



UNDERSTANDING DUoS CHARGE MOVEMENTS 2022/23 – 2026/27

This note was prepared by CEPA¹ and TNEI² in their role as Distribution Connection and Use of System Agreement (DCUSA) modelling consultants to explain how and why Distribution Use of System (DUoS) charges have changed over recent years, with a focus on the most recent set of published charges which will apply from April 2026 to March 2027. It was submitted to the DCUSA Panel for information on 14th March 2025, with the understanding that it may be shared more widely among DCUSA parties at their discretion.

This analysis may be useful to individuals seeking to improve their general understanding of DUoS charges or who are responsible for explaining charge movements to others, such as:

- **Distribution Network Operators (DNOs)** – which are responsible for explaining charge movements to customers within their region, but may lack wider visibility of charge movements at the GB level;
- **suppliers and their customers, generators, and Licensed Distribution Network Operators (LDNOs)** – who are commercially affected by the level and structure of charges, but may lack the internal capacity to assess charge movements themselves; and
- **policy-makers responsible for decisions regarding network and policy charges** – which can have material impacts on social equity, progress towards net zero, and the cost of the future energy system – and who wish to gain a better understanding of the status quo.

This note is structured as follows:

- Section 1 illustrates charge movements for network users connected at **low and high voltages (LV/HV)**;
- Section 2 illustrates charge movements for network users connected at **extra-high voltage levels (EHV)**;
- Section 3 considers the proportion of charges retained by **LDNOs**, and the growth of LDNO net revenues over recent years; and
- Appendix A provides **charge illustrations** for five CDCM tariff categories containing significant numbers of customers and/or volumes – showing the most recent (2026/27) published charges by DNO region, and GB-averages for the past five charging years.

How DUoS charges are set – the basics

The costs of the GB electricity distribution network are recovered by DNOs in accordance with charging methodologies set out in the DCUSA legal text. Network users connected at HV/LV levels receive charges set by the **Common Distribution Charging Methodology (CDCM)** model, and users connected at EHV levels receive charges set by the **Extra-high voltage Distribution Charging Methodology (EDCM)** model. Charges are published annually – 15 months ahead of the charging year to which they apply.

HV/LV-connected users receive one of 32 tariffs produced by the CDCM, whereas EHV-connected users each receive a bespoke set of charges based on power flow modelling and the users' individual characteristics. For this reason, the EDCM model is not published in its populated form.

LDNOs – which own last-mile network assets – are permitted to retain a proportion of their end-customers' DUoS bills for the network levels they operate, as determined in the **Price Control Disaggregation Model (PCDM)**.

¹ "CEPA" is the trading name of Cambridge Economic Policy Associates Ltd (Registered: England & Wales, 04077684), CEPA LLP (A Limited Liability Partnership. Registered: England & Wales, OC326074) and Cambridge Economic Policy Associates Pty Ltd (ABN 16 606 266 602).

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1. CHARGE MOVEMENTS FOR HV/LV-CONNECTED USERS

The structure of the DUoS models has seen no material changes in recent years, yet changes to model inputs have triggered significant charge movements.

Since the last material change to DUoS models – which implemented the outcome of Ofgem’s Targeted Charging Review in the 2021/22 charging year – the structure of DUoS models has remained largely unchanged. DUoS charges for LV/HV-connected network users have nevertheless been affected by several significant movements over the five years for which charges have been published since.

During **2022/23** and **2023/24**, DUoS charges were used to recover £1.3bn of **Supplier of Last Resort (SoLR) costs** – triggered by the failure of retail suppliers during the Winter of 2021/22. SoLR costs were recovered through an adder to the fixed charge for Domestic customers only, set at a uniform level across all DNO regions (adding £34 to the fixed charge for ‘Domestic Aggregated’ customers in 2022/23).

During **2024/25**, the level of **allowed revenue** that DNOs were permitted to recover **increased** by £2.1bn (32%): triggered by (i) a large inflationary adjustment; and (ii) the need to correct for under-recovery during previous years – when demand had been lower than expected because of high wholesale prices during Russia’s full-scale invasion of Ukraine. The “*residual*” revenue component – which ensures that DUoS charges are expected to recover DNOs’ revenue allowances, and which is levied on final demand users as a banded fixed charge – increased accordingly.

In **2025/26**, DNOs’ allowed revenues returned to more usual levels, while the value of “**forward-looking charges**” **increased** by £1.3bn (31%) – causing a large reduction in “*residual*” revenue to be recovered from banded fixed charges.³ The two causes of the sharp increase in forward-looking charges, which had previously been largely stable, were: (i) DNOs’ collective decision to set the “*customer contributions*” input to 0% to reflect Ofgem’s direction that connection charging would move to a “*shallow*” basis;⁴ and (ii) a large increase in the “*real post-tax cost of capital*” used to determine the notional cost of capacity.⁵ Capacity charges, unit rates, and non-banded fixed charges all rose, while banded fixed charges fell to just 15% of the previous year’s level.

In **2026/27**, most model inputs remained at similar levels to the previous year, with no major shifts affecting all DNO regions. However, four of the fourteen regions have been affected by **negative “residual” revenues** (up from one in 25/26; none in 24/25; and one in 22/23, 21/22 and 20/21). In three of the four cases, negative residuals have been permitted to the fullest extent possible without causing the CDCM model to produce errors. This situation appears to be the result of Ofgem guidance issued in November 2024 that DNOs can scale-down “*gross asset*

³ The CDCM model makes a conceptual distinction between setting “forward-looking” charges, which users are intended to respond to, and the recovery of “residual” revenue through fixed charges, which are not intended to affect user decisions. The “forward-looking” element is intended to represent the notional cost of providing an increment of capacity, and is typically converted into time-banded unit rate (p/kWh) charges and / or charges for pre-agreed levels of capacity (p/kVA/day).

⁴ Following Ofgem’s Access and Forward-looking Charges Significant Code Review (Access SCR), DNOs were directed to adopt a “shallow” approach to connection charging, whereby new connectees would have to pay more of the costs of network reinforcements required to facilitate their connections. During 2023, DNOs discussed whether and how to reflect this change of approach in their inputs to the DUoS models through the forum of the Distribution Charging Methodologies Development Group. DNOs agreed that the input to the CDCM model which determines the proportion of asset costs which customers are assumed to have already paid for through their connection charges – “Customer contributions” – should be set to zero. As a result, they no longer reduce the value of “asset costs” customers are required to pay through DUoS charges – leading to an increase in the revenue expected from forward-looking charges. Since the value of customer contributions are not specified in the DCUSA legal text, DNOs were able to make this change without raising a change proposal through DCUSA governance procedures.

⁵ The “real post-tax cost of capital” is a CDCM model input used as part of the calculation to determine the notional cost of capacity. The cost of capital is used to annuitize these asset values over an asset lifetime, before dividing by simultaneous maximum load to give unit costs which are used as a proxy for the (long-run) marginal cost of capacity. A higher cost of capital increases the “asset costs” customers are required to pay through DUoS charges – leading to an increase in the revenue expected from forward-looking charges.

costs” to reduce negative residuals,⁶ but that “interventions to the CDCM should only apply insofar as is necessary to produce a complete set of tariffs, rather than to the point where no surplus residual is created”.⁷

Figure 1 below summarises the source of charge movements for HV/LV-connected network users over recent years in terms of the split between forward-looking; residual and pass-through costs (with annotation).

Figure 1: Expected revenue collected from CDCM customers, by cost source, GB total

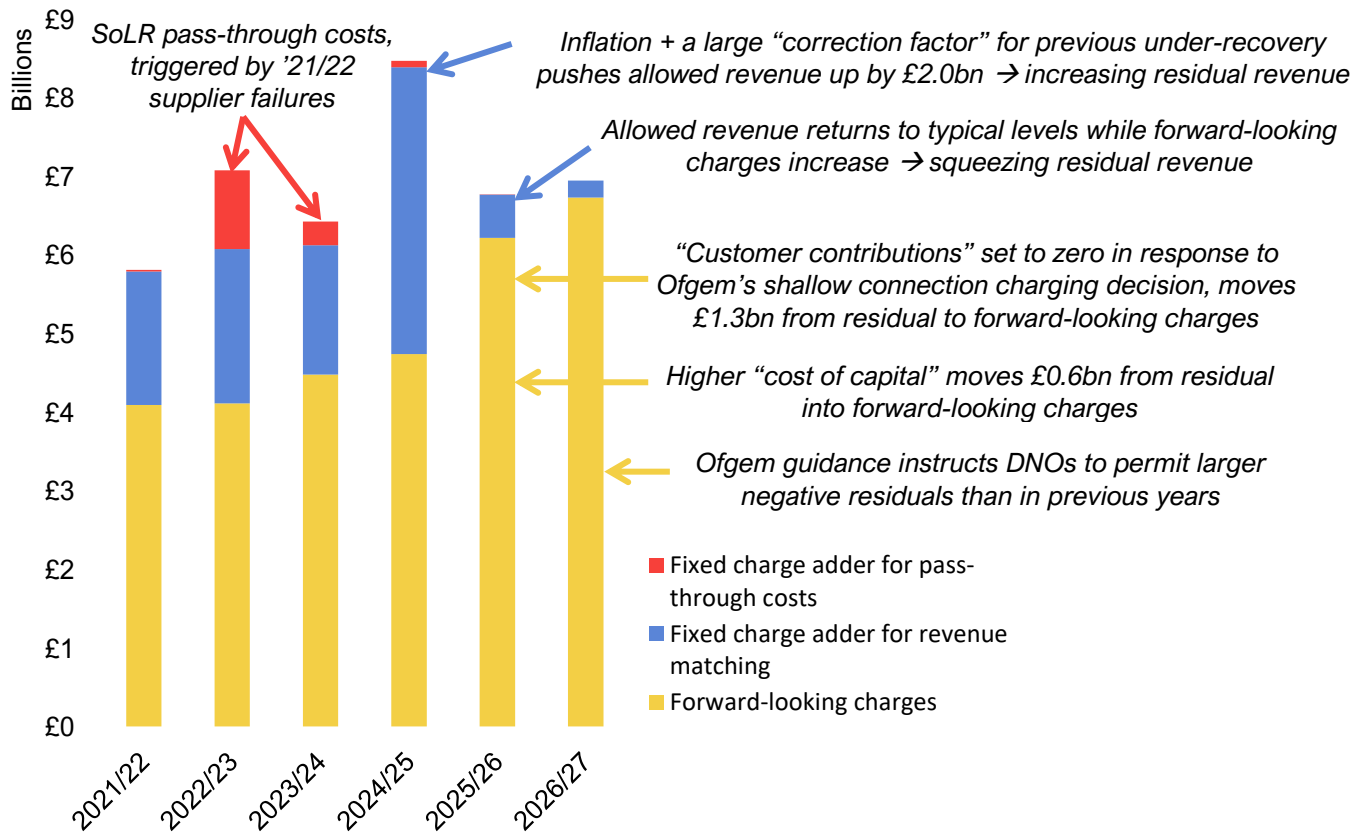
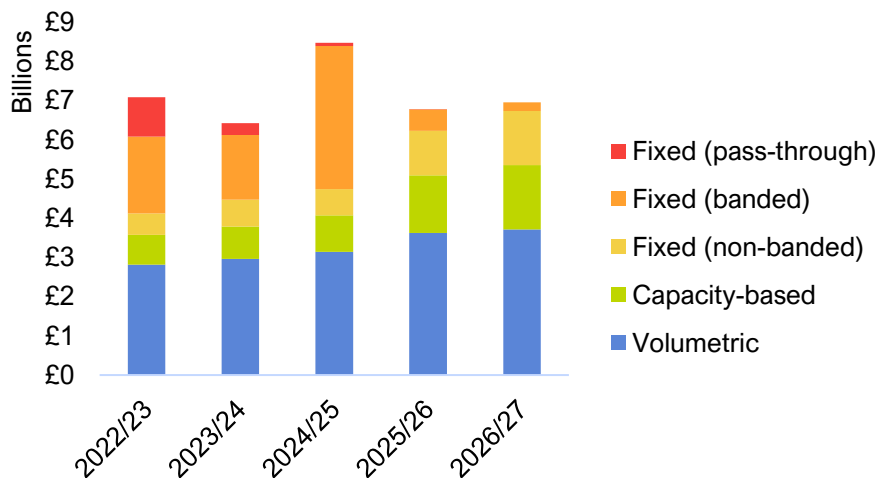


Figure 2 illustrates the same values as Figure 1, but split by charge components – including the distinction between banded, non-banded and pass-through components of the fixed charge. It shows that, in 2024/25, 52% of DUoS revenue was recovered through fixed charges, whereas in 2026/27, just 23% of DUoS revenue is expected to be recovered through **fixed charges**; 53% will be **volumetric**; and 24% will be **capacity**-based. The residual component is the sum both positive and negative values.

⁶ “Gross asset costs” are an input to the CDCM model representing the notional cost of reinforcement per network level that would be needed to accommodate a 500MW increment to peak net demand at the grid supply point (which DNOs calculate through the “500MW” Distribution Reinforcement Model, which is outside of DCUSA governance). Conceptually, the 500MW model implies that capacity is scarce, so CDCM users should pay the long-run average cost of its provision. Higher “gross asset costs” increase the notional cost of capacity and, therefore, the revenue expected from forward-looking charges. Reducing “gross asset costs” can be used as a means of avoiding large negative residuals.

⁷ <https://www.ofgem.gov.uk/publications/managing-effects-surplus-residual-charges-guidance>

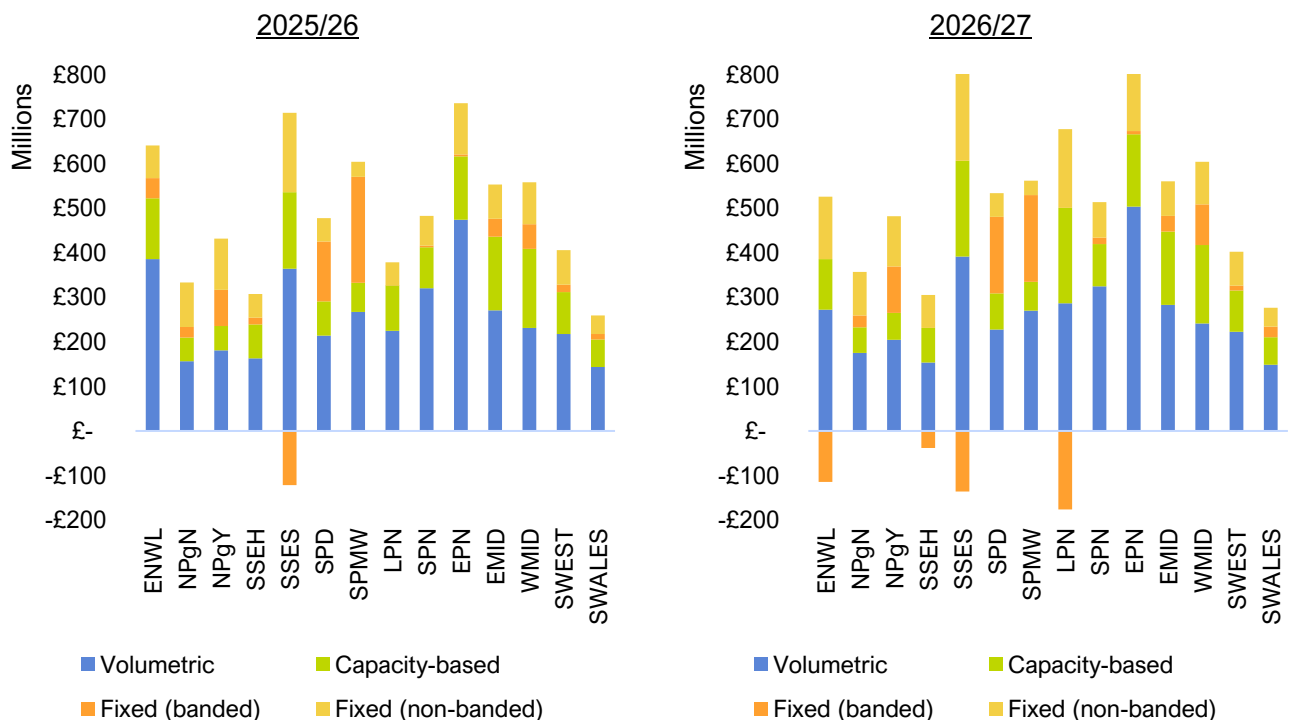
Figure 2: Expected revenue collected from CDCM customers, by charge component, GB total



The greatest charge movements in 2026/27 are focused among the four DNOs experiencing negative residuals – which have arisen for different reasons

Figure 3 illustrates CDCM revenue by charge component for each DNO in 2025/26 and 2026/27 – and demonstrates that **the level and structure of DUoS charges vary widely between DNO regions** (since each DNO is responsible for its own inputs, which can vary according to the underlying nature of the network and business). Unlike in recent years, 2026/27 charges do not exhibit any major shifts affecting all DNO regions. Charges will remain at a similar level and structure to 2025/26 in the majority of regions, but four of the fourteen DNOs will experience negative residuals (ENWL; SSEH; SSES; LPN) – amounting to a combined negative residual of £467m. The reasons for this unprecedented number and value of negative residuals stem from the same underlying factors but are subtly different for the four DNOs.

Figure 3: Expected revenue collected from CDCM customers, by charge component, by DNO



In general, **all DNOs are at greater risk of experiencing negative residuals due to the increase to the forward-looking charges triggered by zeroing out “customer contributions” in 2025/26**. This factor is expected to continue to apply in future years – depressing the value of the residual and making negative residuals more likely.

Ofgem’s November 2024 guidance has formalised a practice which some DNOs had previously used to avoid large negative residuals – of scaling down the gross asset cost (£) for each network level of the Distribution Reinforcement Model: thereby reducing forward-looking charges and increasing the residual to a less negative value. However, **whereas DNOs previously had the freedom to use this approach to avoid negative residuals altogether, Ofgem guidance now explicitly states that DNOs should only intervene to the minimum extent required to produce a complete set of tariffs**. That is, large negative residuals should be permitted as long as they do not create errors.

Figures 4 and 5 attempt to explain how this guidance has interacted with individual DNOs’ allowed revenues and “gross asset costs” to give rise to negative residuals in 2026/27 charges.

Figure 4 shows target CDCM net revenue over the last five charging years as well as DNOs’ projections for 2027/28. It shows that ENWL’s target revenue dropped by 36% in 2026/27 (largely because of revisions to tax allowances implying over-recovery in previous years) but that this drop is expected to be temporary. Likewise, SSEH’s target revenue dropped by 13%. Both DNOs experienced negative residuals as a result. By contrast LPN’s and SSES’s target revenues both increased in 2026/27 (by 33% and 13% respectively).

Figure 4: Target CDCM net revenue, by DNO

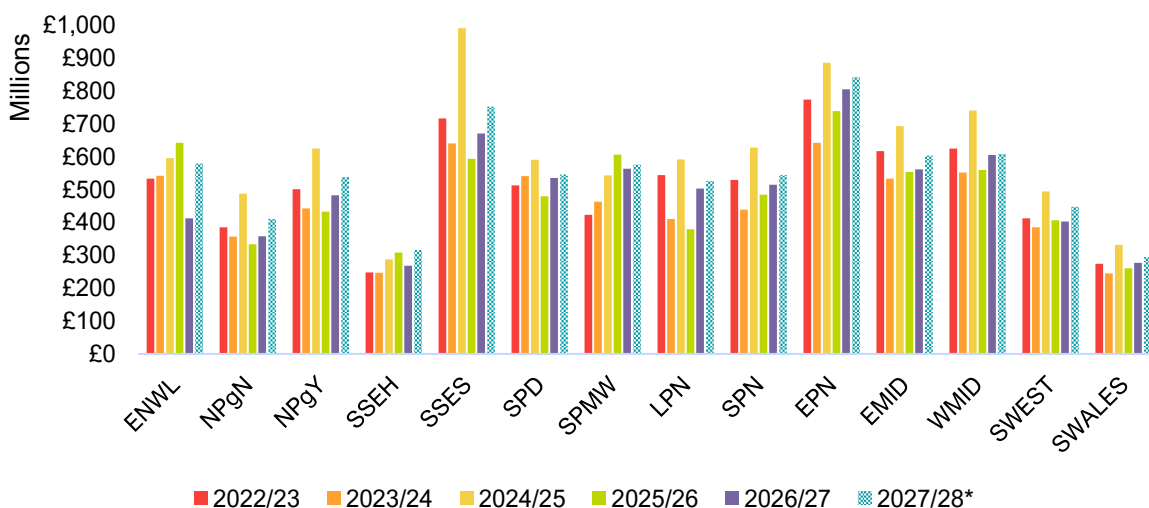
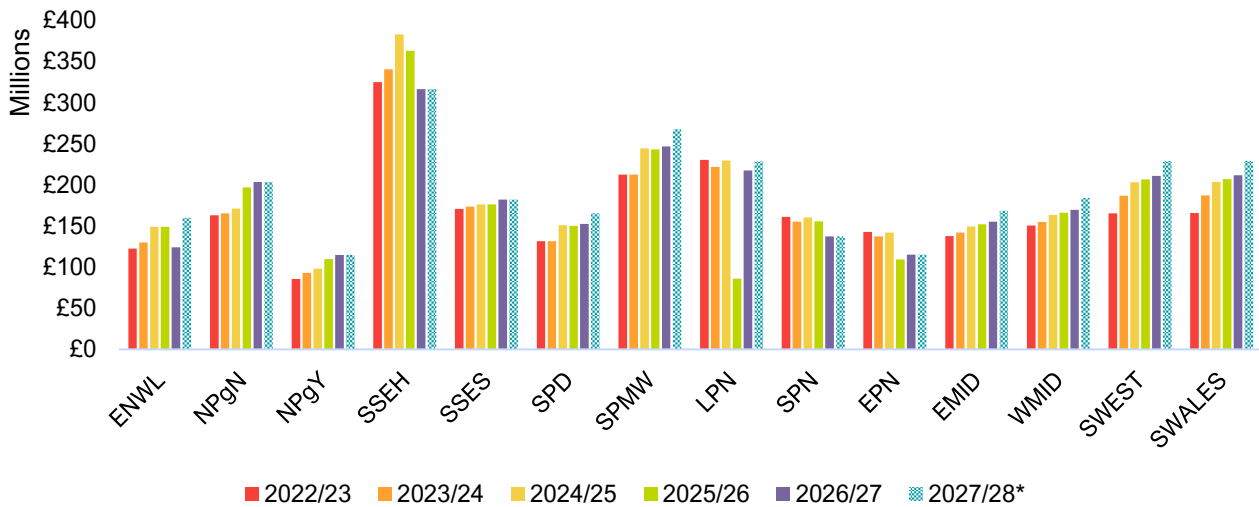


Figure 5 illustrates the “gross asset costs” per kW of simultaneous peak load (shown here for the HV circuit level) which DNOs have used over the past five years and their projections for 2027/28. This figure seems to show each of these DNOs using this input in different ways to manage negative residuals. ENWL has reduced its gross asset costs by a uniform 17% to avoid the CDCM model producing errors, but has otherwise accepted large negative residuals – as per Ofgem guidance. SSEH’s gross asset costs have also reduced, but not by a uniform percentage, and residuals are not at the limit where they could cause errors. SSES’s gross asset costs are moderately increased, though not by a uniform percentage – leaving it with large negative residuals as in 2025/26. By contrast, LPN has increased its gross asset values by a uniform 153% - partially unwinding a 63% reduction in the previous year. This appears to be the result of switching from a policy of removing negative residuals in 2025/26 to permitting large negative residuals in 2026/27.

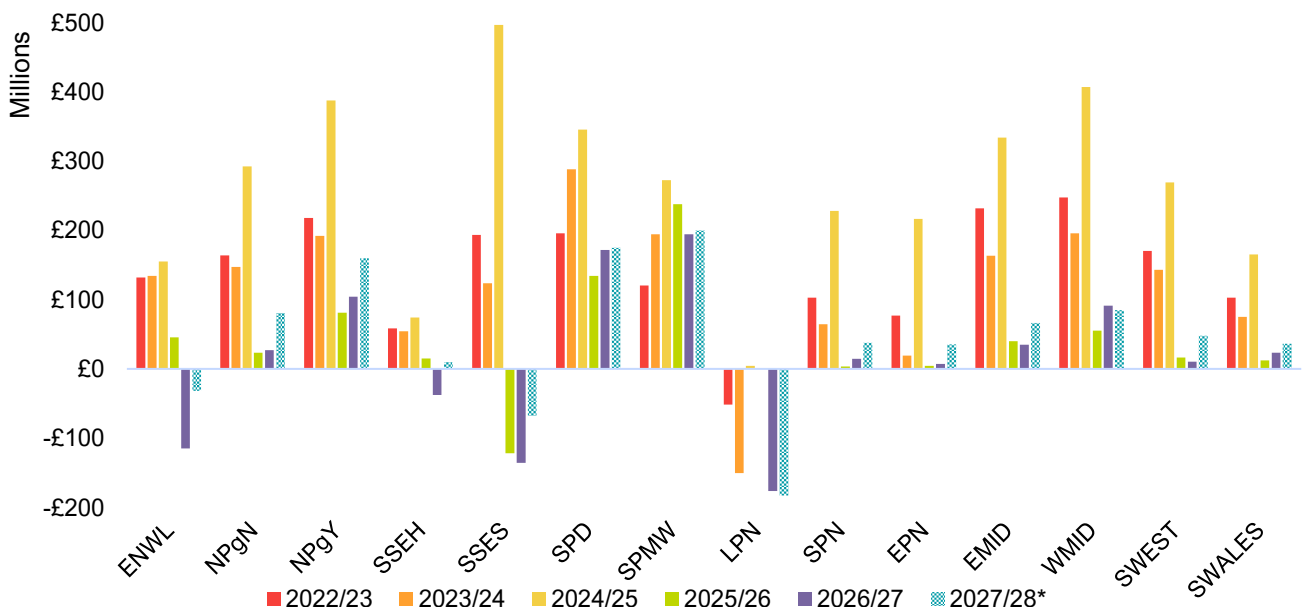
Figure 5: Gross asset costs (£, HV circuits) needed to accommodate an increment of 500MW of peak load at the Grid Supply Point, by DNO



Three of the four DNOs experiencing negative residuals in 2026/27 expect them to persist in 2027/28

Figure 6 shows net “residual” revenue from CDCM models for the last five years, and projections for 2027/28 from DNOs’ Annual Review Pack models. It is notable that the current situation of large negative residuals is expected to partially persist. Higher target revenues are expected to reduce the extent of negative residuals for ENWL and SSES, and to remove it for SSEH, but LPN is still expecting residuals at the most negative extent possible without causing errors.

Figure 6: Net CDCM revenue from the residual, by DNO



Large negative residuals can give rise to charges with no fixed (p/MPAN/day) or volumetric (p/kWh) components

The CDCM model apportions residual revenue between customer categories in proportion to their share of final demand, then apportions it between customers within the same category as an adder to the banded fixed charge. When the residual is negative, the banded fixed charge is reduced, but is not permitted to become negative. If this point is reached and negative residual revenue still remains then time-banded unit rates are reduced up to the non-

negative limit. If the negative residual cannot be recovered without causing negative unit rates then the model returns an error for that tariff.

If DNOs manage their inputs to the minimum extent necessary to avoid the models failing due to large negative residuals then they will have **at least one final demand tariff with no fixed charge and zero unit rate charges** – i.e. it would pay capacity charges only. In 2026/27 this is the case for the HV Site Specific Band 4 tariff for ENWL, SSES and (almost) for LPN. Other final demand tariffs may only have a peak unit rate charge. This gives rise to the situation where **non-final demand tariffs (e.g. storage customers), who do not contribute towards the residual, receive higher charges than final demand tariffs**. Figure 7 illustrates this situation by comparing banded fixed charges and peak unit rate charges for LPN's HV Site Specific tariff over the last three years – during which the residual went from being large and positive, to a very small positive value, to a large negative value.

Figure 7a: Banded fixed charges (£/year) for LPN's HV Site Specific tariff, 2024/25-26/27

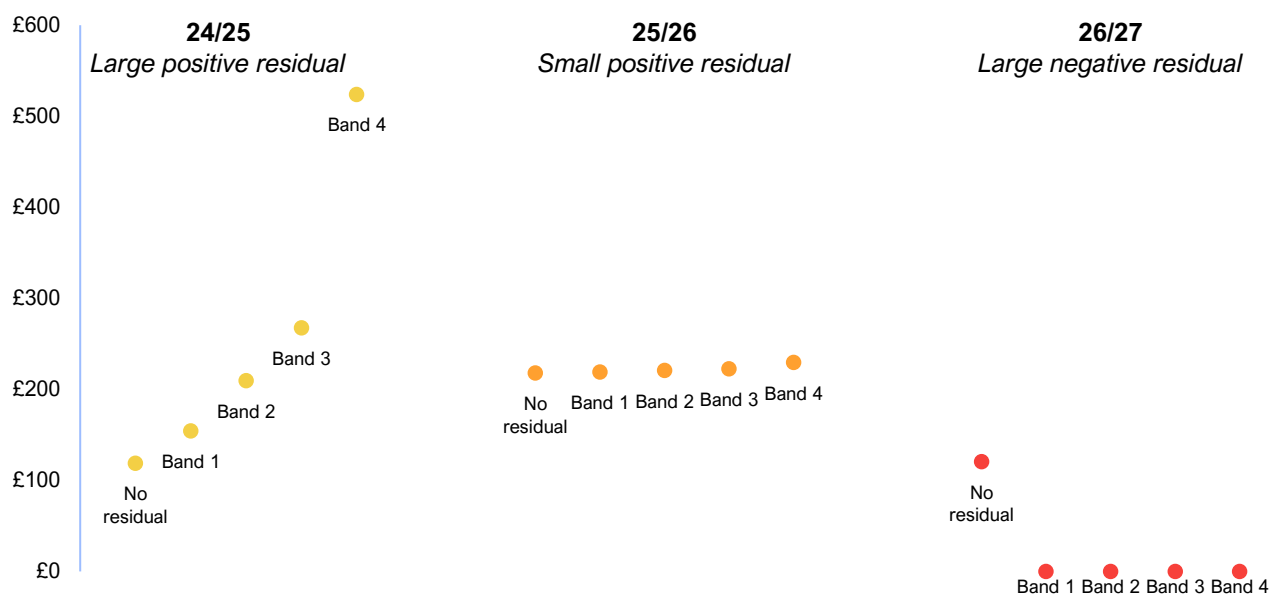
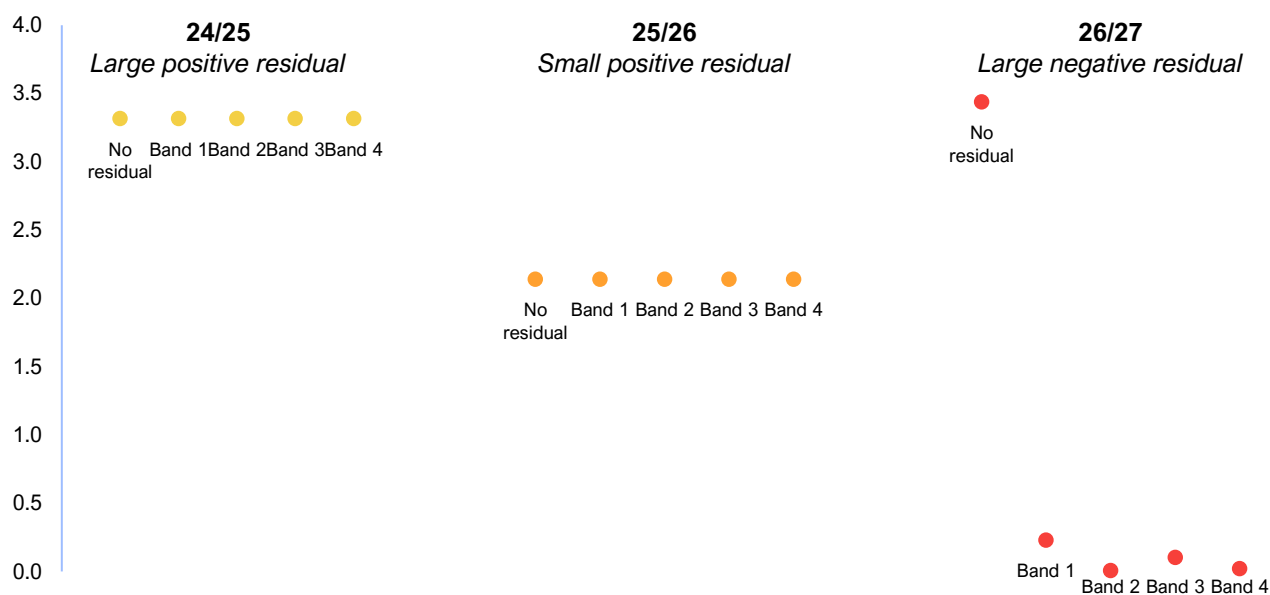


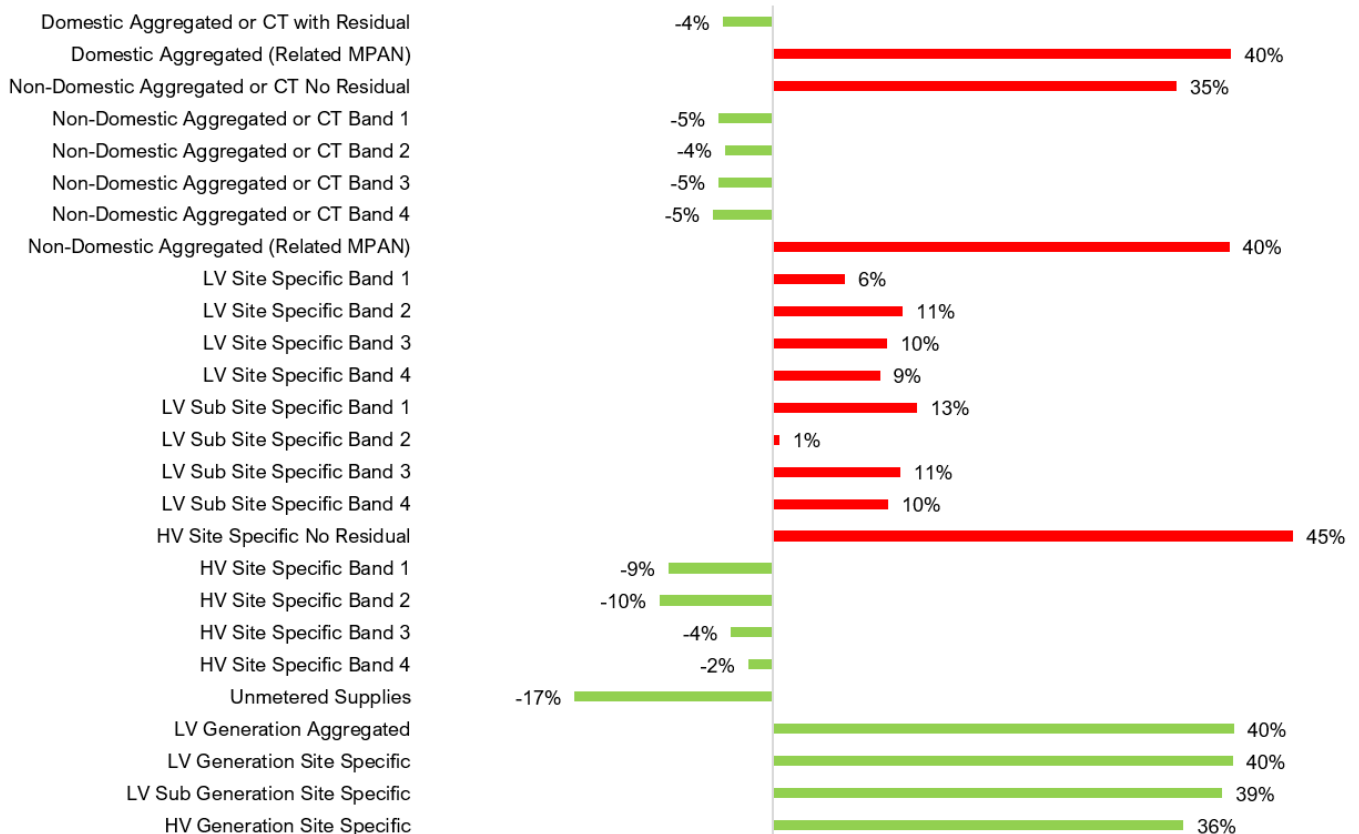
Figure 7b: Unit rate 1 (peak) volumetric charges (p/kWh) for LPN's HV Site Specific tariff, 2024/25-26/27



The incidence effects of permitting large negative residuals are complex, but tend to favour generation and unmetered supplies; and increase bills for customers with high agreed capacity and for non-final demand (i.e. storage)

To get a sense of the impact of Ofgem's direction to permit large negative residuals relative to a no-residual baseline, Figure 8 shows the % movement in typical bills (or generation credits) in the LPN area under published charges relative to a counterfactual in which gross asset values were set to 60% of published levels – consistent with a small positive residual.

Figure 8: Example impact of permitting large negative residuals on typical bills, relative to a no-residual baseline



Source: CEPA/TNEI analysis based on LPN 26/27 inputs, with gross asset values as published (giving a large negative residual) vs 60% of published levels (consistent with a small positive residual). Percentage changes for generation show an increase in the size of credits received.

The incidence effects of residual recovery are complicated by layers of allocation rules between customer categories and between charging bands within those categories, as well as differing allocations across DNO regions. So we should not expect the specific impacts illustrated in Figure 8 to hold for all other DNOs. The impacts that should hold in general are that, relative to a no-residual baseline, permitting large negative residuals gives:

- larger credits for **generation**;
- lower bills for **unmetered supplies** (because this tariff has no capacity charge component);
- higher bills for **non-final demand** (i.e. storage); and
- higher bills for customers with **high levels of agreed capacity** for their band.

At the **domestic** level, charges are insulated from some of the changes described in this note because domestic customers are all in the same band for residual charging purposes and do not have a capacity charge component. The typical GB household will pay £4 more in 2026/27 than in 2025/26 (£121 vs £117), but with a range of movements across DNO regions (-29% to +20%).

2. CHARGE MOVEMENTS FOR EHV-CONNECTED USERS

DNOs do not publish populated EDCM models, only their outputs, so there is limited scope to explain why charges change in certain ways other than when there are significant changes in policy. Therefore, this section focuses on illustrating EDCM charges and nodal prices as published by DNOs through their Statements of Charges. It also explores the view that EHV charges are volatile by highlighting variations over time, between DNO regions, between Long-Run Incremental Cost (LRIC) and Forward Cost Pricing (FCP) variants,⁸ and at the level of the individual customer.

The datasets which this analysis draws from are also not entirely consistent between years, and different DNOs have different naming conventions. While reasonable efforts have been taken to check the accuracy of this analysis, it should not be relied on as definitive.

EHV charges in 2026/27 do not exhibit any major shifts affecting all DNO regions

Figure 9 shows average import and export charges per DNO over the last six years. Figure 9 demonstrates that **average EHV import charges can vary widely** between DNO regions. It also shows that the **average level of EHV charges in 2026/27 appears to be similar to 2025/26 for most DNOs**, without any major shift affecting all DNOs.

Notable year-on-year movements include a large drop in the import fixed charge in the ENWL region – presumably a result of the large reduction in ENWL’s allowed revenue reducing the size of the residual adder.

Figure 10 tells a similar story, but as a cumulative distribution function of all EHV charges across GB. The x-axis gives the value of the charge, and the y-axis shows the proportion of tariffs for which that component is equal to or higher than the corresponding value on the x-axis. In these charts the x-axis has a logarithmic scale to aid readability. The lines representing 2026/27 and 2025/26 follow each other closely – suggesting that **there is no major change in the general distribution of charges** either. This analysis suggests that the volatility observed in EHV charges occurs at the individual level, not the average level.

It is notable that, apart from 2021/22, the **basic shape of the variation in import charges between tariffs has been largely consistent** over the last five years although, as with the previous plots, this may conceal the extent of any year-on-year variability for individual customers. The increase in import fixed charges after 2021/22 was due to the implementation of Ofgem’s Targeted Charging Review, which moved EDCM residual revenue recovery from the import capacity charge to the fixed charge. The corresponding increase in the import fixed charge is also evident. The lines for the fixed charge from 2022-23 onwards become more “stepped” in nature, due to the way fixed charges are banded for residuals.

EHV charge volatility can manifest differently between FCP and LRIC variants

Figure 11 illustrates cumulative distribution functions for the nodal prices which DNOs enter into the EDCM model, sorted by whether they use the FCP or LRIC variant. This is a useful plot for demonstrating how volatility affects these two models differently. The LRIC approach gives nodal prices with a wider range, including negative values, with a smooth function (as should be expected from the LRIC’s nodal definition) that are similar in shape across DNO regions (as should be expected given the blanket assumption of a 1% growth rate in load). By contrast, the FCP approach gives nodal prices which are zero at most locations, including all locations in EMID and WMID regions (as might be expected given the use on actual projected rates of load growth). The lines are also more “stepped” due to the FCP’s zonal definition.

⁸ DNOs may choose one of two cost concepts with which to populate the EDCM: FCP or LRIC. Both use power flow modelling to calculate locational capacity costs as an input to the EDCM model. The former is zonal and based on predicted investment costs and demand increments over a 10-year period taken from DNOs’ Long Term Development Statements. The latter is nodal and based on a notional asset cost required to accommodate an assumed 1% growth rate.

Illustrating variation at the level of individual EHV network users

While charge components may be stable on average across a licence area, **individual customers may experience much more variance** over time – often as a consequence of changes to locational unit costs and network use factors calculated through power flow modelling. Figure 12 demonstrates this point by approximately mapping charging points across the SPD licence area (South & Central Scotland) and using colour scales to indicate their import capacity charges over the last six charging years. It shows firstly that charges can vary widely across locations, even when customers are located close to each other geographically; and secondly that charges can vary over time in different directions to the average. Within this figure it is possible to pick out instances of clusters of nearby sites moving in similar directions between years, but also cases where they diverge. While it is not possible to draw any stronger insights from this analysis, it does support the view that power flow modelling can be a source of charge volatility for individual EHV customers.

Figure 9: Average import (top) and export (bottom) EHV charges by DNO, 2021/22-26/27, as published in DNOs' Statements of Charges

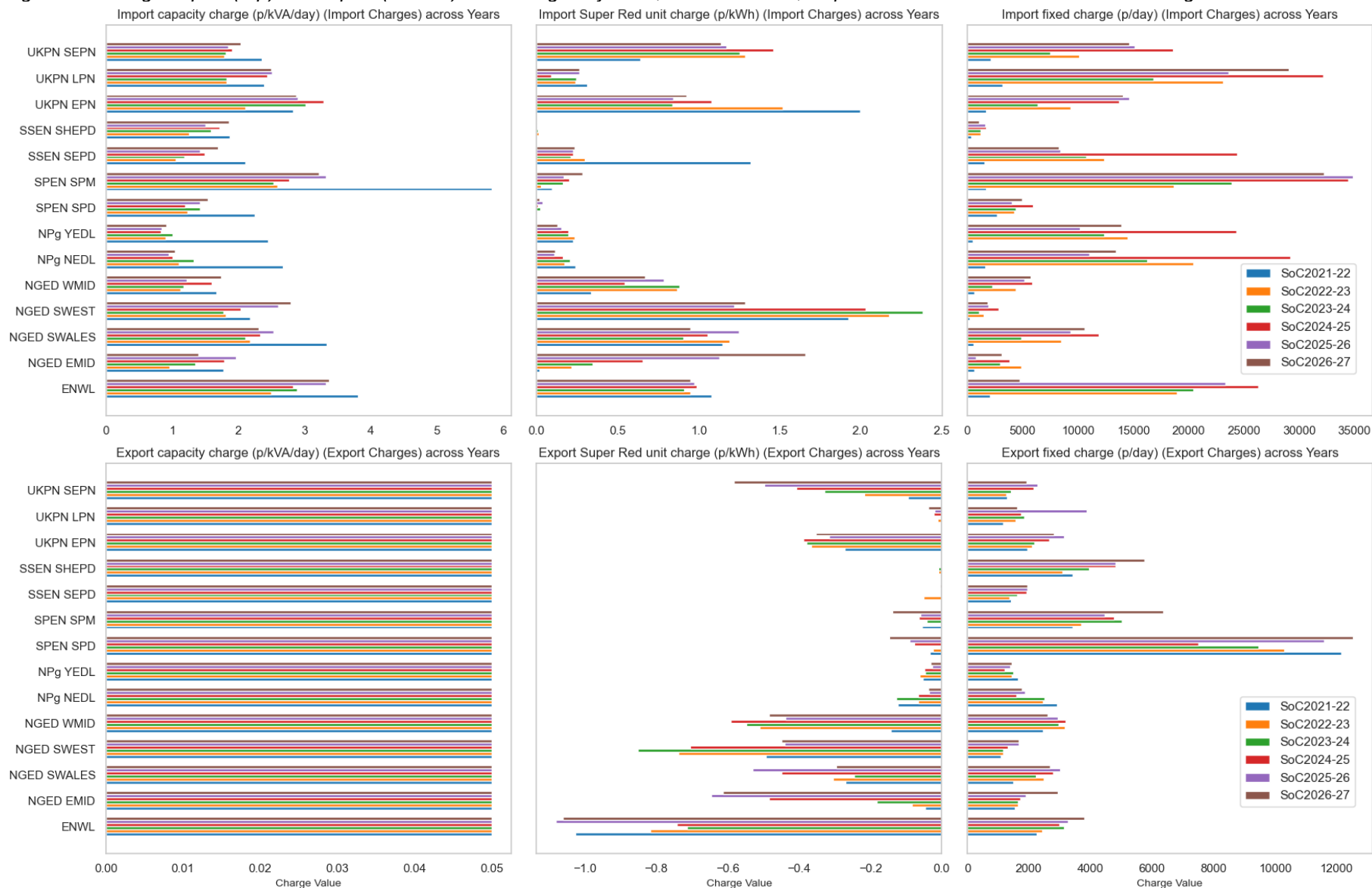


Figure 10: Cumulative Distribution Functions for the proportion of EHV import (top) and export (bottom) charges exceeding x , all DNOs, 2021/22-26/27

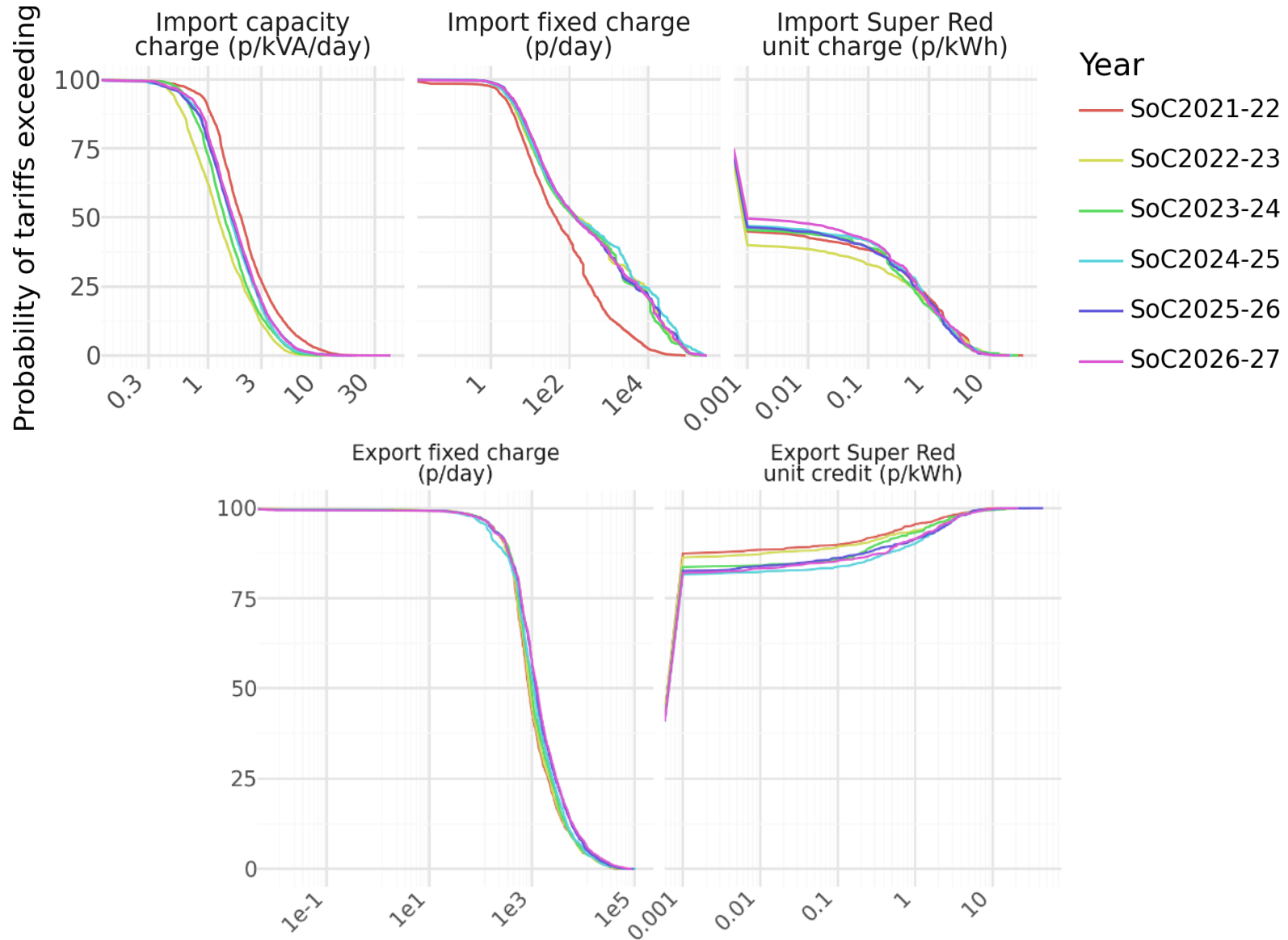


Figure 11: Cumulative Distribution Functions for the proportion of nodal prices exceeding x , by FCP (left) and LRIC (right) variants, 2026/27

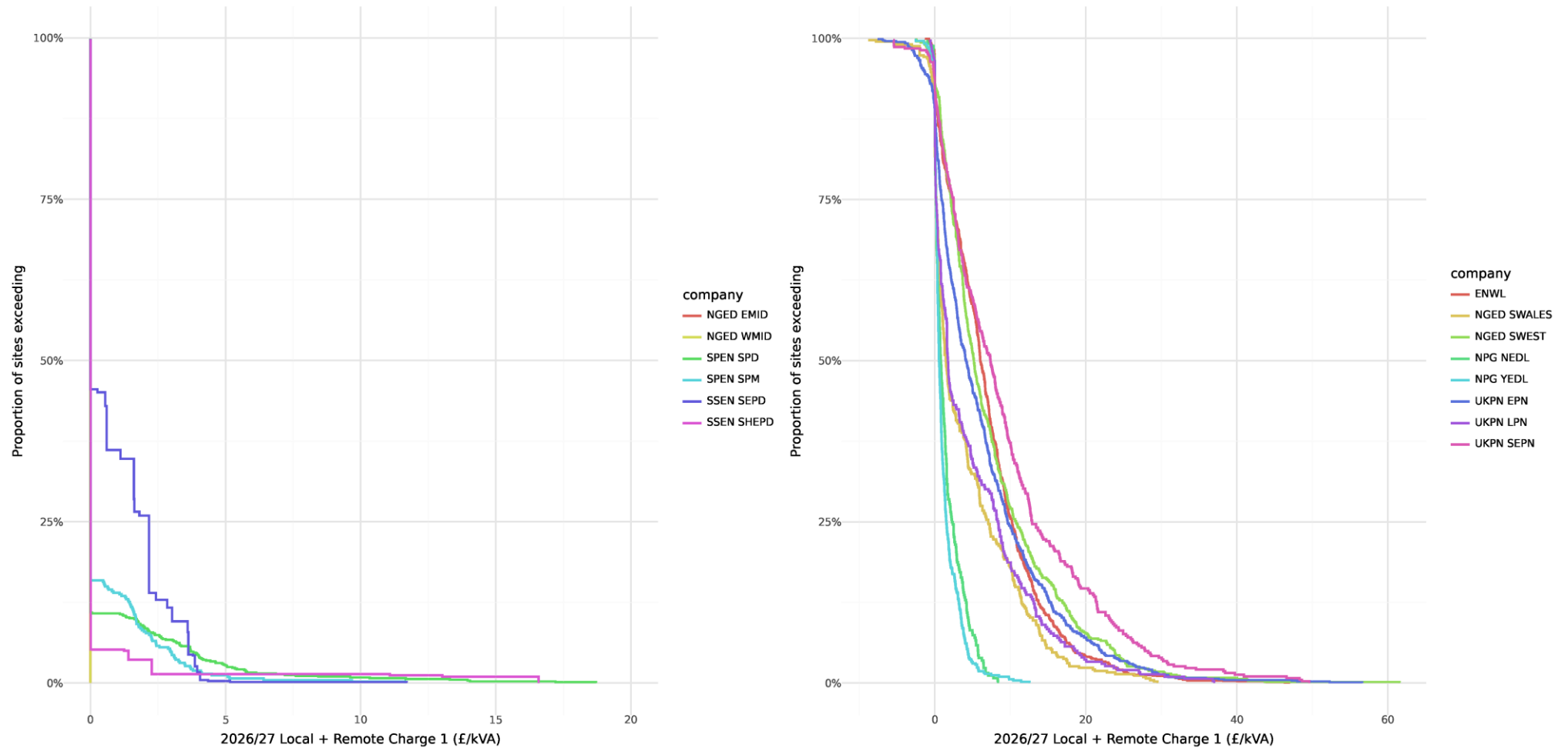
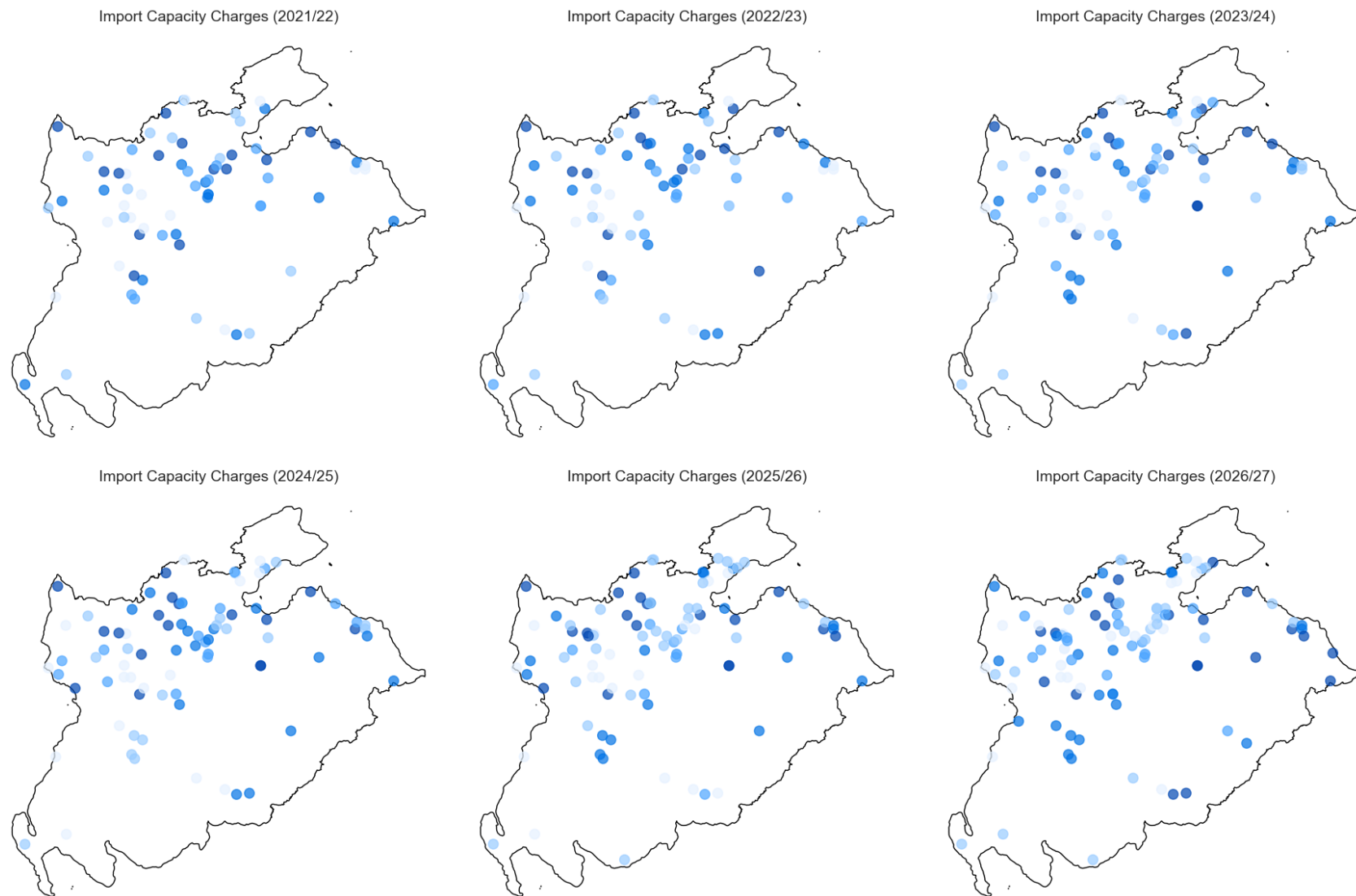


Figure 12: Mapping of EHV import capacity charges in South & Central Scotland (SPD), 2021/22-26/27



CEPA/TNEI analysis. Locations are approximate, using public information sources to match customer names to grid references. Darker shades indicate higher charges.

3. EMBEDDED NETWORK (LDNO) CHARGES

LDNO margins continue to be largely stable in % terms, but are affected by movements in the underlying all-the-way tariffs in absolute terms

The PCDM uses expenditure and load data from DNOs' 2007/08 Regulatory Reporting Packs (RRP) to assess the relative value of network levels, so **% discounts tend to be relatively stable** from year to year, but the **£ value varies** with movements in all-the-way charges.

Figure 13a below shows a flat profile of % discounts, which have barely changed on average between 2022/23 and 2026/27 (shown here for a LV user and an HV DNO:LDNO boundary). Some individual instances of small movements appear to have been primarily driven by changes in "notional asset values" which are passed from the CDCM and EDCM models into the PCDM, which seem to be influenced by "gross asset value" inputs in the CDCM.

Figure 13a: LDNO discounts (%), LDNO HV:LV user

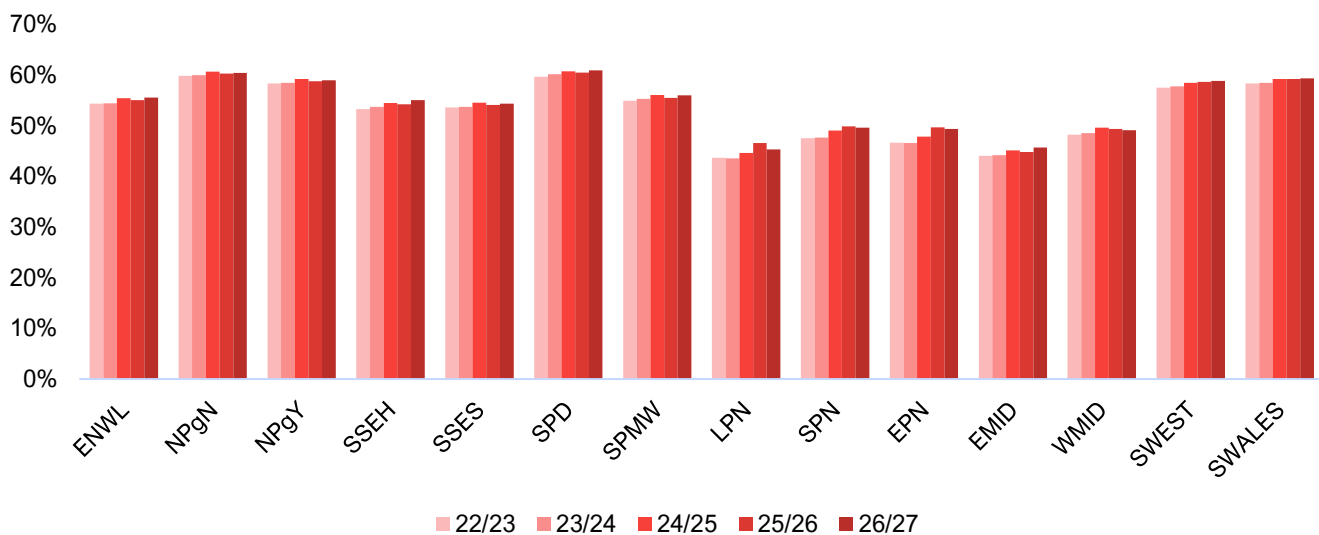
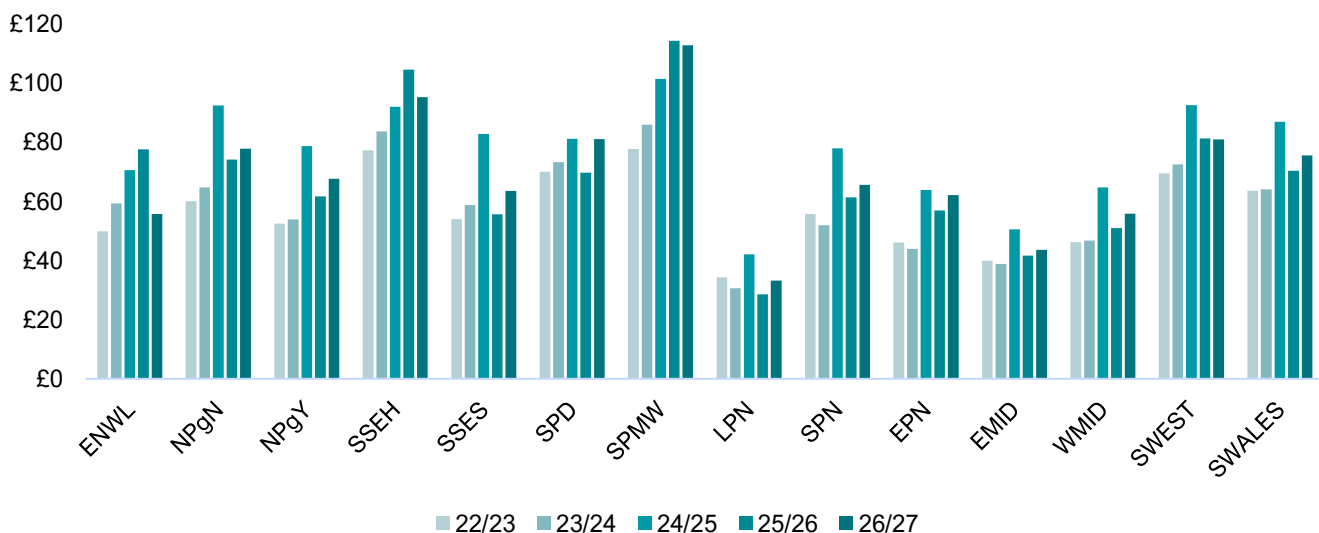


Figure 13b shows the equivalent chart in £ terms for a Domestic Aggregated customer, assuming an HV LDNO:DNO boundary – and demonstrating a much greater level of volatility in absolute terms. Year-to-year movements in LDNO margins and variations between DNO regions almost entirely reflect movements in the underlying all-the-way tariffs.

Figure 13b: LDNO margins (£) per Domestic Aggregated customer (avg.), LDNO HV:LV user, 2022/23-26/27



LDNOs' net revenues continue to demonstrate strong growth

Figure 14a demonstrates that the proportion of DUoS revenue being recovered and retained by LDNOs has grown steadily over the last five years. **In 2026/27, 6.5% of CDCM revenue is expected to be collected by LDNOs (£466m), and 2.9% will be retained as LDNO net revenue (£207m). This is a 29% increase on 2025/26 levels,** despite incumbents' revenues only increasing by 3%. These values only reflect customers below DNO:LDNO boundaries at LV and HV levels, for which the CDCM provides volume estimates. Customers below boundaries at EHV level are not captured because no volume information is available in the public domain.

Figure 14a: CDCM net revenue retained by LDNOs vs DNOs: GB totals, 2022/23-26/27

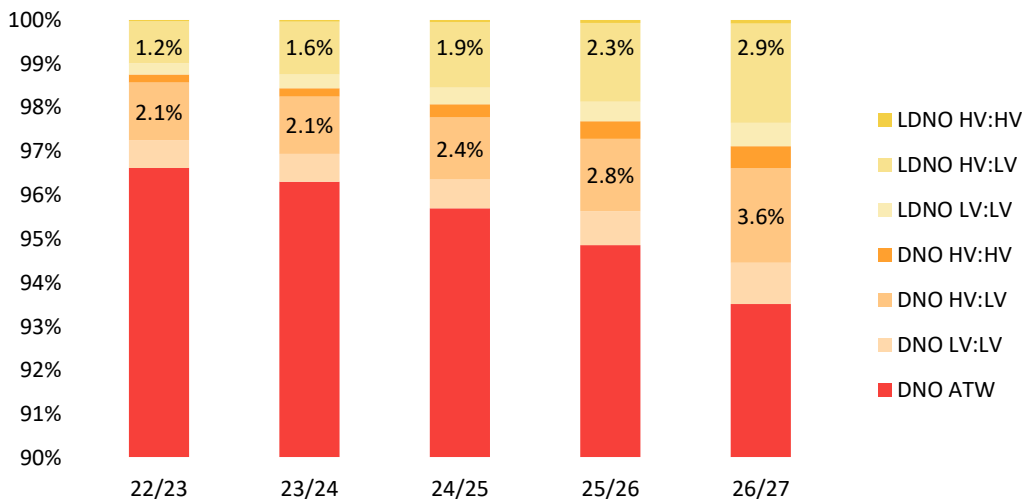


Figure 14b illustrates the same values by DNO for the most recent charging year. It shows that LDNOs are recovering a greater proportion of CDCM net revenue in some regions than others. The SSEH and SWALES regions show a penetration of around 1 and 2% respectively, whereas LPN/SPN/EPN are approaching 8%. This situation may reflect different costs of building and operating last mile assets in some areas than others, which may not be fully reflected in the level of LDNO margins which can be earned there. Alternatively, it could reflect the pace of demand for new connections in different regions more broadly.

Figure 14b: CDCM net revenue retained by LDNOs vs DNOs: 2026/27 by DNO

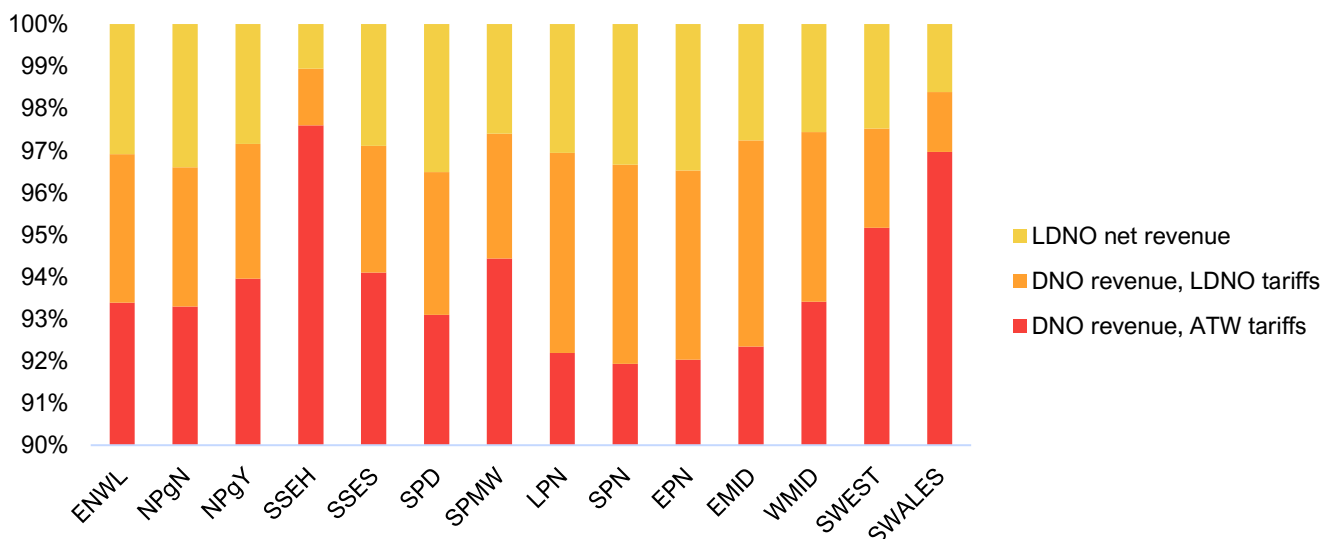


Figure 15 shows the split of LDNO net revenues being collected from different customer categories. Most LDNO net revenues are from Domestic Aggregated (54%) and LV Site Specific (35%) customers – primarily with respect

to HV-level boundaries. Comparatively little is collected from HV-connected customers. Hardly any net revenue is collected from generation customers. The trend from Aggregated to Site Specific reflects a shift in customer numbers between these two categories which applies to DNOs more generally. Within banded customer categories, the majority of net revenue is recovered from larger customers in bands 3 and 4.

Figure 15: LDNO net revenue by customer category (not including EHV boundary levels), 2022/23-26/27



Appendix A CDCM CHARGE ILLUSTRATIONS

The following pages illustrate (i) the most recent (2026/27) published CDCM charges by DNO region, and (ii) GB average CDCM charges for the past four charging years, for the following customer categories:

- Domestic Aggregated
- Non-Domestic Aggregated
- LV Site Specific
- HV Site Specific
- HV Generation Site Specific

These are the most significant customer categories in terms of customer numbers, volumes and / or expected revenues. GB averages are weighted by the most relevant volumes (e.g. unit rate charges are weighted by MWhs; fixed charges are weighted by MPANs; capacity charges are weighted by MVA; etc.). Reactive power charges and exceeded capacity charges are not shown. A consolidated version of inputs to / outputs from published CDCM models is available in the workbook submitted to DCUSA alongside this note.

This analysis was based on inputs to the Annual Review Pack (ARP) models which are published by DNOs and available on the DCUSA website.⁹ Revisions were made to 2022/23 and 2023/24 ARPs to reflect additional SoLR pass-through costs approved by Ofgem after charges were initially published – taken from 2022/23 and 2023/24 CDCM models re-published on DNOs' websites or provided directly by DNOs. CEPA/TNEI do not guarantee that the charts in this note match published charges (since some DNOs have used derogations to make small adjustments to other model inputs not reflected in our analysis).

Model versions and input sources used for this analysis

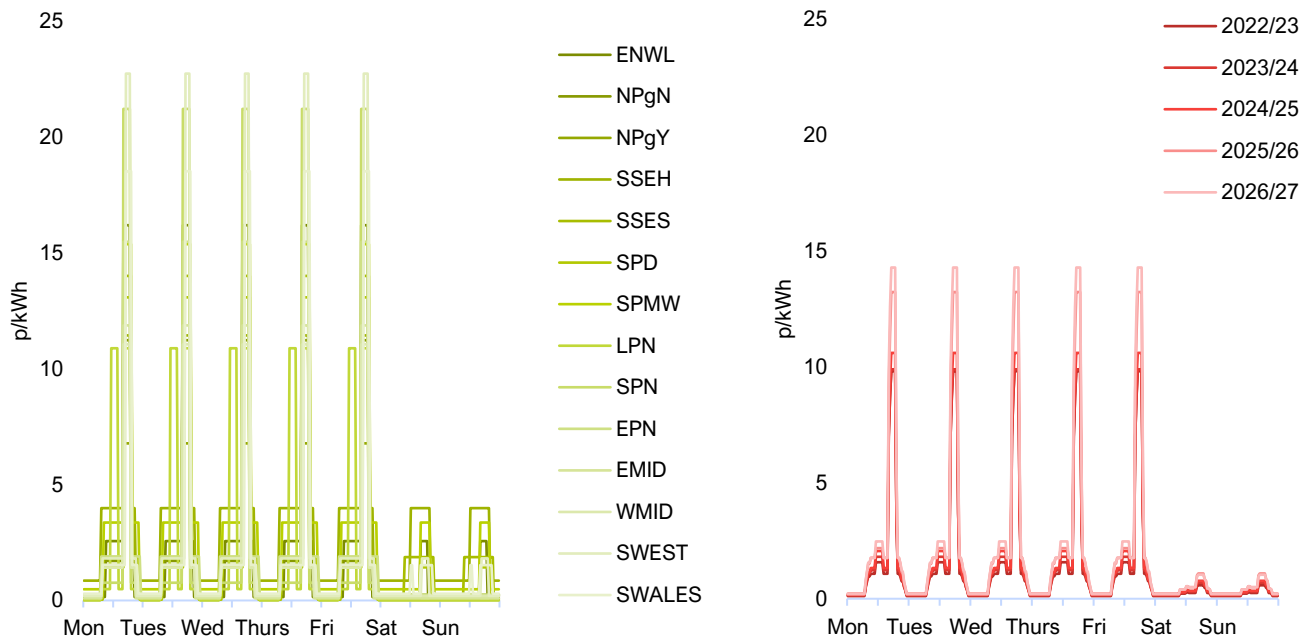
Charging year	Input source	SoLR pass-through source	Calculation file
2022/23	ARP_v7_20201106.xlsm <i>Published to DCUSA website by 31 Dec 2020</i>	CDCM_v7_20201106_v2.xlsx <i>Re-published to DNO websites or shared with modelling consultants following Ofgem derogation letter on 23 December 2021</i>	CDCM_v7_20201106_v2.xlsx
2023/24	ARP_v7_20211122.xlsm <i>Published to DCUSA website by 31 Dec 2021</i>	CDCM_v8_20211122.xlsx <i>Re-published to DNO websites or shared with modelling consultants following Ofgem derogation letter on 13 January 2023</i>	CDCM_v8_20211122.xlsx
2024/25	ARP_v7_20221027.xlsm <i>Published to DCUSA website by 31 Dec 2022</i>	-	CDCM_v9_20221027.xlsx
2025/26	ARP_v8_20231106.xlsm <i>Published to DCUSA website by 31 Dec 2023</i>	-	CDCM_v10_20231106.xlsx
2026/27	ARP_v9_20241025.xlsm <i>Published to DCUSA website by 17 Feb 2025</i>	-	CDCM_v11_20241025.xlsx

⁹ www.dcusa.co.uk

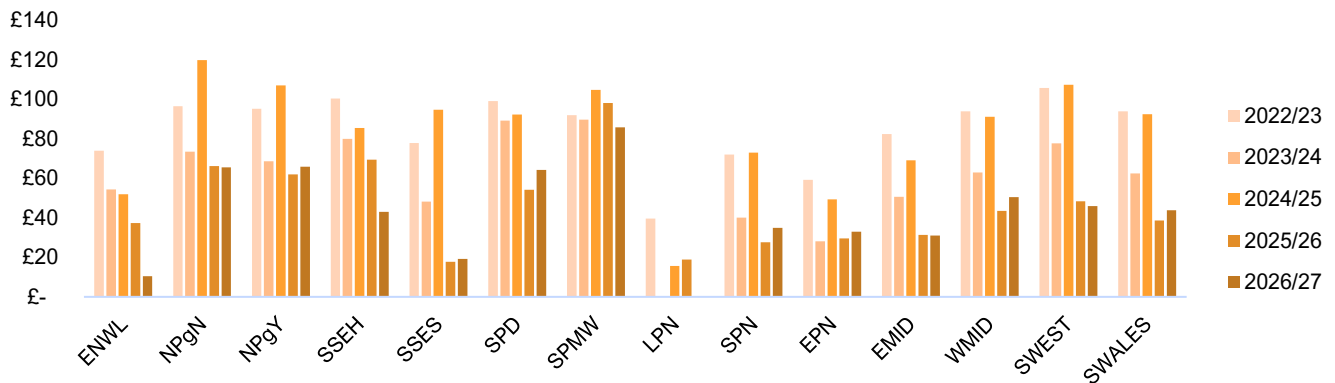
Domestic Aggregated

The 'Domestic Aggregated' tariff is the largest in terms of numbers of customers (29,908,839 in 2026/27) and share of expected CDCM revenue (50% in 2026/27). It has unit rate and fixed charge components. The fixed charge is not banded.

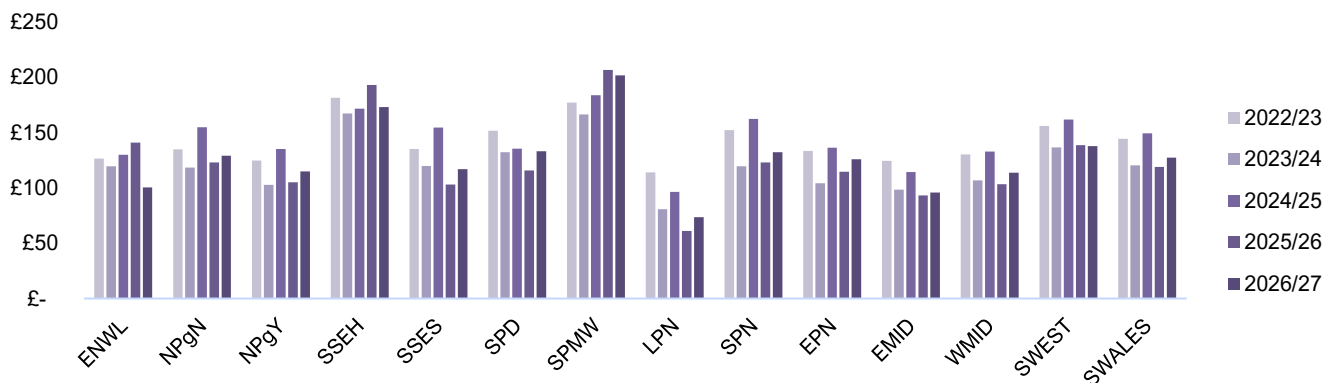
Unit rates, p/kWh, over a typical week (with no public holidays) – 2026/27, by DNO (left); GB average by year (right)



Fixed charges, £/MPAN/year



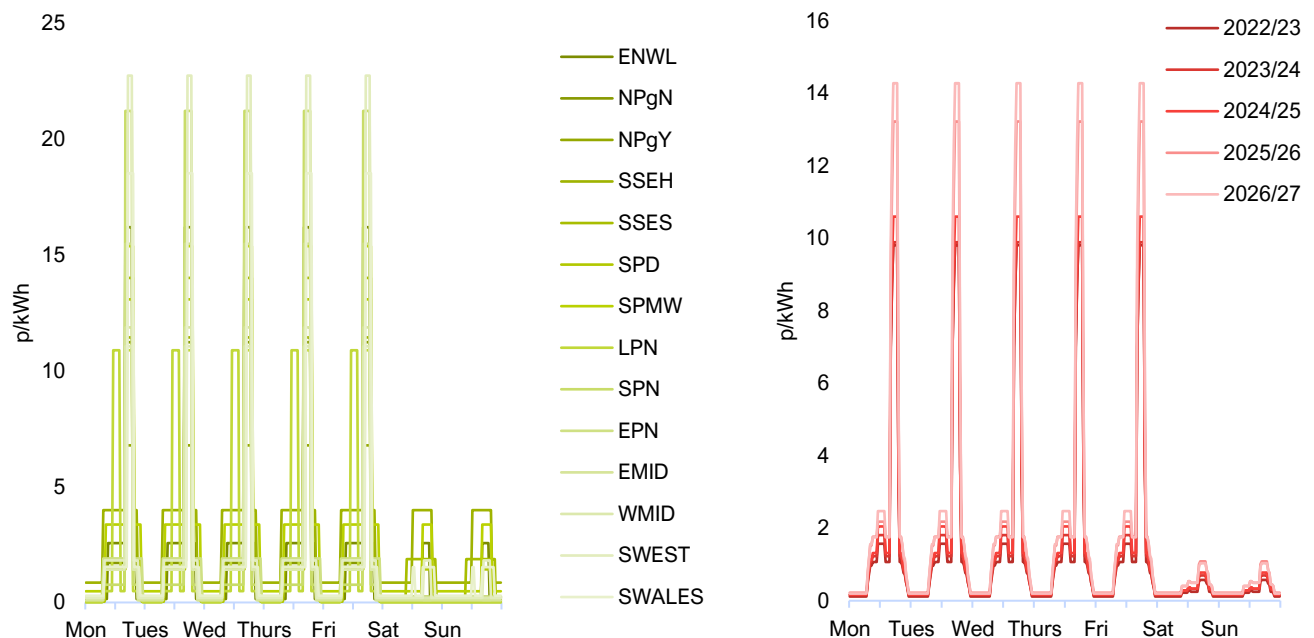
Typical bills, £/MPAN/year



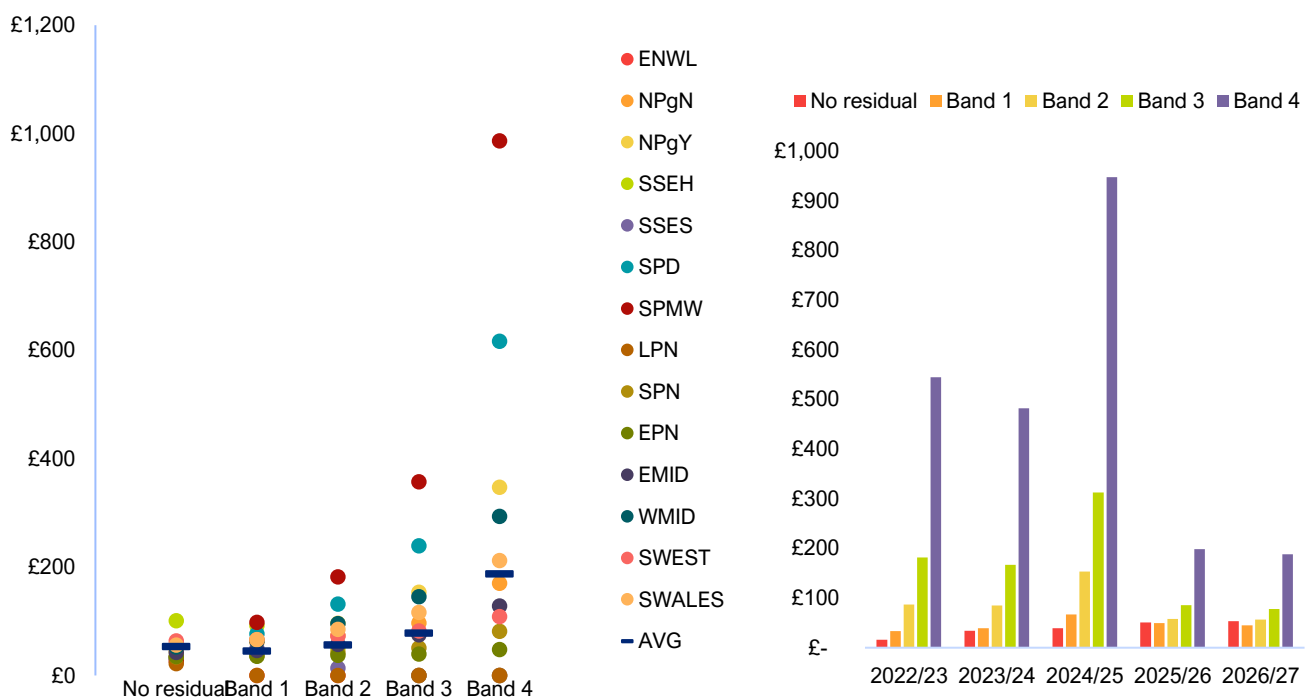
Non-Domestic Aggregated

The 'Non-Domestic Aggregated' tariff is one of the largest in terms of numbers of customers (2,232,087 in 2026/27) and share of expected CDCM revenue (12% in 2026/27). It has unit rate and fixed charge components. The fixed charge is increasing by agreed capacity band.

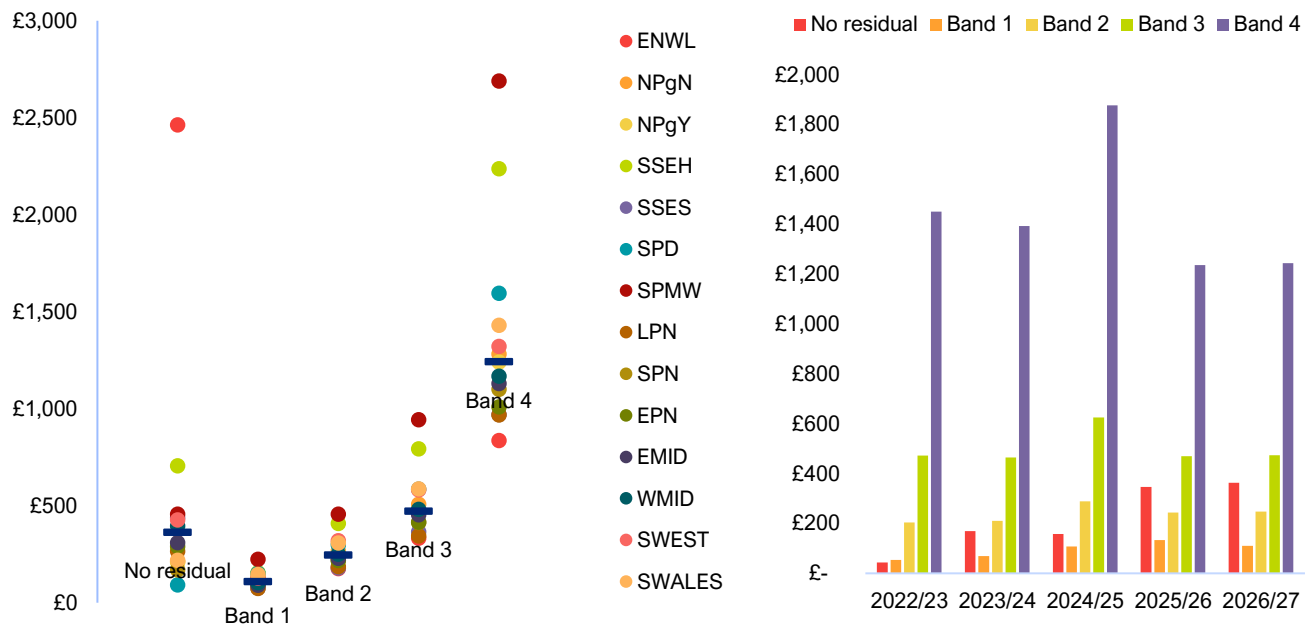
Unit rates, p/kWh, over a typical week (with no public holidays) – 2026/27, by DNO (left); GB average by year (right)



Banded fixed charges, £/MPAN/year – 2026/27, by DNO (left); GB average by year (right)



Typical bills, £/MPAN/year – 2026/27, by DNO (left); GB average by year (right)

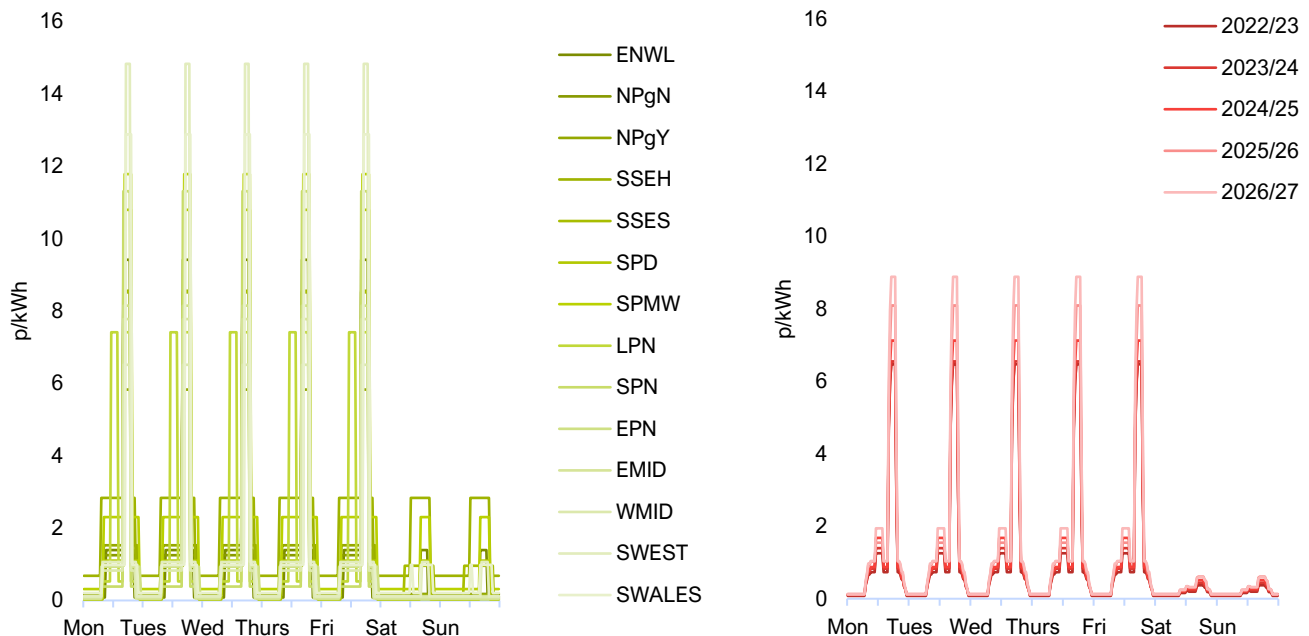


Note: "No residual" can be skewed by a small number of very large customers.

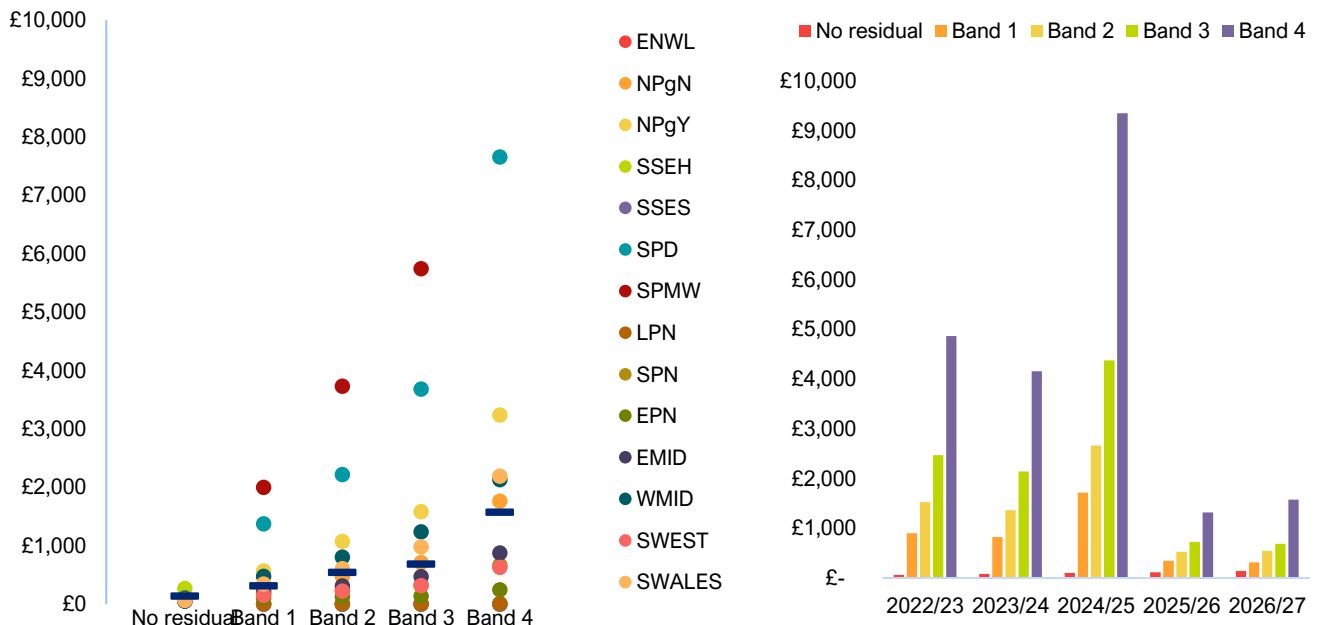
LV Site Specific

The 'LV Site Specific' tariff covers LV-connected customers who are charged for their agreed capacity, as well as through unit rate and fixed charge components. Compared to the other tariffs available at the LV level, it has relatively few customers (199,716 in 2026/27) but contributes a large share of expected revenue (20% in 2026/27).

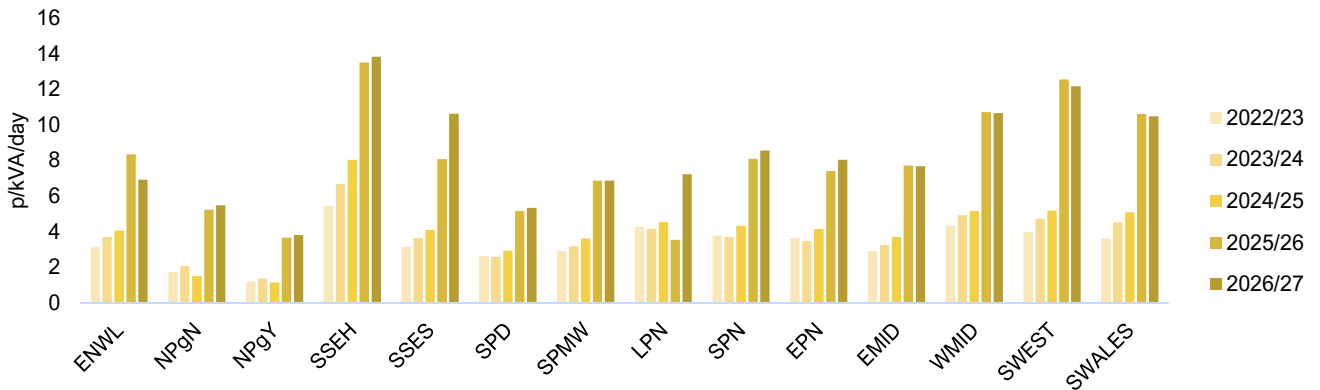
Unit rates, p/kWh, over a typical week (with no public holidays) – 2026/27, by DNO (left); GB average by year (right)



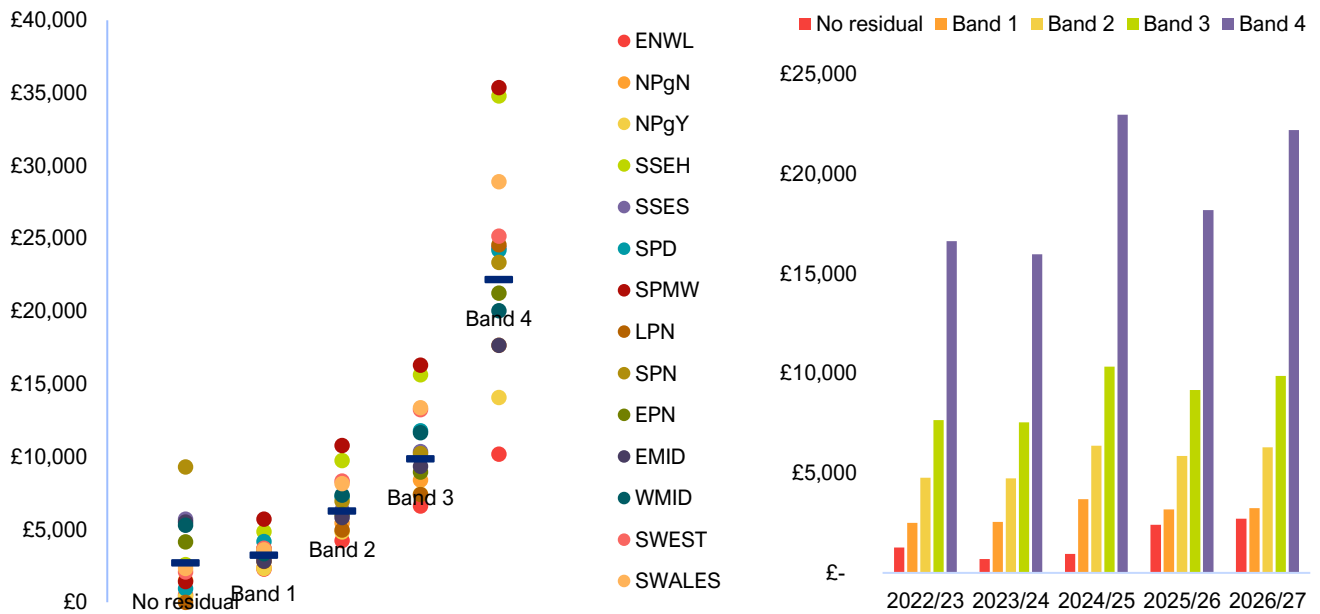
Banded fixed charges, £/MPAN/year – 2026/27, by DNO (left); GB average by year (right)



Capacity charges, p/kVA/day



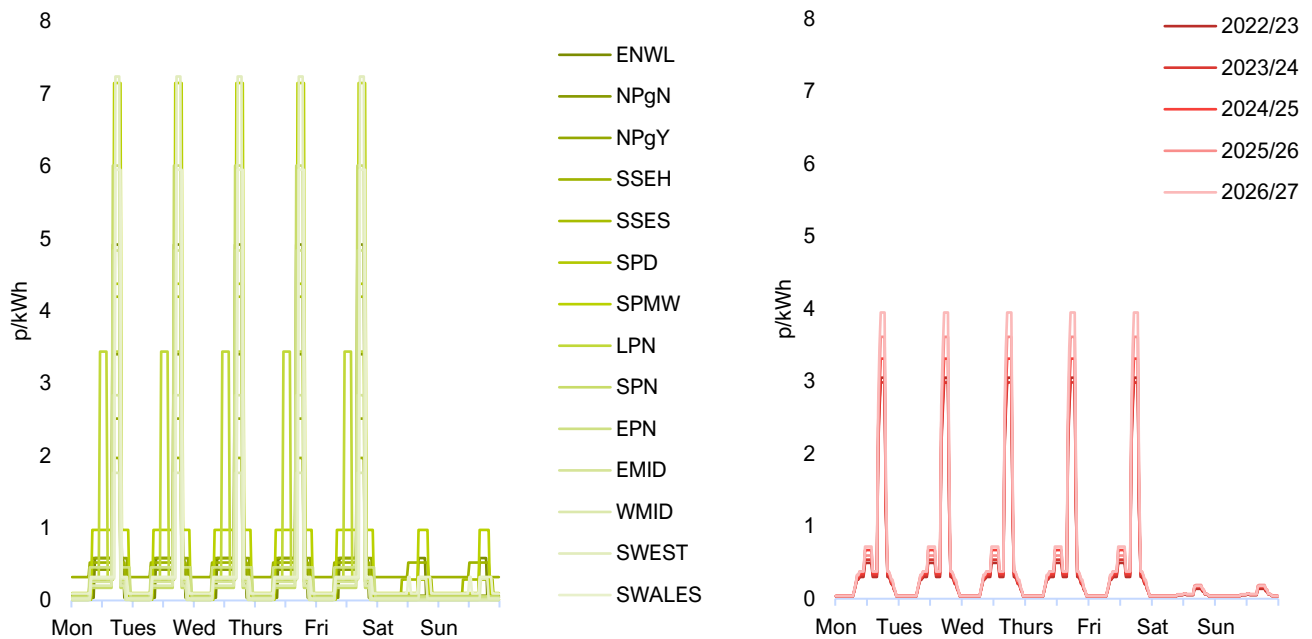
Typical bills, £/MPAN/year – 2026/27, by DNO (left); GB average by year (right)



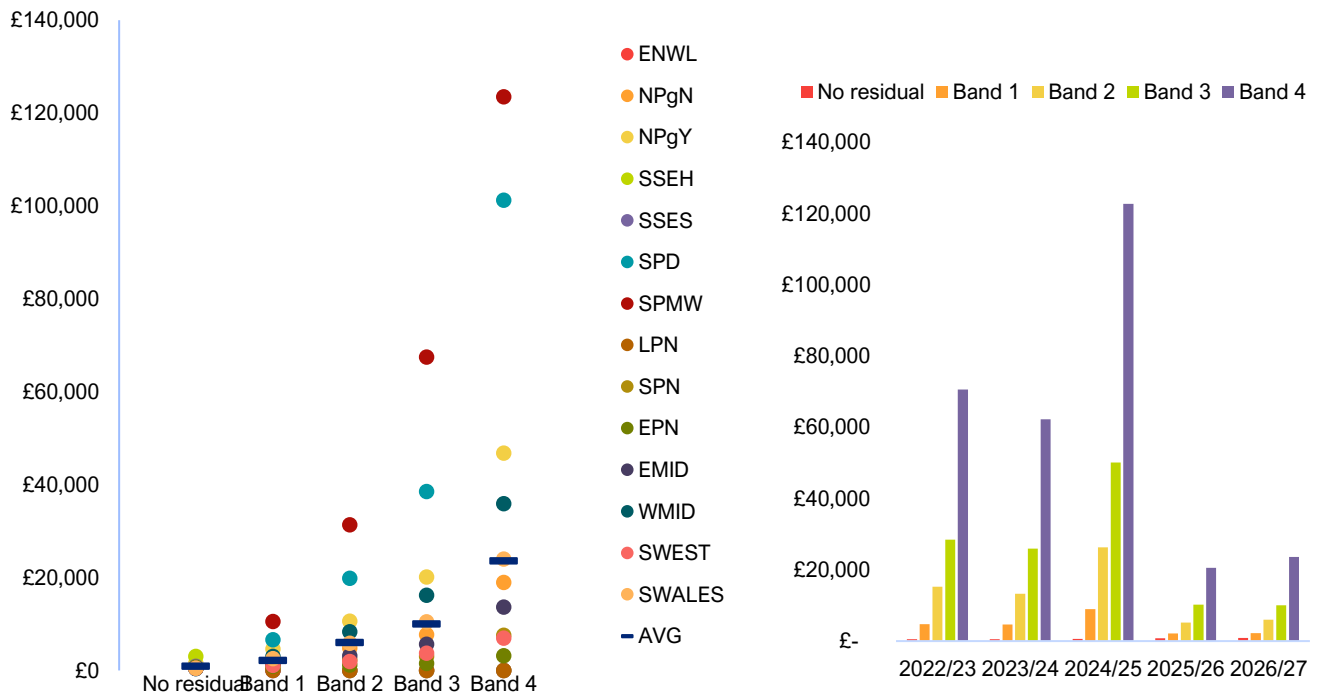
HV Site Specific

The 'HV Site Specific' tariff covers HV-connected customers who are charged for their agreed capacity, as well as through unit rate and fixed charge components. It has relatively few customers (23,460 in 2026/27) but contributes a large share of expected revenue (15% in 2026/27).

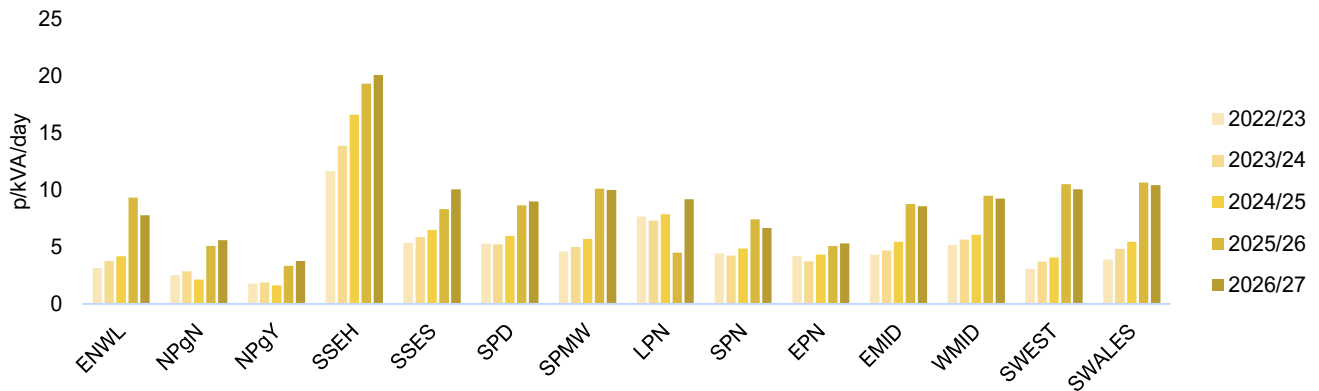
Unit rates, p/kWh, over a typical week (with no public holidays) – 2026/27, by DNO (left); GB average by year (right)



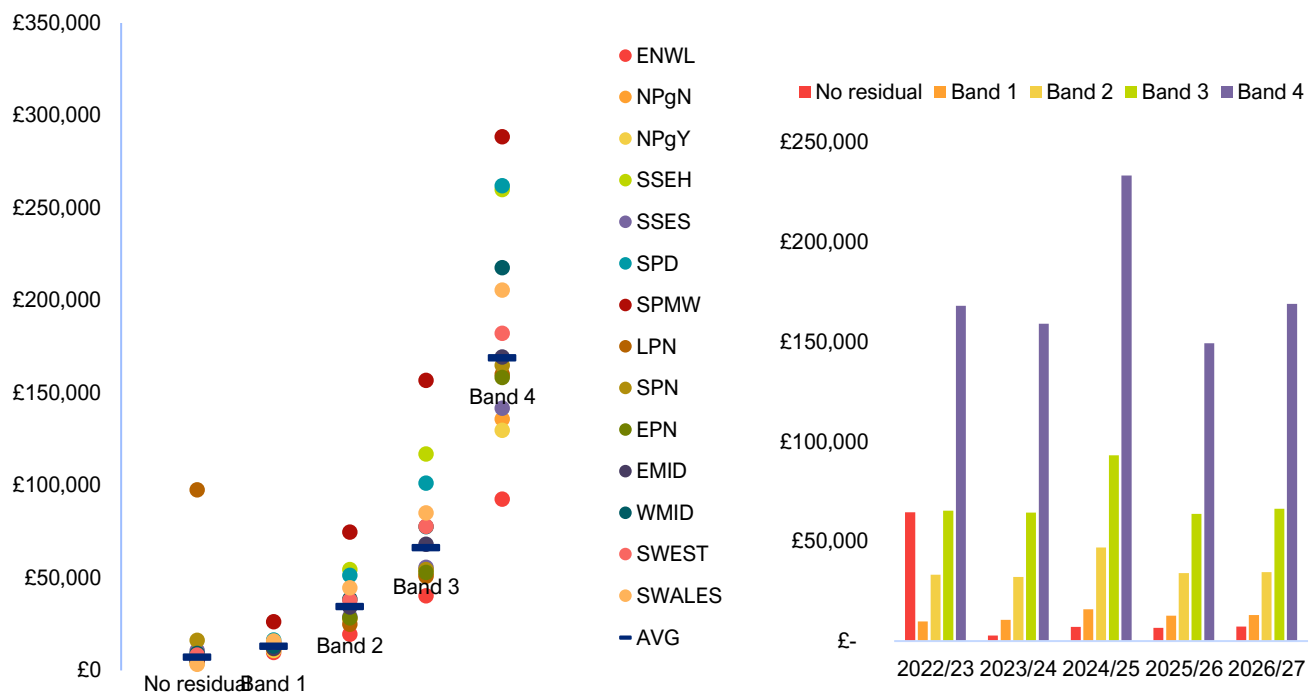
Banded fixed charges, £/MPAN/year – 2026/27, by DNO (left); GB average by year (right)



Capacity charges, p/kVA/day



Typical bills, £/MPAN/year – 2026/27, by DNO (left); GB average by year (right)

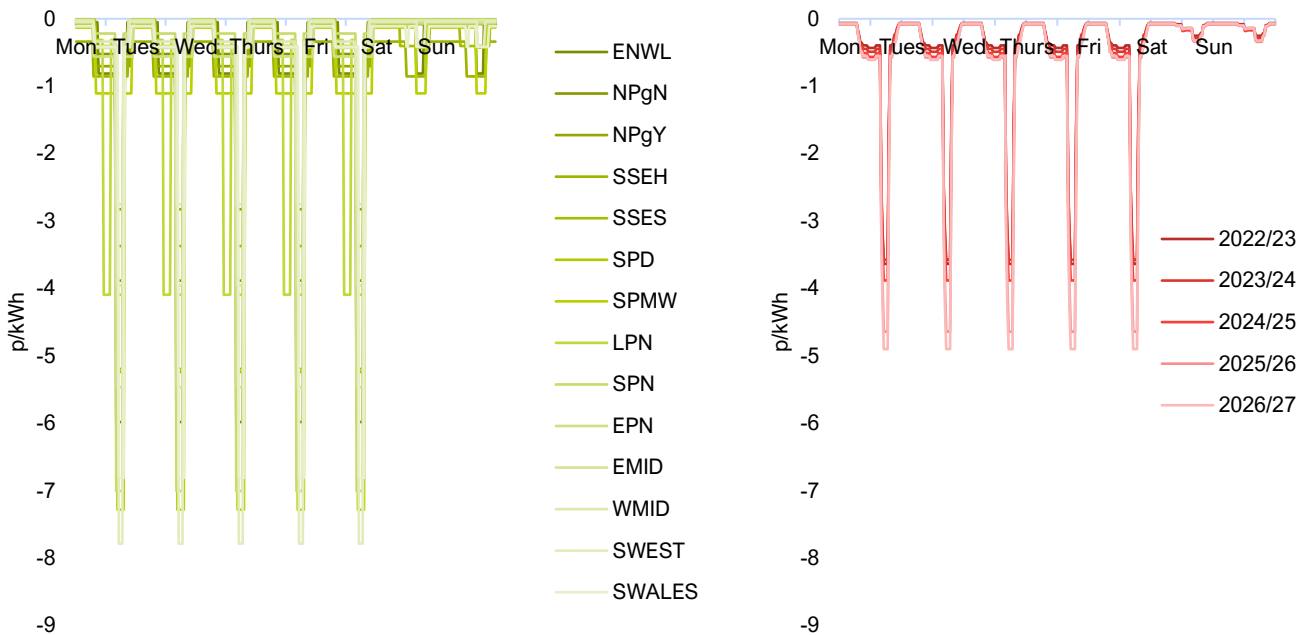


Note: "No residual" can be skewed by a small number of very large customers.

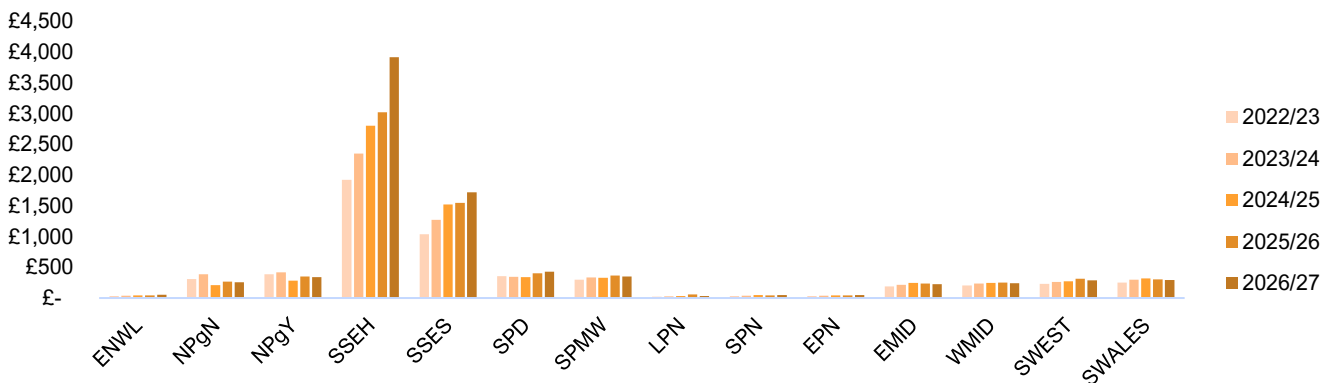
HV Generation Site Specific

The 'HV Generation Site Specific' tariff applies to HV-connected generation customers. It is the largest generation tariff by share of expected revenue (79% of net credits paid to generation customers in 2026/27 which are -2% of overall expected net revenue), though not by number of customers (3,779 in 2026/27). It has a negative unit rate (generation credit) as well as a fixed charge, which does not include contributions to residual or pass-through costs.

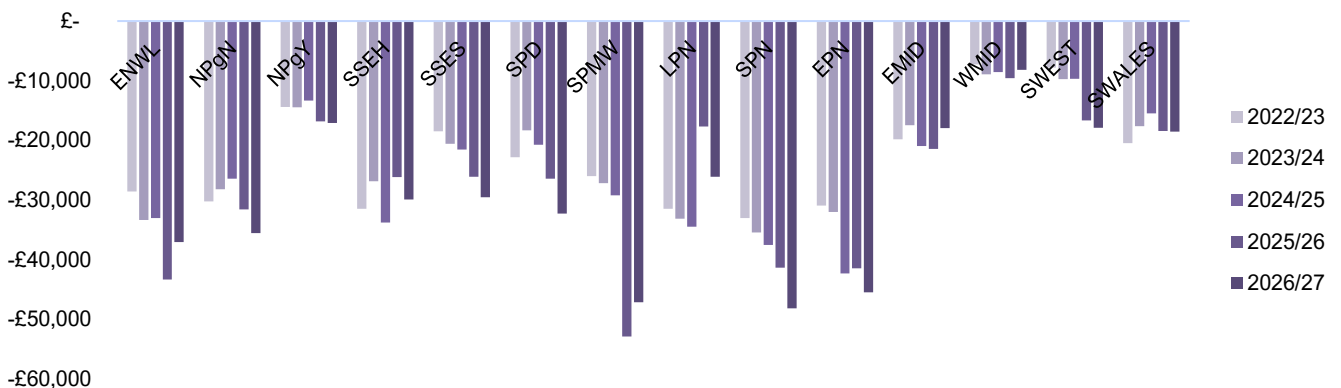
Unit rates, p/kWh, over a typical week (with no public holidays) – 2026/27, by DNO (left); GB average by year (right)



Fixed charges, £/MPAN/year



Typical bills, £/MPAN/year



ABOUT US

CEPA advises on issues where economics, finance and public policy overlap. Our team of economists and financial consultants apply economic concepts with judgement, integrity and skill for the benefit of our clients. We leverage our in-depth knowledge of the energy sector to produce robust analysis and advice in the areas of competition law, regulation, policy, spectrum auctions, transactions, compliance and evaluation.

TNEI is an independent specialist energy consultancy providing technical, strategic, environmental and consenting advice to organisations operating within the conventional and renewable energy sectors.

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