestic, commercial and industrial profiles, informed by public source data and information from stakeholders.
- **Behavioural assessment** – Given the potential impact on network bills for different types of users, we consider the potential for behaviour to be affected in relation to how/when customers use the network, choose to self-generate, and adopt new technologies, e.g., electric vehicles (EVs) and heat pumps.
- **Wider system impacts analysis** – In the final phase of the work we examine what the implications of some of the potential behavioural responses could be

for the total costs[1] of operating the electricity system and costs to consumers up to 2040. This assessment is based on system modelling using the Envision model.

We note that throughout this quantitative analysis we have had to make numerous simplifications and assumptions. For example, particularly for larger customers, tariffs will be a function of a number of site specific factors which it is not possible to capture when estimating the tariffs of a "representative" user. Similarly, 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.

This report is structured as follows:

- In **Section 2**, we provide an overview of the principles behind Ofgem's motivation for reform, and set out the options that Ofgem has asked us to consider.
- In **Section 3**, we set out the qualitative and quantitative assessment of the static distributional impacts for different types of users.
- In **Section 4** we consider potential behavioural responses to the different options.
- In **Section 5**, we set out the quantitative modelling of the wider system impacts.
- In **Section 6**, we set out the implications of this analysis for Ofgem.
- Finally, in **Section 7**, we set some key limitations of our analysis.

[1] In common with our analysis of CMP 264/265, 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.

2 OPTIONS FOR ASSESSMENT

In this section we set out the options that Ofgem has asked Frontier and LCP to assess. First, to provide the context for the high-level options set out by Ofgem we outline the principles behind cost recovery charges. We then describe in more detail the specific options assessed in this report.

2.1 Principles for setting cost recovery charges

There are a number of economic principles which are typically associated with the definition of network charges. These include ensuring efficient market outcomes, fairness, practicality, simplicity and predictability.

With regard to the principles behind ensuring efficient market outcomes, it is typically argued that network charges should be cost reflective. By this, we mean that they should reflect the (forward looking) costs which users impose on the network through a change in their use. If charges are cost reflective, users will internalise the network costs which they cause when making a decision about how to use the network. This will in turn ensure that overall value chain costs are optimised.

Cost reflective charging in this way will ensure that the existing infrastructure is put to efficient use. However, it will not ensure its fixed, or “sunk”, costs are recovered. Therefore, additional charges are required to recover costs. These additional, or residual, charges are the focus of the TCR. Residual charges are set to ensure network companies can recover the cost of building, operating and maintaining the distribution and transmission systems from network users.

This leaves the question as to how any “residual” costs which are unrecovered after taking account of revenues collected from cost reflective charges should be charged. The key economic principle behind the optimal recovery of sunk costs is relatively straightforward to describe. It is typically argued that such charges should have as an objective creating minimal changes in behaviour relative to a set of efficient, cost-reflective charges i.e. minimising distortions.

The logic behind this principle is that, as we have already noted, an efficient outcome is achieved on the basis of cost reflective tariffs. Any further change in behaviour (such as actions by network users to avoid or reduce exposure to residual charges) do not result in any savings to overall network costs and will result in a reduction in social welfare. These costs are already sunk and hence cannot be avoided. Therefore, avoidance behaviour by some users simply distorts efficient outcomes and results in higher costs having to be recovered from other network users.

The high-level options set out by Ofgem primarily aim to reduce the ability to avoid charges by some users. The potential impact of each option on avoidance behaviour is summarised in Figure 2.

Figure 2 Ofgem's short-listed residual demand charge options

Short-listed option	Description	Impact on market distortions
Fixed	▪ Per user demand charge.	▪ Customers unable to avoid charge by means of demand reduction/ onsite generation. ▪ Charges can be avoided through disconnection.
Gross volumetric consumption	▪ Separate metering of onsite generation so total consumption is measured including consumption from onsite generation.	▪ Customers unable to avoid charge by means of onsite generation, gross consumption is relatively inelastic. ▪ Charges can be avoided through load disconnection, and energy efficiency.
Ex-ante capacity	▪ Charges based on user's agreed or connected capacity.	▪ Customers are unable to avoid the charge by means of demand reduction/ onsite generation. ▪ Charges can be avoided through disconnection or agreed changes to the definition of connected capacity.
Ex-post capacity	▪ Charges based on a measure of historic peak system usage.	▪ Depending on exact measure of historic peak, customers will always have some peak consumption. Demand reduction in specific period will have a smaller avoidance effect on future charges than current triad system for example. ▪ Charges can be avoided through load disconnection, and energy efficiency.

Source: Frontier Economics

It is common to each of the high-level options that avoidance behaviour is significantly reduced relative to current arrangements, where onsite generation can help users avoid TNUoS 'triad' charges (i.e. peak consumption net of onsite generation), and energy based DUoS charges (i.e. annual consumption net of onsite generation).

In this report, we consider how the burden of cost recovery is shifted among different types of users under the options relative to the baseline (i.e. through the static bill impact modelling), and the potential efficiency benefits associated with reduced avoidance behaviour (through the behavioural and system wide modelling).

2.2 Options for consideration

We have structured our assessment of the options into two phases. We first considered a set of 'basic' options which represent our interpretation (for the purposes of quantitative evaluation) of Ofgem's TCR options.

The specific design of the basic options was based on a simple interpretation of how Ofgem's high-level TCR options (set out above) could be implemented. The approach was also influenced by data availability. The basic options are only intended to aid understanding of the potential impacts and inform the development of further options. They are not designed to be a statement of Ofgem policy intentions.

The basic options were defined according to the revenue to be recovered and the charging base over which the revenue is recovered. A summary of the basic options is set out in Figure 3. The charges are estimated separately for each of:

- **Transmission (T)** – this is typically above 132kV, and follows the Transmission Network Use of System (TNUoS) charging methodology.
- **Extra high voltage (EHV)** – this is typically for 22kV and above, and follows the EHV Distribution Charging Methodology (EDCM).
- **High voltage (HV) and low voltage (LV)** – these are typically below 22kV and follow the Common Distribution Charging Methodology (CDCM).

Figure 3 Defining the basic options

<table>
<tr><th>Basic option</th><th>Residual to be recovered</th><th>Charging base</th></tr>
<tr><td>1. Fixed</td><td>The residual recovered from each customer segment is held constant with the baseline i.e. the revenue recovered from each segment is fixed at historic levels</td><td>Residual recovered equally from each connection in customer segment.
Customer segments were defined by LLFCs at HV and LV, all transmission connected loads, and all EHV connected loads.
Relevant segments applied based on which users pay different charges</td></tr>
<tr><td>2. Gross volumetric</td><td rowspan="3">Total residual for relevant network area</td><td>Total gross consumption of users paying network charge</td></tr>
<tr><td>3. Ex-ante capacity</td><td>Total connection capacity for users paying network charge</td></tr>
<tr><td>4. Ex-post capacity</td><td>Sum of individual peaks for users paying network charge</td></tr>
</table>

Source: Frontier Economics

Note: 'LLFCs' – Line Loss Factor Classes are defined as part of current CDCM charging arrangements.

Following discussion of the results related to the basic options, Ofgem set out a further set of five options designed to test the impact of a more detailed specification of particular options. These are summarised in Figure 4.

Figure 4 Defining additional options

Option	Description
5. Fixed by volume	The residual recovered from each customer segment is apportioned by share of total net volume (as opposed to historic residual recovery) Segments defined as under the basic fixed charge
6. Fixed charges (75%) and ex-post (25%)	Combination of basic fixed by volume charge (75%) and ex-post capacity charge (25%). Ex-post charge element set of basis of average of 12 monthly peaks (as opposed to annual individual peak).
7. Deemed ex-ante capacity for domestics	Basic ex-ante capacity charge except domestic capacities are deemed to be lower than physical connection size. Specifically: ▪ 4kVA for 75% of domestic customers ▪ 6kVA for 'higher consuming' domestics (assumed to be 15% of all domestics) ▪ 8kVA for EVs and HPs (assumed to be 10% of all domestics)
8. Deemed ex-ante capacity for domestics (75%) and net volumetric (25%)	Combination of deemed ex-ante capacity charge set out under option 7 (75%) supplemented with a net volumetric element (25%).
9. Ex-ante capacity set on historic peak	Basic ex-ante capacity charge set at historical peak (e.g. 5-year individual peak). If exceeded new individual peak becomes new maximum for charging.

Source: Frontier Economics / LCP based on information from Ofgem

3 STATIC BILL IMPACTS

In this section we set out our qualitative and quantitative assessment of the potential static bill impacts of tariff changes i.e. the impacts on the bill when the behaviour of individual users is held constant. This analysis is focused only on the impact of changes to the residual component of network user's bills, and hence all impacts are presented on the basis of this part of the bill before (i.e. the 'baseline') and after the change in charging arrangements.

It is important to note that the bill impacts illustrated in this section are based on an assumption that residual charges under the baseline and under the options are fully passed through to all consumers. As it currently stands, this may not be the case since suppliers are free to determine how they pass on charges to customers. Further, profile classes 1-4 are still settled on a non half-hourly basis, and as such the shape of an individual domestic consumer's profile does not matter from the perspective of network charging. However, should half-hourly settlement for profile classes 1-4 be introduced then domestic consumers with different consumption profile shapes could, where relevant, face different charges if suppliers choose to pass them through.

The figures presented are in general based on charging data relevant to the single year of 2019. We have not attempted to make a projection of bill impacts over multiple future years given the significant uncertainty related to future assumptions, in particular the nature of customer profiles, and the future size of the residual.[2]

However, we have chosen user groups that reflect consumption patterns prevalent today and potentially in the future e.g. providing for users adopting technologies (electric vehicles and heat pumps) that have the potential of meaningfully altering their level and profile of electricity consumption. This will allow us to understand the potential impacts of the charges on consumption patterns today and in the future. In addition, while the specific magnitudes of the estimated bill impacts are likely to vary depending on the level of the residual, the broad direction of the impacts identified should still be applicable.[3]

This section is structured into the following five steps which are also set out in Figure 5:

- In **Step 1** we identify a set of user groups which we have assumed are representative of particular consumer archetypes.
- In **Step 2** we define a set of 'baseline' charges that representative network users would pay should the existing charging arrangements remain i.e. counterfactual charges.
- In **Step 3** we calculate a set of illustrative network tariffs which could apply under each of the basic options (options 1-4) i.e. a set of factual charges.
- In **Step 4** we first consider the expected impacts for different types of users of moving from the baseline arrangements to the basic charging options, and then

2 The future size of the residual is a function of the quantum of network charges and regulatory policy related to the share of those costs recovered through cost reflective charges.

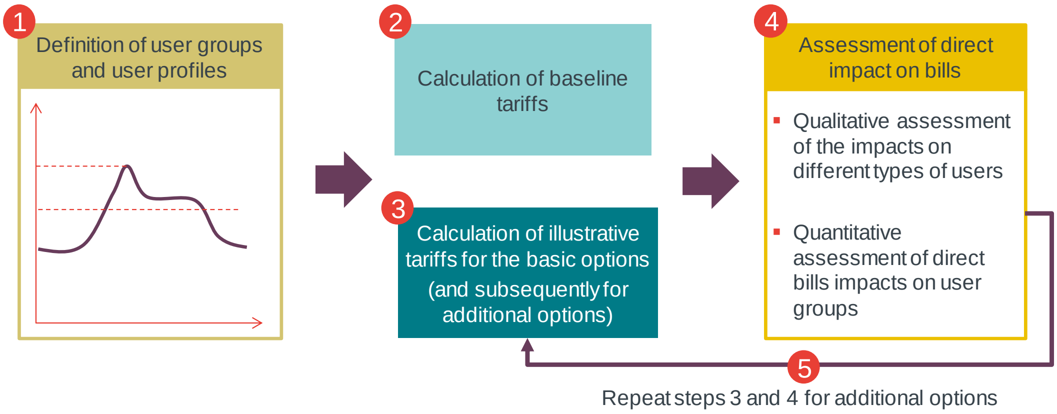
3 The level of residual is important for system modelling and therefore we conduct sensitivities for different levels of residual

demonstrate these impacts by quantitatively assessing the potential change in network residual bills for the representative user groups.

- In **Step 5** we repeat Step 3 and Step 4 based on the additional options (options 5-9) identified by Ofgem. We present these additional options separately from the basic options because a number of the additional options are hybrids of the basic options, and hence it is easier to assess the impacts following a complete discussion of the basic options.

This phase of the work is carried out in five steps, which are set out in Figure 5:

Figure 5 Overview of the approach to assessing the static bill impacts



Source: Frontier Economics

The availability of data has been an important consideration in developing the options to test. Typically, we have relied on information provided by network owners:

- Information to derive CDCM charges has typically been sourced directly from all of the DNOs CDCM models which are publicly available. However, in a number of instances we have applied information from other sources, including based on more detailed analysis carried out by a subset of DNOs on underlying CDCM data which is not publicly available.
- EDCM baseline charges are individually set. By way of an information request, all DNOs provided anonymised site specific residual charges, and descriptive statistics for each site from which charges could be derived.
- TNUoS charges were based on information provided by National Grid. about transmission connected customers, and combined with the CDCM and EDCM data to derive system level data relevant for TNUoS charges.

This section discusses each step in turn.

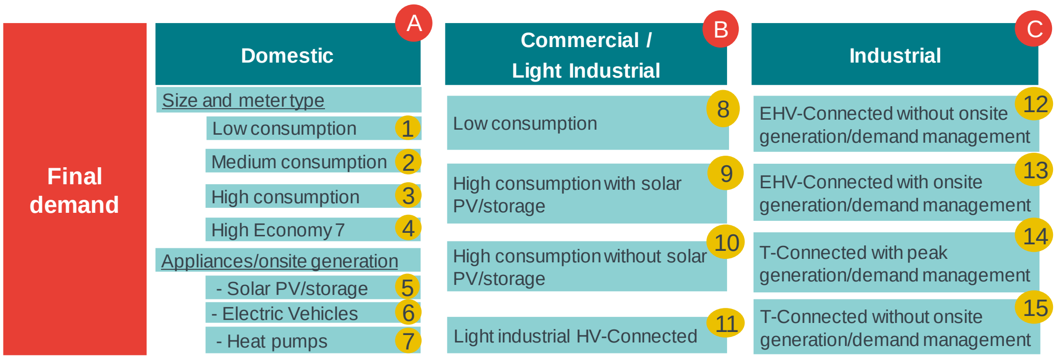
3.1 Step 1 - defining a set of user groups

In Step 1 we identify a set of user groups to understand how different customer groups could be affected by changes in the network charging structure.

We have identified these user groups in relation to a range of actual consumption profiles of different GB consumers and possible changes in consumption resulting from the installation of technologies like electric vehicles, heat pumps or onsite generation. However, it is important to note that they cannot be representative of all consumers.

The domestic, commercial and industrial user groups that we have identified are outlined in Figure 6. In total we have identified 15 final demand user groups spread across domestic, commercial and industrial categories. It is important to note that in reality the boundaries between users may overlap. For example, the baseline results for a larger domestic customer may be more appropriate for certain small commercial customers than our low consuming commercial user group.

Figure 6 User group classifications



Source: Frontier Economics

Note: Note that Group 5 comprises of two sub-groups: solar PV in isolation and solar PV combined with storage.

To identify the domestic user groups (Panel A) outlined in Figure 6 we relied on a combination of:

- **Ofgem's Typical Domestic Consumption Values (TDCVs)**: TDCVs identify the "low", "medium" and "high" consumption levels[4] for domestic GB electricity consumers (Profile Class 1 and Profile Class 2) and are commonly used to derive typical consumer bills when the actual consumption level is not known.
- **Customer-Led Network Revolution (CLNR) data**: The CLNR trials collected electricity consumption and generation profiles of 13,000 domestic and commercial customers. The CLNR data provides the actual consumption levels and patterns of GB domestic and commercial consumers, controlling for changes in consumption resulting from the adoption of technologies like solar panels, electric vehicles and heat pumps.[5]

The annual consumption levels of the first four domestic user groups (Groups 1-4 in Figure 6) are defined with reference to Ofgem's 2017 TDCV values. However, the impact of the charges will also depend on the shape of consumption. We therefore identify domestic users from within the CLNR dataset with similar levels

[4] "The median or second quartile is a more representative of the typical "medium" usage. We use the first and third quartiles to represent the typical "low" and typical "high" usage respectively. In real terms, if consumers were ranked in order of energy consumption, the lower quartile reflects the annual consumption that only 25% of all consumers use less than. The higher quartile reflects the annual consumption that only 25% of all consumers use more than." Ofgem. Decision on revised Typical Domestic Consumption Values for gas and electricity and Economy 7 consumption split. 3 august 2017. Available here: https://www.ofgem.gov.uk/system/files/docs/2017/08/tdcvs_2017_decision.pdf

[5] CLNR. Developing the smarter grid: the role of domestic and small and medium enterprise customers. 2015.

of annual consumption to observe the “typical” shape of half-hourly consumption for these users, and in particular the level of peak demand.[6]

To test the impact of different domestic technologies, we develop a series of domestic profiles assuming the adoption of solar PV and/or storage, electric vehicles and heat pumps (Groups 5-7 in Figure 6). We derive these by adjusting the profile assumed for our domestic user with medium consumption, based on the impact of technologies observed in the CLNR data.

For commercial/light industrial users (Groups 8-11 in Figure 6) we have relied primarily on the CLNR dataset to infer the level and shape of consumption for representative consumer archetypes. The key features of the domestic and commercial user groups are outlined in Figure 7. More details on our analysis is provided in Annex A.

Figure 7 Key aspects of Domestic and Commercial profiles

User group	Voltage level	Connection capacity	Annual gross demand	Annual net demand	Annual 4-7 demand (Median)	Half-hourly peak demand (Median)
		(kVA)	(kWh)	(kWh)	(kWh)	(kWh)
Non-half-hourly metered (NHH)						
1. Domestic – Low consumption	LV	18	1,900	1,900	360	1.71
2. Domestic – Medium consumption	LV	18	3,100	3,100	597	2.29
3. Domestic – High consumption	LV	18	4,600	4,600	904	2.85
4. Domestic – High Economy 7	LV	18	7,100	7,100	1,345	3.41
5a. Domestic – Medium Solar PV	LV	18	3,100	2,204	362	2.29
5b. Domestic – Medium Solar PV with storage	LV	18	3,100	1,918	76	2.29
6. Domestic – Medium Electric vehicles	LV	18	4,622	4,622	682	3.71
7. Domestic – Heat pumps	LV	18	5,651	5,651	697	3.36
8. Commercial – Low consumption	LV	55	10,000	10,000	1,119	4.73
9. Commercial – High with onsite generation/storage	HV	55	25,000	15,470	615	6.61
10. Commercial – High without onsite generation/storage	HV	55	25,000	25,000	3,434	6.61
Half-hourly metered (HH)						
11. Commercial – Light industrial HV-connected	HV	2,000	5,000,000	5,000,000		285.39

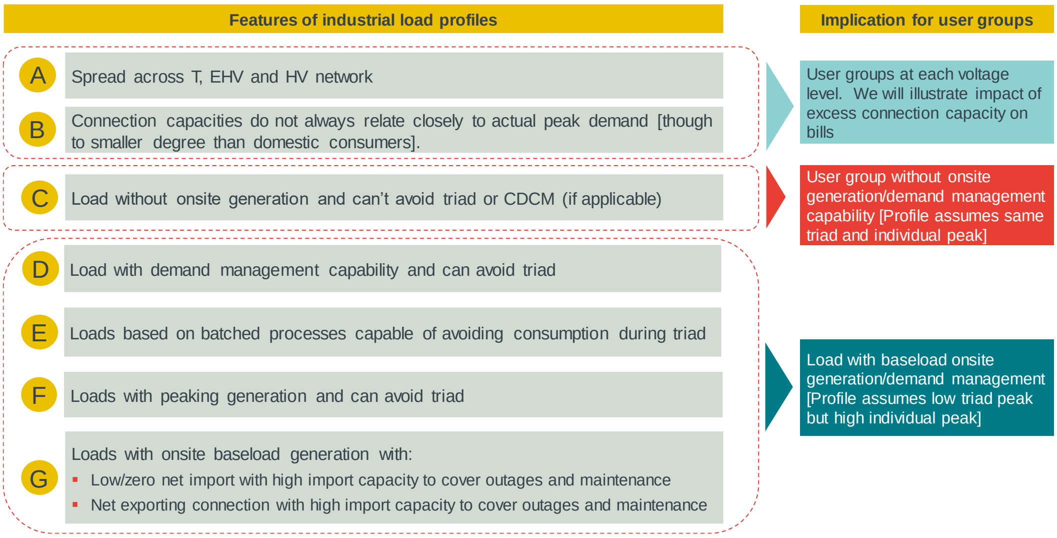
Source: TDCV; Frontier Economics’ analysis of CLNR data

6 These values are aligned to the 1st, 2nd and 3rd quartiles of annual consumption of domestic users in the CLNR dataset for basic domestic users (TC1a). This provides a degree of confidence to draw conclusions for the GB market as a whole based on the CLNR trials which were designed to include households from across different demographic groups so as to provide an overall picture of domestic electrical consumption in the UK.

In relation to representative industrial user groups, because of the very significant diversity among industrial users, we engaged with industrial stakeholders and identified the key features of industrial load profiles that would drive different bill impacts as a result of a change in approach to residual charging. The key features were identified by way of conversations at two stakeholder events, discussions with a number of industrial trade bodies, and the high-level review of some site specific data received from a number of different industrial customers and DNOs. While examining some of the industrial data received provided interesting insights as to different features of industrial sites, no site specific data is used in any of our industrial user groups.

The key features identified are listed in Figure 8 below.

Figure 8 Features of industrial user groups



Source: Frontier Economics

From this list we then ensured these key features mapped across to our industrial user archetypes. Guided by our discussions with the Energy Intensive Users Group and based on publicly available data by BEIS and Eurostat, we have assumed that a typical EHV connected user has an annual gross consumption of 50,000 MWh and a typical transmission connected user has an annual consumption of 100,000 MWh.

As noted in Figure 8 above, at each voltage level we then provide for the ability for load to reduce or shift their gross consumption using onsite generation and demand management (shifting load away from peak periods), respectively. For simplicity, we assume a flat profile for our industrial user archetypes. On this basis, the user groups (12 and 15) without onsite generation of demand management capability have individual peak consumption in line with their system peak. Alternatively, for the user groups (13 and 14) with onsite generation or demand management capability, we assume they can completely avoid consumption during the system peak, though their individual peak is in line with the peak for user groups 12 and 15.

3.2 Step 2 - Baseline (“counterfactual”) charges

In Step 2 we set out the current approaches used for calculating CDCM, EDCM and TNUoS residual charges, and show how we have derived the baseline charges used in the static analysis. The current demand residual charging arrangements are different depending on the particular network charge. We briefly summarise the baseline approach to charging in Figure 9 below.

Figure 9 Summary of current approaches to residual charging

Network	Description
CDCM	Energy based charge (p/kWh) applied to metered net volume
EDCM	User specific (p/kVA) capacity charge. Residual charge varies by location and historic average 4-7pm consumption relative to capacity.
TNUoS	For half-hourly metered customers charges set on basis of consumption during Triad periods i.e. charges closely linked to net consumption at system peak. For non-half-hourly customers charges set on the basis of annual net consumption during 4-7pm

Source: Frontier Economics

The baseline charges that we have used for CDCM, EDCM and TNUoS are outlined in more detail in the sections below.

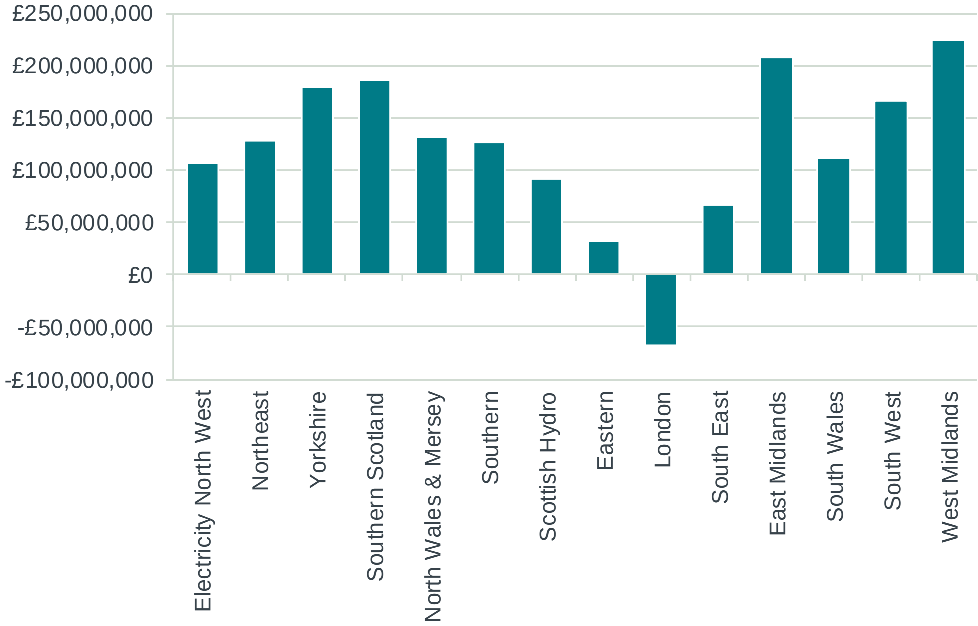
3.2.1 CDCM

The CDCM charging regime recovers the costs associated with the distribution networks at the LV and HV networks. At present, the CDCM residual is recovered through a DNO-specific fixed adder. The fixed adder takes the form of a p/kWh charge on annual at-meter consumption, and is constant across all customer types in a given DNO area.

Figure 10 below presents the total residual to recover from each DNO as presented in the 2019/20 CDCM models.[7] The total residual to recover varies widely across the different DNOs for CDCM.

[7] Note that the chart illustrates the residuals to be recovered as reported in the CDCM models. This data includes the residual to be recovered from UMS sites. We have excluded UMS sites from our basic and hybrid analysis.

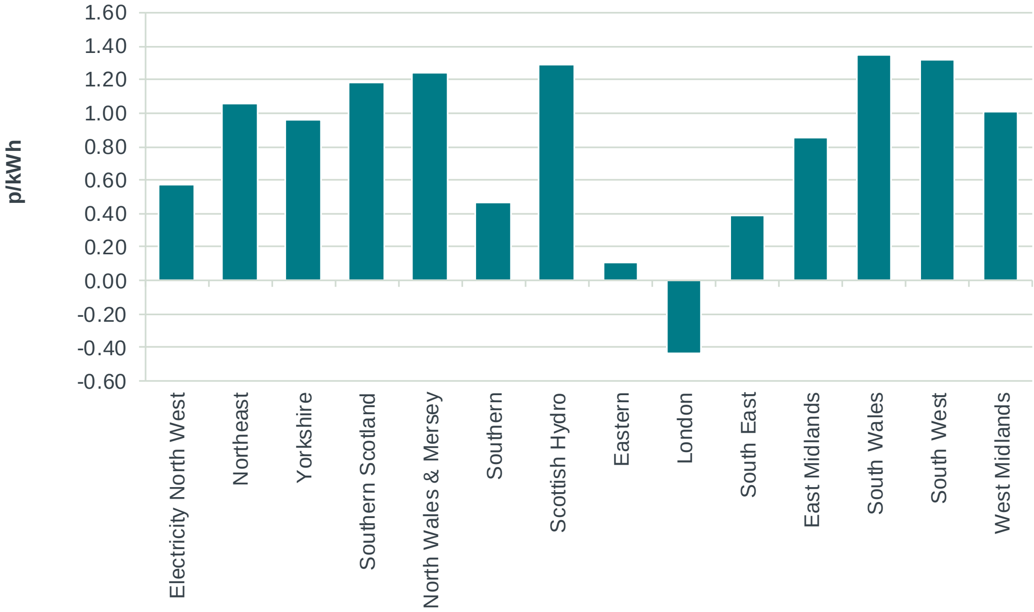
Figure 10 CDCM residual to be recovered from each DNO in 2019/20



Source: CDCM models collated by Franck Latrémolière distribution charging methodologies forum

The distribution of residual charges, which are defined as fixed adders in the CDCM models, are presented in Figure 11. The wide variance in the residual to recover across DNOs results in a wide range of fixed adders across DNOs.

Figure 11 CDCM residual charge for each DNO in 2019/20



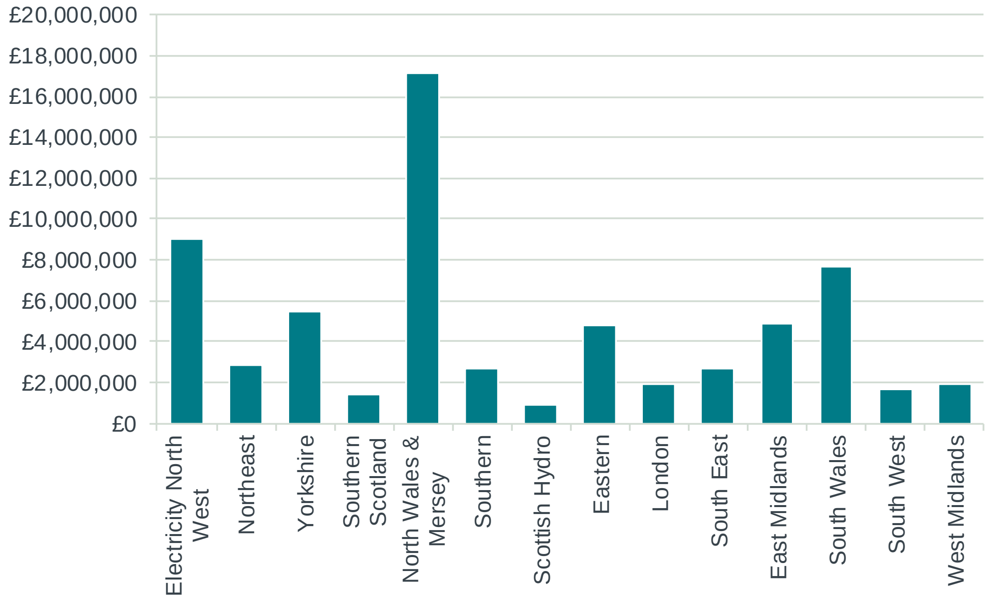
Source: CDCM models collated by Franck Latrémolière distribution charging methodologies forum

Across the DNOs, approximately 42% of the residual is recovered from domestic consumers, 33% from LV non-domestics and 25% from HV non-domestics.

3.2.2 EDCM

The EDCM charging regime recovers the costs associated with each distribution network at the EHV level. Figure 12 below presents the total residual expected to be recovered from each DNO in the 2019/20 charging year. Similar to CDCM, there is also a wide regional variation in the size of the residual to recover.

Figure 12 EDCM residual to be recovered from each distribution area in 2019/20



Source: Data sourced from each DNO

EDCM charges are site specific and therefore there is no single baseline charge against which charges under the options for each user group can be compared. There is a significantly wide range of EDCM charges for each DNO, with charges ranging from a few hundred pounds to several hundred thousand pounds.

3.2.3 TNUoS

The TNUoS residual to recover from demand customers is estimated using information from National Grid's five-year TNUoS forecast[8]. As outlined in Figure 13 below, National Grid splits allowed revenue between demand and generation. To derive the final demand residual National Grid makes adjustments to account for revenue recovered from the locational element of demand tariffs and the amount that is paid to embedded export tariffs. This results in a total residual revenue to be recovered from demand customers of £2.67 billion in 2019/20.

[8] National Grid, Five-year Forecast of TNUoS Tariffs for 2018/19 to 2022/23 (published November 2017)

Figure 13 National Grid forecast HH

Component	2019/20
Total TNUoS revenue (£m)	2,968.4
Proportion of revenue recovered from generation (%)	14.9%
Proportion of revenue recovered from demand (%)	85.1%
Generation Residual	
Generator residual tariff (£/kW)	-3.85
Generator charging base (GW)	73.8
Gross Demand Residual	
Demand residual tariff (£/kW)	52.13
Revenue recovered from the locational element of demand tariffs (£m)	-65.3
Amount to be paid to Embedded Export Tariffs (£m)	81.6
Demand Gross charging base (GW)	51.2
Residual revenue to be recovered from demand customers (£bn) [9]	2.67

Source: National Grid, Five-year Forecast of TNUoS Tariffs for 2018/19 to 2022/23 (published November 2017)

In 2019/20, the residual revenue of £2.67 billion is recovered from:

- half-hourly (HH) customers through a £52.13/kW charge on average triad demand; and
- non-half-hourly (NHH) customers through a location-specific p/kWh charge (the demand-weighted average across the network is 6.57p/kWh in 2019/20) on annual demand between 4pm and 7pm.[10]

3.3 Step 3 - TCR charges for basic options

In Step 3 we estimate a set of illustrative network tariffs which could apply under each of the basic options (options 1-4) i.e. a set of factual charges for the basic options. All of the basic charges are estimated using the same residual to be recovered divided by the charging base relevant to each basic option. We note that while the methodologies used to derive factual charges should provide a reasonable indication of charge level, they are inevitably inexact as we did not have all the information required to derive actual charges.

3.3.1 Fixed Charges

Fixed charges are estimated as a single charge for all users in a given customer segment – i.e. it is the residual to be recovered from the specific segment divided by the number of customers in that segment. To the extent possible, charges are set to recover the same revenue from each segment as expected under the 2019/20 baseline charges. In a number of cases we outline below, the revenue

[9] National Grid’s demand residual tariff multiplied by demand gross charging base

[10] Note that the NHH residual charges are not explicitly calculated as part of the TNUoS methodology. The average residual charge presented here has been derived by National Grid and is for illustrative purposes only.

recovered from each segment is not known, and hence we make a series of assumptions to derive it.

The methodology used to estimate the TNUoS, EDCM and CDCM fixed charges is outlined below, along with a summary of the resulting TNUoS, EDCM and CDCM fixed charges.

TNUoS

TNUoS 2019/20 fixed charges have been estimated across all CDCM, EDCM and T-connected customers. A single fixed charge has been estimated for all T-connected customers, EDCM customers, and for each of the CDCM line loss factor classes (LLFCs) . Charges for each element are calculated as follows:

- *T-connected customers*: The TNUoS fixed charge for T-connected customers is estimated by taking T-connected Triad demand[11] and multiplying it by the 2019/20 HH TNUoS charge of £52.13/kW. This is then divided by the total number of T-connected customers[12] to get a TNUoS fixed charge per customer.
- *EDCM customers*: The TNUoS fixed charge for EDCM customers is estimated by taking EDCM Triad demand[13] and multiplying it by the 2019/20 HH TNUoS charge of £52.13/kW. This is then divided by the total number of EDCM customers[14] to get a TNUoS fixed charge per customer.
- *CDCM customers*: The fixed charges for CDCM customers are estimated as follows:
  - We subtract the total TNUoS residual estimated to be recovered from T-connected customers and EDCM customers (both calculated as above) from the overall residual to be recovered. The remainder is the residual to be recovered from CDCM customers.
  - The total residual to be recovered from CDCM customers is then allocated to the LLFCs in proportion to estimated 2019/20 baseline revenue recovery from each segment. For NHH LLFCs this is based on an estimate of total 4-7pm annual demand multiplied by the NHH TNUoS charge.[15] For HH LLFCs, this is based on an estimate of triad demand multiplied by HH TNUoS charge[16].
  - These estimates are then divided by the total number of CDCM MPANs[17].

The TNUoS fixed charges calculated for T-connected, EDCM and CDCM customers are outlined in Figure 14 below.

[11] National Grid provided the triad demand data for 2017/18, this was scaled to 2019/18 using peak electricity industrial and commercial data from the FES 2018 Steady progression scenario.

[12] Data also provided by National Grid.

[13] Sourced from EDCM triad demand data that the DNOs provided to Ofgem. The average EDCM import across all DNOs is converted from kWh to KW and scaled to 2019/18 using peak electricity industrial and commercial data from the FES 2018 Steady progression scenario.

[14] Sourced from EDCM data provided by DNOs, excluding grid-connected storage sites.

[15] Total 4-7pm demand is calculated by multiplying total demand for each NHH LLFC – which is sourced from 2019/20 CDCM models - by the proportion of domestic and SME consumption in the 4-7pm period – which is based on analysis of CLNR data. This is then multiplied by the NHH TNUoS charge of 6.57 (p/kWh)

[16] Total demand at system peak is calculated by dividing total demand for each HH LLFC – which is sourced from 2019/20 CDCM models - by 8760hrs and multiplying it by the average DNO ratio of coincidence factor to load factor for the relevant LLFC. The load factor and coincidence load factor data is also sourced from the CDCM 2019/20 models.

[17] Sourced from CDCM 2019/20 models.

CDCM

Any number of approaches to segmentation could be adopted. We have used LLFCs given the data availability on customer numbers (MPANs) and expected residual recovery from each LLFC.

We have estimated the fixed charge for each LLFC by dividing the reported residual to be recovered from each LLFC by the number of MPANs in each LLFC. This is calculated separately for each DNO.

EDCM

The EDCM fixed charge is calculated by dividing the total residual to recover by the number of connected customers that are not storage sites. From the data provided by DNOs it is not possible to separately identify sites which are specifically generation sites from those that are load with BTMG. Therefore, the estimate of the fixed charge includes all EDCM customers, which includes generation specific sites. This is unlikely to reflect Ofgem's intended policy position and hence, the fixed charge estimated is likely to be an underestimate. The charge is likely to be particularly sensitive to this assumption. For example, if the actual number of demand sites is half the number of customers assumed, the fixed charge would double.

Summary of fixed charges

The fixed charges for TNUoS, CDCM and EDCM are presented in Figure 14 below. The CDCM and EDCM charges presented are for Northeast distribution area. The CDCM and EDCM charges for other distribution areas are presented in Annex B. TNUoS charges are common to all distribution areas.

Figure 14 TNUoS, EDCM, CDCM fixed charges per customer

		TNUoS	CDCM	EDCM
CDCM NHH	Domestic Unrestricted	£44.09	£31.93	-
	Domestic Two Rate	£62.79	£54.47	-
	Domestic Off Peak (related MPAN)	£48.49	£42.79	-
	Small Non Domestic Unrestricted	£106.16	£117.41	-
	Small Non Domestic Two Rate	£189.99	£219.39	-
	Small Non Domestic Off Peak (related MPAN)	£71.82	£79.49	-
	LV Medium Non-Domestic	£379.45	£766.87	-
	LV Sub Medium Non-Domestic	£791.01	£1,278.76	-
	HV Medium Non-Domestic	£760.21	£2,177.00	-
	LV Network Domestic	£57.36	£27.37	-
	LV Network Non-Domestic Non-CT	£569.75	£464.28	-
CDCM HH	LV HH Metered	£2,057	£2,115	-
	LV Sub HH Metered	£4,954	£10,905	-
	HV HH Metered	£17,380	£31,467	-
EDCM customers		£65,355	-	£47,186
T-connected customers		£264,242	-	-

Source: Frontier Economics analysis of data from National Gird and DNOs

Note: The CDCM and EDCM charges presented are for Northeast distribution area. The CDCM and EDCM charges for other distribution areas are presented in Annex B. TNUoS charges are common to all distribution areas.
EDCM fixed charges are likely to be an underestimate, since the charging base also includes generation specific sites which could not be separately identified from the dataset.

3.3.2 Gross volumetric charges

Gross volumetric charges are estimated by dividing the relevant residual to recover by the total gross consumption in the charging area, resulting in a p/kWh charge. Measures of gross consumption are difficult to estimate since it is only net consumption (i.e. consumption after that met by BTMG) which is directly metered.

The methodology used to estimate the TNUoS, EDCM and CDCM gross volumetric charges is outlined below, along with a summary of the resulting TNUoS, EDCM and CDCM gross volumetric charges.

TNUoS

The TNUoS 2019/20 charge is calculated by dividing the total residual to recover (£2.67 billion) by the total gross consumption figure from the FES 2018 Steady Progression forecast for 2019/20. This figure represents National Grid's estimate of total system gross consumption, including consumption met by way of BTMG. This results in a 0.83p/kWh charge, as presented in Figure 15 below.

CDCM

To calculate the gross volumetric charges across the DNO areas for CDCM (and EDCM), we make an assumption about the location of behind the meter generation (BTMG) consistent with the total level of BTMG included in the Steady Progression scenario.

Using data sourced from the DNOs, National Grid and Ofgem, we have calculated system net consumption. The difference between this and the system gross consumption found in the FES 2018 Steady Progression scenario is assumed to equal the total level of BTMG production.

We then make the assumption that 40%[18] of the total BTMG takes place on the LV and HV networks, and as such can be attributed to CDCM customers. This is attributed to the different DNO areas according to net demand – i.e. we assume a constant rate of BTMG to net demand across each region. Note that we do not rely on an assumption about which customers on each network are generating behind the meter.

We are then able to use the calculated gross consumption for each DNO area to calculate the DNO-specific p/kWh gross volumetric charges. These are presented in Figure 15 below.

[18] 40:60 HV:EHV split applied to BTMG technologies is estimated from data sourced from DNO's for in-front-of-the-meter distribution connected generation. This data was taken from the DNO's LTDS which set out the amount of distribution connected generation connected in each zone along with the voltage of each connection. This was used to determine whether each connection would be subject to HV or EHV charging methodologies. A subset of this data containing only technologies which typically serve as BTMG (Gas, CHP, Gas and Diesel Reciprocating engines) was taken. Analysis of the ratio of capacities for HV and EHV technologies in this subset resulted in the 40:60 split applied to BTMG technologies.

EDCM

The remaining 60% of estimated total BTMG, is then assumed to be distributed across EDCM and T-connected customers in proportion to net demand, again assuming a constant rate of BTMG to net demand across each DNO area. We then use the assumed gross consumption by EDCM customers in each DNO area to calculate the DNO-specific p/kWh charges, which are presented in Figure 15 below.

Summary of gross volumetric charges

The gross volumetric charges for TNUoS, CDCM and EDCM are presented in Figure 15 below.

Figure 15 Gross Volumetric charges (p/kWh)

Distribution area	TNUoS	CDCM	EDCM
Electricity North West	0.83	0.55	0.24
Northeast	0.83	1.00	0.11
Yorkshire	0.83	0.91	0.15
Southern Scotland	0.83	1.12	0.11
North Wales & Mersey	0.83	1.18	0.30
Southern	0.83	0.45	0.05
Scottish Hydro	0.83	1.24	0.17
Eastern	0.83	0.10	0.12
London	0.83	(0.27)	0.05
South East	0.83	0.37	0.11
East Midlands	0.83	0.81	0.23
South Wales	0.83	1.28	0.21
South West	0.83	1.26	0.20
West Midlands	0.83	0.96	0.13

Source: Frontier Economics analysis of data from National grid, FES 2018 Steady progression and data from DNOs

3.3.3 Ex-ante capacity charges

Ex-ante capacity charges are estimated by dividing the relevant residual to recover by the total connection capacity across all relevant users. This results in a series of £/kVA charges. It is not possible to know the total system network capacity, however, we have worked with network owners to identify sensible assumptions for different types of users which can then be aggregated.

TNUoS

To illustrate an ex-ante capacity charge we have divided the residual by the estimated total connection capacity on the network. This has been obtained as the sum of the connection capacities for CDCM and EDCM customers (see below), and by assuming connection capacities for T-connected customers equal to the capacity used in their individual peak half hour. This is a proxy for since National Grid were unable to provide individual connection capacities for all T-connected customers. The resulting charge is £3.78/kVA, as presented in Figure 16 below.

CDCM

To illustrate ex-ante capacity charges across the DNO areas, we have used the total connection capacities provided in the CDCM models where possible. However, these are only available for HH-metered customers. As such, following conversations with the DNOs we assume that each domestic customer has a connection size of 18kVA, and NHH metered non-domestic customers have a connection size of 55kVA. Given these assumptions, it is possible to calculate the sum of connection capacities in each DNO area, and as such the £/kVA charges for each region, which are presented in Figure 16 below.

EDCM

Connection capacities for each EDCM customer were provided by the DNOs allowing us to calculate the sum of connection capacities at EDCM for each DNO. These charges are presented in Figure 16 below.

Summary of ex-ante charges

The ex-ante charges for TNUoS, CDCM and EDCM are presented in Figure 16 below.

Figure 16 Ex-ante charges (£/kVA)

Distribution area	TNUoS	CDCM	EDCM
Electricity North West	3.78	1.95	10.59
Northeast	3.78	3.43	4.14
Yorkshire	3.78	3.39	5.11
Southern Scotland	3.78	3.90	4.18
North Wales & Mersey	3.78	3.93	12.76
Southern	3.78	1.74	1.48
Scottish Hydro	3.78	4.57	2.88
Eastern	3.78	0.37	3.35
London	3.78	(1.09)	1.47
South East	3.78	1.27	2.33
East Midlands	3.78	3.33	5.78
South Wales	3.78	4.37	9.74
South West	3.78	4.37	4.86
West Midlands	3.78	3.84	4.27

Source: Frontier Economics analysis

3.3.4 Ex-post capacity charges

Ex-post capacity charges are estimated by dividing the relevant residual to recover by the sum of individual peak half-hourly demands. We have based the charges on the half-hour with the highest individual metered consumption i.e. this results in a £/kWh charge. This could alternatively be calculated as a £/kW charge based on peak capacity usage. While this would result in a different unit charge, the bill impact calculated in this analysis would be unaffected.

TNUoS

To illustrate a TNUoS ex-post capacity charge, we have divided the TNUoS residual to recover by the estimated sum of individual peaks across the whole system. This is given as the sum of individual peaks for CDCM and EDCM customers (see below), plus the sum of the individual peak import settlements for T-connected demand customers, which was provided by National Grid. The resulting charge is £28.13/kWh, as presented in Figure 17 below.

CDCM

Illustrative ex-post capacity charges for each DNO-area have been calculated by estimating the sum of individual peaks in each area. However, the sum of individual peaks cannot be derived directly from the CDCM models. The CDCM models provide load factors which allowed us to scale average HH-metered demand to demand at system peak. However, system peak is almost certainly less than the sum of individual peaks. We have therefore then applied a ratio of system peak to the sum of individual peaks based on further analysis of a subset of DNO HH data.

For NHH-metered customers, we have estimated the sum of peak individual peaks by applying a ratio of average half-hourly demand, derived from the CDCM models, to individual peak half-hourly demand (domestic and non-domestic) estimated from the CLNR database. The CDCM ex-post capacity charges for the DNO areas are presented in Figure 17 below.

EDCM

Ex-post capacity charges for EDCM customers have been calculated using the sum of the individual peaks for each customer, as provided by the DNOs. The total EDCM residual for each DNO area has been divided by the area's sum of peaks, giving a set of £/kWh charges. The EDCM ex-post capacity charges are presented in Figure 17 below.

Summary of ex-post charges

The ex-post charges for TNUoS, CDCM and EDCM are presented in Figure 17 below.

Figure 17 Ex-post capacity charges(£/kWh)

Distribution area	TNUoS Charge	CDCM Charge	EDCM Charge
Electricity North West	28.13	15.25	25.86
Northeast	28.13	27.74	13.86
Yorkshire	28.13	26.13	16.47
Southern Scotland	28.13	31.29	12.47
North Wales & Mersey	28.13	31.52	31.61
Southern	28.13	12.28	7.76
Scottish Hydro	28.13	32.44	14.22
Eastern	28.13	2.84	7.35
London	28.13	(8.78)	4.57
South East	28.13	9.90	6.52
East Midlands	28.13	25.60	18.51
South Wales	28.13	34.86	28.44
South West	28.13	33.92	16.56
West Midlands	28.13	27.85	15.50

Source: *Frontier Economics analysis*

3.3.5 Summary of basic options static bill impacts

A summary of the TNUoS, CDCM and EDCM charges for the basic options relative to the baseline charges is provided in Figure 18 to Figure 20.[19]

Figure 18 TNUoS Charges

	Baseline (HH charge)	Baseline (NHH charge)	Gross volumetric charge	Ex-ante capacity	Ex-post capacity
	(£/KW)	(p/kWh)	(p/kWh)	(£/kVA)	(£/kWh)
TNUoS Charge	52.13	6.57	0.83	3.78	28.13

Source: *NHH residual not explicitly calculated as part of TNUoS charging methodology. Residuals derived by National Grid are therefore for illustrative purposes only*

[19] Note that we do not list here the estimated fixed charges for all DNOs given the large number of charges estimated per DNO.

Figure 19 CDCM charges

Distribution area	Baseline	Gross volumetric charge	Ex-ante capacity	Ex-post capacity
Metric	(p/kWh)	(p/kWh)	(£/kVA)	(£/kWh)
Electricity North West	0.57	0.55	1.95	15.25
Northeast	1.06	1.00	3.43	27.74
Yorkshire	0.96	0.91	3.39	26.13
Southern Scotland	1.18	1.12	3.90	31.29
North Wales & Mersey	1.24	1.18	3.93	31.52
Southern	0.47	0.45	1.74	12.28
Scottish Hydro	1.29	1.24	4.57	32.44
Eastern	0.11	0.10	0.37	2.84
London	-0.44	-0.27	-1.09	-8.78
South East	0.39	0.37	1.27	9.90
East Midlands	0.85	0.81	3.33	25.60
South Wales	1.34	1.28	4.37	34.86
South West	1.32	1.26	4.37	33.92
West Midlands	1.01	0.96	3.84	27.85

Source: Frontier Economics analysis

Figure 20 EDCM charges

	Baseline	Gross volumetric charge	Ex-ante capacity	Ex-post capacity
		(p/kWh)	(£/kVA)	(£/kWh)
Electricity North West		0.24	10.59	25.86
Northeast		0.11	4.14	13.86
Yorkshire		0.15	5.11	16.47
Southern Scotland		0.11	4.18	12.47
North Wales & Mersey		0.30	12.76	31.61
Southern		0.05	1.48	7.76
Scottish Hydro		0.17	2.88	14.22
Eastern		0.12	3.35	7.35
London		0.05	1.47	4.57
South East		0.11	2.33	6.52
East Midlands		0.23	5.78	18.51
South Wales		0.21	9.74	28.44
South West		0.20	4.86	16.56
West Midlands		0.13	4.27	15.50

Source: Frontier Economics analysis

3.4 Step 4 - Static bill impact of basic options

In Step 4 we consider the distributional impacts that result from each of the basic options. This section is separated into two parts:

- We first consider in broad terms the expected distributional effects due to the basic options relative to the baseline, in particular distinguishing between intra group and inter groups effects;
- We then examine in more detail how these effects are applied in the context of the specific user groups.

3.4.1 Overview of distributional effects

In general, we consider two types of distributional effects:

- **Intra-group effects** – shifts in the burden of residual cost recovery among similar groups of users (e.g. all domestic users). In other words, holding the level of cost recovery equal for a particular group, some users will pay more and some will pay less. These effects occur for all of the basic options simply because the basis on which the residual is charged to different users changes.
- **Inter-group effects** – shifts in the burden of cost recovery between different broad groups of users. In other words, the change in the charging base over which the residual is recovered results in some groups e.g. all domestic users, paying more or less relative to other users e.g. all industrial users.

Intra-group effects

Each of the basic options results in intra-group effects relative to the baseline. Here we summarise the overall nature of expected effects for each option.

Fixed charges

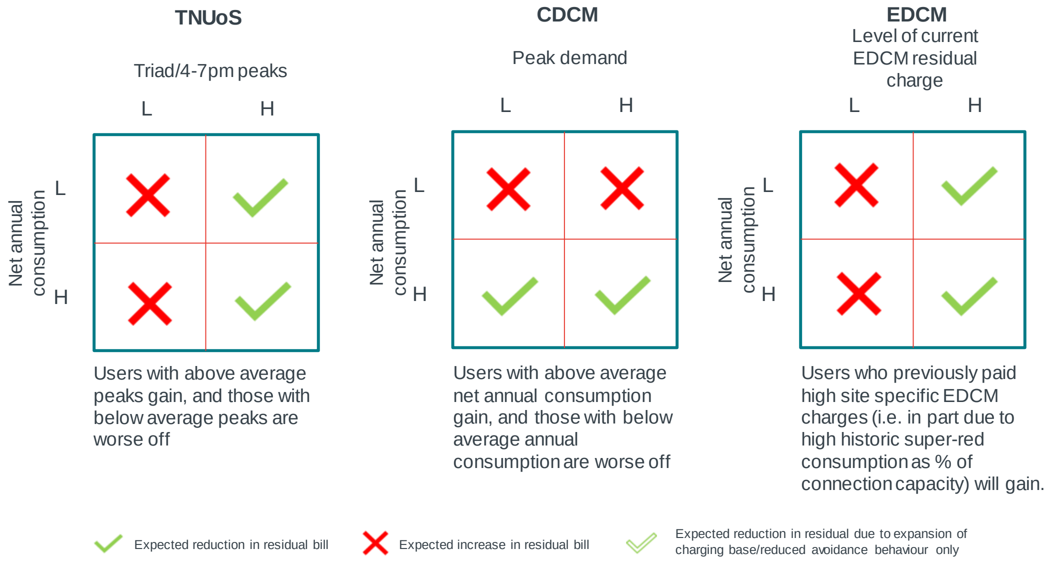
For each specified customer segment, fixed charging results in a single fixed per customer charge i.e. all customers pay the same charge. The impacts on specific customers vary depending on the baseline charging arrangements which is summarised in Figure 21. With respect to:

- TNUoS, we would expect users with above average peak time consumption (Triad demand or 4-7pm consumption) within each segment to pay lower bills relative to the baseline and users with below average net consumption to pay more.
- CDCM, we would expect users with above average net consumption within each segment to pay lower bills relative to the baseline and users with below average net consumption to pay more.
- EDCM, we would expect users who previously paid above average EDCM charges within the relevant segment i.e. due to having a high connection capacity, being located in an expensive part of the network, or having high historic consumption during super-red periods as a proportion of connection capacity, will pay less, and users who previously paid below average EDCM charges will pay more.[20]

[20] Residual costs are currently recovered from the limited import capacities associated with generation only sites. To the extent that in future costs are no longer recovered from generation sites at all, residual costs for all EDCM load would rise.

Under each of the charging regimes, all users should gain due to reduced avoidance behaviour.

Figure 21 Impact of fixed charging on users under the different charging regimes



Source: Frontier Economics

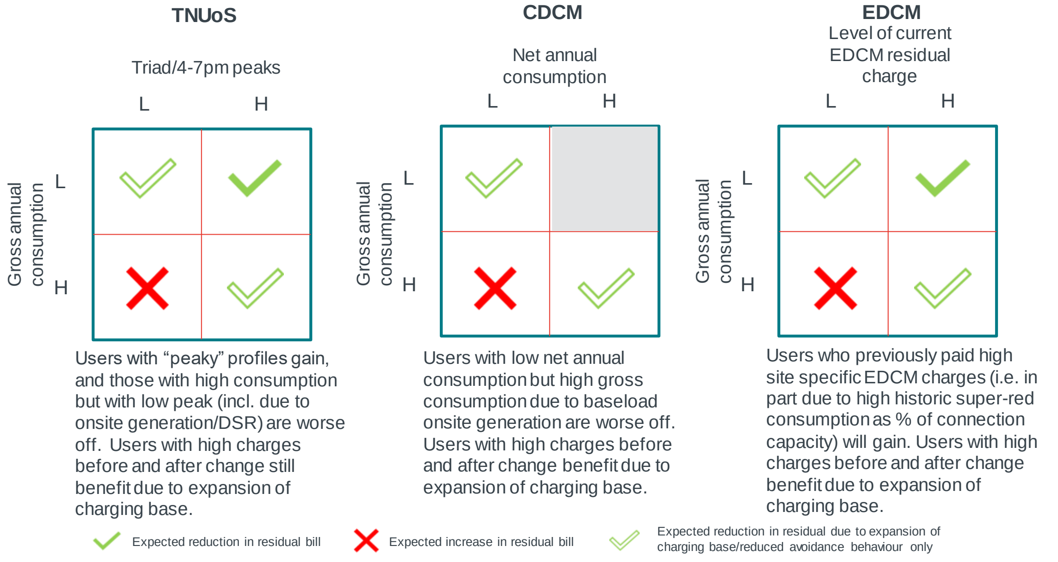
Gross volumetric charges

A gross volumetric charge results in a single p/kWh charge for all users facing the charge. The impacts on specific customers vary depending on the baseline charging arrangements which is summarised in Figure 22. With respect to:

- TNUoS, we would expect users with “peaky” profiles at system peak (Triad demand or 4-7pm consumption) to pay lower bills relative to the baseline and users with low peak consumption (incl. those with onsite generation/DSR) to pay more.
- CDCM, we would expect users with net consumption close to gross consumption to benefit due to the expansion of the charging base (due to reduced avoidance behaviour) and users with high gross consumption but low net consumption to lose out i.e. in particular those sites with baseload onsite generation.
- EDCM, we would expect users who previously paid high EDCM charges and have low gross consumption will pay less, and users who previously paid below average EDCM charges and have high gross consumption will pay more.

Under each of the charging regimes, all users should gain due to reduced avoidance behaviour.

Figure 22 Impact of gross volumetric charging on users under the different charging regimes



Source: Frontier Economics

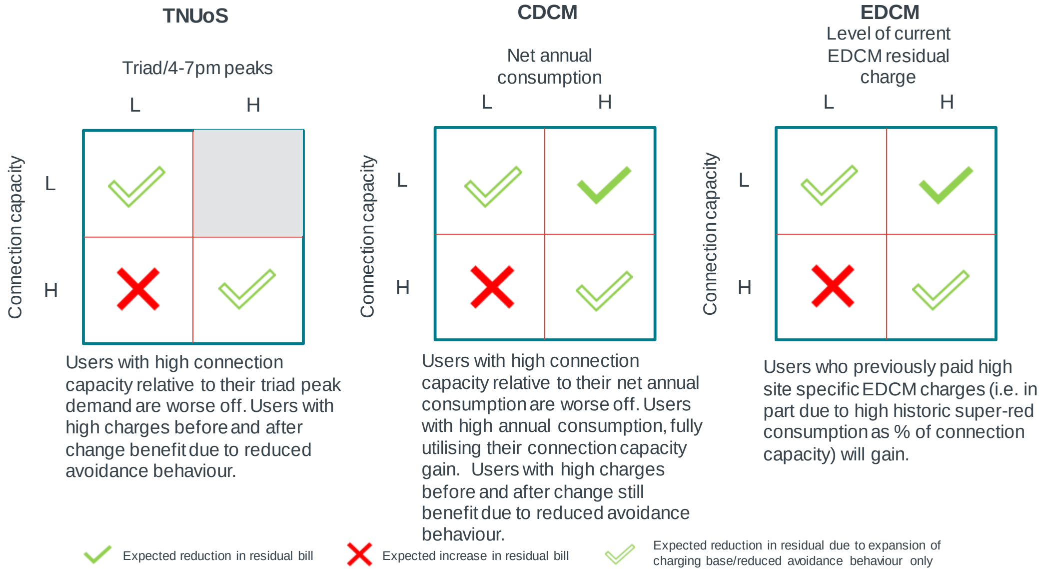
Ex-ante capacity charges

An ex-ante capacity charge results in a single p/kVA charge for all users facing the charge. The impacts on specific customers vary depending on the baseline charging arrangements which is summarised in Figure 23. With respect to:

- TNUoS, we would expect users with high connection capacity relative to their demand at system peak (triad or 4-7pm consumption), including those with onsite generation, to pay more relative to the baseline. Users who utilise a high proportion of their connection capacity at system peak are likely to benefit due to the expansion of the charging base.
- CDCM, we would expect users with high annual net consumption and high utilisation of their connection capacity to pay less, and those with significant spare capacity to pay more.
- EDCM, we would expect users who previously paid high EDCM charges and have low gross consumption will pay less, and users who previously paid below average EDCM charges and have high gross consumption will pay more

Under each of the charging regimes, all users should gain due to reduced avoidance behaviour.

Figure 23 Impact of ex-ante capacity charging on users under the different charging regimes



Source: Frontier Economics

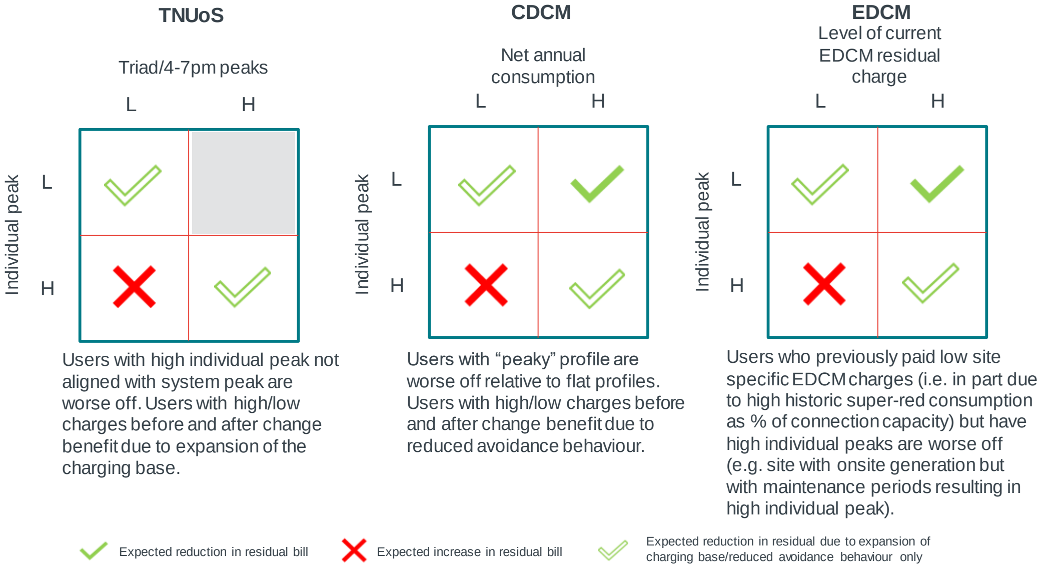
Ex-post capacity charges

An ex-post capacity charge results in a single p/kWh charge for all users facing the charge. The impacts on specific customers vary depending on the baseline charging arrangements which is summarised in Figure 24. With respect to:

- TNUoS, we would expect users with a high individual peak but relatively low consumption at system peak (triad or 4-7pm consumption) to pay more. Users with peak consumption relatively well aligned with triad will benefit from the expansion of the charging due to reduced avoidance.
- CDCM, we would expect users with high annual net consumption but with a relatively flat profile to pay less, but users with relatively “peaky” profiles will pay more.
- EDCM, we would expect users who previously paid high EDCM charges and have low gross consumption will pay less, and users who previously paid below average EDCM charges and have high gross consumption will pay more.

Under each of the charging regimes, all users should gain due to reduced avoidance behaviour.

Figure 24 Impact of ex-post capacity charging on users under the different charging regimes



Source: Frontier Economics

Inter-group effects

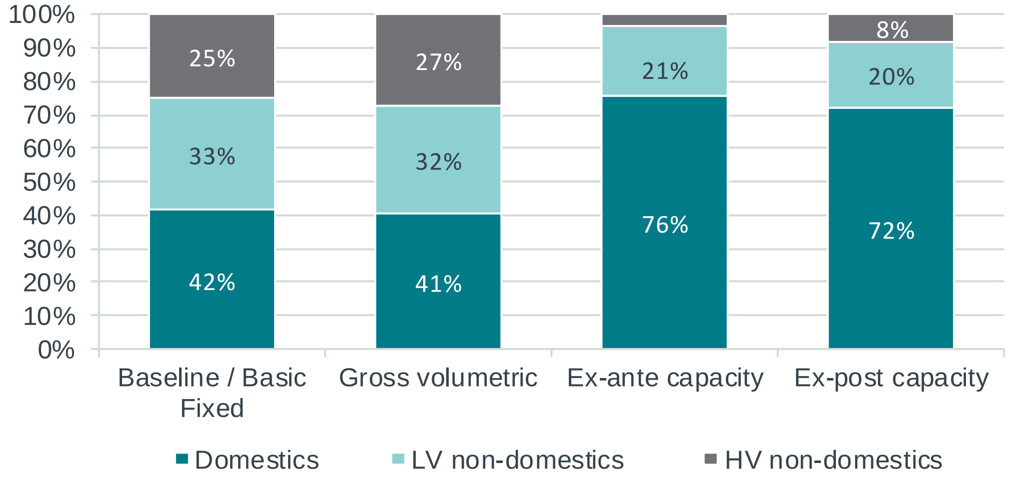
All of the basic TNUoS and CDCM charges, except the fixed charge, result in significant distributional impacts between domestics, commercial and industrial customer groups. In relation to EDCM, we cannot illustrate the distributional effects between customer groups as EDCM only consists of EHV connected customers

Under the basic fixed charge option there is by definition no inter group effects because cost recovery from each consumer segment is fixed at historic levels.

For the other basic options the degree to which there are shifts in the burden of cost recovery is dependent on the share of a particular charging base used to calculate the basic option's charges (e.g. total connection capacity, sum of individual peaks) for a particular group, relative to the share of the baseline charging base.

For the following broad groups (domestics, LV non-domestic, HV non-domestic) of CDCM customers we illustrate the potential shifts in the share of cost recovery relative to the baseline from each of the basic options in Figure 25.

Figure 25 CDCM Inter-group effects relative to the baseline



Source: *Frontier Economics analysis*

Note: *The revenue distribution for the basic fixed charges is the same as the distribution in the baseline. This is because the Basic fixed charge option carries forward existing residual allocations, setting fixed charges based on historic segment levels.*

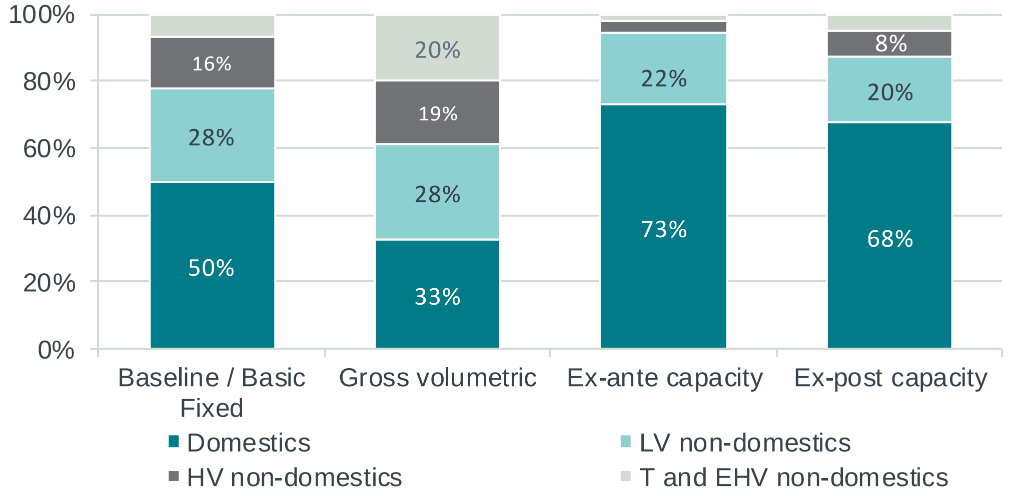
Based on this analysis we can see the following distributional effects:

- The basic fixed charge does not shift the burden cost recovery since by definition it is equal to the historic distribution of cost recovery.
- The gross volumetric charging option increases the HV – non-domestic share of cost recovery slightly relative to the baseline as a result of the expansion of the charging base.
- The largest distributional effects occur as a result of the ex-ante capacity charges. Domestics increase the share of cost recovery significantly since, based on our assumptions, they represent a much larger share of our estimated total system capacity relative to its share of historic recovery which is based on net volume. In other words, based on a standard connection size of 18kVA a domestic consumer typically has significantly more unused connection capacity relative to larger non-domestic users on the system.
- The ex-post capacity charge results in a similar level of redistribution. This is driven by the “peakier” nature of domestic profiles relative the non-domestics, which means they represent a greater share of the estimated sum of the individual peaks than net volume under the baseline.

We present a similar analysis of the inter-group effects under the TNUoS charges in Figure 26. The customer group segmentation is the same as CDCM, except it also includes an additional group of EHV and Transmission connected non-domestic customers.[21]

[21] In relation to EDCM, we cannot illustrate the distributional effects between customer groups as EDCM only consists of EHV connected customers.

Figure 26 TNUoS inter-group effects relative to the baseline



Source: Frontier Economics analysis

Note: The revenue distribution for the basic fixed charges is the same as the distribution in the baseline. This is because the Basic fixed charge option carries forward existing residual allocations, setting fixed charges based on historic segment levels.

For TNUoS, we see similar distributional effects relative to the baseline for ex-ante and ex-post capacity charges, with significant increases in cost recovery from domestics. The increases are not quite as significant as CDCM since we estimate that domestics represent a greater share of cost recovery under the baseline TNUoS methodology than CDCM. This is likely to be due to the fact that TNUoS is a peak usage (triad or 4-7pm) based methodology, for which domestics represent a greater share than of net volume under CDCM.

Under a basic gross volumetric charging option, non-domestic users pay a greater share than under the baseline, recognising the fact that current baseline charging arrangements are based on peak consumption which tends to focus charging more on domestic customers. The shift to a volumetric charge therefore reduces bills for domestics relative to non-domestics.

3.4.2 User groups static bill impacts

In this section we present the combined CDCM, EDCM and TNUoS residual bills for the baseline and basic options for our user groups. We discuss the results taking each of the following groups in turn:

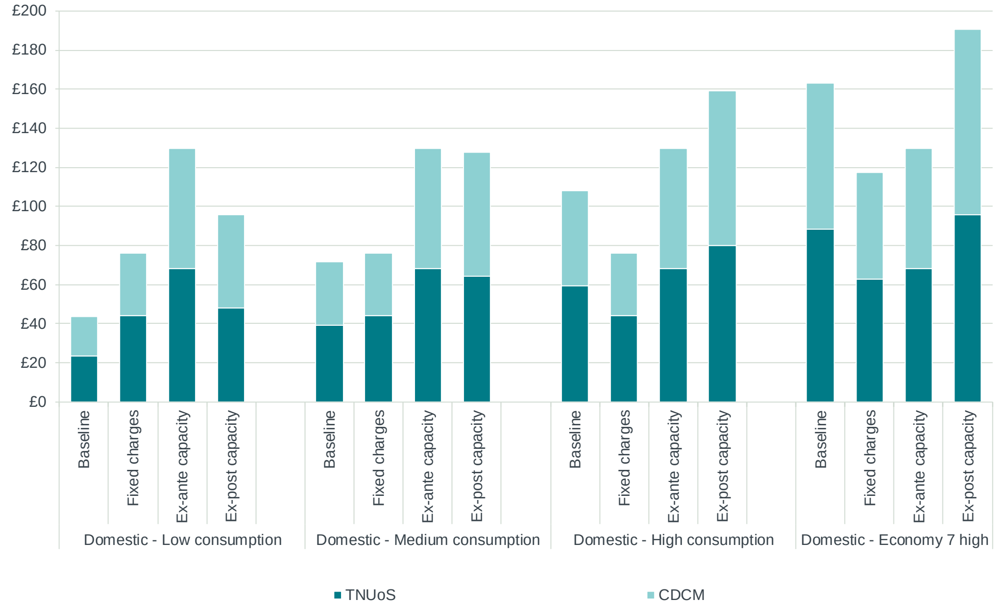
- Domestic user groups;
- Domestic user groups with new technologies;
- Commercial user groups; and
- Industrial users.

The CDCM and EDCM charges presented throughout this report are residual charges for the Northeast distribution area. The CDCM and EDCM charges for other distribution areas are presented in Annex B. TNUoS charges are common to all distribution areas.

Domestic user groups

The combined CDCM and TNUoS residual bills for the baseline and basic options for our domestic user groups are presented in Figure 27. We do not present the gross volumetric charges for domestics since this is not being considered as an option by Ofgem.[22]

Figure 27 Domestic user groups - CDCM and TNUoS residual bills for baseline and basic options



Source: Frontier Economics analysis

Note: Residual bills for Northeast DNO. The residual bill data for all other DNOs is provided in Annex B

Based on this we observe the following distributional effects:

- With respect to fixed charges all customers within the same LLFC pay the same fixed charges. Therefore, 'domestic unrestricted' customers with high annual and high peak consumption and hence higher baseline bills, pay the same fixed charge as low consuming customers. The fixed charge for Economy 7 customers is typically higher than for domestic unrestricted customers given the higher historic recovery from that LLFC.
- The ex-ante capacity bill is the same for all domestic users, including for customers in different LLFCs, because all domestic users are assumed to have the same connection capacity of 18kVa. Bills increase relative to the baseline for all domestic users, except for the Economy 7 user, which is reflective of the fact that under this option domestic consumers face a significant increase in the burden of cost recovery relative to larger industrial users.
- An ex-post capacity charge results in residual bills which increase in line with the consumption level of the domestic users, reflective of the fact that peak consumption also increases in line with the level of annual consumption.

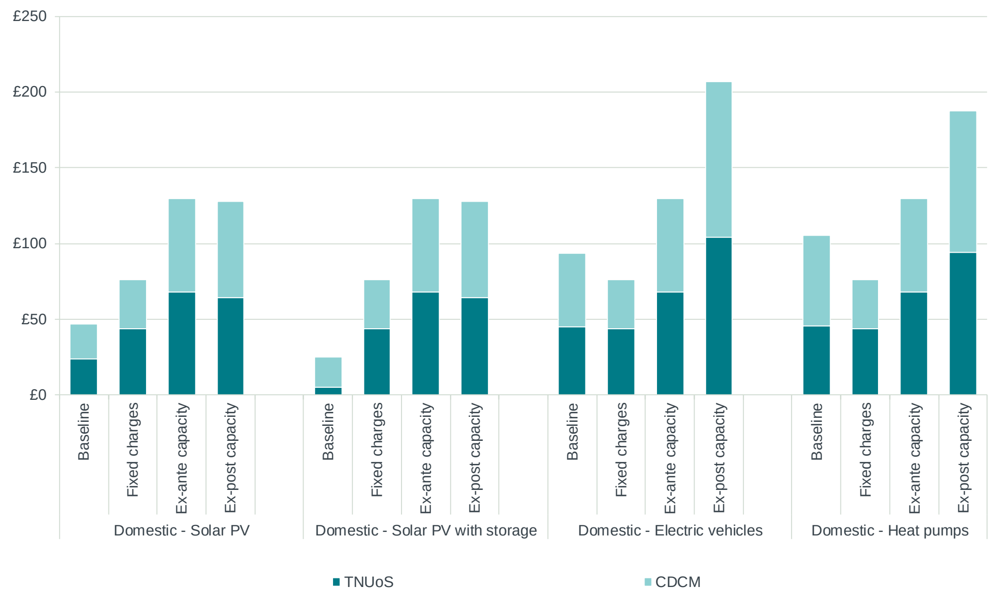
[22] https://www.ofgem.gov.uk/system/files/docs/2017/11/tcr_working_paper_nov17_final.pdf

Residual bills are also higher for each of our domestic user groups reflecting a similar inter-group effect to the ex-ante charges.

Domestic user groups

The combined CDCM and TNUoS residual bills for the baseline and basic options for the medium domestic user groups with new technologies are presented in Figure 28.

Figure 28 Domestic user groups with new technologies - CDCM and TNUoS residual bills for baseline and basic options



Source: Frontier Economics analysis

Note: Residual bills for Northeast DNO. The residual bill data for all other DNOs is provided in Annex B

For domestic customers with new technologies we observe similar distributional effects to those observed for domestic customers without the technologies, though the effects can be magnified. This is because ownership of particular technologies can increase or decrease a household's consumption above or below the level it would otherwise have been.

For example, a medium household with an EV or heat pump is likely to have higher than average annual and more peaky consumption increasing the baseline bill. This therefore increases the benefit of shifting to a fixed charge relative to the medium consuming household. However, an increase in an individual consumer's peak consumption due to the technology would result in those consumers paying more under an ex-post charge, and hence be worse off relative to the medium consumer without such a technology. As noted above, all of the domestic user groups are likely to pay more under the ex-ante capacity charge. However, this effect is less marked for EV and heat pump owners given a higher baseline bill.

To the extent households with solar PV are more likely to have below average net annual consumption they will pay higher CDCM bills following the shift to a fixed charge. Solar PV investment may be more prevalent among higher consuming households and hence it may be possible that some owners gain following the change, though they will gain less than they would have done had they not invested in the solar PV.

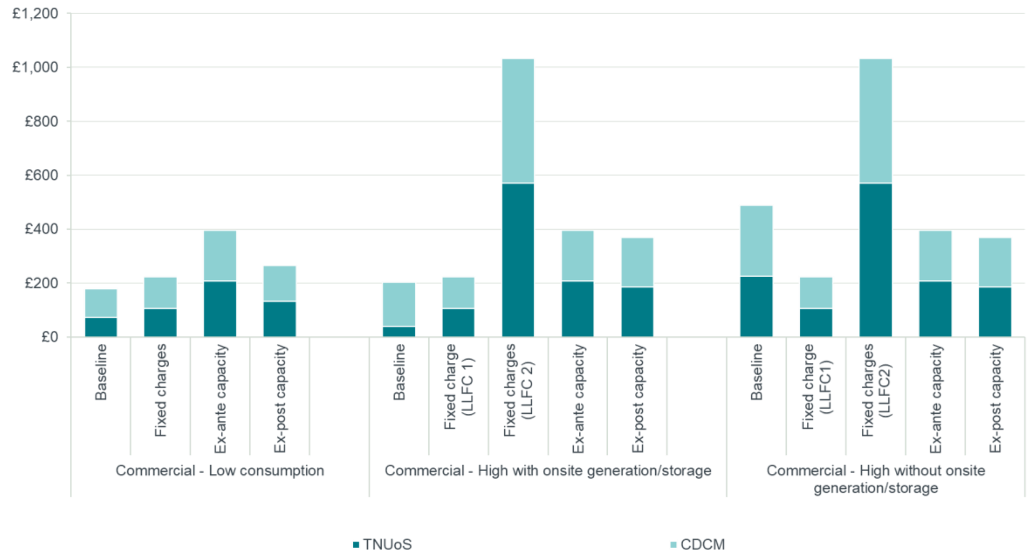
The impact on TNUoS charges is less pronounced given solar generation has a relatively smaller impact on peak 4-7pm consumption. However, the limited impact on peak consumption also means they are likely to face a similar ex-post capacity charge to consumers without solar PV, though the impact of the change is larger due to a lower baseline bill. The shift to an ex-ante capacity would result in a similar impact.

If a storage unit is combined with solar PV, then the unit could in theory shift solar exports in the middle of the day into the evening peak to reduce annual net consumption, and hence the CDCM baseline bill, and more significantly reduce evening peak consumption and the TNUoS baseline bill. Storage therefore reduces baseline bills below that achieved by solar PV alone, and hence increases the impact of the shift to the basic charges set out above.

Commercial user groups

The combined CDCM and TNUoS residual bills for the baseline and basic options for our commercial user groups are presented in Figure 29 below. We do not present the gross volumetric charges for these non-domestic customers on the assumption that a gross volumetric charge is not being considered by Ofgem for these customers.[23]

Figure 29 Commercial user groups with new technologies - CDCM and TNUoS residual bills for baseline and basic options



Source: Frontier Economics analysis

Note: Residual bills for Northeast DNO. The residual bill data for all other DNOs is provided in Annex B. Note that LLFC 1 refers to the Small Non-Domestic Unrestricted LLFC and LLFC 2 refers to the LV Network Non-Domestic Non-CT LLFC

[23] https://www.ofgem.gov.uk/system/files/docs/2017/11/tcr_working_paper_nov17_final.pdf

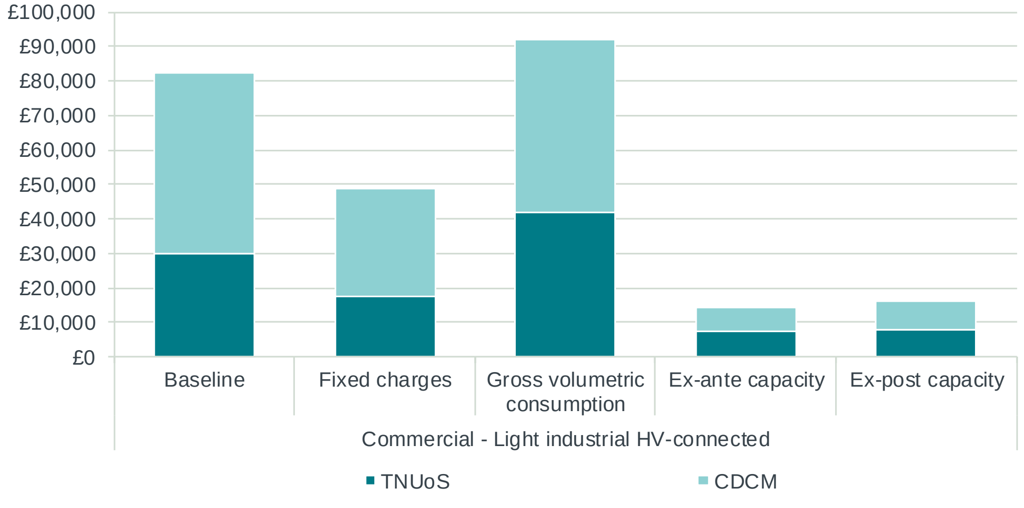
Based on this we observe the following distributional effects:

- With respect to the fixed option, the distributional effect depends on the consumption of the user group relative to the average consumption in the relevant LLFC. For the high consuming commercial user it is possible that they could sit in a number of different LLFCs, each with its own fixed charge. If the user is mapped to the LV Network Non-Domestic Non-CT LLFC (identified as LLFC 2 in the chart above), a significant increase in the residual bill relative to the baseline is observed, since our user is relatively small compared to the average. Alternatively, if it is mapped to the small non-domestic unrestricted LLFC (identified as LLFC 1 in the chart above), a reduction in the residual bill relative to the baseline is observed, unless the user has onsite generation with storage where a small increase is observed.
- In relation to the ex-ante and ex-post options, an increase in the residual bill relative to the baseline is observed for the low consumption user and high consumption user with onsite generation. A decrease in the residual bill relative to the baseline is observed for the high consumption user without onsite generation.

Light industrial user group

The combined CDCM and TNUoS residual bills for the baseline and basic option for our commercial light industrial HV connected user group are presented in Figure 30 below.

Figure 30 Light industrial HV connected user group - CDCM and TNUoS residual bills for baseline and basic options



Source: Frontier Economics analysis

Note: Residual bills for Northeast DNO. The residual bill data for all other DNOs is provided in Annex B

Based on this we observe the following distributional effects:

- With respect to fixed charges we observe a reduction relative to the baseline bill, as the light industrial user group has a higher assumed usage than the average in the HV HH metered LLFC.

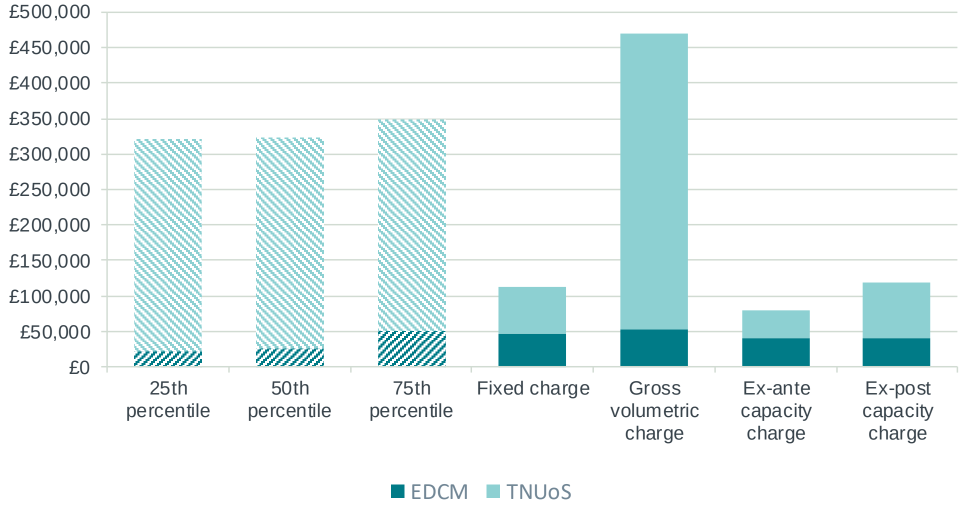
- In relation to the gross volumetric charging option, the expansion of the charging base to gross volume reduces the CDCM per unit energy charge, so sites without onsite generation benefit on the CDCM element of the residual bill. With respect to the TNUoS element of the bill, this user group as defined has a flat profile i.e. high consumption but relatively lower system peak consumption, which results in an increase in the TNUoS residual bill relative to the baseline.
- With respect to ex-ante capacity, a significant reduction in the residual bill is observed, relative to the baseline. This result is a result of two factors. In part this is due to the significant redistribution towards domestic customers under the basic ex-ante charge, but it is also a feature of our assumption that the capacity for this user is relatively highly utilised. However, the assumed capacity could be expanded significantly with the bill still remaining below the baseline.
- There is a similar significant reduction in the residual bill under an ex-post capacity charge relative to the baseline, which again is a feature of the assumed flat profile. That said, typically we would expect industrials to be less peaky than domestic users, and as such should pay less, though this example is relatively extreme.

EHV connected user group

EHV connected customers pay TNUoS and EDCM charges. Given the site specific EDCM baseline charges we are not able to combine both into a single baseline bill. We therefore have set out in Figure 31 a range of possible baseline bills which reflect the combination of the baseline TNUoS bill and the minimum, maximum and quartiles from the distribution of the EDCM bills. For the user with onsite generation/demand management, its baseline bill is represented by the EDCM element only on the assumption it could avoid the TNUoS bill entirely. For ease, this user's baseline bill has not been separated out in Figure 31.

To calculate representative baseline EDCM charges, we have scaled the site-specific baseline charges received from the DNOs to be representative of a 10,000kVA capacity. In other words, we have calculated the bill for a site with 10.000kVA based on the implied p/kVA charge for every existing site. This therefore illustrates the possible range of baseline bills the user group could face under the current EDCM charging arrangements.

Figure 31 Industrial EHV-connected user groups - TNUoS and EDCM residual bills for baseline and basic options



Source: Frontier Economics analysis

Note: Residual bills for Northeast DNO. The residual bill data for all other DNOs is provided in Annex B EDCM fixed charge likely to be an underestimate, since the charging base also includes generation specific sites which could not be separately identified from the dataset.

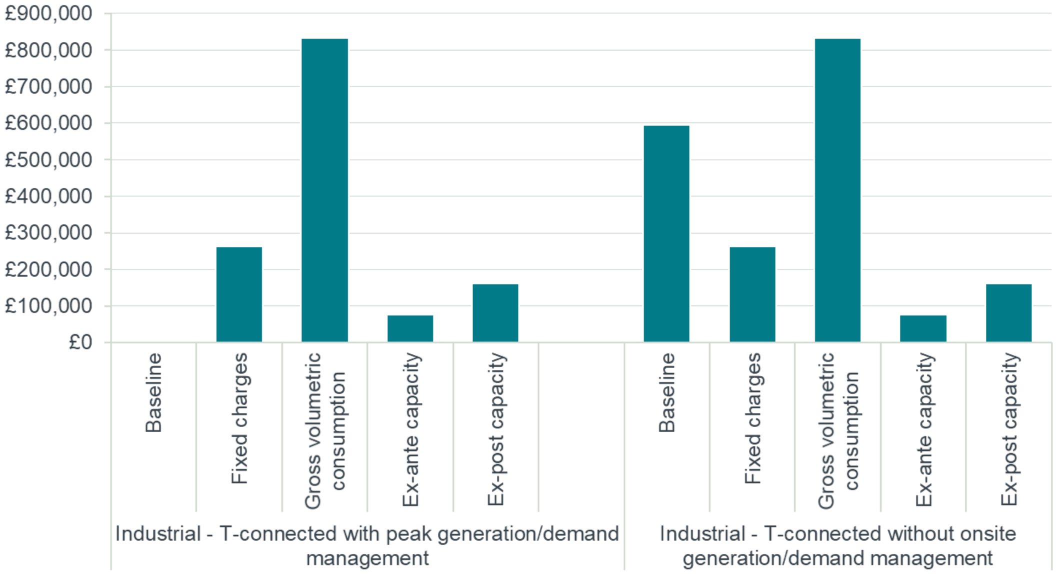
Based on this analysis we observe the following distributional effects:

- With respect to the basic fixed charge, the industrial user group without generation has higher assumed usage than the average EHV connected user and hence its bill is reduced. However, as noted earlier the fixed charge is likely to be lower than it should be in reality since it also includes sites which are 'pure' generator sites. That said, even with the fixed charge doubled this user profile would still gain significantly. Sites with onsite generation/demand management will pay more whatever the level of the fixed charge.
- In relation to gross volumetric charges, the bills increase for the EHV connected industrial user irrespective of whether they own onsite generation. This is because the ratio of assumed gross volume to peak consumption is relatively high due to the assumed flat profile. This results in a relatively high gross volumetric bill compared to the baseline. For sites with onsite generation/demand managements bills will increase since charges can no longer be avoided through the use of onsite generation.
- With respect to ex-ante capacity and ex-post capacity we observe similar effects as described for the light industrial user group where bills are significantly reduced, except if baseline bills had previously been avoided through onsite generation/demand management. We assume that the capacity for this user is relatively highly utilised, however, the assumed capacity could be expanded with the bill still remaining below the baseline, particularly for the user without onsite generation.

Transmission connected user groups

The TNUoS residual bills for the baseline and basic options for our T-connected industrial user group are presented in Figure 32 below, where we observe very similar effects as described above for TNUoS in relation to EHV connected generation.

Figure 32 Industrial T-connected user group - TNUoS residual bills for baseline and basic options



Source: Frontier Economics analysis

Note: Residual bills for Northeast DNO. The residual bill data for all other DNOs is provided in Annex B

3.5 Step 5 - TCR ("factual") charges for hybrid options

In this section, we estimate a set of illustrative network tariffs which could apply under each of the additional options (options 5-9) i.e. a set of factual charges for the additional options.

The options we assess are:

- Fixed by volume
- Fixed 75%, Ex-post capacity 25%
- Ex-ante deemed capacity
- Ex-ante deemed capacity 75%, Net volumetric 25%

We do not include specific static bill impact analysis for the fifth additional option identified by Ofgem of the 'ex-ante capacity ratchet' charge. This charge could be calculated following the same methodology as the basic ex-post capacity charge, but set at the historical peak (e.g. 5-year individual peak). If the peak is exceeded, the new individual peak would become the new basis for charging.

From a static bill impact modelling perspective, individual peak data is not available for the past five years. Therefore, this charge cannot be distinguished from basic ex-post capacity charges already modelled (as presented in section 3.3.4). As a result, no new results are presented for this option.

3.5.1 Fixed by volume

Fixed by volume charges are calculated in a similar way to the basic fixed charges, except the residual amount to be recovered from each customer group is now based on the net consumption of each group. Relative to the basic fixed charges this option only results in changes to the TNUoS fixed charges.

- CDCM is a p/kWh net volumetric charge, and therefore the revenue recovered from each segment under the basic fixed charge is already apportioned by volume. Therefore, the charges are the same as the basic fixed charges. The key difference relates to the fact that this option explicitly allows for changes in the charges over time i.e. the revenues recovered from each segment would adjust year-on-year as net volumes change.
- For EDCM, the basic fixed charging option presents a single fixed charge for all EDCM users. Therefore, this option does not affect the charges since the same residual revenue is recovered from the same number of EDCM users. As noted earlier, this fixed charge is likely to include some pure generation sites and hence in reality we would expect the fixed charge to be higher than this.
- TNUoS charges do change relative to the basic option, since apportionment by net volume will differ to historic revenue recovery, which is driven by peak consumption. The TNUoS fixed by volume charges are estimated as follows:
  - Total net volume of the system is calculated. This consists of CDCM net volume sourced from the CDCM 2019/20 models, EDCM net volume sourced from DNOs and T-connected net volume sourced from National Grid.
  - The proportion of net volume associated with T-connected customers, EDCM customers and each LLFC in CDCM is calculated.
  - These proportions are then multiplied by the total TNUoS residual to recover to get the residual to recover from each segment (T-connected customers, EDCM customers and each CDCM LLFC).
  - This is the divided by the number of customers associated with T-connections, EDCM and each CDCM LLFC to get the fixed by volume charge specific to each segment.

The TNUoS, CDCM and EDCM residual charges for this option are presented in Figure 33.

Figure 33 Fixed by volume option charges

User group	CDCM	TNUoS	EDCM
Domestic - Low consumption	£31.93	£31.63	-
Domestic - Medium consumption	£31.93	£31.63	-
Domestic - High consumption	£31.93	£31.63	-
Domestic - Economy 7 high	£54.47	£48.60	-
Domestic - Solar PV	£31.93	£31.63	-
Domestic - Solar PV with storage	£31.93	£31.63	-
Domestic - Electric vehicles	£31.93	£31.63	-
Domestic - Heat pumps	£31.93	£31.63	-
SME - Low consumption	£117.41	£118.22	-
SME - High with onsite generation/storage (LLFC 1)	£117.41	£118.22	-
SME - High without onsite generation/storage (LLFC 1)	£117.41	£118.22	-
SME - High with onsite generation/storage (LLFC 2)	£464.28	£634.49	-
SME - High without onsite generation/storage (LLFC 2)	£464.28	£634.49	-
SME - Light industrial HV-connected	£31,467	£23,483	-
Industrial - EHV-connected without onsite generation/demand management	-	£107,859	£47,186
Industrial - EHV-connected with peak generation/demand management	-	£107,859	£47,186
Industrial - T-connected with peak generation/demand management	-	£547,838	-
Industrial - T-connected without onsite generation/demand management	-	£547,838	-

Source: *Frontier Economics analysis*

Note: *Note that LLFC 1 refers to the Small Non-Domestic Unrestricted LLFC and LLFC 2 refers to the LV Network Non-Domestic Non-CT LLFC*
The CDCM and EDCM charges presented are for Northeast distribution area. The CDCM and EDCM charges for other distribution areas are presented in Annex B. TNUoS charges are common to all distribution areas.

EDCM fixed charge element for EHV connected users likely to be an underestimate, since the charging base also includes generation specific sites which could not be separately identified from the dataset.

3.5.2 Fixed 75%, Ex-post capacity 25%

To estimate static bill impact for this option we estimate charges on the basis that 75% of the residual is recovered from the basic fixed charge, and 25% from the basic ex-post charge. We note that in practice the ex-post capacity element of this option differs from the basic ex-post capacity charge, in that it is based on the measurement of monthly peaks. However, given the lack of requisite data we have used the same annual data as in the basic option.

The TNUoS, CDCM and EDCM residual charges for this option are presented in Figure 34.

Figure 34 Fixed (75%) Ex-post capacity (25%) option charges

	TNUoS	CDCM	EDCM
Domestic - Low consumption	£45.11	£35.82	-
Domestic - Medium consumption	£49.14	£39.79	-
Domestic - High consumption	£53.12	£43.72	-
Domestic - Economy 7 high	£71.08	£64.51	-
Domestic - Solar PV	£49.14	£39.79	-
Domestic - Solar PV with storage	£49.14	£39.79	-
Domestic - Electric vehicles	£59.16	£49.68	-
Domestic - Heat pumps	£56.70	£47.25	-
SME - Low consumption	£112.89	£120.87	-
SME - High with onsite generation/storage	£126.12	£133.92	-
SME - High without onsite generation/storage	£126.12	£133.92	-
SME - Light industrial HV-connected	£15,042	£25,579	-
Industrial - EHV-connected without onsite generation/demand management	£69,087	-	£45,282
Industrial - EHV-connected with peak generation/demand management	£69,087	-	£45,282
Industrial - T-connected with peak generation/demand management	£238,322	-	-
Industrial - T-connected without onsite generation/demand management	£238,322	-	-

Source: Frontier Economics analysis

Note: CDCM and EDCM results presented are for Northeast DNO. TNUoS results apply to all DNOs. EDCM fixed charge element for EHV connected users likely to be an underestimate, since the charging base also includes generation specific sites which could not be separately identified from the dataset.

3.5.3 Ex-ante deemed capacity

Ex-ante deemed capacity charges are calculated following the same methodology that is used to calculate the basic ex-ante capacity charges (outlined in section 3.3.3), but the connection capacity applied for domestic customers in the charging base is deemed to be lower, and varies depending on usage.

- For the majority of domestics (up to the 75^{th} percentile) we assume 4kVa.
- For the highest consuming domestic customers in the top quartile we assume:
  - 6kVa covering 15% of domestic customers
  - 8kVa for owners of EVs and HPs covering which we assume covers the remaining 10% of domestic customers.

The ex-ante deemed capacity charges for TNUoS, CDCM and EDCM are presented in Figure 35 below. The EDCM charges are the same as the charges for the basic ex-ante capacity option (as the capacities for commercials and industrials remained unchanged relative to the basic ex-ante option), while the CDCM and TNUoS charges are different. Note that we also completed a sensitivity that included deemed capacity for commercials as well as domestics. This had the impact of increased CDCM and TNUoS charges relative to the charges presented below, while the EDCM charges remained unchanged as this category does not include domestic or commercials.

Figure 35 Ex-ante deemed capacity charges (£/kVA)

Distribution area	TNUoS	CDCM	EDCM
Electricity North West	8.23	4.45	10.59
Northeast	8.23	7.82	4.14
Yorkshire	8.23	7.76	5.11
Southern Scotland	8.23	9.19	4.18
North Wales & Mersey	8.23	9.18	12.76
Southern	8.23	3.84	1.48
Scottish Hydro	8.23	9.78	2.88
Eastern	8.23	0.85	3.35
London	8.23	-2.11	1.47
South East	8.23	2.89	2.33
East Midlands	8.23	7.53	5.78
South Wales	8.23	10.04	9.74
South West	8.23	9.44	4.86
West Midlands	8.23	8.49	4.27

Source: Frontier Economics analysis

3.5.4 Ex-ante deemed capacity 75%, Net volumetric 25%

To estimate the static bill impact for this option we calculate charges on the basis that 75% of the residual is recovered from the deemed ex-ante capacity charging option (as calculated above), and 25% from a net volumetric charge.

The net volumetric element of this charge is calculated as follows:

- For CDCM and EDCM, the charges are calculated in the same way as the gross volumetric charge outlined in the section 3.3.2, excluding the adjustment for BTMG.
- For TNUoS, the charge is calculated by dividing the total residual to be recovered by total system net volume (as per the net volume outlined in the fixed by volume section above).

The final bill impact of this combined charge is presented in section 3.6.

3.6 Step 5 - Static bill impacts of additional options

In this section we consider the distributional impacts that result from each of the additional options. Since these options can in some sense be viewed as extensions of the basic options, we consider the impacts relative to the baseline and a relevant basic option. However, we focus only on the additional effects of this option relative to the relevant basic option.

To do this we have placed the additional options in two groups:

- **Group 1 – 'fixed options'**: We compare the impacts of the 'fixed by volume' and 'fixed (75%) ex-post (25%)' with the basic fixed and ex-post capacity charges.
- **Group 2 – 'ex-ante options'**: We compare the 'deemed ex-ante' and 'deemed ex-ante (75%) net volume (25%)' with the ex-ante capacity charge.

This section is separated into two parts:

- We first consider in broad terms how the further adjustments to the options changes the distribution of cost recovery among the groups i.e. inter-group effects.
- We then examine in more detail how these effects are applied in the context of the specific user groups.

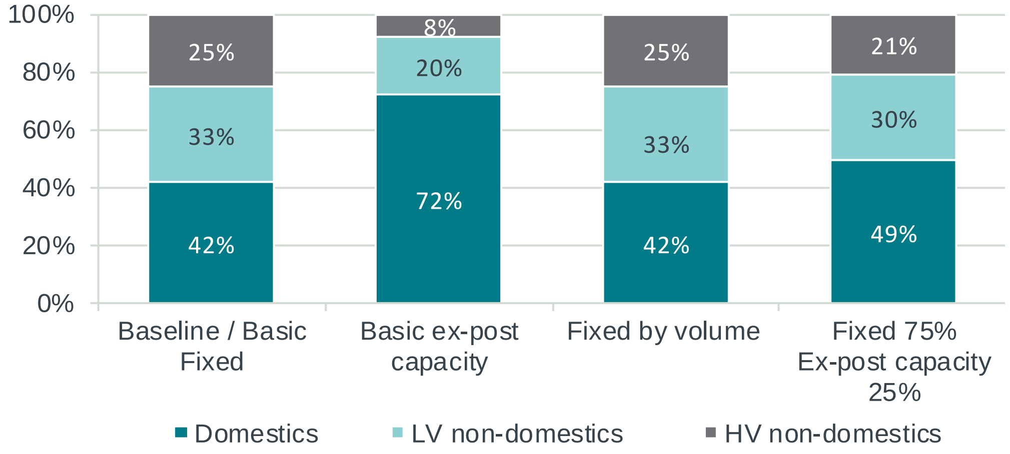
Inter-group effects

We illustrate the potential shifts in the share of cost recovery relative to the baseline for each of the additional charging options and for domestics, LV non-domestic, HV non-domestic, EHV non-domestic CDCM and TNUoS customers.[24]

Figure 36 and Figure 38 show the inter-group effects of the additional 'fixed options' (fixed by volume and basic fixed (75%) ex-post (25%) basic ex-post) relative to the basic fixed and basic ex-post charging options, for CDCM and TNUoS respectively.

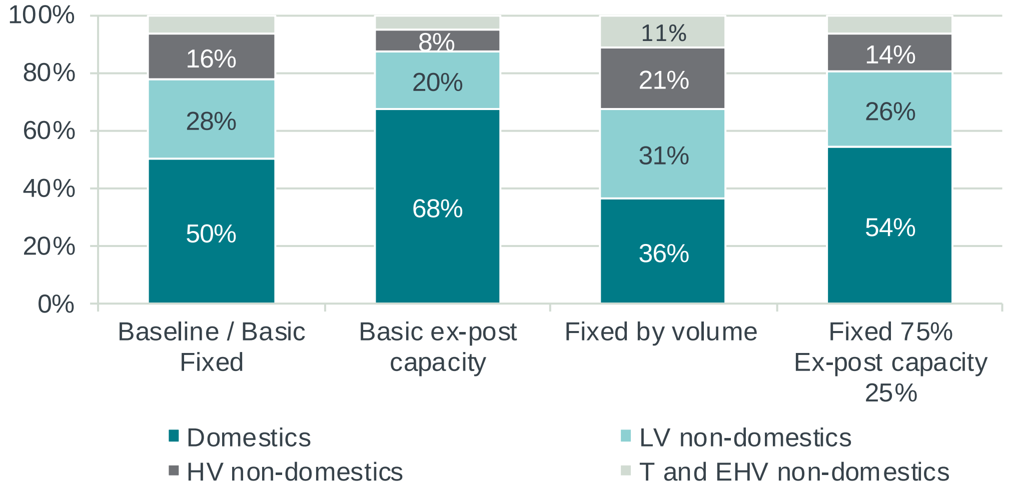
[24] In relation to EDCM, we cannot illustrate the distributional effects between customer groups as EDCM only consists of EHV connected customers.

Figure 36 CDCM Inter-group effects for Group 1 additional options



Source: Frontier Economics analysis

Figure 37 TNUoS Inter-group effects for Group 1 additional options



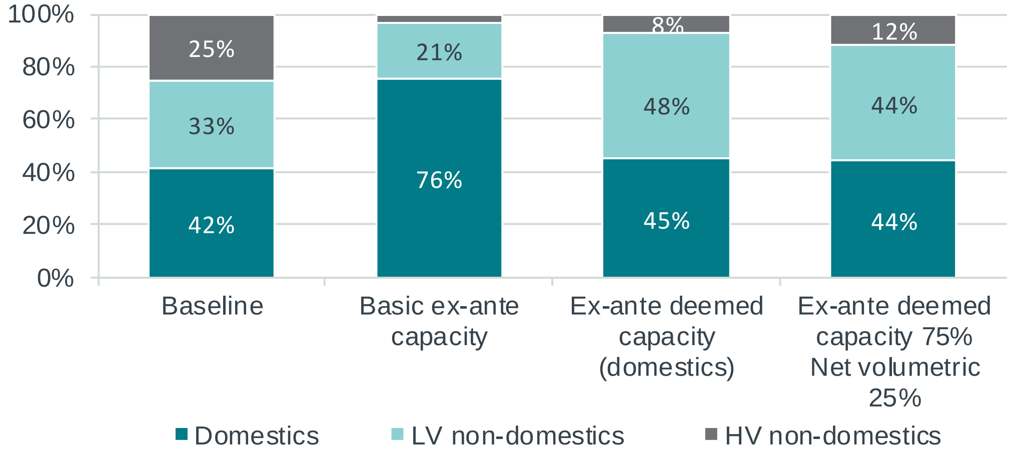
Source: Frontier Economics analysis

Based on the charts above we can see the following key distributional effects:

- At CDCM, the fixed by volume option does not result in a change the burden of cost recovery relative to the baseline or the basic fixed option since costs are already allocated on a net volumetric basis. However, for TNUoS a fixed by volume option reduces the burden of cost recovery from domestics and increases it for industrials because (based on current consumption levels) domestics represent a smaller share of system net volume than historic revenue recovery.
- By introducing an ex-post capacity element, the basic fixed (75%) ex-post (25%) option increases the burden of cost recovery that is placed on domestics, and reduces it for industrials relative to the baseline and basic fixed options for both CDCM and TNUoS.

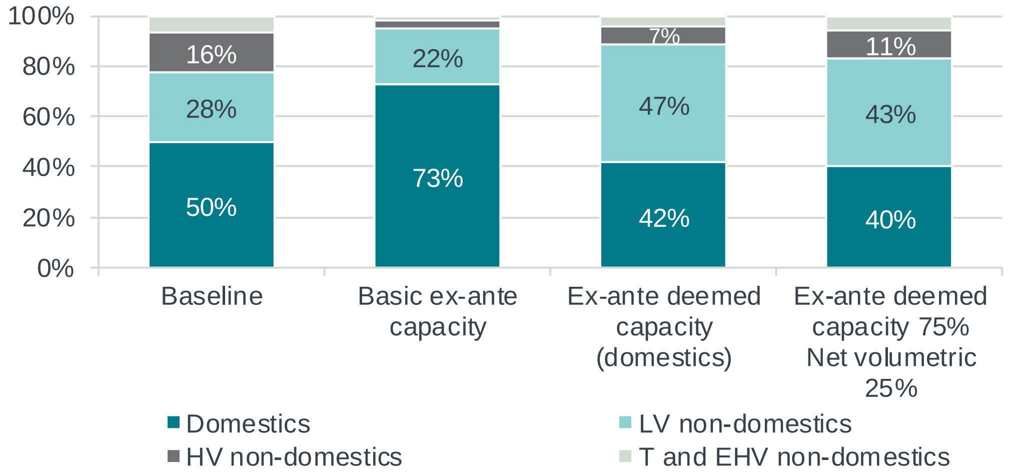
In Figure 38 and Figure 39 we consider the inter-group distributional impacts of the ex-ante deemed capacity option and the deemed ex-ante (75%) net volume (25%) option relative to the baseline and basic ex-ante charging options, for CDCM and TNUoS respectively.

Figure 38 CDCM Inter-group effects for Group 2 additional options



Source: Frontier Economics analysis

Figure 39 TNUoS Inter-group effects for Group 2 additional options



Source: Frontier Economics analysis

Based on the charts above we can see the following key distributional effects:

- By deeming much lower capacities for domestic the burden of cost recovery is shifted significantly towards non-domestic users relative to the basic ex-ante charging option for both CDCM and TNUoS.
- The introduction of a net volumetric element to the deemed ex-ante capacity option only has a minimal additional impact for both CDCM and TNUoS.

3.6.1 User groups static bill impacts (additional options)

In this section we present the combined CDCM and TNUoS residual bills for the baseline and basic options for:

- Domestic user groups;
- Domestic user groups with new technologies;
- Commercial user groups; and
- Industrial users.

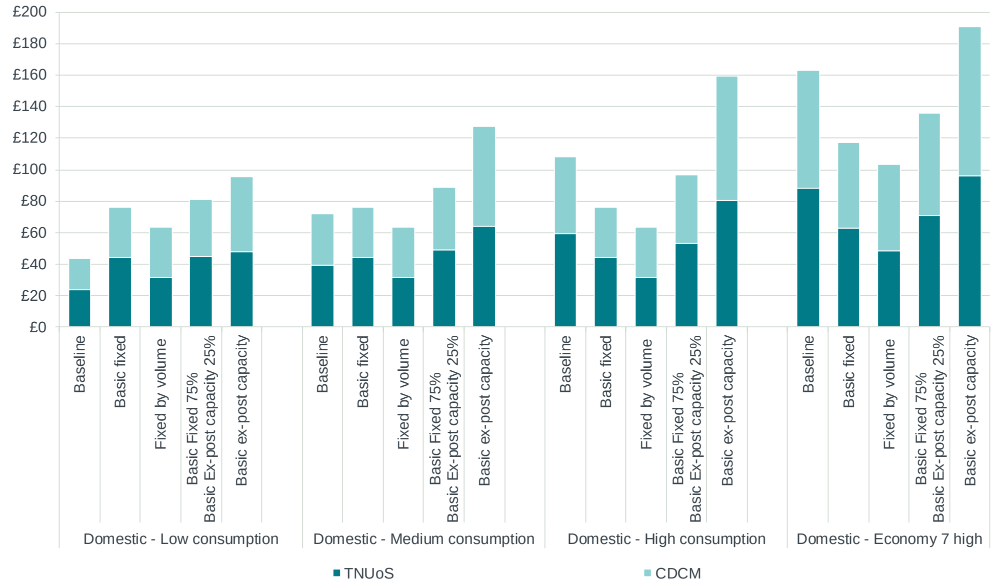
Similar to the section above we present the results for the additional options in two groups:

- Group 1 - fixed options; and
- Group 2 - ex-ante capacity options

Domestic user groups

The combined CDCM and TNUoS residual bills for the Group 1 – fixed options for our domestic user groups are presented in Figure 40.

Figure 40 Domestic user groups – CDCM and TNUoS residual bills impacts for Group 1 options



Source: Frontier Economics analysis

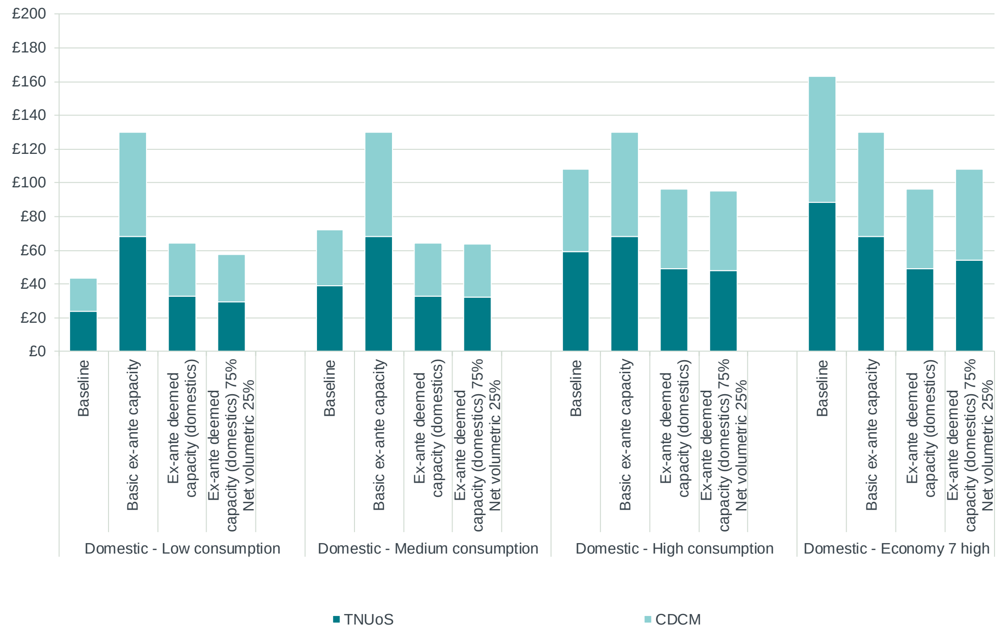
Note: Residual bills for Northeast DNO. The residual bill data for all other DNOs is provided in Annex B

Based on this we observe the following distributional effects:

- Relative to the basic fixed charges, domestic bills with fixed by volume charges are lower due to the lower TNUoS charges. As noted in the previous section, this is because domestic users (based on current levels) represent a smaller share of system net volume compared to historic revenue recovery. The intra-group effects between domestic consumers of different sizes are the same as under the basic charges.
- Introducing an ex-post element to the fixed charge results in residual bills that increase in line with the consumption level of the user groups, reflective of the fact that in our user groups' peak consumption also increases in line with the level of annual consumption. The residual bills sit proportionately between the basic fixed and basic ex-post capacity bills.

The combined CDCM and TNUoS residual bills for the Group 2 – ex-ante capacity options for our domestic user groups are presented in Figure 41.

Figure 41 Domestics user groups – CDCM and TNUoS residual bills impacts for Group 2 options



Source: Frontier Economics

Note: Residual bills for Northeast DNO. The residual bill data for all other DNOs is provided in Annex B

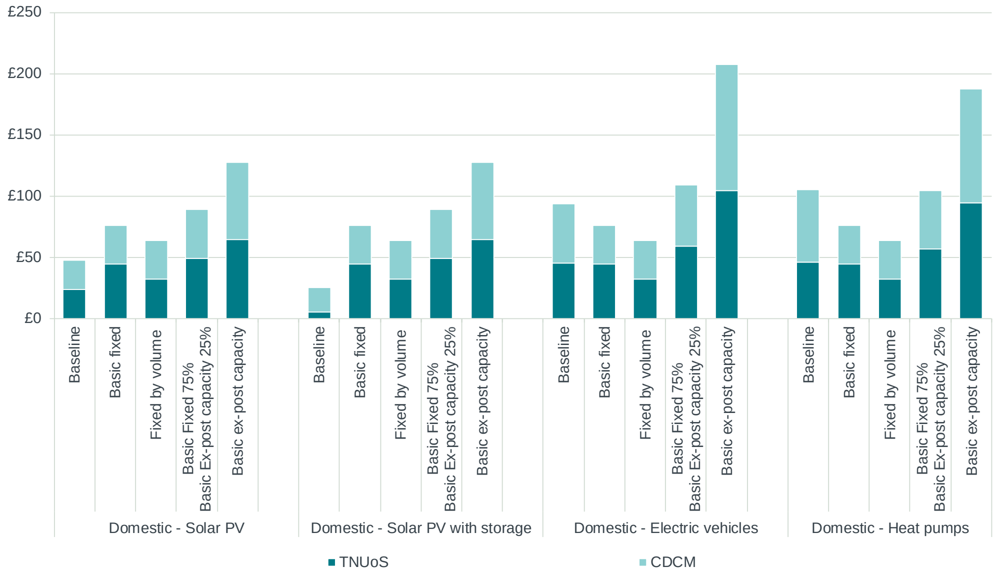
Based on this we observe the following distributional effects:

- Deeming lower domestic capacities results in significantly lower bills than under the deemed ex-ante option. As a result, all of the domestic user groups, except for the low consuming user, pay lower bills that under the baseline.
- Introducing a net volumetric element to the deemed ex-ante capacity charge results in a slightly lower charge than under a pure deemed ex-ante option for domestic users, except for Economy 7 where higher net consumption pulls up the ex-ante charge.

Domestic user groups with new technologies

The combined CDCM and TNUoS residual bills for the Group 1 – fixed options for our domestic user groups with technologies are presented in Figure 42.

Figure 42 Domestic user groups with new technologies – CDCM and TNUoS residual bill impacts for Group 1 options



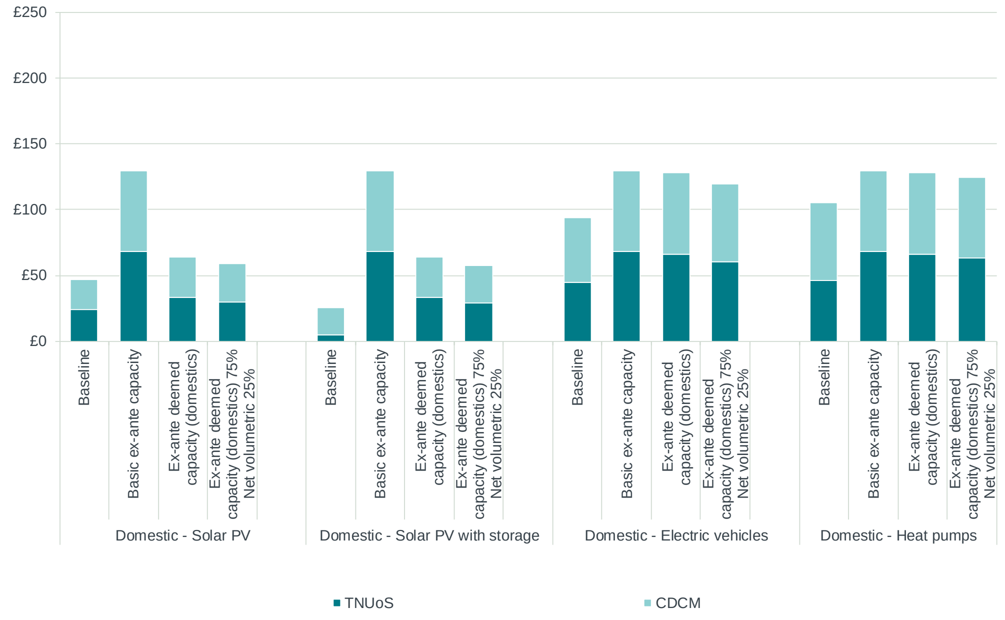
Source: Frontier Economics analysis

Note: Residual bills for Northeast DNO. The residual bill data for all other DNOs is provided in Annex B

We observe similar distributional effects for domestic users with new technologies as the effects observed for domestics without the technologies i.e. the impact on bills relative to the basic options is very similar, and hence the impact relative to the baseline is as described in the previous section on basic options. The only differences relate to the impact of the technologies on the ex-post element in the Fixed (75%) ex-post (25%) option i.e. the bill is increased slightly due to a higher peak for household with a heat pump or EV.

The combined CDCM and TNUoS residual bills for the Group 2 – ex-ante capacity options for our domestic user groups with technologies are presented in Figure 43.

Figure 43 Domestic user groups with new technologies – CDCM and TNUoS residual bill impacts for Group 2 options



Source: Frontier Economics analysis

Note: Residual bills for Northeast DNO. The residual bill data for all other DNOs is provided in Annex B

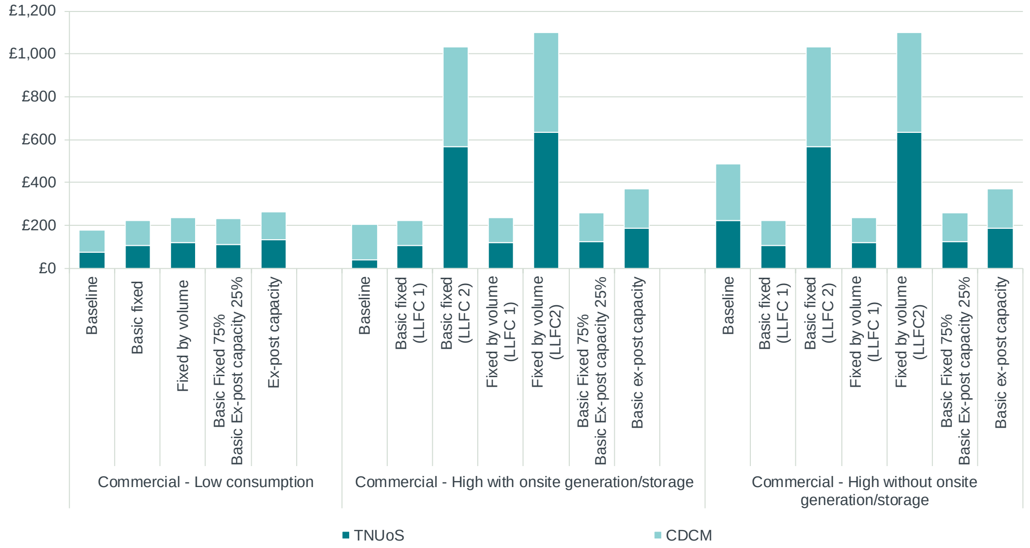
Based on this we observe the following distributional effects:

- Lower deemed ex-ante capacities for domestics with solar and solar/storage results in lower bills for domestics with solar, compared to the basic ex-ante capacity option. However, bills for domestic users with EVs and heat pumps are double other domestic users due to the deemed capacity being double (8kVA as opposed to 4kVA). The impact relative to the basic option is limited is minimal, because the effect of a higher per unit charge for capacity under this option is broadly balanced out by the capacity reduction from 18kVA to 8kVA.
- When the ex-ante deemed (75%) and net volumetric (25%) charging options are combined, this results in a slightly lower charge for the domestic user groups with a technology than under a basic deemed ex-ante option.

Commercial user groups

The combined CDCM and TNUoS residual bills for the Group 1 – fixed options for our commercial user groups are presented in Figure 44.

Figure 44 Commercials - CDCM and TNUoS residual bills for Group 1 – fixed options



Source: Frontier Economics analysis

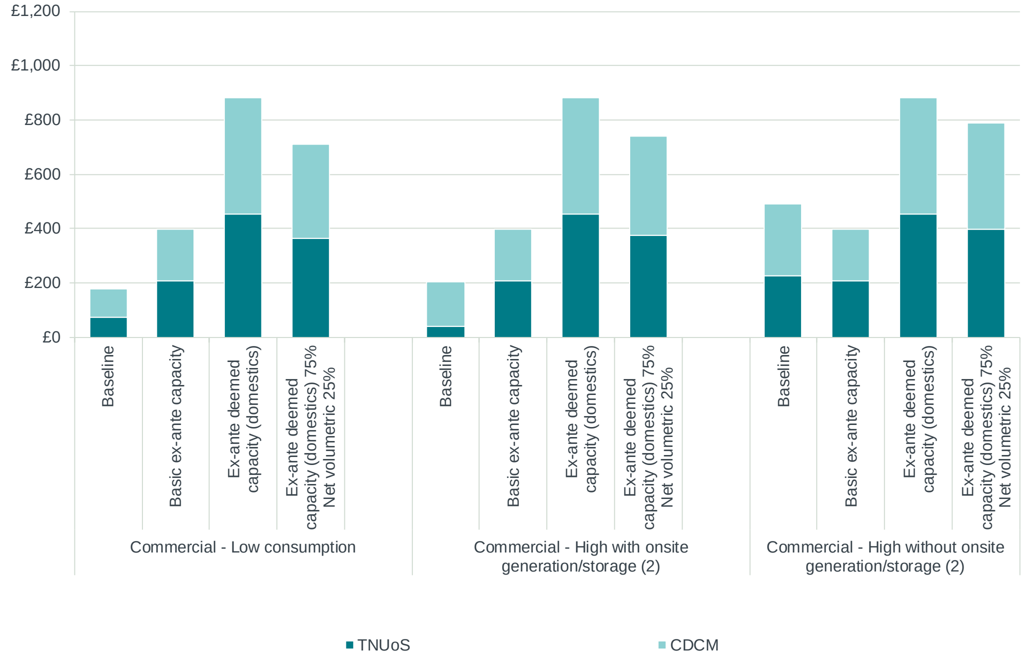
Note: Residual bills for Northeast DNO. The residual bill data for all other DNOs is provided in Annex B. Note that LLFC 1 refers to the Small Non-Domestic Unrestricted LLFC and LLFC 2 refers to the LV Network Non-Domestic Non-CT LLFC

Based on this we observe the following distributional effects:

- Similar to the basic fixed options, the distributional effect of the fixed by volume option depends on the particular LLFC the commercial user group is mapped to. If it is mapped to the LV Network Non-Domestic Non-CT LLFC (identified as LLFC 2 in the chart above), a significant increase in the residual bill relative to the baseline is observed. While if it is mapped to the small non-domestic unrestricted LLFC (identified as LLFC 1 in the chart above), a small increase relative to the baseline is observed.
- The fixed by volume charge is slightly higher than the basic fixed charge, suggesting that commercials represent a higher share of total net volume than historic revenue, though the effect is small.
- Introducing an ex-post element to the charge, results in a slightly higher bill for a low consuming user, but a slightly lower bill for a high consuming user (without onsite generation). However, as with the basic fixed and fixed by volumes charges, the fixed element of this charge is very sensitive to the particular LLFC, and therefore it is equally possible for the bill to increase (a possibility which is not presented in Figure 44.

The combined CDCM and TNUoS residual bills for the Group 2 – ex-ante capacity options for our commercial user groups are presented in Figure 45.

Figure 45 Commercials – CDCM and TNUoS residual bills Group 2 – ex-ante capacity options



Source: Frontier Economics analysis

Note: Residual bills for Northeast DNO. The residual bill data for all other DNOs is provided in Annex B

Based on this we observe the following distributional effects:

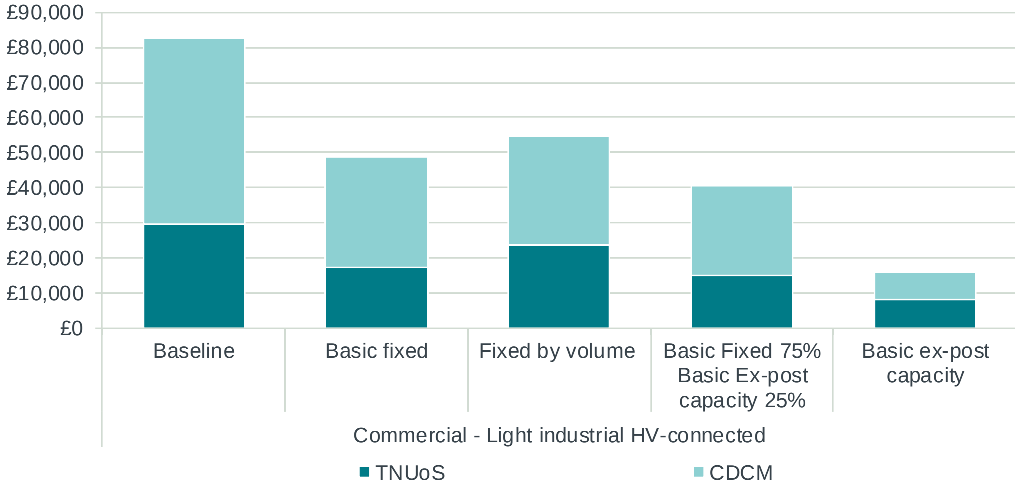
- In relation to the deemed ex-ante option, a significant reduction in domestic capacity over which to recover costs, increases ex-ante bills significantly on all non-domestic users. This is because capacity charges have increased relative to the basic option, yet unlike for domestic users, non-domestic capacity for the purpose of charging remains unchanged. Note that we also completed a sensitivity that included lower deemed capacity for some commercials as well as domestics. This sensitivity reduced the capacity of commercial users, reducing their residual bill significantly, while increasing the bills for domestics and other industrial users. [25]
- Introducing a net volumetric element to the charge mitigates in part the effect of the move to the deemed ex-ante capacity charges.

Light Industrial user group

The combined CDCM and TNUoS residual bills for the Group 1 – fixed options for our light industrial user groups are presented in Figure 46.

[25] Basic ex-ante capacity charge except domestic capacities are deemed to be lower than physical connection size (i.e. 4kVA for 75% of domestic customers, 6kVa for 15% - 'higher consuming' – of domestics, 8kVA for - EVs and HPs -10% of all domestics), and some commercial capacities are deemed lower than physical connection size (i.e, 15 kVA or 30 kVA relative to 55kVA assumed to be the physical capacity).

Figure 46 Light industrial HV connected user group - CDCM and TNUoS residual bills for Group 1 - fixed options



Source: Frontier Economics analysis

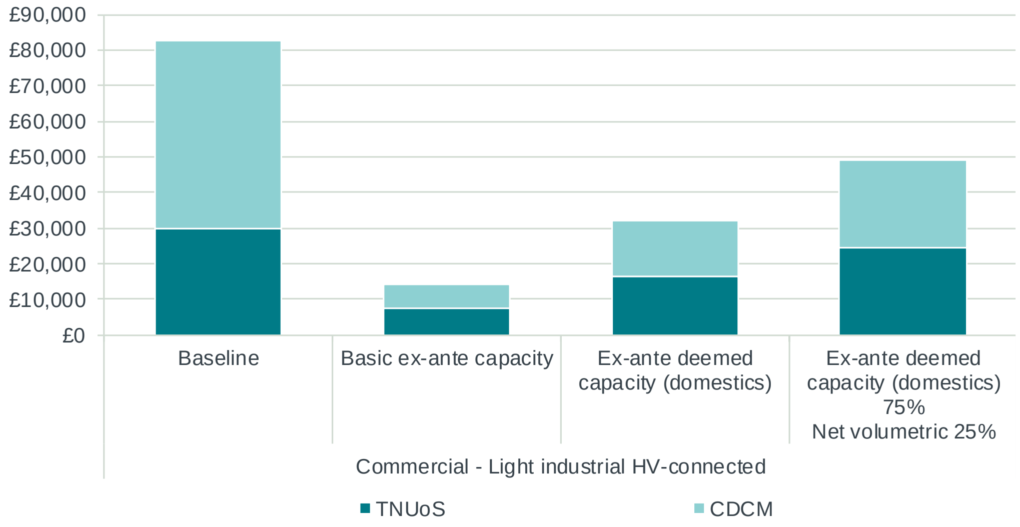
Note: Residual bills for Northeast DNO. The residual bill data for all other DNOs is provided in Annex B

Based on this we observe the following distributional effects:

- The fixed by volume charge is higher relative to the basic fixed charge, given industrial users represent higher share of total net volume than historic revenue, particularly in relation to TNUoS.
- Introducing an ex-post element to the charge reduces the bill slightly relative to the basic fixed option, which is due to very low basic ex-post capacity charge for this user.

The combined CDCM and TNUoS residual bills for the Group 2 – ex-ante capacity options for our light industrial user groups are presented in Figure 47.

Figure 47 Light industrial HV connected user group - CDCM and TNUoS residual bills for hybrid ex-ante, baseline and basic ex-ante



Source: Frontier Economics analysis

Note: *Residual bills for Northeast DNO. The residual bill data for all other DNOs is provided in Annex B*

Based on this we observe the following distributional effects:

- In relation to the deemed ex-ante option, a significant reduction in domestic capacity over which to recover costs, increases ex-ante bills significantly on all non-domestic users. However, for this user it remains significantly below the baseline bill.
- Introducing a net volumetric element to the charge results in a higher bill for the light industrial user group due non-domestic users representing a greater share of system net volume than system capacity.

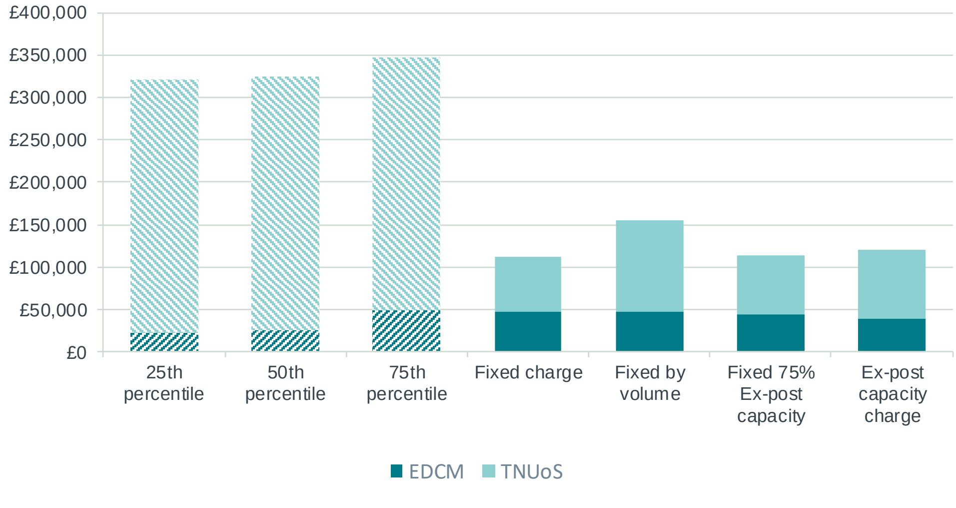
Industrial user groups - EHV connected users

EHV connected customers pay TNUoS and EDCM charges. Given the site specific EDCM baseline charges we are not able to combine both into a single baseline bill. We therefore have set out in Figure 48 and Figure 49 a range of possible baseline bills which reflect the combination of the baseline TNUoS bill and the minimum, maximum and quartiles from the distribution of the EDCM bills. For the user with onsite generation/demand management, its baseline bill is represented by the EDCM element only on the assumption it could avoid the TNUoS bill entirely. For ease, this user's baseline bills are not separated out in Figure 48 and Figure 49.

For EDCM customers, in order to compare the new charges for our user group against a representative schedule of baseline charges, we have normalised the site-specific baseline charges received from the DNOs to a 10,000kVA capacity, as defined in our EHV-connected user group.

The residual bills for the Group 1 – fixed options for our EHV connected industrial user groups are presented in Figure 48.

Figure 48 TNUoS and EDCM residual bills for Group 1 – fixed options



Source: *Frontier Economics analysis*

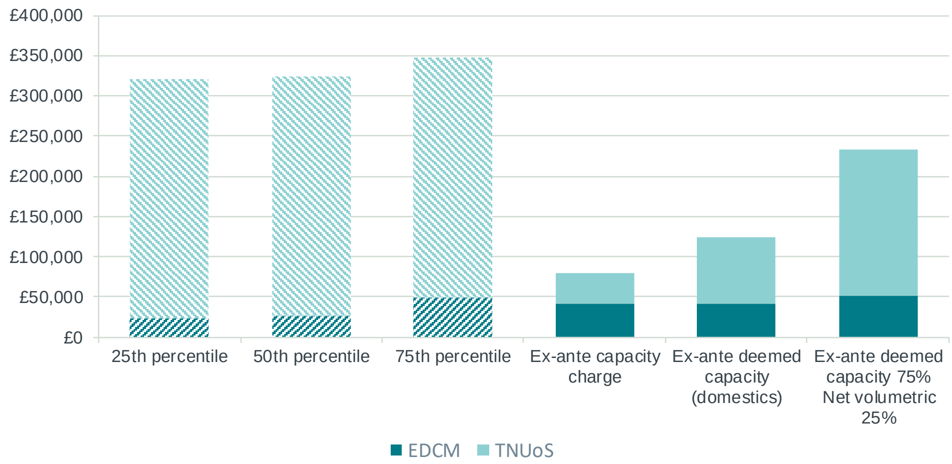
Note: *Residual bills for Northeast DNO. The residual bill data for all other DNOs is provided in Annex B EDCM fixed charge likely to be an underestimate, since the charging base also includes generation specific sites which could not be separately identified from the dataset.*

Based on this we observe the following distributional effects:

- For EHV connected industrials, the TNUoS fixed by volume charge is higher than the basic fixed charge as industrial users represent a higher share of total net volume than historic revenue. For EDCM the fixed by volume charge equals the basic fixed charge, as the same residual revenue is recovered from the same number of EDCM customers under each option. As noted earlier, this fixed charge is likely to include some pure generation sites and hence in reality we would expect the fixed charge to be higher than this.
- Introducing an ex-post element has a limited impact on the EHV connected industrial user group. However, industrial users with a peakier profile than assumed for this user group could face a higher ex-post bill TNUoS and EDCM bill, resulting in a larger increase in their residual bill relative to the basic fixed charge.

The residual bills for the Group 2 – ex-ante capacity options for our EHV connected industrial user groups are presented in Figure 49.

Figure 49 EDCM residual bills for Group 2 – ex-ante capacity options



Source: Frontier Economics analysis

Note: Residual bills for Northeast DNO. The residual bill data for all other DNOs is provided in Annex B

Based on this we observe the following distributional effects:

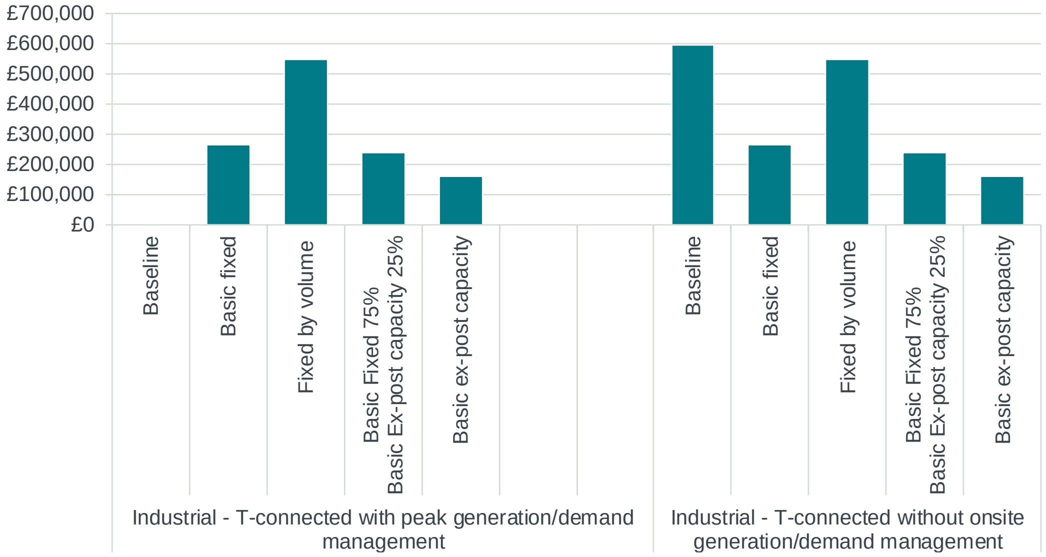
- In relation to the deemed ex-ante option, a significant reduction in domestic capacity over which to recover costs, increases TNUoS ex-ante bills significantly on all non-domestic users. For EDCM, the ex-ante deemed capacity charge equals the basic ex-ante charge, as the capacities for commercials and industrials remain unchanged between the two options.
- Introducing a net volumetric element, results in a higher TNUoS bill for the industrial user groups without onsite generation compared to the deemed ex-ante option. For a user with onsite generation or demand management, we assume the whole net volumetric element could be avoided, resulting in a bill 75% of the TNUoS ex-ante deemed capacity option (this user's bill is not presented in Figure 49). For EDCM, the impact on a particular user of introducing a net volumetric element depends on the utilisation of connection capacity. High utilisation by users would likely result in an increase in the bill.

Industrial – Transmission connected

Industrial T-connected users only pay TNUoS, and the impacts identified are directionally the same as the TNUoS impacts identified above for the EHV connected customers.

The TNUoS residual bills for the Group 1 – fixed options for our T connected industrial user groups are presented in Figure 50.

Figure 50 Industrial T- connected user group - TNUoS residual bills for Group 1 - fixed options



Source: Frontier Economics analysis

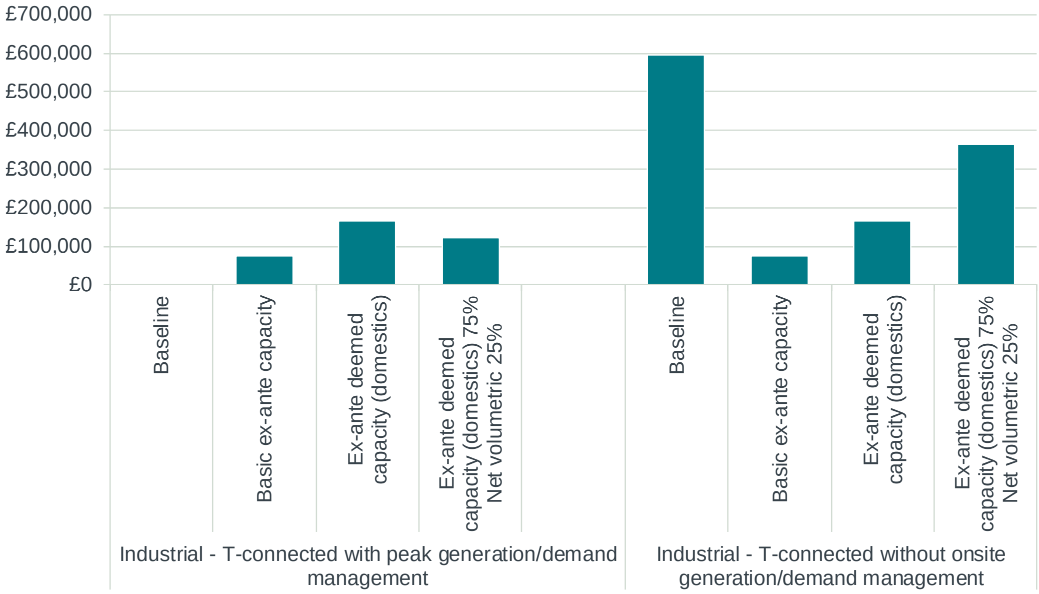
Note: Residual bills for Northeast DNO. The residual bill data for all other DNOs is provided in Annex B

Based on this we observe the following distributional effects:

- For T connected industrials, the fixed by volume charge is higher than the basic fixed charge as industrial users represent a higher share of total net volume than historic revenue.
- Introducing an ex-post element has a limited impact on the T connected industrial user group. However, industrial users with a peakier profile than assumed for this user group could face a higher ex-post bill, resulting in a larger increase in their residual bill relative to the basic fixed charge.

The TNUoS residual bills for the Group 2 – ex-ante capacity options for our T connected industrial user groups are presented in Figure 51.

Figure 51 Industrial T- connected user group - TNUoS residual bills for Group 2 - ex-ante capacity options



Source: Frontier Economics analysis

Note: Residual bills for Northeast DNO. The residual bill data for all other DNOs is provided in Annex B

Based on this we observe the following distributional effects:

- In relation to the deemed ex-ante option, a significant reduction in domestic capacity over which to recover costs increases ex-ante bills significantly on all non-domestic users.
- Introducing a net volumetric element, results in a higher charge for the industrial user groups without onsite generation compared to the deemed ex-ante option. For a user with onsite generation or demand management, we have illustrated the impact of assuming the whole net volumetric element could be avoided, resulting in a bill 75% of the ex-ante deemed capacity option.

3.7 Overview of static bill impacts

We have presented results for eight charging options across 15 of the user groups. The results presented for each user group depend on specific assumptions. However, we can draw a number of more general insights about the potential distributional impacts that result from changes to the residual charging.

A **fixed charge** applies the same charge to all users in a particular segment. Users previously paying above average baseline charges in the segment gain relative to those who previously paid lower charges, including those sites previously able to avoid charges by triggering onsite generation of demand management.

There is no limit to the choices of how to distribute the recovery of the residual among customer segments when setting fixed charges. Ofgem identified an option where the share of cost recovery from each group is based on its net volumetric consumption. Under this model, cost recovery from domestic customers is reduced relative to non-domestic customers, because today TNUoS charging is based on peak consumption which tends to focus cost recovery more on domestic customers.

We have considered **gross volumetric charging** for the larger users. Even though Ofgem is not considering charging domestic customers on a gross volumetric basis, if cost recovery between smaller and larger customers is apportioned on the basis of gross volume, this shift should benefit domestic customers with respect to their TNUoS bill. Since gross volume charges limit the ability to avoid charges, all else equal, gross volume per unit charges would be lower than current charges for all users. However, large users with on-site generation would see increased charges.

Ex-ante capacity charges based on our assumptions for actual physical capacities result in the same residual bill for all users with the same connection capacity irrespective of their consumption patterns. Under this option, all but the highest consuming households are likely to experience an increase in their bill since domestic consumers represent a greater share of physical connection capacity than of annual or peak net consumption. Industrial users with on-site generation would also see increased charges.

This result is sensitive to the particular assumptions on connection capacity. Options with lower 'deemed' capacities for domestic customers can result in a distribution much closer to historic levels.

In a similar way to ex-ante capacity charges, **ex-post capacity charges** (including the ex-ante capacity ratchet option) are also likely to result in greater cost recovery from domestic relative to non-domestic customers.

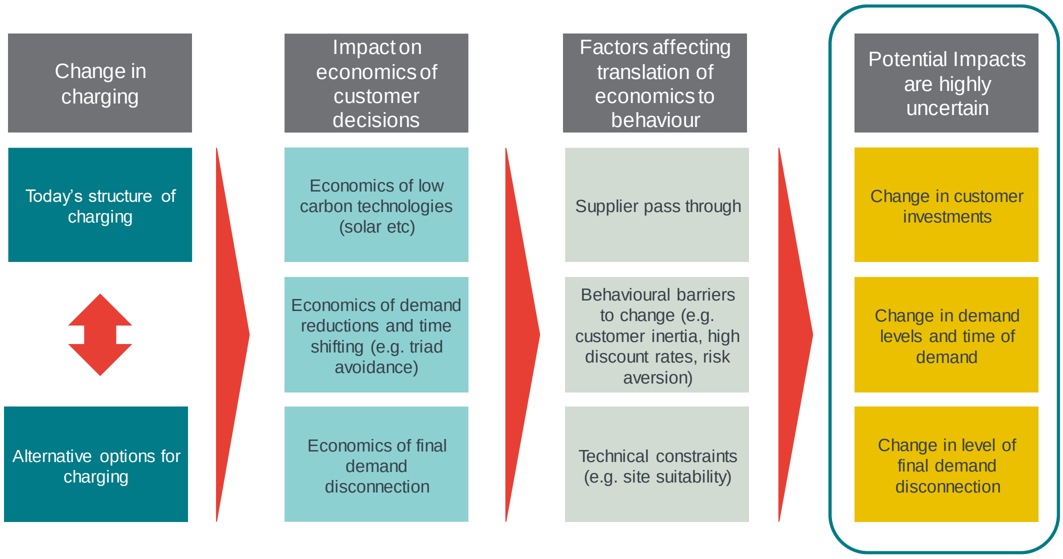
We have also considered a number of '**hybrid' options**. By introducing an ex-post element (25%) to the fixed charge (75%), users with greater consumption at peak would pay higher bills, and a greater share of costs would be recovered from domestic customers, albeit to a limited extent compared to the pure ex-post charge.

In a similar way, introducing a net volumetric element (25%) to an ex-ante capacity based charge (75%), creates differential bills for users with the same capacity (particularly for domestic customers where standard capacity sizes are more likely to apply). As noted above, a net volumetric element is likely to favour domestic customers.

4 BEHAVIOURAL IMPACTS

In the previous chapter of the report we analysed the potential impact of different potential options for residual charging on customer bills holding behaviour change constant. In this chapter, we consider at a high-level the potential impacts of the options on customer behaviour for different user groups, with a view to identifying the areas where there is the greatest potential for behavioural responses to have measurable effects on overall system costs. The purpose of this behavioural assessment is to inform the assumptions used in our system modelling in Envision which is set out in the next chapter. In Figure 52 we summarise our approach.

Figure 52 Overview of the potential for behavioural responses



Source: Frontier Economics

The static bill impacts we have identified have the potential to affect economic decisions of customers, for example with respect of:

- investment in particular technologies, such as
  - dispatchable generation, for example the installation and use of standby-generation;
  - intermittent generation, such as rooftop solar;
  - electrical storage;
  - additional electricity consuming equipment which could involve "new" uses of electricity, such as electric vehicles or heat pumps, or simply more consumption associated with existing use types.
- the timing of consumption either in relation to peak or total demand, and
- whether to disconnect from the network by investing in onsite generation to ensure self-sufficiency and avoid network charges entirely.

However, in each of these areas, it will be important to consider the significant evidence which indicates that small changes in customer payments or marginal incentives are often poorly correlated with behavioural change. There are at least two key issues which will need to be addressed in this assessment:

- customers often do not directly experience distribution charges. These charges are paid by suppliers who may pass them on using a very different charging structure. Our static analysis was estimated on the basis of perfect pass-through of the charges, however, the extent to which this is actually the case will clearly have an impact on incentives;
- marginal prices are not the most important drivers of customer behaviour in many instances. Other factors may be more important, particularly for small customers, including:
  - fashion and branding e.g. prestige associated with being an early adopter;
  - sustainability;
  - balance of up-front vs. ongoing costs;
  - "friction", including transaction and installation costs;
  - complexity or need for assumptions to carry out an economic assessment; and
  - inertia.

We also note that all the LCTs are subsidised currently, and if the subsidy adjusts to maintain the current relativity with alternate technologies, then the customer will not necessarily see any impact of a change in network charges.

These types of effects are likely to diminish the level of behavioural change, and as a result any analysis of behavioural responses is highly uncertain. Our approach is therefore to try and identify those areas where the economics behind particular decisions are most significantly affected and hence, there is the greatest possibility that there could be a behavioural response.

This chapter is structured as follows:

- In Section 4.1 we consider the potential impact on investment in low carbon technologies (LCTs).
- In Section 4.2 we consider potential behavioural responses by industrial and commercial users e.g. related to investment in BTMG and load disconnection.
- Finally, in Section 4.3, we summarise the implications of this review for the system modelling set out in the next chapter.

4.1 Investment in low carbon technologies

Investments in low carbon technologies (LCTs) could in theory be affected by the change in residual charges. Under the baseline charging arrangements, the presence of certain new technologies can result in savings or additional costs on a customer's residual bill. However, because the new residual charging options are typically less sensitive to the consumption patterns of consumers, the impact of technologies on the residual bill is much diminished.

As an example, energy from a solar PV unit reduces a customer's net volumetric charges, such as those under CDCM, resulting in a saving that can be directly attributable to the presence of the solar unit. However, under the residual charging options, most if not all of that saving is removed (as the solar unit is not likely to reduce net peak consumption), effectively increasing the lifetime cost of investing in that technology.

A customer acting purely rationally might respond to this change in technology cost, because it makes the particular technology cheaper or more expensive relative to the cost of investing in an alternative. For example, investing in an electric vehicle depends on its cost relative to a conventional petrol or diesel car, and investing in a heat pump depends on its cost relative to a gas boiler. Similarly, investing in solar PV should be considered against the alternative option of purchasing the power directly from the grid. We consider the impact on these relative investment decisions to understand the potential for a behavioural response due to the changes to residual charging.

Our approach is to examine the potential for such responses and identify those areas where there is the greatest possibility that there could be a behavioural response. As a starting point, we assume that the LCT technology is either equal in cost to the alternate technology (which it should be at the point where subsidy is removed) or that the current level of subsidy has been calibrated such that the costs are equal to each other.

We then estimate the potential impact on the lifetime technology cost[26] of the LCT of the proposed changes to network charges in three steps:

- Step 1: We estimate the impact of change in charging options on each LCT's lifetime technology cost. We consider the residual costs/savings under a range of assumptions in particular, the size of the residual, and (where appropriate) alternative technology usage assumptions.
- Step 2: We estimate the annualised lifetime cost of each LCT, included capex and electricity costs. We consider alternative capex assumptions.
- Step 3: We consider the potential for a behavioural response based on the residual saving or cost as a proportion of the annualised cost for each LCT.

4.1.1 Step 1: Impact of change on lifetime technology cost

We use the static bill impact analysis set out in the previous chapter to understand the potential change in the lifetime cost of investing in the LCTs. The impact on cost can be identified by comparing the impact of the LCTs on the baseline TNUoS and CDCM residual bill for a particular customer, with the impact of the LCTs on the residual bill under the new residual charging options.

We first qualitatively consider the potential impact on the lifetime technology costs in relation to electric vehicles (EVs), heat pumps (HPs), solar PV and storage in Figure 53. We then set out our assumptions for quantifying the range of possible impacts on cost based on the static bill impact analysis.

[26] We consider the key components of LCT lifetime cost e.g. upfront investment cost and on-going electricity costs

Figure 53 Potential impacts on lifetime technology costs

Technology	Change in investment incentives
Electric vehicles/heat pumps	▪ The additional costs of owning EVs or HPs relative to consumers without the technologies under baseline CDCM and TNUoS charges are removed under most charging options - fixed and ex-ante charging options in particular. Though under the basic ex-ante option the increase in all residual domestic bills might dampen any behavioural response. ▪ The additional costs of EVs and HPs may also remain under the basic ex-post option, though the charging of electric vehicles could in theory be profiled to avoid increasing the peak. ▪ The options which incorporate ex-post elements or retain net volumetric elements would dampen any impacts related to the basic fixed and ex-ante charges.
Solar PV	▪ Solar PV customers currently benefit from lower annual net consumption and hence a lower baseline CDCM charge. This benefit would be removed under all of the residual charging options, except the option which incorporates a net volumetric element. ▪ The scale of the impact on TNUoS bills is likely to be less than for CDCM given there is relatively less solar generation in the hours of 4-7pm, and hence the benefit of solar PV under the baseline is more limited.
Solar PV with storage	▪ Storage, when combined with solar PV, could increase the benefit of solar under the baseline CDCM and TNUoS charges, by shifting exports in the middle of the day to the evening peak. As with solar PV alone, this benefit would be removed under most of the charging options. ▪ There is a very limited potential to reduce ex-post peak charges, if a customer's individual peak is reduced by shifting solar generation to the evening peak on that day. However, the days with the highest peaks are also likely to coincide with days without solar generation and hence this may not be significant.

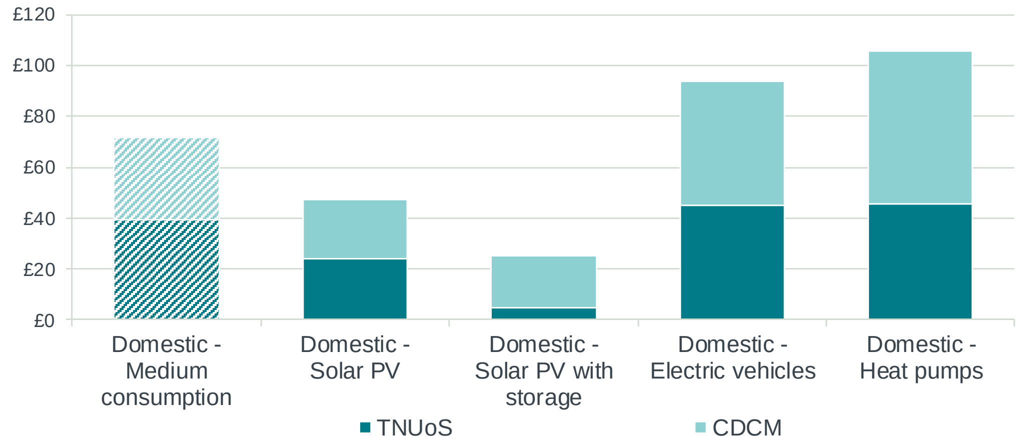
Source: Frontier Economics

Based on the summary in Figure 53, we can see that under most of the residual charging options (fixed and ex-ante options in particular) LCTs do not affect the residual bill. Therefore, the impact of the options on technology cost is to remove a saving or additional cost due to the LCTs under the baseline.

We can therefore explore this lost saving or avoided cost, by comparing the baseline bills of the medium domestic user with and without the LCTs. This should be viewed as an upper bound impact for the residual charging options, since as noted in Figure 53 under some of the options some LCT impact may remain resulting in a smaller impact on the lifetime technology cost (i.e. the impact could be less for the basic ex-post option, and the options which introduce an ex-post and net volumetric elements).

As an illustration we set out in Figure 54 below the estimated baseline residual bills (TNUoS and CDCM) for 2019/20 for a medium domestic customer in the Northeast region with and without each of the LCT technologies discussed above. The central assumptions for the size and consumption related to the LCTs are set out in Figure 56.

Figure 54 Baseline CDCM and TNUoS residual bills for domestic user groups with low carbon technologies



Source: Frontier Economics

Note: Residual bills for Northeast DNO. The residual bill data for all other DNOs is provided in Annex B

Figure 55 Central assumptions for technology usage

LCT	Consumption[27]
Solar PV	2,803 (kWh p.a.)
Storage	286 (kWh usefully stored p.a.)
Electric vehicle	1,500 (kWh p.a.)
Heat pump	2,542 (kWh p.a.)

Source: Technology costs and operating lives based on current technology costs and operating lives, consumption data sourced from CLNR data analysis

Based on this example, we observe that under the residual options a medium domestic customer:

- with solar PV would no longer save approximately £25 per annum relative to a medium domestic customer with no technology;
- with storage and solar PV would no longer save an additional £22 per annum on top of the solar savings;
- with an EV would no longer have to pay approximately £22 more per annum relative to a medium domestic customer without an LCT; and
- with a heat pump would no longer have to pay approximately £33 more relative to a medium domestic customer without an LCT.

[27] Sourced from analysis of CLNR data. HP consumption level is consistent with a 3kW unit and 9%-11% load factor, this load factor range was published in CLNR trial analysis. Solar PV consumption level is consistent with 3kW unit and 11% load factor as this load factor was used by BEIS for a 3kW solar unit in their electricity generation costs report.

To understand the range of potential impacts we carry out this analysis for our medium domestic consumer in each DNO region. We also test assumptions which result in larger impacts on technology costs than under the central assumptions:

- EV savings are particularly sensitive to a customer's use of car (i.e. annual mileage). We therefore consider the savings due to the residual options based on much higher usage of 3,000kWh which is at the top-end of the distribution of EV users in the CLNR dataset.
- Savings directly increase with the size of the residual. Given future uncertainty over the size of network costs, or the level recovered from cost reflective tariffs we consider a sensitivity with a 50% increase in the residual.

The impact on the lifetime technology cost represents an interim step in this analysis, and the full results of the analysis are presented below in Step 3 after thinking about technology costs in step 2.

4.1.2 Step 2: Estimate of lifetime technology costs

For *Step 2* in the analysis, we estimate the annualised lifetime cost of each LCT. This includes both the initial investment cost and ongoing electricity costs (estimated using retail electricity prices published in the UK government Green Book supplementary guidance).

The central assumptions for calculating the annualised lifetime cost for each LCT are outlined in Figure 56. We have used a real discount rate of 4% in this analysis.

Figure 56 Central assumptions used in the annualised cost calculation

LCT	Technology cost[28]	Operating life[29]
Solar PV	£1,500/kW	30 years
Storage	£8,725	10 years
Electric vehicle	£27,823	15 years
Heat pump	£1,380/kW	15 years

Source: *Technology costs and operating lives based on current technology costs and operating lives, consumption data sourced from CLNR data analysis*

The path of future technology costs is highly uncertain, however, they could fall significantly in future. We therefore also consider a 25% reduction in the up-front cost of LCTs, except for solar where we base it on BEIS future cost information (i.e. we extrapolate the trend reduction between 2020 and 2025 giving a 13% reduction by 2030).

4.1.3 Step 3: Consider potential for behavioural response

Finally, we estimate the impact of changing charging options on the lifetime technology costs for each LCT *as a percentage* of the annualised lifetime cost of

[28] Solar PV costs (capex and O&M costs) sourced from BEIS, Electricity generation cost report 2016 Storage technology costs based on cost of a Tesla Powerwall (capex, supporting hardware and installation costs), capacity of 13.5 kWh. EV costs based on average cost of Nissan Leaf plus cost of installing a charging point. HP capex costs sourced from UK government RHI deployment data.

[29] For storage, an operating life of 10 years used as Tesla provides a warranty on Powerwalls for 10 years. Solar PV operating life of 30 years is sourced from BEIS, electricity generation and cost report 2016.

each LCT. We examine this proportion for each DNO and the range of assumptions (central and sensitivities) described in Steps 1 and 2 above. We have combined the sensitivities under both steps to create a 'high sensitivity' i.e. a scenario where we compare potential higher impacts on technology costs from step 1 to an assumed lower estimate of technology costs from step 2. Under this scenario we would expect a greater potential for a behavioural response than under the central assumptions.

The 'high sensitivity' is summarised in Figure 57.

Figure 57 High sensitivity assumptions for each LCT

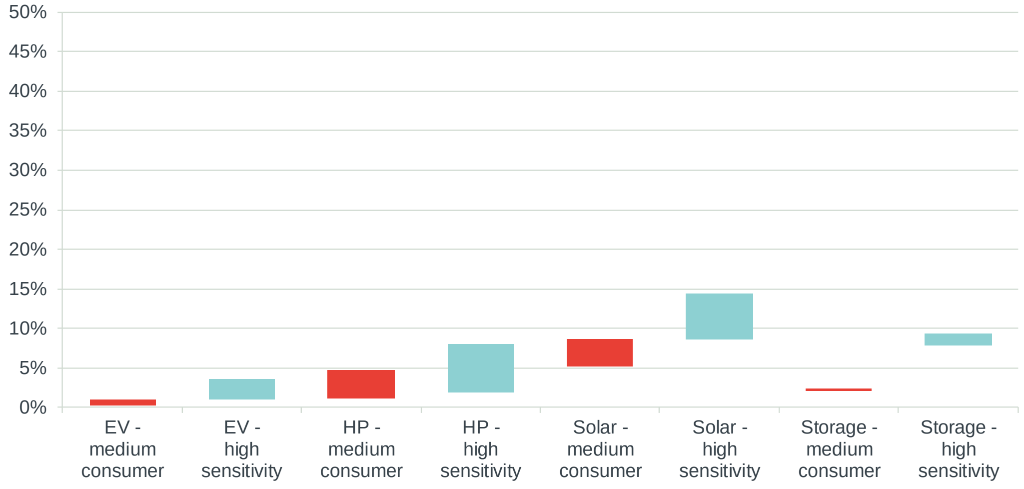
LCT	'High' sensitivity
Electric vehicle	High usage of 3,000kWh, 50% increase in residual and 25% reduction in cost
Heat pump	50% increase in residual and 25% reduction in cost
Solar	50% increase in residual and 25% reduction in cost
Solar with storage	50% increase in residual and 25% reduction in cost

Source: Frontier Economics

The range of proportions for each technology under the central assumptions and high sensitivity is outlined in Figure 58 below.

- For EVs and HPs the bars represent the range of possible percentage *reductions* in the annualised lifetime technology cost under the central assumptions and the high sensitivity. The bottom end of each bar represents the impact in the DNO region with the lowest 2019/20 CDCM residual p/kWh charge i.e. the Eastern region. The top-end of each bar represents the impact in the DNO region with the largest 2019/20 CDCM p/kWh charge (i.e. South Wales). Note we have not included the impact in London on the chart since this is the only region with a negative residual. As a result, in London we would expect an increase in the lifetime technology cost of EVs and HPs.
- For solar and storage, the bars represent the range of possible percentage *increases* in the annualised lifetime technology cost under the central assumptions and the high sensitivity. As for EVs and HPs, we estimate the largest impact to be in the South Wales region and the smallest in the Eastern region. In London, we would expect a decrease in the lifetime technology costs of solar and storage.

Figure 58 Percentage change in the annualised lifetime cost



Source: Frontier Economics

Note: Ranges reflect regional differences. London is not presented as it currently has a negative residual

Based on this analysis we can observe:

- For most technologies, even under the ‘high’ scenario assumptions, the impact of the residual charging options result in changes in the lifetime technology costs of less than 10% in the region with the highest residual costs.
- The most significant impact relates to solar PV, where under the high scenario the impact on the lifetime cost could be up to 15%. This could suggest that a behavioural response is more likely in relation to solar i.e. we could see a reduction in the take-up of solar. However, there is a reasonably wide range of impact across the country, and in London we would actually expect an opposite effect.[30]

Overall, the results suggest a limited behavioural impact for all LCTs as the costs/savings represent a relatively small share of the total lifetime costs for each LCT, even under the ‘high’ sensitivity for most LCTs. Therefore, we suggest that, from the perspective of system modelling, it is not necessary to think about scenarios around faster take up of EVs, heat pumps, or delayed take-up of storage.

The area with the greatest potential for impact relates to solar, suggesting there could be value in considering a sensitivity in the wider system analysis for a small slow-down in solar take-up. However, given the analysis does not necessarily suggest a consistent nationwide impact, and that consumers may not directly see the change in cost or respond rationally to the signal, we do not explicitly consider a solar sensitivity in the system modelling. That said, as set out in the next chapter we do consider the impact of the options against a background of different Future Energy Scenarios (FES) with different levels of solar capacity.

[30] There does not appear to be a correlation between the size of impact and levels of solar radiance.

4.2 Industrial and commercial customers

The change to the residual charging options has the potential to affect incentives for the dispatch and investment in onsite generation, demand management and energy efficiency by industrial and commercial customers. In this section we consider the following potential impacts:

- *Reduced incentives to invest in and dispatch BTMG or demand side response* – the potential residual charging options significantly reduce the ability of onsite generation or DSR to help customers avoid residual charges, weakening incentives to dispatch in certain hours invest in BTMG.
- *Increased incentives to invest in BTMG and disconnection* – incentives to invest in BTMG could increase for those sites where additional investment could enable disconnection from the grid and complete avoidance of network charges.
- *Reduced incentives to invest in energy efficiency* – the incentives to invest in energy efficiency could be reduced by fixed and ex-ante charges in particular.

We consider each of these potential impacts in turn.

4.2.1 Impacts on BTMG or demand-side response

The residual charging options could have a significant impact on the incentives to dispatch and invest in onsite generation and demand side response, by reducing the revenues earned by these investments relative to under the baseline charging options:

- *Under the baseline*, BTMG/DSR are able to help industrial sites avoid TNUoS charges by generating during the triad, and for industrial sites located at HV, generators can avoid CDCM charges by generating in every hour of the year. While EDCM charges are reduced below the level they would otherwise have been by generating during super red hours, we consider that it is unlikely to acts as a significant incentive for investment. There is considerable variation in the scale of EDCM charges to start with making the impact on a final bill difficult to identify, and the impact of generation takes three years to feed-through to a site's bill.
- *Under the residual charging options*, BTMG/DSR is no longer able to reduce fixed, gross volumetric and ex-ante charges. In theory, BTMG/DSR could avoid costs by reducing a customer's ex-post peak. However, the exact impact would depend on the scale of the site's individual peak demand when no production was available (e.g. due to plant outages). In addition, the measurement of the ex-post peak element on a monthly basis (option 9), and retention of a net volumetric element (option 8) would imply some retained ability of BTMG/DSR to avoid charges.

As a result, we would expect the incentives to dispatch and make new investments in BTMG/DSR to be affected. The incentive to dispatch during triad is likely to be much reduced, though incentives due to the locational TNUoS charges, wholesale prices and the links to particular industrial processes still remain. Investment incentives are also likely to be significantly reduced under most options, though with potential mitigation under the options with ex-post and net volumetric elements. We expect the dampened incentives to have a potentially significant impact on the overall costs of operating the system, and therefore we assess the potential scale of these impacts in detail in the system modelling described in the next chapter.

4.2.2 Load disconnection

In theory, the shift to the residual charging options could increase the likelihood that some customers disconnect entirely from the network.

On the one hand, as noted above, the potential residual charging options reduce the ability to avoid charges through the use of onsite generation and hence dampen investment in onsite generation. However, on the other hand, it is possible that under certain circumstances incentives to invest in onsite generation could be increased to facilitate load disconnection and the complete avoidance of network charges.

In this section we consider under what circumstances load disconnection could take place. On the assumption that an industrial customer acts rationally, a particular site may choose to disconnect where the incremental costs associated with disconnection are less than the incremental benefits that arise from disconnecting.

The incremental benefit from disconnection is the avoided residual network charge. Under the baseline charging arrangements disconnection is also an option. However, because residual charges can in part already be avoided without the need for disconnection, the incremental benefit of disconnection under the baseline is relatively low. Under the potential residual charging options, the avoidance of residual charges without disconnection is significantly harder, and hence the incremental benefit from disconnection is significantly increased i.e. the incremental benefit could be the avoidance of the full residual.

The incremental costs of disconnecting from the network stem from the need to invest in sufficient generation and demand-side response to cover the gross load of the site to the required level of security, and/or be comfortable with a lower level of security than the grid connection currently provides. In practice, this is likely to imply sufficient year-round baseload/CHP generation and back-up peakers/demand-side response (to provide some redundancy), with the incremental cost closely related to the level of existing onsite generation.

The costs associated with disconnection are also linked to the regulatory framework for disconnecting from the network, and in particular, the exact treatment of import and export capacity following disconnection.

With respect to the import capacity, there are some important questions affecting the risks and hence costs of disconnection such as:

- Is the physical connection disconnected (i.e. unavailable to be used in an emergency), or is it simply a ‘deemed’ import capacity of zero?
- If deemed, could the disconnection decision be changed from year to year, and what would be the cost of doing so?

- What would be the penalty charge if a site imported above deemed level of zero?

If the decision to disconnect could be relatively easily reversed and at a low cost, or the physical capacity remained to be used in an emergency then this may reduce the risks and costs associated with disconnection.

The costs could also be related to the treatment of export capacity at a disconnected site. For sites with significant existing onsite generation, the cost of disconnection could include lost wholesale market sales revenue if it implies zero export capacity as well as zero import capacity. If this were the case, then a site may respond by simply choosing to pay for a de minimis import capacity under an ex-ante charge (if allowed to reduce their contracted capacity under ex-ante capacity charge) or keep its individual peak very low under an ex-post peak charge through investment in additional generation, rather than formally disconnecting. However, this strategy would not work under a fixed charge.

We consider the implications for different sites based on the degree of existing onsite generation below in Figure 59. We conclude that the disconnection decision is likely to be site specific, and most likely to be considered by those sites with existing CHP/baseload generation i.e. those sites where the incremental costs could potentially be relatively low and the benefits high.

While it is therefore possible that some sites may disconnect as a result of the changes to residual charging options, the impact would be to reduce net demand offsetting some of the impact of reduced investment in BTMG noted in the previous section. As a result, we do not assess directly the impact of load disconnection in the system modelling scenarios described in the next chapter, but note it as a driver of uncertainty around the impact of reduced BTMG investment on net demand which is explored in detail.

Figure 59 Overview of likelihood of disconnection for customers based on level of existing onsite generation

Existing onsite assets	Incremental costs/investment requirements to disconnect	Likelihood of disconnection
No existing onsite generation	Likely to be high cost given need to invest in new year-round baseload/CHP generation, and back-up peaking generation.	Extremely low prob. of disconnection. Incremental costs high and the fact that peaking investment to generate during triad not made under the baseline suggests the more expensive option to disconnect is even less likely.
Existing peaking generation covering triad	Sites with existing peaking generation, can either choose to: ▪ run peaking generation 24/7 even when dispatch is not economic, and invest in new back-up peaker generation. ▪ invest in baseload/CHP plant and use existing peaking generation as backup.	Low prob. of disconnection. Costs associated with disconnection likely to be significant.
Existing baseload/CHP generation with very low imports	For sites with close to zero net imports (and potentially exporting) with imports largely used to cover outages of onsite generation, then disconnection could be facilitated by cost of new peaking investment which could be relatively low.	Some potential for disconnection, given relatively low costs and large impact on residual costs.
Existing baseload/CHP generation with net exports	Same as above, however, the cost of disconnection could now also imply lost profits from exporting generation, if disconnection implies zero imports and exports.	Prob. of disconnection dependent on treatment of exports and hence scale of foregone profits, if any

Source: Frontier Economics

4.2.3 Impacts on energy efficiency

The residual charging options could have a significant impact on the incentives to invest in energy efficiency, by reducing the revenues earned by these investments relative to the baseline charging options:

- *Under the baseline*, energy efficiency would result in lower TNUoS charges by reducing triad demand, and for industrial sites located at HV, lower CDCM charges by reducing annual consumption. While EDCM charges are reduced below the level they would otherwise have been as a result of energy efficiency investments reducing consumption during super red hours, we consider that it is unlikely to act as a significant incentive for investment. There is considerable variation in the scale of EDCM charges to start with making the impact on a final bill difficult to identify, and the impact of reduced consumption takes three years to feed-through to a site's bill.

- *Under the residual charging options*, energy efficiency is no longer able to reduce charges under fixed, and ex-ante charging options. However, energy efficiency could reduce a customer's ex-post peak and gross volumetric charges. Energy efficiency can also reduce costs under the options which introduce monthly measurement of the ex-post peak element, and which retain a net volumetric element.

As a result, we would expect the incentives to make new energy efficiency investments to be reduced under the newest options, except the basic ex-post and gross volumetric options. We expect the dampened incentives to feed through to the overall costs of operating the system. However, given the varied nature of industrial energy efficiency investments and hence the significant uncertainty surrounding the impacts, it is not possible to assess the impacts quantitatively.

4.3 Summary of the implications for system modelling

In Figure 60 we summarise the implications of the discussion in this chapter for the Envision system modelling described in the next chapter.

Figure 60 Implications of behavioural assessment for system modelling

<table>
<tr><th>Behaviour/ technology</th><th>Summary of potential impact</th><th>System modelling implication</th></tr>
<tr><td>Electric vehicles</td><td rowspan="4">Overall, the results suggest a limited behavioural impact for all LCTs as the costs/savings represent a relatively small share of the total lifetime costs for each LCT, even under the 'high' sensitivity for most LCTs. The area of greatest potential for impact is likely to relate to solar.</td><td rowspan="4">On balance, we suggest that it is not necessary to think about scenarios with alternative assumptions around take up of EVs, heat pumps, solar and storage to those assumed in the FES scenarios adopted in the system modelling.</td></tr>
<tr><td>Heat pumps</td></tr>
<tr><td>Solar PV</td></tr>
<tr><td>Solar PV with storage</td></tr>
<tr><td>Onsite generation</td><td>Most significant impacts expected due to the loss of the ability to avoid TNUoS and CDCM charges under gross volumetric, fixed and ex-ante capacity charging options. Potential for effects to be smaller under ex-post charging options.</td><td>We modelled impacts on dispatch and investment incentives within system modelling.</td></tr>
<tr><td>Load disconnection</td><td>There is potential for load disconnection among certain types of users with a relatively low cost of investment in back-up power i.e. those already with existing CHP/baseload generation.</td><td>This could be considered as small offset to any reduction in BTMG investment and therefore can be considered as a driver of uncertainty around impact of reduced BTMG on net demand.</td></tr>
<tr><td>Energy efficiency</td><td>There is potential for impacts on energy efficiency investment due to loss of triad. However, given the varied nature of investments it is difficult to assess impacts quantitatively.</td><td>No change to FES assumptions</td></tr>
</table>

Source: Frontier Economics

5 MODELLING OF WIDER SYSTEM IMPACTS

Thus far we have focused on the direct impact of changes in structure of network charges on customers and assessed the potential for behavioural responses to these changes. As a next step, in this section we look at the potential impact that the changes in charging arrangements, and hence some of the potential behavioural responses identified in the previous chapter, could have in aggregate on the whole system, and understand the knock on impacts that this might have on consumer welfare.

5.1 Methodology and Assumptions

In the last section we discussed how changes to network charging arrangements may affect how consumers use the electric system, e.g. whether they choose to self-generate and adopt new technologies like electric vehicles and heat pumps. In particular, we identified the importance of understanding the whole system implications of changes in the incentives to self-generate. Such behavioural responses when aggregated across all consumers on the system may impact the level and shape of total system demand. More indirectly, they may impact the system-wide generation mix by impacting plant despatch and operation in the short-term, and hence plant investment and retirement decisions in the long-term. These changes will in turn affect many areas of the market and have the potential of having measurable effects on overall system and consumer costs.

LCP's EnVision model, a fully integrated model of the GB power market, which models these direct and indirect effects, has been deployed to assess the impact on system and consumer costs. EnVision was originally developed to model the impact of the UK government's Electricity Market Reforms and was used to undertake the impact analysis for the Embedded Benefits Review.

The model simulates wholesale market dispatch at a granular, half-hourly level, taking into account plant dynamics and constraints such as start costs and ramp rates. It also estimates the revenues available to plant through participation in ancillary markets, including the provision of reserve and balancing services.

EnVision models investment decisions using an agent-based approach, which includes detailed simulations of the annual Capacity Market (CM) auctions. For the purposes of this modelling, non-CM build (e.g., most renewable generation that is supported through other subsidy schemes) is held constant across the scenarios considered.

We use the LCP EnVision model to examine the impact of changes to network charging arrangements on the following key aspects:

- The economics of on-site generation;
- Changes to the capacity mix;
- CM clearing prices;
- Loss of Load Expectation (LOLE);

- Wholesale prices;
- Carbon emissions;
- Overall system costs; and
- Consumer cost.

It is important to note that relying on modelling outputs as the sole, or potentially even main, basis for changes to charging arrangements has its limitations. While the EnVision model attempts to replicate the decisions made by market participants, it does so against the background of a number of input variables (e.g., fuel costs, plant capital costs, and demand). The modelling we have undertaken requires inputs for the future value of these inherently uncertain variables. Changes in these inputs, and to other modelling assumptions, will have potentially significant effects on the results. Therefore, the modelling results should be seen as an indication of the potential direction and broad magnitude of impacts.

We specify our modelling scenarios and key input assumptions in the sub-sections below.

5.2 Modelling scenarios

In the previous chapter, we discussed how the residual charging options could have a significant impact on the incentives to dispatch and invest in onsite generation and demand side response, by reducing the revenues earned by these investments relative to the baseline charging options. The conclusion of the behavioural assessment was to model the impact of the change in incentives to dispatch and invest in onsite generation within the EnVision model.

From our discussions with the Ofgem team we have considered two changes to the benefits captured by on-site generation:

- The benefit of avoiding the **transmission demand residual (TDR)** is removed, and replaced by the Avoided GSP Infrastructure Cost (AGIC). This is equal to the future payment received by in-front-of-the-meter generation. In effect this is equivalent to the extension of the CMP264/265 decision to behind-the-meter generation.
- For those sites connected at HV, the benefit of avoiding the CDCM **distribution residual** by using onsite generation to reduce net metered consumption is removed. As noted in the previous chapter, we do not explicitly model a change in incentives as a result of changes to the EDCM residual charging arrangements.

We have then applied these changes to two factual scenarios, in addition to the counterfactual where these benefits remain in place. In the first factual scenario these changes are applied to all on-site generation technologies (i.e., **Full Reform**) and in the second only to peaking (gas and diesel reciprocating engines) plant (i.e., **Partial Reform**). The latter is consistent with an option (e.g. 100% net volumetric charging) where baseload generators continue to be able to avoid residual charges, but peakers are not.

The system modelling factual scenarios can be mapped back to the charging options under consideration. The initial 'basic' options all reduce incentives for on-site thermal generation and solar, and so are mostly consistent with the Full Reform scenario where the incentives for on-site generation are removed completely.

The additional options either reduce incentives for on-site generation in the same way as the basic ones, or mitigate this somewhat (e.g., the hybrid option with a net volumetric component). The additional options which mitigate the impact map more closely to the second factual scenario, though they are less extreme than the factual scenario implies because the component which is avoidable by baseload/CHP generators only represents 25% of the charges in the options. However, while the second factual scenario does not map exactly to these options as currently specified it helps to illustrate the potential impact on system and consumer costs of introducing some level of avoidable elements to the charges.

We set out how the options map to the system modelling runs as per Figure 61.

Figure 61 Mapping of modelling scenarios to charging options

Tariff option	Most consistent with…
Basic options	
Fixed	Full Reform – incentive completely removed
Gross volume	Full Reform – incentive completely removed
Ex-ante capacity	Full Reform – incentive completely removed (though depends on penalty for overrunning capacity)
Ex-post capacity	Full Reform – incentive completely removed (assuming relatively few periods used for ex-post peak assessment)
Additional options	
Fixed by volume	Full Reform – incentive completely removed
Fixed 75%, ex-post (monthly) 25%	Partial Reform – mitigated incentives (as, for example, CHP can help reduce monthly peaks in some months)
Deemed ex-ante capacity for domestics	Full Reform – incentive completely removed
Deemed ex-ante capacity for domestics (75%), net volumetric (25%)	Partial Reform – mitigated incentives (as still some net kWh signal)
Ex-ante capacity set on historic peak	Full Reform – incentive completely removed

Source: Frontier/LCP

We have used National Grid's 2018 Future Energy Scenarios (FES 2018) to provide the market background for projections of demand, renewable build and interconnector build. More details on FES 2018 are provided in Annex C. We test the impact of Full and Partial Reform scenarios against a market background of the 'Steady Progression' FES scenario.

We also carry out a number of sensitivities:

- We test the sensitivity of the Full Reform scenario to an alternative FES scenario background 'Community Renewables'.
- We test the impact of the Full Reform scenario against the Steady Progression background with High and Low future levels of the residual.

These core modelling scenarios are summarised in Figure 62.

Figure 62 Core Modelling scenario runs

Scenario	FES 2018 Background	Assumption regarding the TNUoS demand residual for on-site generation	Assumption regarding the distribution residual for on-site generation
Baseline scenario	Steady Progression	The charge increases in line with National Grid's forecast until 2023, after which it remains flat in real terms at £63.65/kW (£54.94/kW in £2016 terms).	The charge is held flat at current levels.
Full reform	Steady Progression	From 2020 to 2023, the charge is set to equal the AGIC, after which it remains flat in real terms (£3.12/kW in £2016 terms).	From 2020 the charge is set to zero.
Partial reform	Steady Progression	From 2020 to 2023 (for on-site gas and diesel reciprocating engines only), the charge is set to equal the AGIC, after which it remains flat in real terms (£3.12/kW in £2016 terms).[31] The charge for other on-site generation is set as in the Baseline Scenario.	From 2020 the charge (for on-site gas and diesel reciprocating engines only) is set to zero.
Alternative FES scenario: Baseline scenario	Community Renewables	As per "Baseline Scenario"	As per "Baseline Scenario"
Alternative FES scenario: Full Reform	Community Renewables	As per "Full Reform"	As per "Full Reform"
High Residual	Steady Progression	The charge increases by 50% between 2023 and 2030 remaining flat in real terms thereafter.	The charge increases by 50% between 2023 and 2030 remaining flat in real terms thereafter.
Low Residual	Steady Progression	The charge decreases by 50% between 2020 and 2030 remaining flat in real terms thereafter.	The charge decreases by 50% between 2020 and 2030 remaining flat in real terms thereafter.

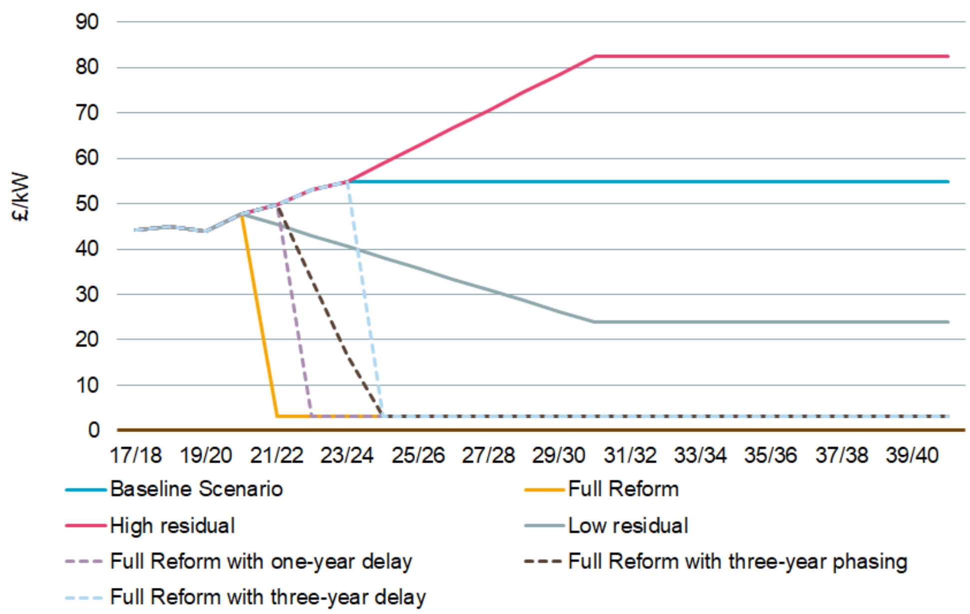
Source: Frontier/LCP

In addition to these core scenarios we test the impact of a one year delay to implementation (i.e. 2021/22), a phased implementation over three years (i.e. between 2021/22 and 2023/24), and a full three year delay implementation (i.e. to 2023/24).

[31] National Grid forecast this to be £3.62/kW in 2023, which is converted to £3.12/kW in 2016 terms.

The value of the maximum value of the TDR that can be avoided using onsite generation under each scenario is provided in Figure 63.

Figure 63 Value of the avoided TDR for onsite generation



Source: Frontier/LCP

Note: All figures in the table are in £2016 real terms.

We have then considered three transitional arrangements scenarios, as agreed with Ofgem, where the impacts of the timing and phasing of the changes to charging arrangements are tested. These scenarios are shown below.

Figure 64 Transitional Arrangements Modelling scenarios

Scenario	FES 2018 Background	Assumption regarding the TNUoS demand residual for on-site generation	Assumption regarding the distribution residual for on-site generation
Full Reform with one-year delay	Steady Progression	From 2021 to 2023, the charge is set to equal the AGIC, after which it remains flat in real terms (£3.12/kW in £2016 terms) [32].	From 2021 the charge is set to zero.
Full Reform with three-year phasing	Steady Progression	From 2021 the charge reduces linearly to meet the prevailing AGIC in 2023.	From 2021 the charge reduces linearly to zero in 2023.
Full Reform with three-year delay	Steady Progression	From 2023 onwards the charge is set to equal the AGIC (£3.12/kW in £2016 terms).	From 2023 the charge is set to zero.

Source: Frontier/LCP

[32] National Grid forecast this to be £3.62/kW in 2023, which is converted to £3.12/kW in 2016 terms.

5.2.1 Residual charging assumptions

The assumptions regarding the TDR used in the report were based on the latest forecasts available from National Grid (dated November 2017) at the time of the analysis.[33]

The distribution residual benefit varies by location and upon the applicable charging methodology (CDCM or EDCM). Data about the particular voltage level of onsite generation is not available. Therefore we have used data from DNO's Long Term Development Statements about the capacity of in-front-of-the-meter generation subject to either HV or EHV charges to provide an indication of a possible split to apply to onsite generation.

On this basis and applying current CDCM and EDCM charges led to the following assumptions:

- 40% of on-site thermal capacity is connected at HV and is concentrated in lower CDCM charge zones, such as Eastern and London, receiving a 0.53p/kWh benefit (0.21p/kWh on average across all on-site thermal generation capacity).
- 60% of on-site thermal capacity is connected at EHV, EDCM charges are offset by running in super-red band hours (258 hours assumed) leading to a 2.5p/kWh[34] benefit (1.5p/kWh on average across all on-site thermal generation capacity). As noted in the previous chapter, we do not consider it likely that a change to EDCM residual charges would affect incentives to invest in and dispatch onsite generation. However, following the change to charges the benefit to onsite generation are removed creating a consumer benefit that is captured in this analysis.
- It is assumed that 25% of on-site solar generation also receives the CDCM residual benefit as it acts to reduce onsite demand (based on CLNR project data). As concluded in the previous chapter we do not consider that a significant behavioural response from solar is likely. However, following the change to charges the payments to onsite solar under CDCM charges are removed creating a consumer benefit.

5.2.2 Cost assumptions

In the analysis, there are several technologies that compete to provide new capacity in the Capacity Market. Figure 65 below outlines the fixed operating expenditure (opex)[35], build costs (total capital expenditure and infrastructure costs), hurdle rate and efficiency assumed when modelling these plants.

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33 An updated forecast (dated September 2018) has recently been published but has not been reflected in our analysis.

34 This is an approximation of the impact calculated using the site specific data provided by DNOs.

35 Expenditure on operating and maintaining the plants.

Figure 65 Cost assumptions

Technology	Build Costs (£/kW)	Fixed costs (£/kW/pa)	Hurdle Rate (%)	Efficiency (HHV %)
CCGT	416	17.6	7.8%	54%
OCGT	353	8.9	7.8%	35%
Distribution-connected reciprocating gas	345	11.0	7.8%	37%
On-site reciprocating gas	345	11.0	7.8%	37%
On-site gas CHP	806	31.3	9.8%	38% (electrical), 44% (heat)

Source: BEIS. Low Assumptions, Electricity Generation Costs. November 2016. Gas CHP assumptions from Ricardo-AEA report for BEIS. Based on industry feedback, assumptions for the efficiencies of gas reciprocating engines are 5% higher than those published by BEIS in their Electricity Generation Costs report.

5.2.3 On-site generation assumptions

The assumptions that define existing on-site capacity and govern future on-site build are key to this analysis. On-site thermal capacity is allowed to build endogenously through the Capacity Market within our modelling and is therefore able to react to changes in the residual charging signals. This allows us to present the changes in on-site generation capacity over time under each scenario.

Existing on-site capacity

To estimate existing total on-site thermal capacity we use FES 2018 data. This provides figures for 'pure DSR' and 'observed DSR' and the difference between these values is assumed to represent on-site generation. Projections for these values are provided to 2050, and in these projections the percentage of 'pure DSR' is assumed to remain constant at 50%.

This gives a total capacity for on-site under each FES 2018 scenario, giving 1,001MW of on-site generation in 2018, but does not provide a technology breakdown.

A technology split is assumed using data on decentralised capacity provided in FES 2018. The decentralised capacities include both embedded and on-site generation. We assume that all current non-intermittent on-site generation is formed of gas and diesel reciprocating engines or gas CHP installations.

Figure 66 On-site generation capacities (2018)

Technology	Decentralised capacity, MW	Proportion of on-site thermal generation capacity	On-site generation capacity, MW
Reciprocating Gas	1,160	1,160 / 3,990 = 29%	1,001 x 29% = 290
Reciprocating Diesel	1,150	1,150 / 3,990 = 29%	1,001 x 29% = 290
Gas CHP	1,680	1,680 / 3,990 = 42%	1,001 x 42% = 421
Total	3,990		1,001

Source: National Grid, Future Energy Scenarios. July 2018.

On-site generation new build assumptions

We then impose caps on the amount of on-site generation build per annum. These limits represent technical limitations such as the capacity of gas CHP sites available for development. This prevents large amounts of on-site generation build under the presence of strong residual charging avoidance signals.

We have set these build limits based on:

- Frontier Economics estimates on the technical potential of on-site generation (5-20GW);
- Emissions legislation (MCPD) which renders on-site diesel generation uncompetitive;
- Projections in the most extreme FES 2018 scenario (Community renewables); and
- What we have seen outturn in recent CM auctions (DSR on-site generation).

Figure 67 On-site generation build limits, MW per annum

Technology	Steady Progression, MW	Community Renewables, MW
Reciprocating Gas	200	500
Reciprocating Diesel	0	0
Gas CHP	200	200

Source: Frontier/LCP.

5.2.4 On-site generation gas CHP assumptions

CHP installations benefit from several policy exemptions. These include:

- Climate Change Levy – Good quality CHP[36] sites are exempt from paying the Climate Change Levy on all electricity and gas utilised onsite. It is assumed that sites are already exempt from 90% of this charge for electricity consumed, so the remaining benefit to the generator is 10%.

[36] Good Quality CHP are those that meet the following criteria as part of the Combined Heat and Power Quality Assurance (CHPQA) programme. These criteria are based on the Quality Index, a metric which aims to compare CHP to separate power-only and heat-only alternatives. Available at: https://www.chpqa.com/guidance_notes/GUIDANCE_NOTE_10.pdf

- Carbon Price Support – Good quality CHP are exempt from paying Carbon Price Floor on fuels used to generate electricity consumed onsite.
- Enhanced Capital Allowance – Businesses are able to write off their energy saving investment against taxable profits.

5.2.5 Other key assumptions

Other notable assumptions include:

- Low-carbon build, interconnector build and demand growth are in line with the 'Steady Progression' and 'Community Renewables' scenarios from FES 2018. Under Community Renewables the assumed level of decentralisation is significantly higher, reaching 50% by 2035 compared with only 30% in Steady Progression.
- Commodity prices are in line with the central projections from FES 2018.
- New build is assumed to build in the same 'generic GB' location. This removes any possible locational distortions to the results due to new build bidding in to the capacity market at differing levels.
- 90% of the benefit that supplier's gain from avoiding residual charges are assumed to be shared with the on-site generator. These costs are passed on to consumers.
- The number of hours a plant must run in order to hit triad is dynamic in the model and is dependent on the deployment of triad-chasing capacity.

5.3 Modelling results

In this section we discuss the modelling results for the following core scenarios:

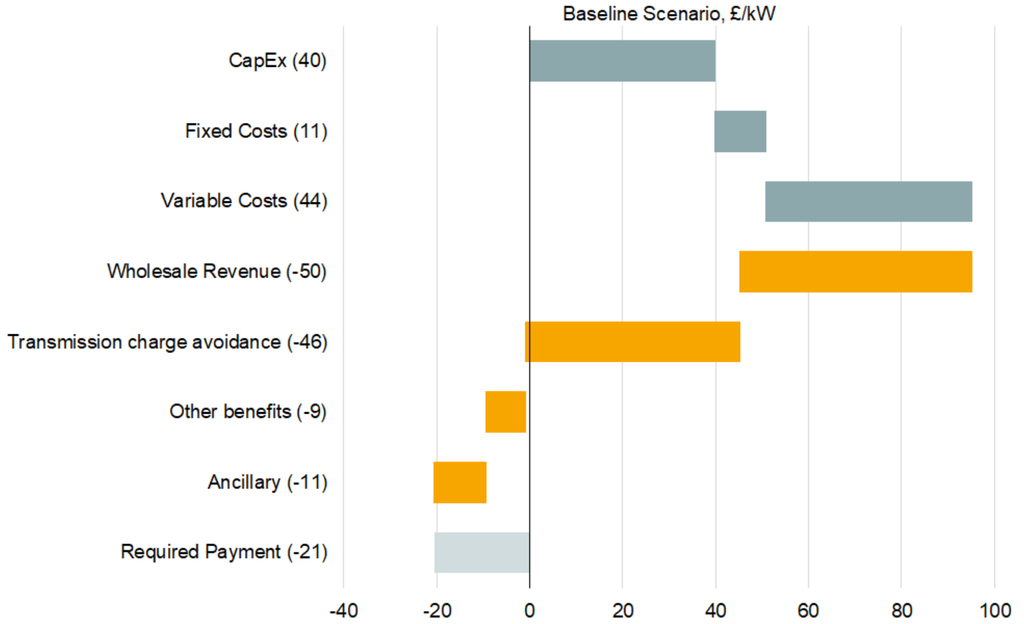
- Subsection 5.3.1 gives the results for Baseline Scenario and Full Reform under Steady Progression. This scenario assumes the largest change to both the TDR and distribution residual and is applied to all on-site generation technologies.
- Subsection 5.3.2 discusses the change between the Baseline Scenario and Full Reform under an Alternative FES 2018 background scenario, Community Renewables.
- Subsection 5.3.3 gives the results for Baseline Scenario and Partial Reform under Steady Progression. In this scenario the changes to transmission demand residual and distribution residual charges are applied to on-site generation peaking plant only.

5.3.1 Results – Full Reform scenario

Economics of on-site generation

The change in level of the transmission and distribution residual charging benefits significantly impacts the profitability of on-site gas reciprocating engines. For the year 2025 we show the required payment per kW per year for an on-site gas reciprocating engine to break even under the Baseline Scenario and Full Reform scenario, in Figure 68 and Figure 69 respectively. The costs and revenues are discounted at the technology's assumed hurdle rate of 7.8%.

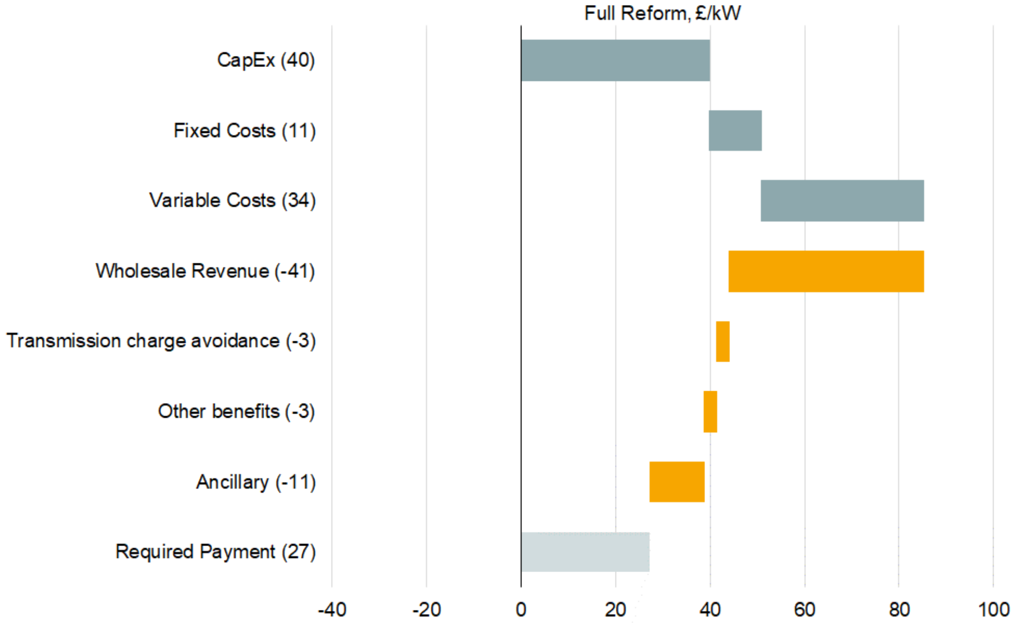
Figure 68 Revenue breakdown under an archetypal on-site reciprocating gas engine under Baseline Scenario, 2025



Source: Frontier/LCP

Our modelling indicates that an on-site gas reciprocating engine does not require any additional capacity payments (the "Required Payment") to break even, therefore a unit would be willing to accept a near zero CM price. The transmission charge avoidance income and income from other benefits (which includes the distribution residual avoidance) are large enough to recover all of the costs associated with build and operation.

Figure 69 Revenue breakdown under an archetypal on-site reciprocating gas engine under Full Reform, 2025

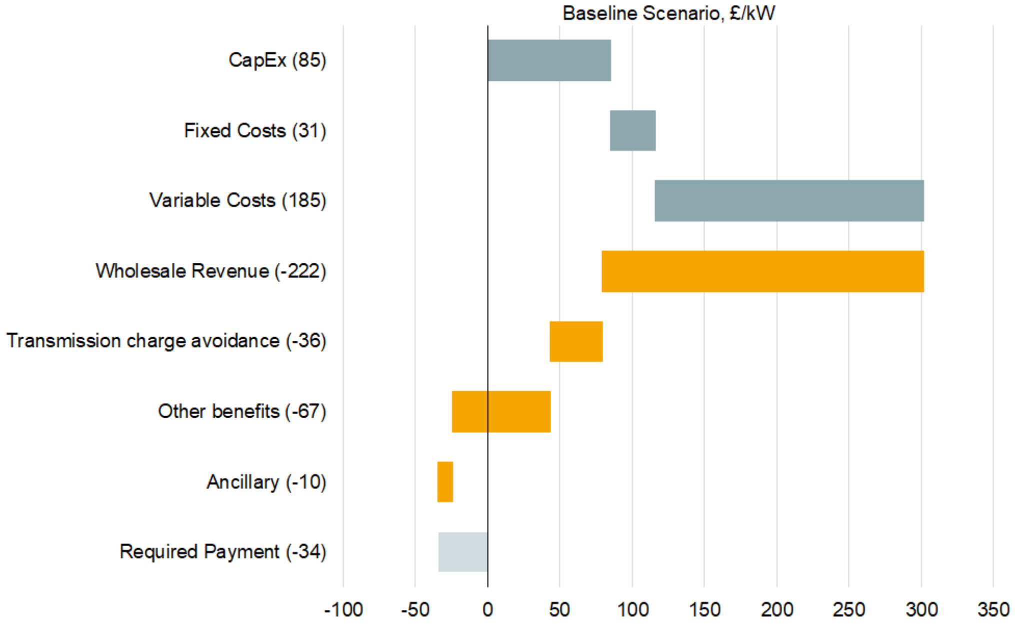


Source: Frontier/LCP

Under Full Reform the level of support required rises to £27/kW per annum due to the loss of the transmission and distribution residual benefits. Therefore, we would expect to see a significant increase in the CM bid of an on-site gas reciprocating engine (or slightly higher than this level due to CM deratings).

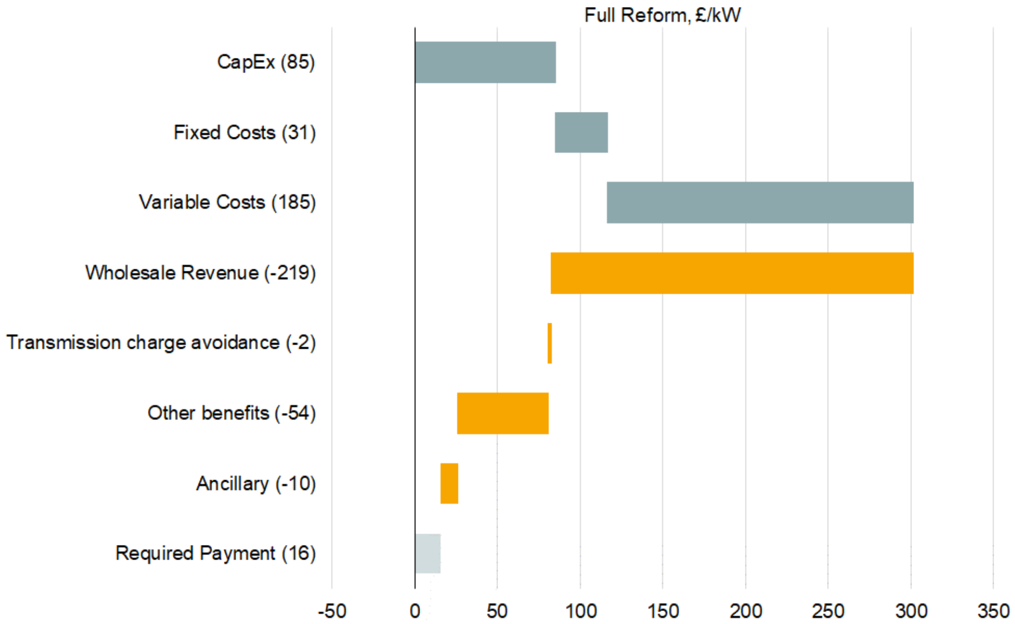
Figure 70 and Figure 71 show similar results for on-site gas CHP. It is assessed using the technology's assumed hurdle rate of 9.8%.

Figure 70 Revenue breakdown under an archetypal on-site gas CHP under Baseline Scenario, 2025



Source: Frontier/LCP

Figure 71 Revenue breakdown under an archetypal on-site gas CHP under Full Reform, 2025

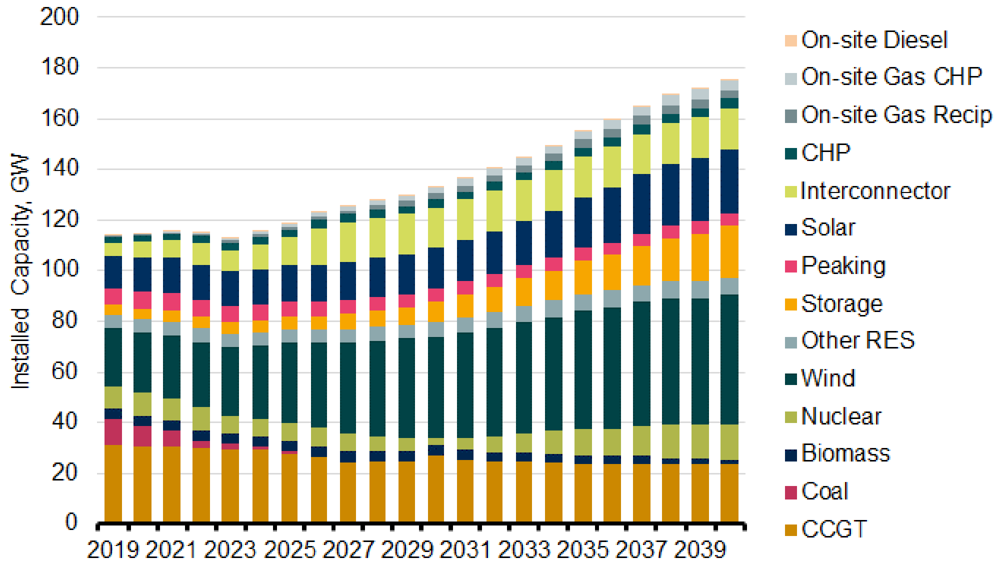


Source: Frontier/LCP

Capacity breakdown

Figure 72 below shows the total installed capacity under the Baseline Scenario. "Steady Progression" scenario in FES 2018 is used to determine the long-term low-carbon and interconnection build. Our modelling is used to determine the Capacity Market build. As in NG's projections, our modelling shows a significant increase in capacity over time, as renewables replace baseload capacity.

Figure 72 Installed capacity under Baseline Scenario



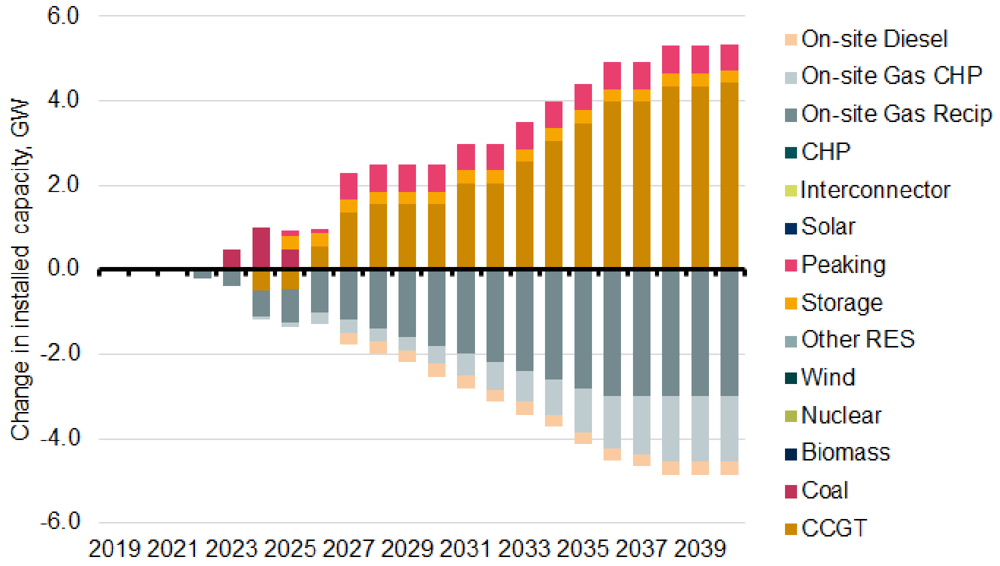
Source: Frontier/LCP

Figure 73 below shows the difference in installed capacity between Baseline Scenario and Full Reform.

Based on the economics outlined in the previous section, our modelling indicates on-site gas reciprocating engines moving from bidding at £0/kW pa under the Baseline Scenario to bidding in the £20-40/kW p.a. range in Full Reform across the full modelling period. On-site gas CHP also shows an increase in CM bid prices moving from essentially £0/kW p.a. to between £5-20/kW p.a across the same period. This results in materially lower levels of new on-site generation clearing in the CM in our modelling, particularly gas reciprocating engines.

The on-site generation is replaced by a combination of delays in retirement of existing plants, new build CCGT, battery storage and front-of-the-meter gas reciprocating engines ("peaking").

Figure 73 Difference in Installed capacity between Baseline Scenario and Full Reform



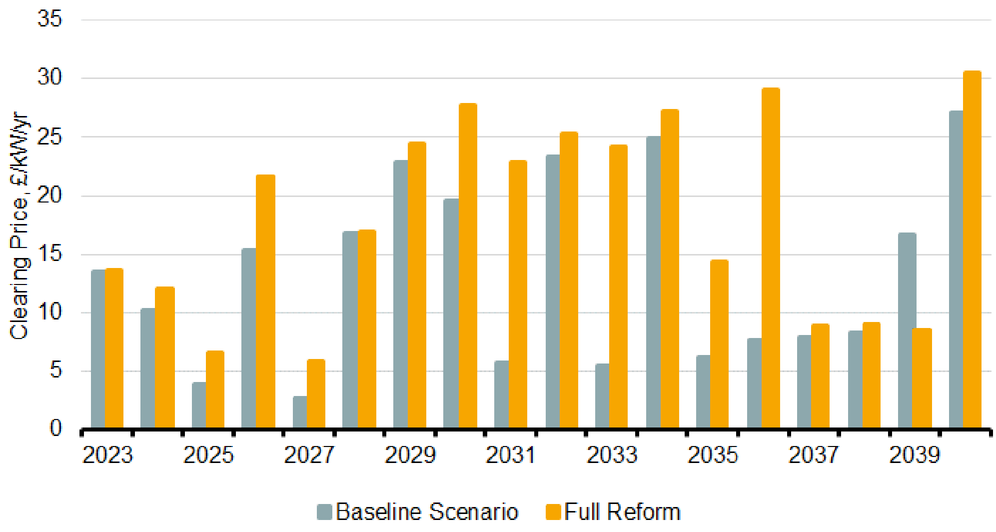
Source: Frontier/LCP

Capacity Market clearing prices

The CM clearing price is shown to increase in most years due to the increase in on-site generation bids. For example, in 2026 our modelling shows the clearing price increasing from around £15/kW to over £21/kW, as the higher bids from on-site generation mean some of this capacity fails to clear, and the clearing price is set by new build CCGT.

Figure 74 shows the modelled clearing prices under the Baseline Scenario and Full Reform.

Figure 74 CM clearing prices



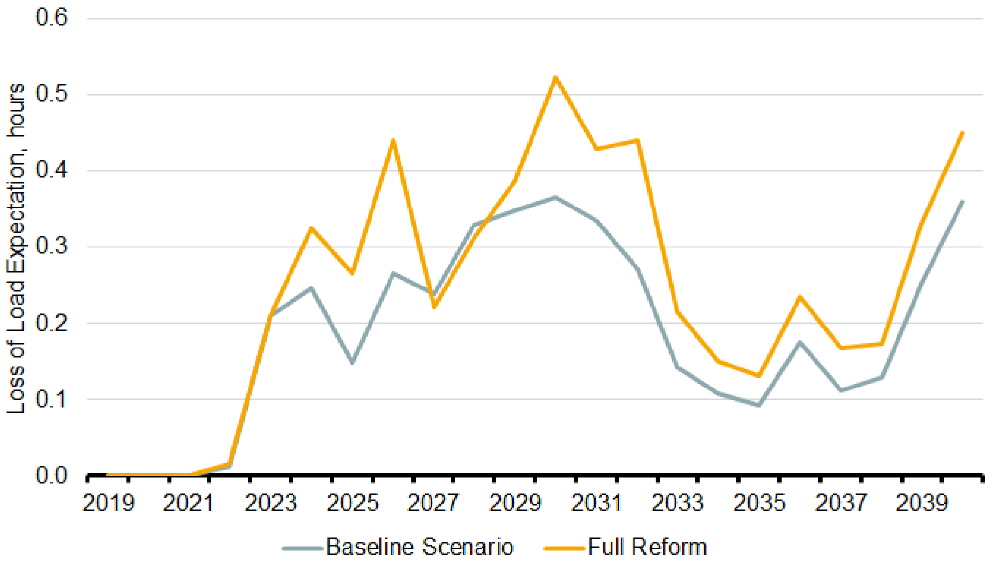
Source: Frontier/LCP

Loss of Load Expectation (LOLE)

Figure 75 below compares the loss of load expectation (LOLE) between the Baseline Scenario and Full Reform. The LOLE is shown to increase in most years, indicating the system has become slightly less secure. This is because the demand for capacity in the CM decreases as the clearing price increases. Therefore, higher clearing prices in Full Reform lead to decreases in the amount of derated capacity procured.

However, in both scenarios the LOLE is well below the security standard of 3 hours per year. This is due to the clearing prices being below the Net-CONE[37] price level, but also due to an assumption that there will be some prudence used when setting the capacity target.

Figure 75 Loss of Load Expectation



Source: Frontier/LCP

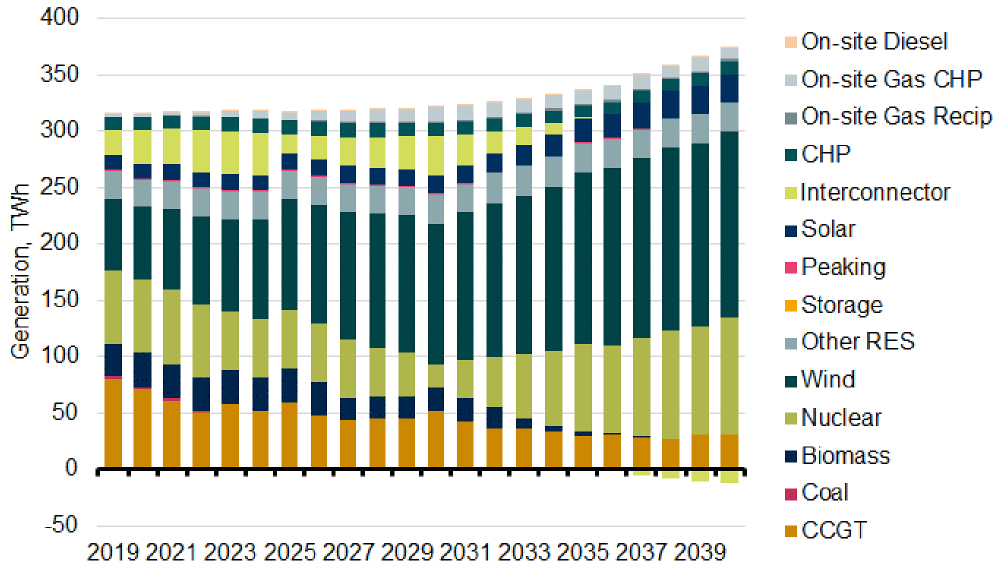
Generation mix

Figure 76 shows annual generation volume by technology under Baseline Scenario. Our modelling shows renewables output increasing over time with CCGT and Coal generation decreasing. Nuclear generation falls through the 2020s due to retirements before increasing significantly through the 2030s.

Figure 77 shows the change in generation volumes between Baseline Scenario and Full Reform. The loss of on-site generation capacity in the Full Reform scenario results in lower levels of generation from these technologies, with a more significant reduction in on-site gas CHP generation due to its higher load factors. This generation is replaced primarily by CCGTs and interconnector imports.

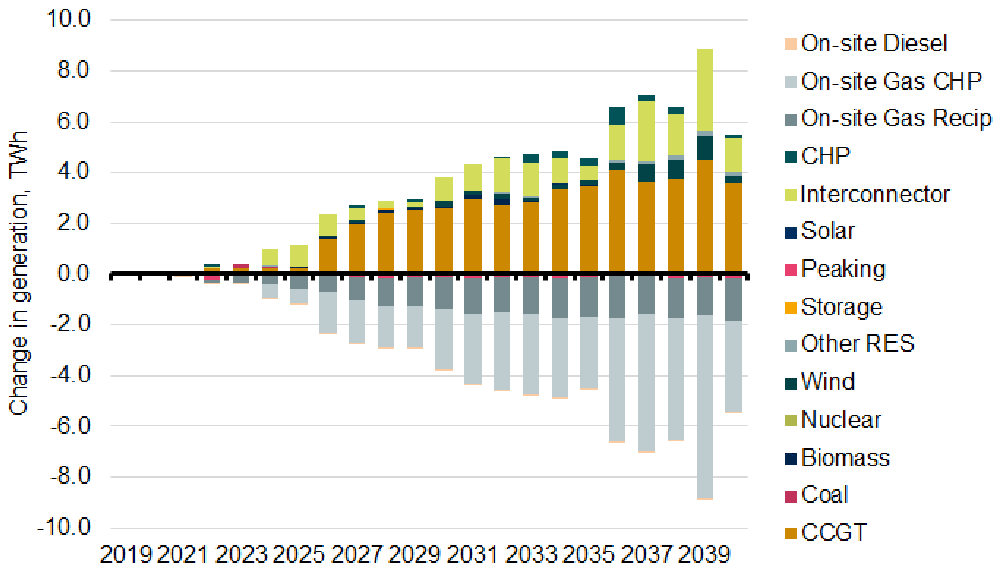
[37] Net-CONE (Cost of New Entrant) is the cost of a new entrant value used in the Capacity Market parameters to set the Demand Curve price that corresponds to an LOLE of 3 hours.

Figure 76 Generation under Baseline Scenario



Source: Frontier/LCP

Figure 77 Difference in generation between Baseline Scenario and Full Reform

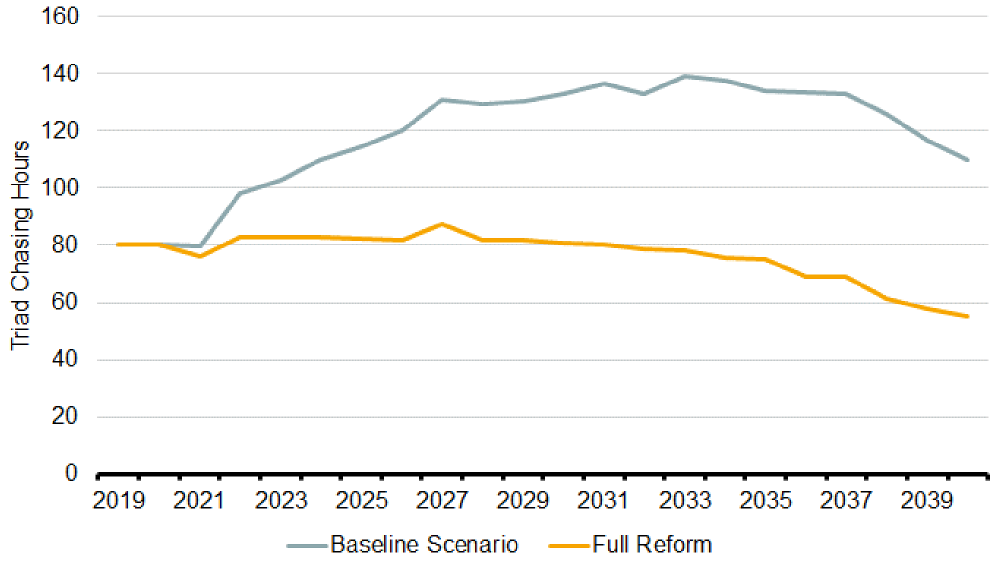


Source: Frontier/LCP

Triad-chasing hours

The modelling considers the number of hours during which on-site plant need to run to be confident of producing during the three half hours that make up triad, and hence be able to reduce a supplier's transmission demand residual charges. The number of hours required to run to chase triad periods increases as the volume of triad chasing on-site generation increases, which is why the running hours required in the Baseline scenario are significantly higher.

Figure 78 Theoretical number of hours required to chase triad



Source: Frontier/LCP

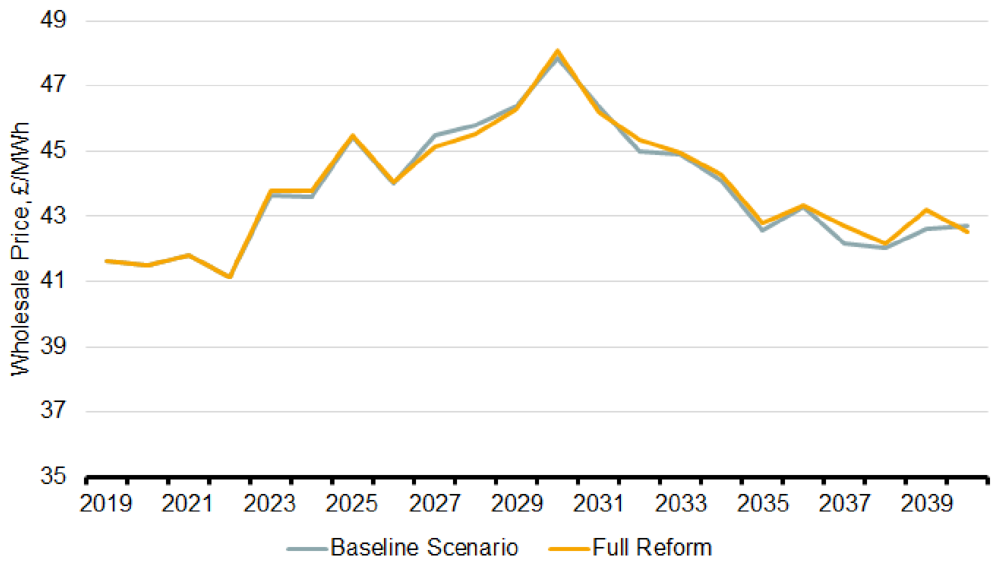
Wholesale prices

Figure 79 below compares average annual wholesale price under Baseline Scenario and Full Reform. Overall we observe that there is a limited impact on wholesale prices. The impacts are a combination of:

- Removal of TDR benefit increasing the wholesale price in triad chasing hours
- Removal of the distribution residual increasing the wholesale price, particularly in super-red band hours.
- Changes in the generation mix impacting wholesale prices, as efficient new CCGT replaces on-site gas reciprocating engines and on-site gas CHP. The direction of the wholesale price shift is sensitive to which of the on-site technologies is displaced.

These impacts offset each other to some degree thus giving a muted overall impact.

Figure 79 Average annual wholesale prices

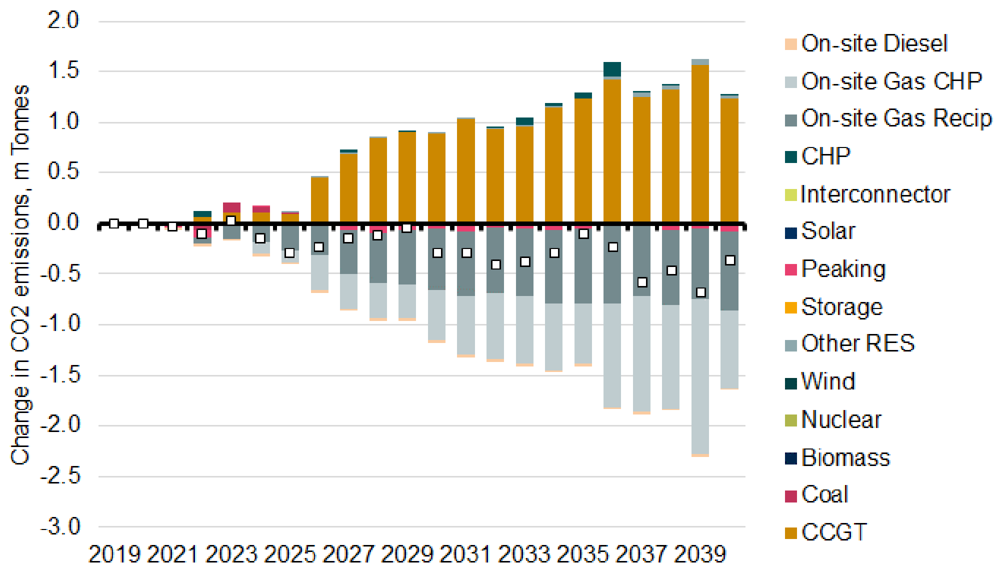


Source: Frontier/LCP

CO_2 Emissions

Figure 82 shows the difference in total annual CO_2 emissions between Baseline Scenario and Full Reform. Overall our modelling shows a slight decrease in CO_2 emissions, due to efficient CCGT generation and increased interconnector imports replacing a combination of less efficient on-site gas reciprocating engines and efficient on-site gas CHP. Note that no CO_2 emissions are attributed to interconnector imports, as it would not be proportionate to calculate associated overseas emissions.

Figure 80 Difference in CO_2 emissions between Baseline Scenario and Full Reform



Source: Frontier/LCP

System Costs

Figure 81 below shows the modelled system cost differences, comparing the Baseline Scenario and Full Reform. These costs represent the actual resource cost of running the system. The cost categories captured are:

- Fuel – this is the cost of the fuel used by the generating fleet, which is driven by technology type, efficiency and commodity prices.
- VOM (Variable Operating & Maintenance) – different technologies have different operating and maintenance costs. This component represents those costs that vary with generation output;
- Carbon – there is a resource cost associated with the emission of CO_2 which is valued at the BEIS carbon appraisal price[38];
- Capex – this represents the financing costs associated with new build. This is driven by the construction costs (including infrastructure costs) of the plant and the cost of capital;
- Opex – the fixed operating and maintenance costs associated with the generation fleet;
- EEU – expected energy unserved, which is assigned a cost of £6,000/MWh. While both scenarios target the security standard through the capacity mechanism, there is the possibility of one scenario achieving a higher or lower LOLE depending on where it exactly clears on the CM curve.
- Interconnection – the net cost of buying power in the connected market less revenues from selling power to the connected market. There is no change in Interconnector capacity assumed between runs.

Fuel, VOM and Carbon costs represent the costs associated with generation in the wholesale market, as well as the net cost of balancing and providing reserve services. For CHP units, the fuel and carbon costs associated with providing heat are netted off, so that only the costs involved with generating power are accounted for.

Overall our modelling shows that there is a system cost saving due to reduced fuel usage, CO_2 emissions (although clearly they may result in emissions in other countries), opex and capex spend. The fuel and carbon savings are significant and stem from the change in the technology mix that results from the scenario considered. Under Full Reform CCGT generation and Interconnector imports displaces on-site gas reciprocating engines and gas CHP which no longer clear in the CM.

The fuel and carbon saving only includes domestic generation. Where domestic generation has been displaced by imports over interconnectors, we must include the costs of these additional imports to partially offset the system cost saving from the reduction in domestic generation. In the Full Reform scenario net imports

[38] There is a resource cost associated with the emission of CO2. Emissions are valued using BEIS's most recent published carbon values for UK public policy appraisal: https://www.gov.uk/government/publications/updated-short-term-traded-carbon-values-used-for-uk-policy-appraisal-2017

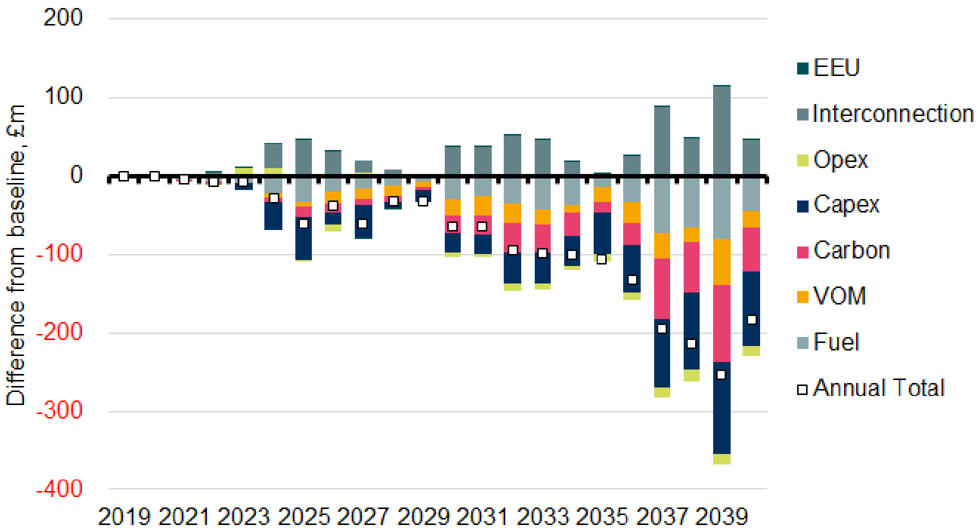
increase in place of domestic on-site generation, resulting in increased costs that offset some of the domestic generation savings, though this does not include the wider welfare effect of an increase in CO_2 emissions in other countries.

Capex spend reduces due to delays in the retirement of existing plant and lower capex costs associated with the new build capacity.

There is a small increase in the cost of EEU as slightly less capacity is procured through the CM, but this is not material in the context of other cost changes.

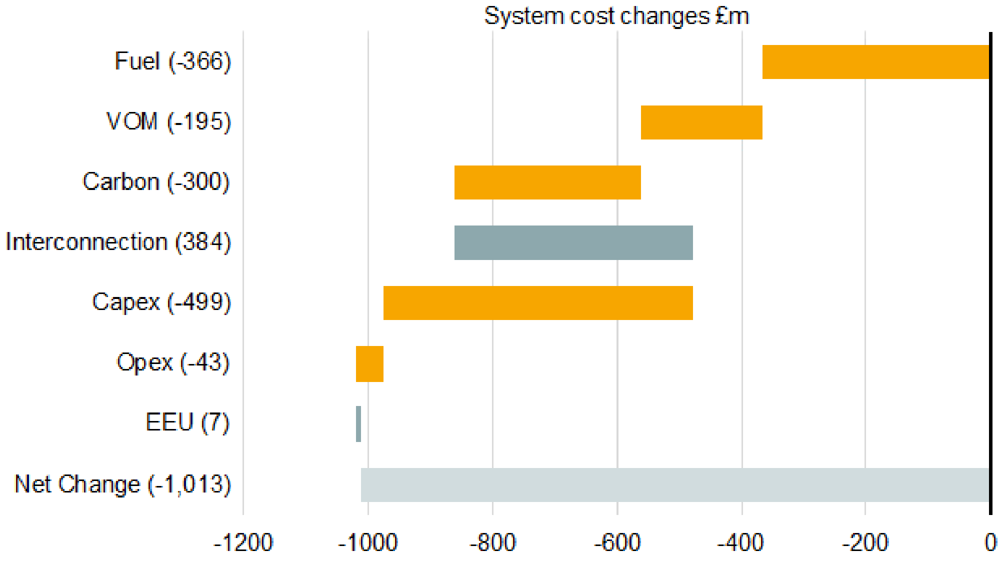
Figure 82 shows total impacts in NPV terms over the 2019-2040 period, using a 3.5% social discount rate. Overall, there is a system cost saving of £1,013m.

Figure 81 Difference in system costs between Baseline Scenario and Full Reform



Source: Frontier/LCP

Figure 82 NPV of the difference in system costs between Baseline Scenario and Full Reform (2019-2040, 3.5%)



Source: Frontier/LCP

Consumer Cost

Figure 83 below shows the modelled consumer cost differences in moving from the Baseline Scenario to Full Reform. Consumer costs measure how consumers are affected by the proposed changes, which is separate to system cost. While system cost represents the true resource cost of running a system, this is independent of who pays and receives money. Consumer costs capture these system-independent transfers.

The cost categories captured as part of consumer costs are as follows:

- Transmission charge avoidance – benefits to generators in the form of avoidance payments represent a direct cost to consumers. This is because the full cost of the transmission demand residual amount must still be recouped from suppliers, but a subset of suppliers will reduce their charges through payments to on-site generation. By reducing the amount of residual that can be avoided by on-site generation, there is a direct saving to consumers.
- Distribution charge avoidance – avoidance of the distribution residual charges represents a cost to the consumer in the same way as transmission charge avoidance.
- CM payments – as has been seen through this analysis, the removal of embedded benefits causes the CM bids of these units to increase. This may cause a more expensive plant to clear, increasing the CM payments made by suppliers, representing a cost to consumers. Step changes in the CM clearing price – as a plant further up the CM supply curve clears – can occur in some years and result in significant changes in these payment.

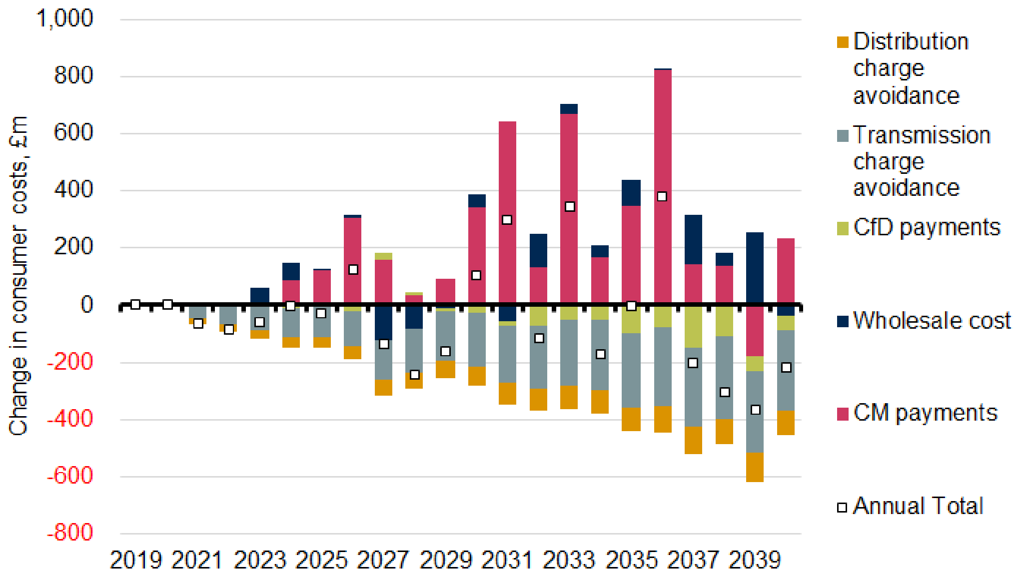
- Wholesale costs – changes in the wholesale price are ultimately passed through to consumers. These changes are driven through a combination of higher prices in peak hours where on-site is no longer incentivised to bid so low, and changes in the overall technology mix, which generally lowers prices.
- CfD payments – Wholesale cost changes will be partially dampened by offsetting changes in CfD top-up payments.

It should be noted that system costs and consumer costs represent fundamentally different economic costs, and as such should not be added or combined to create a total saving. It is possible to have meaningful consumer savings with no system savings, and vice versa. For example, a transfer from consumers to producers will result in higher consumer costs without any impact on system costs. As such, consumer costs represent the sum of system costs and producer surplus (not accounting for any unpriced externalities).

The results show that consumer cost savings arise from reductions in transmission and distribution charge avoidance the cost of which is ultimately borne by the consumer. Increasing CM payments, due to higher CM clearing prices, represent the largest element of increased cost to the consumer. The increase in wholesale costs is partly offset by a corresponding reduction in CfD payments.

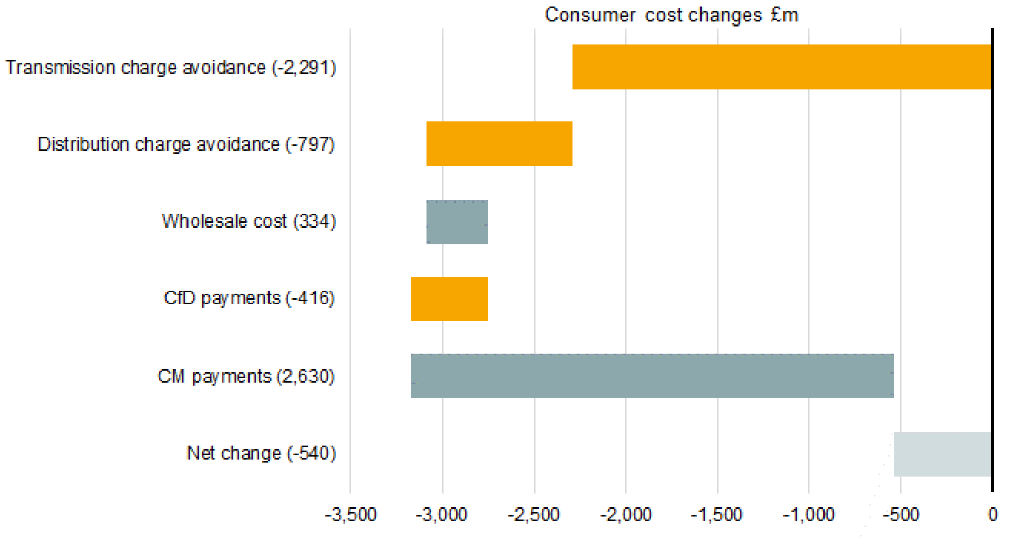
Figure 89 shows a breakdown of the difference in the NPV of the Baseline Scenario and Full Reform over 2019 to 2040. Overall, there is an NPV benefit of £540m.

Figure 83 Difference in consumer costs between Baseline Scenario and Full Reform



Source: Frontier/LCP

Figure 84 NPV of the difference in consumer costs between Baseline Scenario and Full Reform (2019-2040, 3.5%)



Source: Frontier/LCP

5.3.2 Results – Alternative FES background scenario

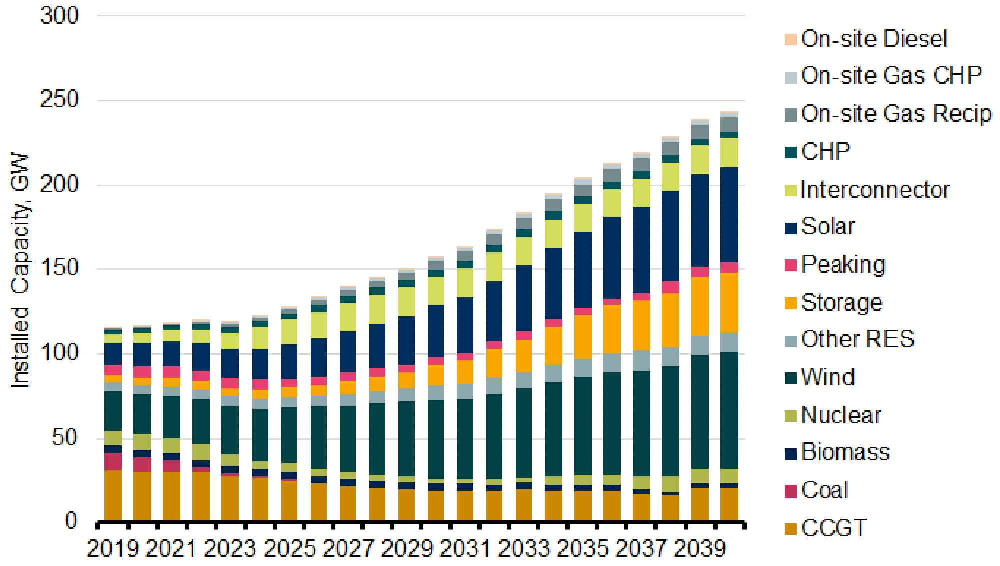
In this section we present the results under an alternative background scenario. The Baseline Scenario and Full Reform are both run under this alternative background, which utilises assumptions from National Grid's "Community Renewables" FES scenario. Community Renewables background assumes a much greater penetration of renewables generation and higher level of decentralisation than Steady Progression and meets 2050 climate targets.

To reflect the greater level of decentralisation the build limits for on-site gas reciprocating engines are increased from 200MW to 500MW per annum.

Capacity breakdown

Figure 85 shows the modelled installed capacity mix under the alternative background's baseline run. In comparison to the baseline scenario there is a greater amount of wind, solar and storage on the system, particularly towards the back end of the modelled period.

Figure 85 Installed capacity under Community Renewables Baseline Scenario

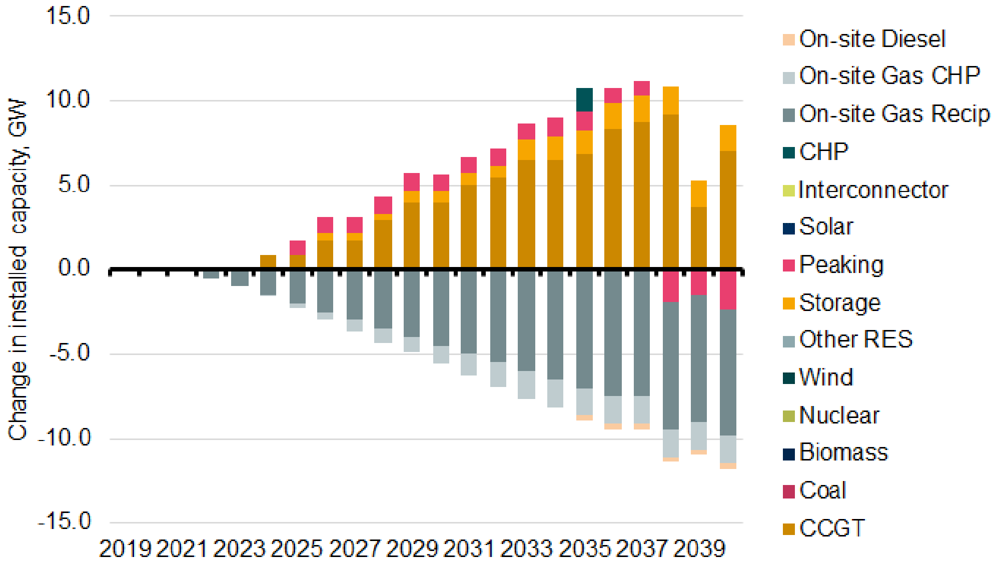


Source: Frontier/LCP

Under the alternative background's baseline on-site gas reciprocating engine and gas CHP units build up to the capacity limits in most years.

Figure 86 shows the change in installed capacity between the alternative background baseline and full reform scenarios. Compared to the equivalent results under Steady Progression a larger amount of on-site gas reciprocating engines are built in the baseline due to the higher build limits. With the removal of the residual avoidance payments these are displaced mainly by new build CCGT or delayed retirement of existing CCGT, with some battery storage and distribution connected gas reciprocating engines now also building.

Figure 86 Difference in generation under Alternative FES scenario between Baseline and Full Reform

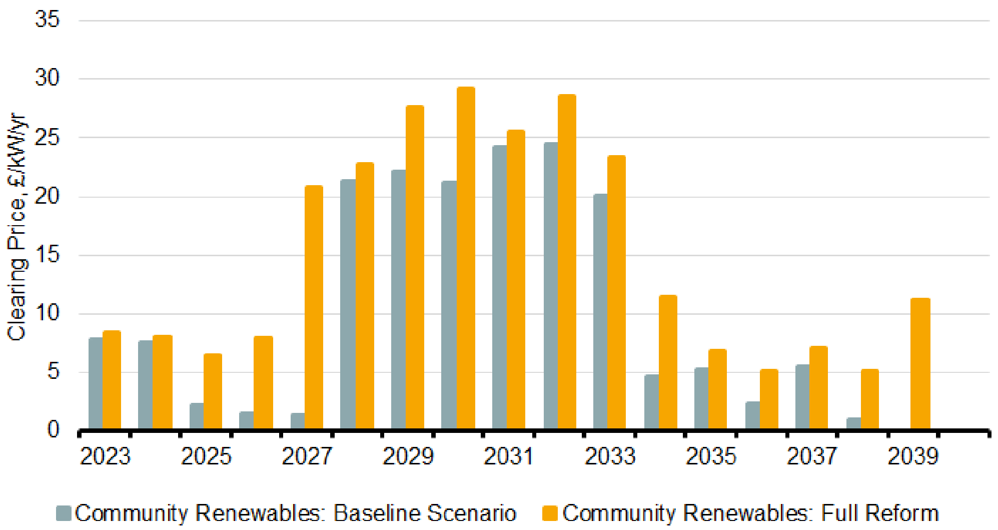


Source: Frontier/LCP

Capacity Market clearing prices

Figure 87 shows the modelled clearing prices under Baseline Scenario and Full Reform. The CM clearing price is shown to increase in all years due to the reduction in both the TNUoS demand residual and DUoS distribution residual.

Figure 87 CM clearing prices

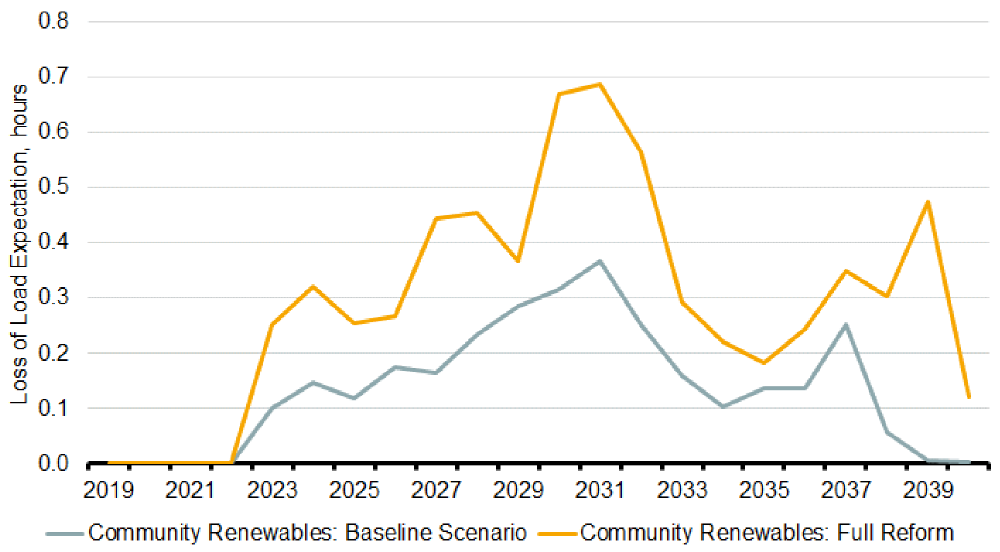


Source: Frontier/LCP

Loss of Load Expectation (LOLE)

Figure 88 below compares the loss of load expectation (LOLE) using the Alternative FES background between the Baseline scenario and Full Reform. While the LOLE does increase in all years it remains well below the security standard of three hours.

Figure 88 Loss of Load Expectation



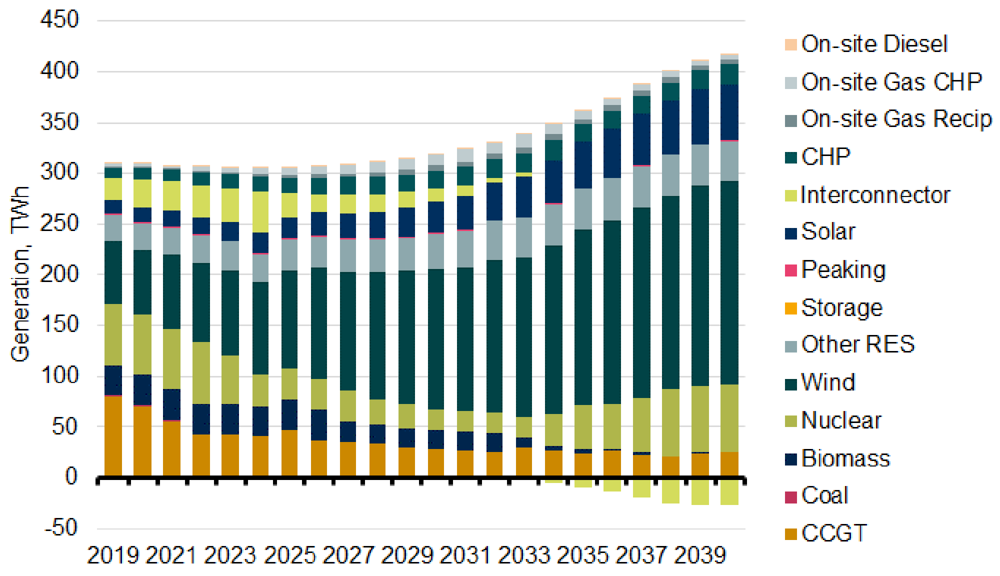
Source: Frontier/LCP

Generation breakdown

Figure 89 shows annual generation volumes by technology under Baseline Scenario. The generation mix is similar to the Steady Progression results but with a greater proportion of wind and solar generation.

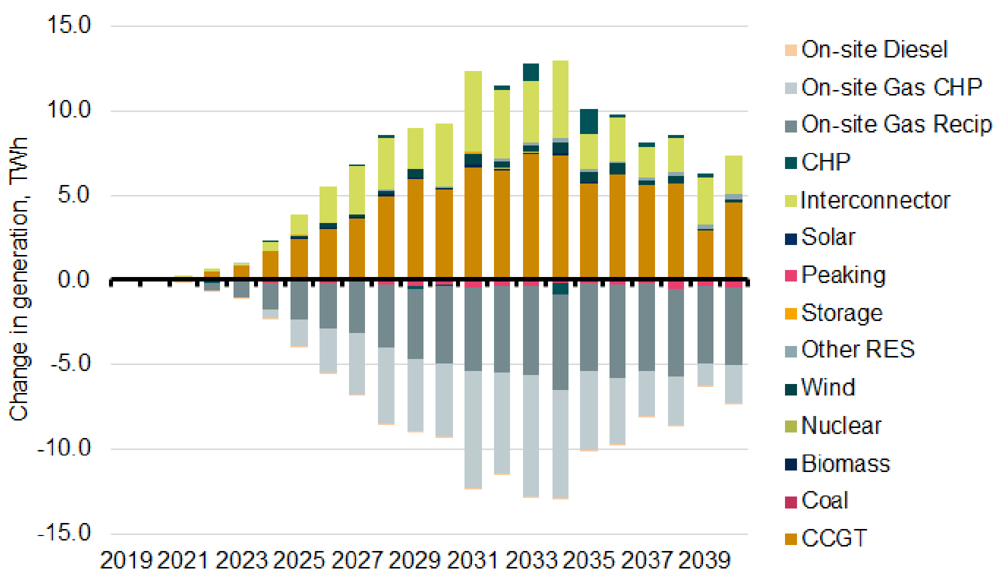
Figure 90 gives the change in generation volume by technology between the Baseline and Full Reform under the Alternative FES background. On-site gas reciprocating engine and on-site gas CHP generation reduces due to the reduction in the residual charge avoidance, primarily as a result of the reduction in capacity. This is replaced mainly by increases in CCGT generation and interconnector imports. There is also a slight increase in wind generation due additional battery storage capacity enabling greater load-shifting.

Figure 89 Generation under Alternative FES background scenario (baseline)



Source: Frontier/LCP

Figure 90 Difference in generation under Alternative FES scenario between Baseline and Full Reform



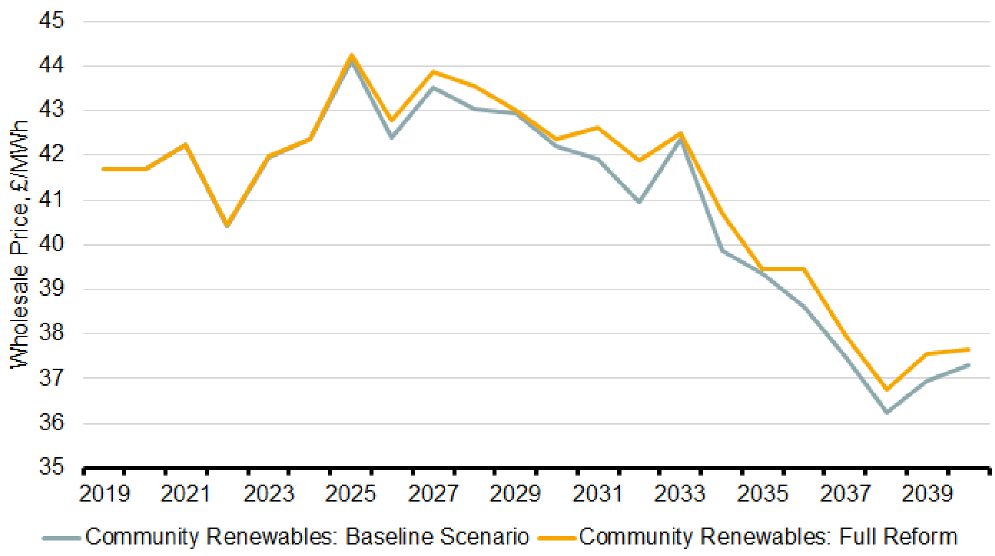
Source: Frontier/LCP

Wholesale prices

Figure 91 below compares the average annual wholesale prices under Baseline Scenario and Full Reform assuming the Alternative FES background. Our modelling shows an increase in wholesale prices under Full Reform due to:

- Higher wholesale prices in peak "triad" periods. On-site generation requires additional wholesale income to run in periods where previously they would have been prepared to generate at lower prices due to incentives to avoid residual charges, i.e. "triad chasing".
- Related to the above, the number of "triad chasing" hours is significantly reduced, due to the reduction in on-site generation capacity. This leads to higher wholesale prices in those peak hours which, under Full Reform, are no longer triad periods.
- Reduction in efficient, baseload on-site gas CHP capacity.

Figure 91 Average annual wholesale prices

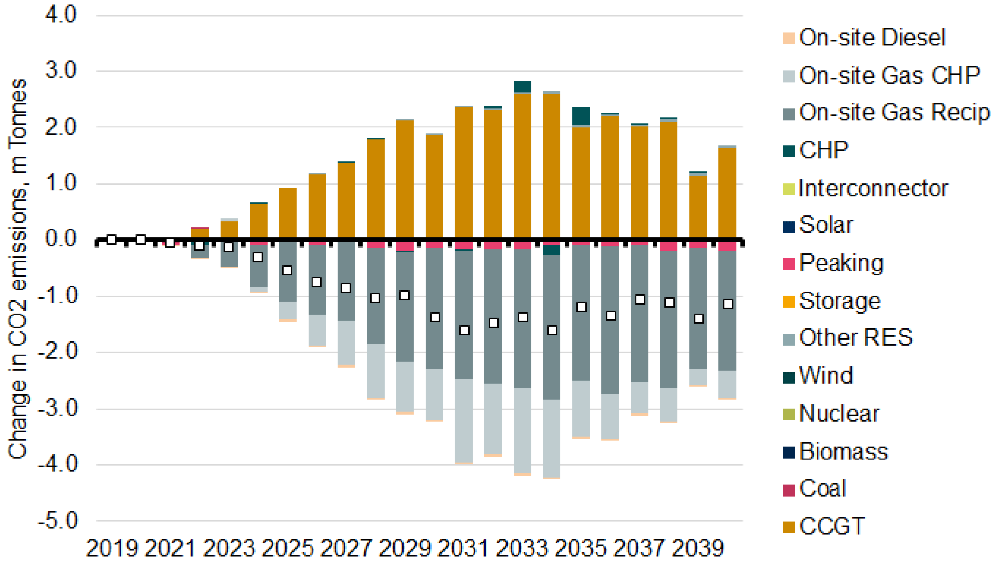


Source: Frontier/LCP

CO_2 Emissions

There is a net reduction in carbon emissions as generation shifts to efficient CCGT plant and increased interconnection imports. Note that no CO_2 emissions are attributed to interconnector imports.

Figure 92 Difference in CO_2 emissions under Alternative FES scenario between Baseline and Full Reform



Source: Frontier/LCP

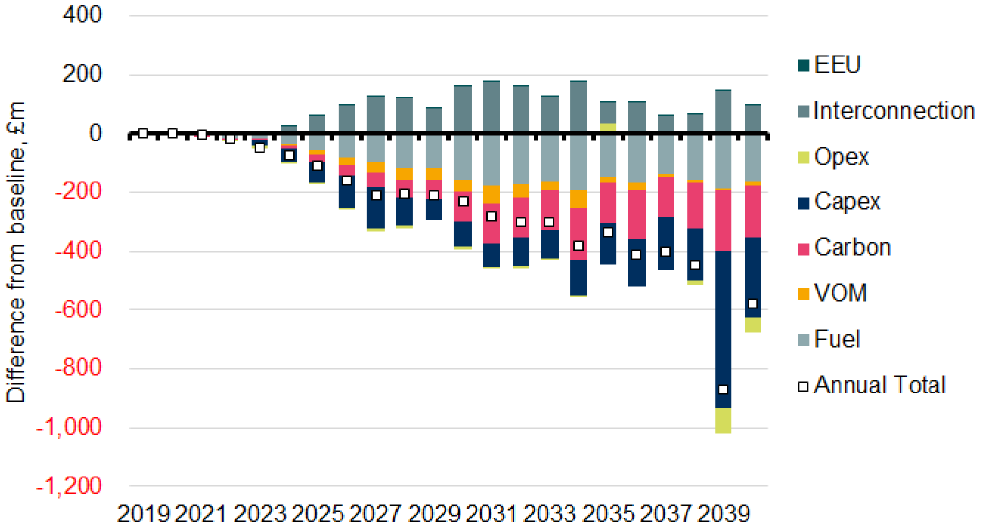
System Cost

Figure 93 shows the change in system costs between Baseline Scenario and Full Reform under the Alternative FES background Community Renewables. Our results show a net decrease in system costs which is larger than that under Steady Progression.

Similar to our results under Steady Progression the saving is composed mainly of reductions in fuel, carbon and capex costs. The fuel and carbon savings are heightened due to a greater capacity of low efficiency on-site gas reciprocating engines being displaced by higher efficiency CCGT generation and relatively low cost net imports, though this does not include the wider welfare effect of an increase in CO_2 emissions in other countries.

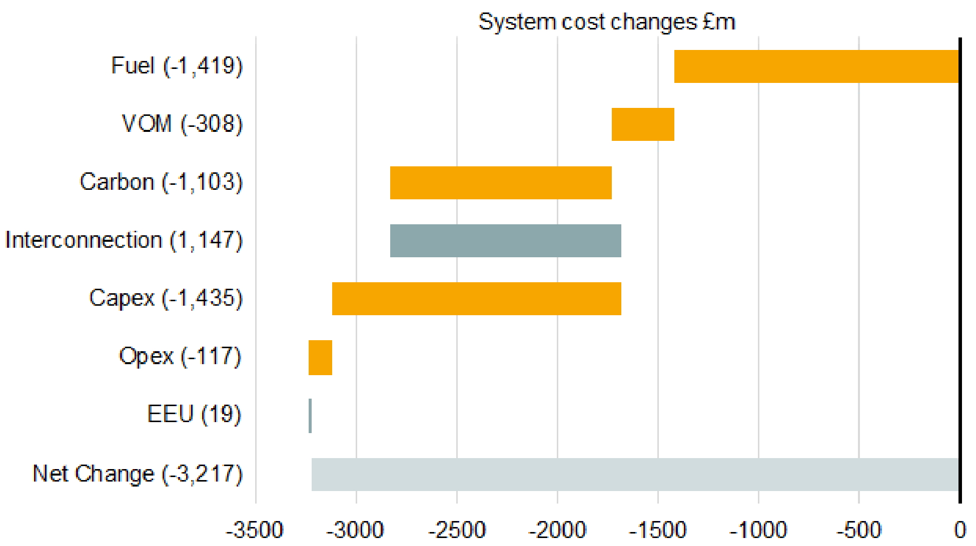
Capex savings are also a major contributor to the system cost savings. As under the Steady Progression background scenario, one reason for this is delays to existing plant retirements, as higher CM clearing prices with the Full Reform in place incentivise these plant to stay online longer.

Figure 93 Difference in system costs under Alternative FES scenario between Baseline and Full Reform



Source: Frontier/LCP

Figure 94 NPV of the difference in system costs under Alternative FES scenario between Baseline and Full Reform (2019-2040, 3.5%)



Source: Frontier/LCP

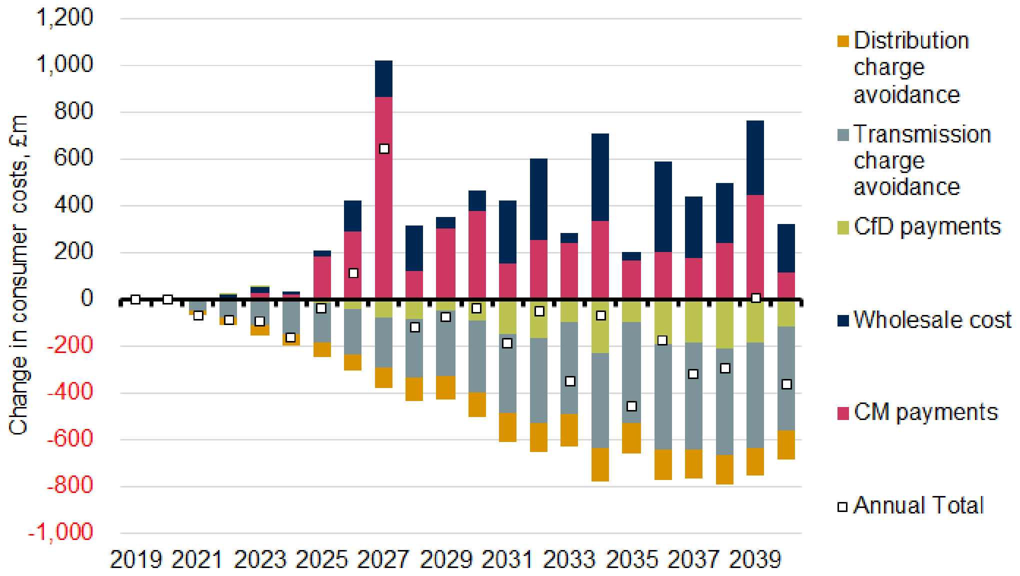
Consumer Cost

Figure 95 below shows the change in consumer costs between the Baseline Scenario and Full Reform under the Alternative FES background of Community Renewables. Our results show a net decrease in consumer costs which is larger than that under Steady Progression.

This is due to a greater decrease in transmission and distribution charge avoidance payments as a larger amount of capacity is affected by the removal of these benefits. This larger amount of affected capacity is primarily driven by the higher build limits for on-site generation that are applied in the modelling of this scenario.

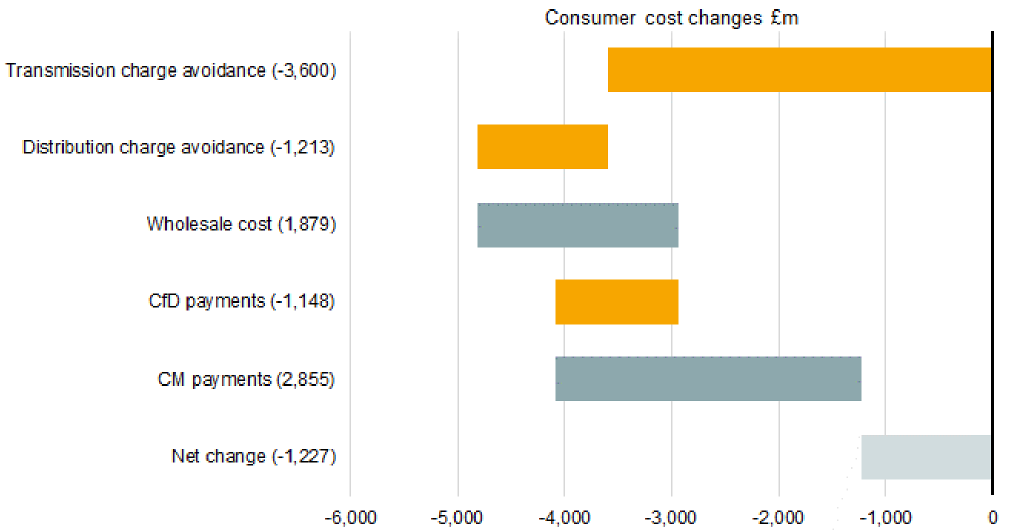
In contrast, the increase in CM costs is only slightly larger than under the Steady Progression case. This is because, the larger amount of affected capacity under Community Renewables doesn't result in increases in capacity prices above that required in under Steady Progression. Both scenarios result in increases in clearing prices to the levels required to incentivise new build CCGT (£25-£30/kW).

Figure 95 Difference in consumer costs under Alternative FES scenario between Baseline and Full Reform



Source: Frontier/LCP

Figure 96 NPV of the difference in consumer costs under Alternative FES scenario between Baseline and Full Reform (2019-2040, 3.5%)



Source: Frontier/LCP

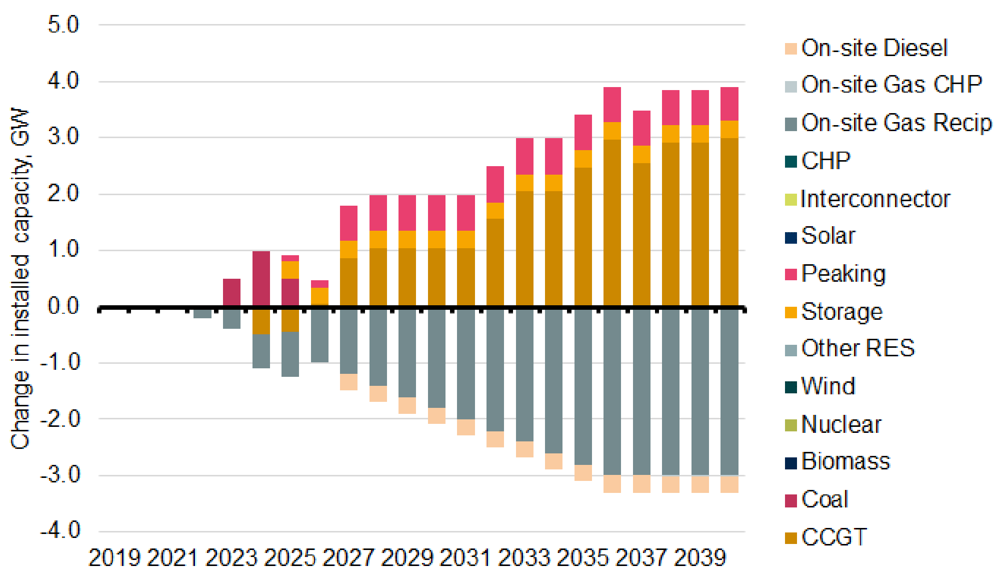
5.3.3 Results – Partial Reform

Under this scenario only the peaking on-site generation (gas and diesel reciprocating engines) have the transmission and distribution residual benefits removed.

Capacity breakdown

Figure 97 shows the change in installed capacity between the Baseline Scenario and Partial Reform. Our modelling shows that there is no change in the capacity of on-site gas CHP, as the residual benefits remain in place and as it is already building up to its build limit. On-site gas reciprocating engines no longer build through the CM, and are replaced with CCGT, battery storage and distribution-connected gas reciprocating engines.

Figure 97 Difference in Installed capacity between the Baseline Scenario and Partial Reform



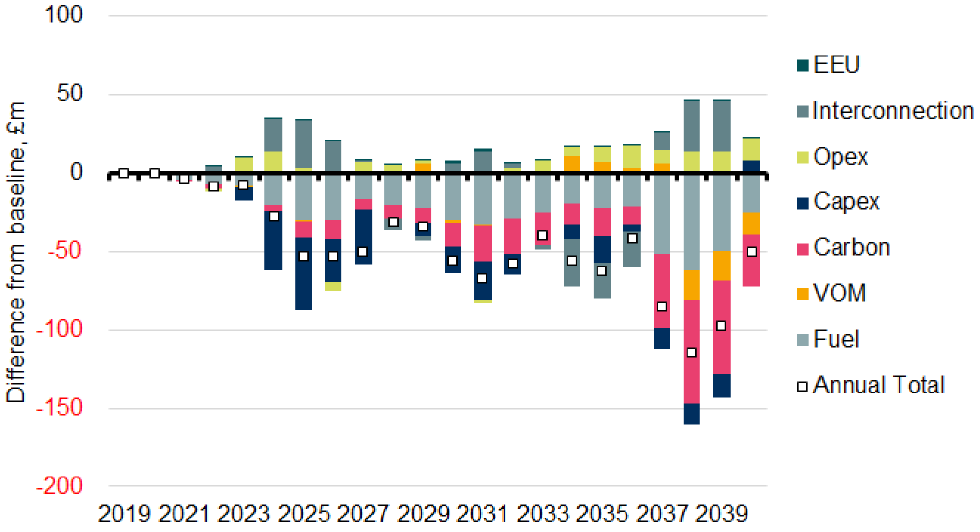
Source: Frontier/LCP

System Cost

Figure 98 shows the change in system costs between the Baseline Scenario and Partial Reform. Our modelling shows an overall decrease in system costs, again primarily due to fuel, carbon and capex savings.

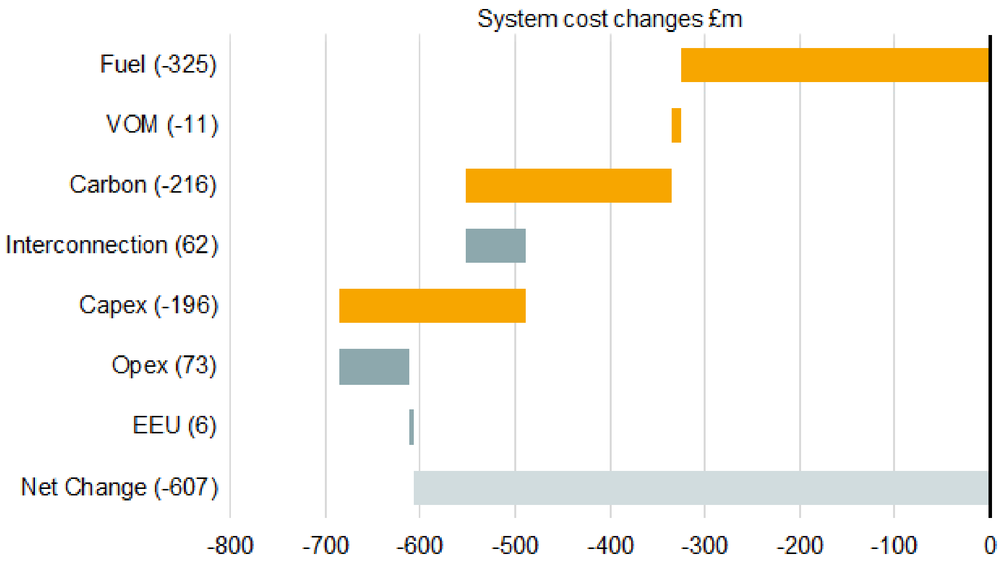
In comparison to Full Reform our results show a reduced offsetting impact from increased interconnector imports. On-site gas reciprocating engines have relatively low load factors and mainly generate in peak periods. The small loss in generation over the peak is met by additional CCGT generation, as interconnectors are already mostly importing, therefore there is only a limited increase in interconnector costs.

Figure 98 **Difference in system costs between the Baseline Scenario and Partial Reform**



Source: Frontier/LCP

Figure 99 **NPV of the difference in system costs between Baseline Scenario and Partial Reform (2019-2040, 3.5%)**



Source: Frontier/LCP

Consumer Cost

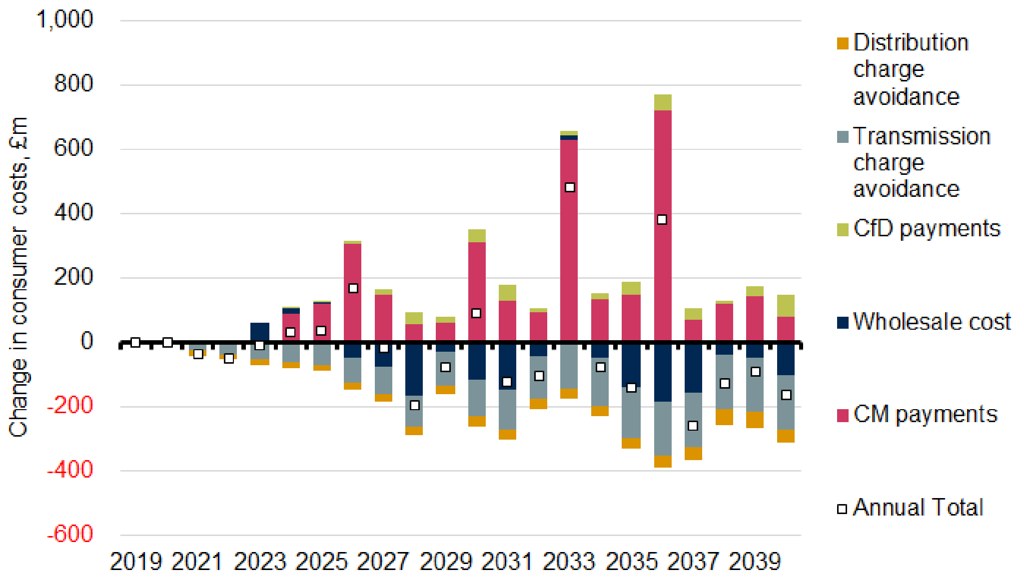
Figure 100 shows the change in consumer costs between the Baseline Scenario and Partial Reform. Our modelling shows an overall reduction in consumer costs albeit lower than that shown for Full Reform. On-site gas CHP is still able to receive the same residual benefits which limits the consumer savings from transmission and distribution charge avoidance payments.

CM payments increase as on-site gas reciprocating engines increase their bids and push capacity market clearing prices up.

There is a wholesale cost saving as the average wholesale price decreases with more efficient CCGT generation replacing that from low efficiency on-site gas reciprocating engines. This is contrast to the Full Reform, where wholesale prices generally increased, confirming that the loss of on-site gas CHP was a significant driver in those price rises.

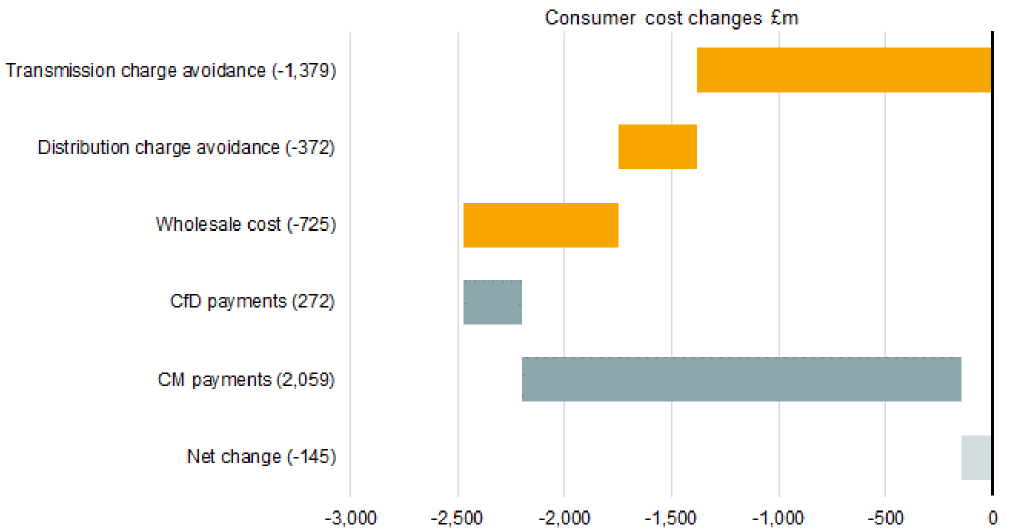
The largest savings to the consumer arise from reduced transmission and distribution charge avoidance payments.

Figure 100 Difference in consumer costs between the Baseline Scenario and Partial Reform



Source: Frontier/LCP

Figure 101 NPV of the difference in consumer costs between Baseline Scenario and Partial Reform (2019-2040, 3.5%)



Source: Frontier/LCP

5.3.4 Results – High residual

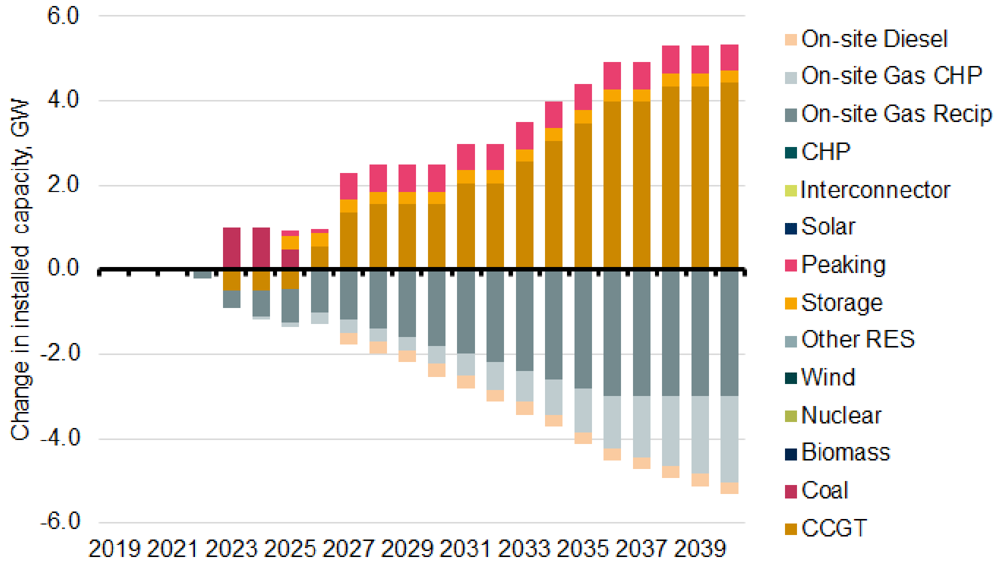
In this scenario an alternative baseline is explored under which the transmission demand residual charge is assumed to continue to rise beyond the end of National Grid's forecasts, increasing by 50% between 2023 and 2030 and remaining flat in real terms thereafter. The distribution residual charges are also assumed to increase, following the same 50% increase.

In the following set of results look at the impacts of the Full Reform scenario, using the High Residual as the baseline.

Capacity breakdown

Figure 102 shows the change in installed capacity between High Residual and Full Reform. Our modelling shows very similar results for installed capacity changes between this sensitivity and the original Baseline Scenario. This is because under the original Baseline Scenario on-site generation was mostly building up to the imposed build limits. The increase in the size of the benefits has little further impact, in terms of installed capacity.

Figure 102 Difference in Installed capacity between baseline with High Residual and Full Reform

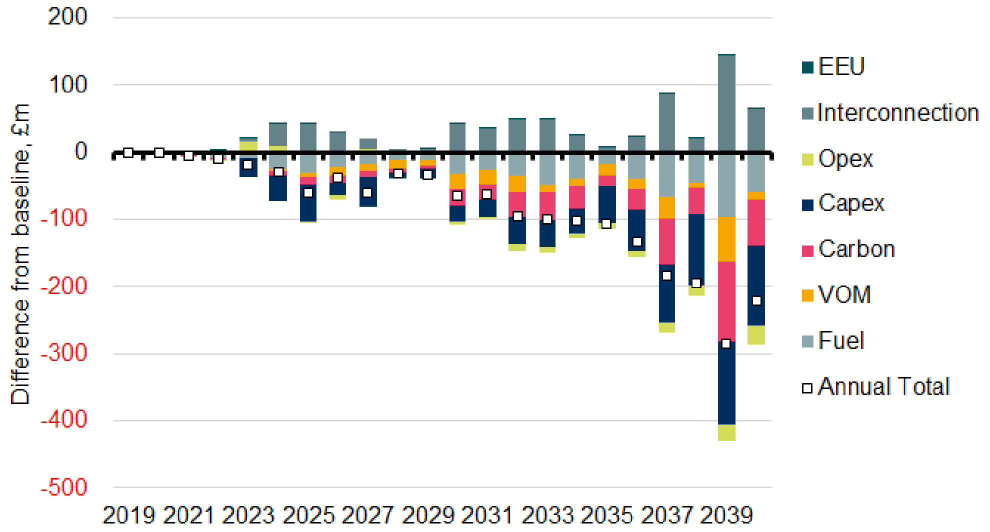


Source: Frontier/LCP

System Cost

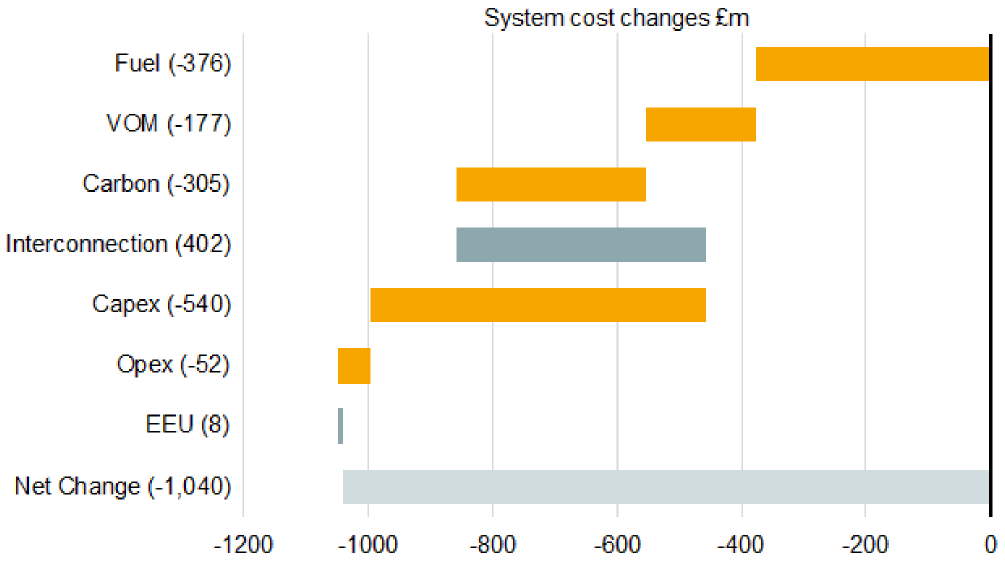
Figure 103 shows the change in system costs between High Residual and Full Reform. Our modelling shows a net reduction in system costs which closely aligns to the savings shown in the comparison of the original Baseline Scenario to Full Reform. This is as a result of the increase to the size of the residual benefits by 50% for on-site generation having little additional impact on the capacity mix.

Figure 103 Difference in system costs between baseline with High Residual and Full Reform



Source: Frontier/LCP

Figure 104 NPV of the difference in system costs between baseline with High Residual and Full Reform (2019-2040, 3.5%)

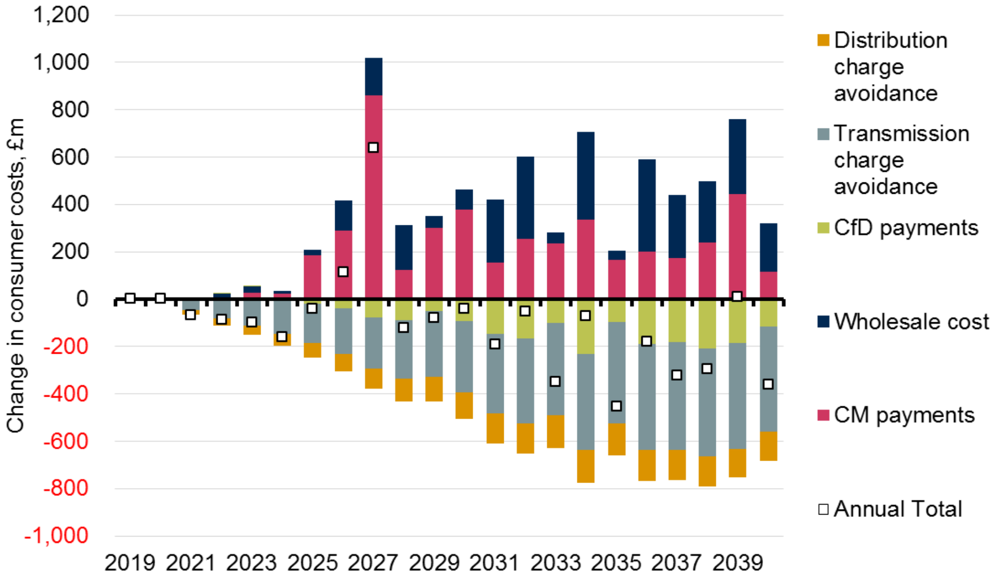


Source: Frontier/LCP

Consumer Cost

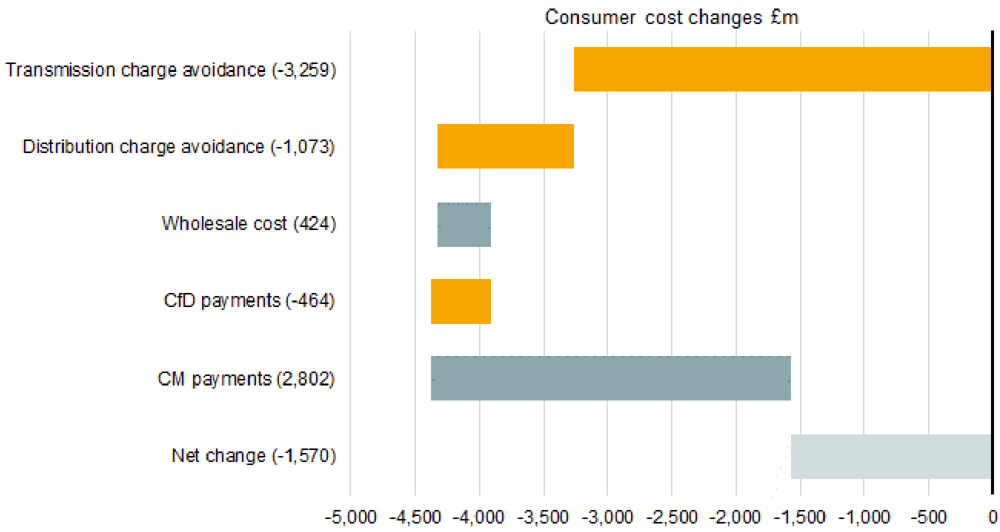
Figure 105 shows the change in consumer costs between High Residual and Full Reform. This shows a reduction in consumer costs which is significantly larger than that shown in our comparison of the original Baseline Scenario to Full Reform. This is due to the larger savings from the residual charging avoidance payments, as a direct result of the higher charges assumed under the High residual scenario. Capacity market costs are not materially different due to the limited impact on installed capacity relative to the Full Reform Scenario.

Figure 105 Difference in consumer costs between baseline with High Residual and Full Reform



Source: Frontier/LCP

Figure 106 NPV of the difference in consumer costs between baseline with High Residual and Full Reform (2019-2040, 3.5%)



Source: Frontier/LCP

5.3.5 Results – Low residual

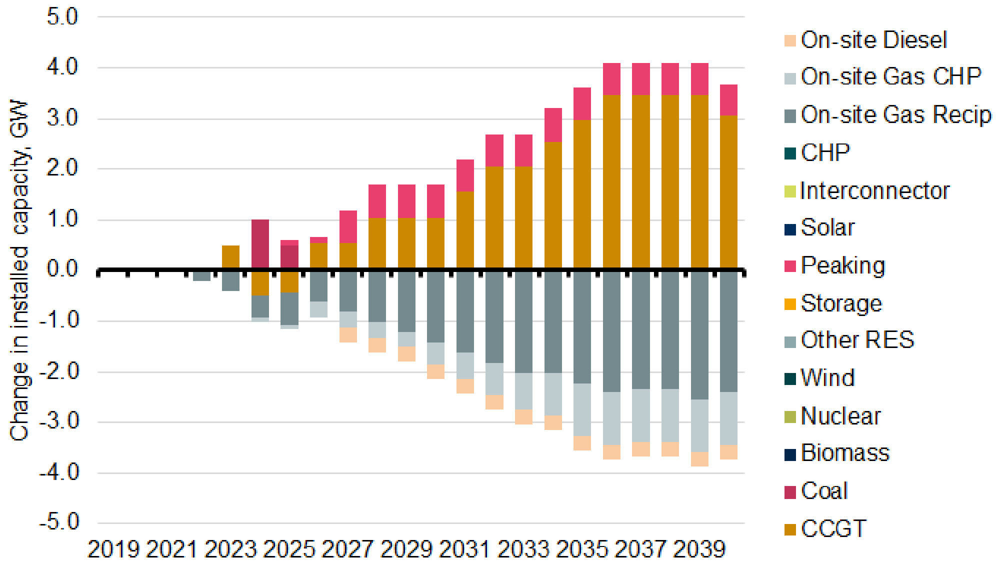
In this scenario an alternative baseline is explored under which the transmission demand and distribution residual charges are assumed to decrease by 50% between 2021 and 2030 remaining flat in real terms thereafter.

In the following set of results look at the impacts of the Full Reform scenario, using the Low Residual as the baseline.

Capacity breakdown

Figure 107 shows the change in installed capacity between Low Residual and Full Reform. Our modelling shows a slightly lower impact than that observed in the High Residual. This is because on-site generation has not built up to the same levels under the Low Residual counterfactual.

Figure 107 Difference in Installed capacity between baseline with Low Residual and Full Reform

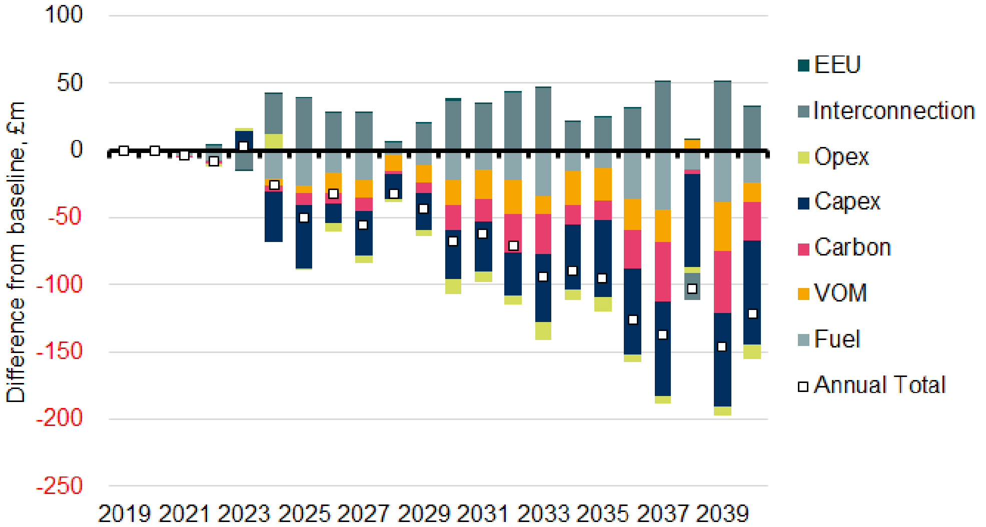


Source: Frontier/LCP

System Cost

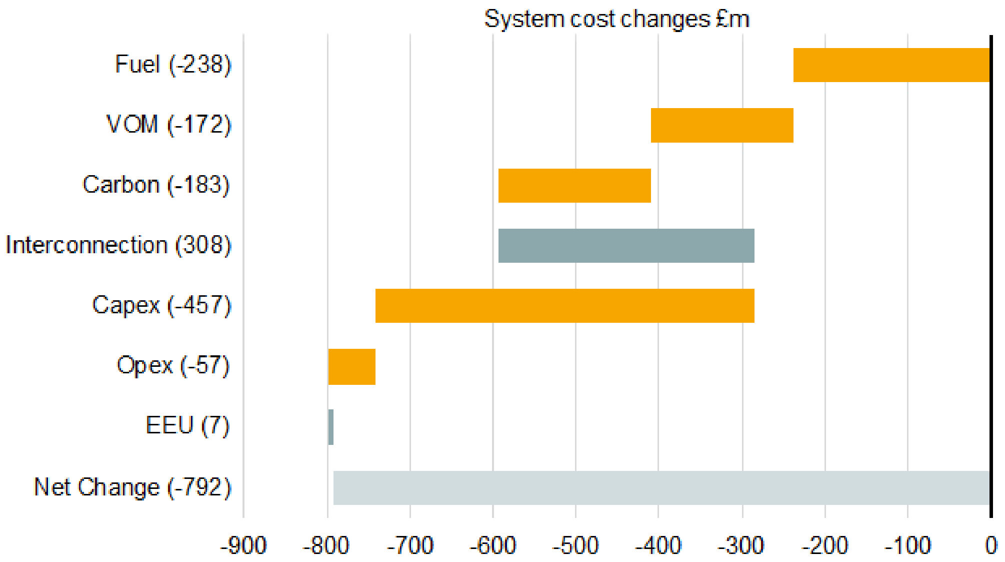
Figure 108 and Figure 109 show the change in system costs between Low Residual and Full Reform. Our modelling shows a net reduction to system costs. This saving is smaller than that shown in our Full Reform scenario results. The reduction in on-site generation relative to the baseline is less than under the Full Reform scenario, which reduces savings in fuel and carbon costs. Capex savings are only slightly reduced relative to the Full Reform Scenario, as there are only small differences in amount of on-site Gas CHP capacity, which is the technology that particularly drives the capex savings.

Figure 108 Difference in system costs between baseline with Low Residual and Full Reform



Source: Frontier/LCP

Figure 109 NPV of the difference in system costs between baseline with Low Residual and Full Reform (2019-2040, 3.5%)

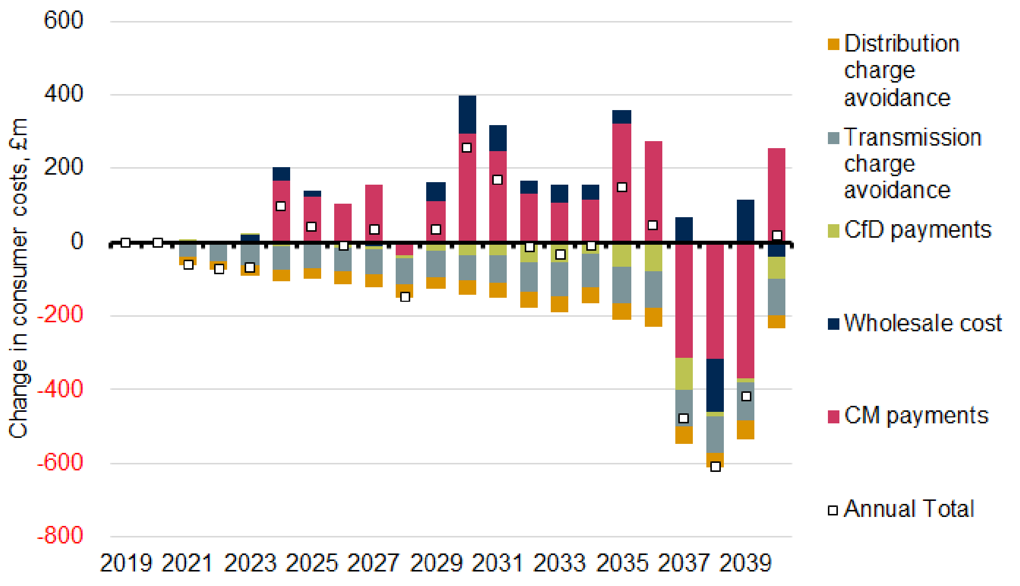


Source: Frontier/LCP

Consumer Cost

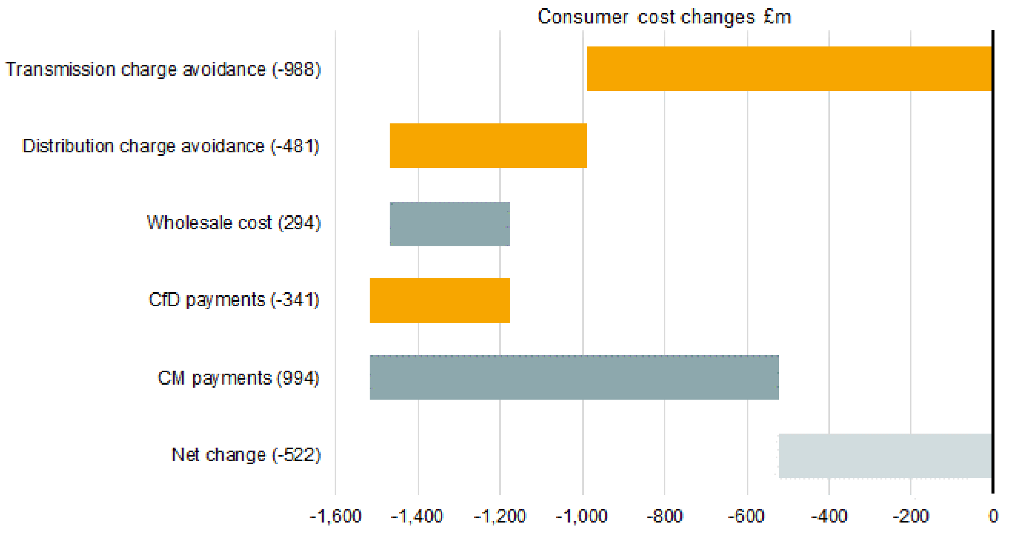
Figure 110 shows the change in consumer costs between Low Residual and Full Reform. Our modelling shows a net reduction in consumer costs with savings in transmission and distribution avoidance charges only partially offset by additional CM payments. Overall, the net saving is £522m in NPV terms, which is similar in magnitude to the consumer cost saving shown in our comparison of the original Baseline Scenario to Full Reform (£540m). Though the scenario shows significantly lower savings from avoidance payments, it also shows lower average increases in CM clearing prices, including drops in later years.

Figure 110 Difference in consumer costs between baseline with Low Residual and Full Reform



Source: Frontier/LCP

Figure 111 NPV of the difference in consumer costs between baseline with Low Residual and Full Reform (2019-2040, 3.5%)



Source: Frontier/LCP

5.3.6 Overview of system modelling results

The tables below summarise the change in the system & consumer cost between each pair of counterfactual and factual scenarios over the 2019 to 2040 period. A decrease in costs (negative value) represents a system or consumer benefit.

In general, all scenarios show a benefit to the system and consumers, with NPVs for the system cost benefits ranging from £0.6bn to £3.2bn, and for consumer benefits from £0.1bn to £1.6bn.

System benefits arise under the residual charging options because less efficient generation (e.g. onsite gas reciprocating engines) supported in the counterfactual by the ability to avoid residual charges, is replaced by generation which from a system perspective reduces overall costs (e.g. more efficient generation such as new CCGTs, or existing units which delay their closure).

Consumer benefits arise because the benefit to all consumers from the reduced avoidance behaviour by sites with onsite generation (i.e. overall residual network costs for all consumers are lower), outweighs any increases in capacity market costs (i.e. capacity market bids of onsite generators are increased resulting in the capacity price being set by more expensive generators).

Figure 112 Total Cost Change, 2019-2040

Counterfactual	Factual	System cost (£bn)	Consumer cost (£bn)
Baseline Scenario	Full Reform	-1.78	-0.92
Baseline Scenario	Partial Reform	-1.00	-0.29
Alternative FES background – Baseline	Alternative FES background – Full Reform	-5.57	-2.21
High residual	Full Reform	-1.83	-2.68
Low residual	Full Reform	-1.36	-1.07

Source: Frontier/LCP

Figure 113 NPV of Total Cost Change, 3.5%, 2019-2040

Counterfactual	Factual	System cost NPV (£bn)	Consumer cost NPV (£bn)
Baseline Scenario	Full Reform	-1.01	-0.54
Baseline Scenario	Partial Reform	-0.61	-0.14
Alternative FES background – Baseline	Alternative FES background – Full Reform	-3.22	-1.23
High residual	Full Reform	-1.04	-1.57
Low residual	Full Reform	-0.79	-0.52

Source: Frontier/LCP

As might be expected, Partial Reform shows a lower system and consumer saving than Full Reform, as the benefits due to avoiding residual charges are only removed from the peaking on-site generation units. Baseload CHP units continue to benefit from avoiding the charges.

The Alternative FES background, which uses the Community Renewables FES scenario, shows significantly larger benefits than the Baseline Full Reform, which use Steady Progression. This is primarily due to higher levels of on-site gas reciprocating engine build coming through in this sensitivity's counterfactual, resulting in a larger a greater decrease in transmission and distribution charge avoidance payments under the Full Reform option. However, the larger amount of affected capacity under Community Renewables doesn't result in increases in capacity prices above that required in under Steady Progression. Both scenarios result in increases in clearing prices to the levels required to incentivise new build CCGT (£25-£30/kW).

The High Residual sensitivity shows a higher consumer benefit, due to the higher levels of avoided charges being removed. The system cost impact, however, is similar, as the same level of on-site generation new build is removed, which also means capacity market impacts are similar.

The Low Residual sensitivity has a lower system cost benefit than the High Residual or Baseline Full Reform, as the lower residual payments don't bring forward the same level of on-site generation new build in this sensitivity's counterfactual.

The next set tables show the same set of results, but only looking over the 2019-2030 period (rather than 2019-2040). There are some significant changes, for example the Alternative FES background scenario now shows a slight net increase in consumer cost. This highlights the sensitivity of the results, particularly the consumer costs, where, for example, large changes in a particular years' CM clearing price can have a material impact on the overall figures.

Figure 114 Total Cost Change, 2019-2030

Counterfactual	Factual	System cost (£bn)	Consumer cost (£bn)
Baseline Scenario	Full Reform	-0.34	-0.55
Baseline Scenario	Partial Reform	-0.33	-0.07
Alternative FES background – Baseline	Alternative FES background – Full Reform	-1.26	+0.06
High residual	Full Reform	-0.35	-0.88
Low residual	Full Reform	-0.31	+0.11

Source: Frontier/LCP

Figure 115 NPV of Total Cost Change, 3.5%, 2019-2030

Counterfactual	Factual	System cost NPV (£bn)	Consumer cost NPV (£bn)
Baseline Scenario	Full Reform	-0.25	-0.43
Baseline Scenario	Partial Reform	-0.24	-0.05
Alternative FES background – Baseline	Alternative FES background – Full Reform	-0.92	+0.01
High residual	Full Reform	-0.26	-0.66
Low residual	Full Reform	-0.23	+0.04

Source: Frontier/LCP

5.3.7 Network Impacts

In addition to the areas above, there may be effects on network costs due to the changes proposed. In general, based on the EnVision modelling we expect investment in onsite generation to decline relative to the counterfactual following a change to the residual charges. This could be the result of a decline in new investment or earlier closure of existing onsite generation relative to the counterfactual, and in both cases would result in an increase in net demand at particular locations on the network.

The impact on network costs of an increase in net demand is highly location specific, and will be closely linked to whether the particular location is load or generator dominated. The impacts will also be different for distribution and transmission networks. We summarise the potential impacts below in Figure 116.

Figure 116 Overview of the impact on network costs due to a reduction in onsite generation

	Distribution network impacts	Transmission network impacts
Load dominated	▪ Likely **increase** in future D network build.	▪ T network needs to **supply more power** to GSP
Generator dominated	▪ Likely **reduction** in future D network build	▪ T network needs to **accommodate less exports** from GSP

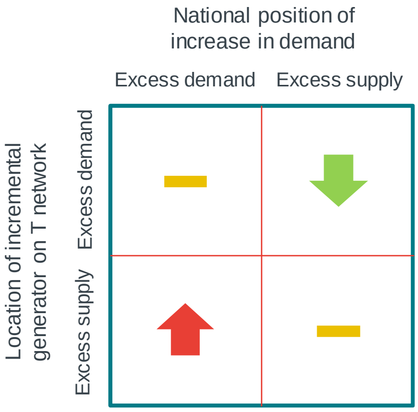
Source: Frontier Economics

From Figure 116 this we can see that for distribution networks, whether an increase in demand increases costs or not is dependent on whether the change is in a load or generation dominated part of the distribution network:

- In a load dominated area, an increase in net demand would likely lead to an increase in future network build to accommodate the increased imports required to meet the new demand.
- In a generator dominated area, an increase in net demand would likely lead to a reduction in future network build as more of the excess local generation can be absorbed locally, resulting in less network needed to export power from the local network.

It is more complicated to determine the impact on transmission network costs due to an increase in net demand. If the changes happen in a load dominated area, the transmission network needs to supply more power to the Grid Supply Point (GSP), and if the change happens in a generator dominated area, the transmission network needs to accommodate less power from the GSP. However, in each case, the impact on network costs could be positive or negative depending on the resultant change in flows on the transmission network. The possibilities are illustrated in Figure 117.

Figure 117 Impact of an increase in net demand due to reduced onsite generation on network costs



Source: Frontier Economics

For transmission networks, a reduction in onsite generation could result in an increase or a decrease in flows over the transmission network dependent on the location of the reduction in onsite generation and the location of the replacement source of transmission connected generation relative to pre-dominant flows over the network. Specifically:

- Transmission network costs could **fall** if the increase in net demand absorbs transmission connected generation in region of excess supply (e.g. North of England) and the incremental transmission connected generation (i.e. plant next in merit) required to meet the increase in demand on transmission network is close to a region of excess demand (e.g. South of England). In this scenario overall flows over the network are reduced despite demand on transmission network increasing.
- T network costs **increase** if the increase in net demand increases excess demand in a region (e.g. South of England) and the incremental transmission connected generation (i.e. plant next in merit) required to meet the increase in demand on T network is close to region of excess supply (e.g. North of England). In this scenario overall flows over the network are increased in line with increased demand on transmission network.

So far we have discussed the potential impact on network costs of an increase in net demand due to a reduction in onsite generation investment. However, in the previous chapter we also identified that the incentive to disconnect from the network could be increased for certain sites as a result of the residual charging options. Load disconnection would result in a reduction in net demand at specific locations, with the impacts on network costs being opposite in direction to those described above.

In summary, there is no particular principled reason to suspect that network costs would be more likely to increase or decrease in aggregate as a result of the changes. The impact of an increase or decrease in net demand could result in an increase or decrease in network costs, dependent on the location of the particular change in onsite generation investment. To model these impacts would introduce significant subjectivity into the modelling. It would require assumptions as to the exact location of newly connecting generation, plant closures or disconnected sites into the future, and estimation of the site specific resulting network costs. The results would simply have reflected these assumptions rather than anything more fundamental, and so would have been very sensitive to the choices made. As such, we have not provided estimates for the effect on network costs as part of the system cost analysis.

5.3.8 Results – Full Reform with one-year delay

In this sensitivity the removal of the residual benefits is delayed by one year to 2021/22.

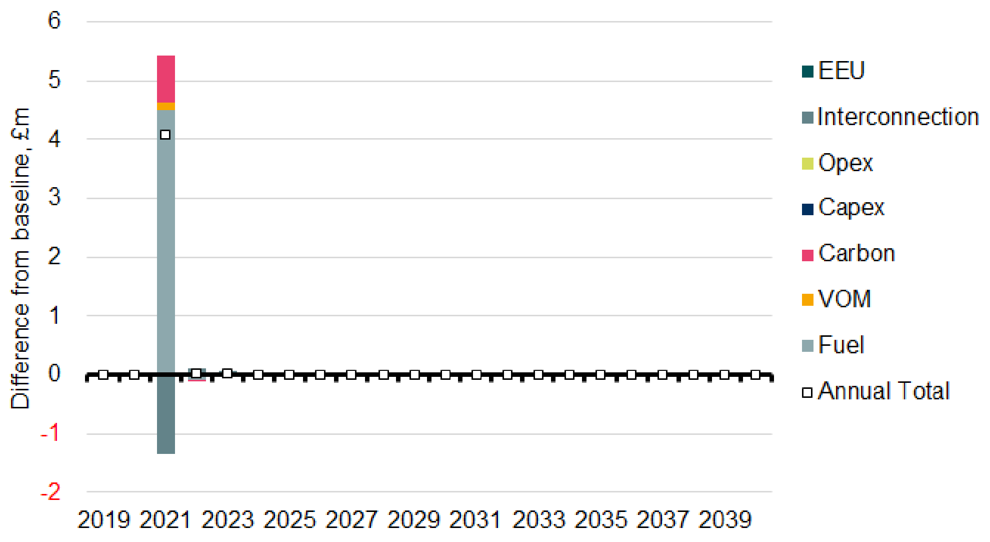
Capacity breakdown

There is **no change** in installed capacity between Full Reform and Full Reform with one-year delay. This is because the one-year delay in the removal of the residual benefits for on-site generation has no impact on decisions for the T-4 CM auction in 2022/23 or beyond.

System Cost

Figure 118 shows the change in system costs between Full Reform and Full Reform with one-year delay. Our modelling shows a relatively small increase in system costs due to the delay, with higher fuel and carbon costs in 2021 as on-site generation continues to receive the residual benefits and run out of merit. There are no material changes beyond 2021 as this delay does not impact build.

Figure 118 Difference in system costs between Full Reform and Full Reform with one-year delay

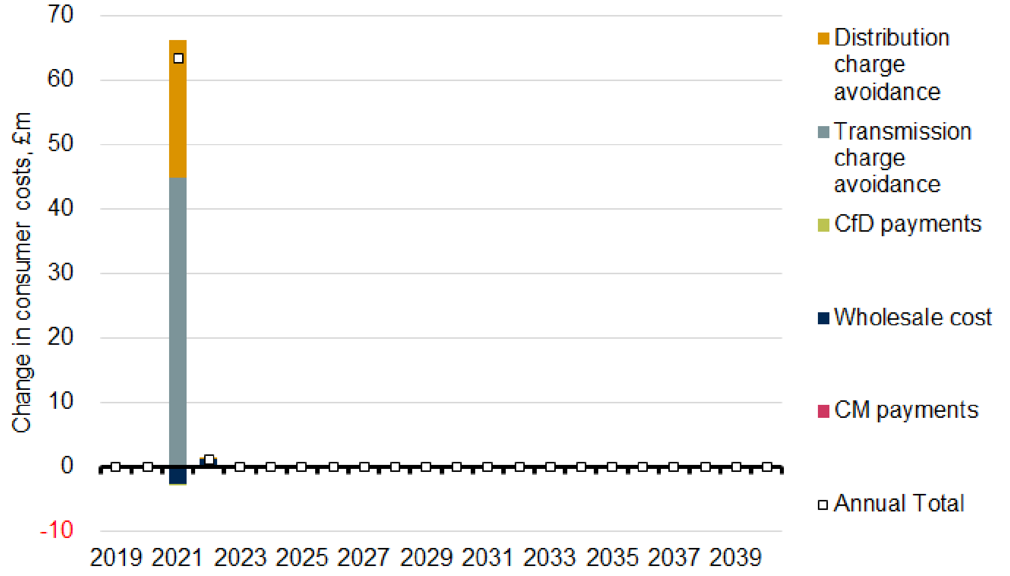


Source: Frontier/LCP

Consumer Cost

Figure 119 shows the change in consumer costs from Full Reform to Full Reform with one-year delay. Our modelling shows an increase in costs to the consumer due to the delay in removal of the residual benefits, meaning on-site generation receives avoidance payments for one further year which are passed on as costs to the consumer. There is a small decrease in wholesale costs due to a decrease in wholesale prices caused by on-site generation pushing down peak prices when chasing triad.

Figure 119 Difference in consumer costs between Full Reform and Full Reform with one-year delay



Source: Frontier/LCP

5.3.9 Results – Full Reform with three-year phasing

In this scenario the residual benefits for on-site generation are phased out over the period from 2021/22 to 2023/24.

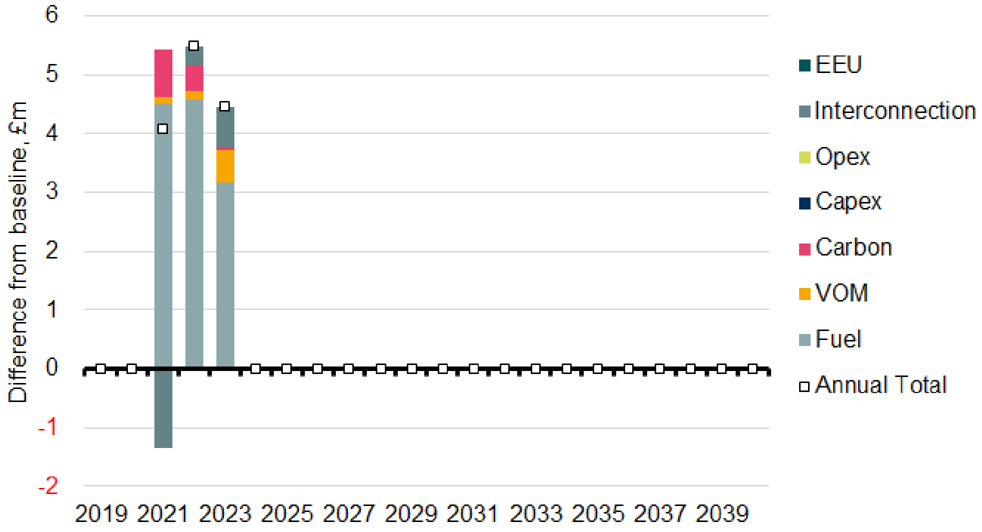
Capacity breakdown

Our modelling shows there is **no change** in capacity between Full Reform and Full Reform with three-year phasing. The remaining benefit is not large enough to impact decisions for the T-4 2022/23 CM auction and is completely phased out by the time subsequent auctions deliver.

System Cost

Figure 120 shows the change in system costs between Full Reform and Full Reform with three-year phasing. Our modelling shows a net increase in system costs in the period in which the residual benefits are phased out. This is due to on-site generation running out of merit to either chase triad or avoid distribution residual costs. Beyond this point there is no change in system costs as the phase-out has no impact on build.

Figure 120 Difference in system costs between Full Reform and Full Reform with three-year phasing

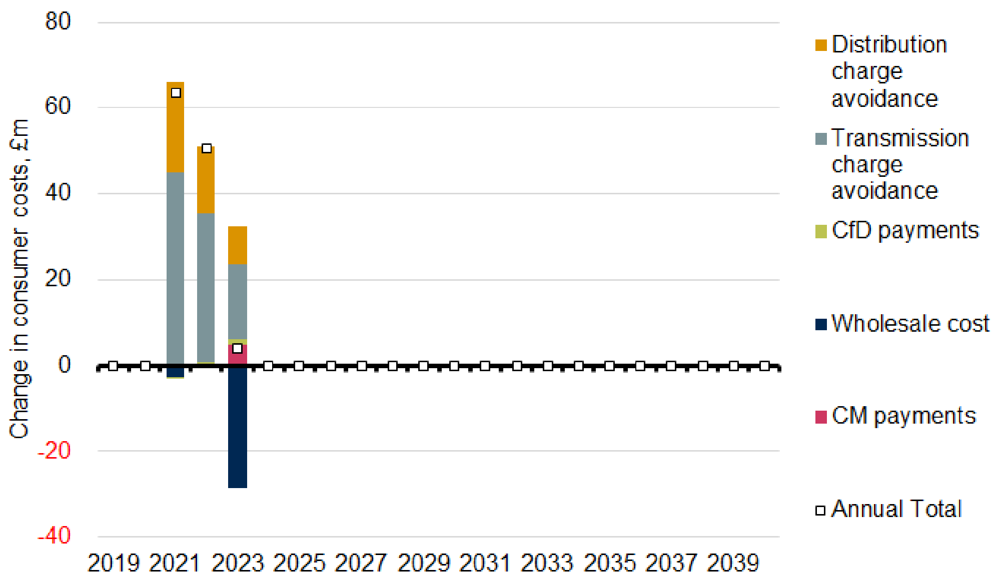


Source: Frontier/LCP

Consumer Cost

Figure 121 shows the change in consumer costs between Full Reform and Full Reform with three-year phasing. Our modelling shows a net increase in costs to the consumer due to phase-out of the residual benefits between 2021 and 2023 with no further impact beyond this. Transmission charge avoidance and distribution payments increase, and a decrease in wholesale costs, due to triad chasing, somewhat offsets this.

Figure 121 Difference in consumer costs between Full Reform and Full Reform with three-year phasing



Source: Frontier/LCP

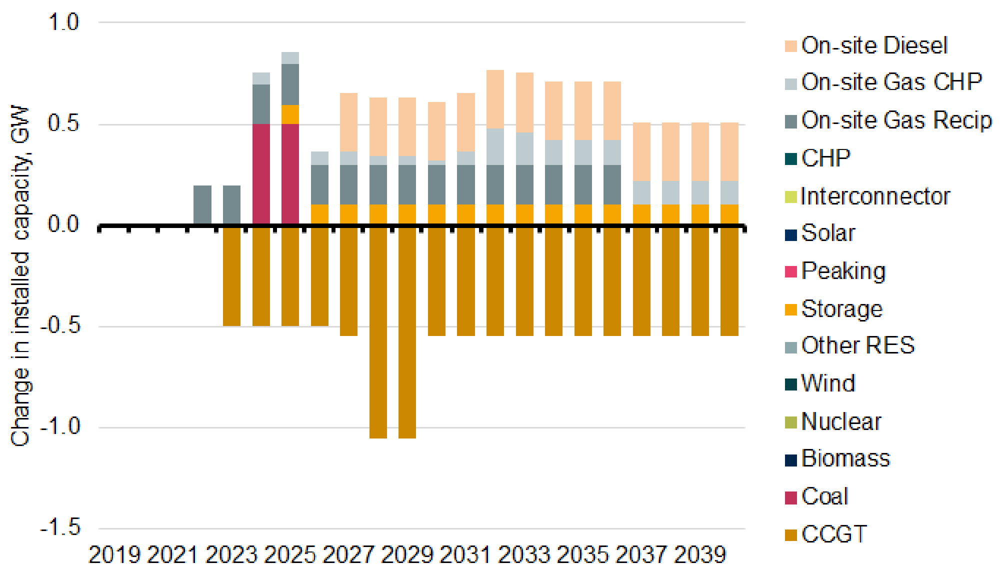
5.3.10 Results – Full Reform with three-year delay

In this scenario the removal of the residual benefits is delayed to 2023/24.

Capacity breakdown

Figure 122 shows the change in installed capacity between Full Reform and Full Reform with three-year delay. Additional on-site generation capacity comes online in 2021 as the additional two years of embedded benefit is sufficient incentive to build. This displaces CCGT build in the CM with this knock-on impact flowing through into subsequent years.

Figure 122 Difference in Installed capacity between Full Reform and Full Reform with three-year delay

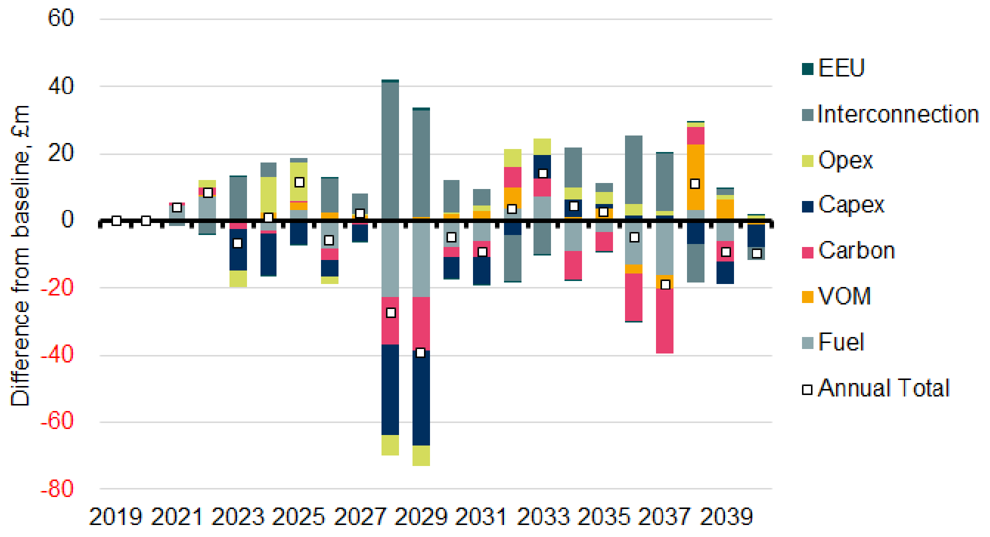


Source: Frontier/LCP

System Cost

Figure 123 shows the change in system costs between Full Reform and Full Reform with three-year delay. Our modelling shows a small net decrease in system costs as the change in build drives changes in system costs throughout the modelled period.

Figure 123 Difference in system costs between Full Reform and Full Reform with three-year delay

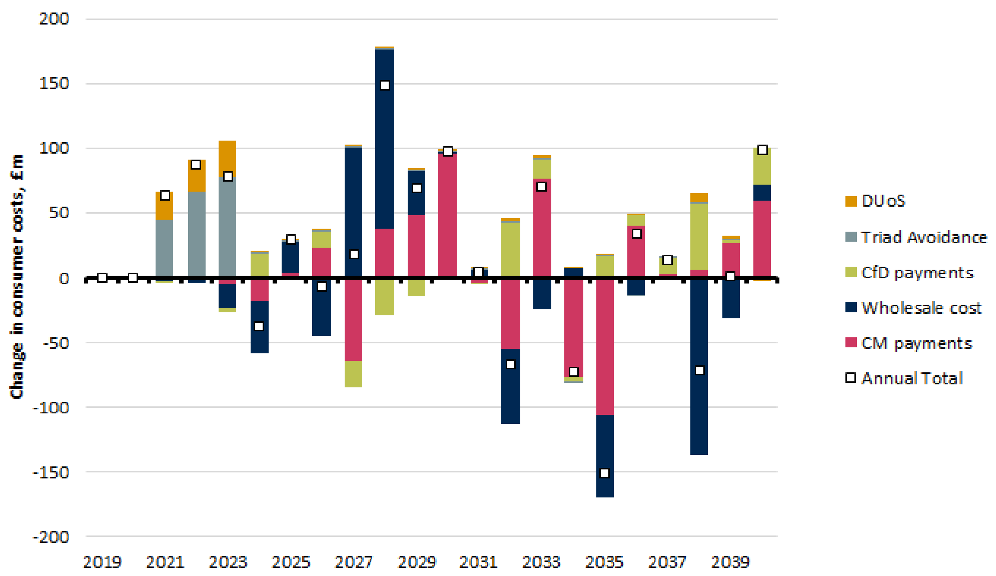


Source: Frontier/LCP

Consumer Cost

Figure 124 shows the change in consumer costs between Full Reform and Full Reform with three-year delay. Overall consumer costs increase, firstly due to the delay in the removal of the residual benefits for on-site generation and then due to second order impacts driven by the change in build across the modelled horizon.

Figure 124 Difference in consumer costs between Full Reform and Full Reform with three-year delay



Source: Frontier/LCP

5.3.11 Overview of Transitional arrangements results

The tables below summarise the system and consumer cost impacts for the transitional arrangement scenarios, with Full Reform also shown for comparison.

Total Cost Change, 2019-2040

Counterfactual	Factual	System cost (£bn)	Consumer costs (£bn)
Baseline Scenario	***Full Reform***	***-1.78***	***-0.92***
Baseline Scenario	Full Reform with one-year delay	-1.77	-0.85
Baseline Scenario	Full Reform with three-year phasing	-1.76	-0.80
Baseline Scenario	Full Reform with three-year delay	-1.85	-0.51

NPV of Total Cost Change, 3.5%, 2019-2040

Counterfactual	Factual	System cost NPV (£bn)	Consumer cost NPV (£bn)
Baseline Scenario	***Full Reform***	***-1.01***	***-0.54***
Baseline Scenario	Full Reform with one-year delay	-1.01	-0.48
Baseline Scenario	Full Reform with three-year phasing	-1.00	-0.43
Baseline Scenario	Full Reform with three-year delay	-1.06	-0.21

The scenarios show only a minor impact on the system cost results (relative to Full Reform). In particular, the Full Reform with one-year delay and Full Reform three-year phasing scenarios showed no change in build or retirements relative to Full Reform, so the impact on system costs is minimal. The full three-year delay in Full Reform with three-year delay did result in small changes to the capacity mix, and hence shows larger impacts.

The impact of transitional arrangements on the consumer costs is more significant and shows a reduction in savings across the three transitional scenarios. This is primarily driven by the transmission and distribution charges residual payments persisting during the transition period. As might be expected the Full Reform with three-year delay shows the largest impact, though the impacts in this scenario are complicated by the changes in new build leading to second order impacts in later years.

6 IMPLICATIONS

The objective of this study was to provide an independent assessment of the potential distributional and wider system impacts of the proposed changes to the residual network charging arrangements. The results of the modelling presented in this report are intended to assist Ofgem in its decision to introduce a new approach to residual charging as part of its TCR, and contribute to the evidence for Ofgem's impact assessment supporting its choice.

However, it is important to stress that relying on modelling outputs as the sole, or even main basis for a decision on the TCR options has its limitations, as modelling outputs are sensitive to a number of assumptions on future uncertain variables and behaviours. Changes to these can result in significant changes to outputs.

Based on the analysis set out in this report, a move to a residual charging approach which is less easy to avoid through the use of onsite generation or demand management, can have a positive benefit to society and customers, driven mainly by a change in behaviour of industrial customers. The system modelling results support this broad conclusion, though the numbers should only be interpreted as providing an indication of the direction and broad magnitude of impacts. Different choices related to the inputs would lead to different results.

Based on the EnVision modelling we estimate that under all scenarios there is a benefit to the system and consumers from removing the ability of onsite generation to avoid charges. Following the proposed changes:

- system costs are lower in the range £0.6bn to £3.2bn (2019-2040); and
- consumer costs are lower in the range of £0.1bn to £1.6bn (2019-2040) depending on the scenario.

In general terms:

- System benefits arise under the residual charging options because less efficient generation (e.g. onsite gas reciprocating engines) supported in the counterfactual by the ability to avoid residual charges, is replaced by generation which from a system perspective reduces overall costs (e.g. more efficient generation such as new CCGTs, or existing units which delay their closure).
- Consumer benefits arise because the benefit to all consumers from the reduced avoidance behaviour by sites with onsite generation (i.e. overall residual network costs for all consumers are lower), outweighs any increases in capacity market costs (i.e. capacity market bids of onsite generators are increased resulting in the capacity price being set by more expensive generators).

The scale of the benefits to the system and consumers is a function of assumptions, and in particular is sensitive to the outlook for the volume of industrial onsite generation going forward and the scale of residual costs to recover:

- Both system and consumer benefits are higher under the Alternative FES scenario (i.e. Community Renewables) which includes significantly more onsite generation than the Steady Progression scenarios. The benefits are still positive, but significantly smaller under Steady Progression.

- Consumer benefits are significantly higher under the High Residual scenario. This is principally because the benefits to consumers of reduced avoidance increase in line with the residual, but the change in capacity market costs does not increase further since onsite generation investment was already at the assumed build constraints. On the other hand, the benefits under the Low Residual scenario are reduced but still positive.

The benefits can also be sensitive to the timeframe over which they are assessed. In particular, when assessing the benefits over shorter timeframes (e.g. 2019-2030) large changes in a single year's capacity market price can have a disproportionate impact on the overall result. As a result, we see a small increase in consumer costs in some scenarios. Changes to capacity market costs are particularly uncertain and sensitive to assumptions.

The benefits are also reduced if the possibility of some degree of avoidance remains following the introduction of a particular option e.g. two of the options considered introduce an element which is avoidable (by CHP in particular) which recovers 25% of the costs. The Partial Reform scenario as modelled is more extreme than these options, however the results illustrate the risk to the benefits case of such an approach.

The scale of behavioural change for smaller customers resulting from a change in charging approach is likely to be lower, and hence is less likely to significantly affect system or consumer costs. The change in residual charging approach is, all else equal, likely to impact the economics of investing in different technologies. However, we believe the effects for most technologies are minimal and that behaviour change is likely to be driven by factors other than network charges, even if changes in these are fully passed through to consumers by suppliers.

Ofgem also asked us to consider the impact of a delay to any change to the charges. In general, the system impacts of a delay are minimal. However, the consumer benefits are reduced, though they remain positive. This is primarily because the benefits from the reduced avoidance behaviour are delayed, yet the impact on the capacity market costs is largely unaffected. This is because capacity market effects do not occur until at least four years after the policy has been announced (whether the introduction is delayed or not) due to the time lag between the auctions and the delivery year.

While the wider system modelling suggests the changes can lead to benefits, the modelling does not distinguish between the different types of options being considered, other than to highlight the impact of an ongoing possibility of avoidance on the benefits case. In other words, from a system perspective there is little to distinguish between a fixed charge or an ex-ante capacity charge, with the key differences relating to the distributional impacts.

The static bill impact modelling assesses the distributional implications of the different options. We have presented results for eight charging options across 15 of the user groups. The results presented for each user group depend on specific assumptions. However, we can draw a number of more general insights about the potential distributional impacts that result from changes to the residual charging.

A **fixed charge** applies the same charge to all users in a particular segment. Users previously paying above average baseline charges in the segment gain relative to those who previously paid lower charges, including those sites previously able to avoid charges by triggering onsite generation of demand management.

There is no limit to the choices of how to distribute the recovery of the residual among customer segments when setting fixed charges. Ofgem identified an option where the share of cost recovered from each group is based on its net volumetric consumption. Under this model, cost recovery from domestic customers is reduced relative to non-domestic customers, because today TNUoS charging is based on peak consumption which tends to focus cost recovery more on domestic customers.

We have considered **gross volumetric charging** for the larger users. Even though Ofgem is not considering charging domestic customers on a gross volumetric basis, if cost recovery between smaller and larger customers is apportioned on the basis of gross volume, this shift should benefit domestic customers with respect to their TNUoS bill. Since gross volume charges limit the ability to avoid charges, all else equal, gross volume per unit charges would be lower than current charges for all users. However, large users with on-site generation would see increased charges.

Ex-ante capacity charges based on our assumptions for actual physical capacities result in the same residual bill for all users with the same connection capacity irrespective of their consumption patterns. Under this option, all but the highest consuming households are likely to experience an increase in their bill since domestic consumers represent a greater share of physical connection capacity than of annual or peak net consumption. Industrial users with on-site generation would also see increased charges.

This result is sensitive to the particular assumptions on connection capacity. Options with lower ‘deemed’ capacities for domestic customers can result in a distribution much closer to historic levels.

In a similar way to ex-ante capacity charges, **ex-post capacity charges** (including the ex-ante capacity ratchet option) are also likely to result in greater cost recovery from domestic relative to non-domestic customers.

We have also considered a number of ‘**hybrid’ options**. By introducing an ex-post element (25%) to the fixed charge (75%), users with greater consumption at peak would pay higher bills, and a greater share of costs would be recovered from domestic customers, albeit to a limited extent compared to the pure ex-post charge.

In a similar way, introducing a net volumetric element (25%) to an ex-ante capacity based charge (75%), creates differential bills for users with the same capacity (particularly for domestic customers where standard capacity sizes are more likely to apply). As noted above, a net volumetric element is likely to favour domestic customers.

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 network charging arrangements. Such principles relate to minimising distortions, fairness and practical considerations. Charging in a manner consistent with such principles should help ensure an optimum outcome for society as a whole.

The static bill impact and behavioural 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. As a result, the charges and bill impacts estimated should only be considered illustrative to provide the broad direction of the expected impacts. Similarly, the behavioural analysis is designed to identify those areas with the greatest potential for a behavioural response to the charges, rather than a quantification of an exact response, and is fundamentally judgement based.

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 2019 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 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.

As a result of these issues, we can therefore accept no liability for losses suffered, direct or consequential, arising out of any reliance on the results presented.

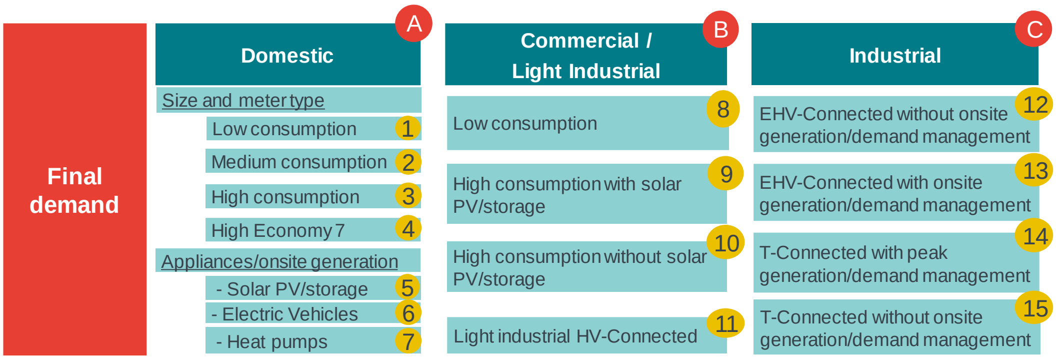
ANNEX A USER GROUP ANALYSIS

As discussed in Section 3, as a first step in our static bill impact assessment, we have identified a set of user groups to understand how different types of customers could be affected by proposed changes in the network charging structure related to the recovery of residual costs.

The domestic, commercial and industrial user groups that we have identified are outlined in Figure 125. In total we have identified 15 final demand user groups spread across various consumer types, as well as consumption and voltage levels.

It is important to note that in reality the boundaries between users may overlap. For example, the results for a larger domestic customer may be more appropriate for certain small commercial customers than our low consuming commercial user group. Also noteworthy is that while representing key consumer archetypes, these users group cannot be representative of all consumers.

Figure 125 User group classifications



Source: Frontier Economics

Note: Note that Group 5 comprises of two sub-groups: solar PV in isolation and solar PV combined with storage.

In this annex, we provide detail of the analysis underlying the identification of the Domestic and Commercial/Light Industrial user groups, i.e. Groups 1 – 11 in Panels A and B in Figure 125. These user groups have been defined in relation to actual consumption profiles of GB consumers, and take into account the possible changes in level and pattern of consumption resulting from consumers' adoption of technologies like electric vehicles, heat pumps or onsite solar PV generation.

We note that in conducting this analysis we have needed to make numerous simplifications and assumptions which we set out in this annex.

A.1 Data to inform domestic and commercial user groups

We have primarily relied on two key data sources to inform the domestic and commercial user groups. These are described below.

A.1.1 Ofgem's Typical Domestic Consumption Values

Typical Domestic Consumption Values (TDCVs) are industry standard values for the annual gas and electricity usage of a "typical" domestic consumer. TDCVs are commonly used to derive typical consumer bills when the actual consumption level is not known. We have relied on the revised TDCVs for GB electricity consumers provided in Ofgem's most recently published decision dated 3 August 2017 summarized in Figure 126.[39]

Figure 126 Ofgem's TDCVs for Domestic Electricity Consumers in GB

	Consumption levels	Revised TDCV (kWh)
Profile Class 1 *(Domestic Unrestricted Customers)*	Low	1,900
	Medium	3,100
	High	4,600
Profile Class 2 *(Domestic Economy 7 Customers)*	Low	2,500
	Medium	4,200
	High	7,100

Source: *Ofgem. Decision on revised Typical Domestic Consumption Values for gas and electricity and Economy 7 consumption split. 3 Aug 2017.*

TDCVs identify the "low", "medium" and "high" consumption levels for domestic GB electricity consumers for Profile Classes 1 and 2, calculated using consumption data from the two most recent years available (2014 and 2015). Profile Class 2 predominantly consists of users with Economy 7 meters, which have two separate rates for peak and off-peak consumption. Profile Class 1 covers most of the remaining domestic consumers.

The median or second quartile of household consumption data is considered to be representative of the typical "medium" usage of GB domestic customers, while the first and third quartiles represent the typical "low" and typical "high" usage domestic consumers, respectively. In other words, if consumers were ranked in order of their electricity consumption, 25% of all consumers would have consumption less than the typical "low" usage customer, and 25% of customers would have consumption greater than the typical "high" usage customer.[40]

A.1.2 Customer-Led Network Revolution

Customer-Led Network Revolution (CLNR) was a smart grid project funded by Ofgem's Low Carbon Networks Fund and led by Northern Powergrid in partnership with British Gas, Durham University, Newcastle University and EA Technology. The project collected data on electricity consumption and generation profiles of around 13,000 domestic and commercial customers and is one of the most significant projects of its kind undertaken in the United Kingdom to date. [41]

The data collected as part of the CLNR trial also provides consumption profiles for domestic customers with low carbon technologies such as solar panels, electric vehicles and heat pumps.

[39] Ofgem. Decision on revised Typical Domestic Consumption Values for gas and electricity and Economy 7 consumption split. 3 August 2017. Available here: https://www.ofgem.gov.uk/system/files/docs/2017/08/tdcvs_2017_decision.pdf

[40] Ibid.

[41] CLNR. Developing the smarter grid: the role of domestic and small and medium enterprise customers. 2015.

We have drawn information from a number of different CLNR datasets which we describe below.

Domestic users datasets

We have sourced half-hourly consumption data for domestic users from four key CLNR datasets, or so-called 'test cells' (TC). These datasets provide annual half hourly electricity consumption profiles for actual domestic users and include consumption profiles for domestic users having air source heat-pumps, solar PVs and electric vehicles.

Below we briefly describe each of these datasets.

The **basic domestic consumers (TC1a)** dataset contains half-hourly electricity consumption data from October 2012 to September 2013 for more than 9,000 customers with basic smart metering. TC1a was designed to cover households from across different demographic groups providing an overall picture of domestic electrical consumption in the UK.[42] No interventions (such as providing a user with a low carbon technology) were applied to the domestic users in TC1a, allowing it to be used as the baseline against which the impacts of interventions applied to other domestic test cells can be compared. We filtered the dataset to look only at customers with full year of data.

The **domestic consumers with heat-pumps (TC3)** dataset contains separate electricity consumption meter readings for the air-source heat pumps and for total household consumption. Both readings were recorded for 381 households every 1 minute for the entire year from May 2013 to April 2014.

We learned from the CLNR documentation on this test cell that there were significant data discrepancies (e.g., missing data from drop-outs) associated with this dataset. We have therefore applied similar filters deployed by CLNR to retain only those households with complete full-year consumption data. Applying these filters brings the actual sample size to 89 households.[43]

The **domestic consumers with solar PV (TC5)** dataset contains electricity consumption meter readings for 143 households as well as electricity generation readings for their respective solar PV cells. The readings were recorded for the entire year from January to December 2013.[44]

The **domestic consumers with electric vehicles (TC6)** dataset contains electricity consumption meter readings for 131 households with electric vehicles for the nine months: July 2014 to March 2015. Given the absence of a full year of data, any aggregated statistics (e.g., annual consumption) were scaled up linearly to a full year for comparison with other datasets. 108 of the EV owners in the study were drawn from employees, or friends and family of employees, of Nissan Motor

[42] CLNR. Insight Report – Baseline Domestic Profile. 2015. Available at: http://www.networkrevolution.co.uk/wp-content/uploads/2015/02/Insight-Report-TC1a.pdf

[43] CLNR. Insight Report – Domestic Heat Pumps. 2015. Available at: http://www.networkrevolution.co.uk/wp-content/uploads/2015/01/CLNR-L091-Insight-Report-Domestic-Heat-Pumps.pdf

[44] CLNR. Insight Report – Domestic Solar PV Customers. 2015. Available at: http://www.networkrevolution.co.uk/wp-content/uploads/2015/01/CLNR-L090-Insight-Report-Domestic-Solar-PV.pdf

Manufacturing (UK) Ltd. These owners drove a Nissan Leaf as part of an employee lease car scheme, and had limited ability to charge the car at work.[45]

Commercial user groups

For our commercial user groups we have primarily relied on the **basic small and medium sized enterprise (TC1b)** dataset which contains half-hourly consumption readings for around 1,500 small commercial and business users spanning a period of one year from September 2011 to August 2012.

For the high consuming commercial user group connected at HV, we have provided for the possibility of the commercial user self-generating with solar PV/storage and have relied on learnings from TC5 with appropriate scaling of net consumption from the level of a typical domestic user to the consumption level of the high commercial user. This is because there was no separate test cell in the CLNR data studying the impact of solar PV/storage adoption for commercial users.

A.2 Definition of the domestic and commercial user groups

In this section we provide details of our analysis of the datasets described above, including any underlying assumptions, that has guided our determination of the key features of the domestic and commercial user groups set out in Figure 127.

[45] CLNR. Insight Report – Electric Vehicles. 2014. Available at: http://www.networkrevolution.co.uk/wp-content/uploads/2015/01/CLNR-L092-Electric-Vehicle-Insight-Report-RW.pdf

Figure 127 Key features of Domestic and Commercial user groups

User group	Voltage level	Connection capacity	Annual gross demand	Annual net demand	Annual 4-7 demand (Median)	Half-hourly peak demand (Median)
		(kVA)	(kWh)	(kWh)	(kWh)	(kWh)
Non-half-hourly metered (NHH)						
1. Domestic – Low consumption	LV	18	1,900	1,900	360	1.71
2. Domestic – Medium consumption	LV	18	3,100	3,100	597	2.29
3. Domestic – High consumption	LV	18	4,600	4,600	904	2.85
4. Domestic – High Economy 7	LV	18	7,100	7,100	1,345	3.41
5a. Domestic – Medium Solar PV	LV	18	3,100	2,204	362	2.29
5b. Domestic – Medium Solar PV with storage	LV	18	3,100	1,918	76	2.29
6. Domestic – Medium Electric vehicles	LV	18	4,622	4,622	682	3.71
7. Domestic – Heat pumps	LV	18	5,651	5,651	697	3.36
8. Commercial – Low consumption	LV	55	10,000	10,000	1,119	4.73
9. Commercial – High with onsite generation/storage	HV	55	25,000	15,470	615	6.61
10. Commercial – High without onsite generation/storage	HV	55	25,000	25,000	3,434	6.61
Half-hourly metered (HH)						
11. Commercial – Light industrial HV-connected	HV	2,000	5,000,000	5,000,000		285.39

Source: TDCV; Frontier analysis of CLNR data

Below we describe how we have derived the total annual and peak demand for each domestic and commercial user group.

Basic domestic users (Groups 1-4)

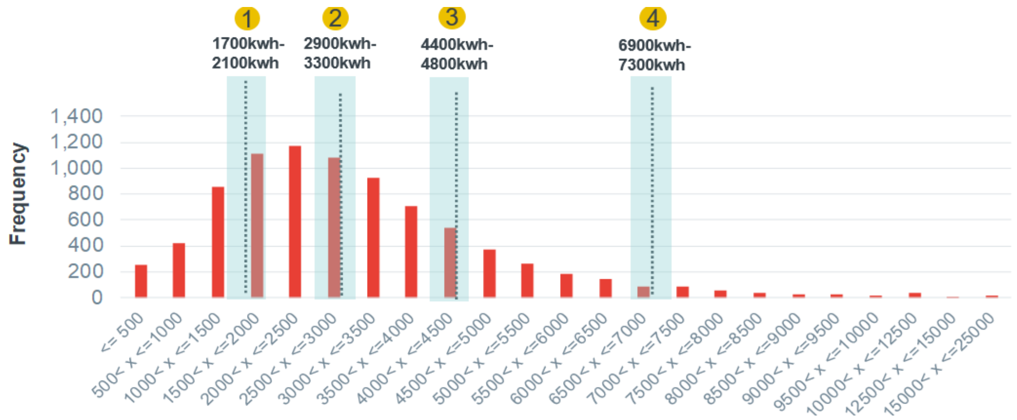
For the domestic user groups, we have adopted assumed connection capacities based on discussions with a number of DNOs. We assume a standard domestic connection size of 18kVA

TDCVs are considered a good proxy for the annual consumption levels for typical domestic GB consumers, and are commonly used for estimating domestic user bills. As such, we have defined the annual consumption levels of the first three domestic user groups – Groups 1, 2 and 3 in Figure 127 – in relation to the most recently available low (1,900 kWh), medium (3,100 kWh) and high (4,600 kWh) TDCVs for Profile Class 1, Domestic Unrestricted Customers (see Figure 126). As previously mentioned, these reflect the 25th, 50th, and 75th percentiles of GB annual household consumption, respectively, averaged over 2014 and 2015.

We observe that the low, medium and high TDCVs for Profile Class 1 users are broadly aligned to the first, second and third quartiles of annual consumption of consumers in the TC1a dataset.[46] Figure 128 provides the distribution of annual consumption for the consumers in the TC1a dataset. This is not altogether surprising given that the TC1a test cell was designed to be broadly representative of the UK population.[47]

Moreover, the tail-end of the distribution of annual consumption of TC1a consumers provides justification for having a domestic user group with ‘super high’ consumption. We defined this fourth user group relative to the TDCV of a high (75th percentile) Profile Class 2 or Economy 7 user having an annual consumption level of 7,100 kWh (see Figure 126).

Figure 128 Distribution of annual consumption for basic domestic customers in TC1a



Source: Frontier s analysis of CLNR data

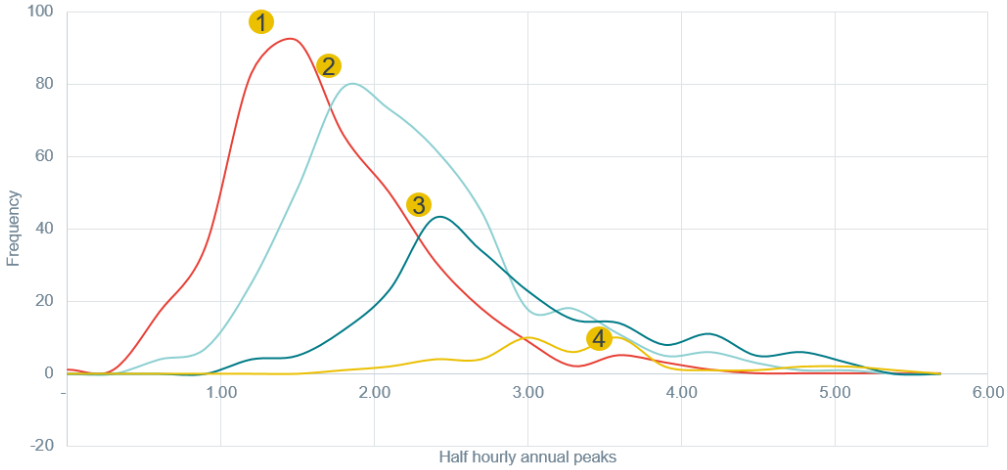
The impact of the changes to charging arrangements may also depend on the shape of consumption i.e. peak consumption. Therefore, we identified peak consumption levels relevant to each of the user groups using the CLNR dataset.

To do this, we first identified consumers from the CLNR basic domestic user (TC1a) dataset with similar levels of annual consumption to our user groups. We added +/- 200kWh (roughly 5% of the medium consumption level) to each of these four selected TDCVs to define annual consumption ‘bands’ for the first four user groups. These are shown in Figure 128. For TC1a consumers with annual consumption levels falling within these bands, we estimated the distribution of peak demand for each user group. Despite the fact that we defined our user groups narrowly (using +/- 200 kWh of TDCVs), we observe a wide distribution of annual peak demand within each group as illustrated in Figure 129.

[46] We note that a perfect match is unlikely given as the TDCVs we use have been calculated using 2014 and 2015 data, and the TC1a dataset covered consumption data over October 2012 and September 2013.

[47] “TC1a is used as the control group or starting point against which the other test cells can be compared. The demographic composition of the participants in this test cell is representative of the UK population.” CLNR. Insight Report – Baseline Domestic Profile. 2015. Available at: http://www.networkrevolution.co.uk/wp-content/uploads/2015/02/Insight-Report-TC1a.pdf

Figure 129 Distribution of annual half-hourly peak demand (kWh) for consumers within each user group (1-4)



Source: Frontier analysis of CLNR data

Based on Figure 129 we observe a high degree of variability in peak demand at each level of consumption. Moreover, annual peak demand generally increases as total electricity consumption increases (Group 1 has the lowest annual consumption and Group 4 the highest). However, across the four groups, there are large overlapping portions of the peak demand distributions. Figure 130 below provides the high, median, and low peak demand (defined in three different ways) for user groups (1-4), representing the third, second, and first quartiles of peak demand, respectively.

Figure 130 Distribution of domestic basic users' peak and (4-7 pm) total demand

User Group (annual consumption)	Distribution of highest half-hourly peak (kWh)			Distribution of total demand (4-7pm)		
	High	Median	Low	High	Median	Low
Group 1 (1,900)	2.15	1.71	1.35	409	360	314
Group 2 (3,100)	2.71	2.29	1.87	705	597	515
Group 3 (4,600)	3.55	2.85	2.44	1,038	904	807
Group 4 (7,100)	3.80	3.41	3.01	1,551	1,345	1,172

Source: Frontier analysis of CLNR data

We have adopted the median peak demand (highlighted in blue) for each user group in our static bills analysis.

Domestic users with Low Carbon Technologies (Groups 5-7)

User groups 5-7 illustrate the impact on the profile of the medium domestic consumer (Group 2 with annual consumption of 3,100kWh), of adopting certain low carbon technologies such as heat pumps, solar PV and electric vehicles. This approach allows us to compare the impacts of changing the residual charges for consumers that adopt these LCTs and those that do not.

To achieve this, we identify consumers in the appropriate CLNR datasets (TC3, TC5, TC6) that have annual household electricity consumption, excluding the impact of the LCT, as close as possible to 3,100 kWh. Based on these consumers we then identify the relevant estimate of net and gross annual and peak demand to observe the effect of adopting the LCTs on the level and pattern of electricity consumption.[48] We present a few key observations for each LCT below.

It is important to note that these profiles are meant to provide an illustration of the impact of LCTs on a user's profile, and hence provide an understanding of the 'directional' impact of the changes to the charges. However, the observed impact of adopting LCTs may vary significantly depending on several factors, including the type/size of LCT, and how it is used. In the observations provided below, we have not made attempts to control for these or other such factors.

Solar PV with/without storage (Groups 5a and 5b)

The CLNR test cell for **domestic consumers with solar PV (TC5)** contains electricity consumption meter readings for 143 households, as well as electricity generation readings for their respective solar PV cells. From this dataset, we explore the consumption patterns under two possible scenarios:

- *Solar PV without storage*: Here we assume that electricity generated by the solar PV offsets the user's electricity consumption in the hour it is produced. Any excess solar energy produced is exported.
- *Solar PV with storage*: Excess solar generation produced during mid-day (when solar generation is at its peak) can be stored and used during peak consumption periods between 4-7pm (when solar generation is relatively less). The optimal capacity of the storage unit is assumed to be at a level that allows the storage of maximum useful excess solar energy produced on a daily basis. We assume a storage efficiency of 90%, i.e. only 90% of solar generation stored can be consumed.[49]

Figure 131 shows the impact of installing solar PV on the profile of electricity consumption for a domestic consumer with medium annual consumption (i.e. 3,100 kWh). The output from the solar PV (red line) offsets some of the electricity consumption during the day (8am-6pm) and hence, on average, we see that the *net* consumption of a consumer with solar PV (green line) falls below the gross consumption of a medium domestic consumer (blue line) without solar PV.

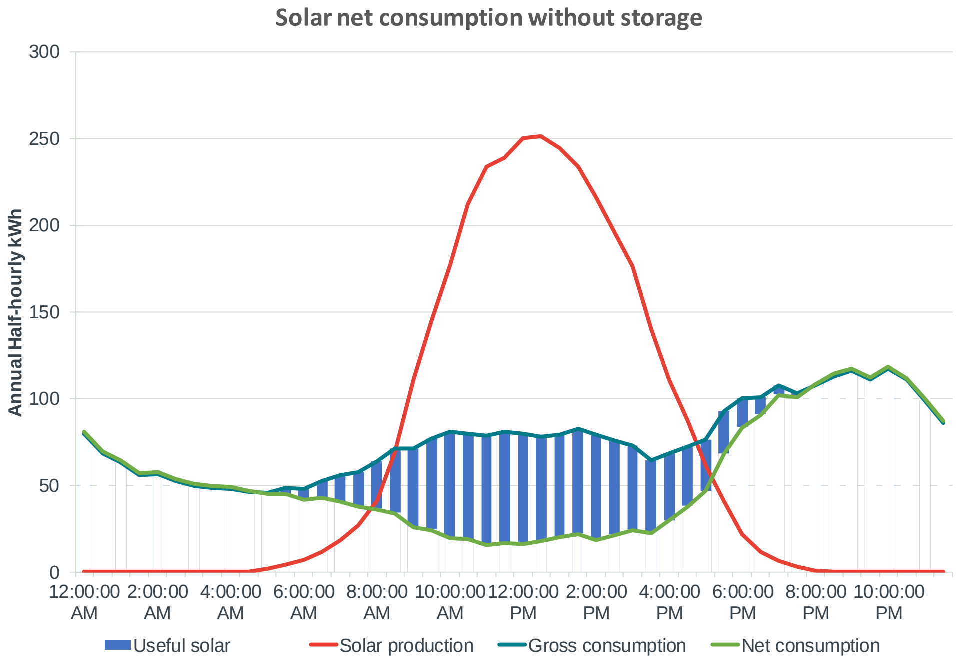
We note that for the specific consumer observed in the TC5 test cell, the annual average solar generation around noon is significantly higher than the consumer's demand for electricity at this time. If households have the ability to store this excess generation, they can use it to offset their electricity demand during the peak period (4-7pm).

[48] Where we cannot find an LCT consumer with exactly the same electricity consumption as the medium domestic user (3,100 kWh), we find the closest one and scale the gross consumption linearly.

[49] While this is guided by a consideration of domestic storage units currently on the market, we recognize that storage efficiency is likely to be quite different depending on the type of storage unit used.

Figure 131 shows the changes in the consumer's net consumption due to solar PV generation as the blue shaded area.

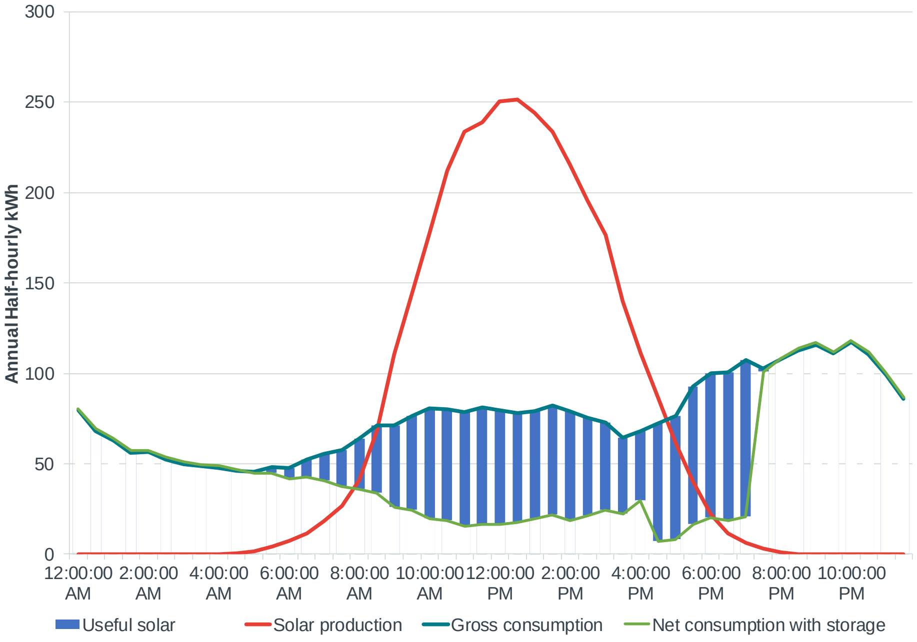
Figure 131 Impact of solar PV installation on consumption of medium domestic consumer (without storage)



Source: Frontier analysis of CLNR data

With the installation of a battery storage unit, a further reduction in net electricity consumption can be achieved as the stored excess solar generation can be utilised to reduce net electricity consumption over the 4-7 pm peak period. This is observed as the expansion of the blue shaded area over 4-7 pm in Figure 132. Based on the analysis of this consumer's profile we observe that over the course of a year 286kWh of excess solar capacity could be usefully stored and consumed, with a maximum daily amount usefully stored of 6.4kWh. Therefore, the appropriate size of a storage unit must be in excess of 6.4kWh.

Figure 132 Impact of solar PV installation on consumption of medium domestic consumer (with storage)



Source: Frontier analysis of CLNR data

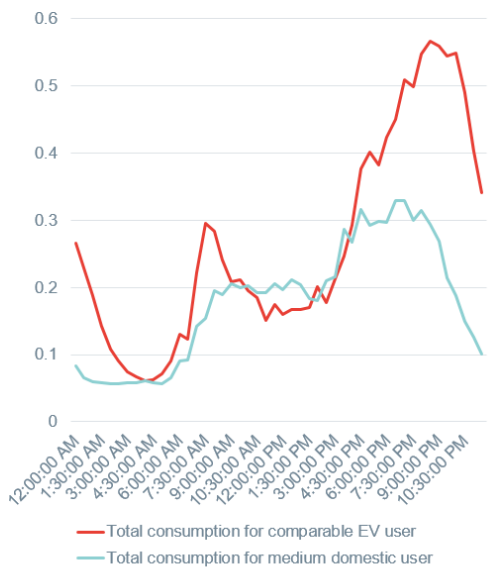
In summary, by choosing to self-generate using a solar PV (or another type of onsite generation) consumers can alter their reliance on the electricity grid. This is reflected in Figure 127 as lower annual net demand and 4-7 peak demand for Group 5a relative to the medium domestic user without solar PV (Group 2).

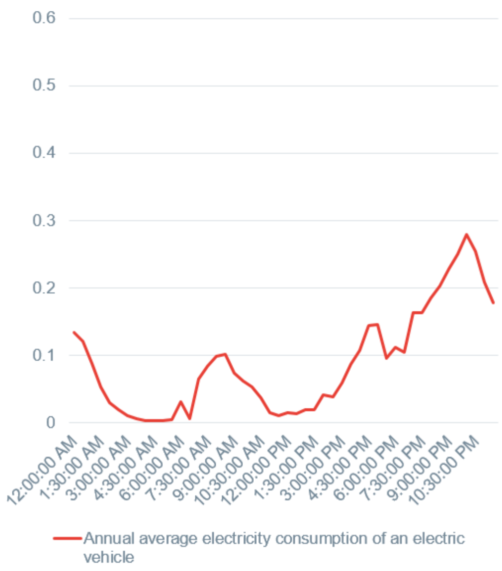
If the solar PV is coupled with a storage unit, consumers will be able to store any excess generation to reduce their consumption further, particularly over the 4-7 pm peak period with a view to lower their network charges. This is reflected as lower net annual and peak demand for Group 5b relative to Groups 2 and 5a.

Electric vehicles (Group 6)

The CLNR test cell for **domestic consumers with electric vehicles (TC6)** contains electricity consumption meter readings for 131 households with EV – a majority of the trial participants drove a Nissan Leaf. Figure 133 compares the consumption patterns of select domestic consumers with the medium annual consumption with (red line) and without (blue line) an EV.

Figure 133: Comparison of annual average consumption profile for homes with and without electric vehicles at medium consumption level (Left). Annual average electricity consumption profile of an electric vehicle (Right)





Source: Frontier analysis of CLNR data

For these consumers in the CLNR dataset, an EV increases the total annual electricity consumption of the domestic consumer by about 50%.[50] We also observe an increase in the consumer's consumption over the night (looking at the red line in Figure 133 relative to the blue) given as electric vehicles are typically charged overnight.

In summary, an EV can meaningfully alter both the level as well as the pattern or profile of a household's electricity consumption. This is reflected in Figure 127 as higher annual gross demand and peak demand for Group 6 relative to the medium basic domestic user (Group 2).

Electric heat pumps (Group 7)

Similar to EVs, electricity consumed by heat pumps represents a significant proportion of total household electricity consumption. In the CLNR test cell for **domestic consumers with heat-pumps (TC3)**, the annual electricity consumption for heat pumps is found to be on average 82% of the annual household consumption.[51] Looking specifically at the evening period during a winter month (January) when demand for electricity is likely to be the highest, the average electricity consumption of the heat pump is observed to be nearly 100% of the average household electricity consumption in TC1a (consumers without heat pumps). This implies that installing a heat pump may double the household

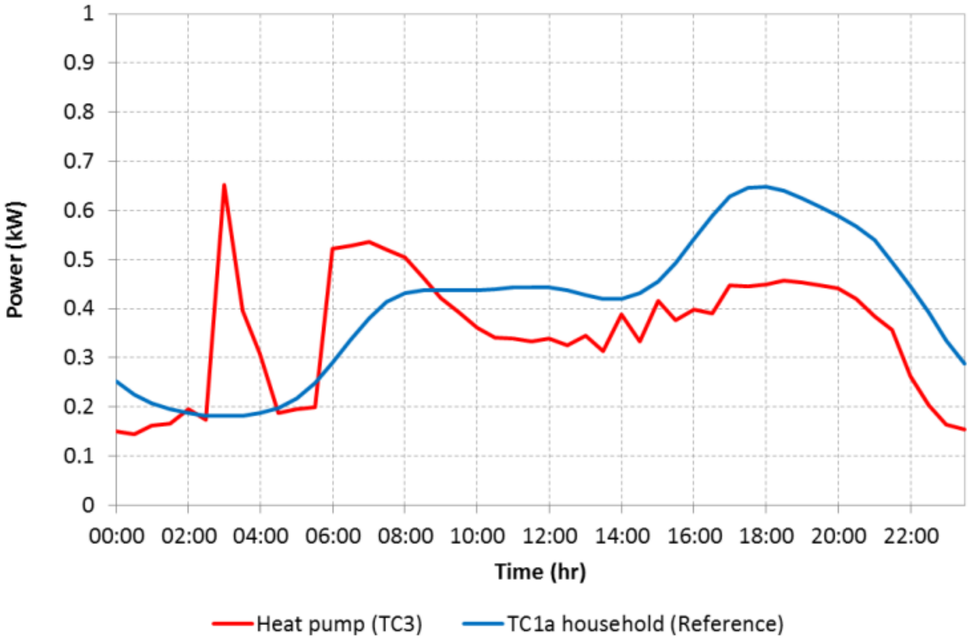
[50] We recognise that the exact impact will depending on the type of electric vehicle, but also whether the consumer charges the EV at home versus at work or a public charging station, among other factors.

[51] We recognise that the exact impact will depending on the type of electric heat pump, but also on the size of the house, the level of insulation and consumer's preference of room temperature levels, among other factors.

consumption at times when the electricity network is already likely to be experiencing high levels of demand.[52]

Moreover, we observe from Figure 134 that consumption of heat pumps (red line) shows a distinct peak in the early mornings (around 3 am) in addition to the typical morning and evening peak periods observed in domestic users' profile.

Figure 134 Annual daily load profile for the heat pump demand (red) and household demand (blue). Averaged across the year and across all customers for each test cell.



Source: CLNR. Insight Report – Domestic Heat Pumps. 2015.

Note: http://www.networkrevolution.co.uk/wp-content/uploads/2015/01/CLNR-L091-Insight-Report-Domestic-Heat-Pumps.pdf

In summary, an electric heat pump can meaningfully alter both the level as well as the pattern or profile of a household's electricity consumption. This is reflected in Figure 127 as higher annual gross demand and peak demand for Group 7 relative to the medium domestic user (Group 2).

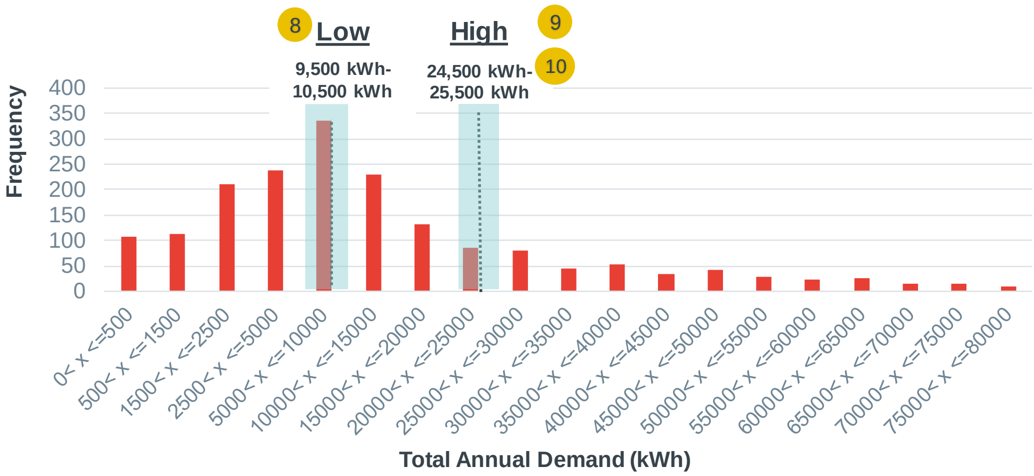
Commercial users (Group 8-11)

We defined our commercial user groups in relation to the CLNR basic small and medium sized enterprise (TC1b) dataset which contains half-hourly consumption readings for around 1,500 small commercial and business users spanning a period of one year from September 2011 to August 2012.

Figure 135 shows the distribution of annual consumption for commercial consumers in the CLNR TC1b dataset. We have identified low and high consumption commercial user groups guided by the median and 75th percentile of total annual consumption, respectively.

[52] CLNR. Insight Report – Domestic Heat Pumps. 2015. Available at: http://www.networkrevolution.co.uk/wp-content/uploads/2015/01/CLNR-L091-Insight-Report-Domestic-Heat-Pumps.pdf

Figure 135: Distribution of annual demand for commercial customers in CLNR dataset

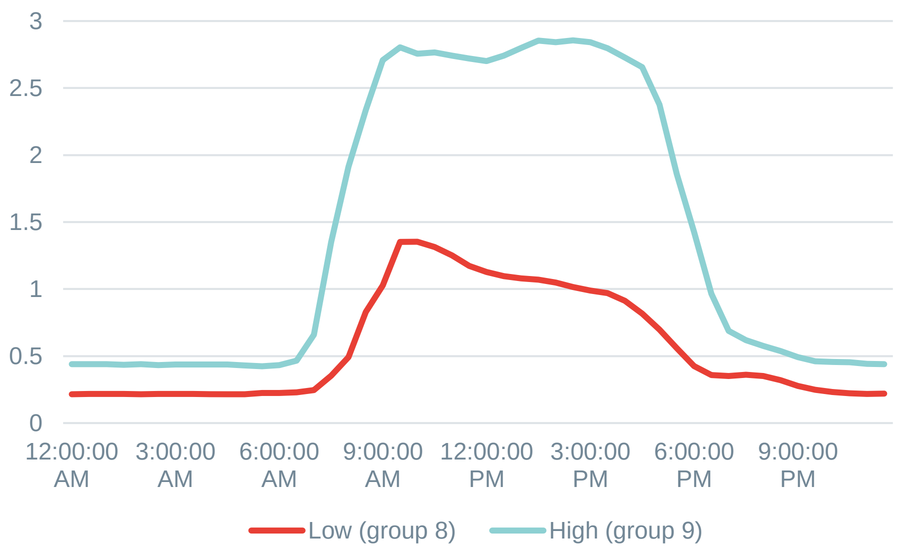


Source: Frontier analysis of CLNR data

To identify the "typical" shape of consumption we examine the distribution of peak demand for customers with annual consumption close to our user groups i.e. we added +/- 500kWh (roughly 5% of the low consumption level) to these annual consumption levels to define the annual consumption 'bands' for the two commercial user groups. These are shown in Figure 135.

We look at the "typical" shape of half-hourly consumption for these users for select low and high commercial users in Figure 136. It can be observed that both profiles show electricity being primarily consumed over the commercial operating hours of 6am to 6pm. The higher commercial user starts its operations earlier and consumes more than twice the amount of energy as the lower commercial user.

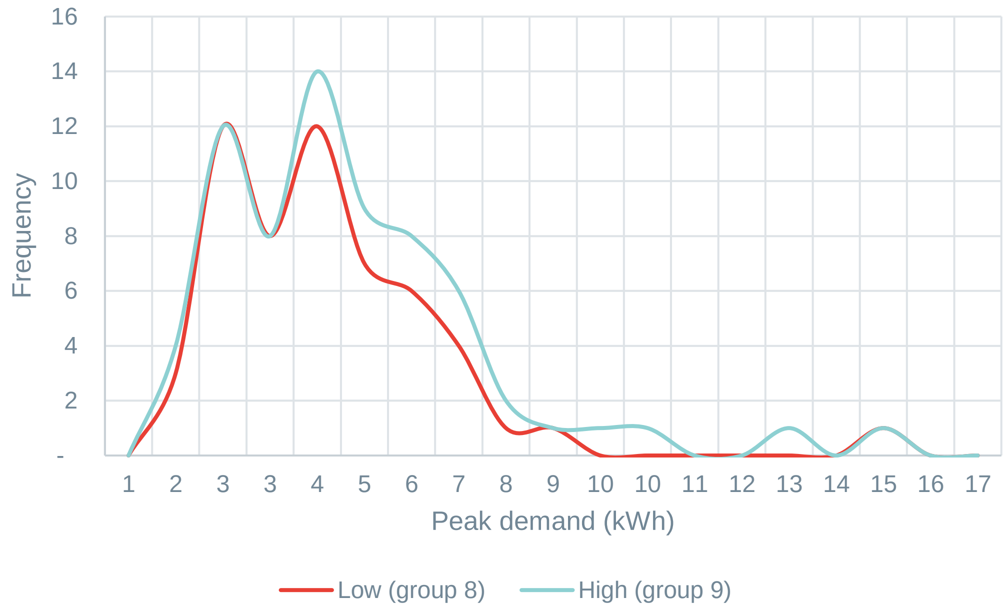
Figure 136 Average annual half hourly consumption profile for representative low and high commercial users



Source: Frontier analysis of CLNR data

For TC1b consumers with annual consumption levels falling within the bands identified in Figure 135, we next look at the distribution of peak demand for each user group. Similar to domestic users, despite the fact that we have defined our user groups narrowly, we observe a wide distribution of annual peak demand within each group as illustrated in Figure 137. As such, we rely on the observed median peak demand of these distributions (see Figure 127) in our static impact analysis.

Figure 137 Distribution of annual half-hourly peak demand (kWh) for consumers within each commercial user group (8 & 9)

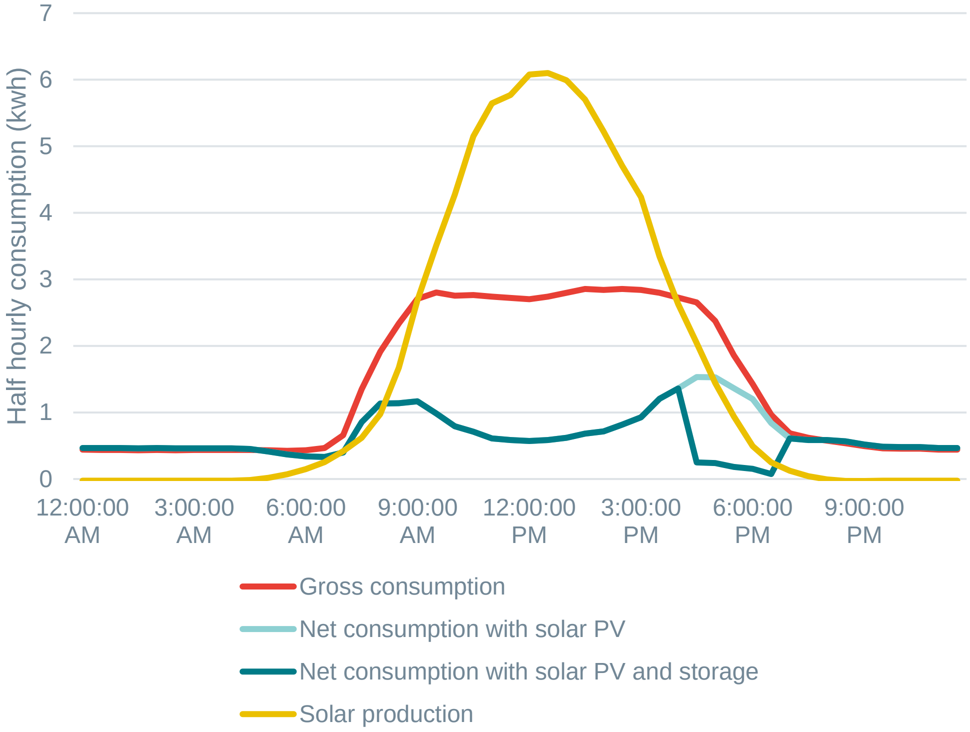


Source: Frontier analysis of CLNR data

For the high consumption group, we also model for the possibility of a commercial user offsetting and potentially shifting their consumption using solar PV and storage. Since there is no CLNR test cell for commercial users with solar PV and storage, we have scaled the gross and peak demand of the domestic user with solar PV and storage (Group 5b) from the TC5 dataset linearly by gross consumption.[53] Figure 138 illustrates the impact of installing solar PV and storage on a high commercial user's consumption profile.

[53] We scaled the domestic user's solar panel production profile linearly by the annual gross consumption to obtain this generation/storage curve. This is to simulate a likely commercial size solar/storage unit for a high consuming commercial user.

Figure 138 High usage commercial customer annual half hourly net consumption profile with storage unit



Source: Frontier analysis of CLNR data

Based on discussions with stakeholders we identified the need for a commercial user group with annual consumption in excess of 25,000 kWh connected at HV. This was because of the large gap between the consumption levels of 25,000kWh and 50,000 MWh which is the assumed consumption for our user group connected at EHV. We therefore defined a light industrial user group, that falls in between these two groups. We assume this user is half-hourly metered, connects at HV with annual consumption of 5,000MWh.

For this HH metered user, we have assumed a connection size of 2,000kVA which compares to a peak consumption of 571kW assuming a flat consumption profile for this user.

ANNEX B BILL IMPACT DATA FOR ALL DNOS

B.1 Fixed charges for all DNOs – EDCM and CDCM

Figure 139 EDCM fixed charges – all DNOs

DNO	EDCM fixed charge
Electricity North West	£77,435
Northeast	£47,186
Yorkshire	£37,207
Southern Scotland	£12,028
North Wales & Mersey	£74,881
Southern	£8,318
Scottish Hydro	£3,159
Eastern	£19,541
London	£39,884
South East	£29,152
East Midlands	£18,491
South Wales	£41,801
South West	£5,936
West Midlands	£18,973

Source: *Data from DNOs sourced from Ofgem*

Note: *EDCM fixed charges are likely to be an underestimate, since the charging base also includes generation specific sites which could not be separately identified from the dataset.*

Figure 140 CDCM fixed charges – all DNOs

	Electricity North West	North-east	York-shire	Southern Scotland	North Wales & Mersey	Southern	Scot-tish Hydro	Eastern	London	South East	East Midlands	South Wales	South West	West Midlands
Domestic Unrestricted	17.94	31.93	30.15	35.18	38.18	16.94	45.10	3.59	(13.18)	13.26	27.96	41.86	44.32	34.32
Domestic Two Rate	29.92	54.47	50.62	54.16	69.57	29.67	87.95	5.14	(13.91)	18.81	37.51	74.28	79.79	53.45
Domestic Off Peak (related MPAN)	19.21	42.79	33.28	37.30	45.06	21.45	71.89	1.82	(7.32)	11.69	15.78	35.12	44.77	25.35
Small Non Domestic Unrestricted	70.2	117.4	125.1	169.7	158.1	65.0	166.9	13.4	(50.7)	38.6	100.6	164.0	142.4	120.7
Small Non Domestic Two Rate	122.2	219.4	253.5	271.4	331.0	111.8	291.7	21.0	(74.2)	82.0	203.4	283.4	253.4	200.6
Small Non Domestic Off Peak (related MPAN)	31.82	79.49	75.81	134.31	59.20	34.02	136.85	11.20	(29.78)	28.28	42.63	72.05	78.00	66.87
LV Medium Non-Domestic	234	767	1,006	1,181	1,243	409	1,394	99	(443)	401	369	597	550	334
LV Sub Medium Non-Domestic	2,436	1,279	-	-	1,243	-	-	-	-	-	498	1,919	1,210	697
HV Medium Non-Domestic	9,231	2,177	1,650	2,035	1,243	596	7,860	-	-	-	658	348	753	857
LV Network Domestic	11.10	27.37	19.40	40.33	47.07	30.52	92.71	4.69	(10.46)	16.39	27.73	44.25	43.71	33.17
LV Network Non-Domestic Non-CT	347	464	588	771	697	342	1,150	79	(194)	309	576	976	963	626
LV HH Metered	1,047	2,115	1,911	3,096	2,269	1,276	3,118	260	(845)	1,132	1,876	3,216	2,243	1,761
LV Sub HH Metered	3,227	10,905	6,746	12,550	5,448	7,437	19,763	1,011	(1,453)	4,925	5,549	12,314	5,537	5,626
HV HH Metered	11,821	31,467	26,207	34,460	28,966	12,221	16,449	3,314	(5,709)	11,719	18,315	30,960	26,525	16,955

Source: Frontier Economics based on calculations using 2019/20 CDCM models for all DNOs

B.2 Annual residual bill under each charging option for all DNOs - CDCM

Figure 141 Electricity North West – CDCM annual residual bill under each charging option

User group	Baseline	Fixed	Gross volum-etric	Ex-ante capacity	Ex-post capacity	Fixed by volume	Fixed 75% and ex-post capacity 25%	Ex-ante deemed capacity for domestics	Ex-ante deemed capacity for domestics 75% and net volumetric 25%
Domestic - Low consumption	£10.92	£17.94	£10.38	£35.01	£26.12	£17.94	£19.98	£17.80	£16.08
Domestic - Medium consumption	£17.81	£17.94	£16.93	£35.01	£34.85	£17.94	£22.17	£17.80	£17.80
Domestic - High consumption	£26.43	£17.94	£25.12	£35.01	£43.48	£17.94	£24.32	£26.70	£26.63
Domestic - Economy 7 high	£40.79	£29.92	£38.78	£35.01	£52.03	£29.92	£35.45	£26.70	£30.22
Domestic - Solar PV	£12.66	£17.94	£16.93	£35.01	£34.85	£17.94	£22.17	£17.80	£16.52
Domestic - Solar PV with storage	£11.02	£17.94	£16.93	£35.01	£34.85	£17.94	£22.17	£17.80	£16.11
Domestic - Electric vehicles	£26.55	£17.94	£25.24	£35.01	£56.58	£17.94	£27.60	£35.60	£33.34
Domestic - Heat pumps	£32.47	£17.94	£30.86	£35.01	£51.24	£17.94	£26.26	£35.60	£34.82
SME - Low consumption	£57.45	£70.21	£54.62	£106.99	£72.16	£70.21	£70.70	£244.77	£197.94
SME - High with onsite generation/storage (1)	£88.87	£70.21	£136.54	£106.99	£100.85	£70.21	£77.87	£244.77	£205.79
SME - High without onsite generation/storage (1)	£143.63	£70.21	£136.54	£106.99	£100.85	£70.21	£77.87	£244.77	£219.48
SME - High with onsite generation/storage (2)	£88.87	£347.32	-	-	-	£347.32	-	-	-
SME - High without onsite generation/storage (2)	£143.63	£347.32	-	-	-	£347.32	-	-	-
SME - Light industrial HV-connected	£28,726	£11,821	£27,308	£3,891	£4,352	£11,821	£9,954	£8,901	£13,857

Source: Frontier Economics

Figure 142 Northeast – CDCM annual residual bill under each charging option

User group	Baseline	Fixed	Gross volum-etric	Ex-ante capacity	Ex-post capacity	Fixed by volume	Fixed 75% and ex-post capacity 25%	Ex-ante deemed capacity for domestics	Ex-ante deemed capacity for domestics 75% and net volumetric 25%
Domestic - Low consumption	£20.05	£31.93	£19.07	£61.80	£47.50	£31.93	£35.82	£31.30	£28.49
Domestic - Medium consumption	£32.72	£31.93	£31.11	£61.80	£63.38	£31.93	£39.79	£31.30	£31.65
Domestic - High consumption	£48.55	£31.93	£46.17	£61.80	£79.08	£31.93	£43.72	£46.95	£47.35
Domestic - Economy 7 high	£74.94	£54.47	£71.26	£61.80	£94.63	£54.47	£64.51	£46.95	£53.95
Domestic - Solar PV	£23.26	£31.93	£31.11	£61.80	£63.38	£31.93	£39.79	£31.30	£29.29
Domestic - Solar PV with storage	£20.24	£31.93	£31.11	£61.80	£63.38	£31.93	£39.79	£31.30	£28.54
Domestic - Electric vehicles	£48.78	£31.93	£46.39	£61.80	£102.91	£31.93	£49.68	£62.60	£59.15
Domestic - Heat pumps	£59.65	£31.93	£56.72	£61.80	£93.20	£31.93	£47.25	£62.60	£61.86
SME - Low consumption	£105.55	£117.41	£100.37	£188.82	£131.25	£117.41	£120.87	£430.37	£349.16
SME - High with onsite generation/storage (1)	£163.28	£117.41	£250.93	£188.82	£183.44	£117.41	£133.92	£430.37	£363.60
SME - High without onsite generation/storage (1)	£263.87	£117.41	£250.93	£188.82	£183.44	£117.41	£133.92	£430.37	£388.74
SME - High with onsite generation/storage (2)	£163.28	£464.28				£464.28			
SME - High without onsite generation/storage (2)	£263.87	£464.28				£464.28			
SME - Light industrial HV-connected	£52,774	£31,467	£50,185	£6,866	£7,916	£31,467	£25,579	£15,650	£24,931

Source: Frontier Economics

Figure 143 Yorkshire – CDCM annual residual bill under each charging option

User group	Baseline	Fixed	Gross volum-etric	Ex-ante capacity	Ex-post capacity	Fixed by volume	Fixed 75% and ex-post capacity 25%	Ex-ante deemed capacity for domestics	Ex-ante deemed capacity for domestics 75% and net volumetric 25%
Domestic - Low consumption	£18.27	£30.15	£17.38	£61.03	£44.74	£30.15	£33.80	£31.04	£27.85
Domestic - Medium consumption	£29.81	£30.15	£28.35	£61.03	£59.70	£30.15	£37.54	£31.04	£30.73
Domestic - High consumption	£44.23	£30.15	£42.07	£61.03	£74.49	£30.15	£41.23	£46.56	£45.98
Domestic - Economy 7 high	£68.26	£50.62	£64.93	£61.03	£89.13	£50.62	£60.25	£46.56	£51.99
Domestic - Solar PV	£21.19	£30.15	£28.35	£61.03	£59.70	£30.15	£37.54	£31.04	£28.58
Domestic - Solar PV with storage	£18.44	£30.15	£28.35	£61.03	£59.70	£30.15	£37.54	£31.04	£27.89
Domestic - Electric vehicles	£44.44	£30.15	£42.27	£61.03	£96.93	£30.15	£46.85	£62.08	£57.67
Domestic - Heat pumps	£54.33	£30.15	£51.68	£61.03	£87.79	£30.15	£44.56	£62.08	£60.14
SME - Low consumption	£96.15	£125.10	£91.46	£186.48	£123.62	£125.10	£124.73	£426.79	£344.13
SME - High with onsite generation/storage (1)	£148.73	£125.10	£228.64	£186.48	£172.78	£125.10	£137.02	£426.79	£357.28
SME - High without onsite generation/storage (1)	£240.36	£125.10	£228.64	£186.48	£172.78	£125.10	£137.02	£426.79	£380.19
SME - High with onsite generation/storage (2)	£148.73	£587.95				£587.95			
SME - High without onsite generation/storage (2)	£240.36	£587.95				£587.95			
SME - Light industrial HV-connected	£48,073	£26,207	£45,728	£6,781	£7,457	£26,207	£21,519	£15,520	£23,658

Source: Frontier Economics

Figure 144 Southern Scotland – CDCM annual residual bill under each charging option

User group	Baseline	Fixed	Gross volum-etric	Ex-ante capacity	Ex-post capacity	Fixed by volume	Fixed 75% and ex-post capacity 25%	Ex-ante deemed capacity for domestics	Ex-ante deemed capacity for domestics 75% and net volumetric 25%
Domestic - Low consumption	£22.44	£35.18	£21.25	£70.23	£53.59	£35.18	£39.79	£36.74	£33.17
Domestic - Medium consumption	£36.62	£35.18	£34.67	£70.23	£71.51	£35.18	£44.26	£36.74	£36.71
Domestic - High consumption	£54.34	£35.18	£51.44	£70.23	£89.22	£35.18	£48.69	£55.12	£54.92
Domestic - Economy 7 high	£83.87	£54.16	£79.40	£70.23	£106.76	£54.16	£67.31	£55.12	£62.30
Domestic - Solar PV	£26.03	£35.18	£34.67	£70.23	£71.51	£35.18	£44.26	£36.74	£34.07
Domestic - Solar PV with storage	£22.66	£35.18	£34.67	£70.23	£71.51	£35.18	£44.26	£36.74	£33.22
Domestic - Electric vehicles	£54.60	£35.18	£51.69	£70.23	£116.10	£35.18	£55.41	£73.49	£68.77
Domestic - Heat pumps	£66.75	£35.18	£63.19	£70.23	£105.15	£35.18	£52.67	£73.49	£71.80
SME - Low consumption	£118.12	£169.70	£111.83	£214.59	£148.07	£169.70	£164.29	£505.23	£408.46
SME - High with onsite generation/storage (1)	£182.73	£169.70	£279.57	£214.59	£206.95	£169.70	£179.01	£505.23	£424.61
SME - High without onsite generation/storage (1)	£295.31	£169.70	£279.57	£214.59	£206.95	£169.70	£179.01	£505.23	£452.75
SME - High with onsite generation/storage (2)	£182.73	£771.38				£771.38			
SME - High without onsite generation/storage (2)	£295.31	£771.38				£771.38			
SME - Light industrial HV-connected	£59,061	£34,460	£55,914	£7,803	£8,931	£34,460	£28,078	£18,372	£28,544

Source: Frontier Economics

Figure 145 North Wales & Mersey – CDCM annual residual bill under each charging option

User group	Baseline	Fixed	Gross volum-etric	Ex-ante capacity	Ex-post capacity	Fixed by volume	Fixed 75% and ex-post capacity 25%	Ex-ante deemed capacity for domestics	Ex-ante deemed capacity for domestics 75% and net volumetric 25%
Domestic - Low consumption	£23.61	£38.18	£22.48	£70.71	£53.98	£38.18	£42.13	£36.73	£33.45
Domestic - Medium consumption	£38.53	£38.18	£36.69	£70.71	£72.02	£38.18	£46.64	£36.73	£37.18
Domestic - High consumption	£57.17	£38.18	£54.44	£70.71	£89.86	£38.18	£51.10	£55.09	£55.61
Domestic - Economy 7 high	£88.24	£69.57	£84.02	£70.71	£107.53	£69.57	£79.06	£55.09	£63.38
Domestic - Solar PV	£27.39	£38.18	£36.69	£70.71	£72.02	£38.18	£46.64	£36.73	£34.40
Domestic - Solar PV with storage	£23.84	£38.18	£36.69	£70.71	£72.02	£38.18	£46.64	£36.73	£33.51
Domestic - Electric vehicles	£57.44	£38.18	£54.70	£70.71	£116.94	£38.18	£57.87	£73.46	£69.46
Domestic - Heat pumps	£70.23	£38.18	£66.87	£70.71	£105.91	£38.18	£55.11	£73.46	£72.65
SME - Low consumption	£124.28	£158.09	£118.34	£216.07	£149.13	£158.09	£155.85	£505.03	£409.84
SME - High with onsite generation/storage (1)	£192.26	£158.09	£295.85	£216.07	£208.44	£158.09	£170.68	£505.03	£426.84
SME - High without onsite generation/storage (1)	£310.71	£158.09	£295.85	£216.07	£208.44	£158.09	£170.68	£505.03	£456.45
SME - High with onsite generation/storage (2)	£192.26	£697.08				£697.08			
SME - High without onsite generation/storage (2)	£310.71	£697.08				£697.08			
SME - Light industrial HV-connected	£62,142	£28,966	£59,169	£7,857	£8,995	£28,966	£23,973	£18,365	£29,309

Source: Frontier Economics

Figure 146 Southern – CDCM annual residual bill under each charging option

User group	Baseline	Fixed	Gross volum-etric	Ex-ante capacity	Ex-post capacity	Fixed by volume	Fixed 75% and ex-post capacity 25%	Ex-ante deemed capacity for domestics	Ex-ante deemed capacity for domestics 75% and net volumetric 25%
Domestic - Low consumption	£8.92	£16.94	£8.54	£31.26	£21.03	£16.94	£17.96	£15.35	£13.74
Domestic - Medium consumption	£14.55	£16.94	£13.93	£31.26	£28.06	£16.94	£19.72	£15.35	£15.15
Domestic - High consumption	£21.59	£16.94	£20.67	£31.26	£35.01	£16.94	£21.46	£23.03	£22.67
Domestic - Economy 7 high	£33.32	£29.67	£31.91	£31.26	£41.89	£29.67	£32.72	£23.03	£25.60
Domestic - Solar PV	£10.34	£16.94	£13.93	£31.26	£28.06	£16.94	£19.72	£15.35	£14.10
Domestic - Solar PV with storage	£9.00	£16.94	£13.93	£31.26	£28.06	£16.94	£19.72	£15.35	£13.76
Domestic - Electric vehicles	£21.69	£16.94	£20.77	£31.26	£45.55	£16.94	£24.09	£30.71	£28.45
Domestic - Heat pumps	£26.52	£16.94	£25.39	£31.26	£41.26	£16.94	£23.02	£30.71	£29.66
SME - Low consumption	£46.93	£65.02	£44.94	£95.50	£58.09	£65.02	£63.29	£211.10	£170.06
SME - High with onsite generation/storage (1)	£72.60	£65.02	£112.35	£95.50	£81.20	£65.02	£69.06	£211.10	£176.47
SME - High without onsite generation/storage (1)	£117.33	£65.02	£112.35	£95.50	£81.20	£65.02	£69.06	£211.10	£187.65
SME - High with onsite generation/storage (2)	£72.60	£342.48				£342.48			
SME - High without onsite generation/storage (2)	£117.33	£342.48				£342.48			
SME - Light industrial HV-connected	£23,465	£12,221	£22,469	£3,473	£3,504	£12,221	£10,041	£7,676	£11,624

Source: Frontier Economics

Figure 147 Scottish Hydro – CDCM annual residual bill under each charging option

User group	Baseline	Fixed	Gross volum-etric	Ex-ante capacity	Ex-post capacity	Fixed by volume	Fixed 75% and ex-post capacity 25%	Ex-ante deemed capacity for domestics	Ex-ante deemed capacity for domestics 75% and net volumetric 25%
Domestic - Low consumption	£24.45	£45.10	£23.47	£82.23	£55.55	£45.10	£47.71	£39.11	£35.45
Domestic - Medium consumption	£39.90	£45.10	£38.29	£82.23	£74.13	£45.10	£52.36	£39.11	£39.31
Domestic - High consumption	£59.21	£45.10	£56.82	£82.23	£92.49	£45.10	£56.95	£58.67	£58.81
Domestic - Economy 7 high	£91.38	£87.95	£87.70	£82.23	£110.67	£87.95	£93.63	£58.67	£66.85
Domestic - Solar PV	£28.37	£45.10	£38.29	£82.23	£74.13	£45.10	£52.36	£39.11	£36.43
Domestic - Solar PV with storage	£24.69	£45.10	£38.29	£82.23	£74.13	£45.10	£52.36	£39.11	£35.51
Domestic - Electric vehicles	£59.49	£45.10	£57.09	£82.23	£120.35	£45.10	£63.91	£78.23	£73.54
Domestic - Heat pumps	£72.73	£45.10	£69.80	£82.23	£109.00	£45.10	£61.08	£78.23	£76.86
SME - Low consumption	£128.71	£166.91	£123.52	£251.26	£153.49	£166.91	£163.56	£537.83	£435.55
SME - High with onsite generation/storage (1)	£199.10	£166.91	£308.80	£251.26	£214.53	£166.91	£178.82	£537.83	£453.15
SME - High without onsite generation/storage (1)	£321.77	£166.91	£308.80	£251.26	£214.53	£166.91	£178.82	£537.83	£483.81
SME - High with onsite generation/storage (2)	£199.10	£1,150.13				£1,150.13			
SME - High without onsite generation/storage (2)	£321.77	£1,150.13				£1,150.13			
SME - Light industrial HV-connected	£64,354	£16,449	£61,759	£9,137	£9,258	£16,449	£14,651	£19,557	£30,756

Source: Frontier Economics

Figure 148 Eastern – CDCM annual residual bill under each charging option

User group	Baseline	Fixed	Gross volum-etric	Ex-ante capacity	Ex-post capacity	Fixed by volume	Fixed 75% and ex-post capacity 25%	Ex-ante deemed capacity for domestics	Ex-ante deemed capacity for domestics 75% and net volumetric 25%
Domestic - Low consumption	£2.00	£3.59	£1.91	£6.70	£4.87	£3.59	£3.91	£3.39	£3.04
Domestic - Medium consumption	£3.26	£3.59	£3.11	£6.70	£6.49	£3.59	£4.32	£3.39	£3.36
Domestic - High consumption	£4.83	£3.59	£4.62	£6.70	£8.10	£3.59	£4.72	£5.09	£5.02
Domestic - Economy 7 high	£7.46	£5.14	£7.13	£6.70	£9.69	£5.14	£6.28	£5.09	£5.68
Domestic - Solar PV	£2.32	£3.59	£3.11	£6.70	£6.49	£3.59	£4.32	£3.39	£3.12
Domestic - Solar PV with storage	£2.02	£3.59	£3.11	£6.70	£6.49	£3.59	£4.32	£3.39	£3.05
Domestic - Electric vehicles	£4.86	£3.59	£4.64	£6.70	£10.54	£3.59	£5.33	£6.78	£6.30
Domestic - Heat pumps	£5.94	£3.59	£5.68	£6.70	£9.55	£3.59	£5.08	£6.78	£6.57
SME - Low consumption	£10.51	£13.44	£10.04	£20.47	£13.44	£13.44	£13.44	£46.63	£37.60
SME - High with onsite generation/storage (1)	£16.26	£13.44	£25.11	£20.47	£18.79	£13.44	£14.78	£46.63	£39.04
SME - High without onsite generation/storage (1)	£26.27	£13.44	£25.11	£20.47	£18.79	£13.44	£14.78	£46.63	£41.54
SME - High with onsite generation/storage (2)	£16.26	£79.49				£79.49			
SME - High without onsite generation/storage (2)	£26.27	£79.49				£79.49			
SME - Light industrial HV-connected	£5,255	£3,314	£5,021	£744	£811	£3,314	£2,688	£1,696	£2,585

Source: Frontier Economics

Figure 149 London – CDCM annual residual bill under each charging option

User group	Baseline	Fixed	Gross volum-etric	Ex-ante capacity	Ex-post capacity	Fixed by volume	Fixed 75% and ex-post capacity 25%	Ex-ante deemed capacity for domestics	Ex-ante deemed capacity for domestics 75% and net volumetric 25%
Domestic - Low consumption	-£8.28	-£13.18	-£5.13	-£19.70	-£15.03	-£13.18	-£13.64	-£8.44	-£8.40
Domestic - Medium consumption	-£13.51	-£13.18	-£8.37	-£19.70	-£20.05	-£13.18	-£14.90	-£8.44	-£9.71
Domestic - High consumption	-£20.05	-£13.18	-£12.42	-£19.70	-£25.02	-£13.18	-£16.14	-£12.67	-£14.51
Domestic - Economy 7 high	-£30.95	-£13.91	-£19.18	-£19.70	-£29.94	-£13.91	-£17.92	-£12.67	-£17.24
Domestic - Solar PV	-£9.61	-£13.18	-£8.37	-£19.70	-£20.05	-£13.18	-£14.90	-£8.44	-£8.74
Domestic - Solar PV with storage	-£8.36	-£13.18	-£8.37	-£19.70	-£20.05	-£13.18	-£14.90	-£8.44	-£8.42
Domestic - Electric vehicles	-£20.15	-£13.18	-£12.48	-£19.70	-£32.56	-£13.18	-£18.03	-£16.89	-£17.70
Domestic - Heat pumps	-£24.64	-£13.18	-£15.26	-£19.70	-£29.49	-£13.18	-£17.26	-£16.89	-£18.82
SME - Low consumption	-£43.59	-£50.66	-£27.01	-£60.21	-£41.52	-£50.66	-£48.37	-£116.11	-£97.98
SME - High with onsite generation/storage (1)	-£67.44	-£50.66	-£67.52	-£60.21	-£58.04	-£50.66	-£52.50	-£116.11	-£103.94
SME - High without onsite generation/storage (1)	-£108.99	-£50.66	-£67.52	-£60.21	-£58.04	-£50.66	-£52.50	-£116.11	-£114.33
SME - High with onsite generation/storage (2)	-£67.44	-£193.55				-£193.55			
SME - High without onsite generation/storage (2)	-£108.99	-£193.55				-£193.55			
SME - Light industrial HV-connected	-£21,797	-£5,709	-£13,505	-£2,189	-£2,505	-£5,709	-£4,908	-£4,222	-£8,616

Source: Frontier Economics

Figure 150 South East – CDCM annual residual bill under each charging option

User group	Baseline	Fixed	Gross volum-etric	Ex-ante capacity	Ex-post capacity	Fixed by volume	Fixed 75% and ex-post capacity 25%	Ex-ante deemed capacity for domestics	Ex-ante deemed capacity for domestics 75% and net volumetric 25%
Domestic - Low consumption	£7.37	£13.26	£7.05	£22.85	£16.95	£13.26	£14.18	£11.56	£10.51
Domestic - Medium consumption	£12.03	£13.26	£11.50	£22.85	£22.61	£13.26	£15.60	£11.56	£11.68
Domestic - High consumption	£17.85	£13.26	£17.07	£22.85	£28.22	£13.26	£17.00	£17.34	£17.46
Domestic - Economy 7 high	£27.55	£18.81	£26.34	£22.85	£33.76	£18.81	£22.55	£17.34	£19.89
Domestic - Solar PV	£8.55	£13.26	£11.50	£22.85	£22.61	£13.26	£15.60	£11.56	£10.81
Domestic - Solar PV with storage	£7.44	£13.26	£11.50	£22.85	£22.61	£13.26	£15.60	£11.56	£10.53
Domestic - Electric vehicles	£17.93	£13.26	£17.15	£22.85	£36.72	£13.26	£19.12	£23.12	£21.82
Domestic - Heat pumps	£21.93	£13.26	£20.97	£22.85	£33.25	£13.26	£18.26	£23.12	£22.82
SME - Low consumption	£38.80	£38.64	£37.10	£69.83	£46.83	£38.64	£40.68	£158.92	£128.89
SME - High with onsite generation/storage (1)	£60.02	£38.64	£92.76	£69.83	£65.45	£38.64	£45.34	£158.92	£134.20
SME - High without onsite generation/storage (1)	£97.00	£38.64	£92.76	£69.83	£65.45	£38.64	£45.34	£158.92	£143.44
SME - High with onsite generation/storage (2)	£60.02	£308.71				£308.71			
SME - High without onsite generation/storage (2)	£97.00	£308.71				£308.71			
SME - Light industrial HV-connected	£19,400	£11,719	£18,552	£2,539	£2,825	£11,719	£9,496	£5,779	£9,184

Source: Frontier Economics

Figure 151 East Midlands – CDCM annual residual bill under each charging option

User group	Baseline	Fixed	Gross volum-etric	Ex-ante capacity	Ex-post capacity	Fixed by volume	Fixed 75% and ex-post capacity 25%	Ex-ante deemed capacity for domestics	Ex-ante deemed capacity for domestics 75% and net volumetric 25%
Domestic - Low consumption	£16.21	£27.96	£15.45	£60.00	£43.84	£27.96	£31.93	£30.11	£26.63
Domestic - Medium consumption	£26.45	£27.96	£25.20	£60.00	£58.50	£27.96	£35.60	£30.11	£29.19
Domestic - High consumption	£39.25	£27.96	£37.40	£60.00	£72.99	£27.96	£39.22	£45.16	£43.68
Domestic - Economy 7 high	£60.57	£37.51	£57.72	£60.00	£87.33	£37.51	£49.97	£45.16	£49.02
Domestic - Solar PV	£18.80	£27.96	£25.20	£60.00	£58.50	£27.96	£35.60	£30.11	£27.28
Domestic - Solar PV with storage	£16.36	£27.96	£25.20	£60.00	£58.50	£27.96	£35.60	£30.11	£26.67
Domestic - Electric vehicles	£39.43	£27.96	£37.57	£60.00	£94.98	£27.96	£44.72	£60.22	£55.02
Domestic - Heat pumps	£48.21	£27.96	£45.94	£60.00	£86.02	£27.96	£42.48	£60.22	£57.21
SME - Low consumption	£85.32	£100.60	£81.29	£183.32	£121.13	£100.60	£105.73	£413.98	£331.82
SME - High with onsite generation/storage (1)	£131.98	£100.60	£203.23	£183.32	£169.29	£100.60	£117.77	£413.98	£343.48
SME - High without onsite generation/storage (1)	£213.29	£100.60	£203.23	£183.32	£169.29	£100.60	£117.77	£413.98	£363.81
SME - High with onsite generation/storage (2)	£131.98	£575.87				£575.87			
SME - High without onsite generation/storage (2)	£213.29	£575.87				£575.87			
SME - Light industrial HV-connected	£42,658	£18,315	£40,647	£6,666	£7,306	£18,315	£15,563	£15,054	£21,955

Source: Frontier Economics

Figure 152 South Wales – CDCM annual residual bill under each charging option

User group	Baseline	Fixed	Gross volum-etric	Ex-ante capacity	Ex-post capacity	Fixed by volume	Fixed 75% and ex-post capacity 25%	Ex-ante deemed capacity for domestics	Ex-ante deemed capacity for domestics 75% and net volumetric 25%
Domestic - Low consumption	£25.52	£41.86	£24.32	£78.66	£59.70	£41.86	£46.32	£40.17	£36.51
Domestic - Medium consumption	£41.63	£41.86	£39.68	£78.66	£79.66	£41.86	£51.31	£40.17	£40.54
Domestic - High consumption	£61.77	£41.86	£58.89	£78.66	£99.40	£41.86	£56.24	£60.26	£60.64
Domestic - Economy 7 high	£95.35	£74.28	£90.89	£78.66	£118.94	£74.28	£85.44	£60.26	£69.03
Domestic - Solar PV	£29.60	£41.86	£39.68	£78.66	£79.66	£41.86	£51.31	£40.17	£37.53
Domestic - Solar PV with storage	£25.76	£41.86	£39.68	£78.66	£79.66	£41.86	£51.31	£40.17	£36.57
Domestic - Electric vehicles	£62.07	£41.86	£59.17	£78.66	£129.34	£41.86	£63.73	£80.34	£75.78
Domestic - Heat pumps	£75.89	£41.86	£72.34	£78.66	£117.14	£41.86	£60.68	£80.34	£79.23
SME - Low consumption	£134.29	£163.97	£128.01	£240.35	£164.96	£163.97	£164.22	£552.36	£447.84
SME - High with onsite generation/storage (1)	£207.75	£163.97	£320.04	£240.35	£230.55	£163.97	£180.62	£552.36	£466.21
SME - High without onsite generation/storage (1)	£335.73	£163.97	£320.04	£240.35	£230.55	£163.97	£180.62	£552.36	£498.20
SME - High with onsite generation/storage (2)	£207.75	£976.27				£976.27			
SME - High without onsite generation/storage (2)	£335.73	£976.27				£976.27			
SME - Light industrial HV-connected	£67,146	£30,960	£64,007	£8,740	£9,950	£30,960	£25,707	£20,086	£31,851

Source: Frontier Economics

Figure 153 South West – CDCM annual residual bill under each charging option

User group	Baseline	Fixed	Gross volum-etric	Ex-ante capacity	Ex-post capacity	Fixed by volume	Fixed 75% and ex-post capacity 25%	Ex-ante deemed capacity for domestics	Ex-ante deemed capacity for domestics 75% and net volumetric 25%
Domestic - Low consumption	£25.07	£44.32	£23.91	£78.66	£58.09	£44.32	£47.76	£37.77	£34.60
Domestic - Medium consumption	£40.91	£44.32	£39.01	£78.66	£77.51	£44.32	£52.62	£37.77	£38.55
Domestic - High consumption	£60.70	£44.32	£57.88	£78.66	£96.71	£44.32	£57.42	£56.66	£57.67
Domestic - Economy 7 high	£93.69	£79.79	£89.34	£78.66	£115.73	£79.79	£88.78	£56.66	£65.91
Domestic - Solar PV	£29.08	£44.32	£39.01	£78.66	£77.51	£44.32	£52.62	£37.77	£35.60
Domestic - Solar PV with storage	£25.31	£44.32	£39.01	£78.66	£77.51	£44.32	£52.62	£37.77	£34.65
Domestic - Electric vehicles	£60.99	£44.32	£58.16	£78.66	£125.85	£44.32	£64.70	£75.54	£71.90
Domestic - Heat pumps	£74.57	£44.32	£71.10	£78.66	£113.98	£44.32	£61.74	£75.54	£75.30
SME - Low consumption	£131.95	£142.39	£125.82	£240.35	£160.51	£142.39	£146.92	£519.34	£422.49
SME - High with onsite generation/storage (1)	£204.13	£142.39	£314.56	£240.35	£224.33	£142.39	£162.88	£519.34	£440.54
SME - High without onsite generation/storage (1)	£329.88	£142.39	£314.56	£240.35	£224.33	£142.39	£162.88	£519.34	£471.98
SME - High with onsite generation/storage (2)	£204.13	£963.15				£963.15			
SME - High without onsite generation/storage (2)	£329.88	£963.15				£963.15			
SME - Light industrial HV-connected	£65,977	£26,525	£62,912	£8,740	£9,681	£26,525	£22,314	£18,885	£30,658

Source: Frontier Economics

Figure 154 West Midlands – CDCM annual residual bill under each charging option

User group	Baseline	Fixed	Gross volum-etric	Ex-ante capacity	Ex-post capacity	Fixed by volume	Fixed 75% and ex-post capacity 25%	Ex-ante deemed capacity for domestics	Ex-ante deemed capacity for domestics 75% and net volumetric 25%
Domestic - Low consumption	£19.13	£34.32	£18.20	£69.06	£47.69	£34.32	£37.66	£33.96	£30.25
Domestic - Medium consumption	£31.21	£34.32	£29.70	£69.06	£63.63	£34.32	£41.65	£33.96	£33.27
Domestic - High consumption	£46.32	£34.32	£44.07	£69.06	£79.39	£34.32	£45.59	£50.93	£49.78
Domestic - Economy 7 high	£71.49	£53.45	£68.02	£69.06	£94.99	£53.45	£63.84	£50.93	£56.07
Domestic - Solar PV	£22.19	£34.32	£29.70	£69.06	£63.63	£34.32	£41.65	£33.96	£31.01
Domestic - Solar PV with storage	£19.31	£34.32	£29.70	£69.06	£63.63	£34.32	£41.65	£33.96	£30.29
Domestic - Electric vehicles	£46.54	£34.32	£44.28	£69.06	£103.31	£34.32	£51.57	£67.91	£62.57
Domestic - Heat pumps	£56.90	£34.32	£54.14	£69.06	£93.56	£34.32	£49.13	£67.91	£65.16
SME - Low consumption	£100.69	£120.66	£95.80	£211.00	£131.75	£120.66	£123.43	£466.89	£375.34
SME - High with onsite generation/storage (1)	£155.76	£120.66	£239.50	£211.00	£184.14	£120.66	£136.53	£466.89	£389.11
SME - High without onsite generation/storage (1)	£251.72	£120.66	£239.50	£211.00	£184.14	£120.66	£136.53	£466.89	£413.10
SME - High with onsite generation/storage (2)	£155.76	£626.19				£626.19			
SME - High without onsite generation/storage (2)	£251.72	£626.19				£626.19			
SME - Light industrial HV-connected	£50,345	£16,955	£47,901	£7,673	£7,947	£16,955	£14,703	£16,978	£25,320

Source: Frontier Economics

B.3 Annual residual bill under each charging option for all DNOs - TNUoS

Figure 155 All DNOs – TNUoS annual residual bill under each charging option

User group	Baseline	Fixed	Gross volum-etric	Ex-ante capacity	Ex-post capacity	Fixed by volume	Fixed 75% and ex-post capacity 25%	Ex-ante deemed capacity for domestics	Ex-ante deemed capacity for domestics 75% and net volumetric 25%
Domestic - Low consumption	£23.6	£44.1	£15.8	£68.1	£48.2	£31.6	£45.1	£32.9	£29.2
Domestic - Medium consumption	£39.2	£44.1	£25.8	£68.1	£64.3	£31.6	£49.1	£32.9	£32.1
Domestic - High consumption	£59.3	£44.1	£38.3	£68.1	£80.2	£31.6	£53.1	£49.4	£48.1
Domestic - Economy 7 high	£88.3	£62.8	£59.1	£68.1	£96.0	£48.6	£71.1	£49.4	£54.1
Domestic - Solar PV	£23.8	£44.1	£25.8	£68.1	£64.3	£31.6	£49.1	£32.9	£30.0
Domestic - Solar PV with storage	£5.0	£44.1	£25.8	£68.1	£64.3	£31.6	£49.1	£32.9	£29.3
Domestic - Electric vehicles	£44.8	£44.1	£38.5	£68.1	£104.4	£31.6	£59.2	£65.8	£60.5
Domestic - Heat pumps	£45.7	£44.1	£47.1	£68.1	£94.5	£31.6	£56.7	£65.8	£62.9
SME - Low consumption	£73.5	£106.2	£83.3	£208.0	£133.1	£118.2	£112.9	£452.5	£363.3
SME - High with onsite generation/storage (1)	£40.4	£106.2	£208.2	£208.0	£186.0	£118.2	£126.1	£452.5	£376.5
SME - High without onsite generation/storage (1)	£225.4	£106.2	£208.2	£208.0	£186.0	£118.2	£126.1	£452.5	£399.3
SME - High with onsite generation/storage (2)	£40.4	£569.8	-	-	-	£634.5	-	-	-
SME - High without onsite generation/storage (2)	£225.4	£569.8	-	-	-	£634.5	-	-	-
SME - Light industrial HV-connected	£29,757	£17,380	£41,640	£7,563	£8,028	£23,483	£15,042	£16,453	£24,338
Industrial - EHV-connected without onsite generation/demand management	£297,581	£65,355	£416,397	£37,814	£80,281	£107,859	£69,087	£82,267	£181,678
Industrial - EHV-connected with peak generation/demand management	£0	£65,355	£416,397	£37,814	£80,281	£107,859	£69,087	£82,267	£61,700
Industrial - T-connected with peak generation/demand management	£0	£264,242	£832,794	£75,629	£160,562	£547,838	£238,322	£164,534	£123,400
Industrial - T-connected without onsite generation/demand management	£595,161	£264,242	£832,794	£75,629	£160,562	£547,838	£238,322	£164,534	£363,356

Source: Frontier Economics

B.4 Annual residual bill under each charging option for all DNOs - EDCM

Figure 156 EDCM baseline and option charges for all DNOs

	Baseline			Basic options				Additional options			
	25th percentile	50th percentile	75th percentile	Fixed	Gross volumetric	Ex-ante capacity	Ex-post capacity	Fixed by volume	Fixed 75% Ex-post capacity 25%	Ex-ante deemed capacity for domestics	Ex-ante deemed capacity for domestics 75% and net volumetric 25%
Electricity North West	£35,050	£45,322	£108,051	£77,435	£119,240	£105,871	£73,811	£77,435	£76,529	£105,871	£124,434
Northeast	£22,578	£26,324	£49,981	£47,186	£53,181	£41,423	£39,570	£47,186	£45,282	£41,423	£51,151
Yorkshire	£26,830	£30,497	£60,953	£37,207	£74,651	£51,115	£47,009	£37,207	£39,658	£51,115	£66,528
Southern Scotland	£6,016	£34,799	£63,028	£12,028	£54,466	£41,840	£35,603	£12,028	£17,922	£41,840	£51,949
North Wales & Mersey	£65,835	£100,805	£177,391	£74,881	£150,386	£127,631	£90,219	£74,881	£78,716	£127,631	£152,516
Southern	£8,459	£10,605	£12,470	£8,318	£25,756	£14,806	£22,141	£8,318	£11,774	£14,806	£20,831
Scottish Hydro	£31,456	£31,555	£31,811	£3,159	£82,537	£28,784	£40,597	£3,159	£12,519	£28,784	£52,757
Eastern	£19,281	£21,240	£28,844	£19,541	£59,809	£33,529	£20,988	£19,541	£19,903	£33,529	£47,733
London	£3,468	£10,794	£16,153	£39,884	£23,501	£14,653	£13,035	£39,884	£33,172	£14,653	£19,865
South East	£15,471	£25,546	£31,190	£29,152	£54,715	£23,264	£18,604	£29,152	£26,515	£23,264	£38,111
East Midlands	£20,920	£26,670	£33,030	£18,491	£112,936	£57,821	£52,837	£18,491	£27,078	£57,821	£86,016
South Wales	£33,992	£42,456	£57,561	£41,801	£102,810	£97,420	£81,166	£41,801	£51,643	£97,420	£111,891
South West	£19,828	£25,373	£31,402	£5,936	£100,441	£48,592	£47,261	£5,936	£16,267	£48,592	£74,375
West Midlands	£14,439	£16,212	£22,949	£18,973	£65,990	£42,677	£44,246	£18,973	£25,291	£42,677	£56,928

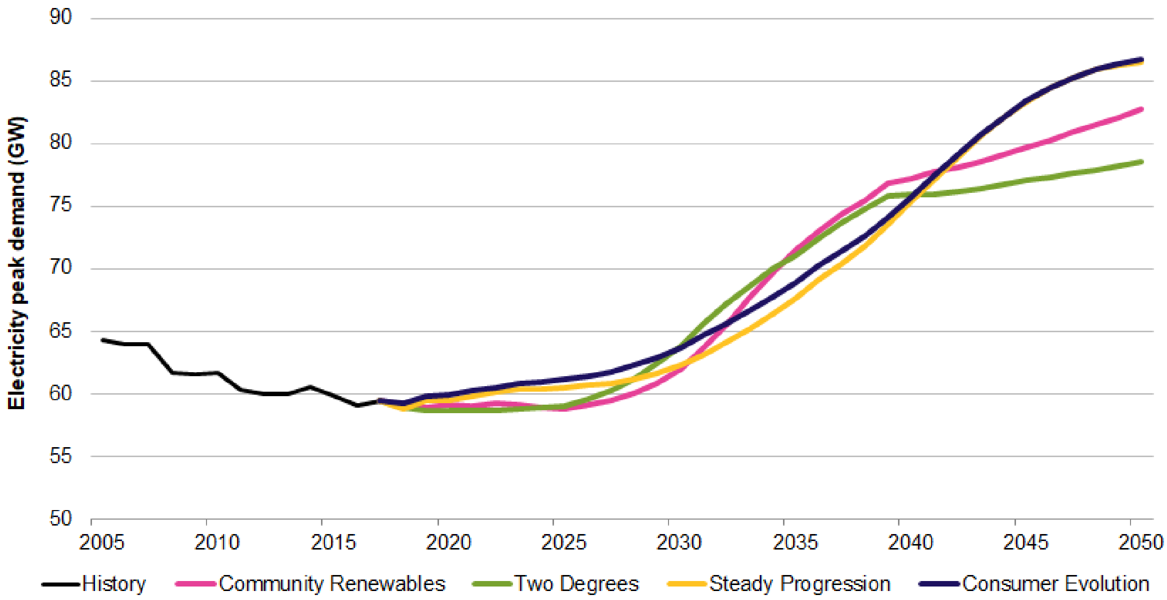
Source: Frontier Economics.

Note: Fixed charge is likely to include pure generation sites and hence in reality we would expect the fixed charge to be higher than this.

ANNEX C ADDITIONAL SYSTEM MODELLING ASSUMPTIONS

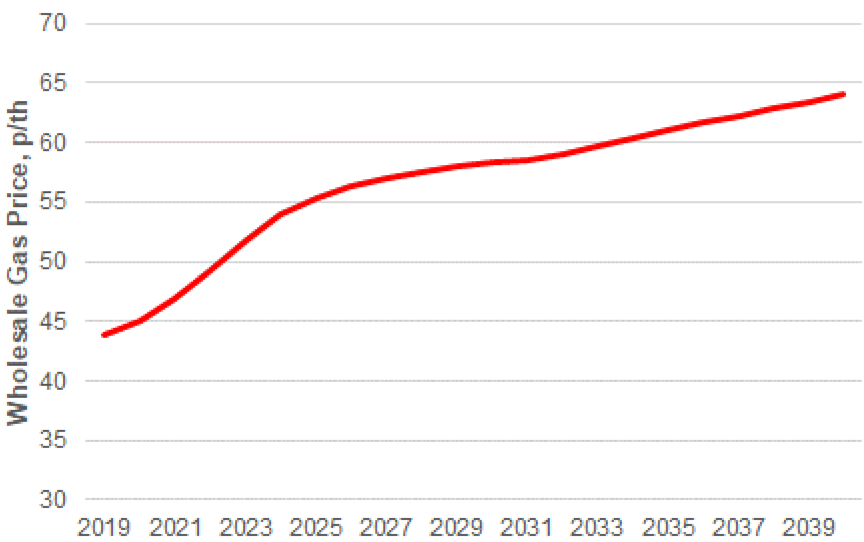
C.1.1 Demand Assumptions

National Grid FES 2018 – Peak Demand, GW

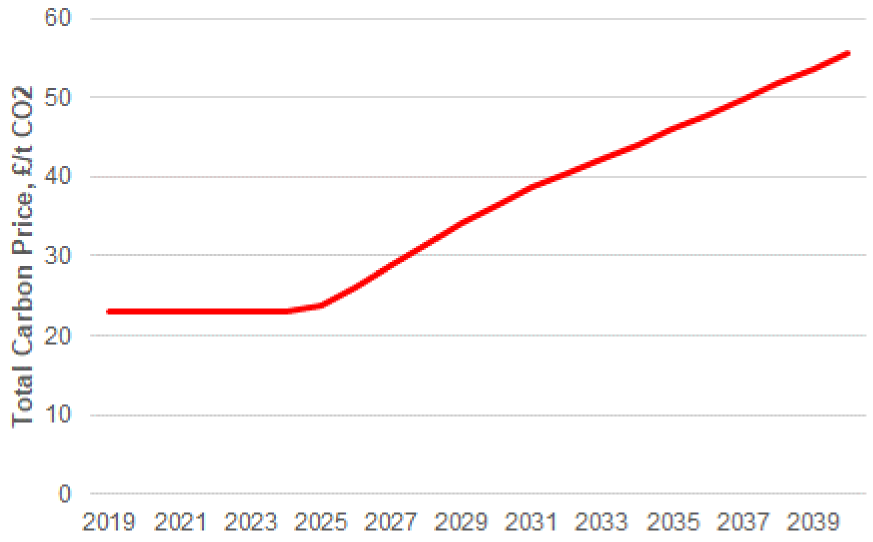


C.1.2 Commodity Prices

National Grid FES 2018 – Base Case Gas Price, p/th

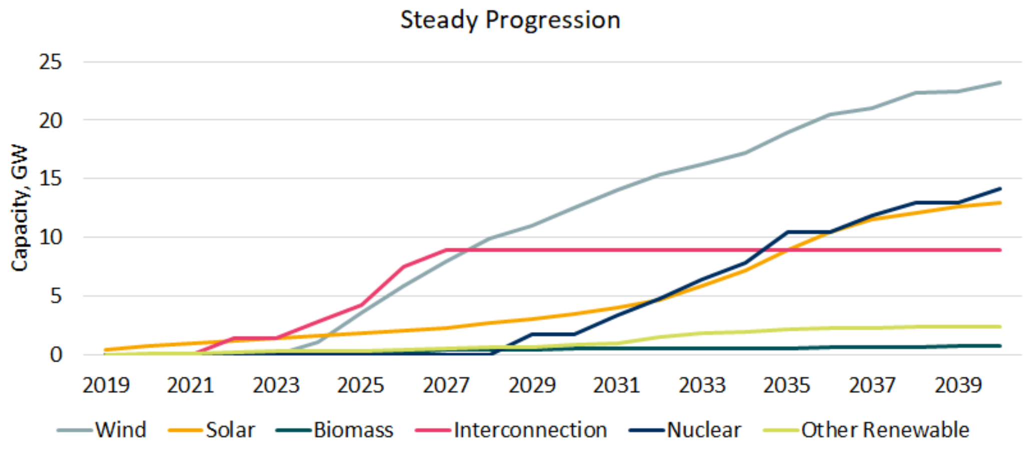


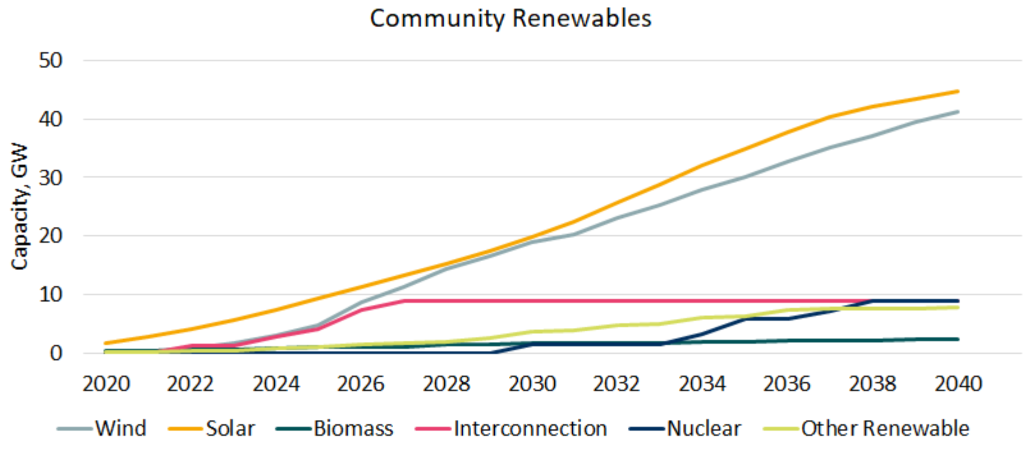
National Grid FES 2018 – Base Case Total Carbon Price, £/t



C.1.3 Low carbon build projections

Projections of post-2018 low carbon build, based on Steady Progression and Community Renewables FES 2018 scenarios.





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