

# The cost of locational signals in network charges to the consumer

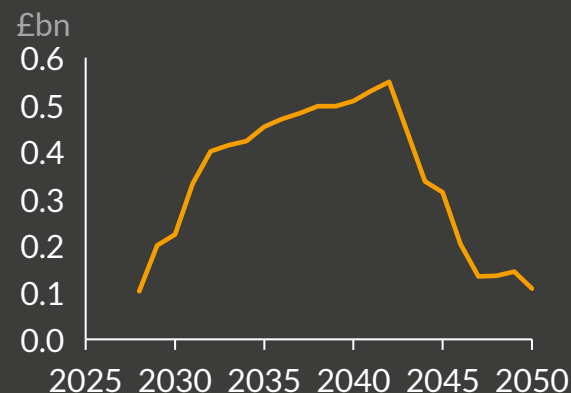
Commissioned by Ocean Winds

October 2024



# Executive Summary

Additional costs to the consumer for CfD-backed offshore wind generation over 2025–2050 due to increase of network fees since 2017



Cumulative Additional Costs, 2025–2050

**£7.9bn**

- The **rise of Transmission Network Use of System (TNUoS)** charges in Scotland compared to 2017 levels leads to **£7.9bn of additional cost** of CfD-backed offshore wind generation **to consumers** cumulatively in 2025–2050<sup>1</sup> in the Central case of our analysis
- There is an urgent need to review TNUoS charging arrangements to ensure they are not slowing down needed development of renewable electricity and in order to minimise costs to consumers
- 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 (GB)
- This report assesses the impact of this divergence on consumer costs focusing on offshore wind<sup>1</sup>
- Based on Aurora's forecast of TNUoS charges, together with costs for network losses (TLM), TNUoS charges lead to a **strike price differential of up to £20/MWh** for offshore wind generation between the North and South of GB in 2025. This corresponds to a total impact of (wider) TNUoS charges of **up to £12/MWh** on CfD bids in Scotland and of **£14/MWh of TNUoS** combined with the cost of **network losses**, compared to negative TNUoS and network losses cost of up to **£5/MWh** in the South of GB ([slide 6](#))
- Rising TNUoS since 2017, when the current charging methodology was introduced, may cause an increase of bids of **Scottish wind farms** for CfD contracts from 2025 onwards by **£3–8/MWh** (adjusted for inflation) ([slide 11](#))
- Scottish wind farms could set the price for at least **80%** of CfD backed offshore wind capacity added up to 2050 ([slide 9](#))
- The **rise of TNUoS** in Scotland compared to 2017 levels leads to an increase of the annual costs of CfD-backed offshore wind generation to consumers **by £340m on average** and **up to £550m** in 2025–2050 in the Central case of our analysis. This corresponds to **£7.9bn additional cost** cumulatively in 2025–2050 ([slide 10](#))
- A large share of these additional costs will be due to wind farms in the South of GB receiving a strike price set by wind farms in Scotland ("TNUoS uplift")
- Development of Scottish offshore wind farms is considered crucial to reach the UK's decarbonisation goals
- Locational signals of TNUoS disincentivising siting of wind farms in Scotland thus could be mis-aligned with UK decarbonisation goals and projected buildout of offshore wind

<sup>1</sup> 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. For onshore wind is expected to be largely concentrated in Scotland. So the same trend would apply to a larger volume of CfD backed generation (onshore + offshore wind).

## I. Introduction

## II. Results of Aurora's analysis

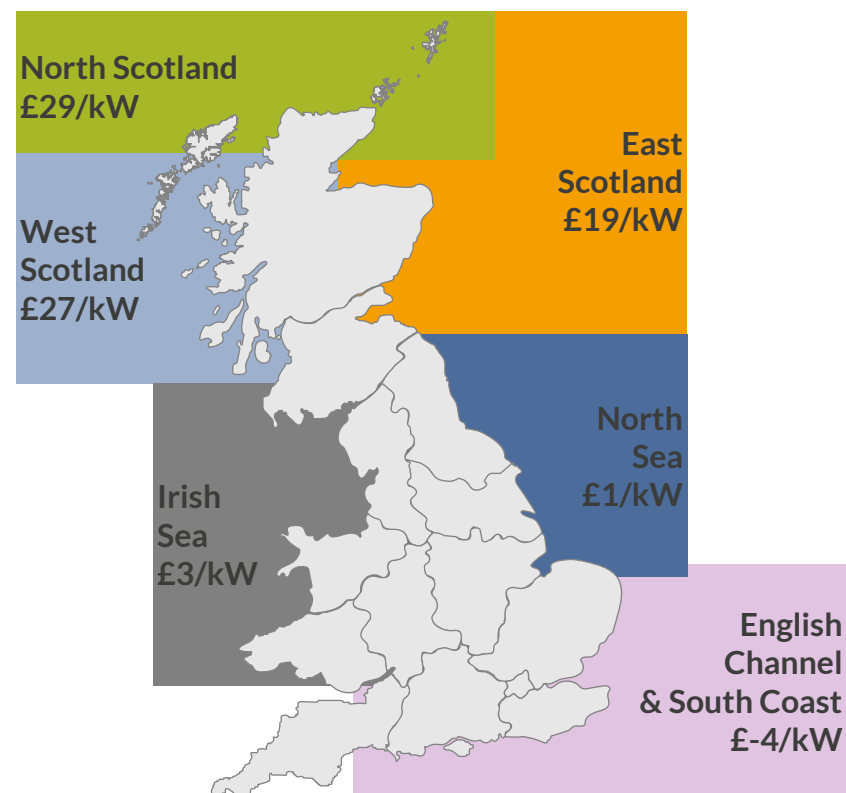
## III. Appendix

# 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 costs

- In Britain, the costs of operating and reinforcing electricity grids are recovered through network charges collected by National Electricity System Operator (NESO)
- These charges are referred to as Transmission Network Use of System (TNUoS) charges<sup>1</sup>
- Electricity generators, as well as consumers, are required to pay TNUoS charges
- (Wider) TNUoS charges differ by location. Key objectives of the design of TNUoS charges include
  - Distributing cost of electricity networks in a fair way (**cost reflectivity**)
  - **Incentivising generation to locate close to demand** helping to minimise electricity network cost<sup>3</sup>
  - **Predictability:** to allow developers to plan around TNUoS

TNUoS Wider Tariff – 2025<sup>2</sup>  
£/kW/year (real 2023)



## 2 Network charges currently disincentivise siting of generation in Scotland

- Currently a large share of wind generation is located in the North of Britain, 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 (see graph) reflecting that transport of electricity to demand (largely in the South) is associated with higher costs in the former case
- However, this could **discourage investment in offshore wind farms in Scotland** even though their deployment is considered key to reach Net Zero in the UK

## 3 Impact of network charges on consumer cost

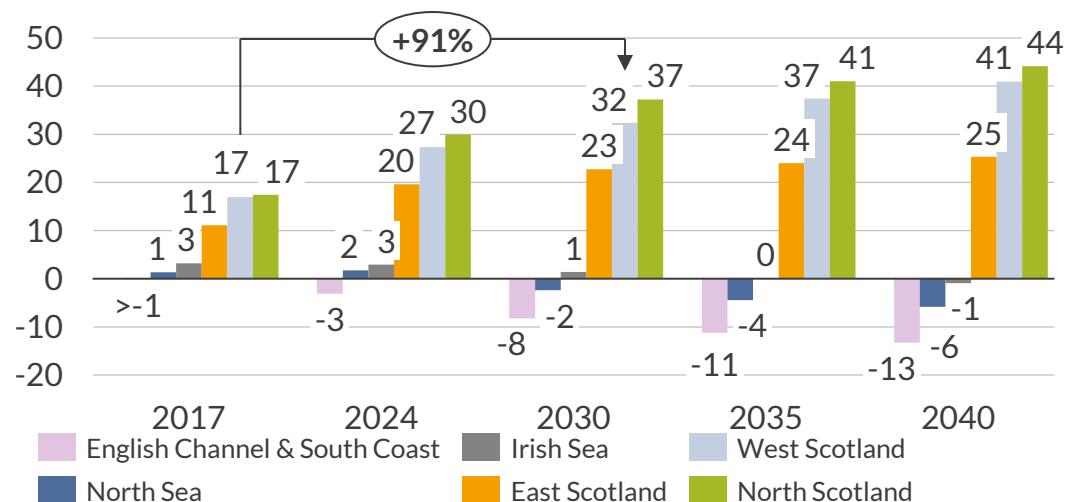
- This report assesses the impact of TNUoS charges on the total cost of renewable electricity to consumers during the CfD subsidy period
- The focus is on offshore wind as the technology expected to dominate renewable supply in GB

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 Tariff<sup>1</sup>

£/kW/year (real 2023)



## 1 TNUoS in Scotland expected to double by 2030

- The current TNUoS charging methodology has been in place since 2017<sup>2</sup> after the implementation of Project TransmiT
- Under Aurora's 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 £18/kW in 2017<sup>2</sup> to £45/kW by 2030 (159% increase)**
- TNUoS in all Scottish regions** is expected to almost **double by 2030**. Indicatively, West Scotland tariff is predicted to be **91% higher** than 2017. **Scottish regions** are likely to set the price for large share of future offshore wind capacity

## 2 TNUoS taskforce aims to improve TNUoS cost reflectivity and predictability

- The TNUoS task force, established by Ofgem and National Electricity System Operator (NESO) in 2022, aims to identify defects in the current TNUoS charging methodology and develop reforms to solve these
- The **current methodology** was largely **developed** in 2012 through Project TransmiT, i.e., **more than 10 years ago**. Due to significant changes though, in particular renewable expansion, the methodology, including assumed generation and demand patterns may no longer be adequate
- Task force mentions **cost reflectivity** and **predictability** as key objectives of the charging methodology, while acknowledging trade-offs between the two
- Recognizing the challenges posed by the evolving energy landscape, Ofgem has published in September 2024 an open letter requesting NGEsO to explore solutions, including a cap and floor mechanism, to better manage the rising TNUoS costs, which are increasingly impacting consumer bills

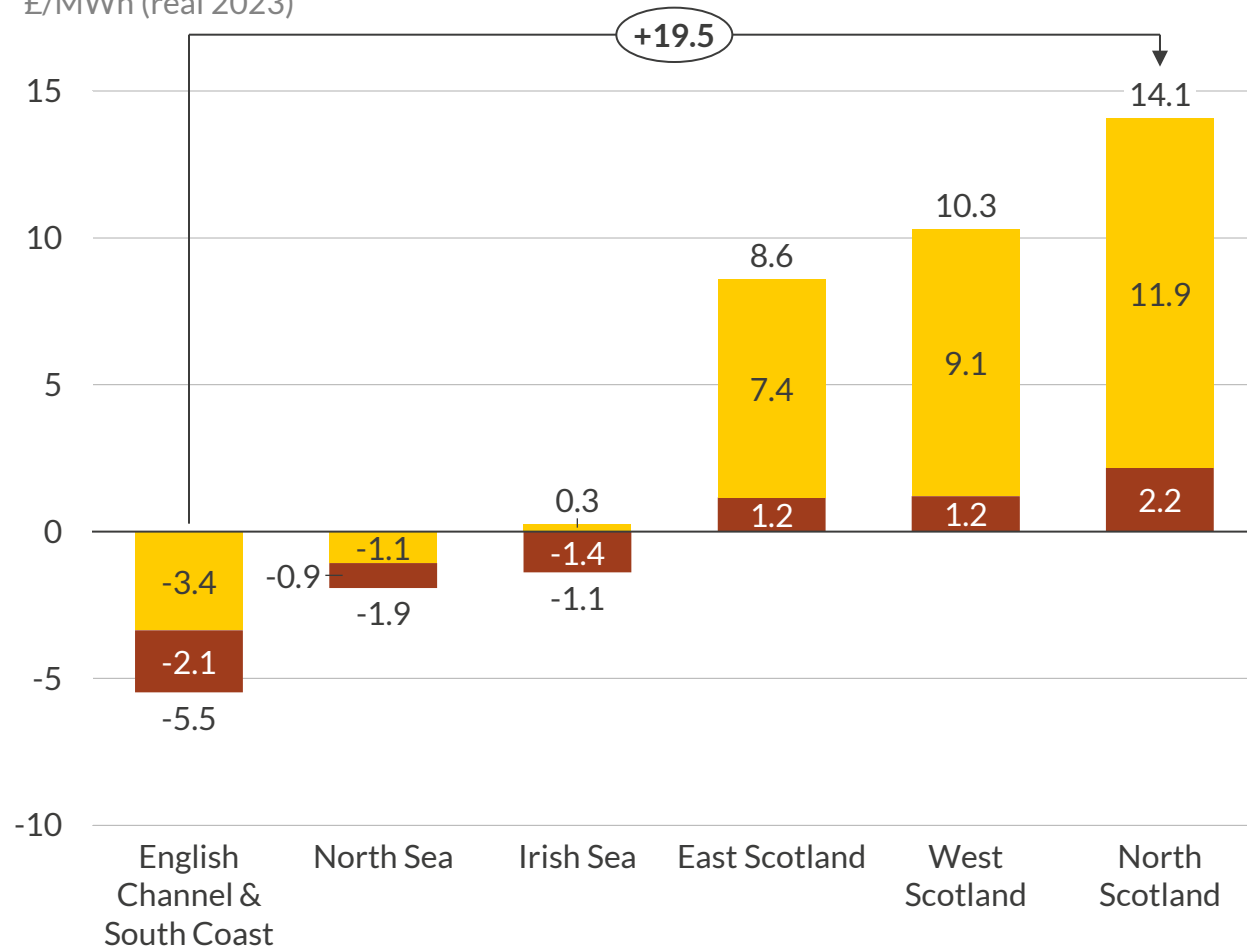
## 3 Divergence of TNUoS as a potential barrier to Net Zero?

- Expansion of **offshore wind in Scotland** is considered **crucial** to reach the UK's decarbonisation targets as reflected in major sector developments: the leasing of seabeds<sup>4</sup> as well as the planned development of the transmission grid<sup>5</sup> focusing largely on offshore wind in Scotland
- Instead of directing wind farm development to regions implying lower network costs, **locational signals** in TNUoS dis-incentivising siting of wind farms in Scotland **could thus simply lead to higher consumer costs in the CfD**
- Increasing divergence of TNUoS between the North and South of GB is debated as a potential barrier to decarbonisation goals and the topic is recognised by the task force as a priority issue to be addressed<sup>6</sup>

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. 2) 2017 refers to the 2016/17 TNUoS year. 3) [Ofgem Open Letter, 30 September 2024](#). 4) 2022 Scotwind auction allocated Scottish seabeds for 25GW of wind generation. 5) 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. 6) [Task Force 2022](#). Source(s): Aurora Energy Research, NESO., Ofgem

# TNUoS charges combined with network loss costs (TLM) lead to differences of up to £20/MWh in CfD bid prices of offshore wind farms across regions

Estimated Impact on Offshore Wind CfD Bid Price – 2025 Entry<sup>1</sup>  
£/MWh (real 2023)



## 1 Impact of TNUoS differs by up to £15/MWh 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 **£20/MWh** higher compared to those in the English Channel and South Coast. The wider TNUoS tariff could contribute approximately **£12/MWh** to CfD bids for wind farms in North Scotland vs **£-3/MWh** for wind farms in the English Channel & South Coast

## 2 Impact of charges for losses differs by up to £4/MWh between regions<sup>2</sup>

- 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 2024 forecast) minus CfD price (TNUoS 2017) ■ CfD price (TNUoS forecast 2024 with varying TLM) minus CfD price (TNUoS forecast 2024 with constant TLM)

1) Under status quo TNUoS in the Aurora Net Zero 2024 scenario. 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 2) The assumptions on TLM are on [slide 17](#)

## I. Introduction

## II. Results of Aurora's analysis

### 1. Total Consumer Costs

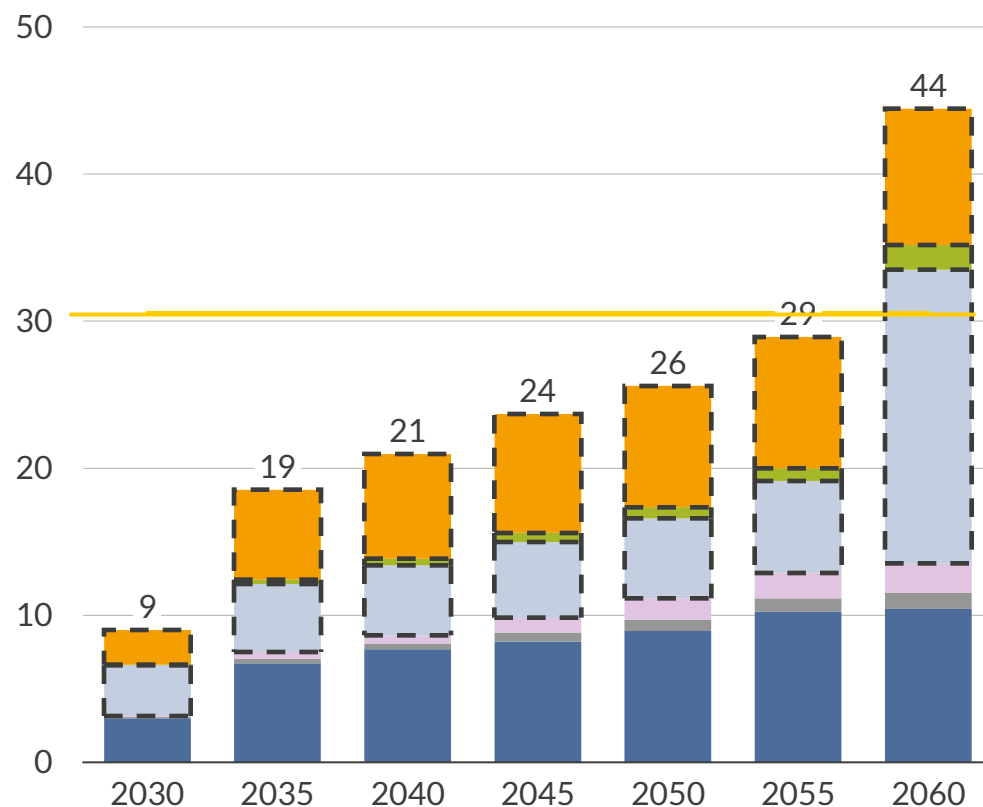
### 2. Costs Due To TNUoS Uplift

## III. Appendix



# Development of offshore wind in Scotland is considered crucial to meet the UK's decarbonisation targets

Cumulatively Added CfD-Backed Offshore Wind Capacity from 2029<sup>1</sup>  
GW



## Wind farms in Scotland are required to meet Net Zero

- Aurora expects significant deployment of offshore wind farms in Scotland will be required to reach Net Zero in the UK; deployment of offshore wind farms solely in the North Sea and the English Channel is unlikely to be sufficient
- The UK is targeting 60GW of offshore wind by 2030<sup>2</sup>. In Aurora's Net Zero scenario, meeting this target requires an additional 31GW of new build capacity on top of existing and Allocation Round 6 capacity. Including Scottish capacity, this target is met in 2046 in Aurora Net Zero, whilst **excluding Scottish capacity** would see this **target missed** even in 2060
- Furthermore, the majority of seabed leases for future offshore wind farms are located in Scotland<sup>3</sup>
- The **ability of developers to react to locational signals** of TNUoS by prioritising wind farms in the South of GB might thus be **limited**
- Up to 2050, almost half of the CfD-backed, new-build **offshore wind** capacity in GB is sited in **Scotland** in Aurora's Net Zero scenario, which amounts to 14 GW out of a total of 26GW

■ North Sea ■ Irish Sea ■ English Channel & South Coast ■ West Scotland ■ North Scotland ■ East Scotland — New build capacity (beyond AR6) needed to reach 60GW target

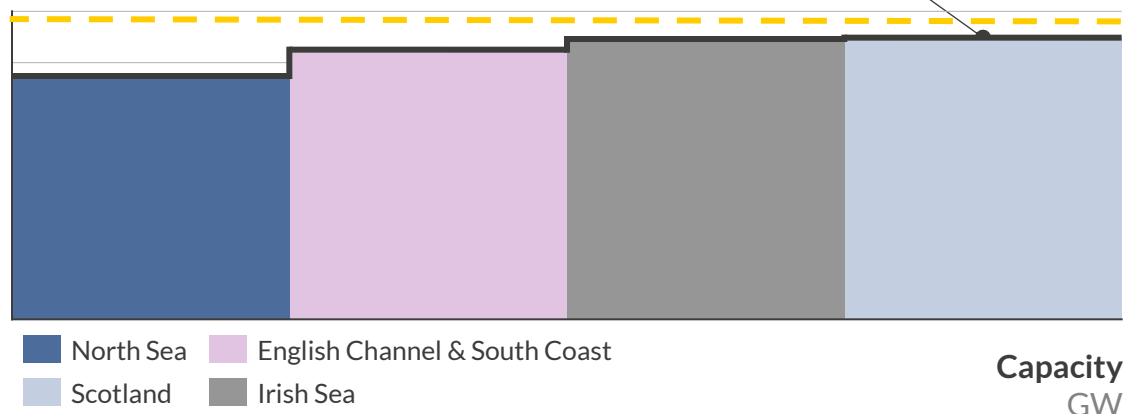
1) Subsidised offshore wind beyond AR6. Please note, this is not the cumulative capacity each year, but only added capacity. Cumulative capacity would also include retirements which this graph does not show. 2) Note that the government target is not legally binding and also includes added capacity without a CfD. 3) The Crown Estate Scotland's 2022 ScotWind auction allocated seabed leases for 25 GW of offshore wind; see [Crown Estate Scotland](#).



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

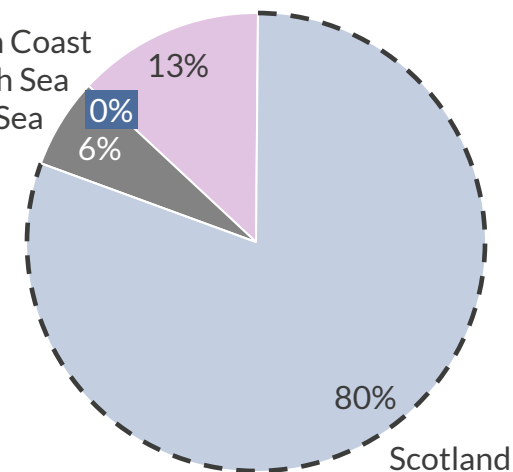
Illustrative CfD Strike Price Bid Stack

Strike Price Bid  
£/MWh



Total New Build CfD-Backed Offshore Wind Capacity by Strike Price Setting Region<sup>2</sup>  
%

English Channel and South Coast  
North Sea  
Irish Sea



## 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 accepted<sup>1</sup> (**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 10% **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 regions<sup>3</sup>

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

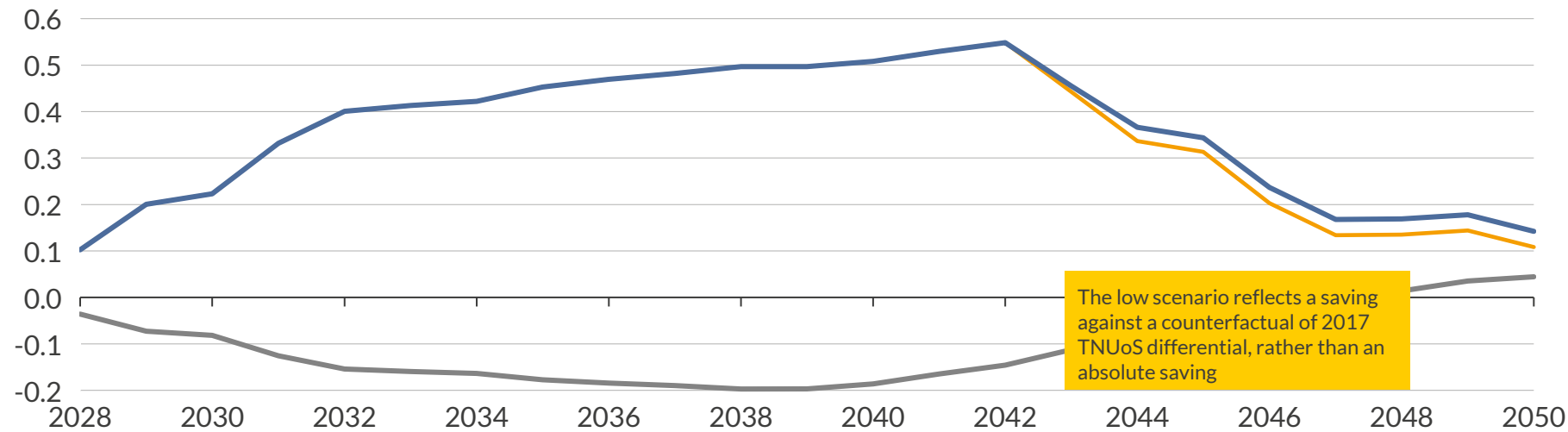
- Due to their higher bid prices, **Scottish wind farms** could **determine the CfD strike price** for a large share of the added CfD-backed offshore wind capacity
- Based on Aurora's buildout of offshore wind across regions, **Scottish wind farms could set the price for 80% of offshore wind capacity added in 2025–2050<sup>4</sup>**
- This analysis focuses on offshore wind. But due to higher load factors and available land in Scotland, onshore wind is also expected to be largely focused on Scotland
- And due to the higher TNUoS in Scotland, Scottish onshore wind farms could thus similarly determine the price of a majority of added onshore wind capacity

1) Before the total available budget is used. 2) Assuming annual CfD auctions; subsidised capacity beyond Allocation Round 6. 3) The load factors for regions can be found in the assumptions slide in the Appendix 4) Assuming that in each year, among the regions in which offshore wind generation is added, the region with the highest electricity generation cost sets the price.

# Increased regional TNUoS divergence could create up to £7.9 bn additional annual consumer costs through to 2050

Estimated Additional Consumer Costs for CfD-Backed Offshore Wind Generation Compared to 2017 TNUoS<sup>1</sup>

£bn/y (real 2023)



Central <sup>2</sup>	High <sup>2</sup>	Low <sup>2</sup>
Aurora’s Central expectation assuming annual CfD auctions, with price-setting plants determined yearly. Scottish wind farms set the price for ~80% of offshore capacity added in 2024–2050	A downside which considers plants in Scotland setting the price of offshore wind for 96% of the capacity brought online. The difference between Central and High is marginal because the Aurora Central already has a high percentage (80%) of capacity for which Scotland sets the price	An upside which considers plants in Scotland setting the price of offshore wind for 29% of the capacity and the North Sea plants set price for 52% of capacity. This is considered <u>highly unlikely</u> due to higher costs of Scottish wind farms. In this case the diverging TNUoS forecast is more favourable

## Cumulative Additional Costs, 2025–2050



### Impact on consumer costs

- We estimate additional consumer costs due to TNUoS changes since 2017, when the current charging methodology was established
- In the **Central** case, additional costs amount to ~£340m/yr on average over 2024–2050, **peaking at ~£550m/yr**

### Similar trend for onshore wind

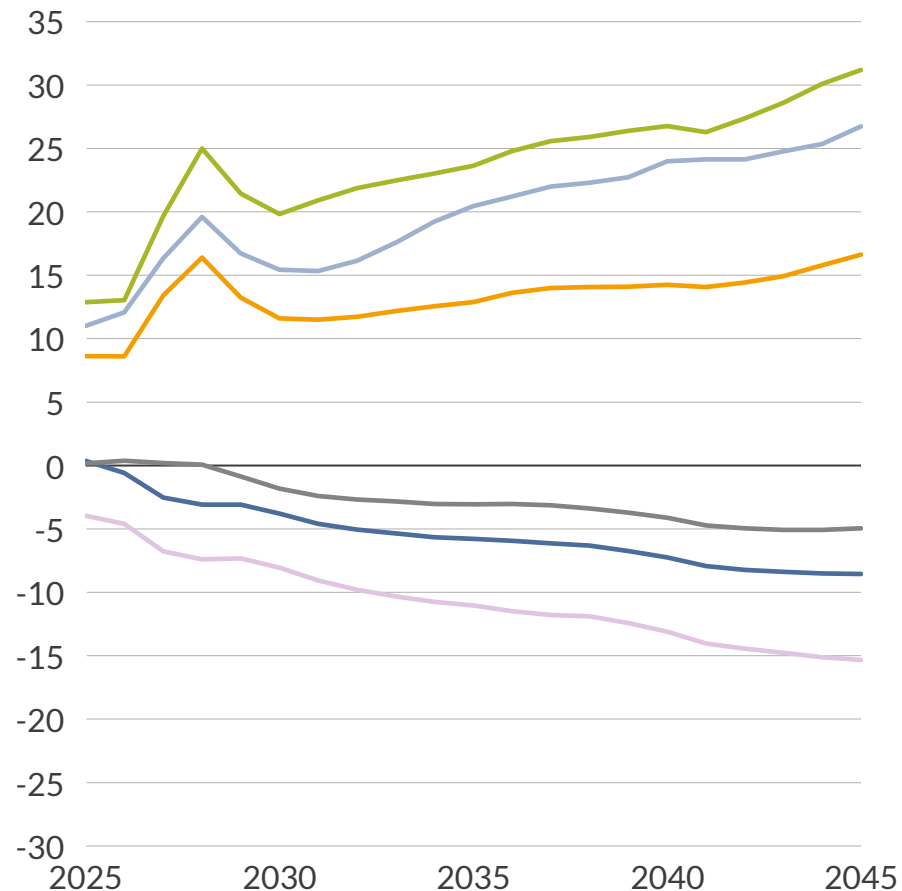
- The above additional costs are based on offshore generation only
- **Including onshore** wind in the analysis is likely to **increase the observed impact**
- For future onshore wind is expected to be largely concentrated in Scotland and Scottish wind farms are likely to set the onshore wind clearing price in future CfD auctions
- The expected continued increase of TNUoS in Scotland would thus also lead to growing costs of CfD backed onshore wind generation to consumers

1) Compares costs of CfD backed offshore wind generation for CfD AR 6 onwards under Aurora’s status quo TNUoS forecast vs 2017 TNUoS charges, representing reduced locational signals. CfD contracts assumed to last 15 years. 2) Assuming the same CfD-backed generation (in TWh) regardless of TNUoS charging regimes.

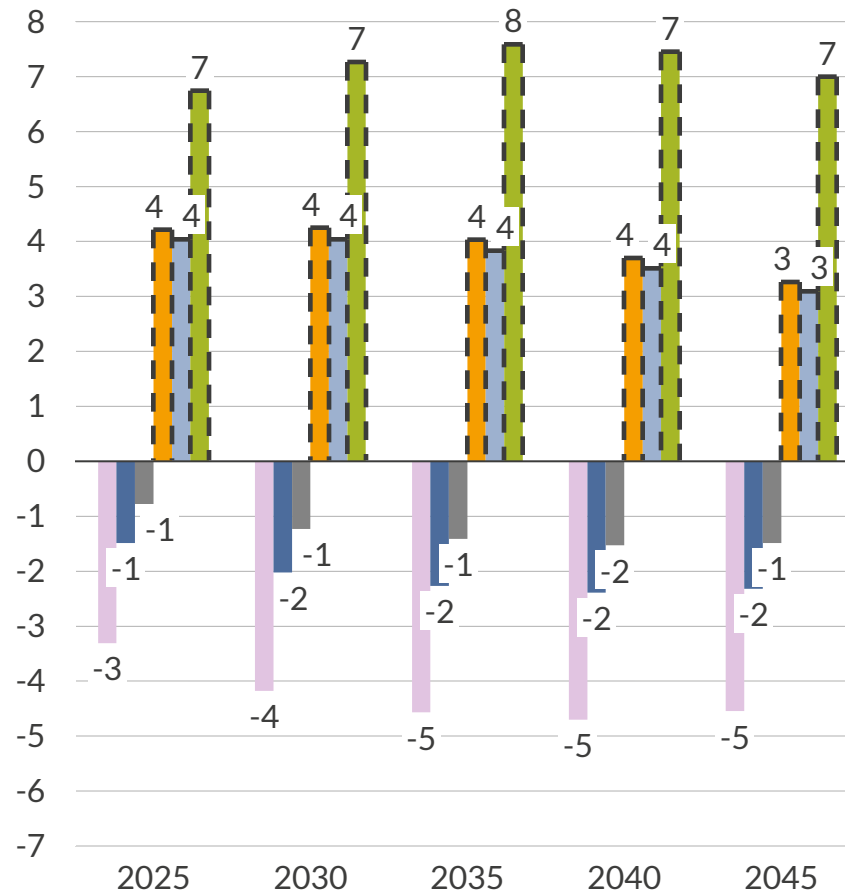
Source(s): Aurora Energy Research

# Key drivers of higher costs to consumers are increases of CfD bids by £3–8/MWh in Scotland due to higher TNUoS

Forecasted TNUoS Increase for Offshore Wind vs 2017<sup>1</sup>  
£/kW/year (real 2023)



Increase of CfD Bids<sup>1</sup> due to Forecasted TNUoS vs 2017  
£/MWh (real 2023)



## Increase in North vs decrease in South

- Aurora estimates that **increases of the TNUoS in Scotland** compared to 2017 (left) will **increase CfD bids of Scottish wind farms by £4–7/MWh in 2025 and by £3–7/MWh in 2045**
- On the other hand, **TNUoS is expected to decrease** compared to 2017 in the **South** of GB (left) leading to higher TNUoS payments wind farms receive in this region
- This will lead to reductions of the bid prices of wind farms in the South by **£1–3/MWh in 2025**, rising to **£1 – 5/MWh in 2045**

## Changes in Scotland are the most impactful

- Scottish wind farms are expected to set the price** for the majority of added offshore capacity ([slide 9](#))
- Therefore, increased TNUoS in Scotland dominates the overall impact on consumer costs

English Channel & South Coast North Sea Irish Sea East Scotland West Scotland North Scotland

1) Under status quo TNUoS in the Aurora Net Zero scenario; only includes TNUoS wider tariff. CfD strike price is that 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

## I. Introduction

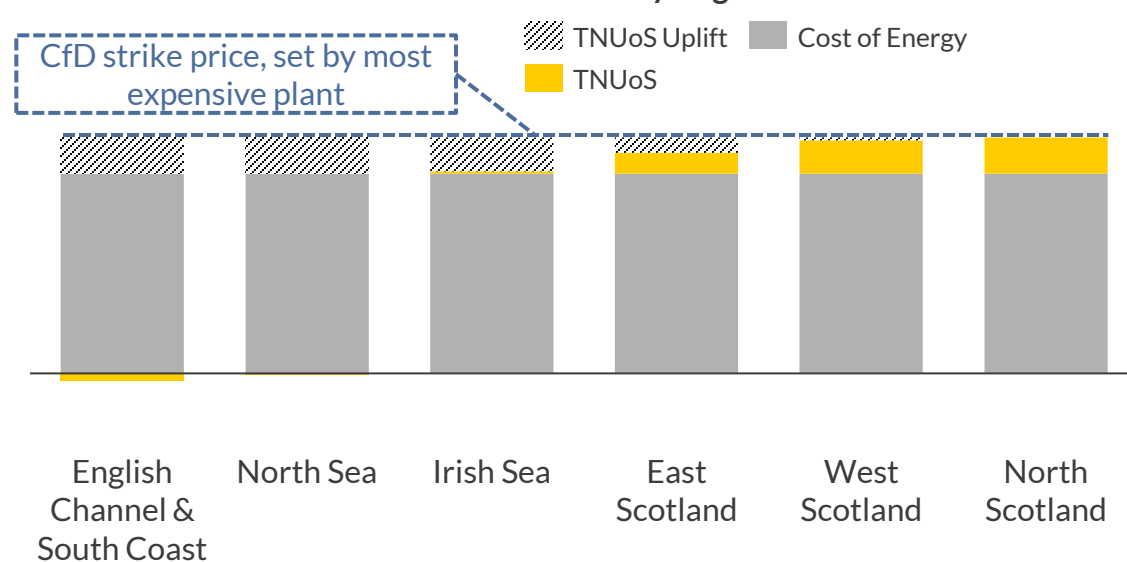
## II. Results of Aurora's analysis

1. Total Consumer Costs
2. Costs Due To TNUoS uplift

## III. Appendix

# Compared to 2017, the Aurora TNUoS forecast provides an uplift per MWh generation between Scotland and other regions

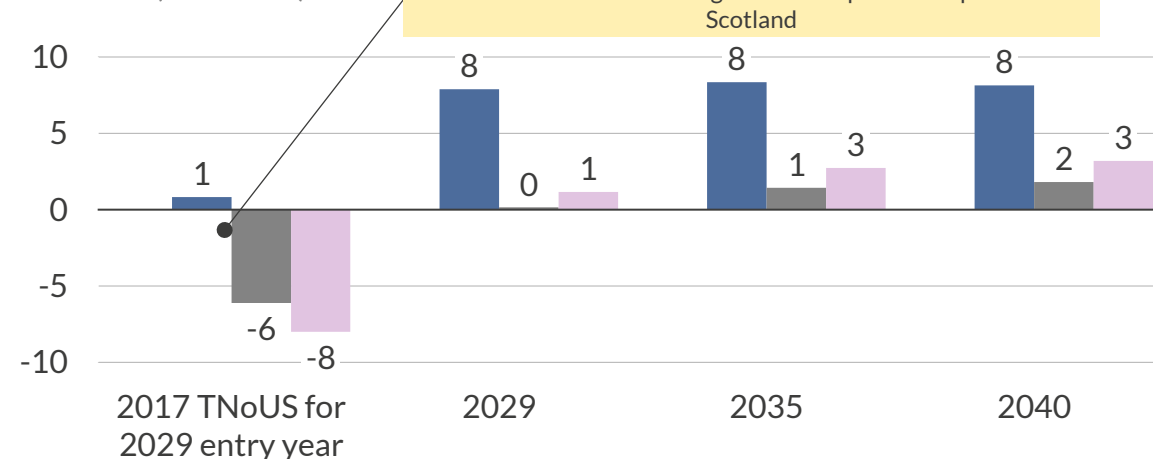
## Illustrative Breakdown of CfD Strike Prices by Region



### 1 Wind farms with lower TNUoS receive “TNUoS uplift”

- CfD auctions are run **pay as clear**, i.e., all accepted capacity receives the auction strike price, given by the bid of the marginal capacity
- As mentioned, Scottish wind farms are expected to bid at higher prices than those in the South, in particular due to higher TNUoS charges, while some wind farms in the South receive a benefit from negative TNUoS charges
- If bids of Scottish wind farms are accepted in auctions in which **wind farms in the South** are participating, the latter **receive** a so called “TNUoS uplift”<sup>2</sup>

## TNUoS Uplift by Region if Scotland Sets the Price under TNUoS 2017 vs Aurora Forecast<sup>1</sup>



### 2 The magnitude of TNUoS uplift is expected to continue increasing

- Aurora forecasts a continued increase of TNUoS charges in Scotland under a status quo regime
- In the Central case, most new build capacity receives a **strike price set by plants in Scotland**, which bid in at higher costs to reflect higher TNUoS charges, meaning **plants in England receive a TNUoS uplift**
- This **TNUoS uplift** is expected to **rise to up to £8/MWh starting 2029 (from £1/MWh in 2017) for North Sea plants** when plants in Scotland set the price, pushing up consumer costs for renewable energy

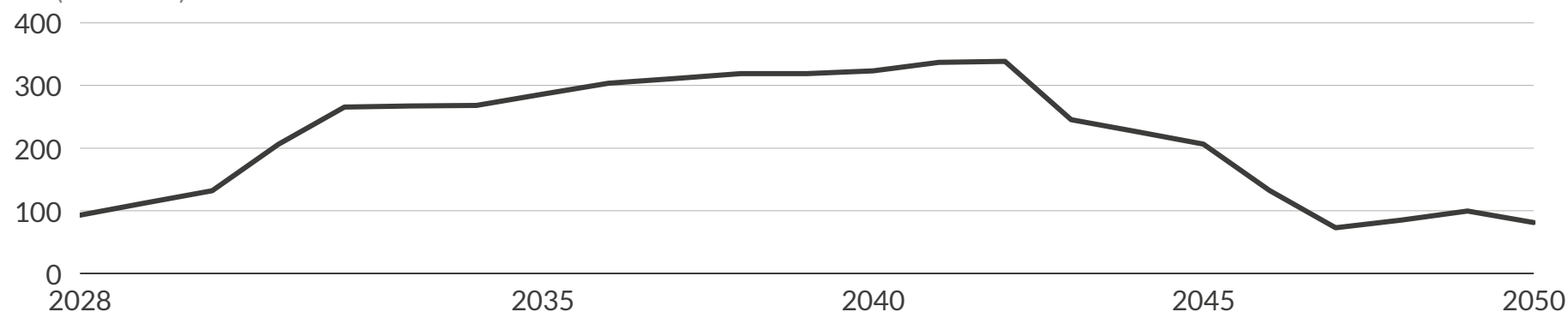
English Channel & South Coast Irish Sea North Sea

1) Difference of TNUoS wider tariff impact on CfD bid price Scotland vs corresponding region; 2017 value is based on TNUoS staying at 2017 levels throughout lifetime, levels in other years based on Aurora's forecast of TNUoS (changing year to year); 2) Note that similar average clearing prices and thus a similar uplift can be expected when switching to pay-as-bid auctions unless bids are scrutinised to a high level of detail (wind developers in the South of GB bidding at the higher costs of developers in the North)  
Source(s): Aurora Energy Research, NESO

# Increasing locational divergence of TNUoS could increase consumer costs due to TNUoS uplift in the South of GB by up to £230 mn per year

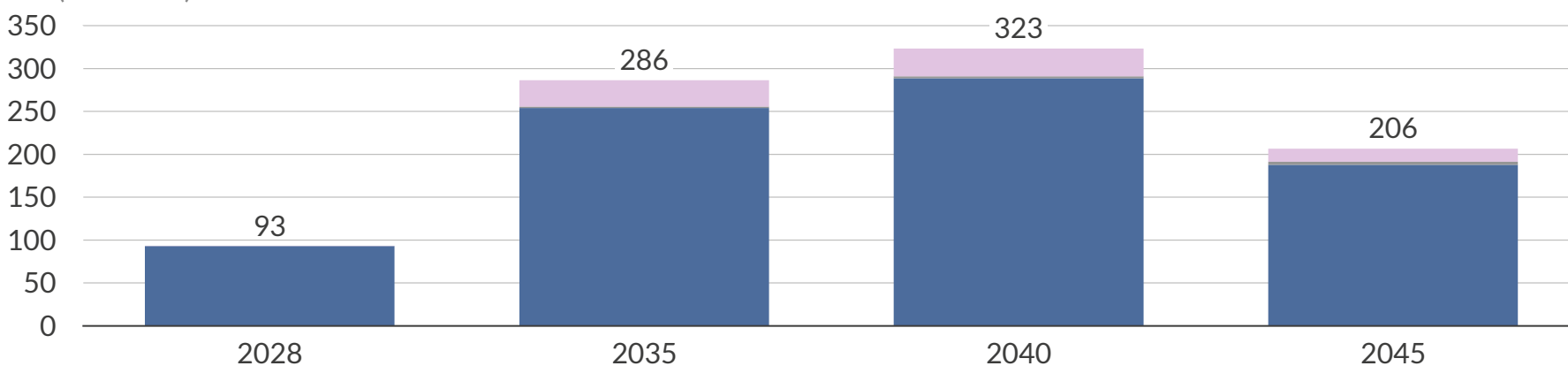
Estimated Consumer Costs Due to TNUoS Uplift of Wind Farms in the South of GB<sup>1</sup>

£m (real 2023)



Total TNUoS Uplift of Wind Farms in the South of GB each year (under forecasted TNUoS)

£m (real 2023)



English Channel and South Coast Irish Sea North Sea

Up to 64% of increasing cost due to TNUoS uplift<sup>2</sup>

- The rising divergence of TNUoS charges between Scotland and other regions compared to 2017 levels **increases consumer costs due to TNUoS uplift by up to £320mn per year by 2040** (above)
- This represents a **significant share of the total increase** of CfD costs due to TNUoS changes
- The remainder of this increase is largely due to the increased cost of wind generation in Scotland itself, due to growing TNUoS in this region

Majority of uplift up to 2040 received by North Sea wind farms

- In the Central case, the uplift is predominantly received by North Sea plants, as they are the cheapest among all regions and therefore have the lowest strike price, receiving the most uplift

1) Consumers will pay the strike price for all generation of any capacity successful in CfD auctions, through wholesale costs and the government support covering the difference between generators' wholesale revenues and strike price. 2) Total Uplift cost is ~£5.0 bn, which is 64% of ~£7.9 bn the cost consumers would incur in status quo vs 2017 TNUoS

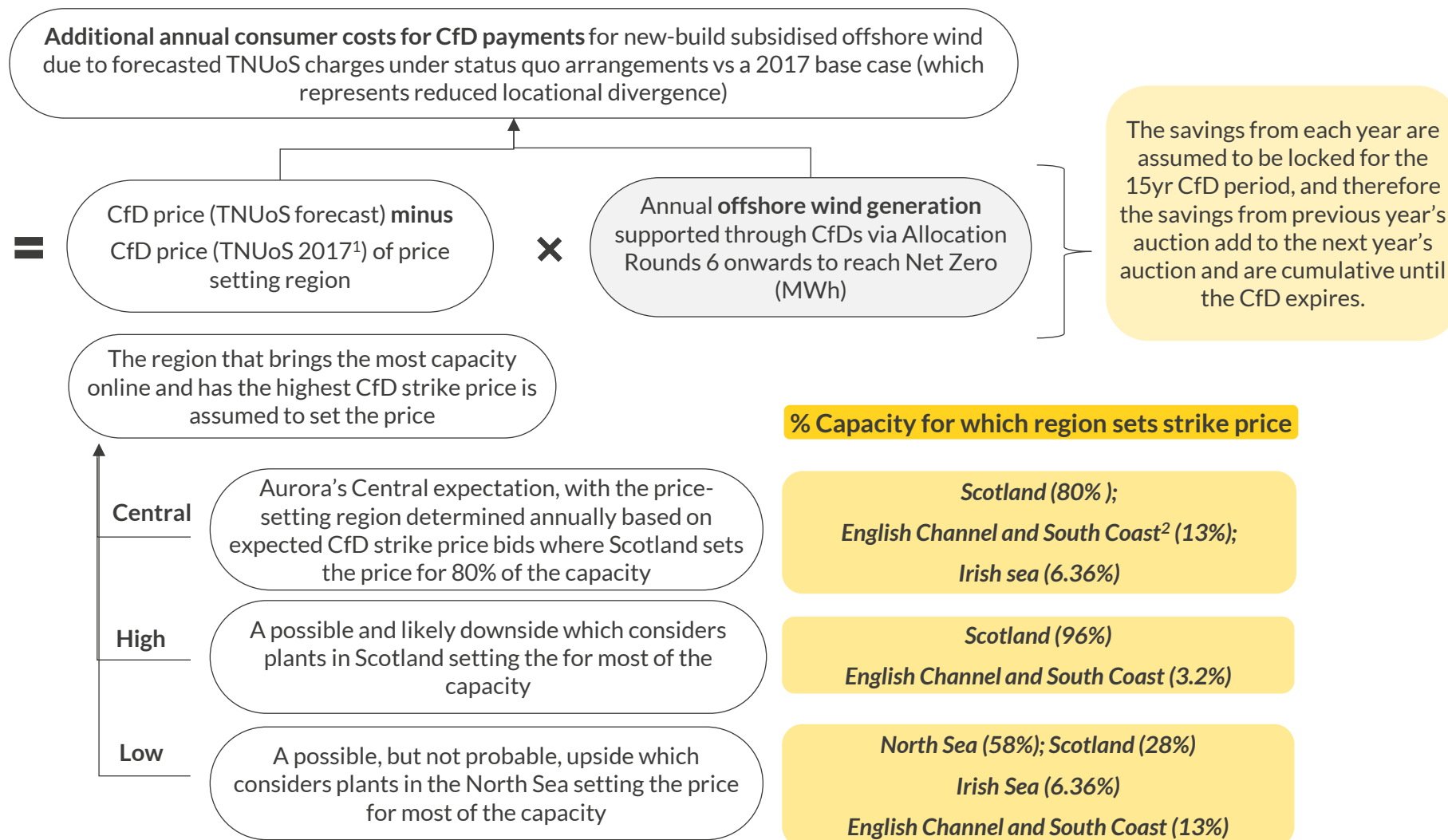
I. Introduction

II. Results of Aurora's analysis

III. Appendix



# 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 the 2017 base case
- 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 three cases (Central, High and Low) to provide a range of cost saving outcomes using three different cases of price-setting regions<sup>2</sup>
- In each of these cases, the impact of forecasted vs 2017 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) All three cases assume the same level of wind deployment across regions, but the price setting behaviour is assumed to be different 2) English Channel sets the price in some years due to its low load factors, which lead to higher strike prices.

# Key Assumptions

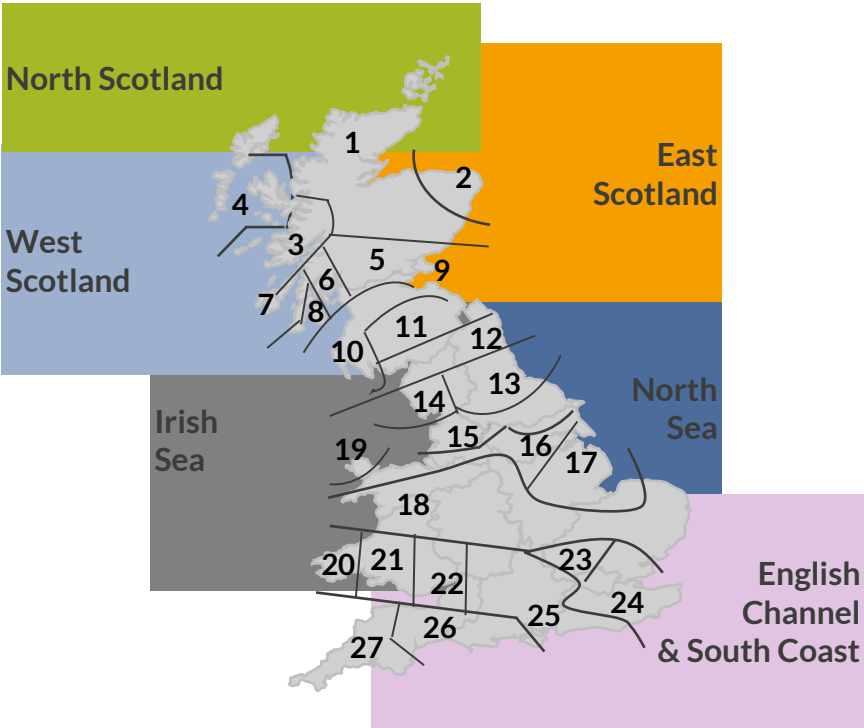
- Based on the TNUoS zone mapping, we aggregate the wider tariffs into the 6 regions analysed in the report. The mapping is shown on [slide 18](#)
- The Load factor used to calculate the tariff is assumed constant for all regions at 51%
- The strike price calculations where we set NPV=0 assume the same CAPEX and OPEX for all regions, while we assume region specific load factors<sup>1</sup> and TLMs<sup>2</sup> to calculate revenues.
- The price setting region is determined on the basis of amount of capacity brought online in the year. The region with the most capacity being bid in the CfD auction is assumed to be the price setting region
- The percentage of capacity that is brought online by the price setting region in High and Low scenarios is an assumption to show an upside and downside case
- 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
North Sea	52.3%	0.989
Irish Sea	48.8%	0.969
English Channel & South Coast	47.5%	0.994
West Scotland	54.1%	1.001
North Scotland	54.2%	0.969
East Scotland	54.5%	0.960

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

# 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	Irish Sea		
13	North Sea		
14	Irish Sea		
15	North Sea		
16	Irish Sea		

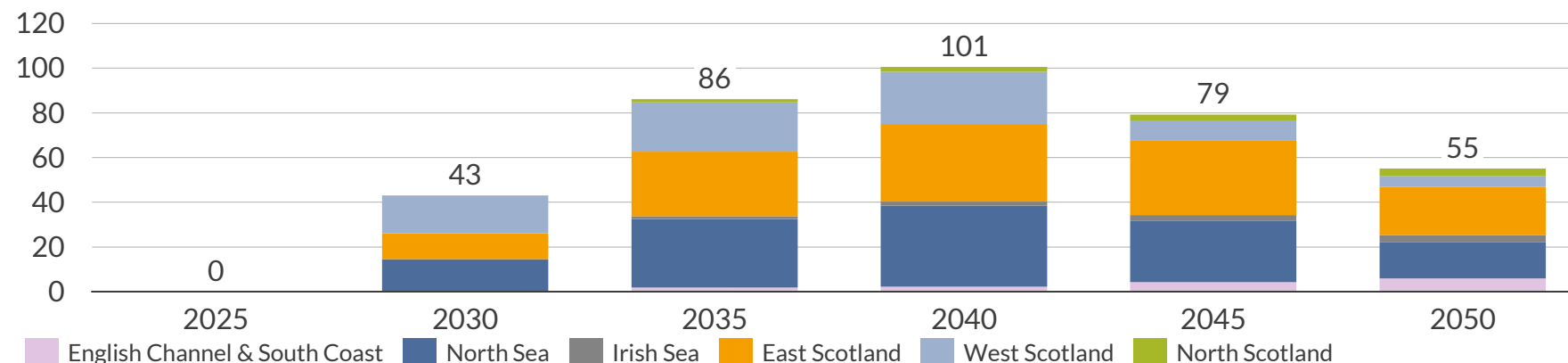


- TNUoS zones were mapped to Aurora’s offshore wind regions by assessing the location of existing offshore wind farms and their corresponding onshore substation, as published by NESO
- The TNUoS charges for each zone were calculated using average GB fleetwide Aurora modelled load factors. A regional 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

# Amplification of additional consumer cost over time is driven by the rise in CfD-backed offshore wind deployment to reach Net Zero

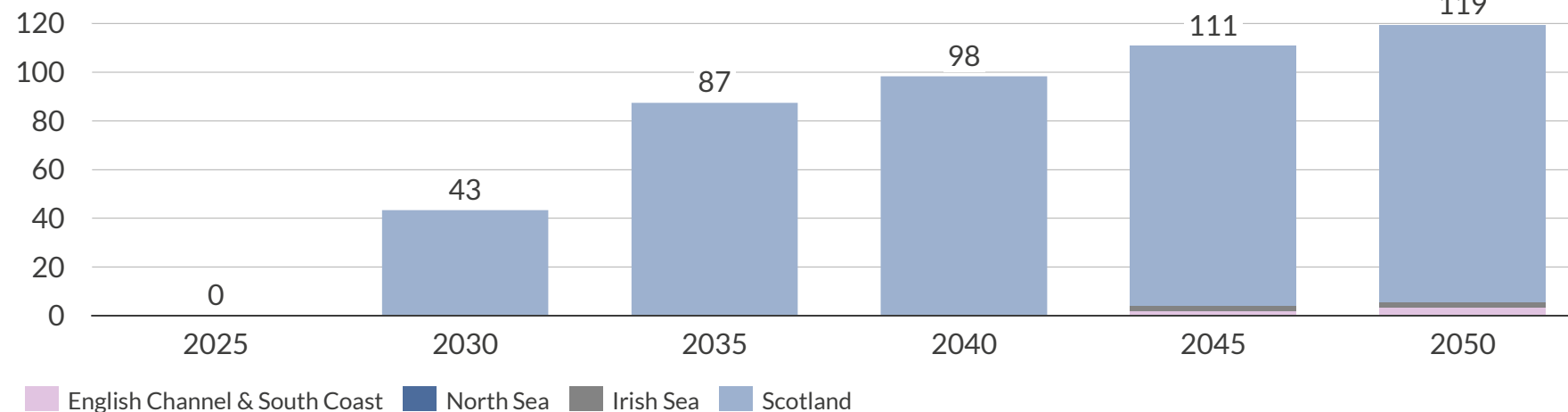
Total Offshore Wind Generation each year (CfD-Backed New Build)<sup>1</sup> by Region of Installation

TWh



Cumulative Offshore Wind Generation added each year (CfD-Backed New Build)<sup>1</sup> by Price-Setting Region<sup>2</sup>

TWh



1) Generation for new build plants from CfD auction rounds 6 and onwards. Please note the lower graph shows the cumulative **additions only** which add upto 111TWh in 2050, whereas the first graph only shows total generation each year.

Source(s): Aurora Energy Research

- This wind generation trajectory reflects a plausible Net Zero scenario designed by Aurora (assumed the same across Central, high and low cases). This includes a significant amount of wind deployment in Scotland to reach Net Zero by 2050, largely supported by CfDs. Generation falls post-2040 as assets begin to come off their CfD
- As CfD-backed wind deployment rises towards 2040, so does the absolute amount of annual additional costs due to increasingly regionally-divergent TNUoS charges
- Under the Central case, majority of the generation added receives the price set by Scotland. Up to 111TWh by 2040—receives a strike price set by plants in Scotland, which are expected to see TNUoS charges continue to rise, driving up additional consumer costs

## Details and disclaimer

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