



ENERGY & EDUCATION CONNECTED

Non-commodity Charges Update Q4 2025

October 2025

Produced in partnership with



Summary

The weakening in wholesale prices compared to recent years means that the share of non-commodity costs as a percentage of fully-delivered costs is now about 55-65%, varying between individual contracts. The prediction is that non-commodity costs will continue to rise in the future – due to both inflation and regulatory change. The number and complexity of third-party charges has increased over time given moves to decarbonise the energy sector and guarantee energy supply. This includes green support schemes which support the deployment of low-carbon generation as well as network tariffs to support transmission and distribution of energy. Non-commodity charges are split into three primary categories: delivery charges; taxes and levies; and system/administration charges. Costs vary between users as they are dependent on factors such as the nature of business, location and size.

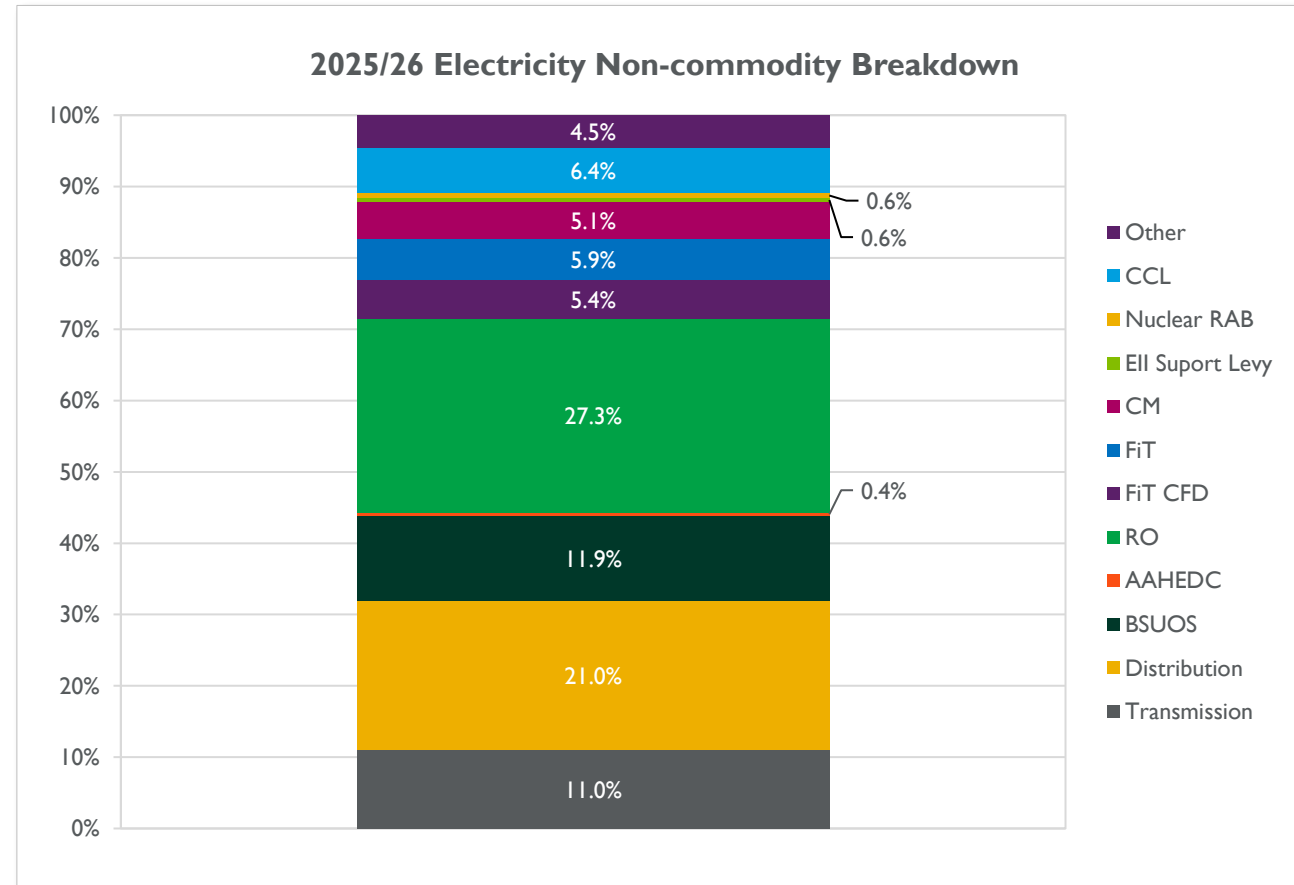


Figure 1: 2025/26 non-commodity breakdown (illustrative only)



Contents

1

Electricity Non-commodity Charges Update

The latest updates and trends surrounding non-commodity charges in the electricity sector

2

Electricity Delivery Charges

Various costs associated with the delivery of electricity from generation sources to end consumers

3

Electricity Taxes and Levies

Governmental taxes and levies imposed on electricity production and consumption

4

System and Admin Charges

Administrative and system-related expenses incurred by management and operation of electricity and gas networks

5

Gas Delivery Charges

Charges involved in transporting gas via pipelines and infrastructure from source to end users

6

Other Charges

Additional costs, such as Unidentified Gas (UIG) that impacts utilities and consumers

7

Gas Taxes and Levies

Various government imposed taxes and levies on gas production, distribution, and consumption

8

Glossary of Terms

Key terminology used throughout this report



Electricity Non-commodity Charges Update



Half way through the charging year we’re starting to get more information on the likely level of non-commodity charges next year. Inflation remains relatively high with the latest predictions forecasting RPI will be close to 4% and CPI at about 3% by the year end. This will impact those charges which have their costs, like generator tariffs or strike prices indexed-linked to inflation.

Another concern is the forecast for transmission charges – currently predicted to move to a much higher level as the new electricity transmission price control takes effect in April. Consequently, the average non-locational demand tariff is forecast to rise to £233.30/site/annum compared to the final tariff of £118.39/site/annum for 2025/26 given a significant increase in predicted allowed revenue. Much more money is expected to be invested in the grid to enable the government to achieve its 2030 clean power plan.

There is also more information now on the new Nuclear RAB charge which is funding the construction of the nuclear plant Sizewell C. The cost of the levy for the first year of the scheme was made known in August and is initially linked to the cost of construction which could be subject to cost overruns.

Meanwhile, looking back over the summer the season has seen CfD rates reach record highs supported through a combination of an increase in offshore wind generation and higher payments to generators and lower demand. The FiT tariff scheme has also seen record costs. A record total of £563.2 million FiT export and generation payments were made in Q2 25, the first quarter of scheme year 16.

Inflation and Price Indices (RPI and CPI)

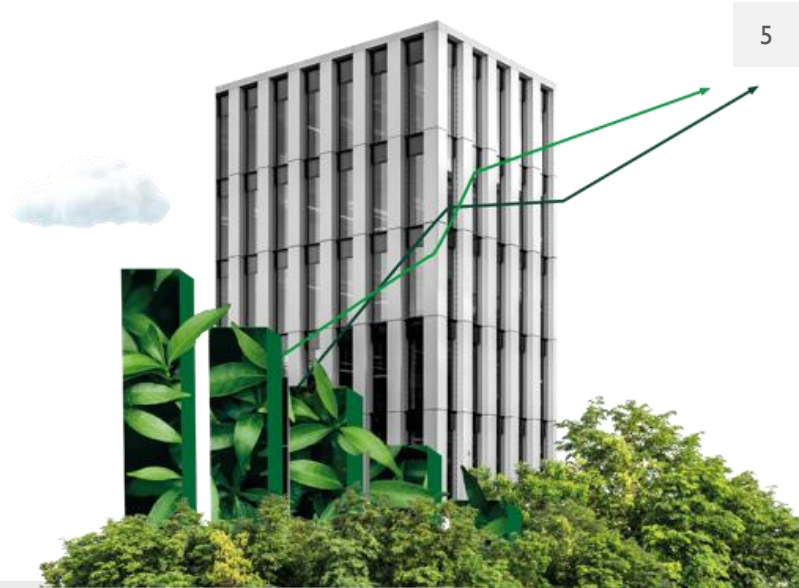
The Retail Prices Index (RPI) and Consumer Prices Index (CPI) measure the rate at which prices change over time. While non-commodity tariffs like FiT and the RO are adjusted by RPI, the CfD, Capacity Market and Hydro Levy schemes are adjusted by CPI.

What is driving it?

RPI (All Items) fell to 4.6% in the 12 months to August 2025 compared to 4.8% in July. The Consumer Price Index (the other main inflation indicator) fell to 4.1% in August compared to 4.2% in July. The largest downward contribution came from air fares but restaurants and hotels, and motor fuels made large, partially offsetting, upward contributions. Core CPIH (excluding energy, food, alcohol and tobacco) rose by 4.0% in the year to August down from 4.2% in July. RPI inflation remains at its highest since March 2024 and is currently close to the high forecast for 2025 of 4.8%.

Year	RPI		CPI	
	2025	2026	2025	2026
Low	2.7	2.5	2.0	1.8
Central	3.8	3.2	3.1	2.3
High	4.8	4.4	3.8	3.2

Table 1: Y-O-Y RPI & CPI movements



2

Electricity Delivery Charges



Transmission Network Use of System (TNUoS) Charges

TNUoS charges take effect each April recovering the cost of operating and maintaining the electricity transmission system. While generators are charged based on their Transmission Entry Capacity (TEC), consumers are charged based on their capacity and consumption. Charges also vary by location, reflecting the costs users add at various points on the network.

NESO (the National Energy System Operator) publishes forecasts throughout the year including a draft tariff schedule in November ahead of the final publication in January. A five-year outlook is also published during the summer.

Network reforms removing distortions caused by Triad avoidance were implemented in April 2023. A single set of non-locational Half-Hourly (HH) and Non-Half-Hourly (NHH) banded charges based on voltage now make up most of the demand charge.

The locational element of the HH demand tariff is charged on Triad demand. Triads are the three half-hourly periods of highest national demand between 4-7 pm during November and February. However NHH consumers pay the locational element based on their aggregated annual consumption during 16:00 – 19:00 hours each day.

Meanwhile, a floor of £0/kW and 0p/kWh applies to HH and NHH locational charges in zones such as Scotland and northern England as well as the East Midlands where the level of demand signals a reduced need for investment in generation.

The demand residual (total demand revenue less locational demand revenue, plus revenue paid to embedded exports) recovers total allowed revenue after forward-looking locational charges have been levied. It accounts for most of the revenue collected from demand.

Latest update:

NESO updated the initial 2026/27 charging schedule published earlier in the year as part of the five-year view released in August. The average non-locational demand tariff is forecast to rise to £233.30/site/annum compared to the final tariff of £118.39/site/annum for 2025/26. This is because revenue collected from the demand residual is forecast to increase to £7,521 million in 2026/27 compared to £3,836 million in 2025/26.

While the average HH locational tariff falls to £3.18/kW in 2026/27 from £8.49/kW in 2025/26, the average NHH locational tariffs rise to 0.43 p/kWh from 0.38 p/kWh. Draft 2026/27 tariffs will be published in November.



Average non-locational tariffs rise to £359.28/kW by 2030/31 in the new five-year outlook covering the period 2026/27 – 2030/31 published in August. Tariffs are likely to be higher than previous years given the increase in allowed revenue in the next transmission price control, ET3, which operates between 2026/27 – 2030/31.

The draft determination for ET3 setting allowed revenues was published for consultation at the start of July with a deadline of the end of August. The final determination will be published in December.

An initial £8.9 billion of upfront investment is being committed with a further £0.5 billion expected. But the amount announced is only a portion of what could be required with capital investment possibly exceeding £80 billion over the price control approved through in-period regulatory mechanisms.

The industry is considering the re-introduction of demand locational signals by removing the zero-price floor. This removes the potential for negative prices and the perverse incentive for users to consume by widening the period over which consumption is measured for charging against negative tariffs. Implementation would take effect from 1 April 2026 if approved.

Network charging continues with the TNUoS task force identifying a number of proposed changes which continue to go through the usual modification process. Key investment decisions required to achieve the government’s Clean Power 2030 plan mean additional action is needed to

reduce uncertainty about future TNUoS charges. A decision is awaited on Ofgem’s consultation on the decision to reject the proposal to implement a ‘cap and floor’ to wider generation charges. The proposal sought to reduce investment uncertainty for generators caused by the unpredictability of tariffs by applying upper and lower limits to charges. The proposal also aimed to reduce costs to consumers from an expected reduction in the cost of capital or risk flowing through to reduced CfD bids, wholesale prices, and balancing costs.

Ofgem published an open letter outlining initial thinking on reform of network charging signals to align with the government’s decision to retain a single GB-wide electricity wholesale market under the Review of Electricity Market Arrangements (REMA). Reform of network and connection charges is an important part of change so that they guide demand and supply sources to locations where grid capacity is expected to be available at the time they are likely to connect. This approach is intended to improve co-ordination of generation, storage, network and demand and reduce costs for consumers by reducing congestion.

The government intends to increase the support Energy Intensive Industries (EIs) receive under the British Industry Supercharger package with an uplift of the Network Charging Compensation (NCC) scheme to 90% from 60%. This will provide additional price relief from 2026 for around 500 eligible businesses, further reducing the competitive gap with comparable neighbouring markets.

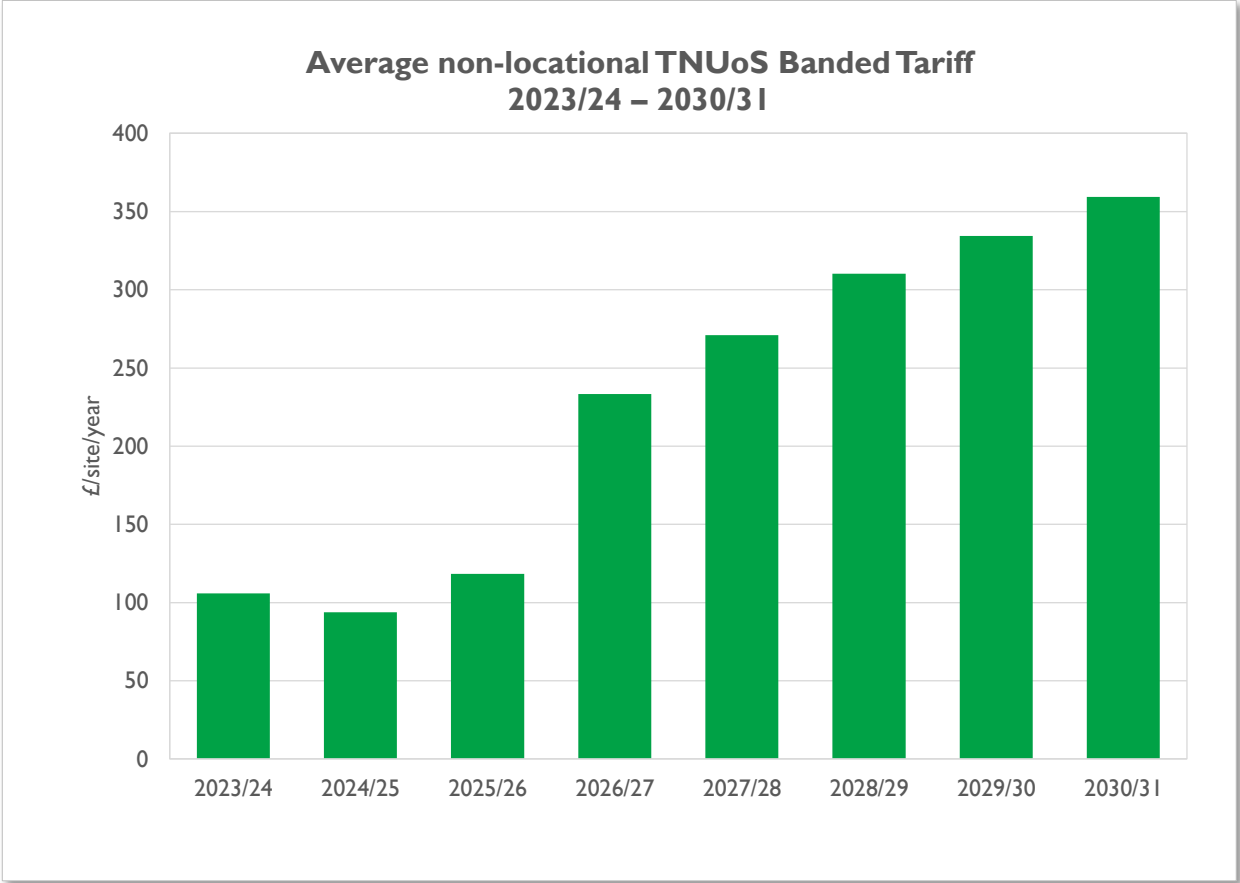


Figure 2: Average non-locational TNUoS banded tariff based on the 2025 five-year outlook

Distribution Use of System (DUoS) Charges

DUoS charges recover the cost of operating and maintaining the local distribution networks.

Changes implemented as part of reforms to make charging arrangements fairer include a fixed £/p per site per day residual charge based on voltage connection. A set of charges for each of the 14 distribution licensed areas applies to each charging band. The introduction of the fixed residual charge makes it more difficult for those who adjust their consumption at peak times to avoid paying their fair share of network costs.

The remainder of the tariff includes capacity and exceeded capacity charges based on contracted connection capacity as well as a reactive power charge. Tariffs also include variable Time-of-Use (ToU) charges, based on consumption represented by ‘Red’, ‘Amber’ and ‘Green’ time bands.

Latest update:

Distribution networks released indicative tariff data for the 2027/28 charging year during August ahead of the outturn tariff schedules expected early next year.

Time-banded tariffs for Low Voltage 2 (LV2) site specific category connections (capacity range 90-150 kVA) are higher compared to rates for the 2026/27 charging year. Capacity and exceeded capacity charges have also increased. Meanwhile, the fixed charge which reflects the collection of revenue from the residual (Allowed Revenue (AR) minus forward-looking revenue) is also higher compared to the 2026/27 fixed charge as the amount of allowed revenue required is higher.

The industry is awaiting Ofgem approval to shorten price notice periods to 12 months from 15. Shorter notice would give DNOs more time to apply tariff assurance. Concerns are that timelines for checking Ofgem’s Price Control Financial Model (PCFM) and applying changes can be challenging as DNOs only receive the PCFM in November ahead of the December tariff deadline for implementation. The PCFM helps determine DNOs’ AR.

A decision is also awaited on managing the effects of surplus residual revenue to enable networks to effectively calculate the fixed charge element of the tariff which recovers residual revenue. Currently some DNOs floor this charge at 0 p/MPAN/day because of a surplus. Work also continues on the review of excess capacity charges. Connection reform has led the excess to be set at the same rate as the capacity charge, providing little incentive to limit uncontrolled capacity expansion.

Work on the DUoS Significant Code Review (SCR) is restarting although reforms will be delayed until more is known about the direction of REMA as well as Ofgem’s Energy Cost Allocation and Recovery review.

	Apr-26	Apr-27	Apr-28	Apr-29
Central scenario	Published	+13.2%	-1.31%	+2.33%

Table 2: current annual movement in DUoS based on published DNO forecasts



3

Electricity Taxes and Levies



Climate Change Levy (CCL)

The CCL is a levy on the business use of energy. Energy intensive users participating in a Climate Change Agreement (CCA) with the Environment Agency pay a discounted rate in return for making energy and carbon savings. Since 1 April 2024 eligible participants have been able to reduce the rate they pay on electricity by 92% and 89% on natural gas.

Latest update:

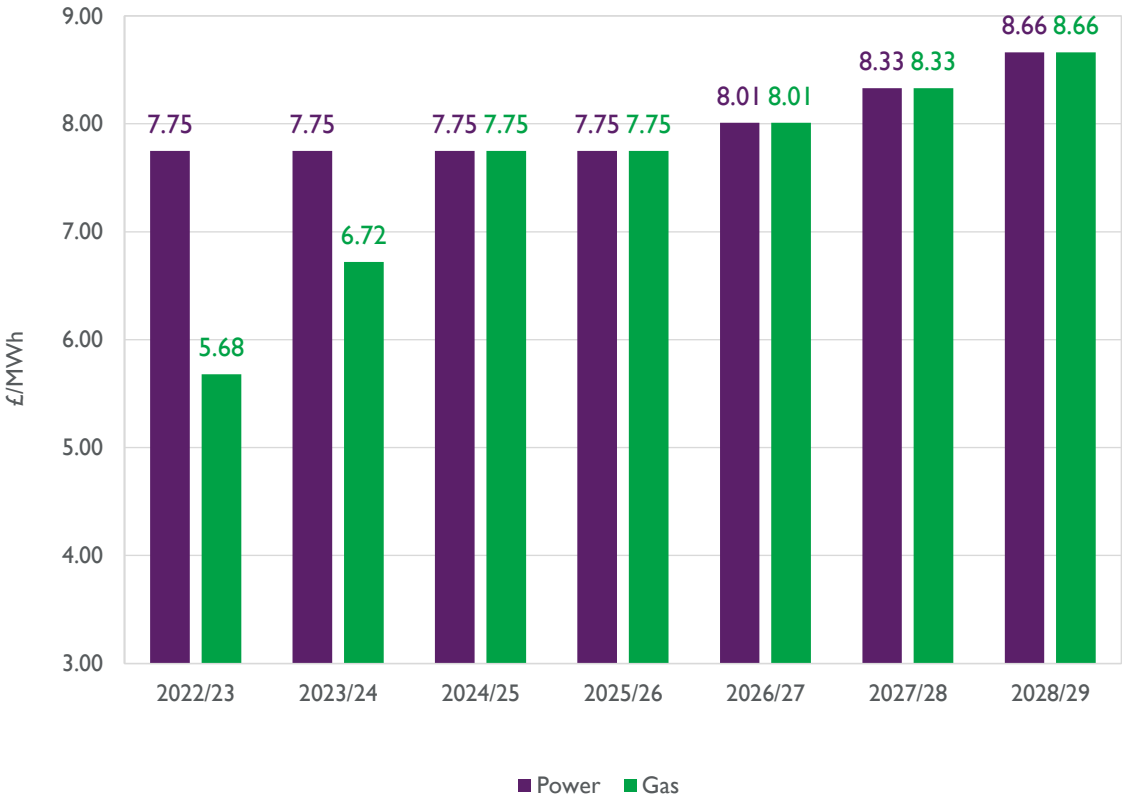
The government is planning a review of the Climate Change Levy (CCL) to ensure it can contribute effectively to its clean power and net zero missions. The scope of the review is expected to be informed by responses to the government’s consultation on the treatment of electrolytic hydrogen in the CCL which concluded during early May.

Since 2001 the CCL has encouraged businesses and the public sector to become energy efficient. But progress towards a low-carbon economy means the wider energy landscape has changed significantly. This raises concerns that decarbonisation could lead to the adoption of less energy-efficient processes while still lowering emissions, i.e. adopting processes that consume more energy but emit less carbon.

Accordingly, the government is seeking to understand whether stakeholder feel the CCL’s energy efficiency objectives are supportive of wider government objectives and whether the CCL creates any barriers to developments in the energy landscape in the next 5-10 years which means CCL may need to adapt to support them instead.



Climate Change Levy Forecast



Renewables Obligation (RO)

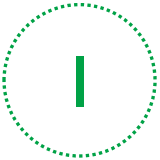
The RO is a government green support scheme incentivising the deployment of renewable generation by obligating suppliers to source a specified amount of electricity generated from renewable sources. Accredited generators receive Renewable Obligation Certificates (ROCs) for a period of 20 years from the date of their accreditation based on the amount they generate. Certificates can be traded or either sold directly or indirectly to suppliers who redeem them against their obligation.

Suppliers are required to present a specified number of ROCs to Ofgem for each unit (MWh) of electricity they supply. If a supplier fails to present a sufficient number of ROCs to meet the obligation,

they are required to pay a specified 'buy-out price' for each ROC not presented. These amounts contribute to a 'buy-out fund', the proceeds of which are redistributed to suppliers in proportion to the ROCs each supplier has presented.

The ROCs generators receive for their output are sold to suppliers through traders or auctions as well as Power Purchase Agreements (PPAs). While prices are currently determined by market forces, the government is considering switching to a fixed-price system to ensure price stability once 'early-years' generators' (those among the first to be accredited) accreditation expires starting from 2027. If adopted this would reduce price volatility by offering generators a fixed ROC price. The RO closed to new applicants in 2017.

The RO charge is calculated annually, from April to March, based on two elements:



Obligation level

The amount of renewable generation suppliers must source as a proportion of overall electricity generation within the obligation period. The obligation is set by the government at least six months before the start of the charging year.



Buy-out price

The price suppliers must pay for each ROC not presented towards compliance with their obligation. The Buy-Out price is indexed-linked to RPI and is set by Ofgem during the February preceding the new charging year.

The RO charge (£/MWh) is calculated by multiplying the obligation level by the buy-out price.

The government implemented the EII Renewable Levy Exemption Scheme in 2015, reducing the impact of renewable policy on the cost of electricity paid by Energy Intensive Industries (EIIs) which led to the exemption of these industries from green support scheme costs. The EII exemption from the RO charge was implemented in April 2018.



Latest update:

In September the government set the number of Renewable Obligation Certificates (ROCs) suppliers are required to produce during the 2026/27 RO obligation period at 0.472 ROCs/MWh in Britain and 0.184 ROCs/MWh in Northern Ireland based on the total exemption for Energy Intensive Industries in Britain from the indirect costs of the RO. The exemption is expected to increase from 2027 as more businesses are shielded by the industrial strategy.

In August Ofgem announced the total obligation for the 2024/25 compliance period was 119.5 million ROCs. Suppliers had until 1 September to meet their obligation by either presenting ROCs or making a buy-out payment or a combination of both. Otherwise suppliers have until 31 October to make a late payment. Any shortfall and possible mutualisation will be announced in November.

In June, the government published its new industrial strategy which aims to lower energy costs for

manufacturers. The British Industrial Competitiveness Scheme will reduce costs for manufacturing electricity-intensive industries from 2027. Eligible businesses will be exempt from paying the costs of the Renewables Obligation, Feed-in Tariffs, and the Capacity Market.

The government has said it is considering the impacts of REMA reform options in respect of a number of legacy arrangements including green support schemes like the RO and Feed-in Tariff. Legacy arrangements could include contracts or trading arrangements agreed before a public decision on proposals made as part of REMA.

What is driving it?

While the RO closed to new generating capacity in April 2017, it continues to support existing schemes for their allowed period, which is normally 20 years (first started in 2001). Capacity is gradually expected to fall, offsetting the increase in RO buy-out price to an extent.

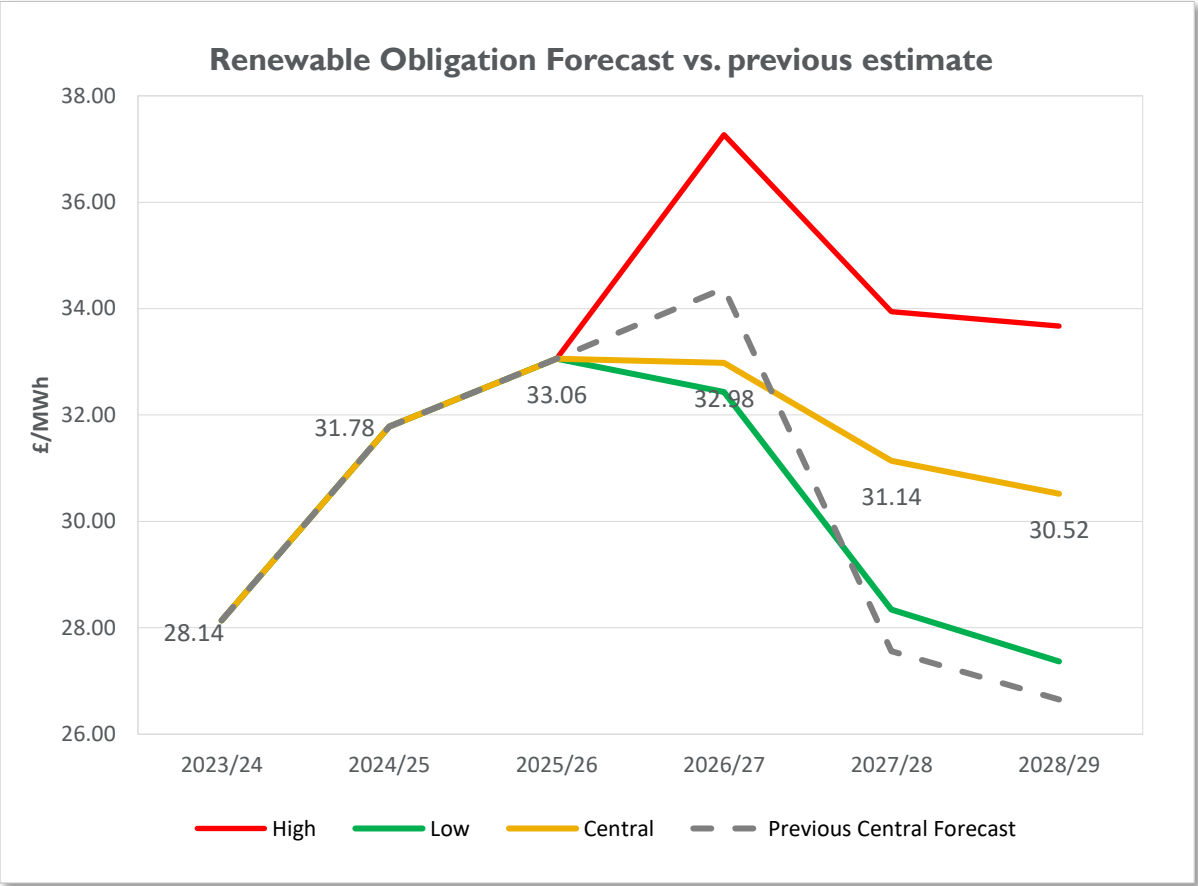


Figure 3: RO Forecast vs. previous estimate

Contracts for Difference (CfD)

The Contracts for Difference (CfD) scheme is the government's preferred support mechanism for the deployment of large-scale, low-carbon generation. The scheme provides developers with price certainty while minimising costs to consumers. Generators compete for the award of multi-annual contracts during an Allocation Round (AR). The developer then sells energy to the wholesale market and receives an additional payment if the pre-agreed strike price is lower than the Market Reference Price (MRP). If the strike price is higher than the MRP the generator pays back the difference.

The MRP is either the Intermittent Market Reference Price (IMRP) (like wind) and so based on the hourly Day-Ahead price or the Baseload Market Reference Price (BMRP) (for programmable generation like biomass). The BMRP is calculated on a seasonal basis based on a weighted average of forward season data and is published each April and October.

The BMRP for Winter 25 (applicable 1 October - 31 March) has been set at £84.75/MWh by the Low Carbon Contracts Company, the scheme's administrator. This is higher than the Summer 25 (1 April — 30 September) rate of £83.50/MWh.

Adjustments to strike prices are made each April based on the change in CPI. Strike prices were adjusted by 4.1% in 2025 compared to 5.4% the previous year.

From 2015, the Government implemented an exemption scheme for Energy Intensive Industries (EIIs) from the indirect costs of funding the RO, CfD and FiT schemes. The EII exemption for CfD was implemented from November 2017. The support has increased to 100% from 85% from April 2024.

Latest update:

The Q325 rate is predicted to be a record £11.10/MWh, exceeding the previous record of £10.46/MWh set during Q225. Unit rates have been supported through a combination of an increase in offshore wind generation and higher payments to generators and lower demand as well as low Day-Ahead prices which averaged £72/MWh. Unit rates are expected to average £10.60/MWh given the scheme's expansion and higher payments.

The size of the CfD portfolio has also increased as 15 AR4 and AR5 solar projects with combined capacity of 342 MW commissioned with a strike price of about £66/MWh. This is in addition to the AR1-contracted 448 MW Neart Na Gaoithe offshore windfarm with a strike price of £163/MWh. The Dogger Bank A cluster of windfarms as well as a number of other solar projects are also due to be accredited by the end of 2025.

A consultation seeking views on regulatory reforms to the Clean Industry Bonus (CIB) was launched in August. These include extending the bonus to onshore wind among other aspects. The CIB helps to reduce the risks associated with deploying low-carbon generating technologies like offshore wind and floating offshore wind by addressing supply chain issues which could hinder construction.

The process for determining successful projects in the AR7 auction round also launched in August continues with results expected to be announced in late 2025 to early 2026. Rules setting out how the round works including strike prices as well as the eligibility requirements applicants need to satisfy were included in the Allocation Framework published in July.

The government published its final response to the AR7 consultation covering the remaining proposals to support the implementation of the Clean Power 2030 Action Plan in July. The consultation considered a relaxation of the eligibility criteria for fixed-bottom offshore wind projects as well as changes to CfD contract terms aimed at giving longer market certainty once contracts are awarded. This also included the extension of the current 15-year CfD term to reduce overall project costs.

The CfD scheme faces a number of challenges and will have to adapt to a decarbonising power system according to last autumn's REMA update. But no substantial changes will be made until AR9 due to be held in 2027 if the scheme is to be reformed under REMA. Policy development concluded in the summer, ensuring timelines could align with the AR7 auctions.



What is driving it?

As CfD costs are dependent upon wholesale prices, predicting costs is difficult. Should wholesale prices increase, scheme costs will fall, as lower top-up payments will be required. The opposite holds true if wholesale prices fall. Wind generation may also affect scheme costs, higher wind production pushes wholesale prices lower and eligible generators will require top-ups.

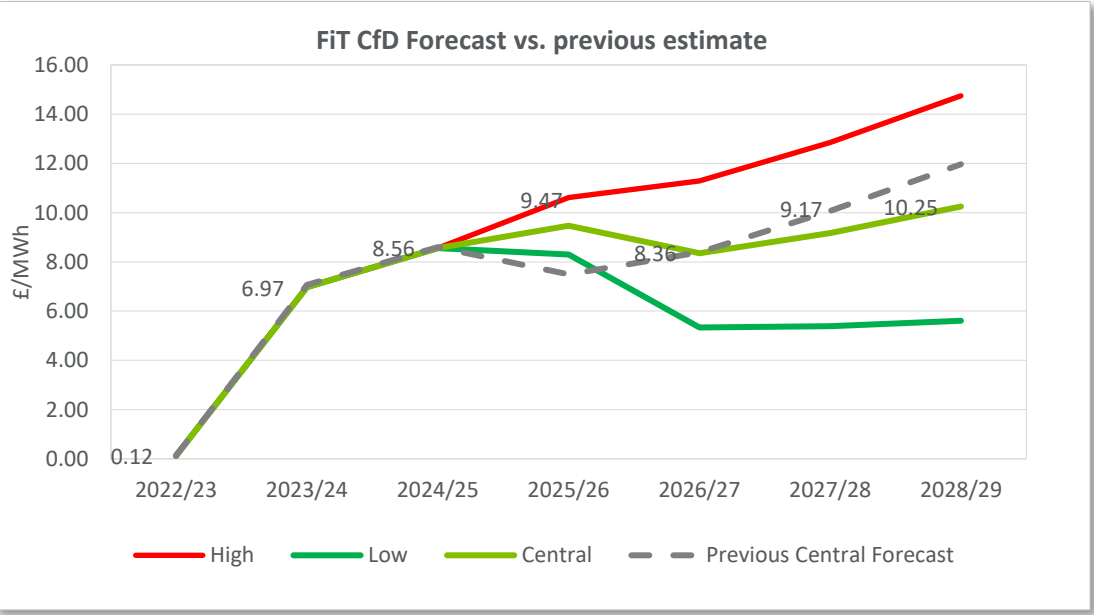


Figure 5: CfD movement per year based on central scenario

Dispatchable Power Agreement (DPA) for Power CCUS

A levy is expected to be incorporated into the CfD interim levy calculation to support the deployment of Carbon Capture Use and Storage (CCUS) technology to help decarbonise the power sector over the longer term.

The plan to capture and store carbon using CCUS technology, known as Power CCUS, is set out in the Dispatchable Power Agreement (DPA) business model. This aims to facilitate the commercial development in a similar way that CfDs are used to support deployment of low-carbon generation at the moment. A DPA is a multi-year agreement with the LCCC which has been named as the counterparty.

The DPA works by providing financial support to generators to fit carbon abatement technology to gas-fired plant to enable deployment of non-weather dependent dispatchable clean generation. Design is similar to the way the CfD scheme operates but adapted to enable gas-fired power generation to displace unabated thermal plant in the generation mix.

In addition to receiving a regular ‘availability’ payment for the plant being available, generators would also receive a ‘variable’ payment to ensure the additional costs of running an abated plant are recovered. This would incentivise plant to run ahead of unabated plant in the merit order. Both payments are designed to ensure plant can be operated flexibly.

Latest update:

The scheme’s first DPA for the East Coast Cluster in Teesside has been signed by the LCCC as the counterparty to the DPA Net Zero Teesside Power project. The project will capture and store carbon emissions from industries in the region.

The East Coast Cluster is one of two industrial clusters to be taken forward by the government in Track 1. The cluster has the potential to include a diverse mix of low-carbon projects including industrial carbon capture, low-carbon hydrogen production, negative emissions power, and power generation with carbon capture. The Net Zero Teesside plant is due to begin construction in 2025 with commissioning due in 2028.

The DPA intends to incentivise deployment through financial support drawn from the Electricity Supplier Obligation levy.

The electricity supplier obligation levy is a compulsory levy on licensed electricity suppliers to meet the cost of the CfD scheme. Obligation payments are collected from suppliers by the LCCC in its role as CfD Counterparty in order to make payments to CfD Generators.

What is driving it?

Government is committed to using power CCUS as part of its plan to decarbonise the electricity system by 2035, subject to security of supply, with the aim of delivering at least one power CCUS plant by the mid-2020s.

Costs relating to the DPA for the eight projects included in Track 1 Phase 2 of the Cluster Sequencing process (the process launched in 2021 by the government and structured into two tracks to select eligible projects) are expected to be applied to consumer bills from 2027/28.

Power Bioenergy Carbon Capture Use and Storage (BECCS)

Government is considering potential transitional support arrangements to enable large-scale biomass electricity generation to move to a power BECCS business model, essentially a dual Contract for Difference (CfD) which rewards negative carbon emissions and generates low-carbon electricity.

Latest Update:

Government is analysing feedback to the consultation on proposals for revenue support regulations relating to greenhouse gas removals (GGRs) and power BECCS business models. The consultation ran between 28 April and 9 June 2025.

Government is progressing a short-term support mechanism for large-scale biomass generators following consideration of potential transitional support arrangements in their planned move to power bioenergy carbon capture and storage (power BECCS). A CfD with a generation collar is preferred, because it lowers overall costs to consumers.

What is driving it?

The concern is a gap in support is likely to emerge when existing arrangements end in 2027 and the potential transition to power BECCS— something that is unlikely to occur until 2030 at the earliest. Large-scale biomass plant would be then disincentivised to generate without support leading to possible retirement and the loss of significant negative emissions capacity through power BECCS.

Nuclear Regulated Asset Base (RAB)

Suppliers are preparing for the introduction of the Nuclear RAB (Regulated Asset Base) charge, which is being passed through to consumers to fund the design, construction, and operation of future nuclear projects like Sizewell C.

The Nuclear RAB is funded in a similar way to the existing Contracts for Difference (CfD) scheme. Suppliers will make interim rate payments to the Low Carbon Contracts Company (LCCC) in its role as the Revenue Collection Counterparty (RCC), channeling funds between suppliers and generators. Payments will be recovered through an Interim Levy Rate (ILR) with 30 days' notice given of the rate which will apply for the following quarter. The ILR will be based on the RCC payment amount and electricity supply for the quarter.

The cost of the levy for the first year of the scheme was made known in August and is initially linked to the cost of construction which could be subject to cost overruns. While under construction the plant will be entitled to the full allowed revenue set by Ofgem. But once operational, the plant would only be entitled to top-up payments, known as difference payments, if the market revenue from selling power in the wholesale market was less than the Allowed Revenue, similar to the CfD scheme.

Latest Update

The levy will come into effect from 4 November according to the LCCC. But the start of levy collection will now take place in December 2025 instead of November. Consequently, the ILR has been set at £0/MWh for November and £3.54/MWh for December. The quarterly obligation period has been split into two parts as part of how the scheme is being launched. This has occurred because of the nature of the timeline which pushes payments to the beginning of December. Subsequent obligation periods will have a single rate.

What is driving it?

Government has an ambition for as much as 24 GW of nuclear capacity by 2050. But financing has been one of the main challenges to building new nuclear capacity. The Nuclear RAB funding model was introduced under the Nuclear Energy (Financing) Act 2022. It provides an eligible company with a regulated revenue stream throughout the construction, commissioning and operational phase of the plant.



Feed-in Tariff (FiT)

The FiT scheme incentivises the installation of small-scale, low-carbon electricity generation. Electricity suppliers pay for the electricity generated with costs passed onto consumers through the FiT charge. The charge is calculated by dividing the total cost of the scheme by total supply. The FiT scheme closed to new installations in April 2019.

In 2015 the government implemented measures to reduce the impact of renewables policy on the costs of electricity for Energy Intensive Industries (EIs) by exempting them from certain renewable charges (RO, FiT, and FiT CfD). The EI exemption for FiT was implemented from April 2019, meaning a consequent additional increase in the FiT charge for non-EIs customers.

Latest update:

A record total of £563.2 million FiT export and generation payments were made in Q2 25, the first quarter of scheme year 16. This was higher than any previous quarter and was achieved given tariff indexation of 3.5% applied to 2025/26 tariffs and largely because of higher solar load factors compared to seasonal normal. Accredited capacity is largely solar PV generation so higher load factors

increased subsidy payments and scheme costs.

In June, the government published its new industrial strategy which aims to lower energy costs for manufacturers. The British Industrial Competitiveness Scheme will reduce costs for manufacturing electricity-intensive industries from 2027. Eligible businesses will be exempt from paying the costs of the Renewables Obligation, Feed-in Tariffs, and the Capacity Market.

The government has said it is considering the impacts of REMA reform options in respect of a number of legacy arrangements including green support schemes like the RO and Feed-in Tariff. Legacy arrangements could include contracts or trading arrangements agreed before a public decision on proposals made as part of REMA.

What is driving it?

The main driver is the support the government makes available to each eligible technology. Scheme costs can vary given most of the output is generated by solar PV. Another contributing factor is national demand, as the cost is distributed amongst total electricity consumed. If demand rises, the cost is spread more thinly and the cost per unit of electricity consumed is lower.

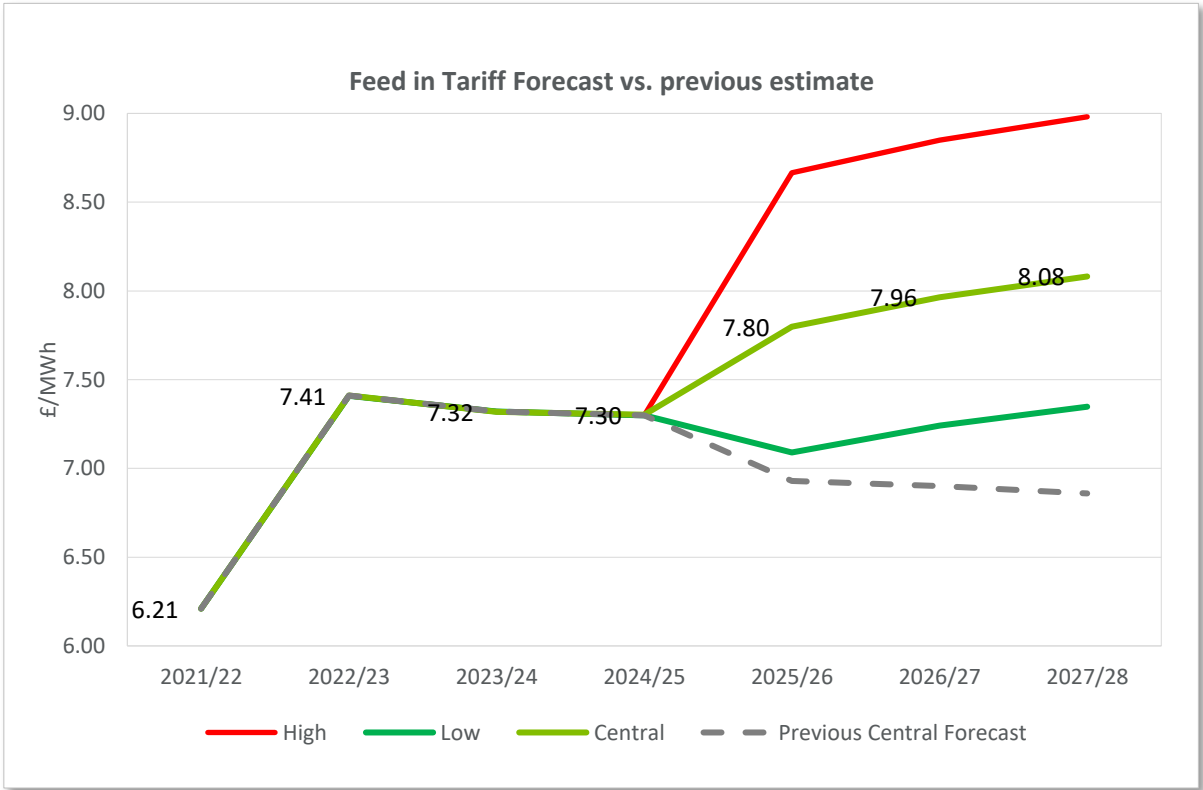
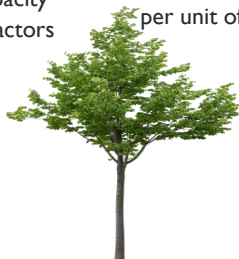


Figure 6: FiT Forecast vs. previous estimate

AAHEDC (Assistance for Areas with High Electricity Distribution Costs)

The AAHEDC was introduced in the Energy Act 2004. It replaces an earlier arrangement, commonly referred to as ‘Hydro Benefit’, which ended in January 2004. The intention is to reduce the costs to consumers for electricity distribution in northern Scotland. Under the scheme, NESO as the grid operator, recovers an Assistance Amount from all authorised suppliers, which is passed to Scottish Hydro Electric Power Distribution Ltd to reduce the distribution costs for consumers in its region.

Tariffs are calculated for each financial year from 1 April, but are published in mid-July. The later publication date allows the previous year’s final quarter payment to be reflected in the tariff thereby including any under or over recovery.

Latest update:

NESO confirmed the tariff for the 2025/26 charging year has been set at £0.41/MWh, lower compared to the 2024/25 tariff of £0.42/MWh. The tariff is composed of a Shetland tariff of £0.122/MWh with the remainder set at a rate of £0.287/MWh. The tariff is effective from April 2025.

What is driving it?

The Assistance Amount and Administration Allowance components of the AAHEDC are indexed to inflation. In addition, variances in out-turn demand compared to the forecast demand for a given period play a role in determining the final tariffs. Any under- or over-recovery or any expected changes in the demand-charging base can have an impact on the final tariff.

£/MWh	Apr-24	Apr-25	Apr-26	Apr-27	Apr-28
AAHEDC	0.421	0.411	0.416	0.419	0.420
Y-O-Y change	+0.3%	-2.5%	+1.2%	+0.9%	+0.2%

Table 3: AAHEDC Y-O-Y rate movement

Capacity Market (CM)

The CM scheme aims to ensure security of electricity supply by offering payments to reliable generators, who commit to provide energy when the system is tight. Generators participate in auctions, bidding for revenue required to have available capacity. The scheme also encourages investment in new capacity or for existing capacity to remain open at least cost to consumers.

Suppliers are charged based on their market share during the peak winter season (November to February) and then pass on the charge to their customers. The CM rate is calculated by multiplying the volume of the contracted capacity for the delivery year by the auction clearing price and then dividing by the amount of electricity supplied.

T3 and T4 auction clearing prices are updated annually by changes in CPI (T-1 auctions are unaffected). Prices must be updated no later than three months before the start of the charging year which operates from October to September.

Latest update:

Target capacity of 5.8 GW for the 2026/27 T-1 top-up auction due to be held next March has been set by the government. This is lower than capacity of 6.5 GW set for the corresponding 2025/26 auction last year, reflecting a lower level of energy security risk. Meanwhile, a target of 39.1 GW has also been announced for the 2029/28 delivery year in the T-4 auction. This is lower than it has been because of the amount of capacity that either already has a long-term agreement or other capacity which receives separate support through a CfD. A total of 1.0 GW of T-4 capacity has been set aside for the associated T-1 auction. The price cap for both auctions remains unchanged at £75/kW/year.

The government is considering changes to the CM for prequalification 2026 ahead of auctions in 2027 to ensure continued security of supply and align the scheme with decarbonisation goals in a consultation launched in October. In addition the government is also seeking to improve functionality.

Targeted price-related reforms to ensure cost-effective security of supply is maintained are being considered. This would be achieved by introducing a second, higher, price cap into the auction that could secure new build dispatchable enduring capacity which can generate over prolonged periods of tight supply.

Meanwhile, a package of interventions to encourage efficient bidding that maximises value for money and deters strategic bidding by increasing the uncertainty related to expected gains and losses associated with this kind of bidding is also being consulted on.

Furthermore, consumer-led flexibility is considered important in providing system response. Consequently, changes include implementing additional delivery assurance processes in relation to Demand Side Response components entering the CM both from an operations perspective and the CM value attributed to diverse Demand Side Response technologies.

Other reforms include self-nomination of connection capacity for battery storage technologies below their full network connection capacity to mitigate the risk of failing extended performance testing due to degradation.

The government is also seeking to determine the appropriate means for non-fossil fuel generation to access low-carbon CM mechanisms as well looking at further improvements to CM administration and delivery assurance.

Alongside the consultation the government has published a call for evidence seeking views on enabling Hydrogen to Power (H2P) to participate in the scheme and on implementing a new methodology for the technical adjustment element of the process by which interconnector de-rating factors are met.

What is driving it?

The rate is determined by auction results and the total UK energy supply. Increasing concerns about market scarcity have provided increasingly strong upward pressure to clearing prices for T-4 auctions. Top-up auctions have also seen recorded high prices in recent years. The costs will spread widely depending on how well the system is supplied. This makes forecasting more challenging.

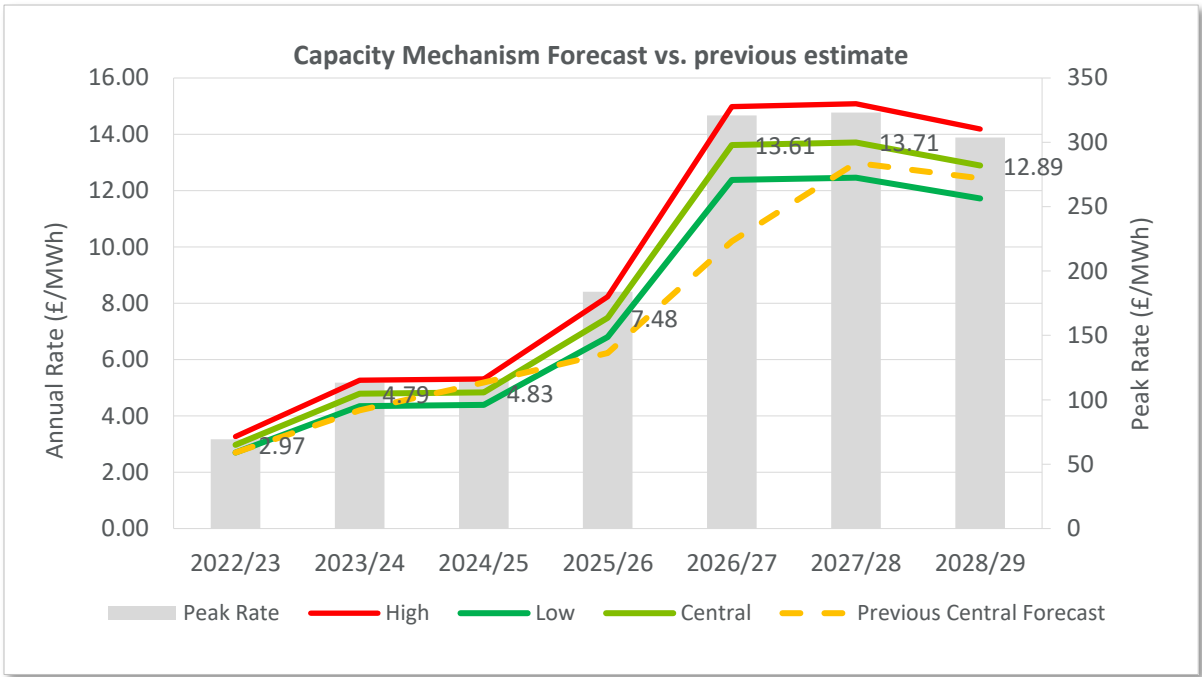


Figure 7: CM Y-O-Y rate movement



4

System and Admin Charges



Balancing Services Use of System (BSUoS)

BSUoS charges recover the cost of the day-to-day operation of the transmission system, including the cost of constraining surplus renewable generation, and are payable to NESO. Tariffs are set in advance using a forecasting model using variables which are difficult to predict. Meanwhile, operational daily costs are detached from what is recovered against the fixed tariff, introducing the potential for significant over and under-recovery of revenue versus costs. Any over or under-recovery is redistributed or collected in subsequent tariff periods.

Latest update:

The Winter 25 BSUoS tariff (1 October – 31 March 2026) was fixed at £15.69/MWh by NESO in December 2024 based on forecast costs of £2,248.2 million. This is relatively high because it includes collection of a payment for under-recovery of £164.3 million from the previous season. While the cumulative cash position at the end of Winter 26 was forecast to be £9.3 million at the time the tariff was set in December 2024, the current cumulative position now suggests over-recovery of £120 million.

Draft tariffs for Summer and Winter 26 were published in September. Summer 26 has been set at £14.21/MWh based on costs of £1,664.8 million and volume of 117.2 TWh. Winter 26 has been set at £11.93/MWh based on costs of £1,718.4 million and volume of 144.0 TWh. These rates include an over-recovery of £117 million (as of 29 September) from Winter 25 split evenly between the two seasons. Final tariffs will be published in December.

The Summer and Winter 26 tariffs are the first to include industry changes which reduce the current notice period for fixing charges from nine months to three and also extend the fixed price period from six months to 12 months.

Reducing the notice period should improve the predictability and stability of charging, benefiting suppliers and consumers by improving the accuracy of cost forecasting through the use of more current data. This should reduce the likelihood of mid-period tariff resets, limiting the risk premia included by suppliers into their pricing.

Meanwhile, extending the fixed price period out to a year should provide suppliers with price certainty so they can manage their costs more effectively, again helping reduce risk premia and creating a more stable and predictable pricing environment for consumers. Consequently, a longer period of certainty (15 months if the notice period is included) means suppliers can spread their financial risks over an extended horizon and consumers can benefit from lower and more predictable costs.

What is driving it?

Intermittent wind generation has significantly affected balancing costs in recent years, as short-term instability in the generation mix requires additional balancing actions. Short-term power prices are important given that it can be expensive to undertake balancing actions. Meanwhile, regulatory reform from April 2023 has led unit rates to establish a new, higher level.

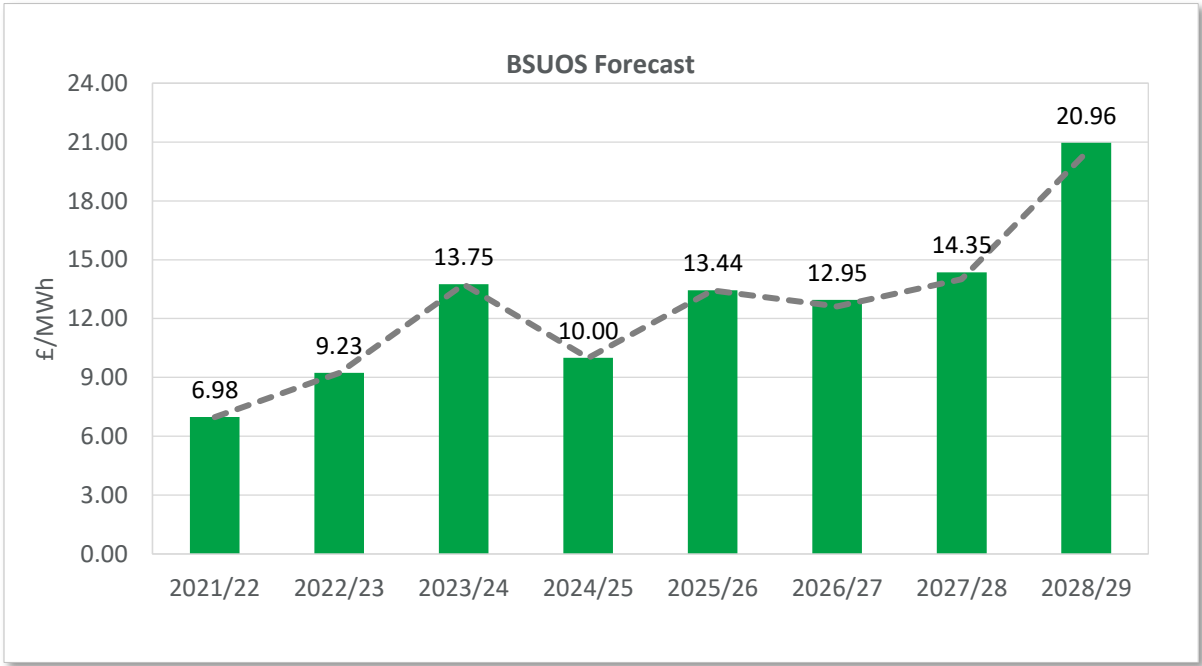


Figure 8: BSUoS Y-O-Y rate movement

Elexon

Consumers pay a supplier charge covering Elexon's operational costs.

What is driving it?

Usually fixed by the supplier at contract tender or at annual renewal.

Imbalance

Imbalance is a supplier fixed charge to reflect the cost of managing the difference between a customer's forecasted and actual consumption on a half-hourly basis.

What is driving it?

Costs are based on customer consumption and intraday spot price volatility.

Margin

Margin is a charge levied by the supplier to cover its administration costs and profit.

What is driving it?

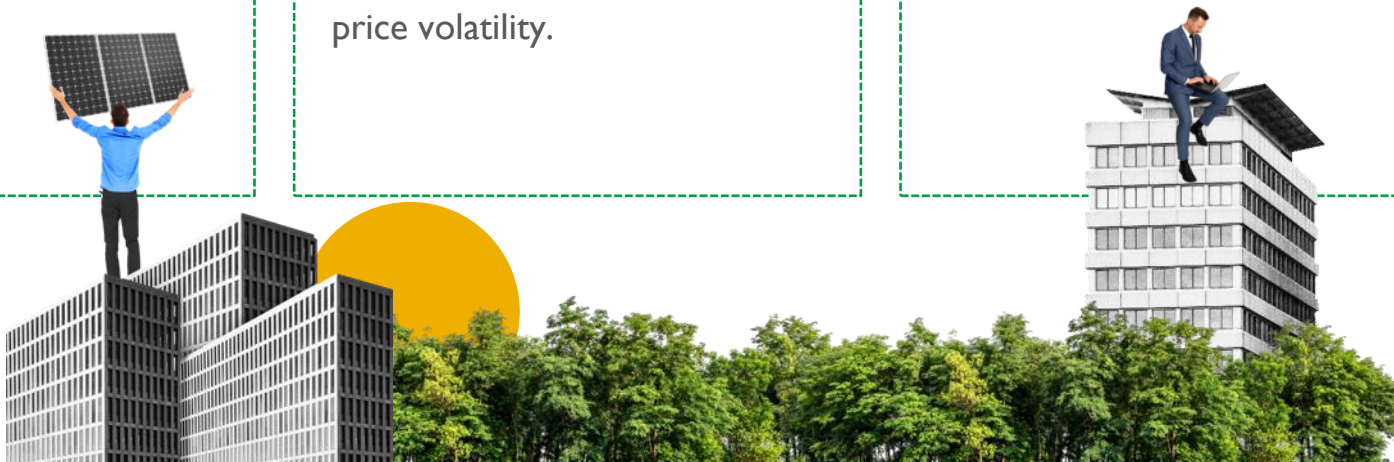
The charge depends on individual contract circumstances.

Shape

Shape represents residual volume i.e. the non-tradeable volume (outside of baseload and peakload blocks). Suppliers evaluate consumption patterns to establish a 'best fit' trading profile.

What is driving it?

The charge depends on individual contract circumstances and the level of base and peakload wholesale prices.



5

Gas Delivery Charges



Transmission Charges

Transmission charges are levied by National Gas Transmission to recover the cost of installing, operating and maintaining the National Transmission System (NTS), the high-pressure network.

Price controls set by Ofgem determine the revenue National Gas Transmission can earn from transmission. A single price control covers National Gas Transmission’s role as the Transmission Owner (TO) and System Operator (SO). Allowed revenues are collected through Transmission Services (TO-related) and General Non-Transmission Services (SO-related) charges.

Shippers pay entry and exit capacity charges to flow gas to and from the system. They are required to buy one unit of capacity to flow one unit of energy across the network. They are charged in units of kWh/day.

Latest Update

The introduction of a single NTS capacity reference price is under consideration by the industry to determine if consumers could benefit from a more efficient and economic operation of the transmission system i.e. reducing the price of entry capacity to make it more attractive for gas to come to the NBP. Transmission entry and exit capacity charges enable National Gas to collect its Transmission Services Allowed Revenue.

A reduction in entry capacity changes could potentially

lower wholesale prices assuming savings are passed on to consumers by shippers. But an increase in exit capacity charges which are passed through to distribution charges (the ECN charge) could offset this. Generally though, the proposed change is regarded as positive. Depending on timing the change could impact gas distribution charges from April 2026.

Notice of General Non-Transmission Services charges applying from October 2025 were published in July. Non-Transmission Services Revenues broadly align to the System Operator (SO) Revenue and are recovered through Non-Transmission Services Charges.

The General Non-Transmission Services (GNTS) charge has risen to 0.0206 p/kWh from 0.0075 p/kWh in October 2024 given higher revenue. The unit rate has been adjusted to take into account a new calculation methodology designed to mitigate volatility in revenue (where there are year-to-year revenue swings) to achieve a greater degree of year-on-year stability of target revenues in General Non-Transmission Services revenues, and GNTS charges.

The GNTS previously covered the exit commodity (NCO) element of the transmission charge and is payable on gas allocated to shippers at exit and entry points. It is included as a line item in supplier transportation charges.

The final notice of Transmission Services Entry and Exit Capacity charges applying from October 2025 was published by National Gas Transmission at the end of May. These charges enable National Gas Transmission

to recover Transmission Services Revenue which broadly aligns to the revenue it is allowed to collect in regard to its status as the owner of the gas transmission network.

Auction reserve prices for exit capacity for offtake at gas distribution zone exit points have been set at 0.0299 p/kWh/day from October 2025 compared to 0.0265 p/kWh/day in October 2024 because of an increase in revenue to be collected. Accordingly, Transmission Services Allowed Revenue has increased to £1,093 million for the 2025 charging year from £894 million in October 2024.

The exit Revenue Recovery Charge (RRC) has been set at 0.000 p/kWh/day from October 2025. The RRC operates as a mechanism to manage any under or over recovery of revenues at entry and exit during the gas year. It is set at zero by default.

What is driving it?

Reforms to the gas transmission charging regime came into effect from October 2020 as part of Ofgem’s Gas Transmission Charging Review. Previously, charges were split between capacity and commodity charges.

The new methodology for setting capacity prices for entry/exit points (the points where gas enters and is taken from the system) is called a ‘postage stamp’ model and applies a single, uniform price on all entry and exit flows regardless of geographic location. This is intended to significantly reduce the locational variations for capacity charging.

Distribution Charges

Distribution charges are levied by distribution networks to recover allowed revenues determined by the price control. The tariff structure includes:

- LDZ Customer Capacity Charge (CCA)
 - LDZ Customer Fixed Charge (CFI)
 - LDZ Exit Capacity Charge (ECN)
 - LDZ System Capacity Charge (ZCA)
 - LDZ System Commodity Charge (ZCO)
-
- CSEP LDZ Capacity Charge (IGT meters only)
 - CSEP Customer Fixed Charge (IGT meters only)
 - CSEP Exit Capacity Charge (IGT meters only)

Capacity charges are expressed in p/peak day kWh/day. Commodity charges are expressed p/kWh.

Latest Update

Distribution networks publish indicative charges applying for the 2026/27 charging year in October. Charges are based on the latest forecasts of Allowed Revenue. Other influencing factors include inflation and forecast demand. The cost of wholesale gas will also affect shrinkage pass-through costs.

What is driving it?

Allowed Revenue is determined by base revenue determined by the price control. It is also inflation-adjusted. Any under or over-recovery is applied through a correction factor which is lagged by a year.

6

Other Charges



Unidentified Gas Charge

Unidentified Gas (UIG) is gas which is lost to the system which cannot be attributable to any particular user. Sources include consumption through unregistered supply points as well as shrinkage, leakage and theft.

Meter points are apportioned an amount of UIG on a daily basis based on information provided by Xoserve, the gas market's data services provider. The amount is subsequently revised as more data from meter reads becomes available.

The cost of UIG is spread across the consumer base with meters categorized by end user category and meter class. Costs are determined by the Allocation of Unidentified Gas Expert (AUGE).

Latest Update

Two network code modifications designed to improve gas invoicing and reconciliation processes were approved by Ofgem in August. Code modification 0886 introduces a change to the way the code cut-off date is managed by shifting from an annual update to a monthly rolling basis. This should smooth out reconciliation activity during the year by reducing the risk of bottlenecks.

Modification 0896 shortens the reconciliation window to 2 to 3 years from 3 to 4 years, reflecting improvements in data accuracy. The changes will take effect from 1 April 2026.

Meanwhile, A change amending UIG reconciliation period arrangements was implemented in July which matches the reconciliation period to the period of individual meter point reconciliations for the month.

What is driving it?

The way UIG is charged to consumers changed following implementation of a revision of the charging methodology. The new charging methodology quantifies the amount of UIG instead of providing an estimate. This has led to a sizeable increase in total volume.

Meanwhile, the table of weighting factors assigning UIG to different classes of meter has been revised with the number of categories in the first two end user categories expanded into four new categories to include: non-prepayment domestic, prepayment domestic, non-prepayment industrial and commercial and prepayment industrial and commercial.

UIG is priced based on that day's forward prices in the wholesale market, meaning that the exceptional strength of wholesale prices has led to a proportionally large increase in the expected cost of UIG.



7

Gas Taxes and Levies



Green Gas Levy

The levy applies to all licensed fossil fuel gas suppliers. But those suppliers whose total gas supply for the duration of a scheme year is sourced from at least 95% certified biomethane qualify for an exemption.

Suppliers seeking an exemption must prove their biomethane supply using retired green gas certificates from a scheme on the approved biomethane certification scheme list including:

- the Green Gas Certification Scheme, run by Renewable Energy Assurance Ltd
- the Biomethane Certification Scheme, run by Green Gas Trading Ltd

Latest Update

The Green Gas Levy (GGL) for the 2025/26 charging year from April has been set at 0.821 pence per meter per day (equivalent to £3.00 per meter over the financial year) by government. This compares to 0.105 pence per meter per day (equivalent to 38p per meter a year) for 2024/25. Scheme expenditure is projected to be £86.3 million compared to £54.6 million in 2024/25. The rate for each scheme year is published by 31 December of the preceding year.

Green Gas Support Scheme tariffs paid to biomethane producers remained unchanged on 1

October 2025 compared to the previous year. These are:

Tier 1: Up to 60,000 MWh per year – 6.86p/kWh

Tier 2: the next 40,000 MWh per year – 4.26p/kWh

Tier 3: above 100,000 MWh up to 250,000 MWh per year – 3.98p/kWh

Tariffs are reviewed annually. The review found that these tariffs are effective in providing revenues which incentivise plant development whilst providing value for money.

The government has extended the Green Gas Support Scheme to 31 March 2028 following conclusion of the mid-scheme review held last year. While the scheme was originally expected to be extended until 31 March 2026, the government is aware of various issues affecting the deployment of new anaerobic digestion plants under the scheme, including supply chain delays and challenges in securing food waste feedstocks.

What is driving it?

The GGL supports the decarbonisation of heat by funding biomethane injection into the gas system through the GGSS.



Hydrogen Levy

A hydrogen levy is being proposed to fund investment in the production of hydrogen from low-carbon sources, otherwise known as 'green' hydrogen. It would provide long-term funding for a hydrogen business model, enabling producers to overcome the operating cost gap between low-carbon hydrogen and fossil fuels.

The Energy Act 2023 enables the government to appoint a levy administrator and to make regulations which will establish the levy to support hydrogen business models concerning production, transportation, and storage. Secondary legislation is expected to be used to enable the scheme administrator to make provision for gas shippers to make payments to fund payments made by it to producers.

As policy development is ongoing, with a number of key decisions still pending, there is uncertainty regarding the precise impact of the levy on consumer bills.

Latest Update

The government is considering feedback to its consultation on a Gas Shipper Obligation (GSO) to support the deployment of hydrogen production. The costs of the Obligation are expected to be passed through to consumers from 2028 onwards.

Two designs are being considered. The first is based on the number of meter points a shipper

supplies. But this is thought unpopular because it means all consumers are charged the same amount, disproportionately affecting small domestic and non-domestic gas users compared to large industrial users.

Option two would apply the GSO based on volume. This looks to address fairness since it would base the charge on quantities of gas shipped and should result in reduced costs for the domestic market.

The GSO is expected to be the long-term funding mechanism for initial hydrogen production projects for the Hydrogen Production Business Model (HPBM) (the route to market for this nascent low-carbon technology).

The GSO is expected to collect a relatively small amount of £150 million a year from 2028 on the basis of the 11 projects in the first Hydrogen Allocation Round (HAR1) which concluded in 2023 and resulted in total capacity of 125 MW.

What is driving it?

The government's ambition is to create up to 10 GW of low-carbon hydrogen production capacity by 2030. While at least 5 GW of capacity would be produced from renewables using electrolysis, the remainder, so-called 'blue' hydrogen, would come from gas-fired plants with CCUS technology fitted.

8

Glossary of Terms



Term	Meaning	Application
AAHEDC	Assistance for Areas with High Electricity Distribution Costs (commonly known as 'Hydro Levy')	Charge applied by National Grid to recover an assistance amount which is passed to Scottish Hydro Electric Power Distribution Ltd to reduce distribution costs for consumers in northern Scotland
Administration Allowance	AAHEDC component	Amount of revenue allowance that National Grid is permitted to retain to cover the costs of administering the scheme
Assistance Amount	AAHEDC component	Amount payable by National Grid to the distributor during the scheme year
BMRP	CfD Baseload Market Reference Price	Measure of the average price of electricity calculated on a seasonal basis to calculate payments to programmable technologies like biomass
BSUoS	Balancing Services Use of System	Charged applied by National Grid to meet the costs of the day-to-day balancing of the electricity transmission system
Buy-out Price	RO charge component	Price suppliers must pay for each ROC not presented towards compliance with their obligation
Capacity Charge	DUoS tariff component	Charge based on a meter's maximum import capacity expressed in kVA which has been agreed can flow from the exit point of the distribution system to the meter
CCL	Climate Change Levy	Environmental levy charged on business use of energy
CfD	Contracts for Difference	Charge applied to support the cost of administering the CfD scheme and the cost of payments to large-scale low-carbon electricity generators
CM	Capacity Mechanism	Charge applied to support the cost of administering and operating the Capacity Mechanism to ensure security of electricity supply

Term	Meaning	Application
Constraint payments	BSUoS constraint payment	Payments to generators to manage the flow of electricity on the network to ensure safe operation of the transmission system
DPA CCUS	Dispatchable Power Agreement for Power CCUS	Scheme to incentivise power generators to capture and storage carbon dioxide which would otherwise be emitted and support power generation with CCUS
DUoS	Distribution Use of System	Charge applied to generators and consumers to recover the cost of operating and maintaining the electricity distribution system
EII NCCC Scheme	Network Charging Cost Compensation Scheme	Compensation scheme for charges paid for using the electricity grid by EIs
EII RLE Scheme	EII Renewable Levy Exemption Scheme	EII exemption scheme from the indirect costs of funding green support schemes including the CfD, FiT, and RO schemes
Exceeded Capacity Charge	DUoS tariff component	Charge applied to excess capacity when additional capacity over and above the maximum import capacity is taken without authorisation
FiT	Feed-in Tariff	Charge applied to support the cost of administering the FiT scheme and the cost of payments made to small-scale low-carbon electricity generators
Fixed charge	DUoS tariff component	Charge recovering operational costs associated with connected assets and a residual amount to ensure recovery of regulated allowed revenue
ILR	CfD Interim Levy Rate	A levy charged to suppliers to cover forecasted payments to generators derived from the difference between the reference price and strike price and expected electricity supply for the period
Imbalance	Supplier charge	Charge applied by suppliers to pay for the cost of managing the difference between a customer's forecast consumption and their actual consumption on a half-hourly basis

Term	Meaning	Application
IMRP	CfD Intermittent Market Reference Price	Measure of the average price of electricity calculated on an hourly basis using day-ahead data to calculate payments to intermittent technologies like solar or wind
Locational Charge	TNUoS tariff component	Charge for use of transmission system based on location
MRP	CfD Market Reference Price	Measure of the average market price of electricity used to calculate payments to generators
Margin	Supplier charge	Charge applied by suppliers to cover administration costs and profit
Non-locational banded tariff	TNUoS / DUoS tariff component	Networks' demand residual revenue is collected from HH/NHH consumers through a set of banded charges categorised by voltage level
Nuclear RAB	Nuclear Regulated Asset Base model	Funding method to support design, construction, commissioning and operation of future nuclear projects
Obligation level	RO component	the amount of renewable generation suppliers must source as a proportion of overall electricity generation within the obligation period
Power BECCS	Power Bioenergy Carbon Capture Use and Storage	large-scale biomass electricity generation fitted with CCUS technology
RCRC	Residual Cashflow Reallocation Cashflow	Charge covering redistribution of any excess or shortfall in cashflow once imbalance charges have been paid by BSC parties
RLR	CfD Reconciled Levy Rate	Rate determined from reconciliation of actual amount owed by suppliers based on actual payments to generators and actual electricity supplied

Term	Meaning	Application
RO	Renewables Obligation	Charge applied to support the cost of deploying renewable generation by obligating suppliers to source a specified amount of electricity generated from renewable sources
ROC	Renewables Obligation Certificate	Issued to operators of accredited renewable generating stations for the eligible renewable electricity they generate
Shape	Shape	Charge applied by suppliers to cover the cost of shaping of the non-tradeable volume outside of base and peakload blocks
Shetland Assistance Amount	AAHEDC component	A cross-subsidy amount collected from all consumers across Britain to limit distribution costs for consumers on Shetland
Strike Price	CfD Strike Price	Fixed price (index-linked with annual adjustments) a generator will earn per MWh of electricity generated for the lifetime of the contract
Time-of-Use	DUoS tariff component	Time-banded tariffs to discourage/encourage network use at certain times
TNUoS	Transmission Network Use of System	Charge applied to generators and consumers to recover the cost of operating and maintaining the electricity transmission system
Triad	TNUoS tariff component	The three half-hour settlement periods with highest system demand between November and February, separated by at least ten clear days used to determine TNUoS locational costs for customers with half-hour metering

Term	Meaning	Application
AQ	Annual Quantity	Amount of gas a site will use in the coming year under normal seasonal weather conditions
AUGE	Allocation of Unidentified Gas Expert	The party appointed by the CDSP to develop an AUGS and calculate a table of Weighting Factors, which are used to share out daily Unidentified Gas
AUGS	Allocation of Unidentified Gas Statement	The document describing the process followed by the AUGS to determine the AUG Table of Weighting Factors
Capacity	Availability of pipeline space	Commercial rights to flow gas onto or take gas off the transmission system
Capacity Auction	Sale of capacity	Sale of right to flow one unit of capacity (kWh) on a particular gas day
Capacity reserve price	Price of capacity	Auctions are 'pay as bid' and subject to a minimum reserve price
CDSP	Central Data Services Provider (Xoserve)	The party appointed by the Transporters to operate central gas industry functions including Settlement and Supply Point Administration and the billing of Shippers for these services
CSEP	Connected System Exit Point	Offtake from a gas distribution network to a network owned by an Independent Gas Transporter

Term	Meaning	Application
CSEP LDZ Capacity Charge (891)	Capacity Charge	Capacity Charge applicable to LDZ CSEP sites
CSEP Customer Fixed Charge	Customer Fixed Charge	Customer Fixed Charge applicable to LDZ CSEP sites
CSEP Exit Capacity LDZ ECN Charge (C04)	Exit Capacity Charge	Exit Capacity Charge applicable to LDZ CSEP sites
EUC	End User Category	Group in which each site is placed for demand attribution, Unidentified Gas sharing and invoicing purposes because they have similar patterns of demand. The EUC is determined by location (Local Distribution Zone) and Annual Quantity
Entry capacity	Availability of pipeline space	Users can buy pipeline entry capacity to be able to flow gas onto the transmission system
Entry Capacity charge	Charge for purchasing entry capacity	Capacity is purchased through auctions with a minimum reserve price
Entry Revenue Recovery Charge	Recovery charge	Charge to recover a large under or over recovery against allowed revenue in respect of entry capacity charges
Exit capacity	Availability of pipeline space	Users can buy pipeline exit capacity to be able to take gas off the transmission system
Exit Capacity charge	Charge for purchasing exit capacity	Capacity is purchased through auctions with a minimum reserve price
Exit Revenue Recovery Charge	Recovery charge	Charge to recover a large under or over recovery against allowed revenue in respect of exit capacity charges

Term	Meaning	Application
GDN	Gas Distribution Network	Network responsible for movement of gas through LDZs
GNTS charge	General Non-Transmission Services charge	Charge to collect the residual amount after the estimate for targeted charges has been deducted from Non-Transmission Services allowed revenue. Applies evenly to all entry/exit points on a commodity basis
GGL	Green Gas Levy	Levy supporting the injection of biomethane into the gas grid to pay for the Green Gas Support Scheme
GGSS	Green Gas Support Scheme	Scheme decarbonising the heating sector through the injection of biomethane into the gas grid
Hydrogen Levy	Hydrogen Levy	Levy proposed to fund investment in the production of hydrogen from low-carbon sources, otherwise known as 'green' hydrogen
IGT	Independent Gas Transporter	A company developing, operating and maintaining a gas network to supply gas locally. All local IGT networks ultimately connect to the large Gas Distribution Networks either directly or indirectly through other IGTs.
LDZ	Local Distribution Zone	An area supplying gas to consumers which is connected to and takes gas from the National Transmission System

Term	Meaning	Application
LDZ CCA	Customer Capacity Charge	LDZ Customer Capacity Charge applicable to direct connect sites
LDZ CFI	Customer Fixed Charge	LDZ Customer Fixed Charge applicable to direct connect sites with an AQ of between 73,200 and 732,000 kWh
LDZ ECN	Exit Capacity Charge	Distribution Network (NTS) Exit Capacity Charge applicable to direct connect sites
LDZ ZCA	System Capacity Charge	LDZ supply point Capacity Charge applicable to direct connect LDZ sites
LDZ ZCO	Commodity Charge	LDZ Commodity Charge applicable to direct connect sites
NTS	National Transmission System	The high-pressure network used to transport gas across Britain
SOQ	Supply Offtake Quantity	The highest daily quantity of gas a site is expected to use in a day under 1-in-20 peak day conditions
UIG	Unidentified Gas	Gas lost to the system which cannot be attributable to any particular user
UIG Charge	Unidentified Gas Charge	Charge to recover cost of unidentified gas based on allocations using applicable UIG Weighting Factors
UIG Weighting Factors		The factors used to share UIG between Classes and EUC (End User Category) bands which are determined by the AUGÉ



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