WWW.FRONTIER-ECONOMICS.COM

frontier economics

NETWORK TARIFFS FOR ENERGY INTENSIVE INDUSTRY

Evaluation of rationale for exemptions

05 DECEMBER 2022

CONTENTS

1 Introduction

1.1 Context

Energy Intensive Industries (EIIs) are a diverse segment of the GB industrial market, covering a wide range of mining and manufacturing sectors, including steel, chemicals, aluminium and textiles. While it is the case that for all EIIs energy costs represent a significant share of total costs, the nature of their consumption in terms of their size and shape and the importance of electricity as an energy source will vary. However, on average, GB EIIs face higher electricity prices than counterparts in many European countries.

Previous analysis[1] has identified three potential drivers of high GB electricity costs for EIIs: wholesale electricity prices, low carbon support policy costs and network charges.

- The wholesale cost is the largest component of the EII's electricity cost and GB has tended to have ***higher wholesale electricity prices*** than many European countries, in part due to the electricity generation mix and the Carbon Price Support. Currently, EIIs in GB receive an exemption for up to 60% of the indirect costs of the EU Emissions Trading System and the Carbon Price Support Mechanism.

- The UK has some of the highest **low carbon support policy costs** in Europe, with these being spread across electricity bills. Currently, EIIs receive an exemption up to 85% of the cost of the Contract for Differences (CfD) and the Renewables Obligation (RO) support schemes.

- Finally, **network costs**, which are an important component of the electricity bill, appear to be higher than in other EU countries largely due to the discounts offered in some jurisdictions to EIIs that meet certain eligibility criteria regarding electricity consumption and off-peak grid utilisation. This allows eligible EIIs in those countries to lower their network costs by up to 90% in some cases. Equivalent discounts that offer an explicit reduction to EIIs are not offered in GB. The effect of these discounts is to redistribute the incidence of network costs between different user groups. Therefore, although aggregate network costs are not necessarily higher in GB than in comparator countries, the share of these total costs paid for by EIIs is higher than in comparator countries.[2]

The focus of this study is on the third driver of network charges, specifically to consider whether there is a rationale for applying similar discounts to those applied in other European countries to GB network charges for EIIs. While it is clear that no such discounts are applied in GB, it is important to note that the structure of network charges is different in GB compared to other European countries making any direct comparison difficult.

Unlike in much of the rest of Europe, GB network charges are typically categorised into:

---

1 https://www.ofgem.gov.uk/sites/default/files/2021-07/Final%20report-%20Research%20into%20GB%20electricity%20prices%20for%20EnergyIntensive%20Industries.pdf

2 See Figure 4.1 in https://www.ofgem.gov.uk/sites/default/files/2021-07/Final%20report-%20Research%20into%20GB%20electricity%20prices%20for%20EnergyIntensive%20Industries.pdf

- "**cost reflective**" charges, which are intended to reflect the forward looking marginal cost network users place on the system, and therefore users will take these charges into account when deciding how to use the system, minimising overall system costs; and
- "**cost recovery**" or "**residual**" charges, which ensure network companies can recover their full costs but which do not reflect costs attributable to any individual network user, and therefore typically are levied in a manner that minimises changes to behaviour.

The implication of this charging structure is that charges for EIIs are not uniform and will reflect to some degree the relative costs/benefits that they impose/bring to the system compared to other network users. In other words, EIIs will pay lower charges where they consume less in peak hours, or are more favourably located (e.g. closer to sources of generation). EIIs will also face significant cost recovery charges, which typically are uniform and by design are more difficult to avoid.

As a result, to develop an understanding of whether similar discounts to those in some European countries could be applied in GB it is first important to understand:

- Whether there are benefits that EIIs offer to the system which are not already reflected in the cost reflective charges they pay, meaning they should be facing lower cost reflective charges than they currently do;[3,4] and
- Whether there are reasons that would justify, for some EIIs, an exemption from all or part of the cost recovery charges.

BEIS has commissioned Frontier Economics and DNV to examine the case for a discount on current charges in the GB context. Specifically, we have been asked to:

- Review the current approach to network charges for GB EIIs, including taking into account expected changes following recently announced reforms;
- Review the nature and rationale for EII network charge reductions in a number of key European comparator countries;
- Consider the extent to which any rationale may reasonably justify network charge reductions for EIIs in GB, either based on a rationale applied in a comparator country or an independently developed rationale; and
- Finally, consider what the implications would be for other network users of discount/charge exemptions for EIIs.

---

3 In this context the term Cost Reflective has a specific meaning and this is explained in more detail in Section 3.1.

4 There may be many reasons why the specific Cost Reflective charges could be improved, and with respect to Transmission charges they are currently under review which may improve their cost reflectivity further. This is not the subject of this study. The focus here is whether there is a justification for a differential treatment for EIIs over other forms of load.

1.2 Scope clarifications

1.2.1 Relevant charges

In GB, electricity network charges are paid by electricity network users[5] and are split into three separate sets of charges.

- Transmission Network Use of System (TNUoS) charges cover use of the transmission system;
- Distribution Use of System (DUoS) charges cover use of the distribution system;[6] and
- Balancing Services Use of System (BSUoS) charges cover the cost of day-to-day operation of the transmission system.

The manner in which these charges are paid by users is set by Ofgem.

In this report we consider all network charges that apply to EIIs in GB, including both Cost Reflective and cost recovery elements of TNUoS, DUoS and BSUoS.

This report does not consider other costs faced by GB EIIs such as wholesale electricity costs, the indirect costs of carbon or the costs of supporting renewable generation.

1.2.2 Relevant companies

The subject of this report is network charges for EIIs in GB. Whilst there is no formal and parameterised definition of EIIs, for the purpose of our research and assessment, we have been informed by the definitions of EIIs used for the administration of the carbon and policy costs exemption schemes currently operating at the time of this research.[7] Given the diverse nature of EIIs, we have also developed a number of archetypes in order to understand the implication of current charging arrangements for EIIs.

1.2.3 Relevant comparator countries

For the purpose of considering EII network charge exemptions in other countries, the focus of this report is on schemes in key neighbouring (and from an EII perspective competitor) countries of Germany, the Netherlands, France and Spain. While globally, EIIs may benefit from other exemptions, detailed consideration of network charging arrangements and discounts in other countries is out of scope.

We set out the operation of network charges and discounts in the comparator countries as well as summarising the views of some of relevant parties in those countries (e.g. regulators). Our focus is on the applicability of the rationale in the GB context – beyond this, we do not comment on the stated rationales for

5 Formally it is electricity suppliers that pay network charges on behalf of their customers. However, these charges are typically passed directly through to users.

6 These charges are not paid by users that are directly connected to the transmission system.

7 We are aware that this is currently being consulted on and therefore the precise definition may change in future.

discounts provided in those countries. We do not make quantitative comparisons between either the discounts and the total network charges in GB or the comparator countries.

1.3 Structure of the report

The rest of this report is structured as follows:

- First, we provide a brief overview of the key relevant industries for EIIs in GB as context for the work.
- Next we describe the current network charging arrangements for EIIs in GB and illustrate the level of annual charges implied by the existing network charging arrangements (taking into account soon to be implemented changes).
- We then summarise the current approach to network charges and the EII discounts that currently apply in identified comparator countries of Germany, the Netherlands, France and Spain, specifically identifying the rationales applied to justify the discounts.
- We then discuss, informed in part by the international review and in part by a technical review, the potential case for network charge discounts in GB.
- Finally, we provide indicative estimates of the potential impact for the charges of other network users of EIIs reducing network demand or receiving discounts.

2 Overview of GB EIIs

EIIs are a diverse segment of the GB market, covering a wide range of mining and manufacturing sectors, including steel, chemicals, aluminium and textiles. Although there is no single definition of characteristics that constitute an EII, based on measures of electricity consumption and trade intensity, the UK government has defined a range of eligible sectors and characteristics for the purposes of determining eligibility for the particular exemptions e.g. with regard to compensation for the indirect costs of the EU ETS and the Carbon Price Support mechanism[8] and renewables policy support costs.

This section focuses on the characteristics of the 15 industries that BEIS identified as eligible for compensation for indirect costs of the EU Emissions Trading System and the Carbon Price Support Mechanism as an illustration EIIs in GB.

Table 1 Sectors eligible for compensation for indirect emission costs

NACE code	SIC code	Sector description
1310	0710	Mining of iron ore
1430	0891	Mining of chemical and fertiliser minerals
1711	1310	Preparation and spinning of cotton-type fibres
1810	1411	Manufacture of leather clothes
2111	1711	Manufacture of pulp[9]
2112	1712	Manufacture of paper and paperboard
2413	2013	Manufacture of other inorganic basic chemicals
2414	2014	Manufacture of other organic basic chemicals
2415	2015	Manufacture of fertilisers and nitrogen compounds
2416	2016	Manufacture of plastics in primary forms[10]
2470	2060	Manufacture of man-made fibres
2710	2410	Manufacture of basic iron and steel and of ferro-alloys
2742	2442	Aluminium production
2743	2443	Lead, zinc and tin production
2744	2444	Copper production

Source: BEIS, 2019, Energy Intensive Industries (EII), Energy Intensive Industries (EII): compensation for the indirect costs of the EU Emissions Trading System and the carbon price support mechanism - guidance for applicants (publishing.service.gov.uk)
For SIC classification see: https://www.ons.gov.uk/methodology/classificationsandstandards/ukstandardindustrialclassificationofeconomicactivities/uksic2007

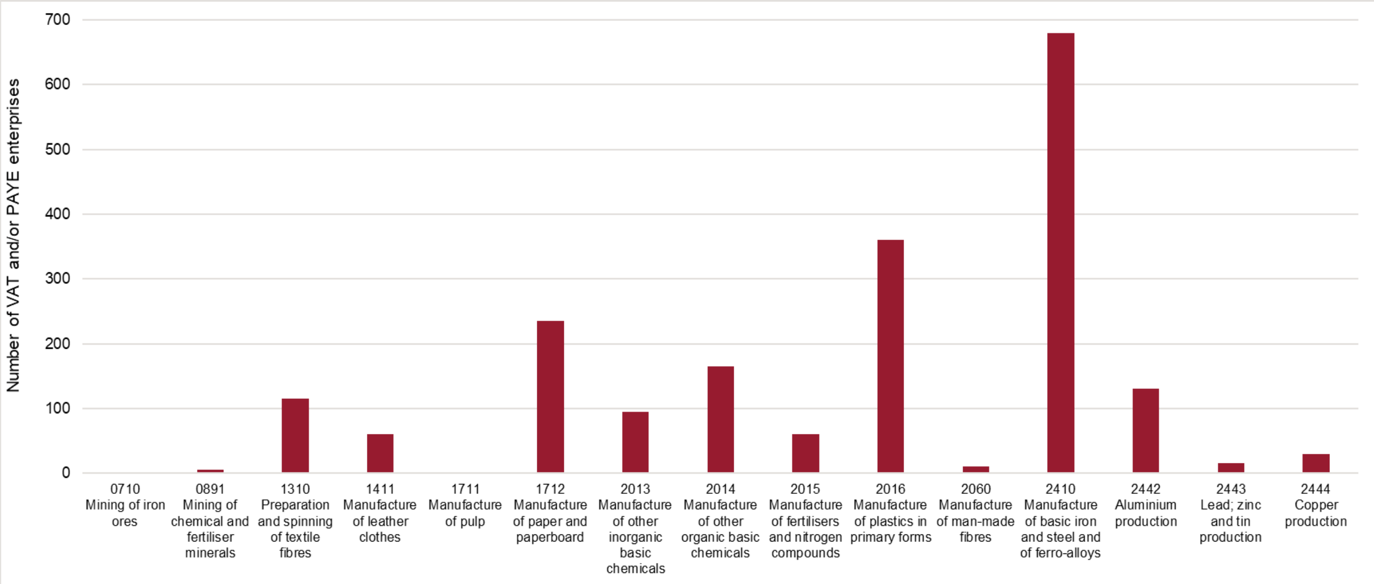
8 BEIS, 2019, Energy Intensive Industries (EII), Energy Intensive Industries (EII): compensation for the indirect costs of the EU Emissions Trading System and the carbon price support mechanism - guidance for applicants (publishing.service.gov.uk)

9 Includes only the following sub-sector within manufacture of pulp: 21111400 – Mechanical pulp

10 Includes only the following sub-sectors: 24161035 – Linear low-intensity polyethylene, 24161039 – Low-density polyethylene, 24161050 – High-density polyethylene, 24163010 – Polyvinyl chloride, 24164040 – Polycarbonate, 24165130 - Polypropylene

EIIs, embedded in many strategic value chains, form an important part of the GB market. The goods produced by EIIs are utilised in numerous sectors of the economy. Furthermore, as the figures below indicate, EIIs are important employers, providing thousands of jobs across GB, as well as providing considerable contributions to the overall economy.[11]

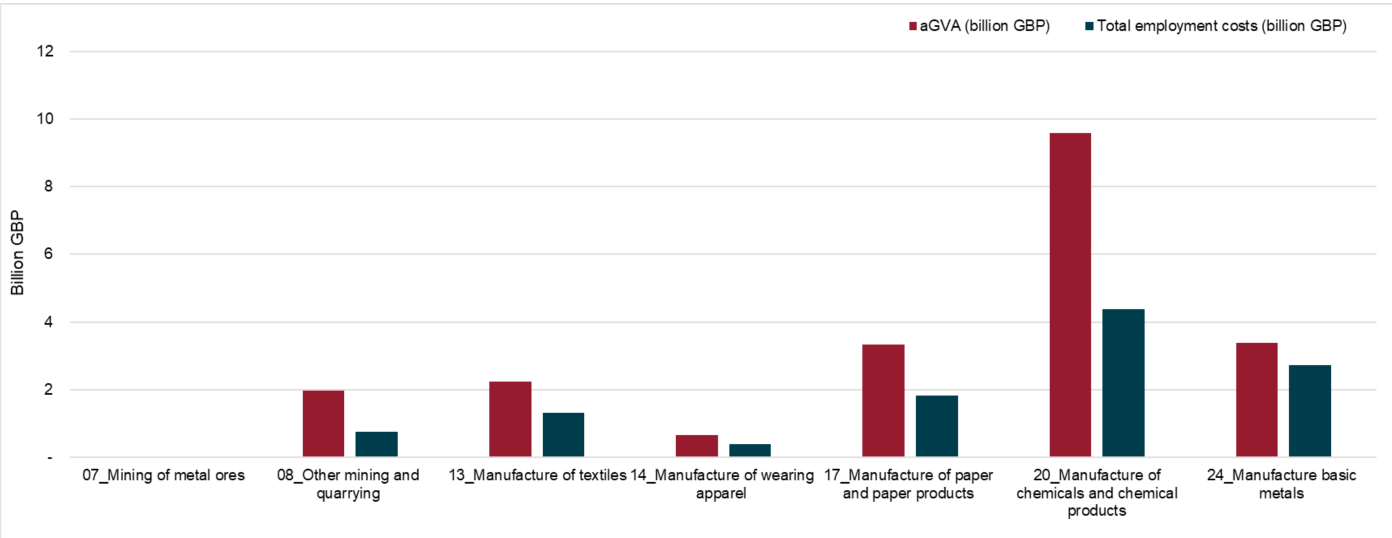
Figure 1 Number of VAT and/or PAYE enterprises in the UK by 4-digit SIC code, 2021



Source: Office for National Statistics: https://www.ons.gov.uk/businessindustryandtrade/business/activitysizeandlocation

Note: [Insert Notes]

Figure 2 Approx. GVA and total employment costs in GB by 2-digit SIC code, 2019



Source: Office for National Statistics: https://www.ons.gov.uk/businessindustryandtrade/business/businessservices/bulletins/nonfinancialbusinesseconomyukandregionalannualbusinesssurvey/2019finalresults

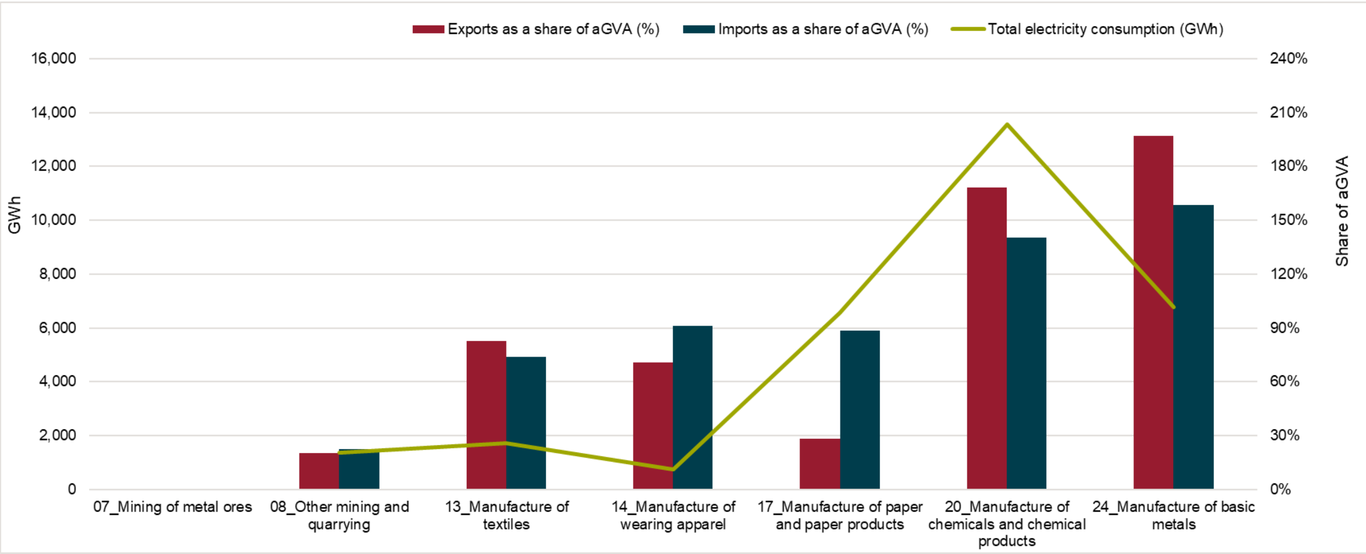
Note: aGVA refers to the approximate gross value added at basic prices

[11] Gov.uk, Press Release, 2022 Government to consider further relief for energy intensive industries: https://www.gov.uk/government/news/government-to-consider-further-relief-for-energy-intensive-industries

The government believes that the relatively high electricity costs faced by EIIs in GB compared to the costs faced by their counterparts in other European countries could hamper investment, competitiveness and commercial viability of hundreds of industrial businesses.[12] Comparatively higher electricity prices pose risks particularly to those electricity-intensive business which operate in internationally competitive markets and are thus unable to pass these higher costs through to consumers.

Figure 3 below provides an indication of the total electricity consumption for key sectors, as well as the volume of international trade as a share of the gross value added as an indication of the degree of international competition in these sectors.

Figure 3 Total electricity consumption and value of internationally traded goods and services as a share of approx. GVA in the UK by 2-digit SIC code, 2019



Source: Office for National Statistics: https://www.ons.gov.uk/businessindustryandtrade/internationaltrade/datasets/uktradeingoodsbybusinesscharacteristics; and Gov.uk 2021: Energy consumption in the UK 2021: https://assets.publishing.service.gov.uk/government/uploads/system/uploads/attachment_data/file/1092943/2021_End_use_tables_July_2022_update.xlsx

Note: aGVA refers to the approximate gross value added at basic prices

12 Gov.uk, Press Release, 2022 Government to consider further relief for energy intensive industries: https://www.gov.uk/government/news/government-to-consider-further-relief-for-energy-intensive-industries

3 Status quo GB network tariffs for EIIs

In this section we describe the baseline set of charges that EIIs in GB are expected to be paying in the next charging year, including presenting some indicative estimates for network charges for a set of EII archetypes. It is important to note that following a number of recent reforms to each of the three main categories of charges in scope of this study, the approach for calculating network charges has either recently changed or is expected to change from the next charging year.

The section is structured as follows:

- We first explain the principles which underpin the approach to charging in GB;
- We then set out a summary of the rules for the relevant GB network charges, including noting how they have recently changed or will be changing for the next charging year;
- We then explain our approach to defining a set of EII archetype consumers; and
- Finally, we present illustrative calculated charges under the baseline GB charging arrangements for our archetype users.

3.1 GB charging principles

There are a number of economic principles which are typically associated with the definition of network charges in GB. These include ensuring efficient market outcomes, fairness, practicality, simplicity and predictability.[13]

With regard to the principles behind ensuring efficient market outcomes, it is typically argued by Ofgem that network charges should be "cost reflective" i.e. that charges should reflect the (forward looking) costs which users impose on the network through a change in their network use. If charges are cost reflective in this sense, then 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.

This form of cost reflective charging 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 allow for the full recovery of sunk investments in the network. These additional, or 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 to charge for any "residual" costs which are unrecovered after taking account of revenues collected from cost reflective charges. 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.

13 https://www.ofgem.gov.uk/sites/default/files/docs/2018/11/annex_1_-_tcr_principles.pdf

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. The costs being recovered through the residual charge 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.

These two principles of cost reflectivity and cost recovery have been a long-standing basis on which the approach to electricity network charges in the GB have been set. In recent years, Ofgem has taken forward a number of reforms to improve the adherence to these principles, most notably to reduce the ability of market participants to avoid cost recovery charges.

It is important to note that while Ofgem's interpretation of cost reflectivity is consistent with the legal requirement in the Trade and Cooperation agreement[14] that charges should be cost reflective, we note that there are other possible interpretations. As we go on to discuss in this report, we identify a number of European countries that do not distinguish between cost reflectivity and cost recovery in their charges. In those countries, the interpretation of cost reflectivity is less about economic efficiency and more about ensuring charges are set only to recover costs related to the network. Under this interpretation, there is no need to have separate cost recovery charges in that "cost reflective" charges are already set to recover all relevant costs.

Given that cost reflectivity is a general term that may have different specific meanings in different contexts, for the rest of this report we define the term "Cost Reflective" to have the specific meaning set by Ofgem, while also using the term "cost reflective" in its more general sense.

3.2 Relevant network charging rules

Electricity network charges are paid by electricity network users and are split into three separate sets of charges.

- Transmission Network Use of System (TNUoS) charges cover use of the transmission system;
- Distribution Use of System (DUoS) charges cover use of the distribution system;[15] and
- Balancing Services Use of System (BSUoS) charges cover the cost of day-to-day operation of the transmission system.[16]

The manner in which these charges are paid by users is set by Ofgem as we explain for each in turn below.

[14] See Section 5.3 for a discussion of the legal requirements in the Trade and Cooperation agreement

[15] These charges are not paid by users that are directly connected to the transmission system.

[16] BSUoS recovers the ESO's costs of managing the electricity system including: ESO internal costs, wholesale redispatch costs to provide adequate generation reserve and resolve locational constraints and the costs of ancillary services such as black start.

3.2.1 Transmission charges (TNUoS)

TNUoS charges have both Cost Reflective and cost recovery elements, with both elements subject to reform.

Historically, both Cost Reflective and cost recovery transmission demand charges were based on so-called "triad demand" i.e. average consumption during the three half-hours with the highest system demand.[17] This means that if a site did not use electricity during periods of peak electricity demand,[18] it would pay no Cost Reflective or cost recovery transmission charges.

As a result, there was a strong incentive on load, including EIIs, to reduce consumption in these periods. While this could be argued to be an efficient response with regard to the Cost Reflective element of the charges, significant avoidance of *cost recovery* charges simply distorts outcomes (e.g. by encouraging too much uptake of behind the meter generation, so-called "BTMG") and results in higher costs to other users who cannot avoid the charge. As a result, through its **Targeted Charging Review (TCR)**, Ofgem adjusted the residual charges for transmission (and distribution) networks to be less easily avoided. These changes will be introduced from April 2023.

The cost recovery element will be levied based on either consumption bands (for transmission connected demand) or connection capacity bands (for distribution connected demand connected at the extra high voltage level).[19] Each site within a given band (e.g. 68,009 – 129,292 MWhs per year or 5,000 – 12,000 kVA connection) pays a flat annual TNUoS residual charge that is independent of their consumption behaviour. As a result of these changes, EIIs will now find it harder to avoid the cost recovery elements of network charges by engaging in demand response/BTMG.

Cost Reflective elements were left unchanged by the TCR, and therefore, as it stands, Cost Reflective charges can still be avoided by demand (including EIIs) to the benefit of the system.

The Cost Reflective element of TNUoS is locational in nature and is intended to reflect the additional forward looking costs that users in certain areas of the network impose relative to equivalent users in other areas. In some regions of the network,[20] Cost Reflective charges are zero,[21] in other regions they are positive and are based on their so-called "triad demand".[22] These differences in charges effectively reflect differences in

17 Measured between November and February. Triad periods are set ex post and each Triad half-hour must be separated by 10 clear days.

18 Strictly speaking this is measured transmission system demand, which may be different from periods of peak electricity consumption due to the contribution of distributed and behind the meter generation which reduce transmission system demand.

19 The charging bands are only revisited periodically, with the TCR final decision stating that the bands are to "*be reviewed at such times as to ensure that the outcome of the review can be implemented at the same time as the next transmission price control takes effect*." However, should substantial changes in usage occur at a site, an exceptions process should allow for the user to be reallocated to another band. (Ofgem, *Targeted charging review: decision and impact assessment*, 21 November 2019).

20 Northern Scotland, Southern Scotland, Northern England, North West England, Yorkshire, North Wales & Mersey, East Midlands and Easter England.

21 In some regions where there is excess generation, the calculation of Cost Reflective charges may imply that demand users would face a negative Cost Reflective TNUoS charge (i.e. would receive a TNUoS credit). However, Ofgem's TNUoS methodology limits the "Cost Reflective" element of charges for demand users to a lower bound of zero. Whilst this introduces a distortion relative to a set of TNUoS charges that are modelled as being economically efficient, this distortion applies to all network users in certain regions and not specifically to EIIs.

22 Midlands, South Wales, South East England, London, Southern England and South Western England

excess generation capacity between regions and therefore the extent to which marginal additional demand in those regions requires or mitigates the need for additional transmission network build.

It is worth noting that the underlying methodology for Cost Reflective TNUoS charges is currently under review by the TNUoS Taskforce and as a result the value of charges faced by EIIs could change. However, the reforms are unlikely to affect the principle that EIIs which avoid stressing the network at times of peak system stress or more favourably located should face lower charges.

3.2.2 Distribution charges (DUoS)

DUoS charges are set under two separate methodologies depending on the connection voltage of the network users. For users that connect to the Extra High Voltage network (EHV), charges are determined by the EHV Distribution Charging Methodology (EDCM). For those users that connect at a voltage below EHV, charges are determined by the Common Distribution Charging Methodology (CDCM). Given their size, the majority of EIIs are likely to be connected to either the transmission system directly (and therefore face no DUoS charges) or to the EHV network (and therefore face EDCM charges).

DUoS charges have both Cost Reflective and cost recovery elements. As for TNUoS, the TCR also changed the way DUoS cost recovery charges were levied. Previously they were recovered based on annual consumption, and therefore avoidable by baseload BTMG. Following TCR, the basis for charging shifted to a flat charge based on connection capacity bands.[23] Each site within a given band (e.g. 5,000 – 12,000 kVA) pays the same flat annual DUoS residual charge that is independent of their consumption behaviour.[24] Similar to TNUoS, EIIs will now find it harder to avoid the DUoS cost recovery elements of network charges by engaging in demand response/BTMG.

The Cost Reflective element is broken down into three charges:

- A site charge that is a flat £/day/site;
- A connection capacity charge that is a £/kVA/day charge; and
- A volumetric £/kWh "super red band" charge which only applies to active power consumed during periods of peak distribution network demand.[25] The relevant time periods are set on an ex ante basis and differ between regions reflecting the relative pattern of electricity consumption in the region and therefore when stress is on the network.[26]

[23] This is true for users connected at the EHV level which we consider for EIIs. At lower voltage connection levels (e.g. domestic) the bands are set on different parameters. The move to charging bands for collection of DUoS residual commenced in April 2022.

[24] As noted above, the charging bands will only be updated periodically, in line with the RIIO price control for Electricity Transmission. (Ofgem, *Targeted charging review: decision and impact assessment*, 21 November 2019).

[25] There is no separate tariff component for any reactive power flows. This is because the method used to calculate the super red band charges takes account of the effect on the network of the customer's power factor (using historical data). Therefore the "super red" band charge for active power includes an implicit charge for reactive flows.

[26] Whilst the exact times and dates of super red band periods vary by region a typical super red band period would be 1600-1900 Monday to Friday, November to February. However, the London region also includes a super red band in the summer and other regions have slightly different winter timings and treatment of bank holidays.

The level of each of these charge components varies by location on the network (e.g. the £/kVA/day charge is different at each location on the distribution network). Individual locational charges reflect, among other things:[27]

- The value of sole use customer assets;[28]
- Site specific shared user assets;[29]
- The share of DNO transmission connection costs; and
- Load flow analysis to estimate either the long run incremental cost or the expected forward looking cost of necessary demand-led reinforcement in the location (estimated by reference to power flows in a maximum demand scenario), including consideration of active and reactive power flows

Overall, the EDCM charging methodology means that EHV charges consider many of the individual drivers of network costs, including the load pattern of users (e.g. avoiding peak consumption and the power factor of different types of electricity use).

3.2.3 Balancing costs (BSUoS)

BSUoS charges recover costs associated with the day-to-day operation of the transmission system. They are purely cost recovery charges with no individually attributable "Cost Reflective" element.

BSUoS charges are levied on a volumetric (£/MWh of network consumption) and historically have been recovered from both generation and demand. Following recent reforms to reduce distortions in the wholesale electricity market (since interconnectors and distributed generation could avoid BUSoS charges), charges are to be recovered fully from demand from April 2023.[30] While this will increase the BSUoS charges which EIIs face, they should experience an offsetting reduction in wholesale costs due to lower wholesale electricity prices as a result of the charge being removed from generation.[31]

At the time of writing, BSUoS charges vary on a half hourly basis reflecting the individual costs of system balancing and operational services that are incurred in each half hour. However, Ofgem has stated that it is minded to adopt Connection and Use of System Code Modification Proposal 361 which will move BSUoS to being a flat rate (£/MWh) charge rather than varying each half hour. While this should reduce some half-

27 https://dcusa-cdn-1.s3.eu-west-2.amazonaws.com/wp-content/uploads/2022/04/01114405/SCHEDULE-18-v14.1.pdf , https://dcusa-cdn-1.s3.eu-west-2.amazonaws.com/wp-content/uploads/2022/04/01114359/SCHEDULE-17-v14.1.pdf

28 "*all assets between the Connectee's Entry/Exit Point(s) and the Point(s) of Common Coupling with the general network are considered as sole use assets*", *SCHEDULE 17 EHV CHARGING METHODOLOGY (FCP MODEL), para 14.2*

29 "*A Connectee's notional site-specific shared network asset value is the value of network assets that are deemed to be used by that Connectee, other than sole use assets as defined earlier.*" *SCHEDULE 17 EHV CHARGING METHODOLOGY (FCP MODEL), para 15.1.* For the purposes of deeming which assets a connectee uses, users are categorised into 1 of 15 categories. For more detail see table 15.6 of the same document.

30 At the time of writing, charges are still split between generation and demand. However, Ofgem has approved code modification proposal 308 with an implementation date of 1 April 2023 which will move charges to be wholly recovered from demand. https://www.nationalgrideso.com/document/249226/download

31 The reduction in wholesale costs may more than or less than fully offset the increase in network charges depending on the consumption pattern of a user and the merit order of generation.

hourly volatility for EIIs (to the extent they were directly exposed to it) and as a result they may be able to reduce the amount of risk capital they need to hold, their total exposure to BSUoS over time should remain unchanged. For the purposes of the analysis in this report, we assume that CMP 361 is adopted.

3.2.4 Summary of implications of current charges and reforms for EIIs

The network charges faced by EIIs will have been materially affected by recent reforms. We briefly summarise below the current status of GB charges for EIIs and the extent to which EIIs are able to influence their final network charge bill through changes to behaviour. When considering behavioural changes, we assume that an existing EII's location is static, as changes in connection / consumption location would likely involve significant costs and planning. Rather, the key behavioural signals considered are temporal.

Table 2 GB EII charge summary

	Cost Reflective charge	Cost recovery charge
TNUoS	Peak consumption ("Triad") based charge which can be avoided via demand response or BTMG at peak	Flat charge for each consumption or connection voltage band, which is difficult to avoid unless consumption can be reduced sufficiently to shift a site to a lower charge band or a site changes its connection capacity.
DUoS	At EDCM, three different charges, with "super-red" volumetric based charge possible to avoid through demand response or BTMG at peak	Flat charge for each capacity band, which is difficult to avoid without adjustments to connection capacity or voltage level.
BSUoS	N/A	Exposed to higher volumetric charge (albeit offset by lower wholesale prices) which can be avoided through energy efficiency or baseload BTMG

Source: Frontier Economics
Note: [Insert Notes]

3.3 Archetype analysis

EIIs are a heterogenous group of users whose characteristics and load profiles vary widely. As it is not feasible to present profiles which are reflective of all the different EIIs in Great Britain, we have identified six different EII archetypes, which reflect a range of different profiles and characteristics of industrial users. We use these archetypes to calculate illustrative annual network charge costs for EIIs in all GB regions. While these represent a reasonable range of potential network charge outcomes for EIIs in GB, it is the case that individual EIIs may face charges that are significantly different from those that we illustrate.

3.3.1 Necessary parameters to specify

Each archetype is defined based on the parameters on which the different charges are set. We describe these below for the three different charges.

To calculate the annual **BSUoS charge** for an EII user it is only necessary to specify net annual consumption - the total volume of electricity, measured in kWhs, that the user imports from the electricity network. This is distinct from the site's gross annual consumption, which may be met either by importing power from the electricity network or by onsite generation.

To calculate the annual **TNUoS charge** for an EII user it is necessary to specify:

- The connection type of the user - either transmission connected or EHV connected;
- Net annual consumption;
- Connection capacity (in kVAs);
- Average demand (in kWs) during the triad period; and
- TNUoS demand zone.

To calculate the annual **DUoS charge** for an EII user it is necessary to specify:

- The connection type of the user - either transmission connected or EHV connected;
- Connection capacity (in kVAs);
- Net annual consumption (in kWhs) during super red band periods; and
- The individual location of the connected user.

With regard to DUoS, while it is possible to specify archetypes reflecting the first of these three parameters, it is not practical to specify the individual location of each archetype given that each DNO region can have hundreds of individual locationally dependent charging sets. Therefore, the approach we have taken is not to specify this location for our archetypes but instead to calculate the charge at every existing EHV connection location that could be relevant for the archetype and report the median charge in each DNO region.

In addition to specifying the parameters strictly necessary to calculate the network charges we also specify the gross annual consumption of each archetype, as this is part of how we have derived some of the other parameters.

3.3.2 Archetype selection and description

The table below summarizes the key parameters of the identified EII archetypes.

Table 3 EII archetype parameters

Archetype	Gross Annual Consumption (MWh)	Net Annual Consumption (MWh)	Triad demand (kW)	Proportion of consumption in "super red" bands	Network connection level	Connection size (kVA)
1	20,000	20,000	2,283	baseload consistent	EHV	8,500
2	20,000	20,000	0	baseload consistent	EHV	8,500
3	20,000	0	0	0%	EHV	8,500
4	100,000	100,000	11,415	baseload consistent	Transmission level	N/A
5	100,000	100,000	0	baseload consistent	Transmission level	N/A
6	100,000	0	0	0%	Transmission level	N/A

Source: Frontier Economics
Note: [Insert Notes]

As the table shows, we have specified 6 archetypes based on two different consumption levels (and associated connection level) and three different patterns of consumption. For each level of consumption (and associated connection level) we have:

- one archetype that has a pure baseload consumption profile;
- one archetype that has a baseload profile other than that the user avoids Cost Reflective TNUoS charges by reducing consumption during the triad periods; and
- one archetype that has onsite generation sufficient to cover their own consumption and is connected to the network for back up purposes.

Below we set out the basis and justification for selecting these parameters values for our archetypes for each of the parameters.

Gross Annual Consumption

We first considered the appropriate scale for our EII archetypes and therefore initially determined the gross annual consumption figures that we would use.

We took an approach consistent with our work for Ofgem on its TCR. Guided by our discussions with the Energy Intensive Users Group at that time, we assumed extra-large users might typically be expected to consume between 70,000-150,000 MWh annually, while large users might typically be expected to consume between 20,000- 70,000 MWh annually.

Based on this information we selected gross consumption values to represent a large user and an extra-large user. For the extra-large user we selected a point towards the middle of the range but for the large user we selected a point at the bottom of the range. This is because we expect the distribution of annual consumption by site to be skewed, with more users at the bottom of the distribution than at the top.

Net Annual Consumption

We determined net annual consumption based on the gross annual consumption figure and an assumption about whether or not the user has onsite generation. The archetypes that do have onsite generation are assumed to use it to meet all of their annual electricity consumption requirement. This choice means that we calculate a broad range of charges, and that a user with onsite generation to meet just some of their annual consumption would face charges in between those that we calculate for our archetypes.

Triad demand

Archetype 1 and 4 are assumed to have a baseload demand profile and no demand response. Therefore their triad demand is equal to the baseload demand that is consistent with their assumed annual consumption figure. Archetype 3 and 6 are assumed to meet their demand through onsite generation. Therefore, their triad demand is equal to zero. Archetype 2 and 5 are not assumed to have onsite generation but are assumed to be capable of engaging in a minimum level of demand response.

To avoid triad charges requires the user to have zero demand in the three triad half hour periods. However, because these are only known on an ex post basis, sites that seek to avoid triad charges typically reduce demand in around 20 half hour periods per year when wholesale electricity prices (and network charges) are typically at their highest.[32] We consider that some sites without onsite generation could still feasibly turn down demand for 20 half hours in a year.

Super red bands

We assume that only archetypes with onsite generation reduce their net demand during super red band periods. Although super red band periods are defined ex ante they represent a significant number of hours in total.[33] Therefore, we assume that sites without onsite generation do not respond to these signals.[34]

Network connection level

EIIs will typically be large users and therefore will tend to be connected at higher voltages. Therefore we consider archetypes connected at the two highest voltage levels.

Connection size

This parameter is only required to be defined for EHV connected sites because it is only used in the calculation of DUoS charges. Our EHV connected archetype has an annual consumption of 20,000MWhs.

---

[32] Commercial operators provide “triad warning services” that predict around 20 half hour periods in the year that could be triad periods and so to avoid the charges levied on the basis of “triad demand” the site will need to be able to reduce its load for around 20 half hour periods in the year.

[33] This varies by DNO but is typically considerably more than 200 hours a year and is 454 hours in the London DNO region.

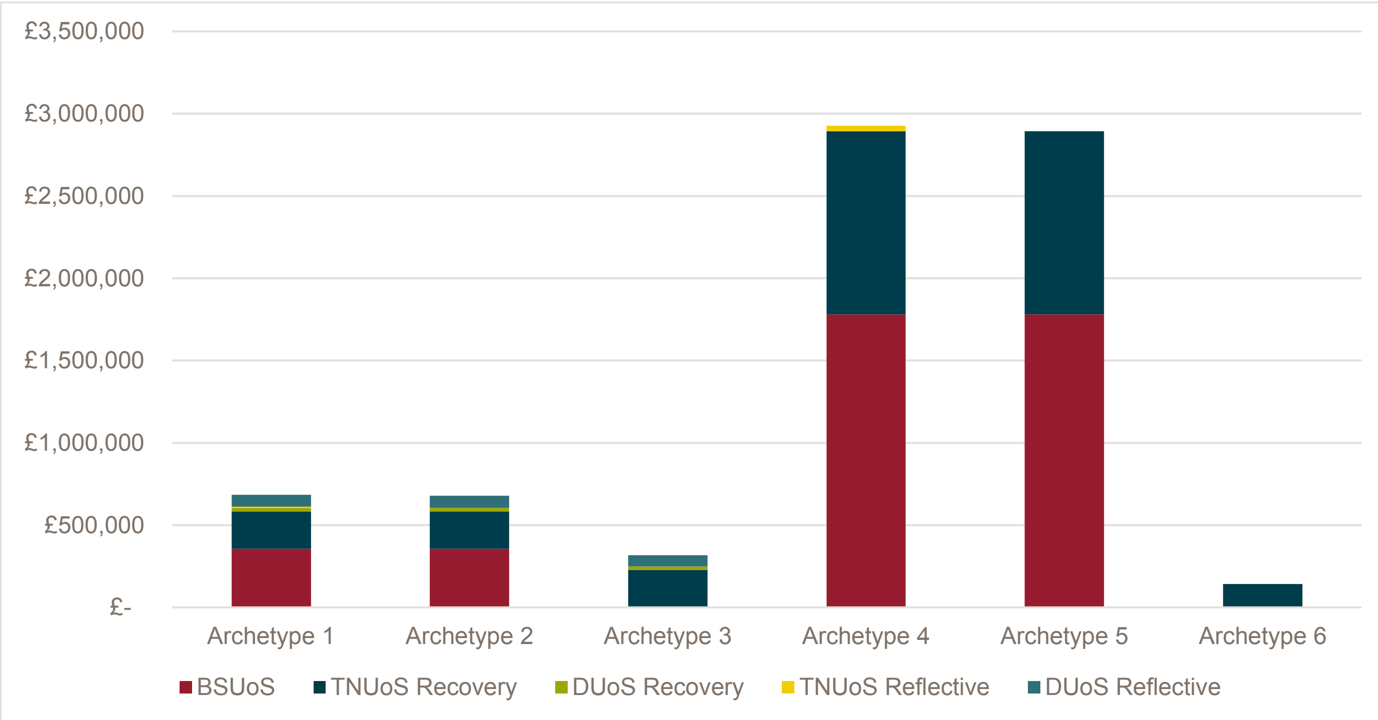
[34] We recognise that many of the 20 half hours that a site may reduce demand for triad response reasons will also be super red band periods and that by making the simplifying assumption of no response to super red bands this is, in a pure sense, inconsistent with assuming a triad response. However, this makes the calculations substantially simpler and the inconsistency will only be minor as it would only apply to around 10 hours per year out of more than 200 super red band hours.

Data drawn from publicly available transmission charging calculations[35] indicates that the average annual consumption of EHV connected users with a connection capacity of 5,000 kVA-12,000 kVA is 19,481 MWh. As this is close to our consumption assumption of 20,000 MWh, we have assumed a connection capacity equal to the middle of that range (i.e., 8,500 kVA).

3.3.3 Annual network charges under status quo arrangements for archetype EIIs

Figure 4 below provides the calculated status quo network charges for the South East DNO region. Full charges for all regions and all archetypes are provided in Annex A.

Figure 4 Network charges by Archetype user in the South East region



Source: Frontier Analysis based on published charging statements and BSUoS forecasts.
Note: Charges calculated for the charging year 2023/24 assuming the implementation of CMP308 and CMP361.

Although Figure 4 above is only presented for a single DNO region and some charges do vary by DNO region, the key messages that we can draw out from these results are the same regardless of the region that is considered. Our key observations on the network charges are as follows:

- The vast majority of network charges paid by our archetypes are cost recovery charges accounting for around 80-90% of charges for EHV connected users and around 99% of charges for T-connected users. The corollary of this finding is that, given the GB network charging methodology that will apply, providing demand flexibility can only save our archetype users a very small amount of their annual network charges.

[35] August Forecast 2023-24 TNUoS Tariff Report Tables PUBLISHED, available at https://www.nationalgrideso.com/industry-information/charging/transmission-network-use-system-tnuos-charges

- Users that have baseload onsite generation can greater reduce their network charges. This is primarily driven by the volumetric nature of the BSUoS charge. Although our archetype's 3 and 6 are assumed to have very significant onsite generation utilisation, because BSUoS is a volumetric charge, smaller levels of onsite generation would still provide a significant reduction in BSUoS costs.

4 International rationales for discounts

In the previous section we outlined the current approach to network charging in GB and its implications for EII network costs. In this section we consider the international rationales for discounts as follows.

- First, we consider the arrangements for Germany, the Netherlands, France and Spain in turn, and for each:
  - we summarise the arrangements relating to the EII discounts; and
  - outline the key rationales for discounts implemented and note the views of the relevant regulatory authorities (or other bodies) in relation to these.
- We finish by summarising the key insights from the international review.

4.1 International review

We have reviewed the network charging arrangements and discounts available to EII type customers in Germany, the Netherlands, France and Spain. We note that unlike GB, charges in each of these countries do not have a “Cost Recovery” and “cost reflective” split although the charges can still be considered to be cost reflective in a broader sense of the term.

Below we provide a short summary of the key findings from our review of the arrangements in each country. Detailed case studies of each of the comparator countries is provided in Annex B.

4.1.1 Germany

In Germany discounts are provided to large users and to non-peak users. Large users, defined based on exceeding a certain consumption threshold, are able to qualify for a maximum discount of up to 90% of their network charges while non-peak users can qualify for a maximum discount of up to 80% of their network charges. We briefly summarise the key points from the German review in Table 4.

Table 4 Overview of network charging and discounts

Charging approach	Discount application	Discount rationale
■ Capacity and volumetric charges ■ No separately identified Cost Reflective charge element	■ Discounts available for: □ Off peak users; and □ Large users ■ Large user discount only available if certain consumptions thresholds are met (e.g. >7,000 full load hours) and if the cost of building a new line from the user to the nearest appropriate power station is less than the general network tariff (so-called "physical path" analysis)	■ Off peak users contribute less to the system peak and therefore are a less of a driver of network costs ■ Large stable power consumption makes the system easier to manage

Source: Frontier Economics analysis. For additional sources see Annex B
Note: [Insert Notes]

While the regulation allows for very large maximum discounts, the actual discounts available for users are determined individually for each site. For non-peak users the discounted tariff is based on adjusting the calculation of the capacity charge such that it is based on capacity utilised during peak load windows instead of contracted capacity (which is used in the calculation of the general tariff). For large users the available discounted tariff is based on the cost of a hypothetical network link that connects the customer directly to the nearest suitable power station. [36]

This calculation of the discount means that conceptually it exempts the user from contributing to the costs of maintaining the network beyond their immediate electrical vicinity. Thus, qualifying users do not have to contribute to the average cost of the whole network, instead they only need to contribute to the average cost of the part of the network that they use directly. In some respects this is similar in principle to the short haul tariff that is available to some users of the GB gas transmission system that are located close to transmission system entry points.[37]

While these discounts remain in place, the German regulator (BNetzA) expressed the view in 2015 that large users no longer bring significant benefits in terms of network cost reductions or network stability. BNetzA observed that, while predictable EII demand can provide positive effects on frequency and voltage stability, the benefits for network management from large stable loads matching with classic baseload power generating technologies will become less important in the future as the prevalence of intermittent renewable generation increases. BNetzA also noted that the exemptions weakened incentives to provide flexibility on the grounds that deviating from a flat profile might affect their qualifying criteria for the exemption in the first place.

36 The costs of a direct line can be considered as an upper approximation of the incremental cost induced by a consumer site, disregarding certain operating constraints. This is not the same as the marginal cost to the network operator of serving the EII user.

37 https://www.ofgem.gov.uk/sites/default/files/docs/2021/04/unc728_decision.pdf

BNetzA also expressed the view that discount eligibility should be limited:

- for EIIs, to those users who are willing and able to react flexibly to network stress events; and
- for off peak users, to those users connected to the highest voltage levels which can be shown to have a significant impact on network load.

4.1.2 The Netherlands

In the Netherlands, discounts are provided to large users with a flat load profile. The level of the discount is calculated formulaically based on measures of the size of the consumer and measures of the load factor of the plant in off peak periods (reflecting the flatness of the overall load profile without discouraging demand flexibility at times of system peak demand). Larger users and users with greater consumption in off peak periods are eligible for larger discounts. The maximum possible discount is 90%. However, in 2013 the average discount for the 10 largest users was estimated to be 55%.[38]

Table 5 Overview of network charging and discounts

Charging approach	Discount application	Discount rationale
■ Contracted capacity and monthly peak capacity charges ■ No separately identified Cost Reflective charge element ■ No geographical differentiation of charges	■ Discounts available for large users with a large share of their consumption in off-peak periods	■ Large flat predictable consumption profile contributes to grid stability and voltage quality ■ Customers with a flat consumption profile make relatively efficient use of the available network capacity. That is to say, customers with the same consumption but a less flat consumption profile cause more peaks in the grid, causing more congestion and requiring grids to be expanded earlier

Source: Frontier Economics analysis. For additional sources see Annex B
Note: [Insert Notes]

In a similar vein to BNetzA, the Dutch regulator (ACM) has noted that:

- in a situation where large scale generation has to follow load, network stability can be improved by sites having a flat consumption profile (this is the justification of the discount policy); but

[38] Kamerstuk 33777, nr. 3, 24-10-2013

- a situation in which load needs to follow generation is not reflected by the policy.

Unlike BNetzA, ACM did not go so far as to say that the need for flexibility is of growing importance. However, ACM did make clear that it was not able to comment on the quantified contributions large users bring to network stability and whether or not this justified the policy. Nor was it aware of the cost efficiencies to the network of a flat consumption profile.

In July 2022 ACM reported that there was currently insufficient evidence to affirm or maintain the discount.

4.1.3 France

In France, network charge discounts were originally made available to users that met EII threshold criteria on international competitiveness grounds. However, more recently measures of electro-intensity have been dropped from the eligibility criteria to reduce the potential for discrimination between sites that are electrically similar. Eligibility criteria now focus on the size of the load, the profile (stable or anti-cyclic) and a requirement for applicants to submit an energy performance plan. Thus EIIs typically still qualify but non-EII businesses are not directly excluded.

Table 6 Overview of network charging and discounts

Charging approach	Discount application	Discount rationale
■ Simple fixed charges and volumetric charges for the highest voltage connections ■ Complex fixed and volumetric charges for lower voltages with consideration of demand at different times of the day and year. ■ Geographic equalisation of charges (no locational difference in charges)	■ Discounts available for large users with a stable or off peak load profile or for very large users with a somewhat off peak load profile and storage providers. Eligible users must also provide an energy efficiency plan. ■ Discount is scaled based on the average cost of building a new line from the user to the nearest appropriate power station for each of the four user categories.	■ The stable or off peak load profiles contribute to the balancing stability of the system ■ High consumption sites are otherwise disadvantaged by the geographical equalisation of network charges

Source: *Frontier Economics analysis. For additional sources see Annex B*
Note: *[Insert Notes]*

The calculation of the size of the discount is conceptually similar to the German approach to calculating the discount for large users based on the costs of building and operating a direct connection, of appropriate scale, between the user and the nearest sufficient generation.[39] The costs of a direct line can be considered

[39] In France the hypothetical connection is to the nearest two sources of generation while in Germany it is just the nearest single source.

as an upper approximation of the incremental cost induced by a consumer site, disregarding certain operating constraints.[40]

In France, discounted rates are not applied individually for each site. Instead they are calculated for each end user site but then an average for each type of site (stable profile sites, anti-cyclic profile sites, large consumer sites) is applied to all sites of that type. This currently results in a reduction in network charges of between 74-81% for eligible end user sites.

In France there is no locational element to network charges as a result of a policy of geographic equalisation of charges. However, in general, high consumption sites tend to be located near to electrical production sites. Therefore, the costs of a direct line for these sites tend to be significantly lower than the general tariff. Thus, part of the justification for the discount in France is to reflect differences in average locations of high consumption sites (close to power production) relative to other users as this is not already captured in tariffs. As with the German approach, this has some similarities with the short haul tariff for GB gas transmission charging.

4.1.4 Spain

In Spain, network charge discounts are available to large users with a flat consumption profile that are electro-intensive businesses.

Table 7 Overview of network charging and discounts

Charging approach	Discount application	Discount rationale
■ Contracted capacity and volumetric charges which vary depending on different time periods. ■ No separately identified Cost Reflective charge element	■ Discounts available to customers with large and flat load profiles, which are electro intensive. ■ Discount covers costs of renewable support schemes as well as pure network access charges.	■ Industrial competitiveness and carbon leakage.

Source: Frontier Economics analysis. For additional sources see Annex B
Note: [Insert Notes]

Until recently in Spain (prior to March 2022), network cost discounts for EIIs only related to the elements of costs that are recovered through network charges but which do not relate to the network itself or the operation of the network (e.g. RES support costs). These were justified on the grounds of international competitiveness

40 For example, it could be considered as an upper bound because it ignores all the ability to share the user of assets that is inherent in a meshed electricity network.

for trade exposed EIIs. In March 2022, an 80% discount on the element of network charges that related to the cost of the network itself was introduced as a temporary measure and was also justified on the grounds of industrial competitiveness.

4.2 Summary of key insights from international review

In Germany, the Netherlands and France, network charge discounts are available to large or extra-large users with a flat or off peak load profile.

Justifications linked to the existing structure of network tariffs are that:

- network charges in Germany are partially based on contracted capacity which does not differentiate based on the timing of individual peak consumption. However, users that have their individual peak consumption outside of the time of system peak consumption contribute less to system stress and reinforcement requirements;
- network charges in the Netherlands are based on contracted capacity and monthly maximum used capacity. Neither of these account for differences in the timing of user peak consumption. However, users that have their individual peak consumption outside of the time of system peak consumption contribute less to system stress and reinforcement requirements; and
- network charges in France do not have any locational element to them, but large users tend to be located closer to large sources of generation.

Justifications linked to the value of large, flat and predictable loads are as follows:

- Germany and the Netherlands both refer to the benefits of matching large stable loads to classic baseload generation (although more recently regulators in both countries have questioned the applicability of this justification);
- The explanatory document accompanying the relevant Dutch legislation refers to such load contributing to grid stability and enforcement of the voltage quality; and
- The German regulator has highlighted that EII type demand can have positive effects on frequency and voltage stability.

Regulators and other bodies in Germany and the Netherlands have challenged the validity of discount justifications linked to the benefits that large stable loads provide to the system.

- In both Germany and the Netherlands the consistency of the rationale of matching stable load with classic baseload generation has been questioned in the context of increasing intermittent power generation.
- The German regulator has recommended that the discount for large users should only be available to plant that can react flexibly to network stress and the Federal Ministry of Economics and Energy noted that the current discount design disincentivises flexibility by large users.

- The Dutch regulator currently considers that there is insufficient evidence of the network or system benefits that large flat loads provide to justify extending the application of the discount.

In Spain network charge discounts are currently available to electro-intensive users on competitiveness grounds, although some of this discount relates to policy costs embedded in the network charge, rather than network costs per se. A similar justification was originally made in respect of network charge discounts in France, although this justification has subsequently been changed.

There are commonalities in how the size of discount is set in France and Germany. Both of these countries link the size of the discount available to qualifying sites to the cost of an alternative “direct line” to the nearest suitable sources of generation.

5 Rationale for exemptions in GB context

In this section, we consider whether there is a case for discounts to network charges in GB which is similar to those in some European countries. Given the structure of GB charges, with separate charges based on the principles of Cost Reflective and cost recovery charges, it is likely to be appropriate that a different rationale for discounts be developed for each category of charge (Cost Reflective and cost recovery).

As set out in the introduction, the case for a discount should rest on the answer to two key questions:

- Whether there are benefits that EIIs offer to the system which are not already reflected in the ***Cost Reflective*** charges they pay, meaning they should be facing lower cost reflective charges than they currently do;[41] and

- Whether there are reasons that would justify, for some EIIs, an exemption from all or part of the ***cost recovery*** charges.

In the previous section, we have identified a number of different potential rationales for a discount from the international review, some of which will be relevant for consideration in the context of Cost Reflective charges (i.e. more technical justifications related to benefits that EIIs may bring to the system) and some in the context of cost recovery charges (i.e. competitiveness arguments). In addition to the rationales identified in the international review, we have also considered other technical or economic justifications.

In this section, we discuss the case for discounting Cost Reflective and cost recovery charges in turn before reviewing the implications of the Trade and Cooperation Agreement (TCA) on the types of discounts that can be provided and concluding on potentially justified network charge discounts for GB EIIs.

5.1 Cost Reflectivity rationales

With regard to developing a rationale on the basis of cost reflectivity in the GB context it will be important to recognise the ways in which the GB charges are already Cost Reflective. In particular, any discount:

- must be because of a benefit/factor that the current charging regime does not already capture; or

- for which EIIs are not currently able to be remunerated through another means (e.g. by contracting with NG ESO).

This section is structured as follows:

- We first review the rationales identified internationally and discuss their relevance in the GB context;

- We then consider other potential technical justifications not identified by the international review; and

[41] There may be many reasons why the specific cost reflective charges could be improved, and with respect to Transmission charges they are currently under review which may improve their cost reflectivity further. This is not the subject of this study. The focus here is whether there is a justification for a differential treatment for EIIs over other forms of load.

- Finally, we draw conclusions on the strength of case for a discount on Cost Reflective charges.

5.1.1 Relevance of international rationales for GB

In assessing the relevance of international discount rationales for GB Cost Reflective charges, we group the observed rationales into two categories:

- those related to the existing structure of network tariffs in comparator countries; and
- those related to system benefits.

We consider each of these in turn below.

Rationale linked to tariff structures

German network tariffs are charged based on contracted capacity and volume consumed. Dutch network tariffs are charged based on contracted capacity and monthly maximum capacity utilised by the user. Neither of these tariff structures fully capture the fact that it is user consumption at time of system peak that is the main driver of network costs and the need for network reinforcement. Therefore, in the context of German and Dutch network tariffs, providing a discount to off peak consumption profiles or potentially a flat load profile (in that it could be argued that it uses the network more efficiently than a peakier profile) appears to have some merit.

However, in GB, network charges already reflect the consumption of the user at the time of system peak because of the time banded Cost Reflective elements of TNUoS and DUoS. Therefore, given the existing structure of GB network charges, it does not appear that a further discount related to consuming power during off peak periods would be justified.

French network tariffs are subject to a policy of geographic equalisation. As such there is no locational element. However, large users are typically located closer to large sources of generation than the generality of network users. Therefore, providing a discount that is linked to the difference in average location between large users and the generality of network users can make the charges more reflective of locational differences in costs.

In GB, network charges already have locationally Cost Reflective elements in TNUoS and DUoS (EHV level DUoS charges are calculated based on a detailed network model and reflect granular differences in location). Therefore GB EIIs which are in “helpful” locations from an overall network perspective should already be paying relatively lower transmission and distribution Cost Reflective charges. Therefore, given the existing structure of GB network charges, it does not appear that a discount related to the location of users would be justified.

Rationale linked to system benefits

The justification for both German and Dutch network charge discounts refers to the benefits that large stable loads can provide in terms of system operation and network stability. Regulators and other bodies in Germany and the Netherlands have challenged the validity of such discount justifications, and we have seen no rebuttals of these challenges.

In GB, there has been, and is expected to continue to be, a significant expansion in the deployment of intermittent RES. Thus, the conditions that Dutch and German regulators have said may undermine the case for a discount to large stable loads are also likely to exist in GB. Therefore, it does not appear that a discount based on the system benefits and network stability that large stable loads can offer would be justified in GB. Even if this rational did provide a justification for a discount we note that the scale of discount that is provided in Germany and the Netherlands significantly exceeds the share of GB network charges that are Cost Reflective. Therefore, to justify the scale of these discounts, the implicit Cost Reflective share of total network charges in Germany and the Netherlands[42] must be significantly larger than it is in GB. However, it is beyond the scope of this analysis to examine whether and why this might be the case.

When commenting on the lack of network stability offered by large stable loads in a system dominated by intermittent renewables, the German regulator noted that predictable EII demand could still have positive effects on frequency and voltage stability. To the extent that German EIIs have this positive impact on the German frequency and voltage stability we would in general expect a similar impact of British EIIs on GB frequency and voltage. Therefore, this benefit may justify a small discount related to the costs that the network incurs to manage frequency and voltage. We consider this in more detail in the next section.

5.1.2 Other potential technical justifications

Looking beyond the justifications identified in the International review, DNV has considered whether there are further potential technical arguments that could be used to justify cost reflective network charging adjustments (both positive and negative) for EIIs in GB. Below we provide a short summary of the key relevant findings from this review and assess of how possible justifications would work in the context of the GB network charging arrangements.[43]

Whilst this following discussion describes potential general justifications for network charge discounts, it is important to recognise that most of the technical arguments for network tariff reduction are site specific, and ultimately depend on the actual condition at the connection point to the network.

Table 8 Technical reasons for possible network charge adjustments

Description	Logic	Direction of adjustment: discount (-) or premium (+)
Fixed costs of serving a network user - proportionally lower administrative	There are certain costs per connected users that are largely invariant to the size of the user connection or the volume of energy they consume (e.g. administrative costs, metering costs and billing costs). Where this is the case and network charges are recovered through volumetric and capacity charges a	Discount

[42] We refer to the implicit share of Cost Reflective charges because Dutch and German network charges do not have the same Cost Reflective and cost recovery distinction as GB charges.

[43] The more detailed write up of the review is provided in Annex C.

Description	Logic	Direction of adjustment: discount (-) or premium (+)
costs for large users	discount for large users may be justified as the charging structure does not reflect the fixed nature of some costs.	
Reduced voltage and frequency control costs for stable users	When demand sites vary their load, all else equal, this causes voltage and frequency fluctuations on the electricity system. To keep voltage and frequency levels to within network tolerances, system operators must engage in voltage and frequency control activities. Voltage control can either be through contracts that procure reactive power services from generators or through the investment in and utilisation of network assets (e.g. capacitors and inductors). Frequency control can be through the procurement of frequency control services (e.g. fast frequency response). Sites with stable load profiles that exhibit little variation in load introduce fewer voltage and frequency fluctuations on the system and therefore reduce network demand for voltage and frequency control services.	Discount
Power quality issues	Large industrial customers sometimes have demand characteristics that create more power quality issues for electricity networks than other load types. For example: Switching type loads can cause power surges while welding machines and HVAC equipment can cause harmonic distortion.[44] This can lead to networks having to incur additional costs to manage power quality.	Premium
Flexibility of demand	Large load users may be able to offer to adjust load in response to network requirements and reduce the overall cost of building and maintaining the network.	Discount

Source: DNV

Note: The DNV review also identified possible rationale linked to the allocation of electrical losses and allocation of network economies of scale. However, in the context of GB network charging neither of these factors would link to Cost Reflective charges and therefore are not included in this summary table.

Proportionally lower administrative costs for large users

If network charging arrangements do not reflect the structure of costs imposed by network users on the network, this may justify a discount. However, unlike other European countries, metering is not the

[44] https://www.hanover.com/businesses/business-customer-resources/hanover-risk-solutions/power-quality-commercial-and

responsibility of the network in GB. Instead it is the responsibility of the supplier. Billing, customer service and general administration are also handled by energy suppliers rather than networks.

It is also the case that GB EHV distribution charges incorporate a site specific fixed element that does not vary with connection capacity or volume consumed. Therefore, to the extent that there are some fixed, per site, costs to DNOs, these can be reflected in DUoS charges.

Overall, it does not seem likely that a GB network charge discount could be justified because of proportionally lower administrative costs for large users.

Reduced voltage and frequency control costs for stable users

Users with very stable load patterns cause system operators to incur lower voltage and frequency control costs relative to an equivalently sized more variable load. This finding from the technical review also seems to align with comments by the German regulator that large stable loads can contribute to voltage and frequency stability.

The current structure of GB Cost Reflective network charges does not include a charge or payment for voltage or frequency control per se. Rather, Cost Reflective voltage and frequency control signals at the transmission level are sent by the contracting for the provision of reactive power, voltage control and frequency control services by NG ESO.[45] The costs of procuring these services are recovered through BSUoS charges that apply equally to all users.

A discount on network charges for users with stable load patterns may be justified on a Cost Reflective basis if customers that are more helpful than average, in terms of limiting voltage and frequency control costs, are not able to capture this value through ancillary services contracting with NG ESO. This could apply to EIIs with stable load patterns. However, in principle such a discount could equally apply to non-EII network users with equivalently stable load patterns.

In theory, a Cost Reflective charge for voltage and frequency control could be introduced where market participants are charged the incremental impact on voltage and frequency control costs of their consumption level and profile. In that case, network users with stable load patterns should benefit from paying a smaller contribution to voltage and frequency control costs than other loads (i.e. effectively receiving a discount), as well as paying lower cost recovery charges (because the total costs that need to be recovered as cost recovery charges would be reduced due to greater Cost Reflective revenue collection). However, precise calibration of such a charge is unlikely to be a practical solution as identifying the incremental impact of load profile on voltage and frequency control costs may not be feasible. However, were it possible to calibrate such a charge or discount, its impact on EII costs is likely to be moderate.

---

45 Frequency control is intrinsically linked to the control of the aggregate system supply and demand balance. At the temporal resolution of the imbalance settlement period (30 min in GB) network users (or their suppliers) are responsible for balancing their demand with contracted supply and therefore effectively managing their frequency impact. They face Cost Reflective imbalance charges when they are out of balance at the 30 minute level. However, at a sub 30 min resolution the system operator has responsibility for balance supply and demand (and hence frequency) and the costs that it incurs to do so are socialised.

To give a sense of scale of a potential voltage control discount, ESO incurred costs of £275m in 2021/22 to manage voltage constraints.[46] If network users with a very stable load were exempt from all voltage control costs (which is likely to be a significant overestimate of the voltage control benefits these users provide) this would imply a discount of around £1/MWh.[47] Furthermore, at the distribution level, we note that the EHV Cost Reflective charging methodology incorporates some charges that will provide an incentive for connected users to manage their impact on network voltage. The EHV Cost Reflective charging methodology is complex and we have not assessed it in detail. However, the presence of connection charges measured in kVA and excess charges for exceeding this means that a site that exceeds its expected impact on voltage will face additional costs.[48] Therefore, conversely, a site that places minimal voltage control requirements on the network may already benefit from lower EHV DUoS costs.

To give a sense of scale of a potential frequency control discount, ESO is forecasting a frequency control cost for the charging year 2023/24 of £390m. If network users with a very stable load were exempt from all frequency control costs (which is likely to be a significant overestimate of the frequency control benefits these users provide) this would imply a discount of around £1.40/MWh.[49]

Power quality issues

Large users with certain load characteristics can induce additional network costs to manage power quality issues. As far as we are aware, marginal impacts on power quality of different sites are not reflected in network charges.[50] Therefore, in principle, this may justify a differentiated charge of load based on its impact on power quality. If this were implemented it would amount to an increase in charges for some EIIs rather than a discount.

These issues may need to be weighed against other possibly justified reasons for a discount (e.g. relating to lower voltage control costs).

Demand flexibility

Certain large demand loads may be able to reduce system and network costs by providing demand flexibility. However, for two reasons this is not a reasonable justification for a discount on network charges in the GB context.

46 https://data.nationalgrideso.com/constraint-management/outturn-voltage-costs

47 Forecast BSUoS volumes for 2023/24 are 276 TWh. This implies that a £275m total annual bill is equal to around £1/MWh in BSUoS charges. For comparison, baseline BSUoS charges are around £17.5/MWh, so a £1/MWh discount on BSUoS charges would be worth around 6% of BSUoS charges for relevant customers.

48 The connection capacity is measured in terms of apparent power (kVA) which captures both the active and reactive power drawn by the site. If a user does not manage their voltage impacts, reactive power drawn can increase resulting in excess capacity charges without additional active power being consumed by the site.

49 Forecast BSUoS volumes for 2023/24 are 276 TWh. This implies that a £390m total annual bill is equal to around £1.40/MWh in BSUoS charges.

50 We are aware that EHV users face a site specific losses assessment. Therefore, because power factors affect distribution losses, sites with low power factors will face higher losses adjustments. However, this does not address issues of surges and harmonics.

First, the system benefit of users reducing demand at times of system peak demand (which is one key element of flexibility) is already reflected in Cost Reflective network charges for TNUoS and DUoS because of their time banding.

Second, if demand sites are able to offer additional value to the network beyond reducing peak demand this can be remunerated through ancillary services contracts that reflect the value the flexibility provider provides to the network. Therefore, providing a discount reflecting this additional flexibility would double count its value.

5.1.3 Conclusions on strength of case for GB Cost Reflective discount

Overall, there does not appear to be a strong case for significant Cost Reflective discounts in GB network charges for EIIs. In many respects, the structure of GB network charges is already aligned to the drivers of network costs (e.g. accounting for locational and temporal aspects of cost drivers). Historic discount justifications linked to a predominance of classic baseload generation capacity do not seem suitable for the current and future GB market.

The only Cost Reflective discount that we have identified a potential justification for is the reduction in voltage and frequency control costs for users with stable loads. However, this is unlikely to represent a very material discount (likely to be equivalent to less than a £2.40/MWh reduction in BSUoS costs) and is likely to be highly complex to calibrate. We also note that the provision of frequency and voltage control services is undertaken by the ESO through ancillary services markets and therefore in principle an alternative way of recognising frequency and voltage control benefits could be through adaptations to these markets.

5.2 Cost recovery rationale

In the international review we identified some limited examples of discounts being justified on the basis of industrial competitiveness in Spain and France, though in the case of France this was only a temporary justification and was also accompanied by technical justifications. However, despite competitiveness not being a commonly used rationale in other European countries, the structure of GB network charges means that it may be more clearly applicable.

As demonstrated in Section 3.3.3, the majority of the network costs for GB EIIs relate to cost recovery charges. As noted in Section 3.1, these charges are generally set to ensure network companies can recover the cost of building, operating and maintaining the network.

There is no single, right way to set cost recovery charges, as these costs are not attributable to any specific network user. As part of the TCR, Ofgem outlined that the following three key principles should guide tariff setting and, therefore, the allocation of cost recovery charges. These are:

- reducing harmful distortions;
- fairness; and
- proportionality and practical considerations.

The key principle for the economic efficiency of cost recovery charges is that they should reduce harmful distortions, or induce minimal changes in behaviour. In relation to this, Ramsey pricing is a recognised approach to determining prices in a way that minimises distortions.

The Ramsey pricing principle sets out that deviations from optimal consumption patterns resulting from Cost Reflective charges are minimised when cost recovery is concentrated on the goods, services or customer types that have the lowest price elasticity of demand (the “inverse elasticity” rule). More specifically, according to this rule, customers that are relatively price inelastic should be charged a higher price than those who are price elastic, as their demand will respond less for a given price increase.

Ofgem did not, as part of the TCR, adopt a full Ramsey pricing approach. However, the Ramsey principle does present a possible justification for discounting cost recovery charges for network users that are particularly likely to reduce their electricity demand in response to such a charge (price elastic users). To the extent that it can be argued that EIIs are particularly likely to reduce their electricity demand in response to the charge then this could justify a discount for EIIs on the basis of reducing harmful distortions.[51]

In response to the application of cost recovery charges, price elastic users, including EIIs, could (inefficiently) reduce demand for network electricity, thereby avoiding network charges, in a number of ways.

- **Relocation in response to international competitiveness** – network users may close or relocate their operations outside of GB, which is a particular risk for EIIs that are exposed to significant international competition (this effect may be exacerbated by network charge discounts elsewhere). To the extent that the network charge drives this behaviour, industrial activity that would have otherwise been economic would be inefficiently moved outside of the UK. This justification has already been applied by BEIS to exemptions to indirect carbon costs and low carbon policy support costs.

- **Investment in BTMG** – network users may choose to invest in BTMG to reduce net consumption, in particular to avoid volumetric BSUoS charges. Given the current scale of BSUoS, and general expectations that it will remain high in future (forecasts of average BSUoS demand charges in 2023/24 are around £17-18/MWh[52]), this is likely to remain a strong incentive for network users. It would over-incentivise BTMG at the expense of other cheaper grid connected alternative sources of supply, and would be relevant whether a network user faces significant trade intensity or not.

- **Disconnection from the network** - In the extreme, network users may invest in sufficient BTMG (including necessary back up generation) to completely disconnect from the electricity network. By disconnecting they would avoid all network charges. There are many factors that would affect the likelihood of this outcome. For example, the extent to which the regulatory regime would allow an easy reversal of any disconnection decision, and the incremental costs required to achieve sufficient BTMG capacity to disconnect i.e. it will be more economic for a site with significant existing BTMG to build additional back-up capacity and disconnect than a site with no existing BTMG at all.

[51] In this context, a reduction in electricity demand should be considered relative to a counterfactual without cost recovery charges and, as such, includes where investment in new EII demand is prevented because of the cost recovery charges.

[52] NGESO BSUoS forecast, October 2022, https://data.nationalgrideso.com/balancing/bsuos-monthly-forecast

All of these responses would represent inefficient outcomes, increasing overall electricity system costs. It also follows that while the costs faced by non-EII users would increase if they had to fund a discount for EIIs, in principle, they would not necessarily be worse off compared to if an EII discount were not provided. This is because EII avoidance behaviour (of the type set out above) could anyway result in higher costs for those (non-EII) customers who are not engaged in avoidance behaviour.

This provides a potential justification for applying a discount. However, this raises the following questions regarding its potential design:

- Is it likely that EIIs will engage in network charge avoidance behaviour, and if so, how should EIIs that are most likely to adjust their behaviour in response to the network charge be identified?

- For those EIIs most at risks, what should be the level of the discount?

To be consistent with the Ramsey principle it is important that the discount is limited to parties that would otherwise change their behaviour, and thereby avoids adding unnecessary further costs to non-EII users. If EIIs would not engage in network charge avoidance behaviour (including reduced investment in new EII activity in GB) in the absence of a network charge discount, then the provision of discount to EIIs would not serve the purpose of preventing a distortion and result in a net increase in costs to other network users.

While it is out of scope of this report to assess the likelihood of significant network charge avoidance behaviour by EIIs, if a significant concern regarding international competition is evidenced, there is some logic to applying the same energy and trade intensity thresholds that apply to existing EII exemptions (e.g. those for low carbon policy support costs). With regard to the other potential distortions, the risk of complete disconnection is likely to be relatively low. However, the risk of further inefficient BTMG investment to avoid BSUoS is likely to have a broader base than just EIIs with a high trade intensity.

With regard to the level of the discount, in principle, Ramsey pricing provides an economic justification for discounts of up to 100% of cost recovery charges. A discount of 100% would ensure that distortions are avoided for eligible EIIs, although it may also raise fairness concerns, as the costs of the discounts would be shouldered by other network users.

In theory, to calibrate the discount that ensures an efficient outcome (i.e. avoids distortions) while minimising the cost increase for other customers, it would be necessary to set the discounted charge to ensure it is less than or equal to the relevant alternative option:

- In the case of closure or relocation, this would require an analysis of the profitability of different EII types operating in different jurisdictions and how this might be affected by GB network charges. The calibrated level of discount necessary would vary over time, by industry, and also more than likely be site specific. This would not be practical to calculate.

- In the case of BTMG investment or disconnection from the network, the calculation is likely more tractable. However, it is still likely to vary considerably based on site specific factors (such as available land), existing availability of BTMG and other commercial considerations.

It is worth noting that France and Germany conduct site specific calculations based on an assessment of an alternative option (although France only applies an averaged version of this calculation). Both France and

Germany calculate discounted tariffs for eligible users based on the cost of a hypothetical direct line between the individual network users site and the nearest suitable generation.[53] In theory, this represents a calculation in the spirit of setting a charge less than or equal to an alternative option. However, in the GB context, it is not clear that such a calculation would correlate with the calculations outlined in the bullets above. In other words, it would not actually represent the cost of the possible practical alternative options for EIIs.

5.3 Review of TCA constraints

It is our understanding that any discount or exemption from network charges that is made for EIIs will need to comply with the requirements of the Trade and Cooperation Agreement ("TCA"), concluded between the EU and the UK in December 2020.[54] While we are not able to provide a legal opinion on the TCA, we are experienced in the requirements for regulation and network charging arrangements. On this basis we have identified a limited number of key requirements of the TCA for any future EII network charge exemption or discount.

The first and most directly relevant requirement of the TCA is Article 306 on the subject of Third-party access to transmission and distribution networks. Article 306 requires that:

> *"each Party shall ensure that charges applied to entities in that Party's market by transmission and distribution system operators for access to, connection to or the use of networks, and, where applicable, charges for related network reinforcements, are appropriately cost-reflective and transparent.*
>
> *…*
>
> *Each Party shall ensure that the tariffs and charges referred to in paragraphs 1 and 3 are applied in a non-discriminatory manner with respect to entities in that Party's market"*

Based on this requirement, our understanding is that any exemption or discount that was purely based on certain users imposing lower costs on the network would be consistent with the TCA. However, the non-discriminatory condition may mean care is required when setting the eligibility for any purely cost reflective discount. Limiting discounts to EIIs if the technical characteristics are not limited to EIIs may present a significant challenge.

It also appears possible, given the structure of many of the GB network charges, for discounts that are not associated with a technical parameter to be consistent with the Article 306 requirements. Specifically, as we discuss above, GB network charges are separated into "Cost Reflective" charges and "cost recovery" charges, and cost recovery charges constitute the majority of revenue collected by networks.[55] These charges do not reflect the cost to the network of the connected user but are necessary to fund the sunk investments that the network companies have made into the network. In principle, any allocation of these charges between network users is as cost reflective as any other, in the sense that it is a pure cost allocation question.

53 Exact details of how this is calculate and how it is applied is different between Germany and France. However, conceptually they are equivalent.

54 TCA, 2020; https://ec.europa.eu/info/strategy/relations-non-eu-countries/relations-united-kingdom/eu-uk-trade-and-cooperation-agreement_en

55 BSUoS is 100% cost recovery, TNUoS is mostly cost recovery in most regions (and only cost recovery in some regions) whilst for DUoS Cost Reflective charges can be a larger share but cost recovery charges are still very significant.

Therefore, EII discounts associated with the cost recovery element of GB network charges could be considered "*appropriately cost-reflective and transparent*".

Article 366 of the TCA also appears potentially relevant to the issue of network charge discounts for EIIs. Article 366 requires that:

> *(a) subsidies pursue a specific public policy objective to remedy an identified market failure or to address an equity rationale such as social difficulties or distributional concerns ("the objective");*
>
> *(b) subsidies are proportionate and limited to what is necessary to achieve the objective;*
>
> *(c) subsidies are designed to bring about a change of economic behaviour of the beneficiary that is conducive to achieving the objective and that would not be achieved in the absence of subsidies being provided;*

Adjustments to the Cost Reflective elements of network charges would not seem to qualify as subsidies. However, it is a legal question as to whether discounts that are effectively a change in the allocation of cost recovery charges between network users could be construed as a subsidy. If they could, then the discount would need to "*remedy an identified market failure or to address an equity rationale*" and the discount granted must be "*proportionate and limited to what is necessary to achieve the objective*".

In the context of Ramsey pricing, as outlined in Section 5.2, EIIs changing their electricity consumption behaviour to try to avoid cost recovery charges could lead to an overall increase in electricity system costs. This would represent a market failure (or a deviation from the efficient outcome) which could potentially justify an adjustment to the imposition of cost recovery charges, if such adjustments are considered to be subsidies.

Finally, Annex 27 to the TCA on the subject of energy and environmental subsidies also appears potentially relevant. It requires that:

> *"If compensation for electricity-intensive users is granted in the event of an increase in electricity cost resulting from climate policy instruments, it shall be restricted to sectors at significant risk of carbon leakage due to the cost increase."*

It is a legal question as to whether this provision relates to end user electricity costs (and therefore includes network charges) or only to wholesale electricity costs (and therefore excludes network charges). If the provision is interpretated as relating to end user electricity costs then it is relevant to note that the total costs of building and maintaining the electricity network can be strongly influenced by climate policy instruments. Therefore, compensation to EIIs related to the impact on network charges of climate policy instruments may need to be "*restricted to sectors at significant risk of carbon leakage due to the cost increase*".

5.4 Conclusion on potentially justifiable EII network charge exemptions in GB

Overall we conclude that in general, the discounts applied in other European countries do not directly translate into the GB context. The structure of GB charges is different, and as a result some of the justifications for discounts applied in Europe are already reflected in the Cost Reflective charges or other markets.

However, through this review we have identified two potential justifiable discounts for EIIs in GB:

- A Cost Reflective discount for network users with stable load profiles on the basis that this can reduce voltage and frequency control costs, although the complexity may mean it is not practical, and in any case it is likely to be very small; and
- A cost recovery discount for network users that would otherwise be at risk of engaging in inefficient behaviour to avoid cost recovery charges.

Given the importance of cost recovery charges to EII costs (at least 80%), a cost recovery discount has the potential to have a much greater impact on EII costs. It could be applied consistent with current exemptions based on trade exposed sectors, but could also be broader for those that could invest in BTMG. It would be important to ensure any discount could be limited to parties that would otherwise change their behaviour, in order to avoid adding unnecessary further costs to non-EII users. If eligibility was wider than trade exposed sectors then defining a clear and justified boundary for eligibility could be challenging. In principle, a discount on cost recovery costs could be up to 100%, although such a level could potentially raise fairness considerations as the cost of the discount would be paid for by other customers, and may be contrary to the proportionality requirements in the TCA if the discount is construed as a subsidy.

6 Impact of EII demand reduction and discounts

In this section we present illustrative calculations of the impact on other network users if EII users were provided a 100% discount on all cost recovery elements of network charges. Due to a range of data limitations which we describe below, these results are only intended to provide a broad sense of scale for the possible impacts on different types of users, and therefore should only be interpreted as illustrative.

The rationale for providing a discount on cost recovery network charges, as set out in the previous section, is to prevent eligible users from engaging in socially inefficient network charge avoidance behaviour (e.g. relocation internationally, investment in BTMG or disconnection from the network).

To understand fully the impact on other users of an EII discount, any assessment needs to be compared to an appropriate counterfactual. In other words, we should compare:

- the costs to other network users that arise due to EII network charge avoidance behaviour in a counterfactual where discounts are not offered; and
- the direct cost of applying a discount that needs to be recovered from other network users, plus any EII network charge avoidance behaviour that continues to take place should the discount be less than 100%.

Therefore, the impact on other network users, depends on the extent of avoidance behaviour in the counterfactual, the level of the discount offered, and the behavioural response by EIIs to the discount. For example:

- If we assume a 100% discount, and that absent the discount 100% of network charges would have been avoided by EIIs, then the impact of the discount would be to prevent socially inefficient avoidance behaviour without additional costs to other network users. However, if, as is more likely to be the case, not all network charges would have been avoided in the counterfactual, then the inefficient avoidance would still be prevented but with some increase in costs to other network users.
- Alternatively, if the discount is small and does not prevent any avoidance behaviour that would have taken place in the counterfactual, then the impact on network users will at best be unchanged, but costs could also increase to the extent the discount is also provided to EII users that would not have changed their behaviour in the counterfactual.

It is not possible to estimate the cost of avoidance behaviour in the counterfactual or under different levels of discount, therefore, in this analysis we focus our estimates on the direct cost of any discount, while noting that the final impact on customers could be more or less than this value. We also note that at least in principle the rational for a network charge discount for EIIs (Ramsay pricing) could be used to justify discounts on network charges for a much wider range of network users than just EIIs. If this were the case then the impacts could be significantly larger than those estimated for EIIs below and may raise further fairness and proportionality considerations.

In the rest of this section we first set out the basis of the calculations that we undertake, including the range of assumptions that we make. We then present the key findings from the analysis.

The full analytical results are presented in Annex D -

6.1 Key assumptions

As noted earlier in Section 3.3 when estimating current EII network charges, we do not have access to detailed data on EII users in GB. Therefore, similar to the earlier calculations we base our approach on EII archetypes. We also make some additional assumptions in order to estimate aggregate impacts across all EIIs.

First, we have to make assumptions about the number of EII sites that may potentially be eligible for network charge discounts. We have assumed there are 310 EII sites in GB that could be eligible. This is based on the number of unique sites we understand are eligible for either compensation for the indirect emission costs in electricity prices or an exemption from the indirect costs of funding Contracts for Difference (CFD), the Renewables Obligation (RO) and the small scale Feed in Tariff (FIT).[56]

Of the 310 sites, we have assumed that 10 of these are Archetype 4 users i.e. a large (100,000MWh annual consumption) transmission connected user. This is based on data from NGESO that shows that there are 10 sites in TNUoS residual charging band 3, which is the charging band that Archetype 4 falls into.[57] We assume that the other 300 sites are Archetype 1 users i.e. a smaller (20,000 MWh annual consumption).

We calculate network charges for each of our archetype users (as we did in Section 3.3) and aggregate the results up for all EIIs using the assumptions above to calculate the total value of TNUoS and BSUoS cost recovery charge discounts.

To calculate the impact of a DUoS discount, in addition to the data and assumptions above, we must also make assumptions about the spatial distribution of eligible EIIs between DNO regions. We do not have data on which to make this assumption. Therefore, we have simply assumed that each DNO region has 1/14th of the total assumed EII EHV connected users. We recognise that this is a major simplification and that the true distribution of EIIs between DNO regions is unlikely to be uniform, and therefore just present this calculation as an illustration for a single region.

Finally, we calculate the impact of the redistribution of costs on the annual network charge bill for an average customer in each of the 21 TNUoS/DUoS charging bands. This means that we present results for all levels of voltage connection and for users ranging from the small to the very large.

- To calculate the TNUoS and DUoS redistribution impact, we calculate the aggregate cost of the discount as a percentage of the aggregate TNUoS and DUoS cost recovery charges. We then apply this percentage as an uplift to the existing fixed £/site/year charges that a user in each band would face.

56 Based on discussions with BEIS officials we understand that there are around 300 sites eligible for an exemption from the costs of CfDs, the RO and FIT costs and around 60 sites eligible for compensation for the indirect costs of carbon emission in electricity prices. However, there is significant overlap in eligible sites between these two schemes such that the number of unique sites is around 310.

57 In total there are 65 T-connected users in GB and in reality some T-connected EIIs will fall into different charging bands.

- To calculate the BSUoS redistribution impact, we first calculate the increase in the £/MWh BSUoS charge necessary to allow for the aggregate cost of the discount to be recovered across the non-EII charging base (£0.52/MWh) and then multiply this by the average consumption of a user in each charging band to calculate the annual impact.

6.2 Key findings

6.2.1 TNUoS and BSUoS

Providing a 100% discount to EIIs in respect of their BSUoS and TNUoS cost recovery charges results in an increase in these charges for other users of around 3%. This is equivalent to an annual increase of:

- around £2.80 for an average domestic user;
- up to £6,750 for a high voltage user;
- up to £89,000 for an EHV user; and
- up to £230,000 for a large transmission connected user.

The impact on other users is proportional to the size of the discount provided to EIIs. Therefore, if EIIs were provided a 50% discount then the increase in these charges for other users would be around 1.5% instead of 3%.

As noted above, the actual impact on other users is dependent on the degree of charge avoidance that would have taken place absent any discounts. Therefore, if EIIs engaged in charge avoidance (via relocation or BTMG) such that their total cost recovery TNUoS and BSUoS bill was reduced by 50% then the impact of applying a 100% discount on other network users would be half the direct cost of the discount.

6.2.2 DUoS

The DUoS charging regime treats users connected to the EHV network separately from all other users. There is one charging methodology and one set of cost recovery charges that applies to domestic users and both high and low voltage non-domestic customers. There is a separate charging methodology and separate set of cost recovery charges for EHV connected users.

Given our assumption that all EII customers that pay DUoS charges are connected to the network at the EHV level,[58] non EHV connected customers do not face any impacts on their DUoS bills from providing a DUoS cost recovery discount or from EIIs engaging in behaviour to avoid DUoS cost recovery charges.[59]

DUoS charges are also regional. Illustratively, looking at the South East DNO region, we calculate that a 100% discount on DUoS cost recovery charges for EIIs could result in an increase in DUoS cost recovery

58 We understand that there may be a small number of EIIs connected at HV level but we expect that the vast majority of EIIs that pay DUoS charges are connected at the EHV level.

59 In principle these charging methodologies could be adjusted if the impact of an EII discount on non-EII EHV users was deemed to be too large and the burden needed spreading more widely.

charges for other EHV users of around 12%.[60] This is equivalent to between around £340 and £12,000 depending on the size of the EHV connected user. It should be noted that this result is highly illustrative and the impact on any individual EHV connected site will vary significantly depending on both the total scale of cost recovery charges in the region and the proportion of EHV connected users in a given region that are eligible for a discount.

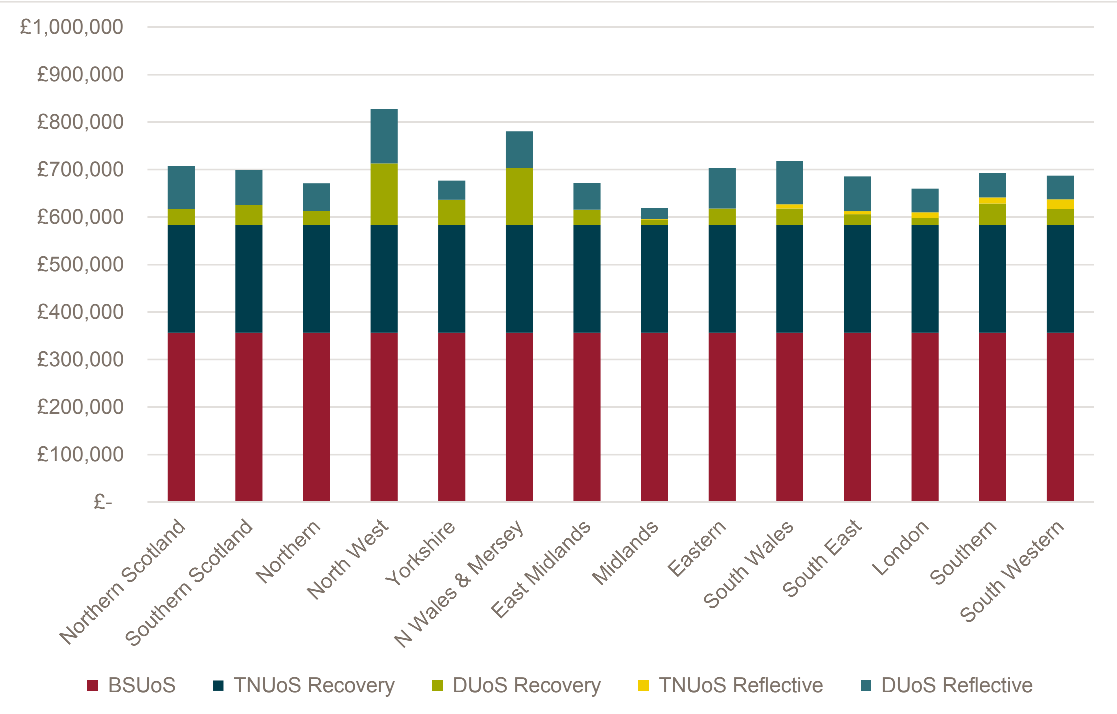
60 This calculation is highly illustrative and final outcomes are likely to vary significantly between regions.

Annex A - Additional Archetype charge results

In section 3.2.4 we presented the results of our archetype network charging analysis for all archetypes for an example DNO region. However, the charges faced by EIIs varies by region. Therefore this annex provides the full set of results for each archetype and each region. For ease of comparability, the first three charts (for archetypes 1-3) all have the same Y axis scaling as each other and the second three charts (for archetypes 4-6) have the same scaling as each other. The two different sets of Y axis scaling reflects the difference in the scale of annual consumption between archetype group 1-3 and archetype group 4-6.

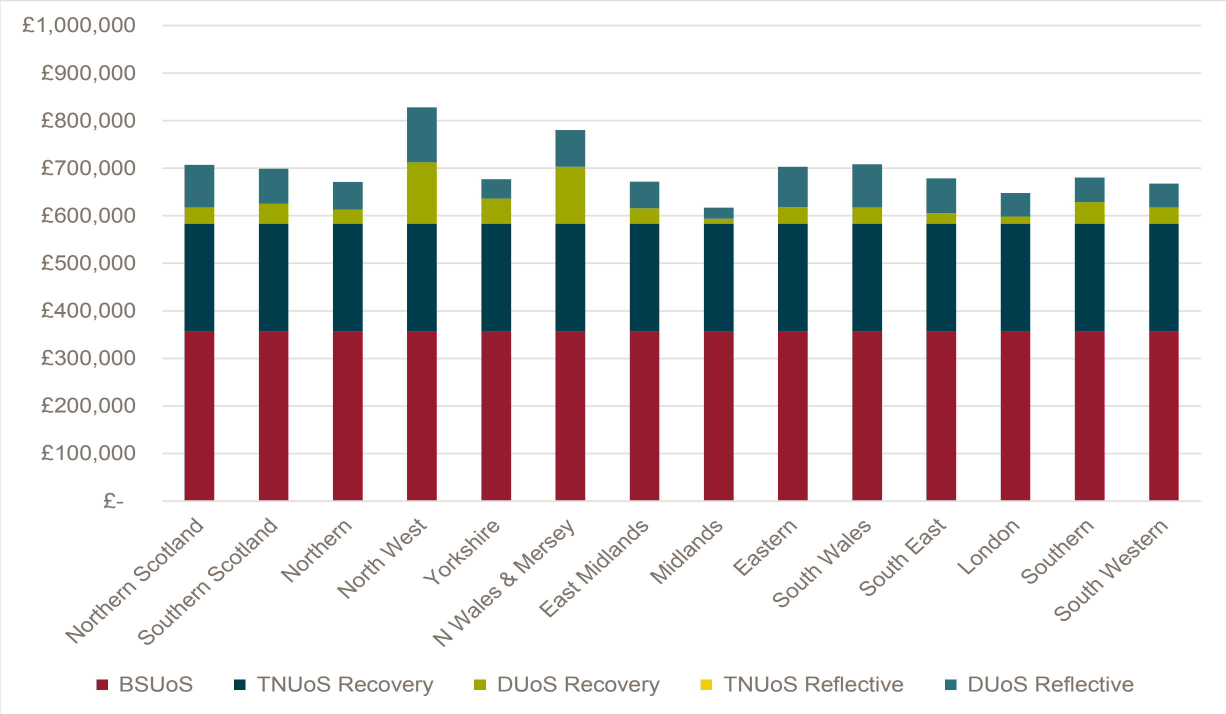
Whilst the charts below provide additional detail on the charges in each region, the key messages from the results are largely unaffected by the region considered.

Figure 5 Archetype 1 annual network charges by DNO region



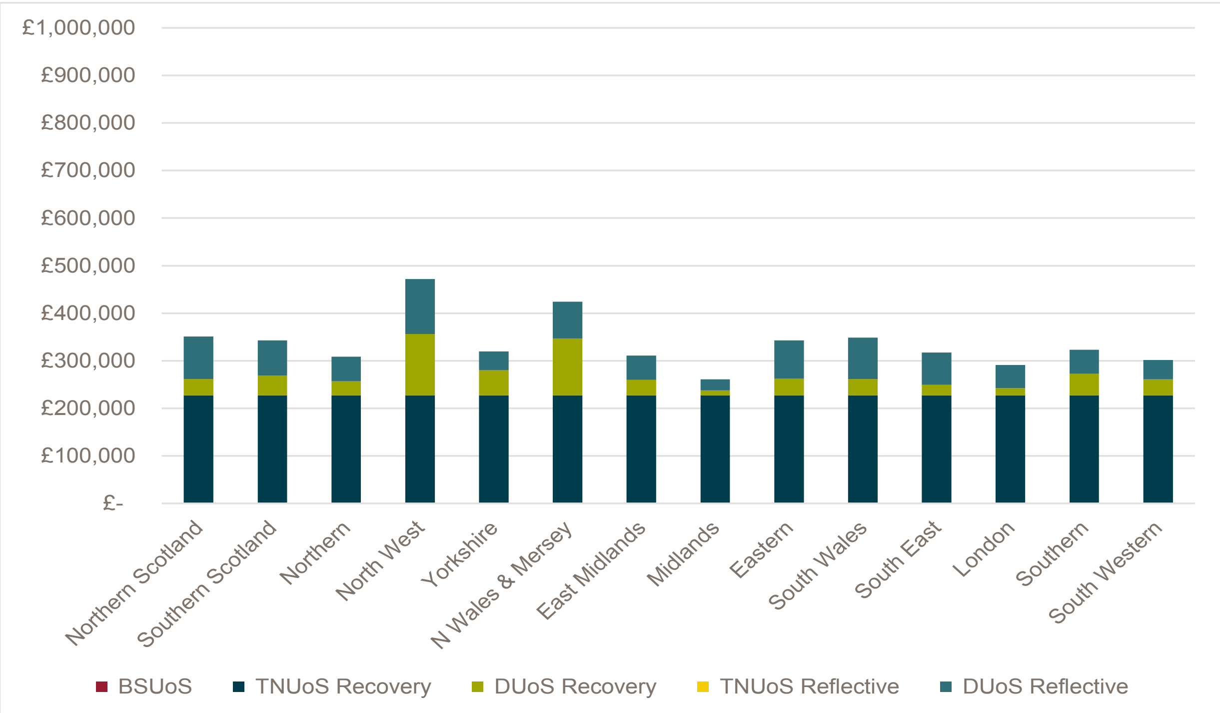
Source: Frontier Analysis based on published charging statements and BSUoS forecasts.
Note: Charges calculated for the charging year 2023/24 assuming the implementation of CMP308 and CMP361.

Figure 6 Archetype 2 annual network charges by DNO region



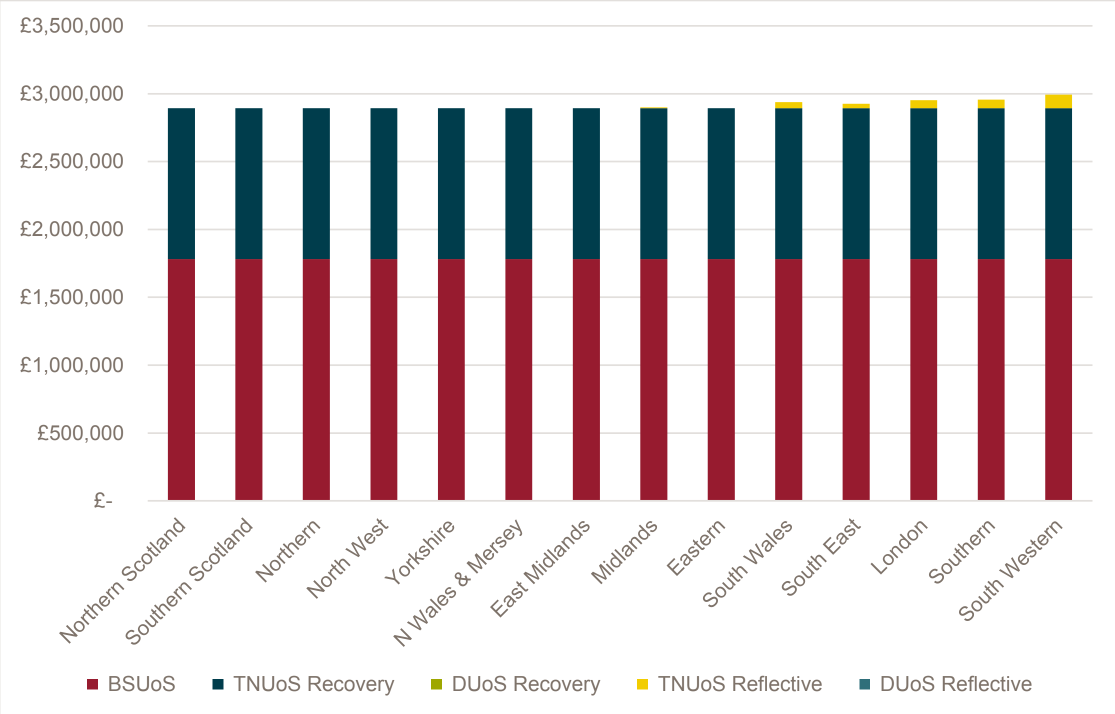
Source: Frontier Analysis based on published charging statements and BSUoS forecasts.
Note: Charges calculated for the charging year 2023/24 assuming the implementation of CMP308 and CMP361.

Figure 7 Archetype 3 annual network charges by DNO region



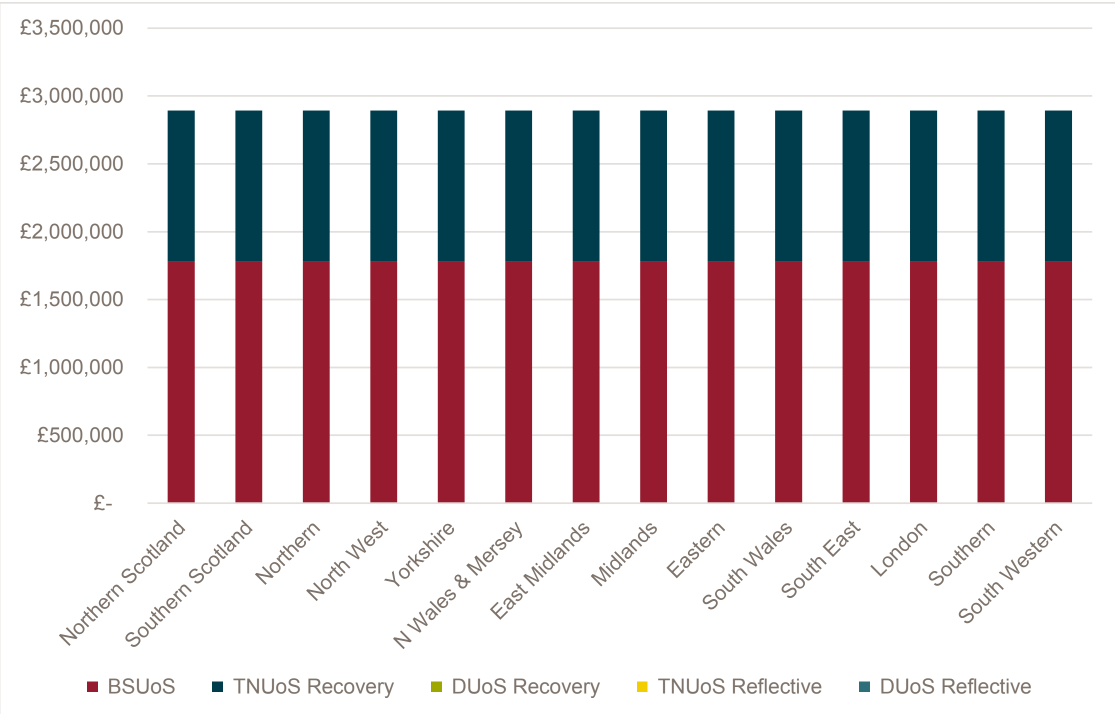
Source: Frontier Analysis based on published charging statements and BSUoS forecasts.
Note: Charges calculated for the charging year 2023/24 assuming the implementation of CMP308 and CMP361.

Figure 8 Archetype 4 annual network charges by DNO region



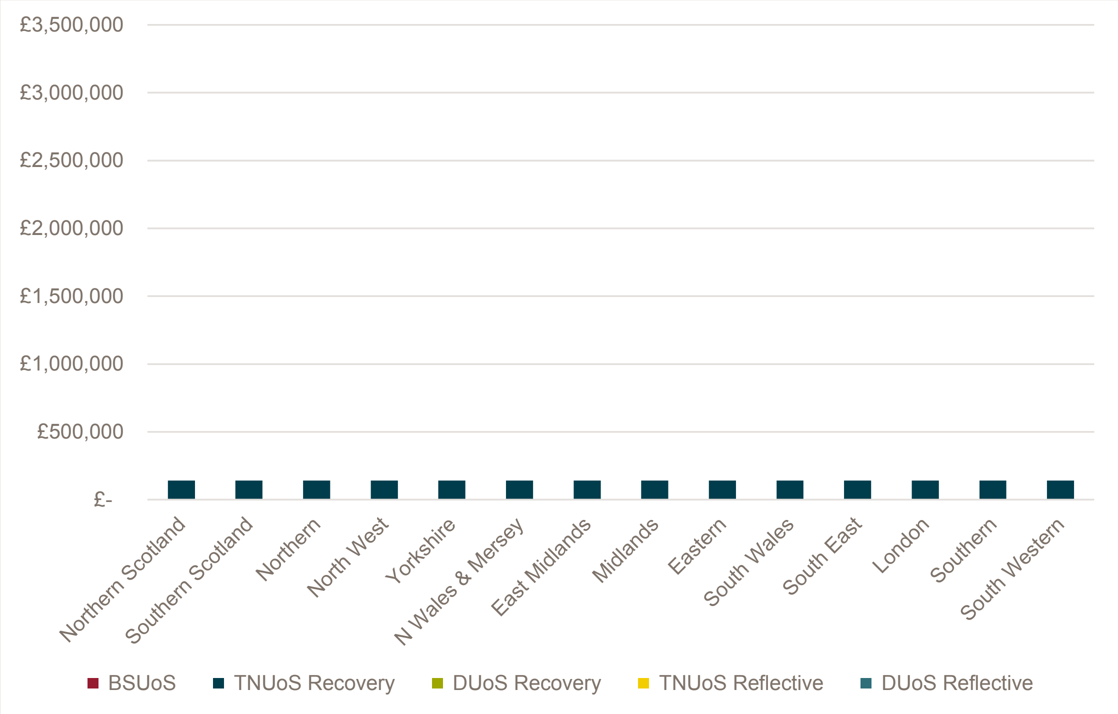
Source: Frontier Analysis based on published charging statements and BSUoS forecasts.
Note: Charges calculated for the charging year 2023/24 assuming the implementation of CMP308 and CMP361.

Figure 9 Archetype 5 annual network charges by DNO region



Source: Frontier Analysis based on published charging statements and BSUoS forecasts.
Note: Charges calculated for the charging year 2023/24 assuming the implementation of CMP308 and CMP361.

Figure 10 Archetype 6 annual network charges by DNO region



Source: Frontier Analysis based on published charging statements and BSUoS forecasts.
Note: Charges calculated for the charging year 2023/24 assuming the implementation of CMP308 and CMP361.

Annex B - International Comparisons case studies

In this annex we discuss the rationale for exemptions in selected European counties. For each of the countries we discuss:

- the structure of transmissions system charges including:
  - which costs are recovered through the tariffs, e.g. including network losses and system services;
  - whether the tariffs are based on separate cost-reflective and cost-recovery elements;
  - whether the tariffs are differentiated based on location or not;
  - how the tariffs are structured, e.g. volumetric, annual peak, monthly peak, contract or actual capacity;
  - current tariffs (expressed in native format); and
  - if available, the proportion of revenue collected by each of the tariffs;
- the exemption or discount provided, including the level of the discount and the conditions for the discount;
- the publicly available rationale for the discounts; and
- historic and current developments for the discount, as appropriate.

B.1. Germany

B.1.1 - Tariff structure

In Germany, all network operator charges are applied to load (i.e. not on generators). The TSO tariffs include the recovery of costs for network losses and system services. They do not include seasonal or geographical price signals (i.e. there is no seasonal or geographical differentiation in tariffs).[61]

The tariffs are recovered from customers through both volumetric and capacity charges.[62] More specifically, customers connected to the maximum voltage network (Höchstspannung (“HöS”), with voltage exceeding

[61] ENTSO-E: Overview of Transmission Tariffs in Europe: Synthesis 2019, p.8: https://eepublicdownloads.entsoe.eu/clean-documents/mc-documents/201209_ENTSO-E%20Transmission%20Tariff%20Overview_Synthesis%202019.pdf

[62] ENTSO-E: Overview of Transmission Tariffs in Europe: Synthesis 2019, p.14: https://eepublicdownloads.entsoe.eu/clean-documents/mc-documents/201209_ENTSO-E%20Transmission%20Tariff%20Overview_Synthesis%202019.pdf

125kV[63]) or high voltage network (Hochspannung ("HS"), with voltage between 72.5kV and 125kV[64]) are charged on the basis of:

- a capacity charge, based on the annual contracted capacity (kW);
- a consumption charge, based on the annual volume of energy consumed (kWh); and
- a metering charge, which is a fixed charge related to the costs of metering and invoicing.[65]

Table 9 Network usage tariffs DE, Tennet region, 2022

ANNUAL OPERATING HOURS :		≥2,500 h/a		<2,500 h/a	
		CAPACITY CHARGE (€/kW)	CONSUMPTION CHARGE (ct/kWh)	CAPACITY CHARGE (€/kW)	CONSUMPTION CHARGE (ct/kWh)
Maximum voltage network ("HöS")	Company-specific network fee	21.26	0.09	2.91	0.82
	Federal network fee	57.10	0.41	9.32	2.32
	Total network fee	**78.36**	**0.50**	**12.23**	**3.14**
High voltage network ("HS")	Company-specific network fee	23.05	0.06	4.19	0.81
	Federal network fee	63.82	0.29	13.32	2.31
	Total network fee	**86.87**	**0.35**	**17.51**	**3.12**

63 BNetzA, Monitorbericht 2021, p. 530: ;
TenneT: https://www.tennet.eu/de/stromnetz/unser-stromnetz/netzausbau

64 BNetzA, Monitorbericht 2021, p. 530: Bereiche von Elektrizitätsversorgungsnetzen, in welchen elektrische Energie in Höchst-, Hoch-, Mittel- oder Niederspannung übertragen oder verteilt wird (§ 2 Nr. 6 StromNEV)

65 FORBEG May 2020; A European comparison of electricity and natural gas prices for residential, small professional and large industrial customers; https://www.creg.be/sites/default/files/assets/Publications/Studies/F20220513EN.pdf

B.1.2 - The exemption

Customers with particular consumption characteristics may be eligible for reduced network costs.[66] Paragraph 19(2) of the StromNEV (German Electricity Network Fees Ordinance) identifies two eligible groups of atypical network users:

- electricity intensive network users; and
- non-peak network users.

We explain the nature of the exemption or discount available to each of these user types below.

Electricity-intensive network users

A grid fee reduction is available for energy intensive customers, typically heavy industry customers, with:

- annual consumption in excess of 10 GWh; and
- annual usage hours in excess of 7,000 hours.

The maximum fee reduction depends on annual usage hours.[67] The total usage hours are calculated as customer's total annual consumption divided by maximum annual load capacity. For example, for a customer with annual consumption of 20,000,000kWh and maximum load of 2,500kW, annual usage hours = 20,000,000kWh / 2,500kW = 8,000h.[68]

The network charge reduction in a given year is calculated using total annual consumption from the previous year.[69]

66 Bundesnetzagentur December 2015: Bericht der Bundesnetzagentur zur Netzentgeltsystematik Elektrizität; https://www.bundesnetzagentur.de/SharedDocs/Downloads/DE/Sachgebiete/Energie/Unternehmen_Institutionen/Netzentgelte/Netzentgeltsystematik/Bericht_Netzentgeltsystematik_12-2015.pdf?__blob=publicationFile&v=1

67 ENTSO-E: Overview of Transmission Tariffs in Europe: Synthesis 2019, p.55: https://eepublicdownloads.entsoe.eu/clean-documents/mc-documents/201209_ENTSO-E%20Transmission%20Tariff%20Overview_Synthesis%202019.pdf

68 BNetzA FAQ, 22, : https://www.bundesnetzagentur.de/DE/Beschlusskammern/BK04/BK4_71_NetzE/BK4_71_Ind_NetzE_Strom/Downloads/FAQ_Haeufig_gestellte_Fragen.pdf?__blob=publicationFile&v=4

69 TenneT: Individual grid charges as per §19 para. 2 Clause 2 StromNEV: https://netztransparenz.tennet.eu/electricity-market/german-market/grid-charges/individual-grid-charges-as-per-19-para-2-clause-2-stromnev/

Table 10 Grid fee reduction conditions

ANNUAL ELECTRICITY CONSUMPTION	ANNUAL USAGE HOURS	MAXIMUM GRID FEE REDUCTION
>10 GWh	≥ 7,000 hrs	80% reduction
>10 GWh	≥ 7,500 hrs	85% reduction
>10 GWh	≥ 8,000 hrs	90% reduction

Source: Bundesministerium der Justiz, §19 Sonderformen der Netznutzung; https://www.gesetze-im-internet.de/stromnev/__19.html

Note: The grid fee reduction conditions apply on an individual site basis[70]

The fulfilment of the necessary consumption and annual usage conditions, summarised in Table 10 above, does not guarantee reduced network tariffs for electricity-intensive customers. In addition to meeting these conditions, the customers must either contribute to a reduction of network costs or prevent network costs from increasing in order to become eligible for a discount.[71] This is assessed by comparing the cost of the general network tariff to the cost of physical network between the site of the customer and a suitable power generation plant. This is the so-called "physical path" analysis.

The size of the reduction of network tariffs associated with a customer is calculated by first estimating, the cost of a hypothetical network that connects the customer's connection point to a suitable power generation plant[72] on the already existing network route. The difference between the costs of this hypothetical network usage[73] and the general network tariffs that the customer would ordinarily be charged constitutes the customer's contribution to reducing or avoiding an increase in the network tariff at the respective voltage level.[74] In principle, this applies to all voltage levels.[75]

Non-peak network users

The second group of customers that may receive tariff reductions are non-peak network users. These users are identified by looking at their existing or forecasted consumption data or their technical and contractual circumstances. If, from this evidence, it is clear that the peak load of a customer will considerably deviate from the peak load of the network (i.e. if the customer's peak load occurs at a different time period than the

70 In Germany there are several examples of EIIs with consistent load profile (>7,000 hrs/yr). For example glass plants, refineries and possibly data centres. Electricity consumption, however, varies considerably depending on the presence of on-site generation. Qualification is likely to focus on those EIIs that do not have onsite generation.

71 BNetzA Beschluss BK4-13-739, 2014, p.6: https://www.bundesnetzagentur.de/DE/Beschlusskammern/1_GZ/BK4-GZ/2013/2013_bis0999/2013_bis799/BK4-13-0739/BK4-13-0739_Beschluss.pdf?__blob=publicationFile&v=8

72 Power plants able to continuously cover the end user's electricity consumption needs.

73 The costs of the physical path are computed from the annuities of the operating resources, cost of provision of grid reserve services in the event of power plant failure (if necessary), cost of ancillary services (if necessary), grid loss costs and, in the case of building the hypothetical physical path up to the nearest network node, the network charges of the upstream voltage level.

74 BNetzA Beschluss BK4-13-739, 2014: https://www.bundesnetzagentur.de/DE/Beschlusskammern/1_GZ/BK4-GZ/2013/2013_bis0999/2013_bis799/BK4-13-0739/BK4-13-0739_Beschluss.pdf?__blob=publicationFile&v=8

75 BNetzA Calculation tool according to § 19 paragraph 2 sentence 2 StromNEV: https://www.bundesnetzagentur.de/DE/Beschlusskammern/BK04/BK4_71_NetzE/BK4_71_Ind_NetzE_Strom/Downloads/Tool_ind_NetzE_22-12-2021.xlsx?__blob=publicationFile&v=2

maximal power in the grid[76]), the network operator is required to offer an individual network tariff to the customer. The individual tariff offered should account for the specific usage behaviour of the customer.

The networks' general, published network tariffs forms the basis for calculating individual tariffs. Calculating the individual network tariff involves the following steps.

- The general capacity charge is multiplied by the highest measured capacity value within the network's peak load window, determined one year in advance.[77]
- The consumption charge is multiplied by the measured annual consumption.
- When summed, the outcomes of steps 1 and 2 constitute the individual network tariff.

If the individual network tariff amounts to less than 20% of the general network tariff, it is limited to this value as stipulated by Paragraph 19(2) of the StromNEV.[78] In other words, the discounted tariff must not fall below 20% of the published network tariff.[79] In principle, this applies to all voltage levels.[80]

Table 11 below summarises how general network tariffs and the individual network tariffs are calculated.

Table 11 Calculating individual network tariff for non-peak network users

CALCULATION OF GENERAL NETWORK TARIFF	CALCULATION OF INDIVIDUAL NETWORK TARIFF
Capacity charge x annual maximum contracted capacity + consumption charge x annual consumption = general network tariff	Capacity charge x highest measured capacity value within peak load window + consumption charge x annual consumption = individual network tariff
Condition: individual network fee ≥ general network fee x 20%	

Source: *Bundesnetzagentur; Verinbarung ueber ein individuaelles Netzentgelt gemaess §19 Absatz 2 Satz 1 StromNEV: https://www.bundesnetzagentur.de/DE/Beschlusskammern/BK04/BK4_71_NetzE/BK4_71_Ind_NetzE_Strom/Paragr_19Abs2Satz1/2018/Netzentgelte_Paragr19_2_S1_Mustervereinbarung_12-03-2018_dl_BF.doc?__blob=publicationFile&v=4*

---

76 Bundesnetzagentur December 2015: Bericht der Bundesnetzagentur zur Netzentgeltsystematik Elektrizität; https://www.bundesnetzagentur.de/SharedDocs/Downloads/DE/Sachgebiete/Energie/Unternehmen_Institutionen/Netzentgelte/Netzentgeltsystematik/Bericht_Netzentgeltsystematik_12-2015.pdf?__blob=publicationFile&v=1

77 Federal Ministry of Economics and Energy, Electricity market for energy transition, 2015, p. 70: https://www.bmwk.de/Redaktion/DE/Publikationen/Energie/weissbuch.pdf?__blob=publicationFile&v=33

78 Bundesnetzagentur; Verinbarung ueber ein individuaelles Netzentgelt gemaess §19 Absatz 2 Satz 1 StromNEV: https://www.bundesnetzagentur.de/DE/Beschlusskammern/BK04/BK4_71_NetzE/BK4_71_Ind_NetzE_Strom/Paragr_19Abs2Satz1/2018/Netzentgelte_Paragr19_2_S1_Mustervereinbarung_12-03-2018_dl_BF.doc?__blob=publicationFile&v=4

79 Bundesministerium der Justiz, §19 Sonderformen der Netznutzung; https://www.gesetze-im-internet.de/stromnev/__19.html

80 Bundesnetzagentur; Verinbarung ueber ein individuaelles Netzentgelt gemaess §19 Absatz 2 Satz 1 StromNEV, p.2-3: https://www.bundesnetzagentur.de/DE/Beschlusskammern/BK04/BK4_71_NetzE/BK4_71_Ind_NetzE_Strom/Paragr_19Abs2Satz1/2018/Netzentgelte_Paragr19_2_S1_Mustervereinbarung_12-03-2018_dl_BF.doc?__blob=publicationFile&v=4

Transmission system operators are required to reimburse downstream distribution network operators for lost revenues resulting from individual network charges awarded to electricity-intensive and/or non-peak customers. These payments, as well as the transmission system operators' own lost revenues, are to be balanced between the four transmission network operators.

German legislation states that the costs described above can be passed proportionally to end consumers in the form of a surcharge – resulting in maximum increases in the network fees of:

- 0.025 c/kWh for electricity consumed in excess of 1GWh for industrial customers in the manufacturing sector, whose electricity costs in the past year exceeded 4% of their respective revenues; and
- 0.05 c/kWh for electricity consumed in excess of 1GWh for other customers.[81]

The surcharge for the first 1GWh of electricity consumed is not stipulated in the legislation. In 2022, this surcharge was equal to 0.437 c/kWh.[82, 83]

B.1.3 - The rationale provided

Between 2011 and 2013, electricity users with annual consumption above 10 GWh and with a particularly stable electricity consumption profile were fully exempt from paying network charges. This exemption was based on the alleged stabilising effect that energy-intensive network users have on the network. The exemption was financed by a special levy imposed on final electricity consumers (the so-called §19-surcharge, introduced in 2012).

As the surcharge was obligatory under German law and the German State had control over the funds and the revenues from the §19-surcharge were considered state resources. Consequently, the full exemption granted in years 2012 and 2013 constituted State aid (as defined by the European Union) to the exempted electricity users. Germany had, however, not presented any compatibility ground for the aid. While it had referred to the stabilising impact of the exempted users on the networks, it did not quantify such impact.[84] According to the European Commission, each user should pay for the costs it causes to the network. The European Commission therefore concluded that there was no objective justification for the full exemption from network charges because large and stable network users also generate costs and make use of network services.[85]

As a result, the German legislation was amended in 2013.[86] Under the current provisions, according to the rationale provided in the legislation, the individual network charge is intended to reflect the atypical network users' (i.e. electricity-intensive network users' and non-peak network users') contribution to the reduction of

81 Bundesministerium der Justiz, §19 Sonderformen der Netznutzung; https://www.gesetze-im-internet.de/stromnev/__19.html

82 'The charge is less than half a cent per kWh. Illustratively a GB domestic customer has typical electricity consumption of around 3,000kWh/year. At this level of consumption, the charge implies an annual cost to the user of €13.11

83 Netztransparenz.de, Umlage nach § 19 Abs. 2 StromNEV für 2022 (§ 19 StromNEV-Umlage)

84 Commission Decision, 2018: On Aid scheme implemented by Germany for baseload consumers under paragraph 19 StromNEV, p.14: 247905_2014230_596_2.pdf (europa.eu)

85 EC Press release, May 2018; https://ec.europa.eu/commission/presscorner/detail/en/IP_18_3966

86 Bundesanzeiger Verlag, 2013: Verordnung zur Änderung von Verordnungen auf dem Gebiet des Energiewirtschaftsrechts, p.5;

overall network charges or to avoiding an increase in network charges.[87] The minimum contribution for atypical network users (i.e. 20% of the general network fee for non-peak network users and 10%-20% of the network fee for electricity-intensive users, as described above) is intended to guarantee that they financially contribute to the management of the public grid to which they are connected.[88]

Below, we detail the views of various German government bodies on the current provisions.

Views expressed by the Federal Council of Germany and German Federal Government

According to the Federal Council of Germany and the German Federal Government: "flexible large-scale customers can, under certain conditions, relieve the network and can offer their flexibility on the electricity market".[89]

Nevertheless, according to the recommendations of the committees of the Federal Council of Germany, published at the end of 2015, the current system of network tariffs may negatively affect flexibility incentives, in particular for large industrial customers. [90] This is because the network tariffs, both published and individual (discounted) tariffs are partially based on peak load.[91] This means that customers are reluctant to increase their peak load even if, at times, this may be beneficial for network stability. A similar view was also shared in the 2016 draft legislation of the German Federal Government.[92]

View expressed by Federal Ministry of Economics and Energy

According to the Federal Ministry of Economics and Energy, flexible, electricity-intensive network users can offer flexibility in the electricity market and relieve the network.[93]

However, as the need to react flexibly to market price signals increases with the share of intermittent wind and solar power in the generation mix, the view of Federal Ministry of Economics and Energy (2015) is that even greater flexibility should be promoted and individual network charges should be revised to ensure they are not restricting the flexibility potential. Further, the Ministry outlined that the current individual network tariffs for electricity-intensive customers are indeed restricting this flexibility potential, as below.

- Flexible large-scale customers are strongly incentivized to maintain their consistent purchase behaviour, as they may lose their network fee reductions if they decrease their consumption (if full load hours fall below the outlined thresholds).

---

87 Bundesministerium der Justiz, §19 Sonderformen der Netznutzung; https://www.gesetze-im-internet.de/stromnev/__19.html

88 Commission Decision, 2018: On Aid scheme implemented by Germany for baseload consumers under paragraph 19 StromNEV, p.8: 247905_2014230_596_2.pdf (europa.eu)

89 German Federal Government, 2016, Draft of a law for the further development of the electricity market, p.177: https://dserver.bundestag.de/btd/18/073/1807317.pdf

90 Federal Council of Germany, Recommendations of the committees, 2015 p. 28: https://dserver.bundestag.de/brd/2015/0542-1-15.pdf

91 This is either by connection capacity or expected peak load at time of system peak demand.

92 German Federal Government, 2016, Draft of a law for the further development of the electricity market, p.167: https://dserver.bundestag.de/btd/18/073/1807317.pdf

93 Federal Ministry of Economics and Energy, Electricity market for energy transition, 2015, p. 70: https://www.bmwk.de/Redaktion/DE/Publikationen/Energie/weissbuch.pdf?__blob=publicationFile&v=33

- For non-peak customers, current network tariff reductions also lead to limited incentives to provide flexibility. If a non-peak customer were to increase electricity consumption during the system's peak load window this could lead to a decrease in the network tariff reduction, as described above. As the network's peak load windows are determined one year in advance, there is a limited incentive for atypical network users to adapt their behaviour to the actual current network situation. These incentives to provide flexibility are increasing in importance, as the expansion of wind and solar power (which means that maximum power flow over certain network elements may not be at the time of peak system demand) requires the possibility to adjust the system's peak load windows more regularly. Incentives should therefore encourage consumers to adapt their behaviour to reflect the network situation more precisely and thus contribute to stable grid operation and the relief of network stress.[94]

View expressed by the Bundesnetzagentur

In 2015, the Bundesnetzagentur[95] ("BNetzA") also shared sceptical views regarding the aforementioned exemptions. BNetzA stated its belief that atypical network users no longer bring significant benefits in terms of network cost reductions or network stability. This applied in particular to the reduced network costs for electricity-intensive network users, though BNetzA also appeared sceptical towards the potential benefits of non-peak network users.

In relation to electricity-intensive network users, BNetzA expressed the opinion that consumption matching with the must-run capacities of classic base load power plants will become less important in the future. Consequently, whilst energy intensive customers with their large and stable power consumption may provide positive effects on frequency and voltage stability they will become less important with regard to network stability. The inflexibility of such customers may, in certain situations, even become damaging for the network. For example, in situations of critical network states, it may intensify such situations. Therefore, according to BNetzA, the reduced tariffs for electricity-intensive network users need to be modified in such a way that the reduced tariffs only benefit flexible network users.

In relation to non-peak network users, as noted above, BNetzA questioned the benefits they bring. This is because the consumption behaviour of customers, in particular at lower voltage levels, often only has a comparatively minor impact on total network costs. At the same time, a relatively strong free-rider effect (in which network users that provide little benefit to the system still seek to receive the discount) can be observed if large discounts to network costs are provided. Nevertheless, BNetzA did not consider complete abolition of this provision necessary because of its partly positive impact. According to BNetzA, only customers connected to high voltage levels should benefit from the provision, as these customers can actually generate benefits for the network operator.[96]

---

94 Federal Ministry of Economics and Energy, Electricity market for energy transition, 2015, p. 75-76: https://www.bmwk.de/Redaktion/DE/Publikationen/Energie/weissbuch.pdf?__blob=publicationFile&v=33

95 Federal Network Agency for Electricity, Gas, Telecommunications, Post and Railway

96 BNetzA 2015, Bericht Netzgeltsystematik Elektrizität, p75-76: https://www.bundesnetzagentur.de/SharedDocs/Downloads/DE/Sachgebiete/Energie/Unternehmen_Institutionen/Netzentgelte/Netzentgeltsystematik/Bericht_Netzentgeltsystematik_12-2015.pdf?__blob=publicationFile&v=1

B.1.4 - Recent developments

In September 2022, BNetzA announced the initiation of a procedure, which included the intention to determine the right to continue the aforementioned individual (discounted) network tariffs. In the context of the currently significantly reduced gas imports to Germany, there are companies that would be willing and able to reduce their production by lowering their respective gas purchases. These companies would consequently also need to adapt their electricity network usage behaviour. A purpose of the initiated review with regard to the individual (discounted) network tariffs is to ensure that these companies would not be additionally affected by the loss of their entitlement to a network tariff reduction as a result of their flexible response to gas market conditions.[97]

B.2. Netherlands

B.2.1 - Tariff structure

Large customers connected to the high voltage network (HV: 110/150 kV) or extra-high voltage network (EHV: 220/380 kV) are charged on the basis of two tariff parameters:

- kW contracted on an annual basis; and,
- maximal kW utilised per month, summed across the year.

Table 12 Transmission tariffs NL, 2022

	KW CONTRACTED	MAXIMUM KW UTILISED PER MONTH
EHV	€15.21	€1.65
HV	€27.24	€2.79

Source: *rekenmodule-tarievenbesluit-tennet-2022, extracted from https://www.acm.nl/nl/publicaties/tarievenbesluit-tennet-2022*

The tariffs are calibrated such that TenneT recovers 50% of its allowed revenue per voltage level on the basis of each tariff parameter.[98] These allowed revenues include the recovery of costs for network losses and system services. Customers do not face a volumetric charge. There is no geographical differentiation in tariffs.

Unlike the tariff methodology in GB, there is no explicit differentiation between cost-reflective and residual (cost recovery) elements in the tariff methodology. Instead, cost reflectivity is used as a principle to apportion allowed revenue collection from different customers at different voltage levels.

97 BNetzA, 2022: https://www.bundesnetzagentur.de/DE/Beschlusskammern/1_GZ/BK4-GZ/2022/BK4-22-0086/BK4-22-0086_Verfahrenseinleitung_Konsult.html?nn=355992

98 A very small share (<1%) of revenue is recovered independently from transport-related charges.

Customers connected to the middle voltage network (25-50 kV) face a similar tariff structure based on kW contracted and maximum kW utilised per month, but the exact tariffs are different and depend on the specific distribution network. The tariff structure for customers connected to the medium voltage network (1-20 kV) also includes a volumetric kWh charge.

A separate tariff is determined as part of the tariff methodology for customers with a very low load factor. This tariff is not part of the exemption regime described in the next section.

B.2.2 - The exemption

The exemption for EIIs is set out in the Dutch Energy Act and was introduced in 2013.[99] The exemption applies to sites with the following characteristics:

- consumption of at least 50 GWh annually; and,
- a minimum load factor of 65% during off-peak hours, where the load factor is the consumption relative to the peak power requirement.

The discount is independent of the network and voltage to which the site is connected.[100] The size of the discount is determined based on the formula below, which consists of two elements.[101]

- The first element reflects the volume of electricity consumed, and leads to a gradually increasing discount per incremental GWh consumed above 50 GWh, with a maximum considered consumption of 250 GWh. The volume value is calculated in the following way:

  $Volume\ value = ((\min\ (annual\ consumption\ (GWh), 250\ GWh) - 50\ GWh)/(250\ GWh - 50\ GWh))$*100%.

  A total consumption of 250 GWh or more leads to a volume value of 100%. A total consumption of 100 GWh leads to a value of 25%.

- The second element is designed to capture the 'flatness' of a consumption profile and leads to a gradually increasing discount with every increment of the calculated off peak load factor above 65%. The values used for the load factor are set such that these reflect and reward a relatively flat consumption profile. The load factor is calculated based on the total off-peak consumption, which is then:
  - extrapolated to all hours of the year; and,
  - considered relative to the maximum required power (maximum kW p.a.).

---

99 Elektriciteitswet 1998, last amendment on 01-08-2022, article 29, paragraphs 7-10

100 In 2013, it was estimated that 30 to 35 sites would be eligible for the discount, of which 9 were connected to the high voltage network. The total discount across all network operators was estimated to be €21 million. Kamerstuk 33777, nr. 3, 24-10-2013

101 The elements and later "values" are separated in this paper for clarity. The Energy Act sets out the single formula, but the accompanying explanatory document does explicitly discuss the two elements separately

  – Consumption during peak hours is not considered.

- The minimum off-peak load factor for eligibility is 65%, representing what is considered a minimum for a relatively stable load, with a maximum of 85% used in the calculation, which is considered as a very flat but attainable load profile. The load value is calculated in the following way:

$$Load\ value = (\min\ (load\ factor\ (\%), 85\%) - 65\%)/(85\% - 65\%)$$

A load factor of 85% or more (described as very flat) leads to a load value of 100%. A load factor of 70% leads to a load value of 25%.

The resulting discount is then determined by multiplying the two values, with a maximum discount of 90%:

$$Discount = \min\ (volume\ value * load\ value, 90\%)$$

A site with an annual consumption of 250 GWh or more and a load factor of 85% or more is eligible for a discount of 90% (maximum discount). A site with an annual consumption of 100 GWh and a load factor of 70% is eligible for a discount of 6.25%.

In 2013 the average discount for the 10 largest users was estimated to be 55%.[102]

B.2.3 - The rationale provided

The qualitative rationales[103] for the exemption are set out in the accompanying explanatory document.[104]

- The first rationale relates to the management of the system, and is described as: *"Due to a flat and predictable consumption profile energy-intensive companies contribute to grid stability and enforcement of the voltage quality by the grid operator of the national high-voltage grid."*

- The second rationale relates to the required network reinforcements, and is described as: *"Customers with a flat consumption profile also make relatively efficient use of the available network capacity. That is to say, customers with the same consumption but a less flat consumption profile cause more peaks in the grid, causing more congestion and requiring grids to be expanded earlier."*

The discount is therefore based on the two characteristics through which large consumers are deemed to create benefits to the system: their significant consumption (expressed through the volume value described above), and their flat load profile (expressed through the load score).

The policy also recognises two other factors contributing to the stability of the electricity system.

102 Kamerstuk 33777, nr. 3, 24-10-2013

103 Whilst qualitative rationales are provided we are unaware of public information on the justification of the specific quantitative level of the discounts.

104 Staatscourant 2013 nr. 32872, 27 November 2013

- Demand reductions during peak hours: In order not to disincentivise demand reductions at peak times, the load value is calculated only based on the consumption during off-peak hours, or, put differently, the load factor is based on an extrapolation of the load factor during off-peak hours to the entire period.

- Residual energy use: An energy consumer who self-generates from residual or by-products (e.g. heat or gas) contributes to energy efficiency and is able to contribute to balancing of the wider system by self-generating. In order not to disincentive own production from these sources, the hours of self-generation are considered in the load value. Residual energy use is not considered in the volume factor, because the contribution to the stability of the network is only relevant in case of significant consumption from the network.

As part of the legal and parliamentary process in 2013, both the regulator (ACM) and the Council of State[105] were consulted. They provided the following advice and commentary on the policy.

- The Council of State noted that the policy does not make clear what the cost structure of the maintenance and operation of the network is. Similarly, it does not quantify the claimed efficiencies that the large and stable loads of EIIs bring to the network within the context of this cost structure. This makes an assessment of compliance with the principles of non-discrimination and cost-reflectivity difficult.[106]

- ACM provided the following commentary:
  - ACM defines network stability as the ability of the system to return to stable operations after a sudden change in load, generation or network availability. In a situation with large scale generation following load, network stability can indeed be improved by a flat consumption profile. ACM also noted that a situation in which load needs to follow generation (more demand response) is not reflected in the policy.
  - ACM was not able to comment on the quantified contributions large users bring to network stability and whether or not this justified the policy, nor was ACM aware of the cost efficiencies to the network of a flat consumption profile.

B.2.4 - Recent developments

National regulatory authorities in the EU have the authority to set network tariffs, including discounts such as those set out above. This was affirmed by the 2021 ruling from the European Court of Justice, [107] which highlighted the existing provisions of the Electricity Directive that confirm regulatory independence. As a result of this, the legal basis for the discount can no longer be the Dutch Energy Act, but must be a decision from ACM.

---

105 The Council of State is a constitutionally established advisory body on governance and legislation to the Dutch government and parliament and highest general administrative court.

106 Staatscourant 2013 nr. 32872, 27 November 2013

107 C-718/18, European Commission v Federal Republic of Germany, Judgment of 2 September 2021

In July 2022, ACM announced that it is reviewing the discount.[108] At the same time, it noted the evidence presented in parliament is insufficient for ACM to affirm or maintain the discount. It is therefore seeking external consultancy support to assess whether large industrial users contribute to lower costs. To avoid uncertainty and to allow for a proper legal process, the current discount will remain in place through 2023.

B.3. France

B.3.1 - Tariff structure

Network use tariffs are called TURPE in France, also referred to as "Tarifs d'acheminement de l'électricité" and their level is decided by the French regulator (CRE).[109] The relevant tariff for the transmission network is the TURPE HTB.

The CRE sets the TURPE methodology every four years and revises it yearly, to reflect inflation in particular. The current TURPE tariff is the TURPE 6 and is made up of a number of different sub-charges,[110] meaning that there is not a single tariff that applies. Rather, the tariff depends on the type of customer/entity connected and the voltage level of connection. For example, a large user's (connection voltage over 350 kV) tariff is made up of a base level of fixed annual charge, volumetric charges for grid injections and grid withdrawals, as well as additional charges if the site has a backup line, with values as below:[111]

- a fixed charge of just under €10,000 per site per annum;
- €23/MWh for any injections;
- €33/MWh for withdrawals; and
- at least €110,000 if the site has a backup line (with an additional cost of €10,134 per kilometre of line).[112]

Volumetric charges for lower voltage customers are more complex and allow for the consideration of consumption during peak and off peak hours and during high and low seasons.

There is no locational differentiation in the TURPE, that is the same charges apply irrespective of location.

B.3.2 - The exemption

Since 2014, EIIs have benefitted from a reduction in electricity transmission network use tariffs.

---

108 https://www.acm.nl/nl/publicaties/acm-onderzoekt-korting-grootverbruikers-elektriciteit-en-laat-deze-2023-onveranderd

109 The TURPE recovers the costs of network losses and system services.

110 CRE outlines the current sub-parts of the tariff in its decision https://www.cre.fr/Documents/Deliberations/Decision/evolution-au-1er-aout-2022-turpe-6-htb-et-montant-de-la-compensation-a-verser-a-strasbourg-electricite-reseaux (page 27-31)

111 The range of charges are listed in the CRE's publication, Annex 3:

112 To give an order of reference, the TSO in France, RTE, the discount for electro-intensive users was €166 m in 2021, compared with €4,212 m of forecast revenue (4.1% of post-discount planned revenues)

The first reduction applied to industries between 1 August 2014 and 31 July 2015. It was a one-off rebate of 50% on transmission network tariffs to eligible EIIs and was said to cover companies in the chemical, metallurgy, steel, paper and cardboard industries. The French regulator, CRE, introduced this first reduction given its consideration of the price-sensitive nature of electricity intensive companies and their exposure to international competition.

To be eligible for the reduction, companies had to be directly connected to the network or connected on a settlement basis and had to meet one of the two following conditions:

- had used its connection for at least 7,000 hours in the year with energy used of over 10GWh, or
- belonged to an electro-intensive company with its electricity demand exceeding 500 GWh.

The rebate represented around €60 million and, according to CRE, was equivalent to a €1 / individual annual bill.

Given that the rebate was a temporary measure, the CRE subsequently sought to implement a permanent rebate. This occurred in the context of a new law in August 2015 on the energy transition for green growth (loi relatif à la transition énergétique pour la croissance verte) which saw a reduction introduced permanently. More formally, in February 2016 the rebate was specified under the French energy code under Articles L 341-4-2 and D341-9 and varied from 5% to 90% depending on the how the company met the eligibility criteria.

The discount was further reformed in March 2021.[113] Under the latest version of the discount, the requirement for the user to be in an electro intensive industry was dropped with the CRE stating that the removal of the EII requirement reduced the potential for discrimination between users whose consumption characteristics are similar. In addition to changing eligibility criteria the regulator introduced a new calculation method for the rebates. As noted above, prior to this change, the rebates were defined in a normative way, without reference to the costs of the network and varied from 5% to 90% rebate depending on the category. Under the latest method the regulator applies rebates that are calculated in order to reflect the average cost of a “direct line” for each category of eligible sites. Specifically, the current rebates are calculated such that the bill after the application of the rebate reflects the average cost of a direct line for each category of eligible site.

The costs of a direct line are defined as the minimum of:

- the capital and operating costs, increased by 10%, of a line whose maximum power is calibrated to supply the site's peak demand from the nearest source of sufficient generation; and
- the capital and operating costs of a line at maximum power rated to supply that site’s peak demand using the combined generation from the two nearest sources of generation.

The current rate reductions that result are outlined in the table below. These can be revised every 4 years.

113 https://www.cre.fr/content/download/23589/296386

Table 13 Network tariff reduction rates since 2021

CATEGORY	ELIGABILITY CRITERIA	REDUCTION IN TARIFF RATE
Stable profile	Power used > 10 GWh and Duration of connection use ≥ 7000 hours	81%
Anti-cyclical profile	Power used > 10 GWh and Off peak utilisation rate ≥ 44%	74%
Large consumer	Power used > 500 GWh and Off peak utilisation rate between 40% - 44%	76%
Storage	Power used > 10 GWh and Off peak utilisation rate ≥ 44%	50%

Source: CRE, Déliberation 2021-104 (25 March 2021)

In addition to these general levels of discount, the latest version of the discount also introduced a floor level of network charges for each site that is equal to the directly attributable costs for each site.[114] The floor level means that that no discount beneficiary will pay less than the costs that would be saved in the long run if the site disconnected from the network. This is more similar to the concept of the cost reflective elements of network charges in GB.

RTE has estimated that this discount will be worth on average €173m per year in the period 2021-2024.[115]

B.3.3 - The rationale provided

The rationale for the original 50% discount was twofold.

- First, the regulator's decision was motivated by helping to make French companies more competitive. The CRE explicitly stated that it took into account the situation of French companies subject to strong international competition to help improve their competitiveness and maintain their location in France.
- Secondly, there was a positive balance in the electricity transmission system tariff for that year. Essentially, RTE would otherwise have collected more than its allowed revenues for the year.

Given the first discount was temporary in nature, and in line with enacting a permanent reduction, the justification for the permanent rebate was more explicit and was justified by the implicit balancing stability that they provide to the system operator, insofar as only sites that have a predictable and either stable or anti-cyclic demand profile are eligible for the discount:

> *"reduction is only available to EII companies that have predictable and either anti-cyclic or stable consumption and the reduction is determined as a function of the positive benefits that their consumption*

[114] Directly attributable costs correspond to the costs that would be avoided if the site disconnected from the network.

[115] https://assets.rte-france.com/prod/public/2021-07/TURPE6_tariff_decision.pdf Table 31

profiles brings to the network (…) The percentage reduction shall be determined taking into account the positive impact of these consumption profiles on the electricity system."[116]

The regulator has not published any quantification of the benefits provided by these sites in exchange for the discount.

The most recent incarnation of the discount also references other justifications linked to the nature of network charges in France. Specifically, the regulator highlights that high consumption sites tend to be located near to electricity production sites whilst the network charges are deliberately geographically equalised (there is no locational element).[117] This means that absent a targeted discount, on average high consumption sites pay for more KM of network than they typically make use of.

In addition, to qualify for a network charge discount, sites must put in place an energy performance plan no later than 12 months following application and an energy management system no later than 18 months following application. The plan must demonstrate what measures the site/user will put in place to reduce its electricity consumption over the following five years.[118]

B.4. Spain

B.4.1 - Tariff structure

In addition to energy costs, electricity consumers pay for access fees for transmission and distribution networks, the promotion of renewable energies, the higher cost of non-mainland generation, and deficits from previous years.[119] [120]

These costs are set at the national level, and are divided into:

- transmission and distribution network costs ("peajes"), which correspond to access fees and are charged to all consumers depending on their contracted capacity; and
- other fees that are non-dependant on the grid usage ("cargos"). These cover the excess costs due to the promotion of renewable energies, the higher costs faced by non-mainland systems, and tariff deficits.

Access fees include a capacity component (Tp) and an energy component (Te) which, together, recover the cost of the network. These fees include the cost of network losses but exclude the cost of system services (which are recovered through the energy price instead). The regulator defines different periods which impact tariffs, considering seasons, weekdays, and daytimes. Table 14 sets out the access fees for 2022.

---

116 Article L341-4-2 French Energy Code, in application since 9 December 2020, article 62

117 CRE DÉLIBERATION N°2021-104

118 https://www.ecologie.gouv.fr/sites/default/files/plan_performance_energetique_turpe_industrie_2021-011510.pdf

119 Deficits arose because access tariffs were insufficient to cover costs.

120 Energía y Sociedad (2022). *Manual de la Energía: Electricidad.* Chapter 7. https://www.energiaysociedad.es/manual-de-la-energia/7-1-los-peajes-de-acceso-y-cargos-estructura-costes-y-liquidacion-de-los-ingresos/

Table 14 Access fees for transmission and distribution networks in 2022

TP - ACCESS FEE FOR TRANSMISSION AND DISTRIBUTION (€/KW/YEAR)							
Rate group	Group definition	Period 1	Period 2	Period 3	Period 4	Period 5	Period 6
2.0 TD	Contracted Capacity ≤ 15 kW (Voltage ≤ 1kV)	22.988256	0.93889				
3.0 TD	Contracted Capacity > 15 (Voltage ≤ 1kV)	10.49392	9.152492	3.688512	2.802739	1.122833	1.122833
6.1 TD	1 kV ≤ Voltage ≤ 30 kV	18.320805	18.320805	9.988571	7.565889	0.50255	0.50255
6.2 TD	30 kV ≤ Voltage ≤ 72.5 kV	13.59289	13.59289	6.648956	6.048771	0.418446	0.418446
6.3 TD	72.5 kV > Voltage ≤ 145 kV	10.021051	10.021051	5.543157	3.24096	0.638147	0.638147
6.4 TD	Voltage > 145 kV	10.314368	7.894062	3.797235	2.79529	0.52812	0.52812

TE - ACCESS FEE FOR TRANSMISSION (€/MWH)							
Rate group	Group definition	Period 1	Period 2	Period 3	Period 4	Period 5	Period 6
2.0 TD	Contracted Capacity ≤ 15 kW (Voltage ≤ 1kV)	27.79	19.15	0.70			
3.0 TD	Contracted Capacity > 15 (Voltage ≤ 1kV)	17.75	14.57	7.96	5.36	0.32	0.32
6.1 TD	1 kV ≤ Voltage ≤ 30 kV	17.36	14.25	8.12	5.43	0.32	0.32
6.2 TD	30 kV ≤ Voltage ≤ 72.5 kV	9.17	7.53	4.23	2.95	0.17	0.17
6.3 TD	72.5 kV > Voltage ≤ 145 kV	7.77	6.52	3.92	1.88	0.24	0.24
6.4 TD	Voltage > 145 kV	7.05	5.74	3.06	2.43	0.16	0.16

Source: *CNMC. Resolution 16 December 2021. https://www.boe.es/eli/es/res/2021/12/16/(5)*
Note: *[Insert Notes]*

B.4.2 - The exemption

The Statute of Electricity-Intensive Consumers (RD 1106/2020) allows for exemptions, primarily for costs other than pure grid access changes, for certain consumers that, at least during two of the previous three years, fulfil the following requirements:

- have annual consumption over 1 GWh, of which a minimum of 50% is consumed during off-peak hours; and
- have a ratio between the annual consumption and the gross value added of the company[121] that is greater than 0.8 kWh/€ (previously set at 1.5).

[121] Defined as the sum of net revenues, variations in stock of finished products and work-in-progress inventories, in-house work on assets, other operating income, allocation of grants on non-financial fixed assets, minus materials consumed and other operating expenses.

The support scheme includes: [122]

- A state aid to compensate two of the costs that don't depend on the grid usage ("cargos"):
  - to cover the costs of the promotion of renewable energies, and
  - to offset higher costs of non-mainland systems.
- Applications for this aid open every year. In 2022, the government set a cap at compensating 85% of the costs. In 2021, €91 million was divided between the applicants.
- State guarantees against risks related to bilateral medium and long-term power purchase agreements (PPAs).

Other support schemes apply to this sector. Specifically, consumers can apply for subsidies that offset costs resulting from the emissions trading system[123] and they are also subject to fiscal benefits.

Since March 2022, these consumers will also benefit from a temporary 80% reduction of access fees ("peajes") for 2022.[124]

B.4.3 - The rationale provided

The Statute of Electricity-Intensive Consumers was introduced to increase the competitiveness of a sector that is highly sensitive to energy costs, across Europe and internationally. Until electricity markets across the EU are fully integrated, achieving unique and competitive energy prices, the cost of energy is crucial for the competitiveness of those industries whose main production factor is electricity. To this end, the Spanish regulator established exemptions "aimed at mitigating the effects of energy costs on competitiveness" (RD 1106/2020) and, at the same time, provided certainty and stability regarding Energy Intensive Consumers' energy costs.

This regime was first introduced in 2018 through the Real Decreto-ley 20/2018. In this document, the industrial sector is identified as a key strategic sector for ensuring the sustainable development of the Spanish economy as a whole. However, at the same time, its relative growth is said to be compromised:

> *"Industry competitiveness is essential to ensure growth is sustainable and inclusive. The industrial sector represents 14.4 percent of GVA, 3.7 percent more if considering the energy sector, and 14.1 percent of employees in Spain, but its relative importance as a lever is even larger due to its synergies and role as a driving force for the economy. However, as economies become increasingly globalised and digitalised, many elements undermine industry competitiveness, and thus require that measures*

122 We note that this discount is more similar to the EII exemption and rebate schemes that BEIS already runs (in respect of the indirect costs of carbon and the support costs of renewables) than to a network charge discount per se. .

123 Royal Decree 1055/2014

124 https://www.mincotur.gob.es/es-es/gabineteprensa/notasprensa/2022/documents/20220329%20np%20ayudas%20industrias%20electrointensivas.pdf

are taken quickly based on companies' needs. Hence, in 2018, the industrial sector's decline in growth, both in terms of GDP and employment, was above that of the wider Spanish economy."

Within this context, the regulator gives special mention to electricity-intensive industries because they bear to a greater extent the costs resulting from climate and energy policies. These policies may distort the costs of electricity-intensive industries and, thus, exemptions are considered essential to prevent their relocation.

B.4.4 - Recent developments

Since its establishment, the government has made two main changes to the discount and tariff regime.

- In March 2022, it allowed for a temporary 80% discount of the access fees ("peajes") during 2022.[125] This measure was part of a package of measures implemented to offset higher energy costs resulting from the Ukrainian war. Its goal was to preserve the competitiveness of electricity-intensive sectors.
- In April 2022, it modified the criteria used to define an electricity-intensive consumer.[126] Due to the increase in average energy prices, the ratio between the annual consumption and the gross value added of the company was lowered from 1.5 to 0.8 kWh/€ to ensure that the electricity-intensiveness is at 10% minimum.

125 Plan Nacional de respuesta a las consecuencias económicas y sociales de la guerra en Ucrania (RD 6/2022). https://www.boe.es/boe/dias/2022/03/30/pdfs/BOE-A-2022-4972.pdf

126 Resolution MINCOTUR 7 April 2022. https://www.boe.es/diario_boe/txt.php?id=BOE-A-2022-6429

Annex C - Review of technical case for GB network charge discounts

Electricity network utilization tariffs are generally set based on:

- the capacity of the connection (in terms of kW or AMPs); and
- the utilization of the connection (in terms of kWh).

The capacity element of a network charge generally covers infrastructure investments, operation, maintenance due to aging and fixed costs for metering, administration, billing, etc. The utilization element of the network charge covers the costs associated with losses and maintenance due to utilization.

These costs can be further disaggregated by network level, such as transmission system, sub transmission system, and different levels of distribution systems. This is because the connection voltage level has a significant impact on the tariff. Higher voltage level connections will have lower overall tariffs, since customers connected at this level do not need to pay for transformation to lower voltages or for lower level distribution.

Larger customers, especially industrial customers, might also have to pay for reactive power or have to keep the reactive power exchange within certain limits.

C.1. Consideration of possible system benefits from large customers

C.1.1 - Provision of flexibility services

Large and flexible customers may be able to provide ancillary services such as balancing, frequency control, voltage control and inertia support. These services are procured through the ancillary services market or agreed with the system operator, such that customers receive separate financial compensation for the benefits that these services provide to the system. They are therefore not related to the network tariff.

C.1.2 - Physical and administrative characteristics affecting network system costs

While the above benefits are accounted for in separate markets, there are a number of technical arguments that may support an adjusted network tariff for large and steady “base” load users. We set out each of these technical arguments below in turn. However, it is important to recognise that most of the technical arguments for network tariff reduction are site specific, and depend on the actual condition at the connection point to the network.

Fixed administrative costs

When allocating fixed administrative costs – such as for administration, metering and billing – it should be accounted for that the EII is **one customer** despite its large capacity subscription. The level of these costs will be relatively similar whether the customer is large or small. Therefore, if the costs are being allocated on the basis of connection capacity, a discount for EIIs may be justified.

Reduced voltage control costs

A large stable load does not cause any voltage fluctuations in the grid. Where voltage control costs are included in the network tariff and the EII is not being separately compensated for the voltage control benefits it brings to the system, a discount on the voltage control element of the tariff could be justified.

Allocation of network losses

EIIs may receive a discount for the reduction they bring to the costs for network losses. As the "base" load is always there, it could be regarded as the "bottom" or first current for the purposes of loss calculations. In other words, because the losses vary with the square of the current (and the current is basically proportional to the load (in kW)), the first current in the stack can be thought of as being responsible for a lower level of losses than the last current in the stack.[127]

For example: Consider an electricity intensive industry has a steady load of 1 pu current while other consumers have a current of X, which varies from 0 to 1 pu.

Losses cost for the industry:

- $R(1^2) = R$

Total cost for losses:

- $R(X+1)^2 = R(X^2+2X+1) = R(X^2+2X) +R$

Losses cost for other consumers (i.e. total losses cost less losses cost for the industry):

- $R(X^2+2X)$

The losses for other customers vary from 0 to 3R; when the current varies from 0 to 1 pu.

Recovery of investment costs reflecting the costs of alternative provision for users

In a similar way as for the losses, investments costs could be recovered in proportion to weighted individual alternative costs instead of with respect to capacity needs. This would account for the fact that, by sharing network infrastructure with smaller customers, EIIs reduce the total cost for those smaller customers relative to a scenario in which the EII did not exist and increased volumes of smaller network infrastructure was needed to service the smaller customers.

For example: Take the case of a 100 m cable will carry the current for 11 customers; one requesting 90 Amps and 10 requesting 1 Amp each. Assume costs as below for the 100 meter cable:

- A 100 Amp cable (what is currently needed to support all 11 customers): £100
- A 1 Amp cable (the alternative for each small customer): £10
- A 90 Amp cable (the alternative for the large customer): £95

127 Whilst this may be a conceptually consistent engineering point, From an economic point of view, given the GB principles of cost reflective network charging, all users should faced with the cost of losses imposed by the marginal unit of consumption in their location as this provides efficiency incentives for marginal decisions. If any network user were to reduce their consumption marginally, then the change in losses reflects the change in the total network current whoever the user is that has changed their current.

When the cost of the common 100 Amp cable is allocated among users based on the capacity requirement of each, the large user will be allocated £90 and the ten small users will each pay £1.

However, if the costs of the common 100 Amp cable were allocated in line with the proportion of total costs that each customer would be responsible for in the world of weighted individual alternative costs, large and small users would pay the following charges:

Small users: 10/195 x 100 = £5.13 each

Large user: 95/195 x 100 = £48.7

Power quality issues

Power quality issues normally point in the opposite direction for industrial customers, i.e. they have problems fulfilling power quality requirements. However, this will vary depending on the nature of each site and note all industrial loads will generate power quality issues.

Annex D - Detailed results from illustrative analysis of the impact on other network users of providing a 100% exemption to EIIs on all cost recovery charges

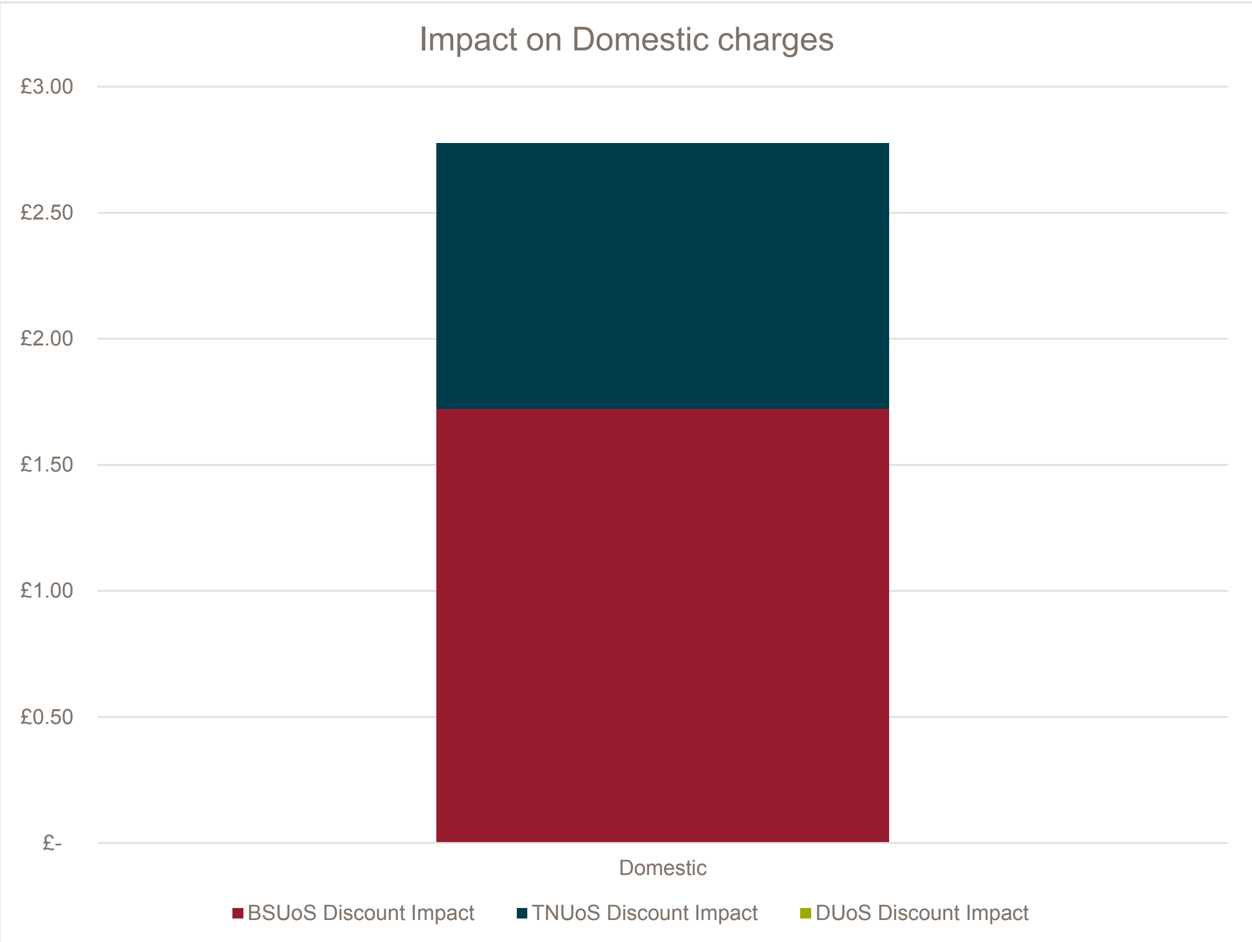
D.1. Results by user type

D.1.1 - Domestic

Domestic users have an average consumption of 3.32MWh per year and see a 3% BSUoS and TNUoS cost recovery charges, equal to a £2.80 increase in annual network charges if EIIs receive a 100% discount on these charges.

There is no impact on DUoS costs because a discount on EHV cost recovery charges only affects other EHV connected customers.

Figure 11 Increase in annual network charges for domestic users if EIIs are provided with a 100% discount on cost recovery network charges



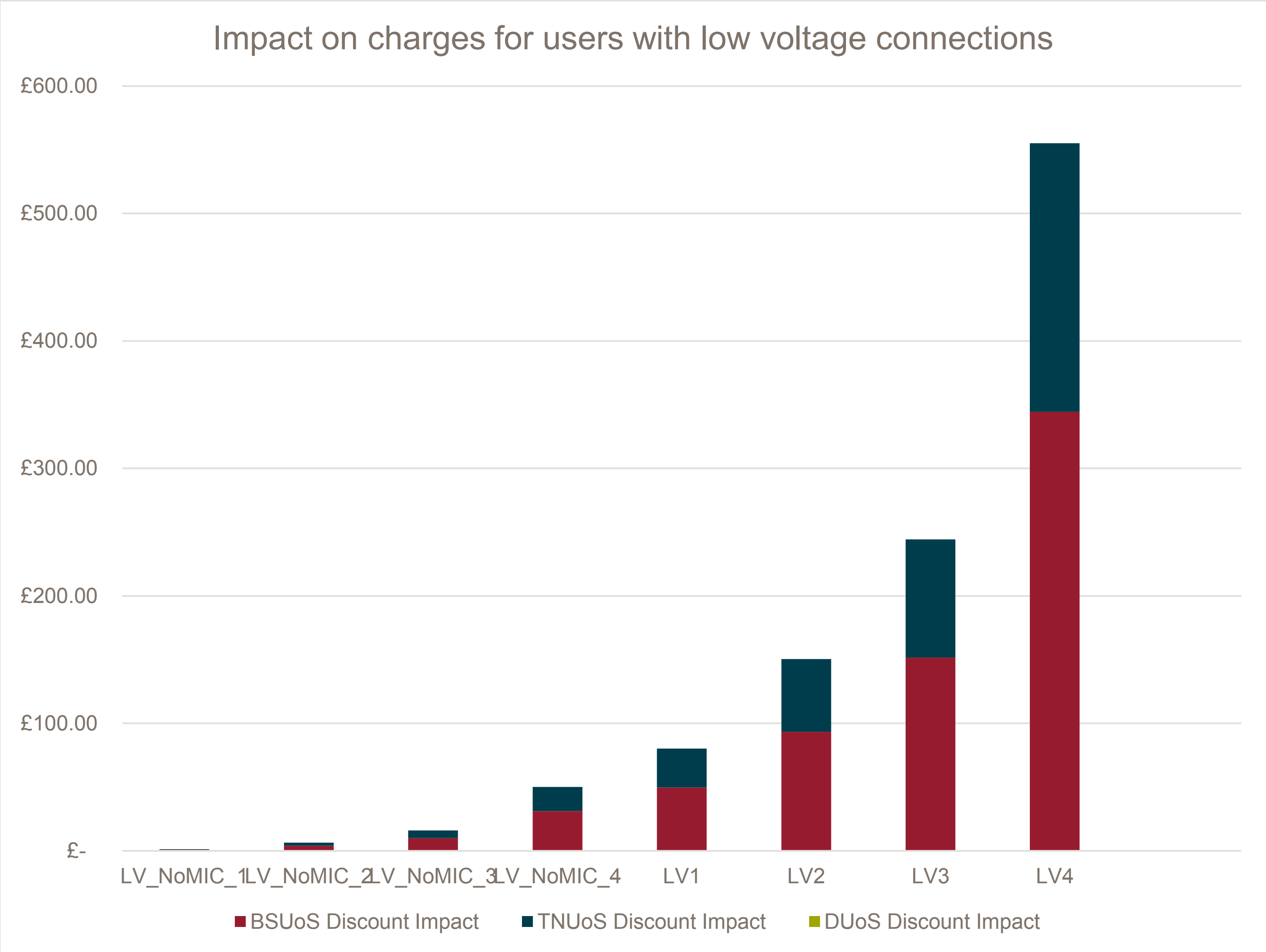
Source: Frontier Economics

D.1.2 - Low Voltage non-domestic

Low voltage non-domestic users have an average consumption of between 1.36MWh per year and 663MWh per year. Each of these users and sees a 3% BSUoS and TNUoS cost recovery charges, equal to an increases of between £1.10 and £555 in annual network charges if EIIs receive a 100% discount on these charges.

There is no impact on DUoS costs because a discount on EHV cost recovery charges only affects other EHV connected customers.

Figure 12 Increase in annual network charges for low voltage users if EIIs are provided with a 100% discount on cost recovery network charges



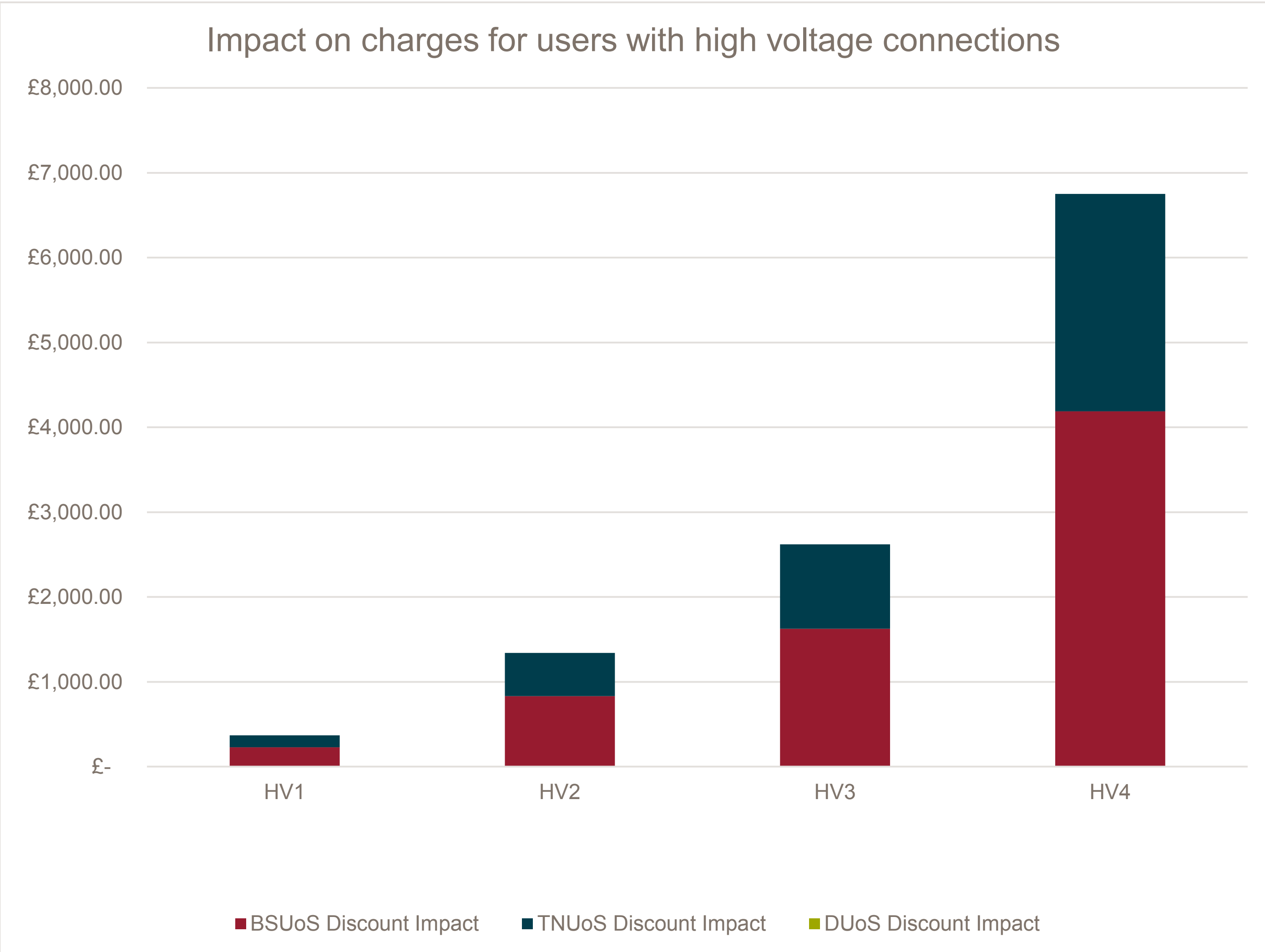
Source: *[Insert Source here]*
Note: *[Insert Notes]*

D.1.3 - High voltage non-domestic

High voltage non-domestic users have an average consumption of between 442MWh per year and 8,066MWh per year. Each of these users and sees a 3% BSUoS and TNUoS cost recovery charges, equal to an increases of between £370 and £6,750 in annual network charges if EIIs receive a 100% discount on these charges.

There is no impact on DUoS costs because a discount on EHV cost recovery charges only affects other EHV connected customers.

Figure 13 Increase in annual network charges for high voltage users if EIIs are provided with a 100% discount on cost recovery network charges



Source: Frontier
Note: [Insert Notes]

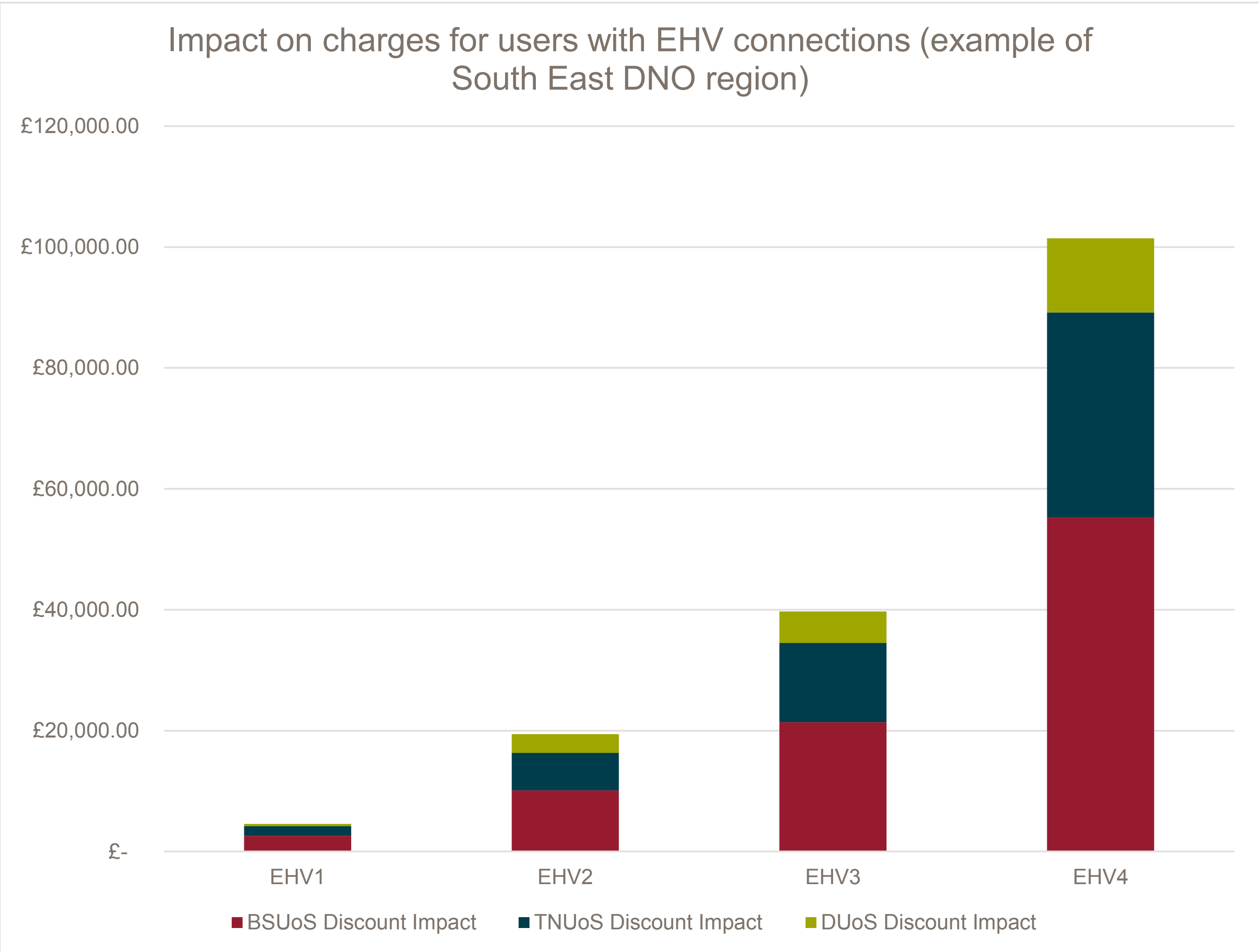
D.1.4 - Extra high voltage non-domestic

Extra High Voltage non-domestic users have an average consumption of between 5,000MWh per year and 107,000MWh per year. Each of these users and sees a 3% BSUoS and TNUoS cost recovery charges, equal to an increases of between £4,500 and £101,000 in annual network charges if EIIs receive a 100% discount on these charges.

The impact on EHV users of an EII discount DUoS costs is likely to be highly regionally specific. This is because a discount on EHV cost recovery charges only affects other EHV connected customers in the same region. Therefore, the impact on users in a region will depend strongly on the number of EIIs that are eligible for a discount on DUoS cost recovery charges.

Th chart below illustrates the calculation of the possible impact of a 100% discount on DUoS cost recovery charges for EIIs in the South East DNO Region. It shows that other users would see an increases in their DUoS cost recovery charges of around 12% or between £340 and £12,000 per user depending on the size of their connection capacity.

Figure 14 Increase in annual network charges for extra high voltage users if EIIs are provided with a 100% discount on cost recovery network charges



Source: Frontier

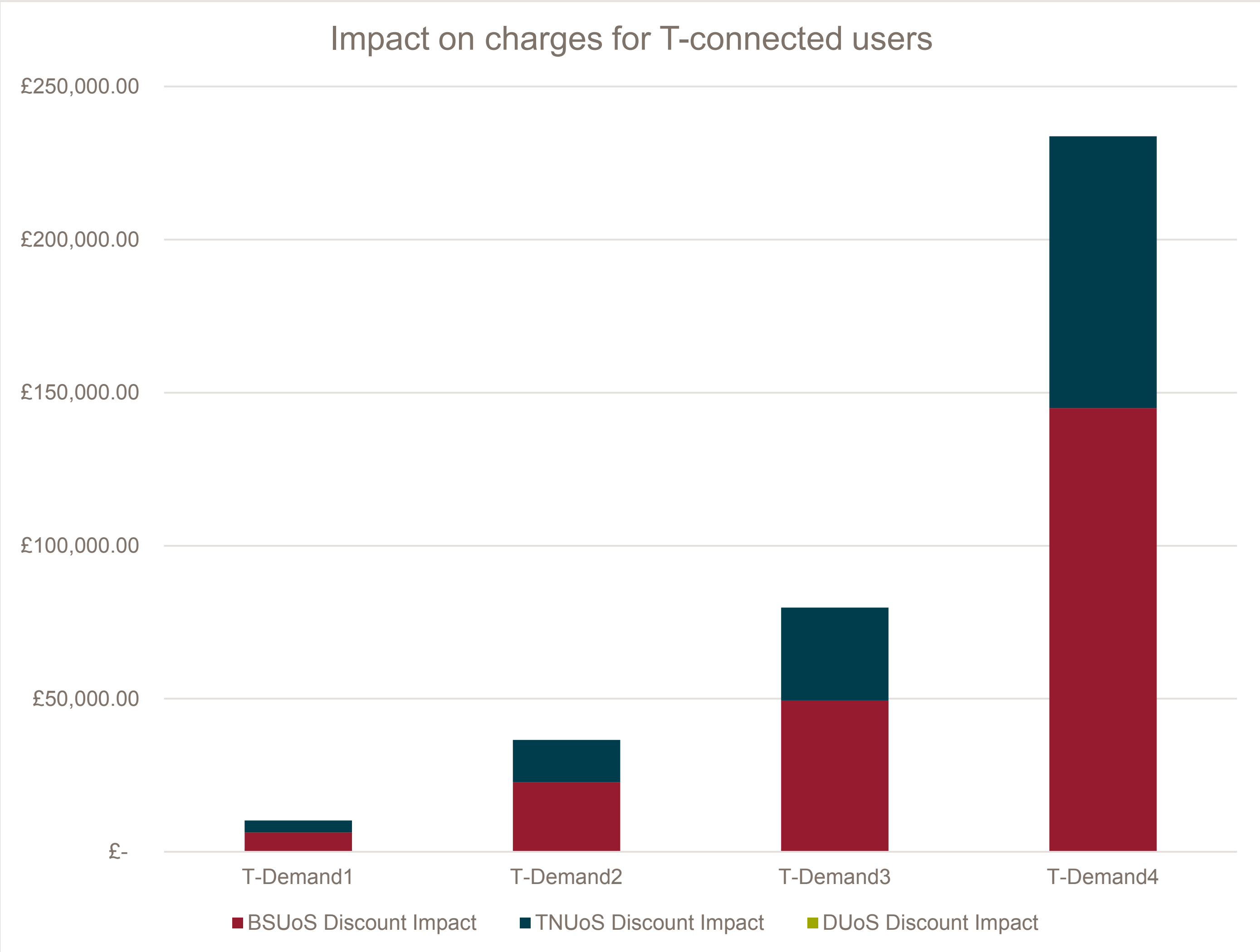
Note: [Insert Notes]

D.1.5 - Transmission connected

Transmission connected users have an average consumption of between 12,200MWh per year and 280,000MWh per year. Each of these users and sees a 3% BSUoS and TNUoS cost recovery charges, equal to an increases of between £10,000 and £230,000 in annual network charges if EIIs receive a 100% discount on these charges.

There is no impact on DUoS costs because T-connected users do not pay DUoS charges.

Figure 15 Increase in annual network charges for transmision connected users if EIIs are provided with a 100% discount on cost recovery network charges



Source: Frontier
Note: [Insert Notes]