CORNWALL INSIGHT

CREATING CLARITY

Charging differentials for 132kV generation

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Summary

Introduction

Cornwall Insight has been commissioned by Scottish Renewables to provide analysis to identify and quantify any differential in network charges paid by small (<100MW) generators connected to the 132kV transmission network in Scotland compared to those connected to the 132kV distribution network in England and Wales.

The GB electricity system is composed of high-voltage transmission lines for moving power in bulk up and down the country, and lower-voltage distribution lines that carry power to the majority of end users. Lines operating at 275kV and above are classed as transmission all over GB, and sub-132kV lines are all classed as distribution. However, 132kV lines are treated differently north and south of the Scottish border. In England and Wales (E&W) 132kV lines are classed as distribution, whereas in Scotland they are classed as transmission.

In E&W the electricity system has been upgraded since the 1950s to include 275kV and 400kV circuits. The 132kV network, no longer acting as the system's backbone (that role being adopted by 275kV and 400kV assets), was subsequently transferred from the Central Electricity Generating Board to distribution companies in the 1970s through a number of orders such as *The Electricity (Transfer of Transmission Assets) (East Midlands Electricity Board) Order 1973*. This process was not undertaken in Scotland - a July 2003 select committee report cited that 132kV is used for "bulk transfer" of electricity in Scotland, with 132kV circuits comprising 70% of the North Scotland transmission network, supporting its classification as transmission. With the integration of the E&W and Scottish markets under BETTA in 2005, it was decided that reclassifying 132kV networks may impact visibility and control of the network and ultimately "endanger the objectives of having a single system operator". Therefore, 132kV networks were retained as transmission in Scotland.

This means the approaches to recovering the costs of transmission and distribution assets through network use of system (UoS) charges for customers and generators connected at 132kV differ significantly between the two localities. Additionally, transmission-connected generators incur Balancing Services Use of System (BSUoS) charges, meaning 132kV-connected sites in Scotland are exposed to these charges while their counterparts in E&W are not. This leads to a differential in incurred charges which historically was partially offset by the application of the "small generator discount" (SGD) to Transmission Network Use of System (TNUoS) charges for 132kV-connected generators in Scotland with a capacity of less than 100MW.

Background to the Small Generator Discount

The Small Generator Discount (SGD) was originally introduced in 2005 as an interim measure to reduce the disparity between 132kV generator charging specifically in relation to “residual” network charges. There are two types of residual charge applicable to TNUoS:

- Demand residual charges which make up the difference between revenue derived from the “forward-looking” demand charges (which give users cost signals about how their behaviour impacts network costs) and the total revenue allowances of the transmission network companies which transmission charges are calculated to recover in full
- Generator residual charges which are used to ensure that the average TNUoS charge for transmission connected generators falls within €0-2.50/MWh, as required by (retained) EU regulation

132kV generators in England and Wales are eligible for the Embedded Export Tariff, which was historically set to the inverse of TNUoS demand charges including the demand residual. This meant 132kV generators in E&W were eligible for a payment of the inverse of the forward-looking demand charge (reflecting their ability to reduce overall transmission costs) **and** the demand residual. The residual element has since been phased out from the Embedded Export Tariff. 132kV generators in Scotland pay generator TNUoS, including the generator residual element. Historically, the residual has been positive. This meant that 132kV generators in England and Wales were paid credits in respect of the residual while 132kV generators in Scotland paid residual charges. The generator residual is now a small negative, with recent regulatory changes having reduced its magnitude significantly.

The SGD was repeatedly extended by Ofgem until being allowed to expire on 31 March 2021, on the basis that changes developed under the Targeted Charging Review (TCR) scheduled to be implemented by that date would render it unnecessary. Despite implementation delays, Ofgem rejected calls for the discount to be extended further. While the disparity between *residual* charges for 132kV generators in Scotland compared to those in England and Wales no longer exists, a significant differential remains, which is the subject of this report.

Summary of findings

There is a clear differential between the charges paid by 132kV-connected generators in England and Wales and those they would pay if located in Scotland.

The lowest charges faced by any of our modelled England and Wales generators are always a credit in each of the years we modelled. The minimum for any modelled site in Scotland is always a charge several times this level.

The mean charge for England and Wales generators is a fraction of the mean for their Scottish equivalents. In 2021-22 and 2022-23 the differential was over £1mn for our modelled 40MW sites. Even after reforms expected to be introduced in 2023-24, our modelling suggested the Scottish generators would pay more than six times as much in network charges on average.

For sites in the most expensive locations, the difference is smaller in relative terms but very high in absolute terms: over £1.5mn today and almost £1.0mn in 2022-23. In 2023-24 the differential is similar to that for the mean, although the Scottish generator still pays over three times as much as its counterpart in England and Wales.

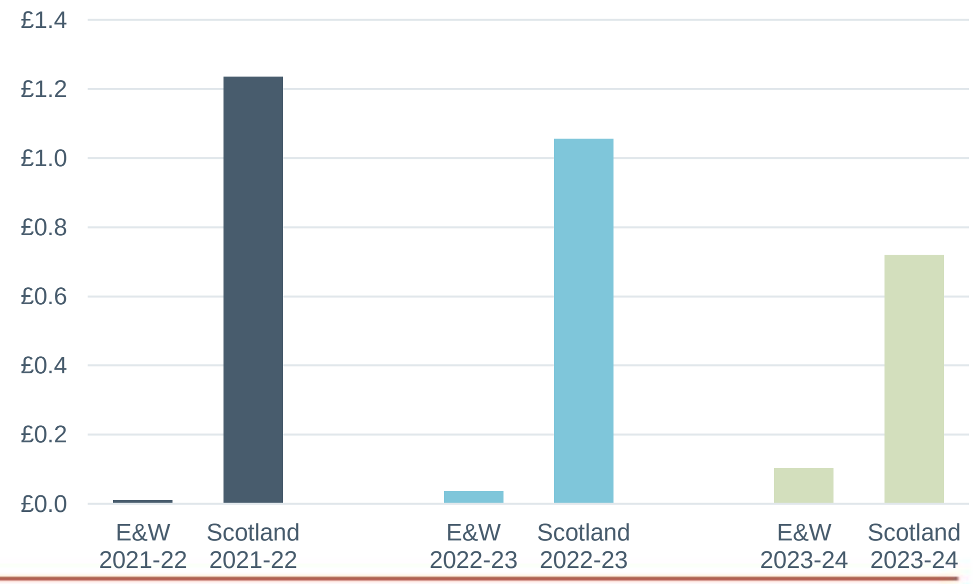
The trends generally recur when looking at individual technologies, but the differential does vary slightly. Wind is the technology that predominates in Scotland so has been presented in Figures 1 and 2.

These assessments have also been made on a £/MWh basis, the results of which can be found in slides 18, 24 and 30. Generally, this highlights the load factors of different technologies – with the lowest load factors solar has the highest cost at £22/MWh in Scotland and £0.35/MWh in E&W in 2021-22. In comparison wind sites in E&W pay £0.11/MWh on average, while the average Scottish windfarm would pay almost £11/MWh in network charges.

Figure 1: Mean differential in network charges for 40MW onshore wind (£k)

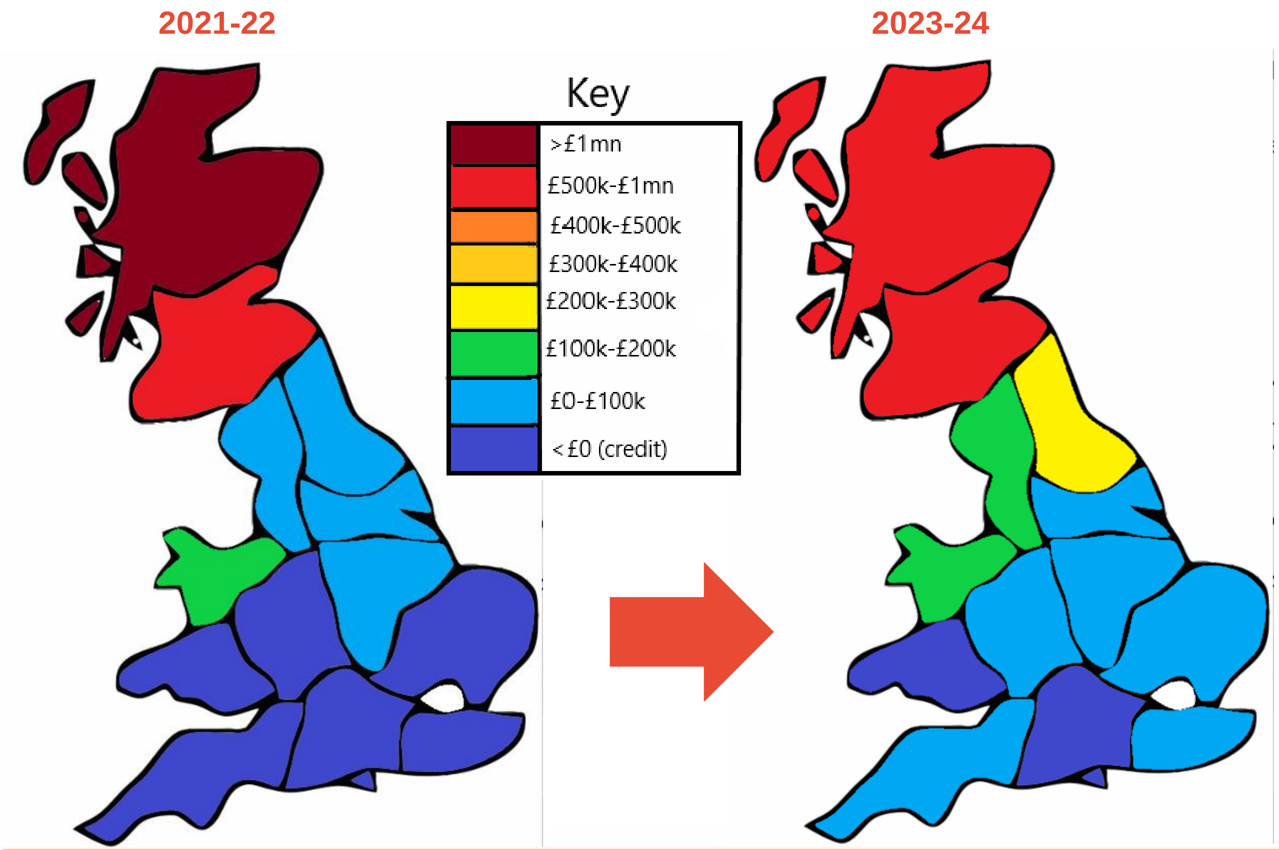
Region	2021-22	2022-23	2023-24
Scotland	1,236	1,057	720
England and Wales (E&W)	11	37	103
Differential	1,225	1,020	617

Figure 2: Scotland vs E&W mean charging differential for 40MW onshore wind (£mn)



Regional comparisons

Figure 3: Modeled network charges for 40MW 132kV wind 2021-22 to 2023-24



If we apply our wind profile to all E&W 132kV connected sites used in this analysis and apply an average cost for this profile in each of the generation charging zones to each demand zone, we can compare average annual network costs regionally.

As previously outlined, the network costs for a 40MW 132kV connected plant in Scotland are significant – in excess of £1mn per annum in the North and £500k per annum in the South using our average figures and load profile. In comparison, around half of all E&W regions receive a credit while the remainder pay a small charge, with the greatest costs in the Manweb region

By 2023-24 there is expected to be much more differentiation in charges. Only the Southern and South Wales regions continue to receive a credit on average, while the majority of sites located in the south of E&W now pay a small charge. Sites located in the north of E&W now pay charges in excess of £100k as the application of TNUoS costs impact these regions.

Meanwhile, in Scotland the removal of BSUoS costs means the Northern Scotland region falls below £1mn while the Southern Scotland region is on average only very slightly above the £500k threshold “red” map threshold.

Key takeaways

There are material differences in regulatory treatment between 132kV generators in Scotland compared to those in England and Wales under current arrangements:

- Generators in Scotland are required to pay balancing services charges while those in England and Wales are not
- Generators in Scotland pay transmission network charges while those in England and Wales either receive credits under the Embedded Export Tariff (in the South) or pay no charge
- Generators in England and Wales pay distribution network charges

These give rise to a material differential between charges faced by the two groups, with the average charge in England and Wales in 2021-22 modelled at over £1mn lower than in Scotland for a 40MW site.

Some ongoing regulatory reforms will remove some of the differentials, including:

- Changes following the second Balancing Services Task Force which seek to move balancing services charges onto demand only, which would result in all 132kV generators not paying those charges, decreasing charges for 132kV generators in Scotland. Implementation is expected in 2023-24
- Reform to transmission charging under Ofgem's Network Access and Forward Looking Charges review, which may result in distribution connected assets paying similar transmission charges to transmission connected assets, increasing costs for 132kV generators in England and Wales. Implementation timescales are uncertain, but following recent delays to Ofgem's timetable, April 2024 may be the earliest implementation date.

But even once those reforms have been applied, a significant differential remains, with the average 40MW generator charge in England and Wales in 2023-24 modelled at around £500k lower than in Scotland. This is predominantly due to transmission network charges, which have a very strong locational element which, broadly speaking, drives charges higher the further north a generator connects.

There are a few ways in which Scottish Renewables could look to implement change, including through participating in Ofgem's likely detailed review of transmission charges (as noted in the Access SCR minded-to decision), propose a levelising of charging methodologies, an alteration in the way TNUoS charges are recovered, or arguing for a reduction in the expansion constant. These options are covered in more detail in slide 39.

Analytical approach

Approach

Cornwall Insight's modelling approach consisted of identifying appropriate regional charges for 132kV generators using Embedded Capacity Registers and DNO charging statements, then modelling these for archetypal solar, onshore wind and hydro generation sites of 40MW each. Our assumed characteristics of these sites are shown in Figure 4.

Figure 4: Assumed characteristics of archetypal generators

Technology	Export capacity (MW)	Load factor	% Export super red	Export Capacity KVA headroom	MVA capacity	Triad capture (EET, kW)	Assumed output (MW)
Onshore wind	40	30%	8%	5%	42	3,000	105,120
Solar	40	11%	2%	5%	42	0	38,544
Hydro	40	35%	8%	5%	42	14,000	122,640

We calculated appropriate regional charges for our archetypal generators by referring to the Embedded Capacity Registers published by the DNOs. We then cross-referenced this data with DNO charging statements and long-term development statements, identifying the charges for these sites by reference to their line loss factor classes.

Approach – by technology

Figure 5: Number of sites by technology and region

Region	All	Solar	Onshore Wind
North West England	2	0	0
North East England	3	0	1
Yorkshire	5	0	1
North Wales	2	0	1
West Midlands	1	1	0
East Midlands	2	0	0
Eastern England	9	6	0
South Wales	9	1	7
South East England	6	1	1
Southern England	3	3	0
South West England	7	1	4
Total	**49**	**13**	**15**

This provided us with 49 unique sites across England and Wales (E&W). 28 are onshore wind or solar assessed in this study – 15 onshore wind and 13 solar – while the remainder were gas-fired plant, offshore wind, batteries or "Other". There was at least one site from each distribution region in England & Wales except for London Power Networks

For solar and onshore wind, we applied the tariffs for the actual solar and wind sites to our assumed capacity and volumes (shown on the previous slide). Readers should be aware that solar sites are skewed to the south and east of the country (based on solar resource), further increasing the potential TNUoS-related benefit available to these plant.

As there are no hydro sites demonstrated in this analysis, we used the average charge for all 49 sites for hydro. Therefore, while we are not comparing "like for like", we are comparing charges with actual costs incurred by 132kV connected plant in E&W. We consider this to be valid because the type of plant connected is likely to have a limited to intermediate bearing on the actual charges for the site.

Approach – by year

2021-22

2021-22 is our baseline and represents the current charging regime for 132kV generators. Those in Scotland incur TNUoS and BSUoS (which always manifest as charges), while those in E&W incur DUoS and the Embedded Export Tariff (EET), the former generally being a charge with the option for a super red credit, and the latter having an upper cap of £0 and thus being a credit or of no value or cost.

2022-23

This modelling run used final published DUoS charges and projected TNUoS charges for **2022-23**. The latter take into account the expected changes from CMP368 and CMP369 *Updating Charges for the Physical Assets Required for Connection,* which National Grid's Five Year Forecast provides the best available view on.

2023-24

The **2023-24** modelling reflects two major shifts in generator charging:

- From April 2023, generators should no longer incur BSUoS charges as these are expected to be moved wholly onto demand users under CMP308.
- The reforms of the Network Access & Forward-looking Charges ("Access") significant code review could expose distribution-connected generators to wider TNUoS charges, replacing the EET.

Both changes remain under development so implementation is not yet certain. Access SCR proposals are not yet finalised and it is likely Ofgem will want to provide the industry with at least two years' notice of such a significant change to generator charges (not to mention modification development time and potential appeals or legal challenges). As such we believe that embedded generators are unlikely to become liable for TNUoS charges until 2024 at the earliest. However, the removal of BSUoS and application of TNUoS to distribution-connected generators represents a potential end state of network charge reform for EHV connected generators. Therefore, readers should consider the 2023-24 charges to be a useful illustration of what might be the enduring generator charging regime.

Sensitivities

We also comment on two important sensitivities:

Central Volume Allocation (CVA) registered generators

Generators in England and Wales connected at 132kV can sign a Bilateral Embedded Generation Agreement (BEGA) and become CVA registered. Typically this would result in the asset paying TNUoS charges, however license-exemptible plant (typically <100MW in E&W) can choose to request to be exempt from these charges.

Therefore, there are a subset of 132kV connected generators paying (or receiving) wider TNUoS and BSUoS charges as if they were transmission connected. They are also liable for DUoS charges.

We have assumed that 132kV generators in E&W are not liable for TNUoS and BSUoS charges in this analysis.

CMP 315 and high impact mods

We comment and approximate the impact of other high-impact CMPs (most notably CMP315 *Review of the Expansion Constant and the Elements of the Transmission System Charged For*) on 132kV connected generators.

CMP315 in particular could drive a material increase in TNUoS for 132kV connected generators in Scotland, potentially widening any disparity under current arrangements.

CMP375 *Enduring Expansion Constant & Expansion Factor Review* opens this matter up to workgroup discussions. However, there is no meaningful direction of this proposal to date and little we can infer for this paper.

2021-22 charging differentials

Outline methodology

2021-22 charges are our baseline and represent the current charging regime for 132kV generators. Those in Scotland incur TNUoS and BSUoS (which always manifest as charges), while those in E&W incur DUoS and the Embedded Export Tariff (EET), the former always being a charge, and the latter being either zero or a negative charge (credit). The assumption we have applied to tariffs to determine charges for each technology type are restated in Figure 6.

Figure 6: Assumed characteristics of archetypal generators

Technology	Export capacity (MW)	Load factor	% Export super red	Export Capacity KVA headroom	MVA capacity	Triad capture (EET, kW)
Onshore wind	40	30%	8%	5%	42	3,000
Solar	40	11%	2%	5%	42	0
Hydro	40	35%	8%	5%	42	14,000

Sources:

- TNUoS – Confirmed charges for the 2021-22 charging year
- DUoS – DNO LC14 charging statements and associated documentation, available from DNO websites

Comparison

Figure 7 shows the range of net network charges that would be incurred during the current year by our archetypal 40MW sites if connected at 132kV in E&W. It shows the minimum, maximum and mean, along with mean less one standard deviation and mean plus one standard deviation to indicate the distribution of charges.

The average site receives a small credit overall, while the site with the lowest charges receives a credit of around £180,000. This contrasts with the site that has the highest charges, which pays around £92,000.

By comparison, Figure 8 shows the equivalent picture for the same generators if they were located in Scotland. The average site would receive a charge of just over £1mn. The lowest-cost generator still faces a charge of around £450,000 – more than four times that which the generators in the most expensive location in E&W would see. The Scottish generator with the highest charges faces charges around 17 times the highest in E&W.

Figure 7: Modeled range of charges for 40MW E&W 132kV generators, £mn 2021-22

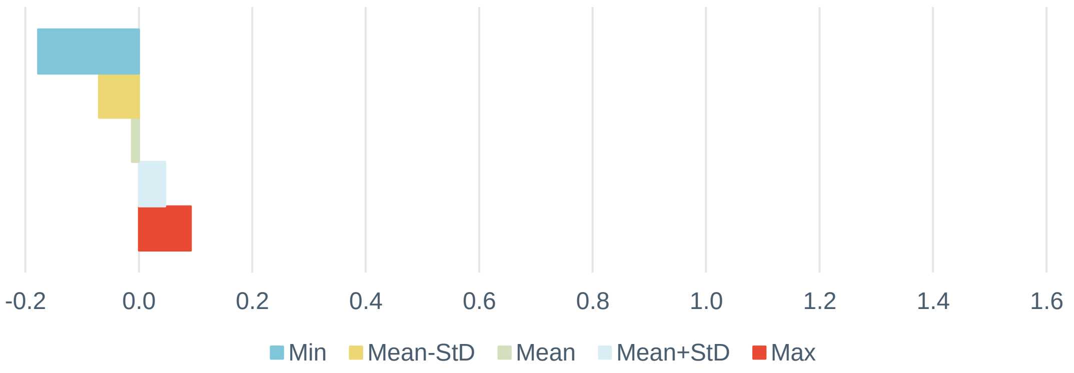
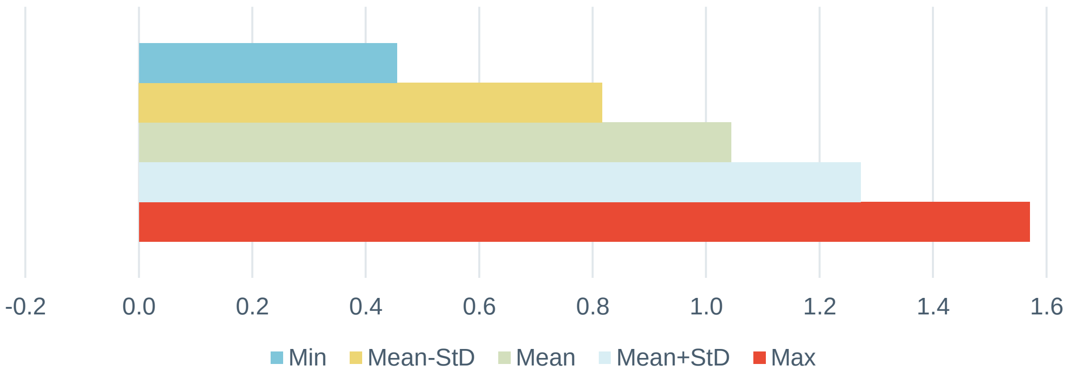


Figure 8: Modeled range of charges for Scottish 40MW 132kV generators, £mn 2021-22



Technology assessments

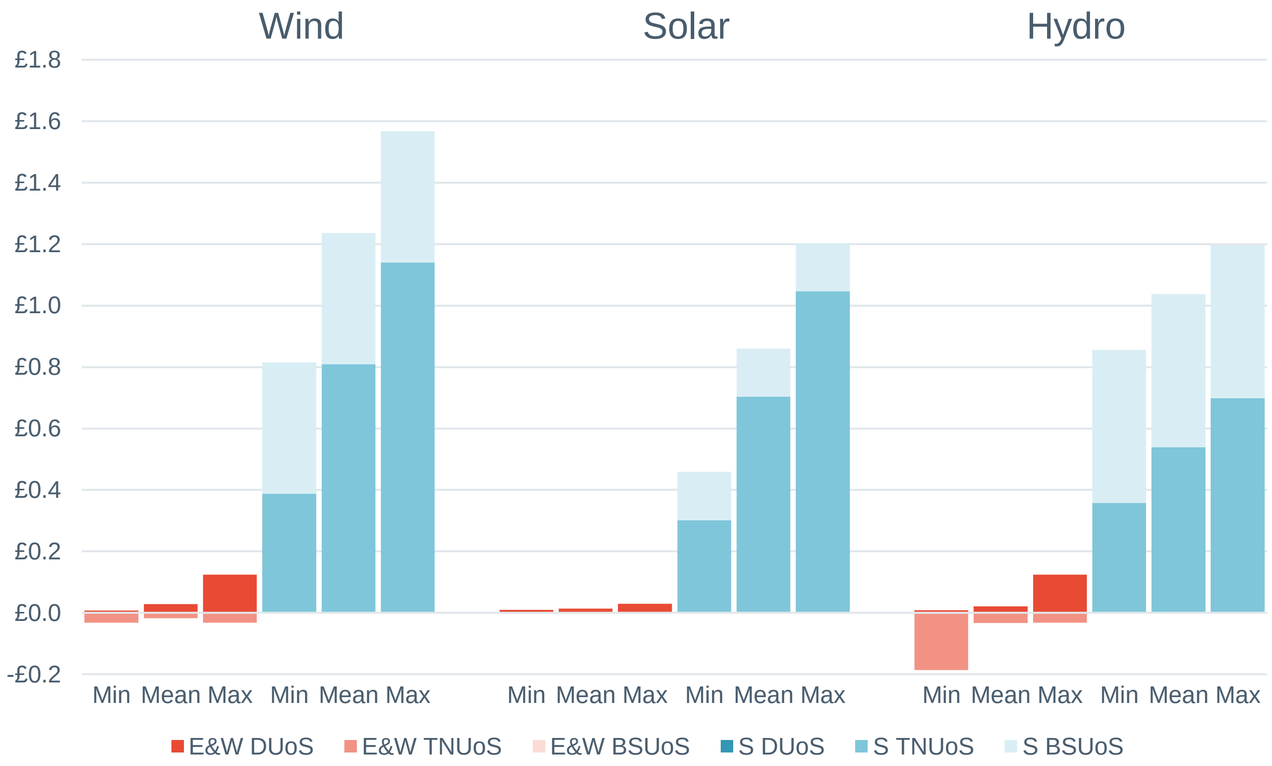
Our modelling identified that the disparity between E&W and Scotland is currently greatest for onshore wind but still significant for solar and hydro.

The onshore wind sites in E&W on average receive a small charge (£11,300) with DUoS charges partially offset by negative TNUoS rates (based on our assumption of small wind export in Triad periods), while Scottish wind receives a considerable charge, the majority of which (65%) is TNUoS. The mean difference is £1.2mn/year. The most expensive E&W wind site is £725k lower than the cheapest site in Scotland.

Our modelled 132kV solar sites in E&W always receive a net charge due to the positive DUoS rates south of the border with no offsetting effect from TNUoS as Triads invariably occur after dark so solar will not be exporting. Solar in Scotland faces appreciably lower charges than wind, primarily due to lower BSUoS exposure. Nevertheless, charges to solar in E&W still pale in comparison to Scotland, with a mean difference of £850k/year and the most expensive site in E&W £400k below the lowest cost site in Scotland.

Our modelling shows that hydro would experience similar differentials, although we note that we did not identify any hydro sites at the 132kV level in E&W, making the comparison somewhat artificial. Hydro is disproportionately affected by BSUoS in Scotland as well. Overall, the mean hydro site incurs ~£1mn of additional charges compared to an equivalent site located in E&W.

Figure 9: Modeled network charges for 40MW 132kV wind, solar and hydro, 2021-22 (£mn)



Technology assessments - £/MWh

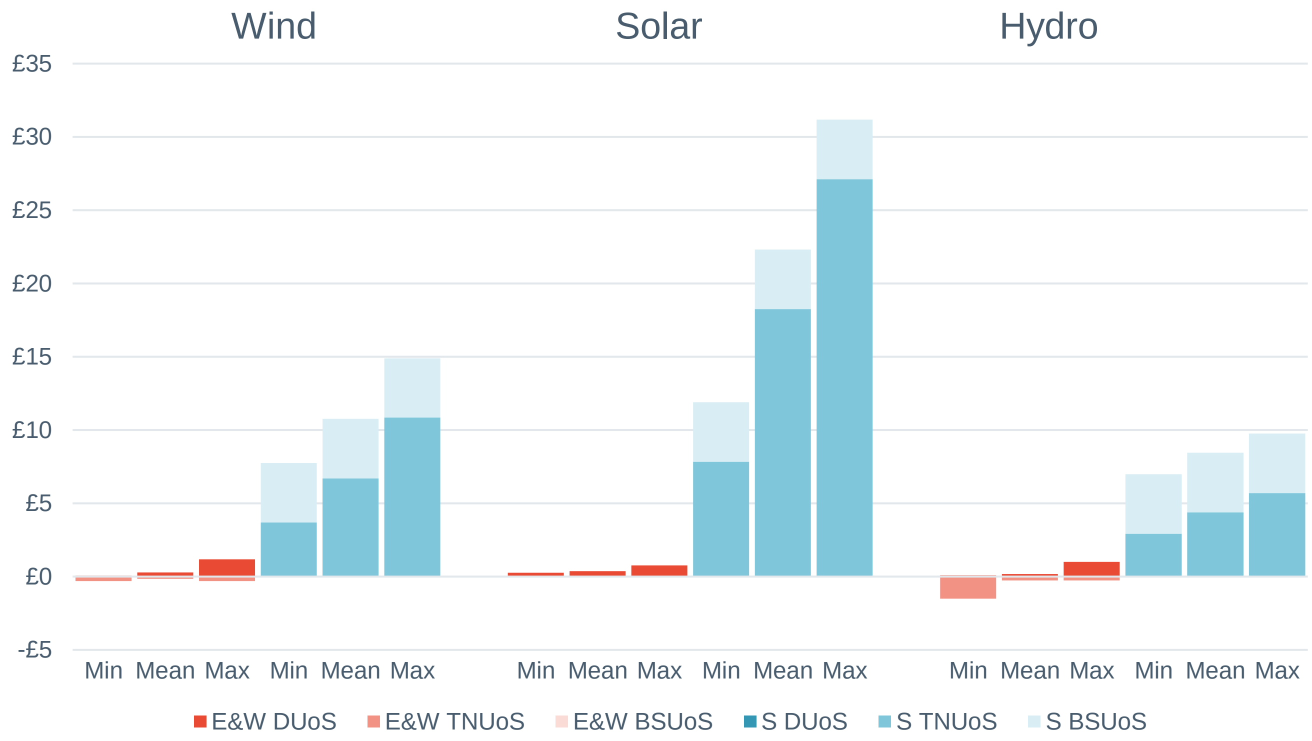
Figure 10 shows how the charges apply to the different types of 40MW generator on a £/MWh basis. The picture is changed considerably as a result of the solar generator having a much lower output than the wind and hydro plants, meaning the total cost of charges is spread over a smaller number of units. This is magnified by the fact that a large portion of EHV DUoS and TNUoS charges are levied on a fixed basis depending on the site's connected capacity, rather than p/kWh rates.

Wind sites in E&W pay £0.11/MWh on average, with the most expensive charges faced by any site in the analysis amounting to less than £1/MWh. This contrasts to Scotland, where the average windfarm would pay almost £11/MWh, and even the cheapest pays almost £8/MWh.

Solar farms in E&W effectively pay just £0.35/MWh in network charges on average; appreciably higher than wind but still insignificant. The maximum paid is just £0.77/MWh. In Scotland, however, a 40MW solar farm would pay over £22/MWh, rising to £31/MWh at the high end of the scale.

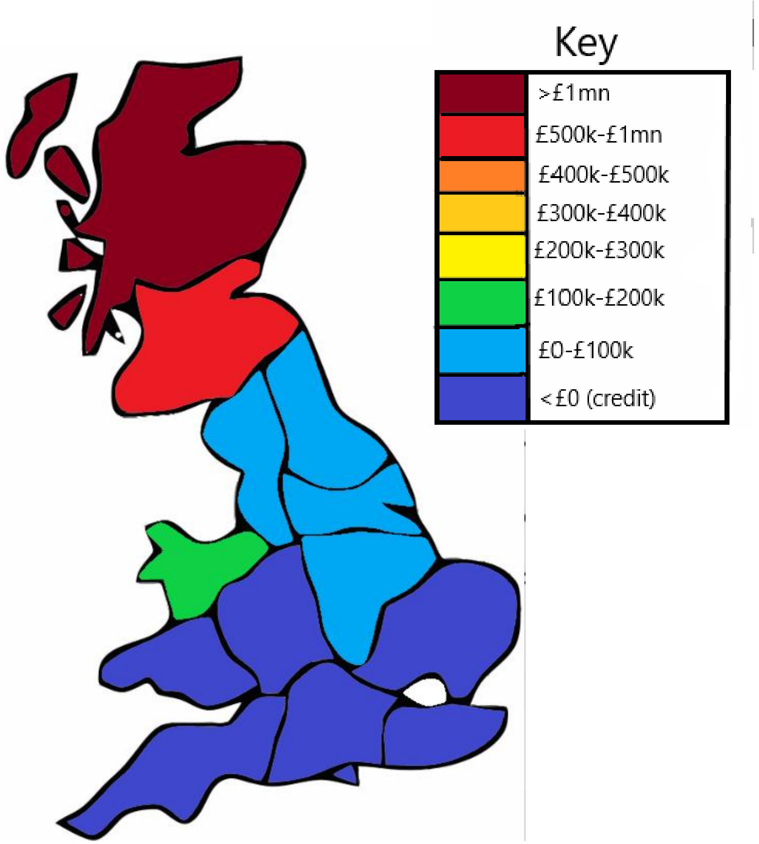
Costs for hydro south of the border are slightly negative on average at -£0.10/MWh, and at most are comparable to those for solar. The higher load factor (hence output) of hydro generation means that the £/MWh rate is lower than for other technologies and this is most notable in Scotland, where they pay around £8.50/MWh on average, £7/MWh at a minimum and no more than £10/MWh at most.

Figure 10: Modeled network charges for 40MW 132kV wind, solar and hydro 2021-22 (£/MWh)



Regional variation

Figure 11: Modeled network charges for 40MW 132kV wind 2021-22



If we apply our wind profile to all E&W 132kV connected sites used in this analysis, and equally apply an average cost for this profile in each of the generation charging zones to each demand zone, the average costs are shown in Figure 11.

As previously outlined, the network costs for a 40MW 132kV connected plant in Scotland are significant – in excess of £1mn per annum in the North and £500k per annum in the South using our average figures and load profile.

In comparison, around half of all E&W regions receive a credit while the remainder pay a small charge, with the greatest costs in the Manweb region.

2022-23 charging differentials

Outline methodology

This modelling run used final DUoS charges for 2022-23 (as published by the network companies in December 2020) and projected TNUoS charges for 2022-23. The latter take into account the expected changes from CMP368 *Updating Charges for the Physical Assets Required for Connection* using the approximation published in National Grid ESO's five-year forecast of TNUoS charges.

This modification seeks to amend the definition of the “Connection Exclusion” that had been implemented in CMP317/327. The overall aim had been to define what assets are required for connections and so should have their costs included when assessing compliance with the limit of generation transmission charges to a range of €0-2.50/MWh. This limit forces a large negative charge to be applied to generator charges, increasing TNUoS for other users. CMP368 will ensure that local charges for pre-existing assets when a generator connects to the system will be excluded from the calculation for determining compliance with the range. The modification is not yet fully developed, but implementation is targeted for 1 April 2022.

Sources:

- TNUoS - National Grid 5 Year Forecast
- DUoS - DNO LC14 charging statements and associated documentation, available from DNO websites

Comparison

In 2022-23 the disparity between Scotland and E&W is still very clear, even after the implementing the changes detailed in the previous slide.

The modelled 132kV-connected generator south of the border with the highest credit still receives around £180k. The average site's charges now net out to a very small credit, with this shift being driven by major increases for a small number of sites. For example, the most expensive site has increased to £332k, which we expect is the result of a large generator connecting to that site's part of the network, driving up its locational DUoS charge.

Charges in Scotland have slightly reduced overall compared to 2021-22. The mean site is paying is £910k per year, down from £1.0mn (-13%), and the most expensive pays £1.3mn, down from £1.6mn (-19%). However, the site with lowest cost in Scotland is still ~15% more expensive than the site with the highest cost in E&W, and the charges paid by the highest cost in Scotland are around four times that of the highest cost in E&W, despite the latter having more than trebled in cost year-on-year.

Figure 12: Modeled range of charges for 40MW E&W 132kV generators, 2022-23 £mn

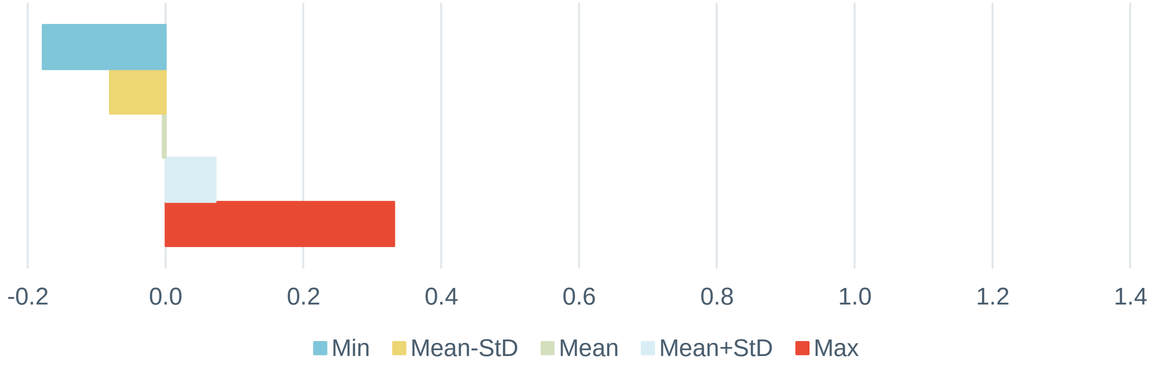
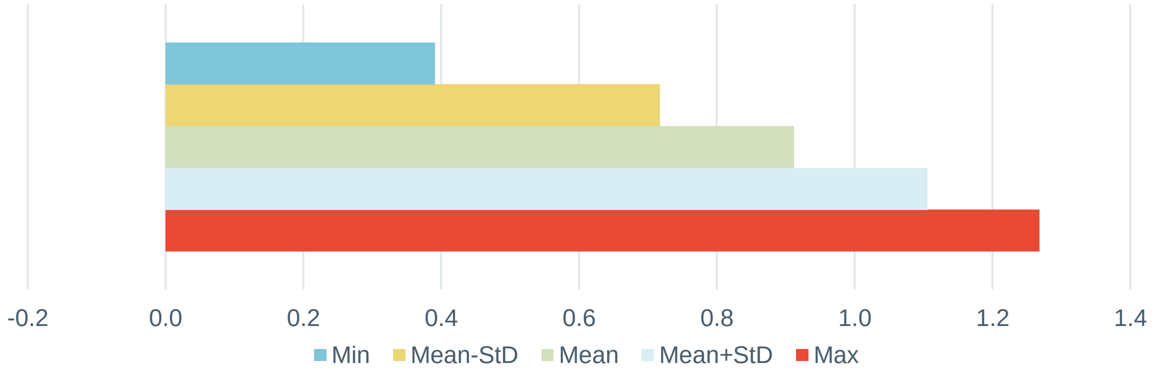


Figure 13: Modeled range of charges for Scottish 40MW 132kV generators, 2022-23 £mn



Technology assessments

The view by technology for 2022-23 is similar to the previous year.

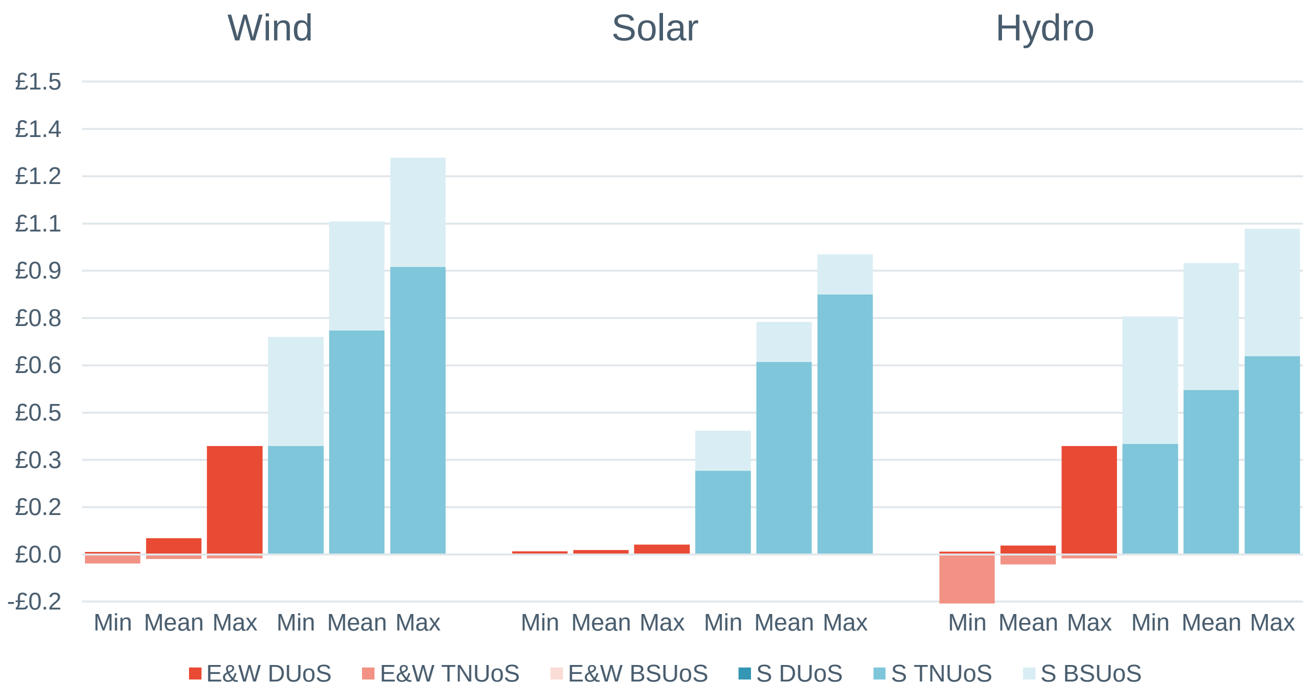
The DUoS and TNUoS for the average modelled windfarm in E&W will net off to a £37k charge, while the average in Scotland will incur a £1.0mn cost. The highest charges faced by E&W windfarms have almost trebled year-on-year, but are still £925k lower than the highest in Scotland and still less than half of those faced by the “cheapest” Scottish windfarm.

The picture for solar power barely changes year-on-year, either in absolute or relative terms. The average and lowest cost sites in E&W still face charges that are less than 5% of their equivalents in Scotland.

The costs faced by hydro power are still similar in shape to wind, but have reduced appreciably since 2021-22. The cheapest Scottish site now pays £755k, the mean site £925k and the most expensive £1.0mn, all down about 12% on 2021-22.

One point of interest is the fact that the DUoS charges for the most expensive wind or hydro generators modelled in this exercise in E&W exactly equal the TNUoS charges of the cheapest in Scotland. However, the application of BSUoS costs for transmission-connected plant means there is still a considerable discrepancy.

Figure 14: Modeled network charges for 40MW 132kV wind, solar and hydro 2022-23 (£mn)



Technology assessments - £/MWh

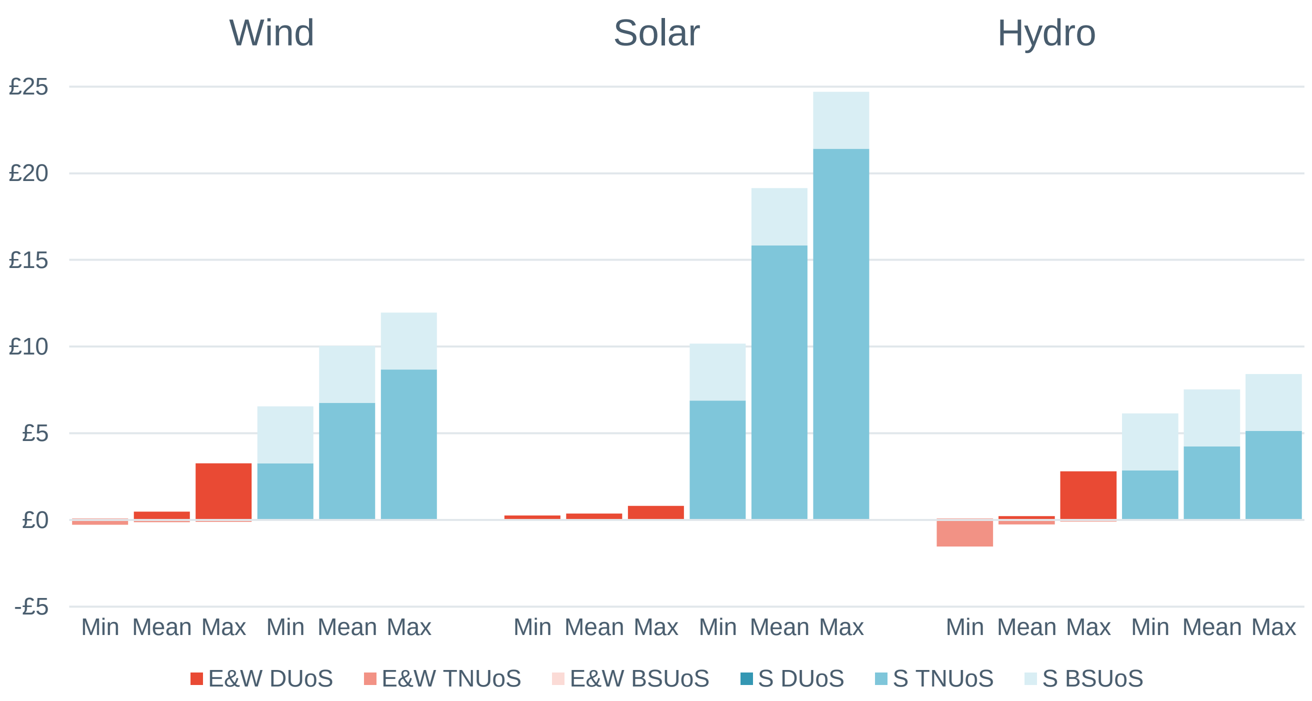
Converting Figure 14 data into a £/MWh value creates the situation shown in Figure 15.

Compared to the 2021-22 values in Figure 9, costs for the average 40MW windfarm located in E&W would still be negligible (£0.35/MWh), although the most expensive site modelled is seeing much more significant charges £3.15/MWh). In Scotland charges vary from £6.50/MWh to £12/MWh, with an average of £10/MWh.

Solar charges are almost identical to the previous year's level in E&W, averaging £0.37/MWh and almost exactly the same as for wind. In Scotland they have fallen slightly, now averaging £19/MWh, with a minimum of £10/MWh and maximum of £25/MWh.

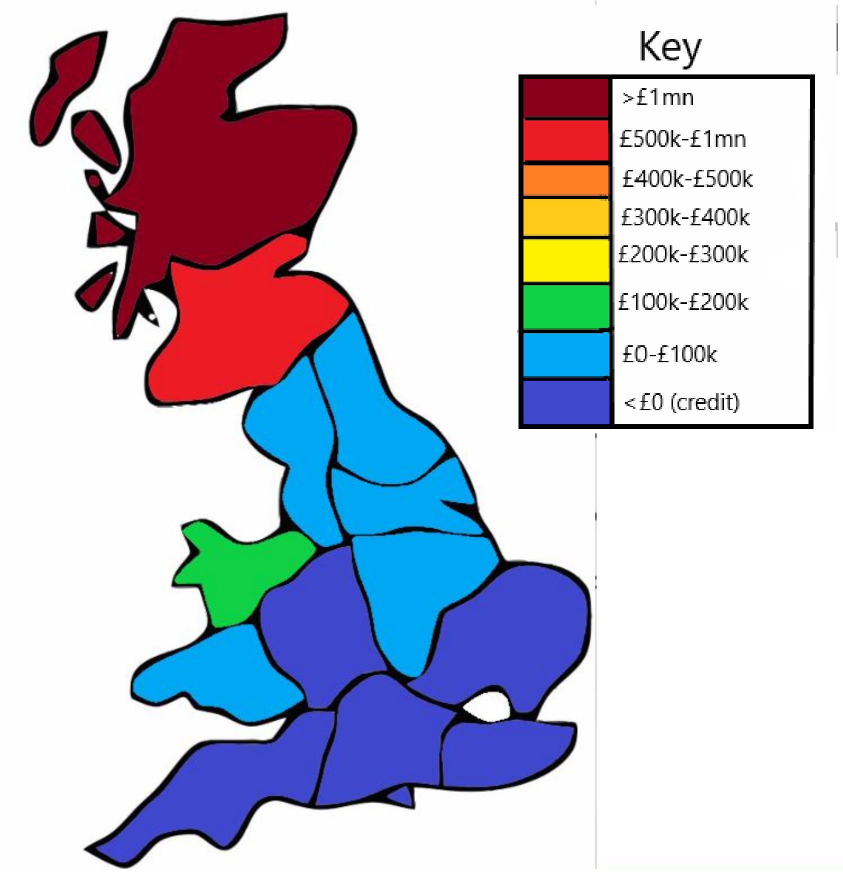
There is again a fairly consistent spread with charges for the modelled hydro sites. In E&W average charges effectively net to zero, varying between a £1.50/MWh credit and a £2.70/MWh charge. In Scotland there is a fairly smooth climb from a minimum of £6/MWh, to a mean of £7.50/MWh, and a max of £8.40/MWh.

Figure 15: Modeled network charges for 40MW 132kV wind, solar and hydro 2022-23 (£/MWh)



Regional variation – 2022-23

Figure 16: Modeled network charges for 40MW 132kV wind 2022-23



Again, if we apply our wind profile to all E&W 132kV connected sites used in this analysis, and equally apply an average cost for this profile in each of the generation charging zones to each demand zone, the average costs are shown in Figure 16.

Network costs for a 40MW 132kV connected plant have barely changed within the boundaries of our key compared to our previous analysis. The main alterations will be driven by forecast use on the local EHV networks meaning generator charges – the presence of an additional generator locally or loss of demand may increase charges. This is potentially what has happened in the South Wales region, driving net network charges into a cost for this year.

2023-24 charging differentials

Outline methodology

The 2023-24 modelling reflects two major shifts in generator charging:

- From April 2023, generators are likely to no longer incur BSUoS charges as these are likely to be moved wholly onto demand users under CMP308.
- The reforms of the Network Access & Forward-looking Charges ("Access") significant code review could expose distribution-connected generators in E&W to TNUoS charges, which – prior to COVID-19 delays – were planned for implementation this year.

Due to the fact that Access proposals are not yet finalised and that it is likely Ofgem will want to provide the industry with at least two years' notice of such a significant change to generator charges (not to mention modification development time and potential appeals or legal challenges), we believe that distribution connected generators (including 132kV generators in E&W) are unlikely to become liable for TNUoS charges until 2024 at the earliest. However, the removal of BSUoS and application of TNUoS to distribution-connected generators represents the current expected end state of network charge reform, so we consider that modelling 2023-24 under these parameters can still provide a useful illustration of what might be the enduring generator charging regime.

Since there are not yet any confirmed Access proposals, we have modelled what could be considered a worst-case scenario for generators, applying TNUoS to distributed generators in E&W on the same basis as those connected at the transmission level.

Sources:

- TNUoS - National Grid ESO 5 Year Forecast
- DUoS - DNO LC14 charging statements and associated documentation, available from DNO websites

Comparison

While the internal proportions of Figures 17 and 18 strongly resemble those of previous years, there has been an appreciable change in aggregate in both E&W and Scotland.

Once again, the lowest cost site in E&W is in receipt of a credit of over £80k, but that credit is now derived from generator TNUoS (which is a capacity-based credit in the South of England) rather than the Embedded Export Tariff. The sites in the most expensive location is paying several times more than the mean. However, the average site is now paying £107k – a major increase on 2022-23. The most expensive site is now paying roughly twice as much as 2022-23 year-on-year (£630k), due to the introduction of material TNUoS charges in the North of England.

On the other hand, Scottish sites are now seeing the lowest charges of any year we have modelled. The average generator is now paying 32% (£300k) less, the cheapest 30% (£120k) less, and the most expensive almost 28% (£360k) less. This is predominantly due to the removal of BSUoS charges, which only applied to transmission-connected (Scottish) sites in the other years under consideration.

As a result of these changes, there is significant overlap, with the lowest cost Scottish sites now lower cost than the most expensive sites in E&W. But it should be noted that this outcome is contingent on reforms under the Access review increasing costs for sites in E&W which remain highly uncertain, and such reforms would be highly damaging to distribution connected sites in Scotland.

Figure 17: Modeled range of charges for 40MW E&W 132kV generators, 2023-24

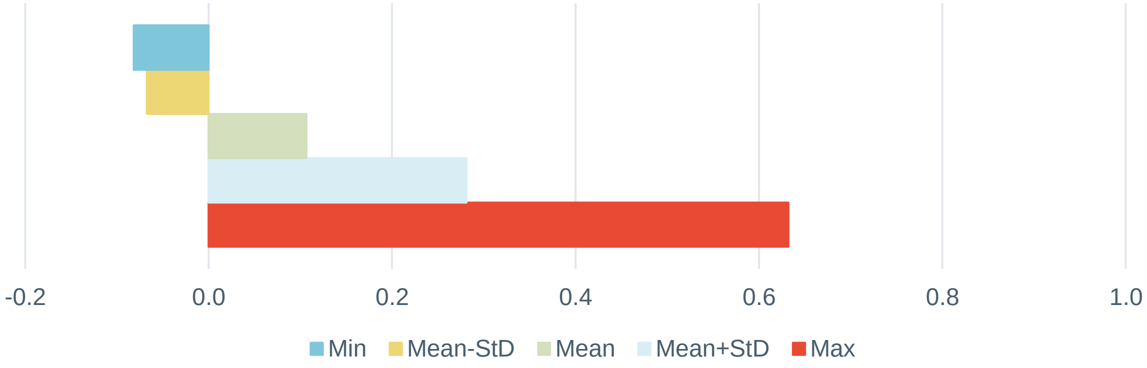
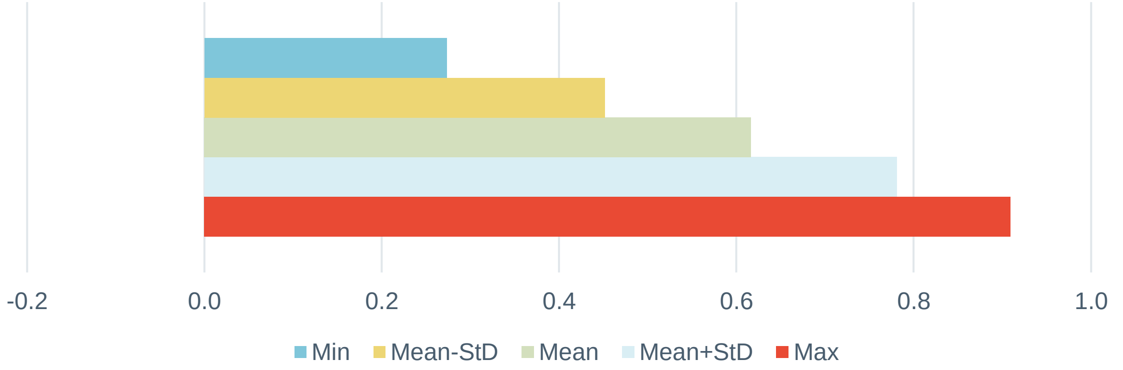


Figure 18: Modeled range of charges for Scottish 40MW 132kV generators, 2023-24



Technology assessments

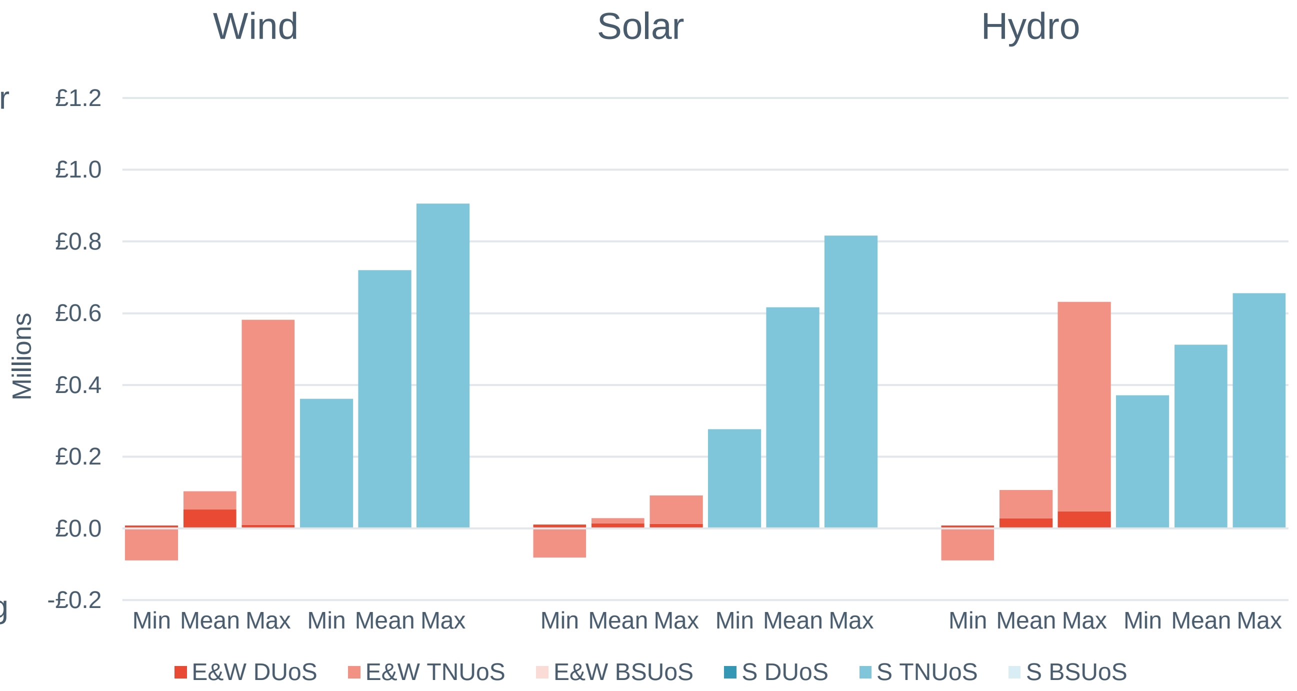
The picture has shifted dramatically in our 2023-24 scenario due to the removal of BSUoS charges from Scottish generators (reducing their cost stack by an average of around £135k for solar, £350k for wind, and £380k for hydro) and the addition of TNUoS charges to those in E&W (increasing their cost by an average of around £14k for the average solar generator, £50k for wind, and £80k for hydro).

The average windfarm south of the border is now paying ~£105k rather than receiving a net credit, but this is still considerably less than the ~£615k average in Scotland. The 'most expensive' windfarm in E&W is facing charges that are closer to its Scottish equivalent, although this is still less than the average Scottish windfarm has to pay.

Solar sites face a similar situation, only in E&W some sites will now receive net credits due to the introduction of capacity-based TNUoS credits. The average site will still pay far less than it would if located in Scotland, and the highest cost site will also pay charges that are much closer to its equivalent in Scotland.

The pattern is repeated for hydro sites. The lowest cost site is still paying ~£655k more than the lowest cost site in England, and the average site in Scotland ~£410k more than the average in England.

Figure 19: Modeled network charges for 40MW 132kV wind, solar and hydro 2023-24 (£mn)



In short, even with the removal of BSUoS costs from Scottish 132kV generators and the addition of TNUoS to those in E&W, the difference remains considerable for sites in all but the most expensive locations. However, the regulatory treatment of both is now equal, and the remaining difference is driven by locational elements in the charges.

Technology assessments - £/MWh

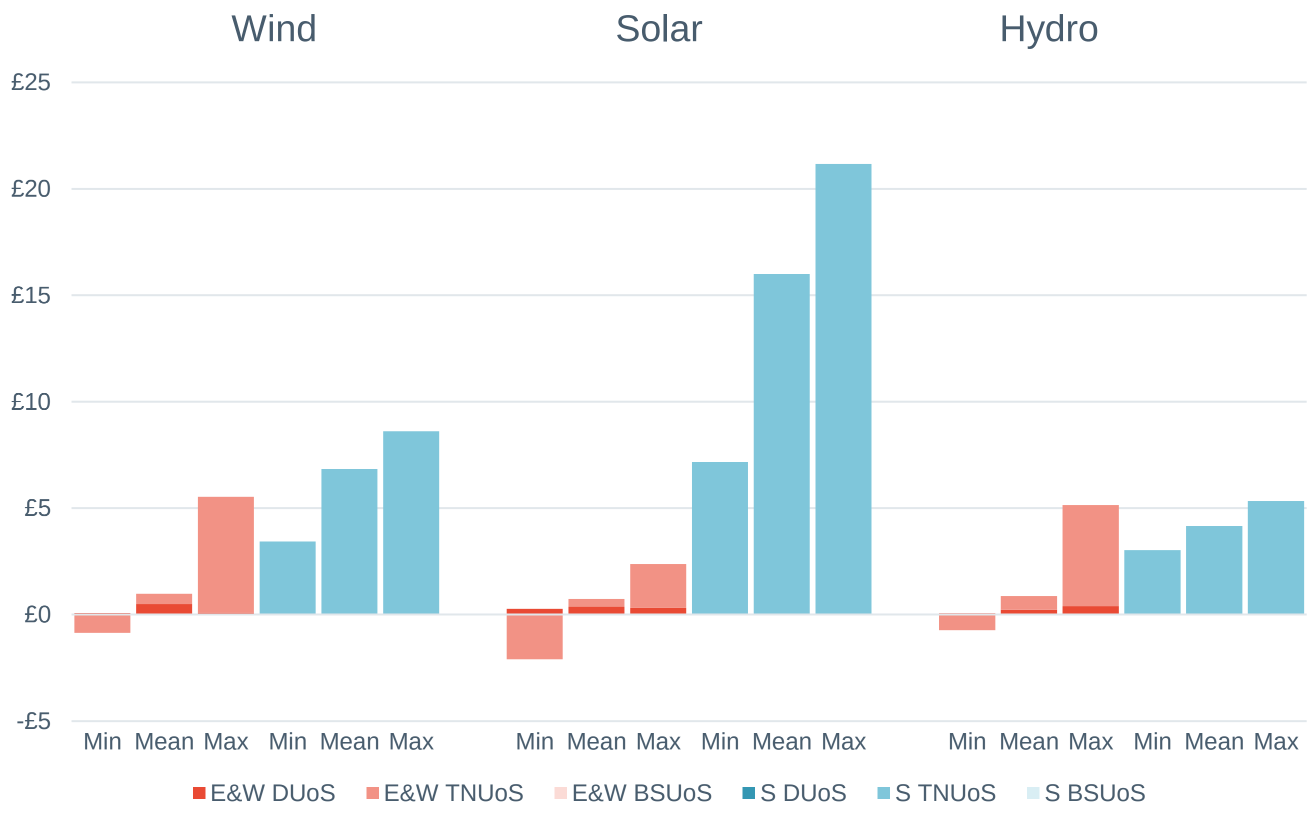
As in Figures 10 and 15, switching from absolute values per technology to £/MWh gives the appearance of levelling out charges for wind and hydro, while exaggerating the differences for solar in Figure 20.

The average modelled windfarm in E&W is now paying £1/MWh, similar to the most expensive site in 2021-22. The most expensive now faces a charge of £5.50/MWh, almost all of which is TNUoS, and about six times what it paid in 2021-22. The Scottish sites face a fairly even spread, averaging £7/MWh between extremes of £3.50/MWh and £8.60/MWh.

Solar farms in E&W now pay about £0.7/MWh on average, with the most expensive still paying under £2.50. Those in Scotland would face an appreciably lower average charge of £16/MWh, although this will vary between £7.20 and £21.20/MWh depending on location.

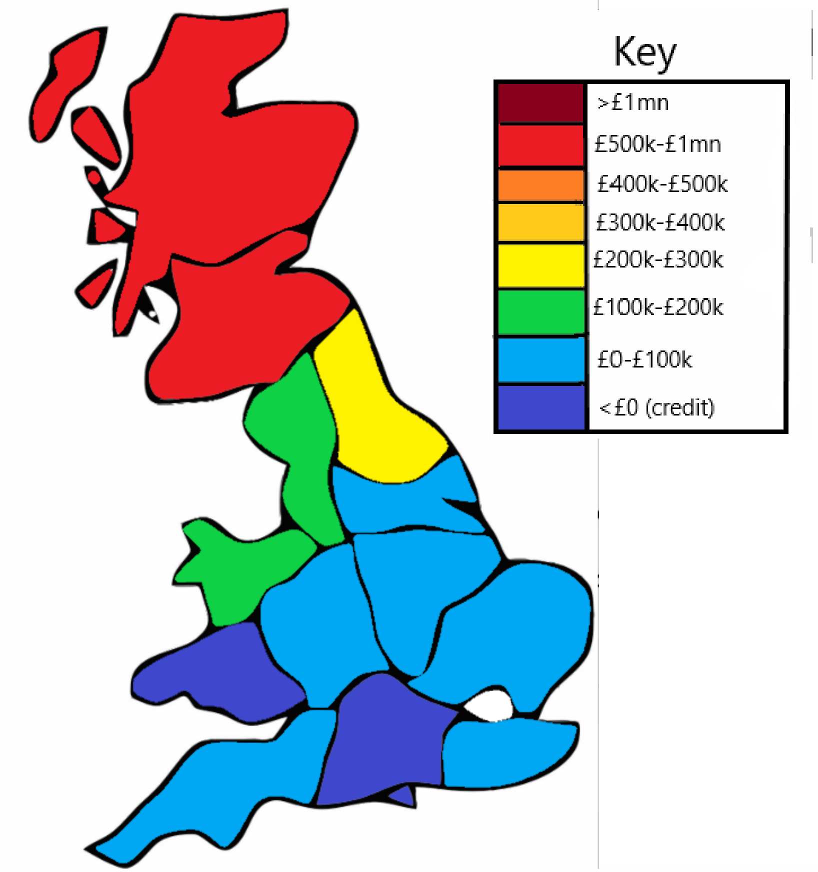
For hydro plants in E&W, the average charge would be under £1/MWh, with the most expensive paying around £5/MWh. The average in Scotland is now £4.20/MWh, and the maximum £5.30/MWh.

Figure 20: Modeled network charges for 40MW 132kV wind, solar and hydro 2023-24 (£/MWh)



Regional variation – 2023-24

Figure 21: Modeled network charges for 40MW 132kV wind 2023-24



Again, if we apply our wind profile to all E&W 132kV connected sites used in this analysis, and equally apply an average cost for this profile in each of the generation charging zones to each demand zone, the average costs are shown in Figure 21.

This shows much more differentiation in charges. Only the Southern and South Wales regions continue to receive a credit on average, while the majority of sites located in the south of E&W now pay a small charge. Sites located in the north of E&W now pay charges in excess of £100k as a combination of BSUoS and TNUoS costs impact these regions.

Meanwhile, in Scotland the removal of BSUoS means the Northern Scotland region falls below £1mn while the Southern Scotland region is on average only very slightly above the £500k threshold "red" map threshold.

Impacts of the Access SCR on DUoS

This modelling run uses projected charges for 2023-24, taking into account the possible changes that might ensue from the Network Access & Forward-looking Charges Significant Code Review (Access SCR) on TNUoS charges for distribution connected generators. Other elements of that SCR could introduce reform to DUoS charges, including those for 132kV connected generators in England which have not been modelled.

Ofgem's objective in reforming DUoS charges is to improve locational and time-of-use signals for distribution customers connected at HV and LV, where currently the same DUoS rates are applied to all customers of a given type across a DNO's entire region. The likely outcome of the DUoS reform would be charges which vary more by location, and potentially more dynamically by time. The extent of the increase in locational granularity is not yet known – the maximum level expected would be charges which vary by primary substation (i.e. substation with EHV/HV transformation, of which there are ~5,500 across GB). However, this would represent an extreme outcome for the change.

Such reform would have significant impacts on demand and generation customers connected to the HV and LV networks, but would be less marked on 132kV connected generators because:

- Those customers already face charges which vary by location, so the addition of locational granularity should not have as widespread impacts as it will have on HV and LV customers which currently face non-locational charges
- 132kV connected generators have a relatively small portion of distribution network between their connection and the transmission network, so are shielded from the most significant impacts of the reform by virtue of having relatively low DUoS charges compared to customers connected deeper in the distribution network

We do not yet have sufficient detail from Ofgem to enable the impacts of the Access review on DUoS charges for 132kV generators in E&W to be modelled, but we think it is likely that, on aggregate, charges for the group of generators will remain broadly flat, albeit potentially with some locational redistribution.

Sensitivities

CVA registered generation E&W

Generators in England and Wales connected at 132kV can sign a Bilateral Embedded Generation Agreement (BEGA) and become CVA registered. This enables them to access the Balancing Mechanism without operating via a licensed supplier.

This would typically result in the generator paying (or receiving) wider TNUoS and BSUoS charges as if it were a transmission connected plant. It would also remain liable for DUoS charges. There are exemptions to this rule however – a license-exemptible plant (<50MW and potentially up to 100MW) can choose to exempt itself from TNUoS costs. Regardless, there are a subset of 132kV connected generators in E&W that are paying TNUoS and BSUoS, and this slide explores the impact.

The impacts for a plant connected in the South East region are outlined in Figure 22. TNUoS costs are partially a credit in this region and additional BSUoS costs mean an additional £400k in cost. In the North East region (Figure 23), the impacts are over an additional £700k because wider TNUoS costs are much higher in this region.

Given there are a number of these sites, this impacts comparability between E&W and Scotland. However, this may be determined by the size of the generator or opted into by the generator, which is an important distinction to the exposure of 132kV in generators in Scotland which is unavoidable.

Figure 22: 40MW CVA registered wind, Essex and Kent, 2021-22 (£000)

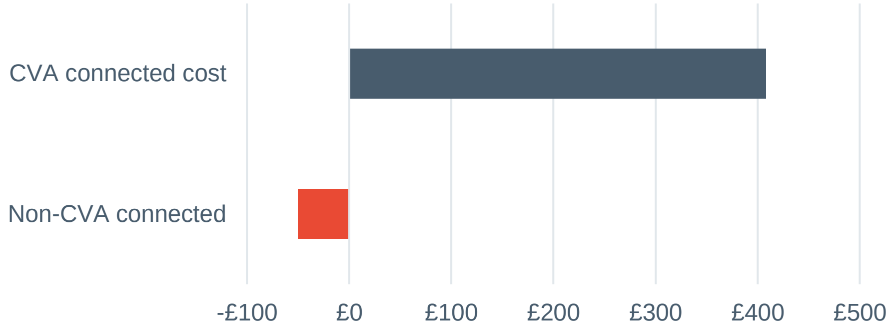
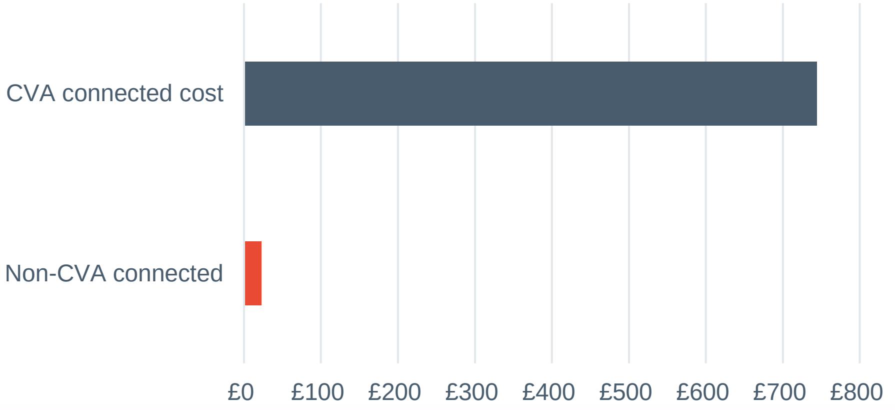


Figure 23: 40MW CVA registered wind, North East region, 2021-22 (£000)



CMP315 and CMP375

CMP315 *Review of the Expansion Constant and the Elements of the Transmission System Charged For* and CMP375 *Enduring Expansion Constant & Expansion Factor Review* could drive a material increase in TNUoS for 132kV connected generators in Scotland, potentially widening any disparity which exists under current arrangements.

This effectively enhances the differential in TNUoS between the north and south of GB. As such, a doubling of the expansion constant would result in a near doubling of TNUoS charges (the only element that does not double being the residual, which will reduce in order to keep overall charges below the €2.50/MWh cap).

This is shown in Figures 24 and 25 – Figure 24 outlines the forecast charges under current arrangements for the generators connected in Scotland. Figure 25 shows the same with a doubled expansion constant.

The change would increase the TNUoS credits for generators in the south and effectively result in a much more significant difference in TNUoS charges between Scotland and E&W.

Figure 24: Modeled range of charges for Scottish 40MW 132kV generators, 2023-24, £mn

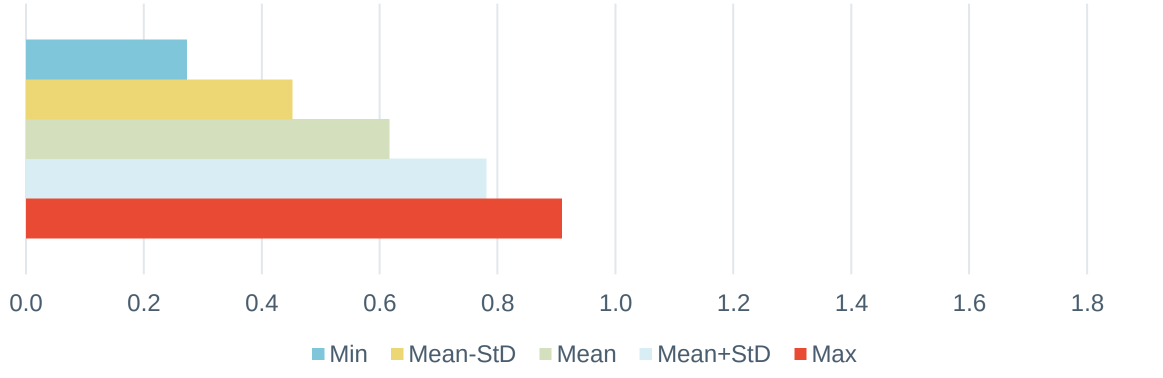
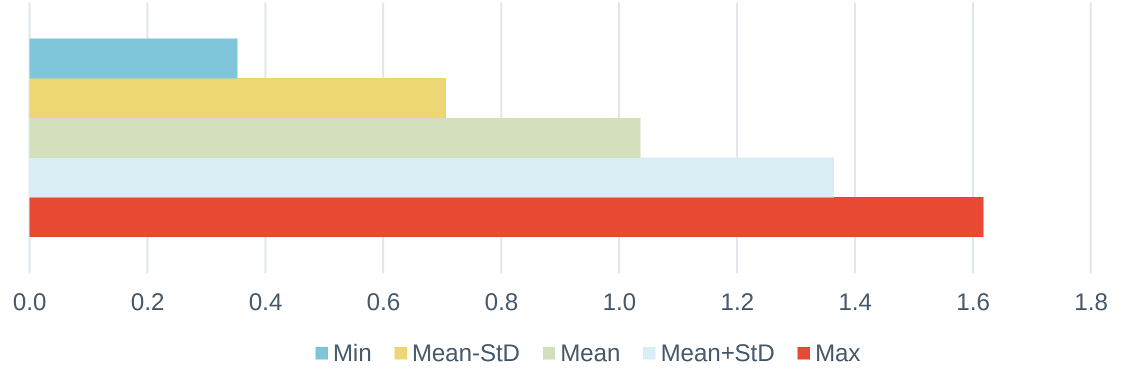


Figure 25: Same charges with doubled expansion constant



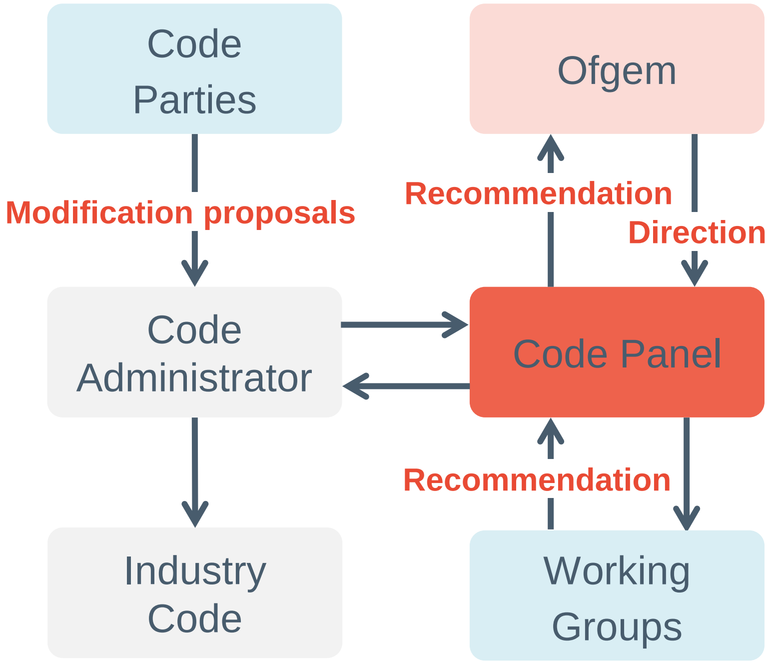
Addressing the differential

Changes – process and timetable

The TNUoS methodology is specified in the Connection and Use of System Code (CUSC), which is subject to open governance arrangements. Members of Scottish Renewables who are CUSC signatories are therefore able to raise modification proposals to amend the methodology, which we would see as the most appropriate route to take when trying to address the differential. This tends to be an extended and time-consuming process, however.

The modification process is illustrated in Figure 26. Code parties may raise proposals, which will be reviewed by the code administrator (in the CUSC's case, National Grid Electricity System Operator, or NGESO) to ensure they are properly constituted. These proposals are then considered by the CUSC Panel, which will determine if the modification requires further development (all but the simplest do), and if so, will send it to a workgroup comprised of code party representatives for discussion.

Figure 26: Illustrative modification process



The working group will prepare a report of its findings, which will then be issued to parties for consultation, then potentially updated and re-consulted on if new issues arise. Once ready, the modification and report are considered by the CUSC Panel. If the proposal is deemed non-material the Panel can decide to approve or reject it, while if it is material (as a charging proposal is likely to be) the Panel must instead make a recommendation to Ofgem, which will take the final decision.

Examples of past CUSC modifications that we believe are of relevance are:

- CMP358 *Implementation of the Small Generation Discount into the CUSC* – this modification was raised in January 2021 by Red Rock Power, seeking to extend the SGD. However, Ofgem rejected a request that CMP358 be classified as Urgent and it has been assigned low priority by the CUSC Panel, so it has little prospect of being progressed in the near term. This illustrates how the modification process can be drawn-out and stymie changes that do not have widespread support.

Changes – process and timetable (2)

- CMP343 *Transmission Demand Residual Bandings and Allocation for 1 April 2022 Implementation* – this is the modification that will implement reform of residual TNUoS charges into the CUSC. It is a progression of CMP332, which had been raised in December 2019 and targeted implementation in April 2021, but was timed out due to its complexity and required extension. Indeed, Ofgem now intends to further defer implementation to 2023. This illustrates how complicated changes to the charging methodology can be, and how implementation targets can be missed.
- CMP368 *Updating Charges for the Physical Assets Required for Connection* – this modification was raised in May 2021 but continues a workstream initiated under CMP317/327 from 2019 that sought to clarify which assets should have their costs included in the calculation of whether TNUoS charges fall within the €0-2.50/MWh range specified by (retained) EU regulation, and remove the TNUoS generator residual. Ofgem accepted CMP317/327 for implementation from April 2021 but deemed it an incomplete solution and directed a further modification to be raised. This again demonstrates the complexity of charging modifications, but also Ofgem's powers over the process.

Considering the above, we would highlight that:

- Code modification development involves numerous steps
- If a proposal is not fast-tracked (typically for housekeeping changes) or granted Urgency (allowing an accelerated timetable), there will usually be at least three months of workgroup discussion and two separate consultations of typically one month apiece.
- Ofgem frequently takes ~three months to decide on modifications sent by the Panel, and there is typically a delay before implementation to give industry notice
- It is unusual for any modification to go from proposal to implementation in less than six months, and charging modifications are likely to take longer
- Despite forming a key part of Ofgem's TCR reforms, CMP343 effectively took 11 months of development and is now expected to be implemented 44 months after being raised
- CMP317/327 took over 9 months of development and its successor, CMP368, will be implemented at least 29 months after the original modification was raised.

Additionally, changes to the charging methodologies usually require two modifications due to the CUSC rules: one to change the methodology, and another for consequential changes such as definitions. This will also need to be taken into account, though in practice splits the workload into two parts rather than doubling it.

Changes – potential reform options to explore

Scottish Renewables requested a high-level view of potential reform options that could be pursued to reduce the charging differential between Scotland and E&W for 132kV connected plant. Considering the significant level of existing and proposed reform in the space, we believe there are a few avenues that could be explored and outline the potential options from most to least likely to receive traction and have an impact:

- Ofgem is likely to perform a detailed review of transmission charges going forward (as noted in the Access SCR minded-to decision). We would recommend Scottish Renewables (and/ or its members) be heavily involved in the reform and, on the grounds of fairness challenge the significant transmission costs impacting generators located in Scotland.
- The following two items could be stand alone (progressed through one or more code modification proposals) or a subset of the first bullet point (and pursued as part of the transmission charging review):
    - Propose that all 132kV network is charged under the same charging methodology i.e. all generators are charged under the EDCM model. While there would be opposition to this proposal, charging all generation connected at the same voltage level in the same manner provides a consistent methodology and aligns with some of the charging objectives.
    - Propose an alteration to the charging elements that renewables are subject to - for example the year-round not shared element being multiplied by ALF. This, however, would require a fundamental reform including modification of the SQSS and assumptions around technology availability and actions which means this may be too significant a reform to progress.
- Propose a reduction to the expansion constant. This could be progressed as a standalone modification or alternatively as a WACM for CMP375 provided a member of Scottish Renewables were engaged in the working group.
    - It should be noted that previous analysis from National Grid ESO indicated that a rise in the expansion constant would be likely under the existing arrangements, leading to the development and implementation of CMP353 *Stabilising the Expansion Constant and non-specific Onshore Expansion Factors from 1st April 2021*, which held the expansion constant at its existing level for 2021-22 and sought an enduring solution through further modifications (CMP375).

Code changes – estimated timescales

If a member of Scottish Renewables wished to raise a code modification to address the differential between 132kV charging in Scotland and E&W, we estimate that this would require 9-12 months of development. A hypothetical timeline might be as follows, with the most resource-intensive marked in red:

- Discussion with other Scottish Renewables members to ensure as many parties' concerns are addressed as feasible
- Air intention to raise modification at Transmission Charging Methodologies Forum to gauge industry support and identify potential 'show-stoppers'
- Draft modification
- Submit modification to code administrator for Critical Friend appraisal
- Code Panel sends modification to workgroup for development with an expected requirement of six meetings (six months)
  - Alternatives (WACMs) can be raised throughout the process, which may necessitate an extension to the development timetable
- Modification is sent for workgroup consultation (3 weeks)
- Workgroup considers consultation responses and amends modification in response to issues being raised
  - Considerable amendments may require a second workgroup consultation to be conducted, and for the responses to that to be considered
- Modification is sent for code administrator consultation (three weeks)
- If no further issues are identified, modification is considered by Panel and a recommendation made to Ofgem
- Ofgem makes decision on modification (25 working days is Ofgem's target time)

We estimate that these would take 3-4 days of work each (e.g. reading consultation responses to understand stakeholder views, or prepping for then presenting at workgroup meetings). Considering this, we believe such a modification would require the proposer to commit 30-42 work days.

Scottish Renewables, or one of its members, may wish to lead the development and consult an independent expert as a critical friend/ for direction. This would support in managing the external costs for the modification.

Conclusions

Conclusions

There are material differences in regulatory treatment between 132kV generators in Scotland compared to those in England and Wales under current arrangements:

- Generators in Scotland are required to pay balancing services charges while those in England and Wales are not
- Generators in Scotland pay transmission network charges while those in England and Wales either receive credits under the Embedded Export Tariff (in the South) or pay no charge
- Generators in England and Wales pay distribution network charges

These give rise to a material differential between charges faced by the two groups, with the average charge in England and Wales in 2021-22 being over £1mn lower than in Scotland.

Some ongoing regulatory reforms will remove some of the differentials, including:

- Changes following the second Balancing Services Task Force which seek to move balancing services charges onto demand only, which would result in all 132kV generators not paying those charges, decreasing charges for 132kV generators in Scotland. Implementation is expected in 2023-24
- Reform to transmission charging under Ofgem's Network Access and Forward Looking Charges review, which may result in distribution connected assets paying similar transmission charges to transmission connected assets, increasing costs for 132kV generators in England and Wales. Implementation timescales are uncertain, but following recent delays to Ofgem's timetable, April 2024 may be the earliest implementation date.

But even once those reforms have been applied, a significant differential remains, with the average charge in England and Wales in 2021-22 being around £500k lower than in Scotland. This is predominantly due to transmission network charges, which have a very strong locational element which, broadly speaking, drives charges higher the further north a generator connects.