

Consumer savings under TNUoS reform proposals

Commissioned by Ocean Winds, West of Orkney and
Spiorad na Mara

April 2025

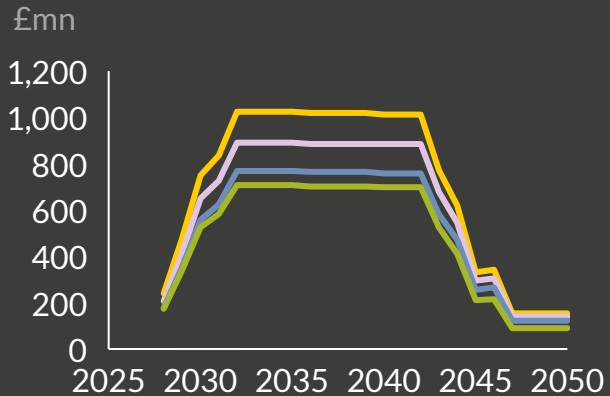
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Executive Summary

Savings to the consumer for CfD-backed offshore wind generation over 2028–2050 due to different TNUoS reform options



Cumulative Savings, 2028–2050

£16.2bn

£14.1bn

£12.2bn

£11.1bn

- The **rise of Transmission Network Use of System (TNUoS)** charges in Scotland can be mitigated by TNUoS reform. The **CMP 432** proposal will incur **£11.1bn** of savings to the consumer between 2028-2050, by reducing the CfD bid prices of Scottish wind farms. Under the **CMP 444** proposal, the **WACM 1** alternative incurs the highest savings to the consumer with **£16.2bn** over the same period.
- There is an urgent need to review TNUoS charging arrangements to ensure they are not slowing down needed development of renewables and are minimising costs to consumers
- Development of Scottish offshore wind farms is considered crucial to reach the UK's decarbonisation goals. NESO expects 12GW of offshore wind in Scotland by 2030 in their Further Flexible Energy and Renewables scenario, in line with the leasing of Scottish seabeds and development of the Scottish transmission capacity
- The **divergence of (wider) TNUoS** charges across regions **has increased significantly in recent years** and is expected to rise further over the next decades with TNUoS increasing in Scotland and decreasing in the South of Great Britain. This uncertainty **disadvantages** Scottish wind farms, increasing their cost of capital and opportunities to secure debt financing, increasing their bid prices in CfD auctions
- Based on Aurora's forecast of status quo TNUoS charges, TNUoS charges lead to a **bid price differential of up to £21/MWh** for offshore wind generation between the North and South of GB in 2025. (Wider) TNUoS charges are shown to increase CfD bids in Scotland by **up to £17/MWh**. When accounting for the **TLM divergence** between the North and South, the differential rises to **£27/MWh** ([slide 6](#))
- Scottish offshore wind farms could set the clearing price for at least **90%** of CfD backed offshore wind capacity up to 2050 ([slide 17](#)). When Scottish farms set the price, the increased strike prices due to the high TNUoS will increase costs to the consumer; incurred through the retail price
- This report² assesses **4 TNUoS reform proposals** and their relative impact on **managing the TNUoS divergence** which directly **increases savings to the consumer** ([slide 19](#)). All TNUoS reform proposals offer significant consumer savings according to this analysis, ranging between 704mn and 408mn per year on average between 2025-2028. The CMP 444 (WACM1) forecast delivers the **greatest consumer savings**, reducing TNUoS costs in Scotland the most at 59%. CMP 444 (WACM5) follows at 51%, with CMP 444 (Original) at 45% and CMP 432 at 40%

— CMP 444 (WACM 1) — CMP 444 (WACM 5) — CMP 444 (Original) — CMP 432

1) Workgroup Alternative CUSC Modification; 2) This analysis considers offshore wind, the projected major electricity source in GB. Including onshore wind in the analysis is likely to increase the observed impact since onshore wind is expected to be largely concentrated in Scotland. The same trend would apply to a larger volume of CfD backed generation (onshore + offshore wind).

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1. Current TNUoS direction
2. TNUoS reform proposals

II. Results of Aurora's analysis

1. Analysis assumptions under Aurora CP2030
2. CP2030 TNUoS projections under each scenario
3. Total Consumer Costs

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Network charges recover the costs of the electricity grid and are significantly higher in Scotland than in the South of Britain

1 Network charges recover grid costs

- In Britain, the costs of operating and reinforcing electricity grids are recovered through network charges collected by National Energy System Operator (NESO)
- These charges are referred to as Transmission Network Use of System (TNUoS) charges¹
- Electricity generators and consumers are required to pay TNUoS charges
- (Wider) TNUoS charges differ by location. Key objectives of the design of TNUoS charges include
 - **Cost reflectivity:** distributing cost of electricity networks fairly
 - **Locational incentives:** incentivising generation to locate close to demand helping to minimise electricity network cost³
 - **Predictability:** to allow developers to plan around TNUoS

TNUoS Wider Tariff – 2025²
£/kW/year (real 2023)



2 Network charges currently disincentivise siting generation in Scotland and the key objectives of TNUoS are not met

- Currently a large share of wind generation resides in the North, while centres of demand are in the South. This leads to **congestion on the electricity grid** due to insufficient transport capacity between the North and the South
- **Network charges** for generation are currently **significantly higher in Scotland** than in the South of Britain, where they are low or even negative (i.e. the North pays the South). This trend is expected to continue in the future with the gap widening
- The resulting **cash transfer** from North to South has **raised concerns about its fairness**. Additionally, the increasing uncertainty around TNUoS takes a toll on the cost of capital for Scottish projects which have difficulties securing debt.
- These factors **discourage investment in offshore wind farms in Scotland** even though their deployment is considered key to reach CP2030 in the UK

3 Impact of network charges on consumer cost

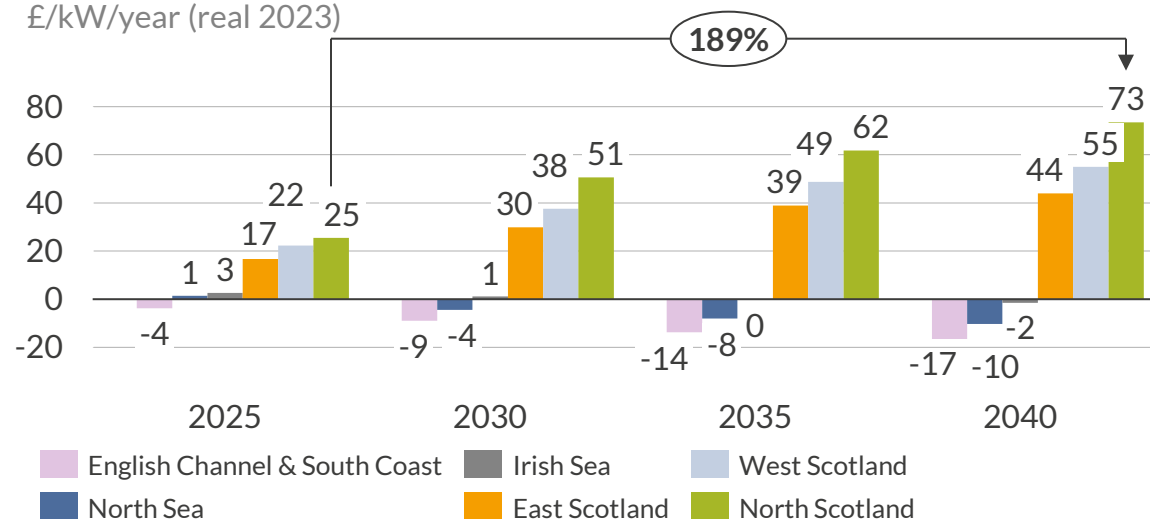
- This report assesses the **impact of TNUoS charges** on the **total cost of renewable electricity to consumers** during the CfD subsidy period. The focus is on **offshore wind** as the technology expected to dominate renewable supply in GB

1) This analysis focuses exclusively on the wider tariff part of the TNUoS, which is incurred for the use of the whole system. Generators also pay so called additional local tariffs, which are charged for the use of electricity grid assets in the immediate vicinity of the generator (substations and local circuits); these are not part of this analysis; 2) Average values for Aurora's offshore wind regions for the calendar year 2025, assuming an average load factor of 51%. 3) Congestion management and reinforcement.

TNUoS charges are expected to grow significantly in the North while declining in the South of Britain

TNUoS Total Wider Tariff¹

£/kW/year (real 2023)



1 TNUoS in Scotland expected to increase by up to 189% by 2040

- The current TNUoS charging methodology has been in place since 2017 after the implementation of Project TransmiT
- Under Aurora's CP2030 TNUoS forecast, the **maximum difference** in TNUoS between regions in GB (North Scotland vs English Channel, see Appendix for mapping of TNUoS zones to Aurora's offshore wind regions) is expected to rise **from £29/kW in 2025 to £90/kW by 2040 (97% increase)**
- TNUoS in all Scottish regions** is expected to increase. Indicatively, North Scotland tariff is predicted to be **189% higher** in 2040 than 2025. Consequently, **Scottish regions are likely** to set the price for future CfDs.

2 TNUoS taskforce aims to improve TNUoS cost reflectivity and predictability

- The TNUoS task force, established by Ofgem and National Energy System Operator (NESO) in 2022, aims to identify defects in the current TNUoS charging methodology and develop reforms to solve current challenges
- The **current methodology**, developed primarily through Project TransmiT in 2012, is now **over a decade old**. Due to significant changes though, in particular renewable expansion, the methodology, including assumed generation and demand patterns may no longer be adequate
- Recognizing the challenges posed by the evolving energy landscape, Ofgem has published in September 2024 an open letter³ requesting NESO to explore solutions. In January 2025, another open letter⁴ was published, detailing how decision timelines will be approached. Multiple **proposals** are currently being considered for reforms, some of which are **discussed in detail in this study**

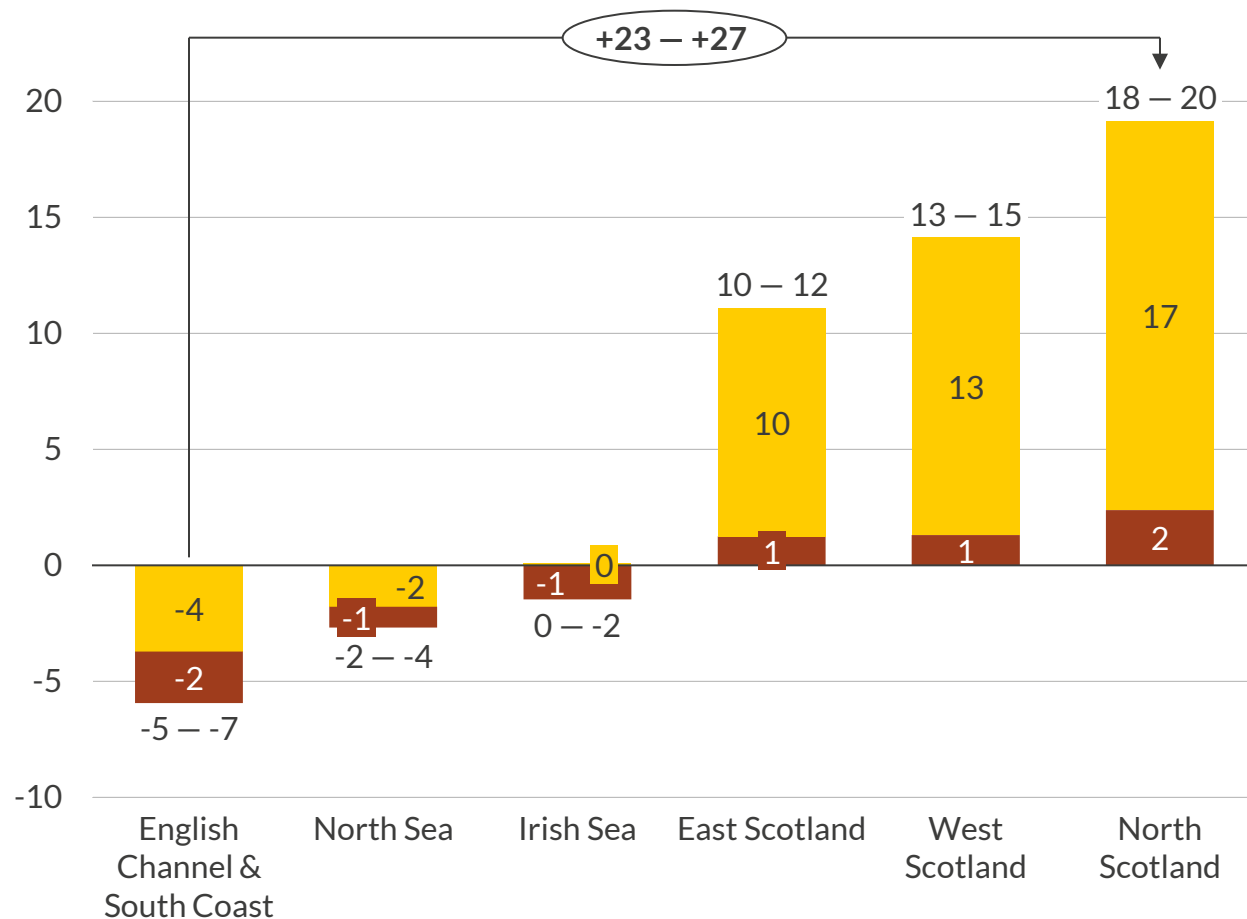
3 Divergence of TNUoS as a potential barrier to CP2030?

- Expansion of **offshore wind in Scotland** is considered **crucial** to reach the UK's CP2030 targets. This is reflected in major developments: the leasing of Scottish seabeds⁵ as well as the Scottish transmission grid capacity⁶. Instead of directing wind farm development to regions with the most renewable resource potential, **locational signals** in TNUoS are dis-incentivising siting of wind farms in Scotland
- This leads to **higher consumer costs in the CfD**. Consumers face the costs of the CfD scheme through **retail costs**. The Aurora CP 2030 scenario estimates that **2,300TWh⁷** of generation needs to be subsidised between 2028-2050 to achieve CP2030. Each £/MWh point increase on CfD strike price due to TNUoS divergence in Scotland thus costs **£2.3bn** over the period or **£100mn** per year

1) Average values for Aurora's offshore wind regions on calendar year basis, assuming average load factor of 51%. Years beyond the current National Grid 5-Year Forecast use Aurora's TNUoS forecast. Negative values = generators receive TNUoS. Scenario is based on Aurora CP2030; 3) [Ofgem Open Letter, 30 September 2024](#); 4) [Ofgem Open Letter, 31 January 2025](#); 5) 2022 Scotwind auction allocated Scottish seabeds for 25GW of wind generation; 6) NESO initiatives (HND, ASTI) are centred around bringing offshore wind generation in Scotland to centres of demand in South GB, see also [2023 FES](#), p. 172; 7) According to the capacity buildout on [slide 11](#) and assuming 15-year subsidy period; Source(s): Aurora Energy Research, NESO., Ofgem

TNUoS charges combined with network loss costs (TLM) lead to differences of up to £25/MWh in CfD bid prices of offshore wind farms across regions

Estimated Impact on Offshore Wind CfD Bid Price – 2025 Entry^{1,2}
£/MWh (real 2024 – as quoted in the next CfD auction)



1 Impact of just TNUoS differs by up to £21/MWh³ between regions

- TNUoS charges are a **key operational cost** during a wind farm's lifetime, which need to be accounted for in its bid price in a CfD auction
- Aurora has projected that the combined impact of TNUoS and TLM on CfD bids for offshore wind farms in North Scotland will be up to **£27/MWh** higher compared to those in the English Channel and South Coast. The wider TNUoS tariff alone could contribute approximately **£17/MWh** to CfD bids for wind farms in North Scotland vs **£-4/MWh** for wind farms in the English Channel & South Coast

2 Impact of charges for losses differs by up to £4/MWh between regions⁴

- Transmission Loss Multipliers (TLMs) are network charges which are incurred **to recover the costs of losses** on the electricity network
- Similar to TNUoS wider tariffs, they differ across regions
- Generators in the North of GB, which are further from demand centres, pay higher charges for losses than those in the South, where generators can even receive small payments instead of being charged for TLM
- Aurora estimates **TLMs increase CfD bids in the North by up to £2/MWh** compared to **£-2/MWh in the South**
- In the reminder of the analysis, we focus on the TNUoS wider tariff

■ CfD price (TNUoS Aurora CP2030 forecast) minus CfD price (no TNUoS) ■ CfD price (TNUoS Aurora CP2030 with varying TLM) minus CfD price (TNUoS Aurora CP2030 with constant TLM)

1) The projections are based on a 'CP2030 scenario' which has been developed by Aurora and does not represent the views of any of the individual parties, nor does it suggest that the parties will calculate the impact of TNUoS/TLMs on their CfD bids in the same way. Aurora does not state that this is their best or 'Central' view of how deployment/TNUoS/TLMs will evolve. TNUoS/TLM values presented in this report are aggregated across multiple zones and do not represent values for any individual zone/project; 2) The TLM assumption for constant TLM is 98%. The analysis is done for AR6 onward plants. CfD strike price is the price necessary to give NPV = 0, assuming a 15-year contract and 30-year lifetime. The 2025 entry year is shown as an illustration. The capacity added beyond AR6 is expected to be installed 2028 onwards; 3) Accounts for difference between North Scotland and South Coast for TNUoS only; 4) The assumptions on TLM can be found on slide 26; Source(s): Aurora Energy Research, NESO

I. Introduction

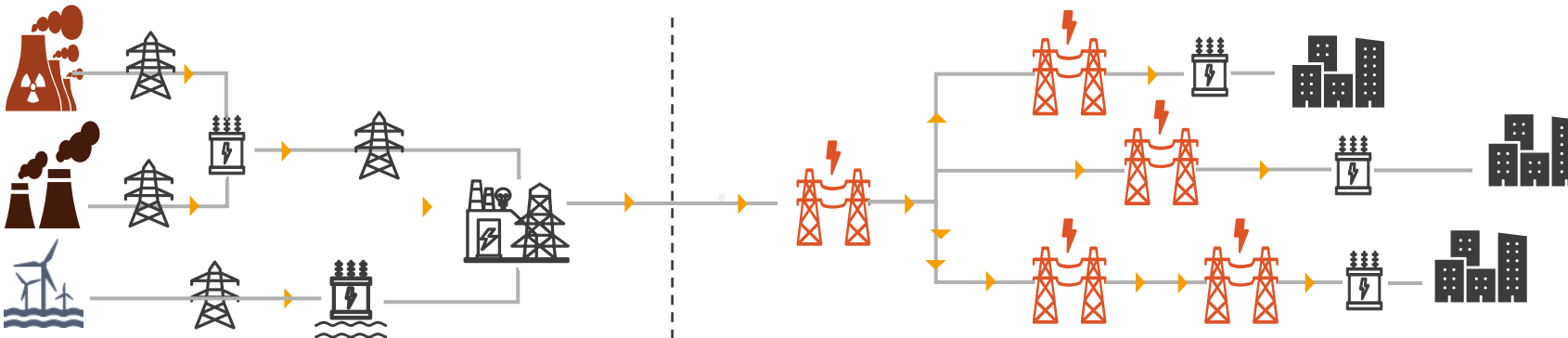
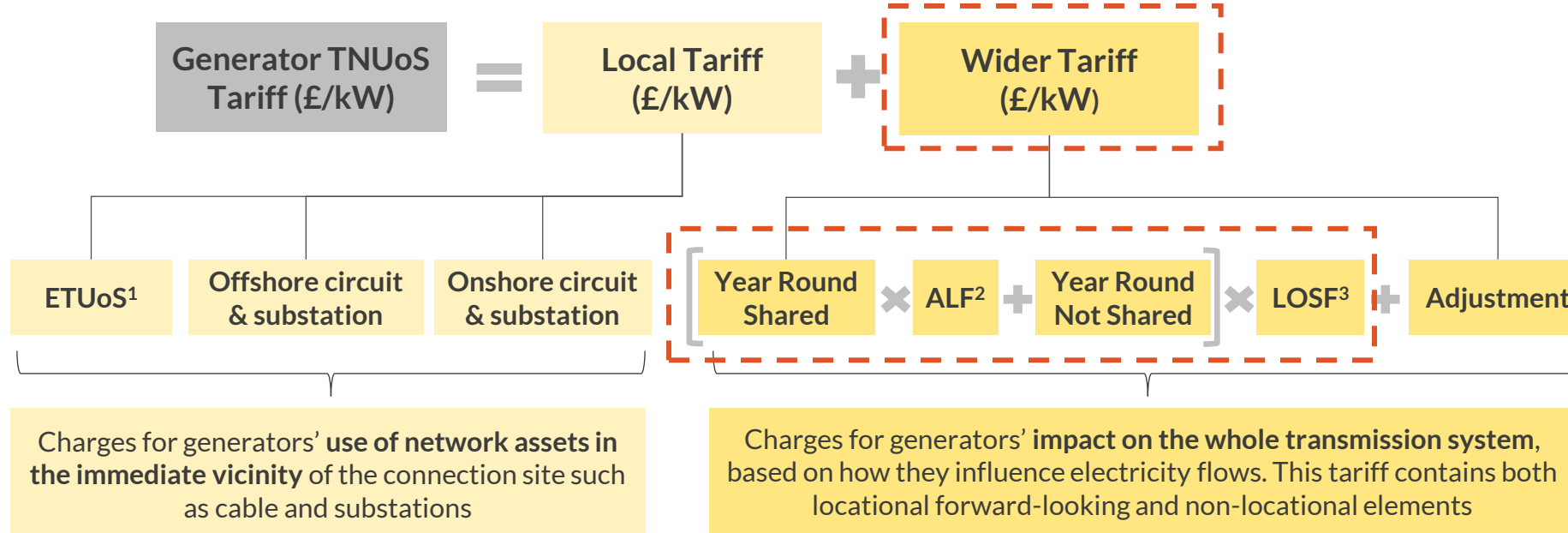
1. Current TNUoS direction
2. TNUoS reform proposals

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Currently, the total TNUoS charges for offshore wind is made up of the wider and local tariff, and is charged on a £/kW basis

Focus of this report



- The analysis in this report focuses all the Wider Tariff component and more specifically into the locational elements
- The proposals reviewed in the report are specific reforms to these charges and aim to reduce divergence between the North and South regions in the long term. This will make Scottish generation more competitive. More detail on the proposals in the next slide
- Under these proposals, the adjustment tariff calculation methodology remains unchanged. It is based on the maximum revenue recoverable from the Wider Tariff, which EU regulations set at an average of €2.50/MWh
- Consequently, under all these proposals, the total system costs recovered will stay the same and capped at €2.50/MWh

1) Embedded Transmission Use of System charges (ETUoS) only apply to offshore generators when they connect to the transmission network via a local distribution network; 2) Annual Load Factor; 3) Locational Onshore Security Factor: designed to quantify the additional redundancy that is built into the network to meet safety requirements. Currently set at 1.76.

Recognising the disadvantages of the wide divergence in TNUoS costs, multiple proposals on the reform of wider tariff charges are being considered

More details in Appendix

In this report, Aurora analyses the impact of some of these proposed reforms and its impact on the cost to consumers, comparing it to a baseline (status quo) scenario

1

Baseline

- Aurora's TNUoS forecasts between 2025-2050 based on **CP2030 Further Flexible Energy and Renewables Scenario**¹. Acts as a **reference scenario** to quantify the impact of TNUoS reforms

2

CMP 432²

- This proposal suggests that the current application of the **LOSF**³ in the NESO TNUoS tariff model results in **unnecessary additional network security capacity**, which does not align with the **SQSS**⁴ criteria that is used by transmission owners to plan for network additions. It is proposed that this factor be adjusted from **1.76 to 1**
- This factor functions as a scalar in the final TNUoS calculation and will have a **greater impact** on the **North and South** regions in absolute terms

CMP 444²

- This modification proposes single GB-wide cap and floor to TNUoS locational charges, offering more certainty to generators in the North, aiding investment decisions

3

Original Solution²

- Wider locational charges should be capped at the **97.5th and 2.5th percentiles** for all tariff elements and generation zones using the NESO 5-year view published in April 2024
- A cap provides clear security against potential future increases in the tariffs

4

WACM 1²

- WACM1 views the original CMP 444 solution as **not effective in terms of the floor price**; most southern generators are affected only post-2030
- In this proposal, cap and floor are adjusted to the **90th and 10th percentiles**

5

WACM 5²

- WACM 5 maintains the cap and floor concept but introduces a **maximum tariff range and a cap** to preserve locational signals in Northern GB
- Tariffs are calculated as usual, then scaled to stay within the range, with a final check to ensure the cap is obeyed

1) 50.6GW offshore wind by 2030 with 12GW deployment in Scotland; 2) More detail on the methodology and the impacts to locational charges can be found in the appendix; 3) Locational Onshore Security Factor; 4) Security and Quality of Supply Standard: These criteria are what Transmission Owners use to plan future network additions and should therefore align with the TNUoS model assumptions for cost reflectivity

Source(s): Aurora Energy Research, NESO

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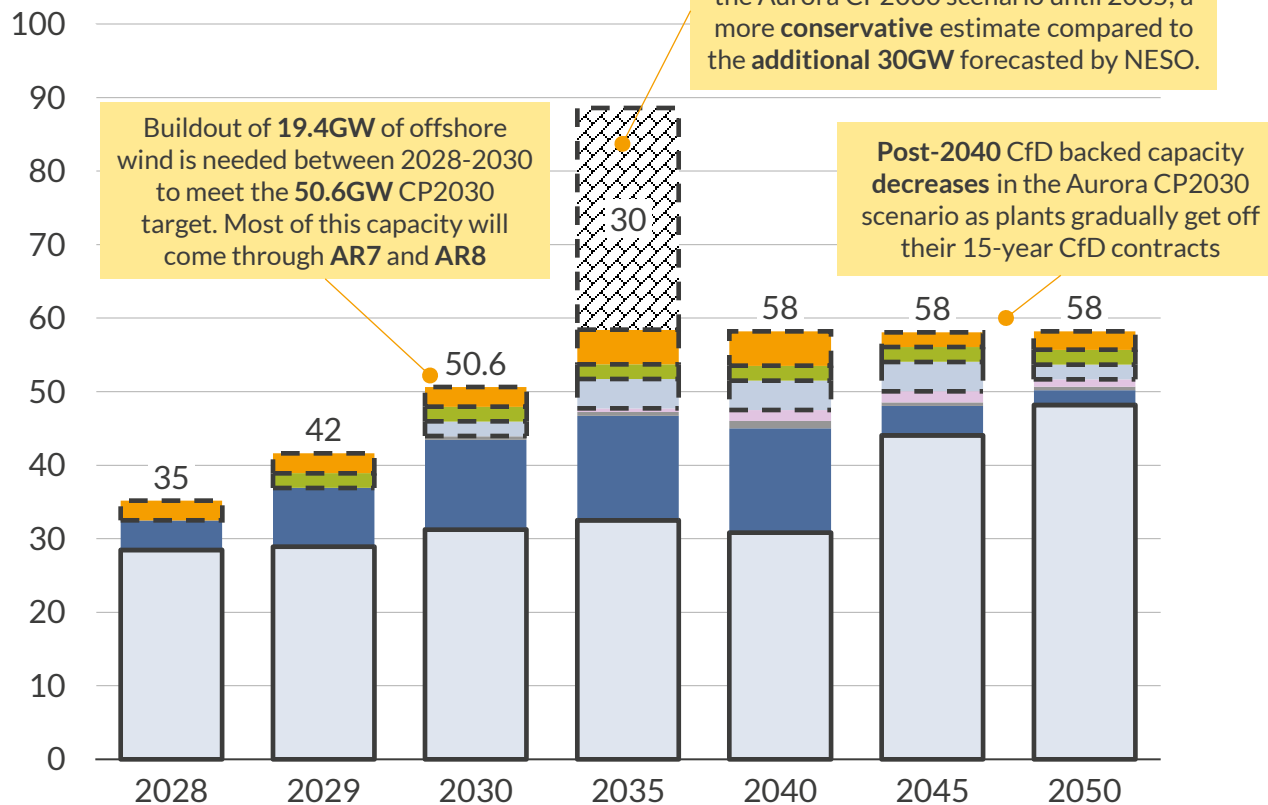
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The Aurora CP2030 scenario projects 50.6GW of offshore wind by 2030, aligning with NESO's forecast; but takes a more conservative approach post-2030

CfD-Backed Offshore Wind Capacity coming online post-AR6¹ GW



Wind farms in Scotland are required to meet CP2030

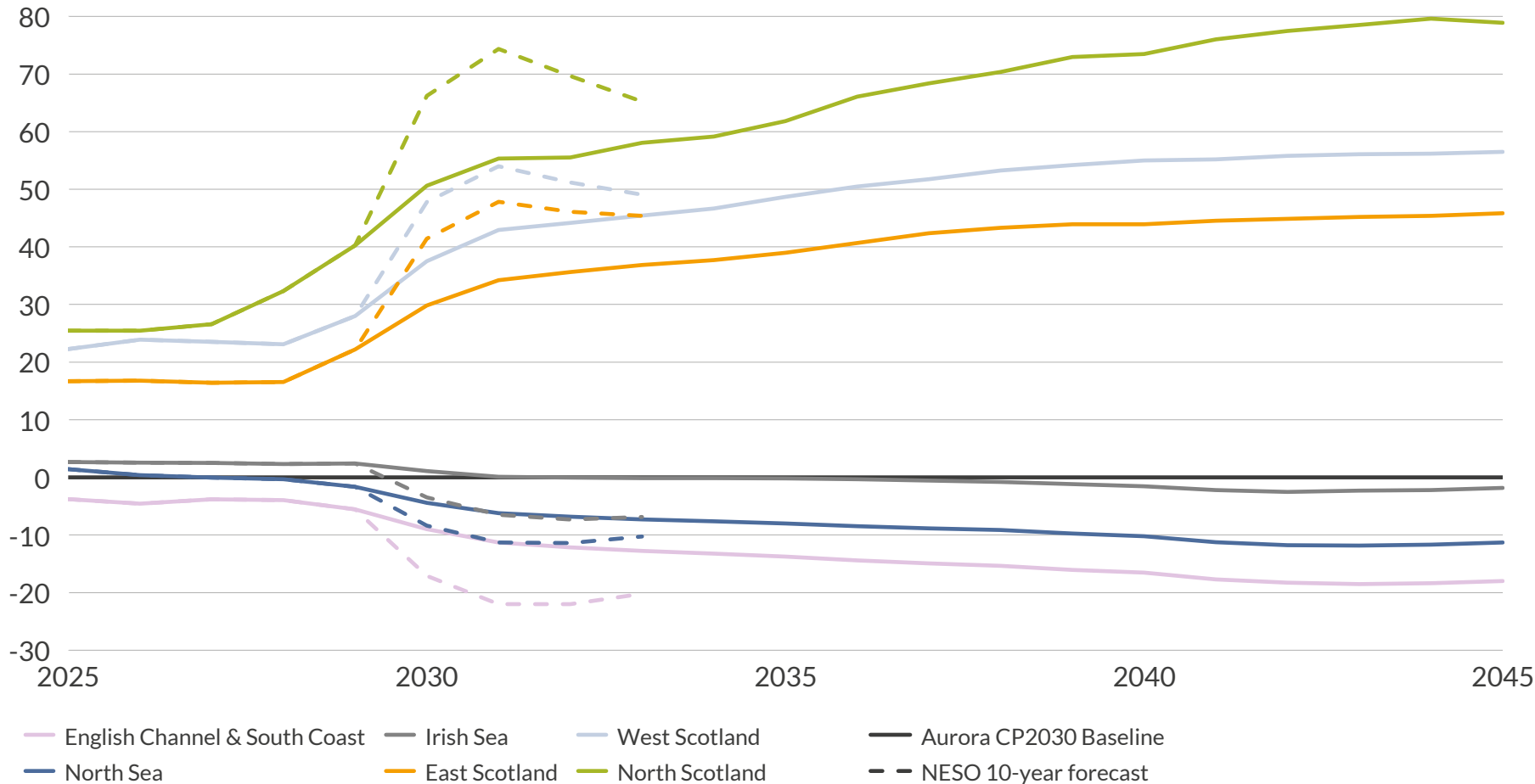
- Under the Aurora CP2030 scenario, Scotland is to have **12GW** of offshore wind capacity, contributing to a total of **50.6GW** across Great Britain by 2030. These assumptions align with NESO projections:
 - The majority of seabed leases for future offshore wind farms are located in Scotland³
 - Deployment of offshore wind farms solely in the North Sea, English Channel and Irish Sea is unlikely to be sufficient to meet the 50.6GW target
- In Aurora's CP2030 scenario, meeting the 50.6GW target requires an additional **19.4 GW** of new build capacity on top of existing and pre-allocation Round 7 capacity by 2030. Of these, **6.7GW** of capacity is expected to come from Scotland
- The Aurora CP2030 scenario falls short of the 2035 NESO target of 88.6GW, reaching only 58GW by 2035. The CP2030 target considers all leased seabed areas
- After 2040, total offshore wind capacity remains steady at 58GW⁴, with new farms replacing retiring ones. This aligns with the long-term of Aurora's Net Zero scenario⁴



1) In the Aurora CP2030 all capacity is assumed to be fixed bottom offshore wind; 2) Note that the government target is not legally binding and also includes added capacity without a CfD; 3) The Crown Estate Scotland's 2022 ScotWind auction allocated seabed leases for 25 GW of offshore wind; see [Crown Estate Scotland](#); 4) Only considering fixed-bottom offshore wind

Under the Aurora CP2030 scenario, the status-quo TNUoS charges fall short of the 10-year NESO forecast published in 2023

TNUoS Direction for 51% intermittent generator^{1,2}
£/kW/year (real 2023)



- The NESO 10-year forecast is on average 51% higher in 2030 compared to the Aurora CP2030 scenario for Scottish regions
- Southern regions show more negative outcomes due to high charges recovered from the North being redistributed as benefits through the adjustment tariff
- The NESO 10-year forecast, released two years ago, is considered overly aggressive, as evidenced by its misalignment with the latest 5-year forecast, which Aurora CP2030 factors in for 2029/30
- **Impact on Consumer Savings:** If the NESO 10-year forecast materializes, this analysis would be a conservative estimate, as greater divergence in the forecast could increase the consumer savings of different reform proposals ([slide 19](#))

1) The Aurora CP2030 Baseline (with underlying capacity shown on [slide 11](#)) reflects 2030 government capacity targets (NESO Further Flex + Renewables) and uses a top-down approach to achieve them, based on publicly available information such as the Renewable Energy Planning Database and the Transmission Entry Capacity Register; 2) The 10-year TNUoS forecast includes the 5-year forecast released in 2024 from 2025/26 to 2029/30 and the 10-year forecast from 2030/31 to 2033/34. TNUoS years are converted to calendar year average. The Aurora CP2030 also takes into account the 5-year forecast released in 2024

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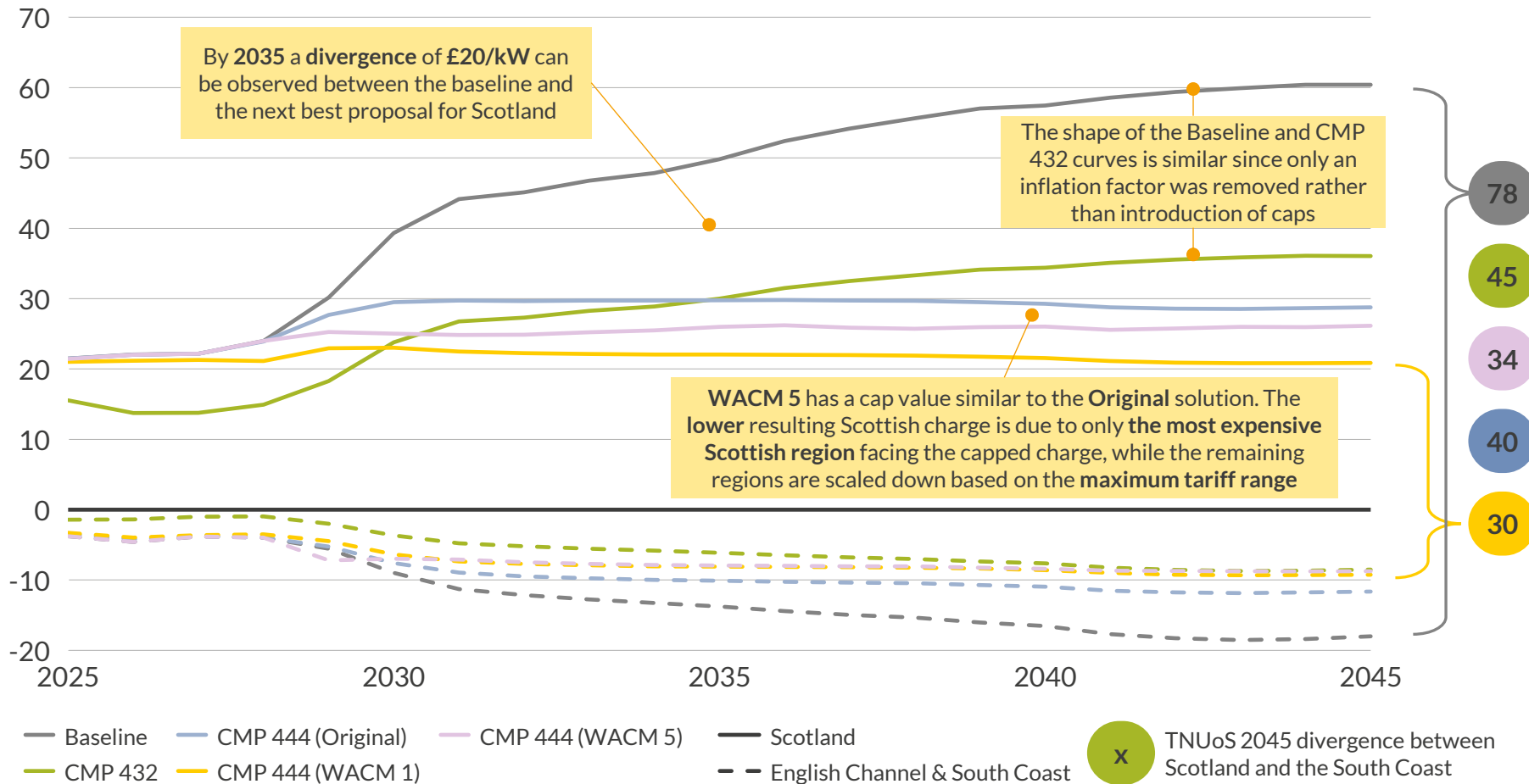
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The TNUoS reforms will reduce the divergence of network charges across regions in the North and the South throughout the forecast

TNUoS Direction for 51% intermittent generator, Scotland¹ vs English Channel & South Coast
£/kW/year (real 2023)

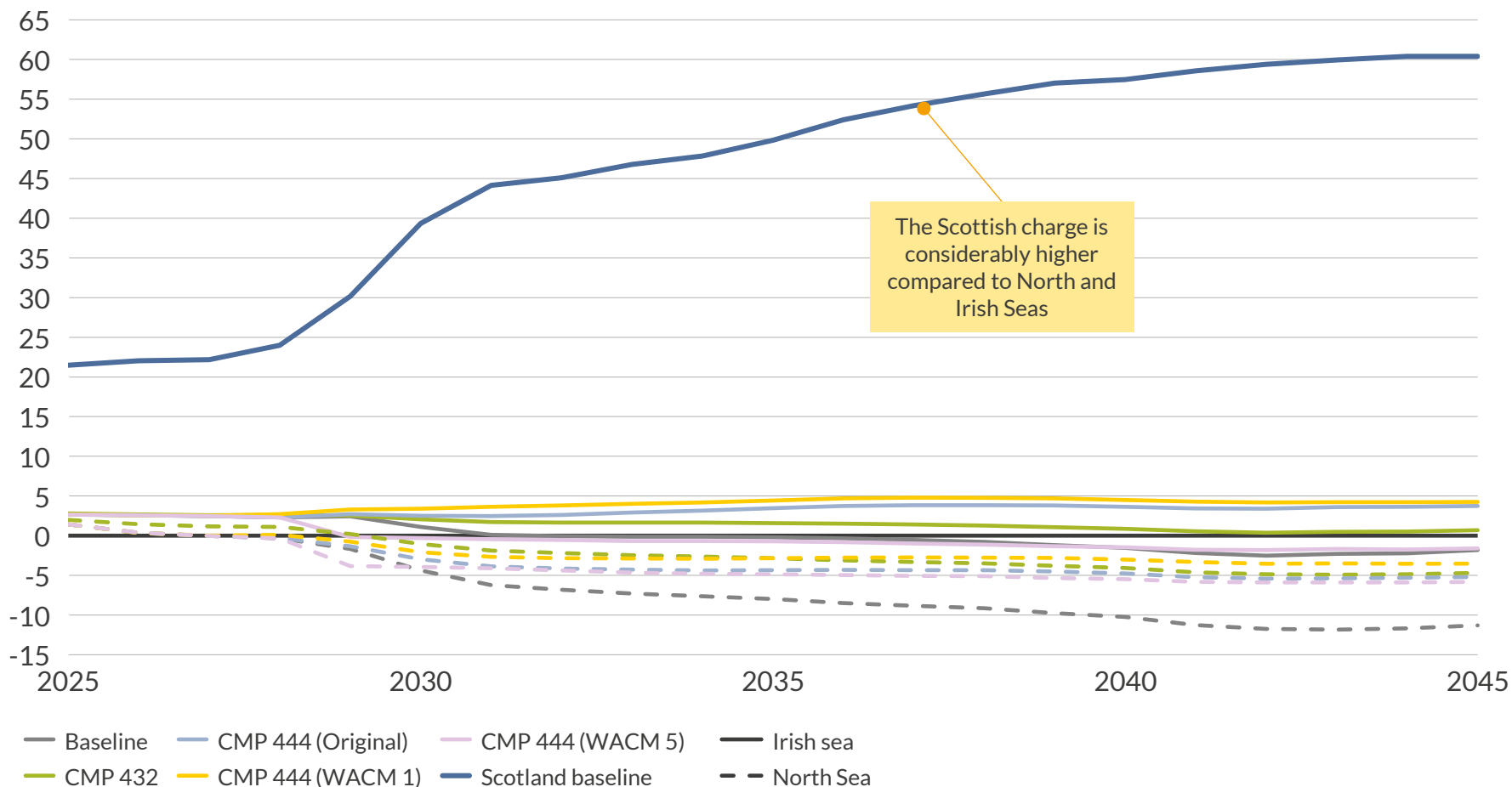


- The **Baseline** scenario shows the greatest divergence in TNUoS between the North and South, as the aggressive buildout of offshore wind in Scotland further increases the generation vs demand imbalance of the region
- Under the **CMP 444** proposals, Scotland reaches a peak charge in the 2030s where the caps then prevent further increases
 - **WACM 1:** sees the lowest divergence at £30/kW due to the tighter cap and floor
 - **Original:** sees the highest divergence out of CMP 444 due to the higher cap and floor
 - **WACM 5:** Lies in between the other CMP 444 proposals as the maximum tariff range adjustment ensures that only the most expensive Scottish region will face the cap
- Under the **CMP 432** proposal the divergence is higher than all CMP 444 iterations at **£45/kW** in 2045

1) Average of North, West and East Scotland; 2) More detail on the adjustment tariff can be found in the appendix

For intermittent generators in the North and Irish Seas, the change is lower and is a result of the adjustment tariff providing less benefit

TNUoS Direction for 51% intermittent generator, North and Irish Sea
£/kW/year (real 2023)



1) More detail on the adjustment tariff can be found in the appendix

- The locational element of TNUoS charges in the North and Irish Seas are closer to zero when compared to Scotland. These zones are located in between the North and South, where the demand and generation are more in balance
- The North Sea acts as a competitor to Scottish wind, both due to favourable TNUoS and high load factors. The NESO CP2030 Scenario forecasts 32GW to come online in the North Sea compared to 12GW in Scotland by 2030
- The **Baseline** fares the best for the North Sea due to the highly negative adjustment tariff¹. The different proposals succeed in leveling the competition with Scotland
- The **CMP 444 (WACM 5)** fares the best out of the different proposals for these middle regions as it preserves the locational signals of the zones, preventing increases in the locational charges

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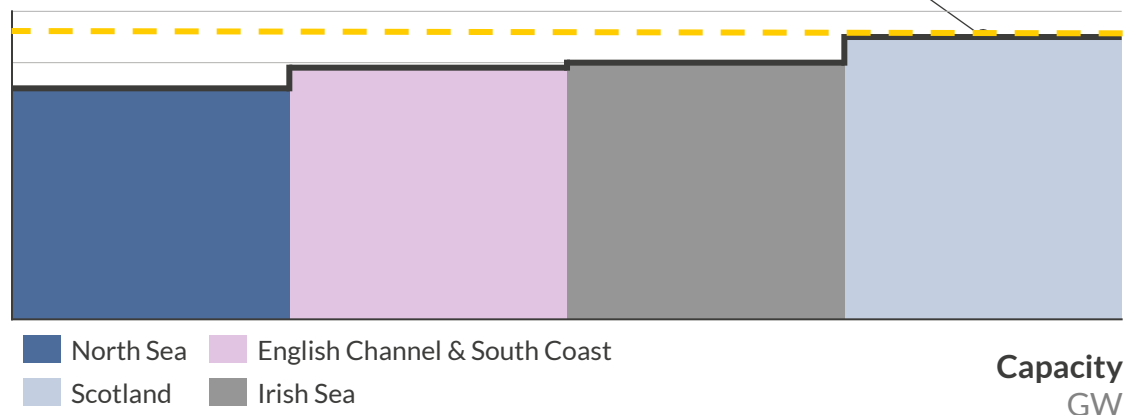
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Wind farms in Scotland could set the CfD strike price for the majority of subsidised offshore wind capacity added in 2025–2050

Illustrative CfD Strike Price Bid Stack

Strike Price Bid
£/MWh

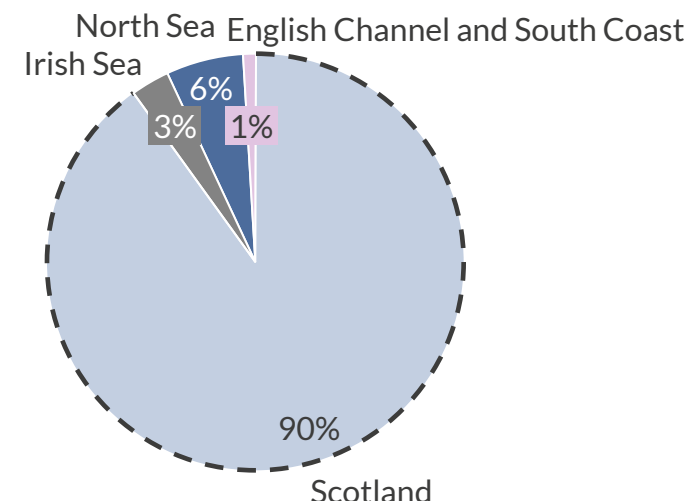
Strike price set by Scotland, assuming a Scottish asset participates in the auction



1 In CfD auctions the marginal generator sets the price

- CfD auctions are run pay as clear, i.e. the strike price is set by the most expensive bid accepted¹ (**marginal generator**, above)
- Bid prices of generators will depend on the type of generation (AR5 Pot 1—offshore wind, onshore wind, solar, etc.) as well as the location
- **Scottish offshore** wind farms are expected to have **CfD bid prices** up to **22% higher** than offshore wind farms in North Sea, strongly driven by higher TNUoS charges
- A further key driver of differences in CfD bids are wind load factors varying across regions³

Total New Build CfD-Backed Offshore Wind Capacity by Strike Price Setting Region in Aurora CP2030²



2 Scottish wind farms setting wind CfD prices due to higher costs

- Due to their higher bid prices, **Scottish wind farms** could **determine the CfD strike price** for a large share of the added CfD-backed offshore wind capacity
- Based on Aurora's buildout of offshore wind across regions, **Scottish wind farms** could **set the price for 90% of offshore wind** capacity added in 2028–2050⁴

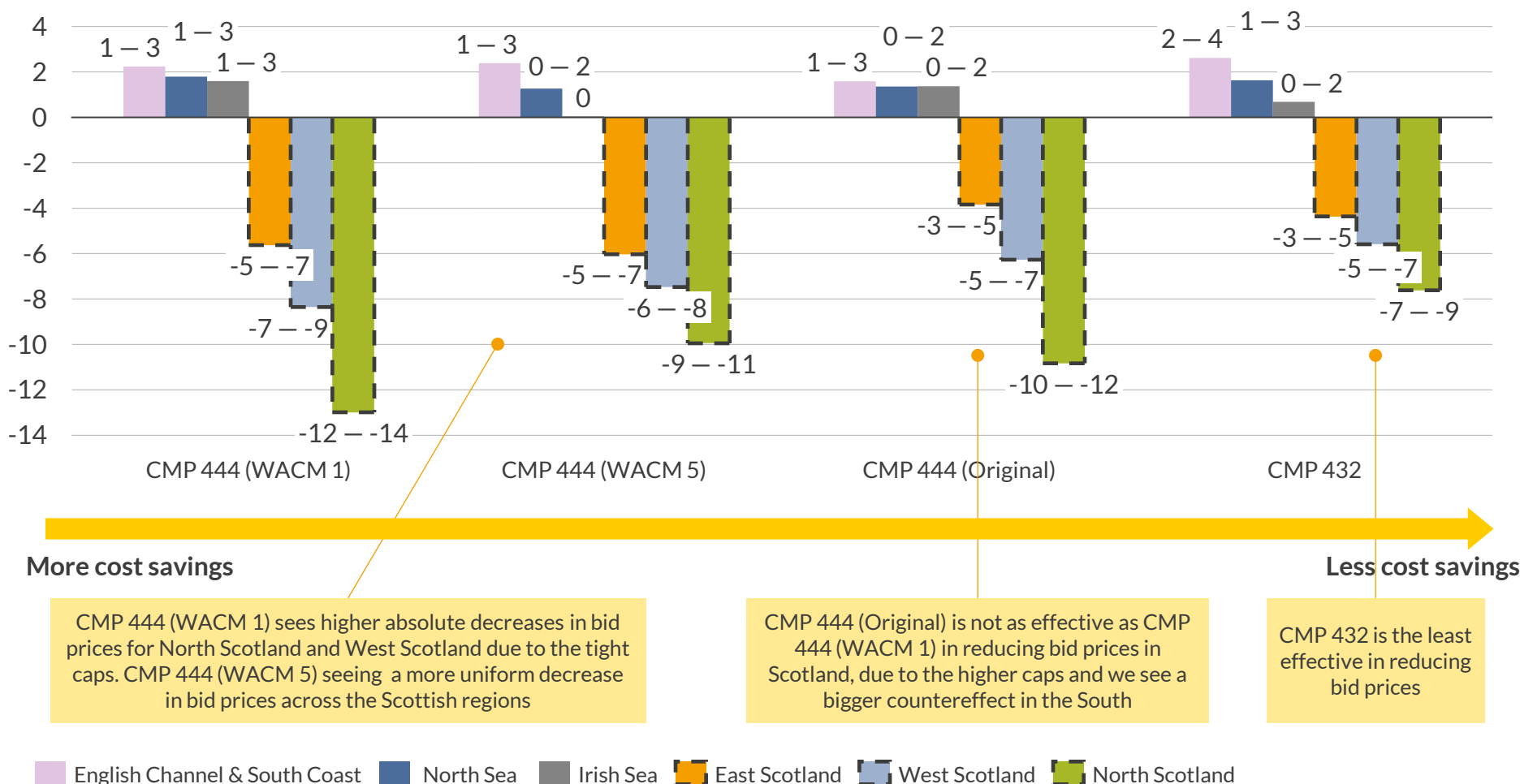
Onshore wind will see the same effect

- This analysis focuses on offshore wind, but **onshore wind** is also expected to be concentrated in Scotland due to **higher load factors and available land**. Given Scotland's higher TNUoS charges, Scottish onshore wind farms are likely to **set the price** for most new onshore capacity. The CP2030 scenario forecasts 27.3GW of onshore wind in Great Britain by 2030, with 20GW located in Scotland.

1) Up to when the target capacity is reached 2) Assuming annual CfD auctions; subsidised capacity beyond Allocation Round 6. 3) The load factors for regions can be found on [slide 26](#) in the Appendix; 4) Assuming that in each year, among the regions in which offshore wind generation is added, the most expensive generator sets the price. Capacity buildout assumptions can be found on [slide 11](#)

Cost savings to consumers is driven by the decrease in Scottish CfD bids which will be setting the strike price of future auctions

Average change in CfD Bids¹ due to TNUoS reforms (2025-2050)
£/MWh (real 2023)



CMP 444 (WACM 1) sees higher absolute decreases in bid prices for North Scotland and West Scotland due to the tight caps. CMP 444 (WACM 5) seeing a more uniform decrease in bid prices across the Scottish regions

CMP 444 (Original) is not as effective as CMP 444 (WACM 1) in reducing bid prices in Scotland, due to the higher caps and we see a bigger countereffect in the South

CMP 432 is the least effective in reducing bid prices

Impact on bid price

North increases, South decreases

- Aurora estimates that the TNUoS reforms will decrease CfD bid prices of Scottish wind farms by **3 up to 14£/MWh** across the forecast
- In the South, TNUoS will increase relative to the baseline, increasing bid prices by **0 up to 3 £/MWh**

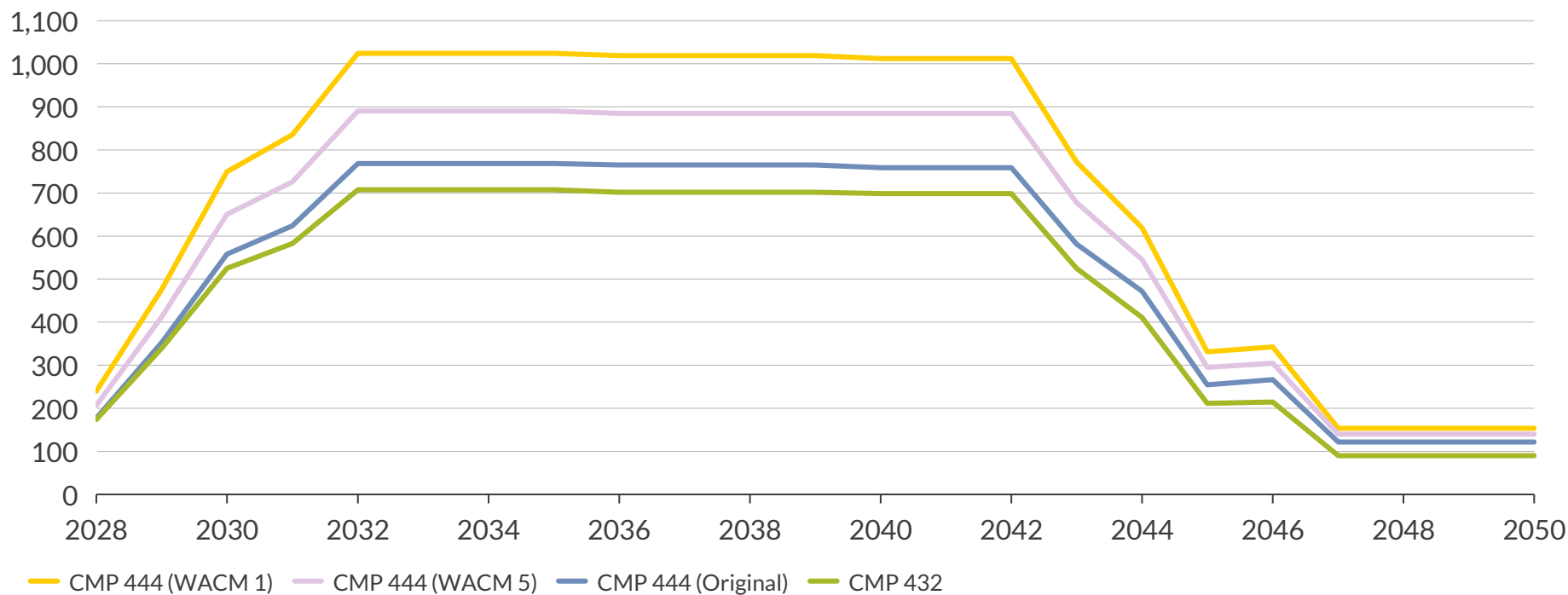
Changes in are most impactful in Scotland

- Scottish wind farms are expected to set the price** for the majority of added offshore capacity ([slide 17](#))
- Therefore, increased TNUoS in Scotland dominates the overall impact on consumer costs

1) Comparing CfD bid price in the TNUoS reform scenarios against Aurora's baseline scenario, where the only change is the TNUoS costs. CfD bid price is calculated as the bid price is that necessary to give NPV = 0, assuming a 15-year contract and 30-year lifetime. The capacity added is expected to be installed 2028 onwards

Proposed TNUoS reforms can lead to up to £16.2bn of savings in consumer costs if CMP 444 (WACM 1) were to be implemented

Estimated Savings for Consumer Costs for CfD-Backed Offshore Wind Generation to the Baseline Scenario in CP2030¹
£mn/y (real 2023)



Percentage decrease in TNUoS charges in Scotland²

59%

51%

45%

40%

Cumulative Savings (2028-2050)

£16.2bn

£14.1bn

£12.2bn

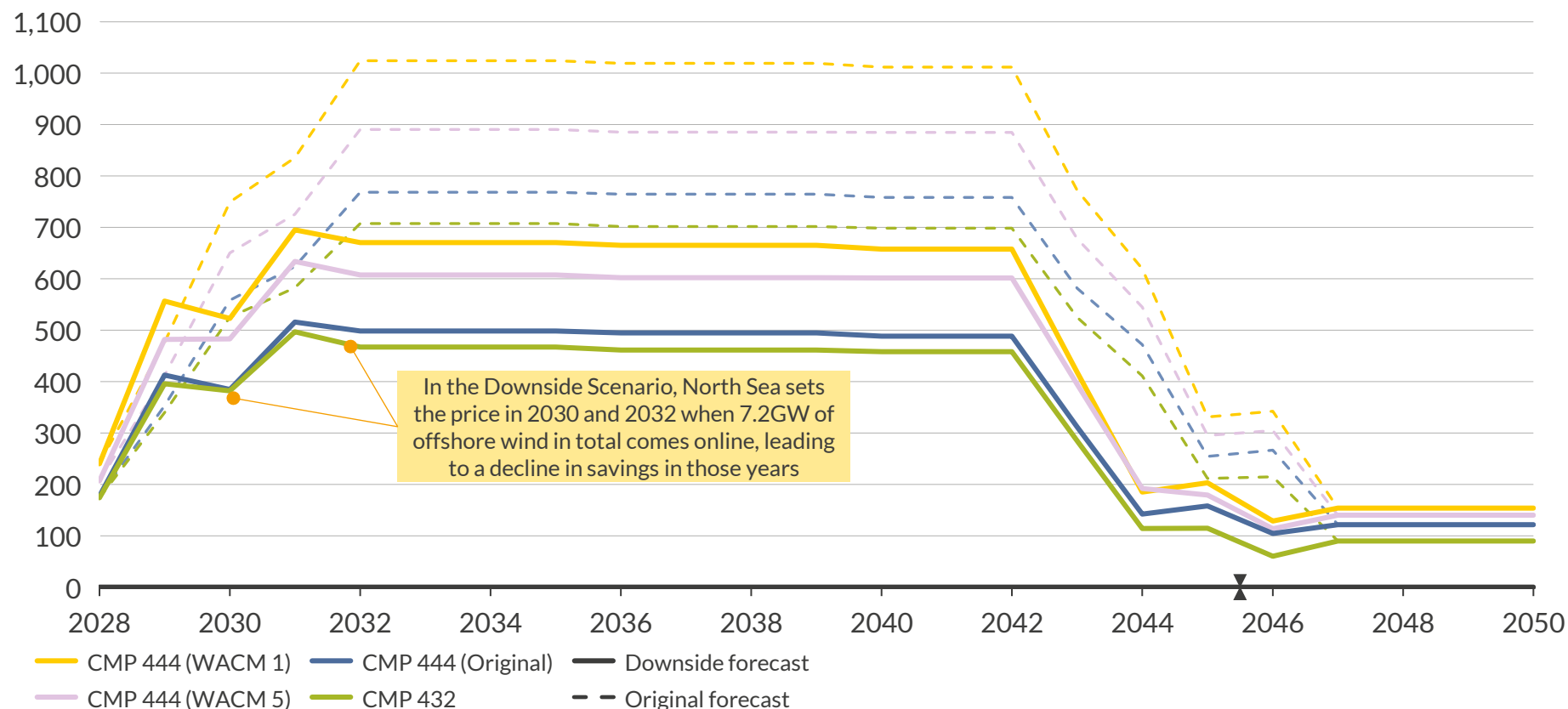
£11.1bn

- With Scottish Plants price setting, Aurora expects that a decrease in TNUoS costs leads to direct consumer cost savings
- All proposed TNUoS reforms lead to cost savings to consumers to varying degree. The cost savings correlate broadly with reduction in TNUoS charges faced by Scottish generators
- CMP 444 (WACM 1) reduces TNUoS charges in Scotland the most (by 59%) while CMP 432 reduces it the least (40%)
- As a result, CMP 444 (WACM 1) sees the most cost savings, averaging £704 mn cost savings per year in 2028-2050, while CMP 432 sees the least impact, averaging £482mn per year
- CMP 444 (WACM 5) and CMP 444 (Original) are in between, averaging £615mn and £530mn cost savings per year respectively

1) Compares costs of CfD backed offshore wind generation from 2028 onwards in the alternative TNUoS scenarios compared to the baseline, Aurora's CP 2030TNUoS forecast. CfD contracts assumed to last 15 years. CP030 Assumes the same CfD-backed generation (in TWh) regardless of TNUoS charging regimes. 2) 2025-2025 average

Considering a Downside Scenario, TNUoS reforms could still deliver £7.5bn to £10.9bn in consumer cost savings

Estimated Consumer Cost Savings from CfD-Backed Offshore Wind Generation in the CP2030 – Downside Scenario¹
£mn/y (real 2023)



Cumulative Savings
(2025–2050)

£10.9bn

£9.9bn

£8.1bn

£7.5bn

- In Aurora's CP2030 scenario, build out in Scotland is in line with NESO's target of 12GW with annual additions through 2028-2032. In these years, Scotland is assumed to set the price in the annual auction
- In a less likely downside scenario, Scottish assets do not participate in the 2030 and 2032 auctions leading to the Irish Sea and English Channel setting the price
- Because the TNUoS reform proposals primarily affect Scottish bid prices, consumer savings are lower in this scenario
- Aurora estimates that there will still be cost savings of £325-£473mn per year (2028-2050) under a downside case

1) Compares costs of CfD backed offshore wind generation from 2028 onwards in the alternative TNUoS scenarios compared to the baseline, Aurora's status quo TNUoS forecast. CfD contracts assumed to last 15 years. CP2030 Assumes the same CfD-backed generation (in TWh) regardless of TNUoS charging regimes.

I. Introduction

II. Results of Aurora's analysis

III. Appendix

Key Assumptions for calculation of TNUoS directions under different TNUoS proposals

- The starting point of the TNUoS analysis is the Aurora Baseline TNUoS wider tariff which includes projections for all 27 TNUoS zones for:



- Under each TNUoS proposal the locational charges are adjusted as follows

Proposal	Legal text adaptation summary	How it works
CMP 432	<ul style="list-style-type: none"> ▪ LOSF adjusted from 1.76 to 1 	<ul style="list-style-type: none"> ▪ Aurora Baseline locational tariffs divided by 1.76 across years
CMP 444 (Original)	Cap and Floor added: <ul style="list-style-type: none"> ▪ Cap: 9.53, 26.91, 27.69 (PS, YRS, YRNS), nominal values for 2025, units £/kW ▪ Floor: -2.95, -8.83, -6.85 (PS, YRS, YRNS), nominal values for 2025, units £/kW 	<ul style="list-style-type: none"> ▪ Locational tariffs cannot exceed the cap or become lower than the floor
CMP 444 (WACM 1)	Cap and Floor added: <ul style="list-style-type: none"> ▪ Cap: 4.40, 21.47, 19.60 (PS, YRS, YRNS), nominal values for 2025, units £/kW ▪ Floor: -1.32, -6.85, -0.01 (PS, YRS, YRNS), nominal values for 2025, units £/kW 	<ul style="list-style-type: none"> ▪ Locational tariffs cannot exceed the cap or become lower than the floor. WACM 1 proposal introduces lower caps and floor to the original solution
CMP 444 (WACM5)	Tariff Cap and Maximum Tariff Range added: <ul style="list-style-type: none"> ▪ TC: 9.72, 27.82, 27.87 (PS, YRS, YRNS), nominal values for 2025, units £/kW ▪ MTR: 14.31, 36.23, 36.93 (PS, YRS, YRNS), nominal values for 2025, units £/kW 	<ul style="list-style-type: none"> ▪ If the Aurora Baseline locational tariff range (Most expensive – least expensive zone) exceeds the maximum allowed, tariffs in all zones are scaled down using a multiplier until they fit within the range ▪ If any zone's tariff still exceeds the cap, a uniform reduction is applied across all zones until the tariff falls below the cap

- Under these proposals, the adjustment tariff calculation methodology remains unchanged. It is based on the maximum revenue recoverable from the Wider Tariff, which EU regulations set at an average of €2.50/MWh. This is in-line with the NESO methodology.

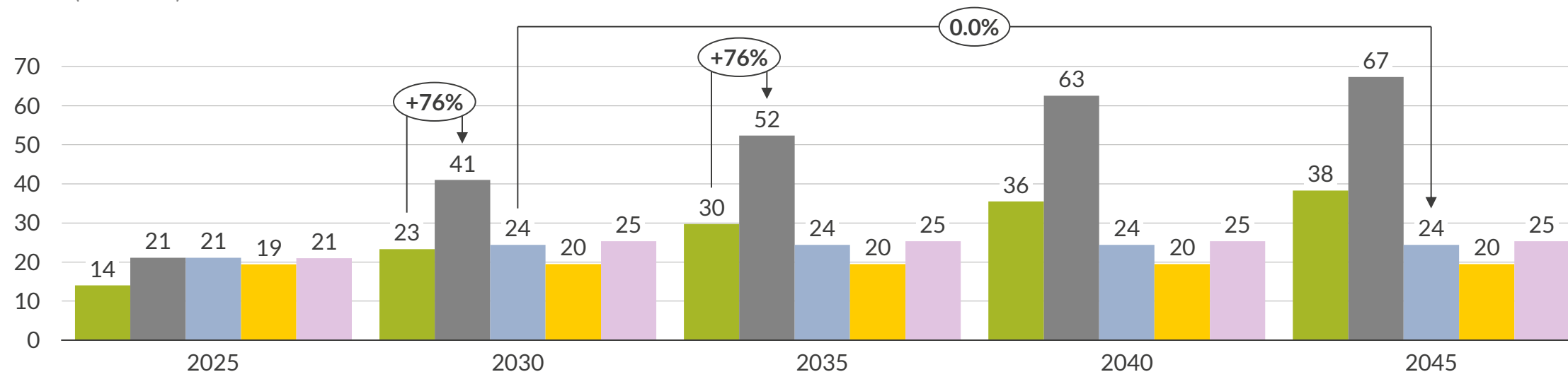
1) Average load factors for the period 2025 to 2050. 2) Average transmission loss multiplier for the period 2025-2050

TNUoS tariff calculation example for North Scotland

This slide focuses on the Year-Round Shared Tariff for North Scotland. The same methodology has been applied across all TNUoS regions and locational tariffs

Year-Round Shared Tariff under each Scenario for North Scotland (TNUoS Zone 1)

£/kW (real 2023)



CMP 432

- The is direct relationship due to the 1.76 factor change. Baseline values are 76% higher than CMP 432 across the forecast

CMP 444 (Original)

- North Scotland is the most expensive TNUoS zone. By 2030 the tariff cap (£24.4kW in real 2023) is in effect until the end of forecast

CMP 444 (WACM 1)

- The tighter cap (£19.5/kW in real 2023) is still hit by 2030 in North Scotland. The charge thus stays constant until 2045

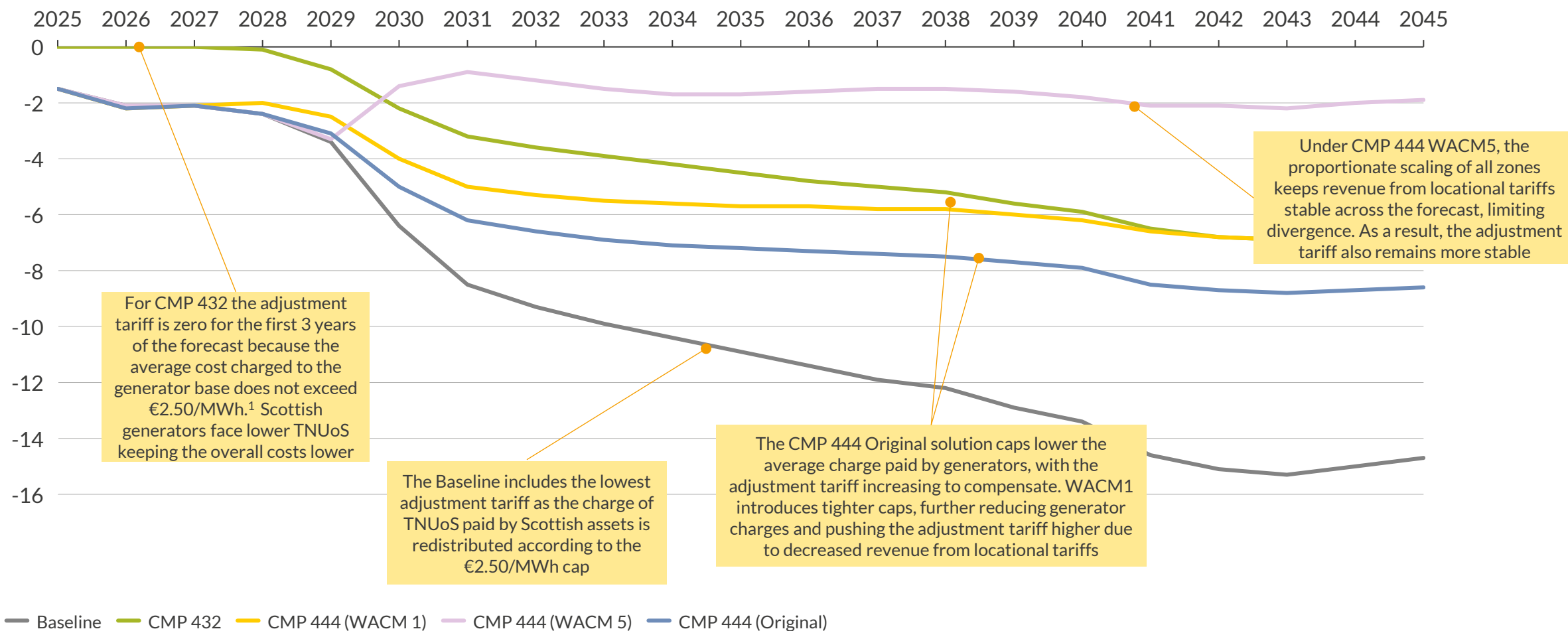
CMP 444 (WACM5)

- For WACM5 the tariff Cap is hit only by North Scotland in the Year Round Shared Tariff
- Charge is capped £25.3/kW (in real 2023) 2030 onwards

■ CMP432
 ■ Baseline
 ■ CMP 444 (Original)
 ■ CMP 444 (WACM 1)
 ■ CMP 444 (WACM5)

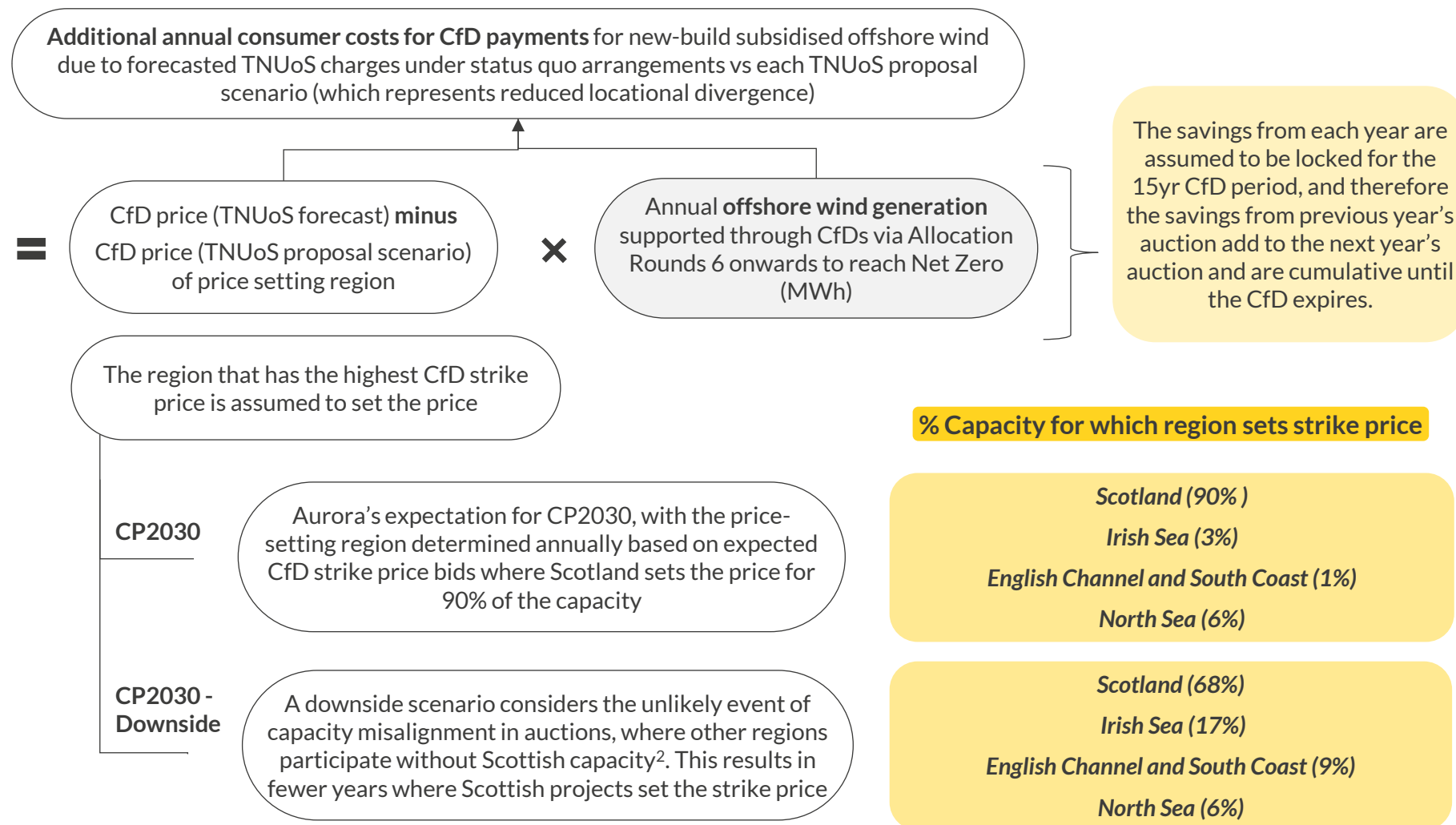
Adjustment tariffs are charged on the total generator base and a higher charge implies a fairer distribution of charges

Adjustment tariff under each scenario
£/kW (real 2023)



1) After accounting for the error margin.

Aurora has analysed the impact of increasingly locationally-divergent TNUoS charges on consumer costs relating to CfD payments



- Consumer cost changes would be driven by changes to CfD clearing prices as a result of changes to TNUoS charges relative to each proposal scenario
- The degree of change in CfD prices depends on the location of the offshore wind farm whose bid sets future clearing prices.
- Aurora has analysed a CP2030 scenario and a CP2030 – Downside scenario to provide a range of cost saving outcomes using two different cases of price-setting regions
- In each of these cases, the impact of proposed TNUoS vs baseline TNUoS charges on CfD strike prices is calculated, where the strike price is the bid needed to achieve NPV = 0, assuming a 30-year lifetime

1) TNUoS impact is calculated based on strike prices for entry years 2028–2045. Strike prices are calculated for each entry year; 2) The same total capacity is assumed to come online by 2030, with regional capacities shifting the years of delivery

Key Assumptions for cost to consumer analysis

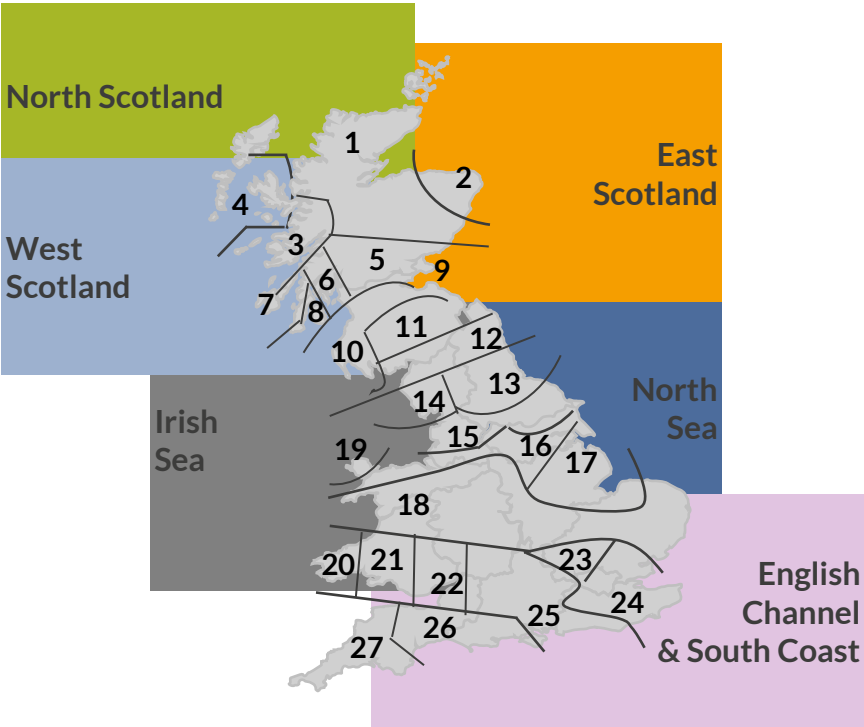
- Based on the TNUoS zone mapping, we aggregate the wider tariffs into the 6 regions analysed in the report. The mapping is shown on [slide 27](#).
- The Load factor used to calculate the tariff is assumed constant for all regions at 51%.
- Scottish regions are averaged in the price-setting analysis to reduce uncertainty about the timing of wind farm construction in specific areas. Consumer savings, when 'Scotland' is the price-setting region, represent the average savings across all three Scottish regions.
- The strike price calculations where we set NPV=0 assume the same CAPEX and OPEX for all regions, while we assume region specific load factors¹ and TLMs² to calculate revenues.
- The percentage of capacity that is brought online by the price setting region in the Downside scenario reflects a case where capacity misalignment in auctions exists and other regions participate for more years without Scottish capacity
- The savings for consumers assumes a 15-year CfD, therefore, savings from a specific auction will be locked in for the period of that CfD for the generation brought online in that auction.

Region	Load Factor	Transmission Loss Multiplier ²
North Sea	52.3%	0.989
Irish Sea	48.8%	0.994
English Channel & South Coast	47.5%	1.001
West Scotland	54.1%	0.969
North Scotland	54.2%	0.960
East Scotland	54.5%	0.969

1) Average load factors for the period 2025 to 2050; 2) Average transmission loss multiplier for the period 2025-2050. TLM assumptions are based on the Aurora's fundamental forecast of delivering TLM as of April 2024. Aurora has not updated the TLM assumptions for April 2025

Mapping TNUoS zones to Aurora offshore wind regions

Zone	Aurora wind region	Zone	Aurora wind region
1	North Scotland	17	North Sea
2	East Scotland	18	North Sea
3	West Scotland	19	Irish Sea
4	West Scotland	20	n/a
5	East Scotland	21	n/a
6	n/a	22	n/a
7	West Scotland	23	n/a
8	n/a	24	English Channel & South Coast
9	East Scotland	25	English Channel & South Coast
10	West Scotland	26	English Channel & South Coast
11	East Scotland	27	English Channel & South Coast
12	North Sea		
13	North Sea		
14	Irish Sea		
15	North Sea		
16	Irish Sea		



- TNUoS zones were mapped to Aurora’s offshore wind regions by assessing the location of existing offshore wind farms and their corresponding onshore substation, as published by NESO
- The TNUoS charges for each zone were calculated using average GB fleetwide Aurora modelled load factors. A regional average charge was then determined
- Multiple regions are marked as not applicable as they do not correspond to any of Aurora’s offshore wind regions due to being mostly land-locked
- The TNUoS charges in these regions were hence not used to calculate regional averages

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