Impact of locational pricing in Great Britain
Research commissioned by Policy Exchange

December 2020

Introduction

- Aurora Energy Research was commissioned by Policy Exchange to study the impact of introducing locational pricing in Great Britain (GB), using its propriety Power Market Model (AERES).
- Due to network constraints, power generation capacity located far from demand centres is often required to turn down, whilst generators on the other side of the constraint boundary are required to increase generation.
- With increasing penetration of renewables, constraint management is becoming increasingly important, as renewables are often located far from demand centres (such as offshore wind in Scotland).
- This increases network management costs, and, when thermal generators are required to dispatch up, will increase carbon emissions.
- The modelling work was undertaken to understand how locational pricing of electricity would affect the location of new-build capacity and to what extent this would shift towards demand centres. We then considered the effect this would have on generation, system spend, household bills and carbon emissions.
- GB was divided into three price zones for the work, based on the location of current transmission constraints: Northern, which covered Scotland; Central, which covered the north of England; and Southern, which covered the Midlands, Wales and the south of England.

Executive summary
Regional Pricing could save customers £50bn by 2050

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The implementation of regional pricing in GB could:

- Reduce total system spending by ~£50bn cumulative from 2025-2050.
- Provide £37 p.a. savings per household[1] (2030-2050 ave).
- Reduce annual CO2 emissions by 1 MtCO2e p.a. (2030-2050 ave).

These savings are driven by:

- More efficient dispatch of storage and flexible demand sources like EVs, heat pumps and electrolysers, which are better able to take advantage of locally generated excess RES. The accounts for nearly half (£900 million/a) of total system spend savings.
- Incentives for supply to build near demand as constraints and curtailment are largely managed via regional wholesale price signals instead of system actions in the balancing mechanism, which results in 10GW new wind capacity to relocate from the Northern price zone to the Southern price zone.
- The capacity mix in each zone becoming more efficient as the technology mix of firm capacity is optimised based on regional requirements, with, for example, battery capacity relocating from the Southern price zone to the Northern price zone to take advantage of the increased price volatility. This more optimal capacity mix results in ~£1,200million/a in savings.

The full magnitude of savings are partially mitigated by:

- Increased CfD spending, particularly for assets in the Northern price zone where lower prices necessitate higher CfD support for wind.

1. Assumes annual household demand of 4200 kWh p.a.

Source: Aurora Energy Research

Aurora's Power Market Model iterates between dispatch and investment decisions to find the market equilibrium

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1

Input

- **Technology** assumptions (plant parameters)
- **Policy** assumptions (e.g. renewables subsidies, CO_2 prices)
- **Demand** assumptions (based on in-house analysis on the effect of EVs)
- **Commodity price** assumptions (based on in-house AER-GLO model)

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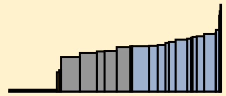
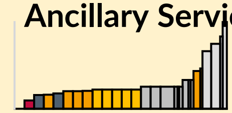
Time horizon: 2019 - 2050

Dispatch module (on an hourly/half-hourly basis)

Wholesale market



Balancing Mechanism/ Ancillary Services



- **Dynamic dispatch** of plant, considering ramping costs and rate restrictions, and availability of plants and individual generators to form the supply stack
- **Endogenous interconnector flows** according to estimated gradient between domestic and foreign electricity spot prices
- **Iterative modelling** between wholesale and balancing markets

Iterations across modules to

- reach equilibrium solution
- ensure internal modelling consistency

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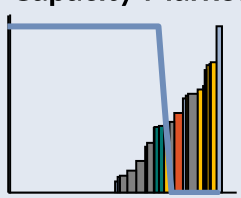
Investment decision module (on an annual basis)

Capacity Market



- **Detailed modelling of the Capacity Market** mechanism and associated bid levels/clearing prices
- **Forecasts investor behaviour** for correct entry/exit of plants based on modelling of future cash flows
- **Entry and exit of technologies modelled endogenously**, not assumed

4

Output

- **Capacity mix** (New build entry and exit decisions)
- **Generation mix** (at technology/plant level)
- **Wholesale & imbalance prices** (half-hourly granularity)
- **Capacity Market prices**
- **Profit & loss and NPV for modelled technologies**

Source: Aurora Energy Research

To model locational pricing, we divided GB into three zones with differing demand and supply characteristics

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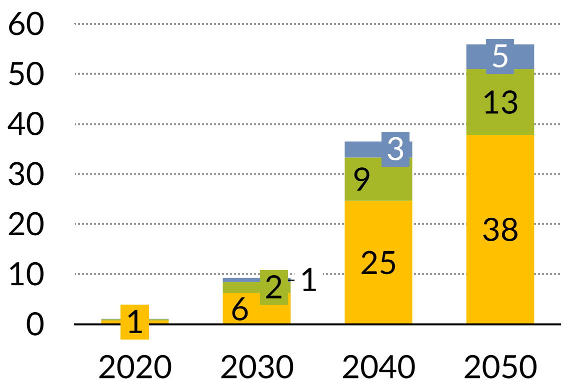
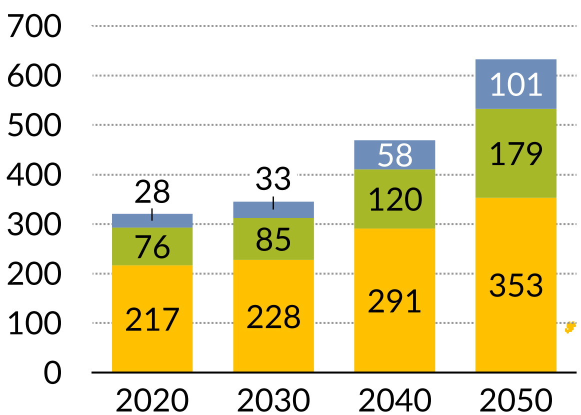
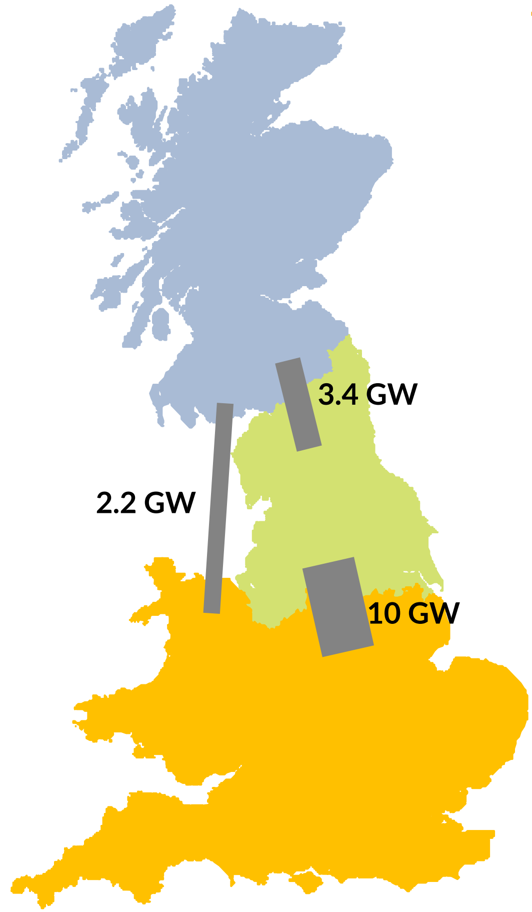
North Central South

EV demand between regions
TWh



Electricity demand between regions
TWh





Installed transmission network capacity
MW

Interconnectors	**Capacity,** MW Forward/reverse
North – Central	3,400
North – South	2,200
Central - South	10,000

- We constructed locational pricing scenarios (Regional pricing (no capacity change) & Regional pricing) for GB, where the country is split into three zones to represent the energy flows from north to south.
- We assumed Net Zero emissions scenarios in all three cases with pre-determined levels of nuclear and specified minimum levels of RES deployment.
- Half-hourly demand within each zone is flexible, as EVs, heat pumps and electrolysers respond to regional pricing however demand is assumed not to relocate between zones (i.e. industrial demand is unable to relocate in response to regional prices).

Sources: Aurora Energy Research, BEIS, National Grid

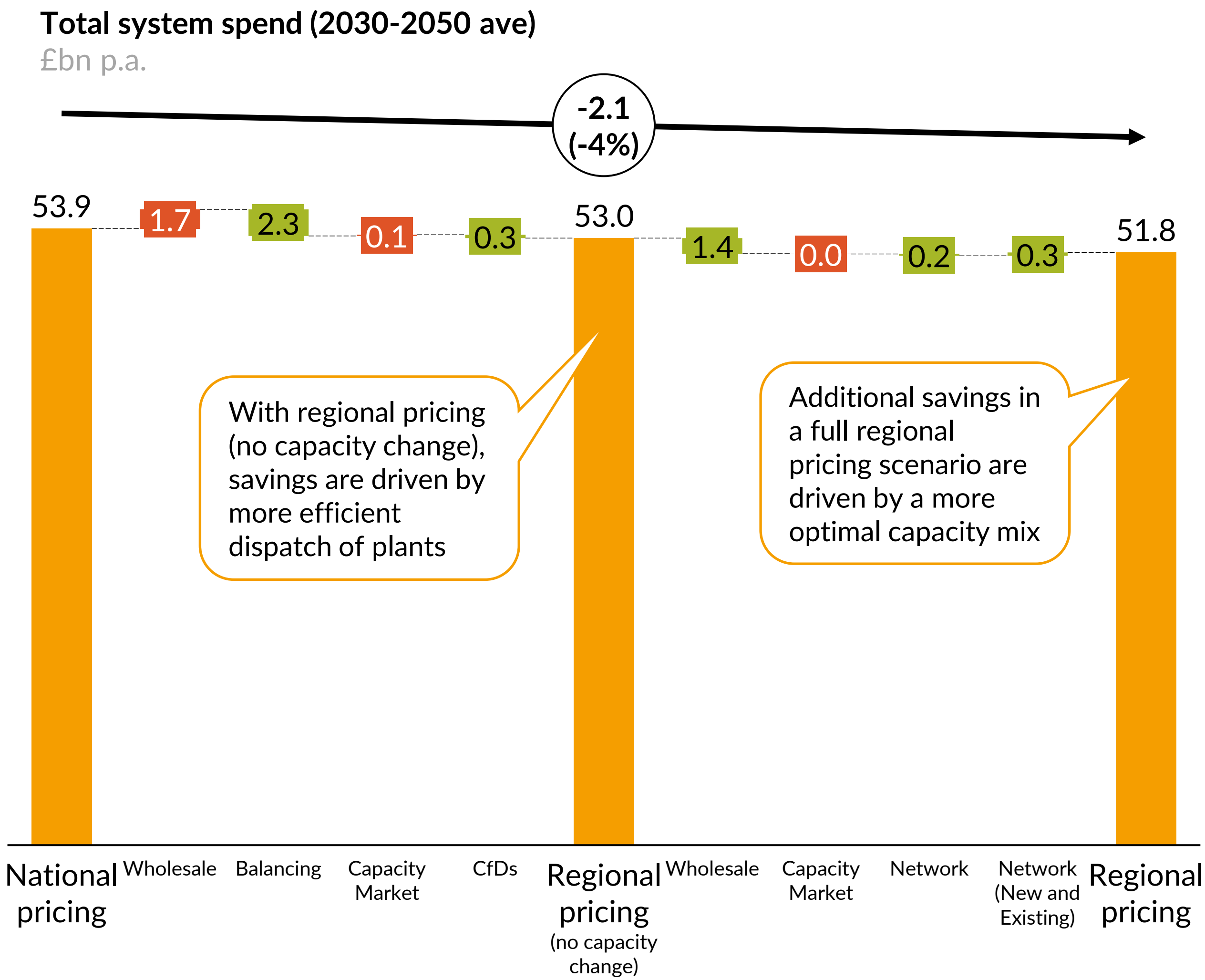
Aurora has tested three market scenarios to study the impact of introducing regional pricing in GB

National Pricing	A base case Net Zero market scenario with a single price zone in GB
Regional Pricing (unchanged capacity mix)	The capacity mix from the National Pricing scenario is unchanged but mapped to the three price zones according to geographic location of plants and the share of demand by zone
Regional Pricing	Three price zones are implemented in GB where new-build capacity decisions are determined by the level of return within each zone

- Three scenarios were considered:
  - National Pricing; this reflects Aurora's view on how the market will develop with a single electricity price zone (the status quo).
  - Regional Pricing with an unchanged capacity mix; this studies the impact of improving the efficiency of dispatch of generators without prices affecting decisions on where new-build capacity is installed.
  - Full Regional Pricing; under this scenario decisions on where new capacity is built is affected by electricity pricing, so the capacity mix is optimised to local prices, resulting in fewer network constraint issues.
- All scenarios result in Net Zero emissions by 2050.

Source: Aurora Energy Research

Aurora's modelling suggested switching to regional pricing would results in a decrease in system costs



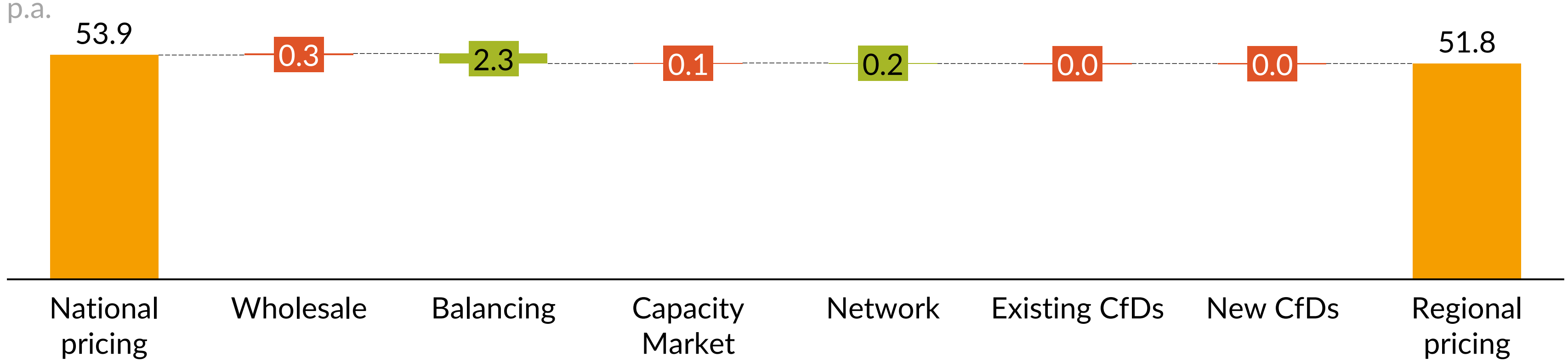
- Aurora used the results of its modelling to calculate total system spend.
- Aurora's model outputs include half hourly dispatch prices which were used alongside half hourly demand data to calculate overall wholesale market expenditure per year.
- The Capacity Market spend was calculated using yearly auction prices and procured capacity.
- Balancing Mechanism spend includes both energy actions and system actions; system actions would be incentivised by regional prices in those scenarios.
- CfD spending was calculated by comparing CfD contract prices against modelled capture prices in each region.
- Network costs calculations used TNUoS forecasts and reallocate capacity and demand in each zone.

1. No network upgrades between Scotland and England are assumed in these scenarios 2.Regional pricing. Existing CfD spending includes nuclear, offshore wind, onshore wind and solar plants that have already been awarded CfDs 3. Top-up support is calculated as the total support required for new build capacity that is assumed as a model input to achieve an NPV of zero and includes offshore wind, onshore wind, solar, gas-CCS, H2-CCGTs, and CfDs with a strike price of £70/MWh (real 2012£) for new nuclear post Hinkley Point C

Source: Aurora Energy Research

The introduction of regional pricing could decrease system spend by £2.1bn p.a. (2030-2050)

Total system spend (2030-2050 ave)
£bn p.a.



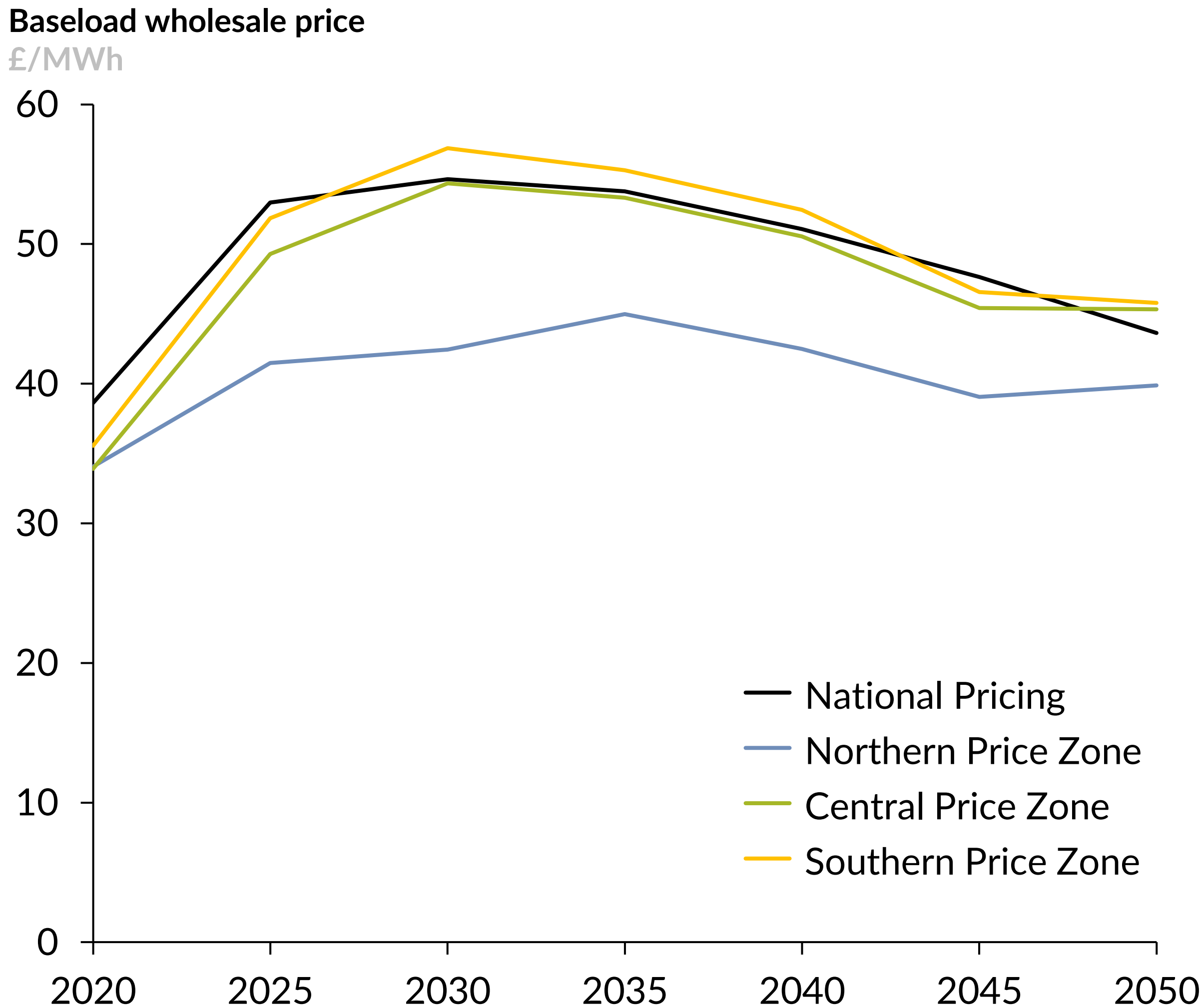
Summary of system cost differences (Regional pricing vs National pricing)

- **Balancing spending decreases**[1] by £2.3bn p.a., driven by the reduction in constraint costs as regional pricing introduces a signal for RES, particularly in Scotland, to curtail.
- **Network spending** decreases by £0.2bn p.a., as regional pricing incentivises supply to build closer to demand.
- **ROC and FiT spending** is unchanged as these costs are independent of wholesale prices.
- **Existing and New CfD spending**[2,3] remain similar at +£10m p.a., as the benefits of higher capture prices for nuclear outweigh small increases in support for RES and gas-CCS, which sees fewer running hours.
- **Wholesale spending** increases by £0.3bn p.a. due to the reduction in frequency of very low prices when Scottish wind sets the price in GB.
- **Capacity Market spending** increases by £0.1bn p.a., as less RES curtailment leads to fewer running hours and lower margins for thermal assets.

1. No network upgrades between Scotland and England are assumed in these scenarios 2 Regional pricing. Existing CfD spending includes nuclear, offshore wind, onshore wind and solar plants that have already been awarded CfDs 3. Top-up support is calculated as the total support required for new build capacity that is assumed as a model input to achieve an NPV of zero and includes offshore wind, onshore wind, solar, gas-CCS, H2-CCGTs, and CfDs with a strike price of £70/MWh (real 2012£) for new nuclear post Hinkley Point C

Source: Aurora Energy Research

With regional pricing, regional differences in baseload wholesale prices occur



- Under full regional pricing, baseload wholesale prices vary between regions, with lowest prices seen in the Northern Zone.
- This is because a higher proportion of electricity in the Northern Zone is generated from low-cost renewables.
- At times of high renewable generation, wholesale prices in the Northern Zone often fall to ~£0/MWh.

Source: Aurora Energy Research

When transmission constraints are not binding, market coupling results in similar prices in each zone

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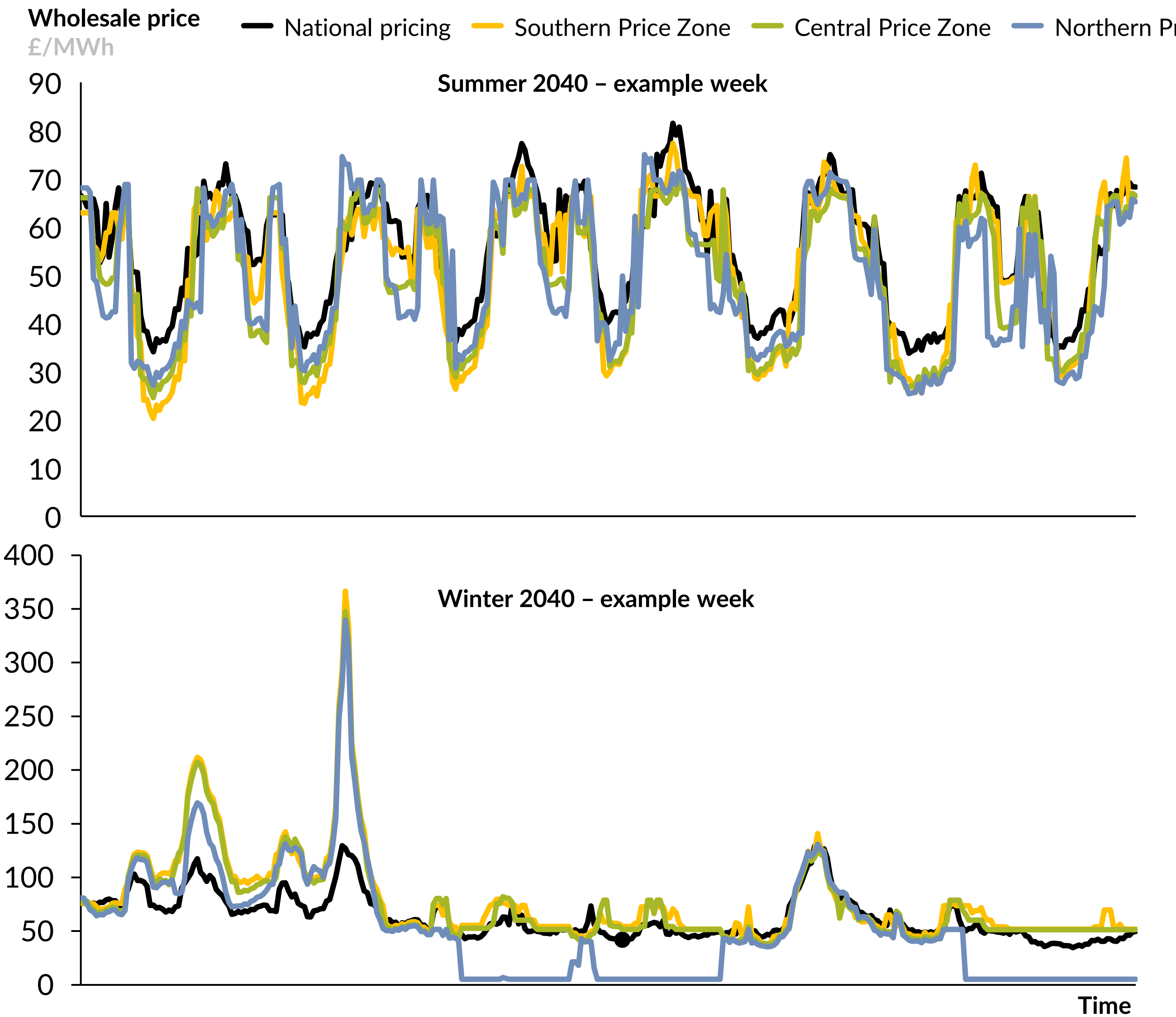
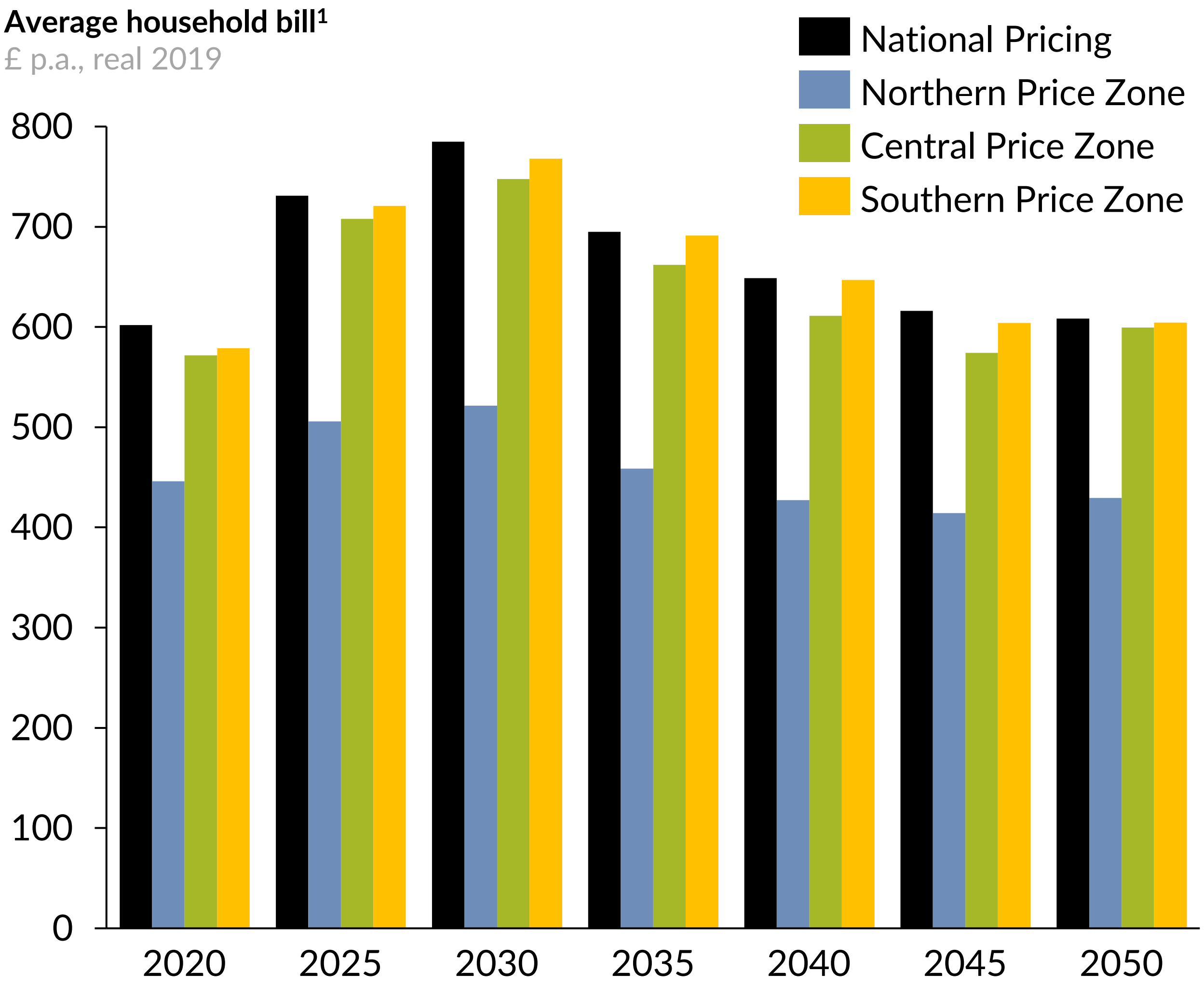


- Aurora looked at variations in wholesale prices on a half hourly basis in summer and winter weeks with high renewable dispatch in the national pricing scenario and the full regional pricing scenario.
- Market coupling leads to similar regional pricing when transmission constraints are not binding.
- Power prices drop to zero in the Northern Price Zone when wind generation here exceeds demand and transmission constraints limit exports to the Central and Southern Price Zones.

Source: Aurora Energy Research

Regional pricing in GB would lead to lower household bills



- Under regional pricing, household bills are lower in all regions.
- The Northern Price Zone sees the lowest prices and overall customer bills could be ~33% lower then in the Central and Southern Price Zones.
- This is driven by lower wholesale costs in the Northern Price Zone, with other costs split equally across zones.

1. Assumes annual household demand of 4200 kWh p.a.

Source: Aurora Energy Research

Consumer bills in each price zone are assumed to differ by wholesale costs only, with other costs distributed evenly

Bill component	Approach	Regional or GB wide
Wholesale market	Based on regional wholesale prices and demand for each scenario, assuming 8% transmission losses	Regional
Balancing market (BSUoS)	The cost of energy actions is assumed constant across scenarios. The regional pricing scenarios are assumed not to face the constraint costs incurred via system actions in the national pricing scenario.	Distributed across regional bills by share of total demand
Capacity Market (CM)	Missing money required for sufficient capacity to build in each zone in order to meet capacity targets and security of supply	Distributed across regional bills by share of total demand
Network (TNUoS, DUoS)	Estimate of the costs required to expand the network to connect new capacity and the costs to operate and maintain the existing network	Distributed across regional bills by share of total demand
Existing subsidies	Subsidy payments to plants with existing support contracts (e.g. ROC, FiT, CfD). Regional wholesale prices are used as reference prices for CfD payments.	Distributed across regional bills by share of total demand
New CfDs	Total missing money required for assumed capacity additions and new RES capacity to break even	Distributed across regional bills by share of total demand
Other	Operating costs and supplier margins are assumed at 19% of the total bill and VAT of 5% is applied	Applied to total regional bill

Sources: Aurora Energy Research, Ofgem

Under regional pricing, capacity will build closer to demand centres to minimise constraints

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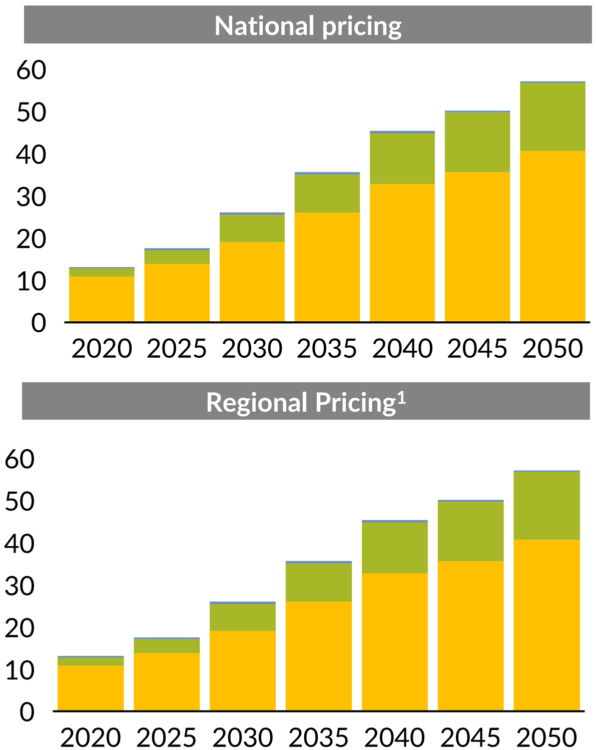
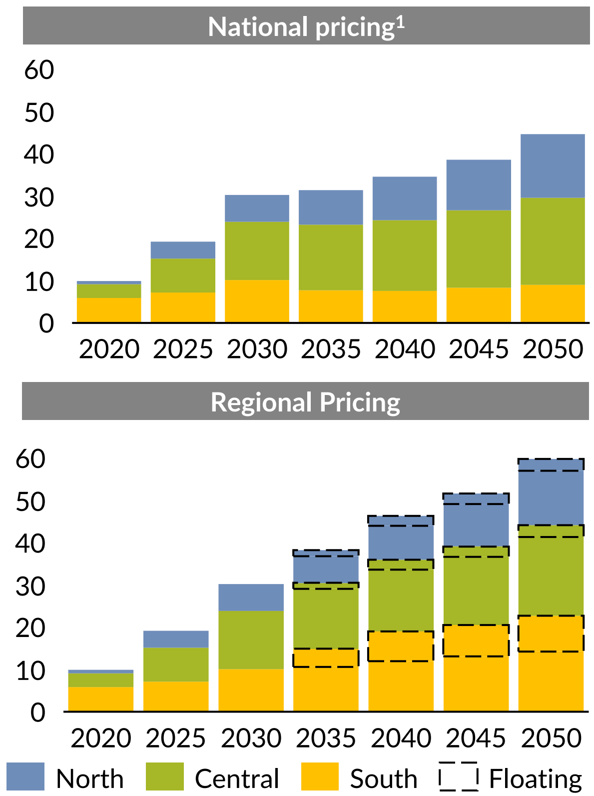
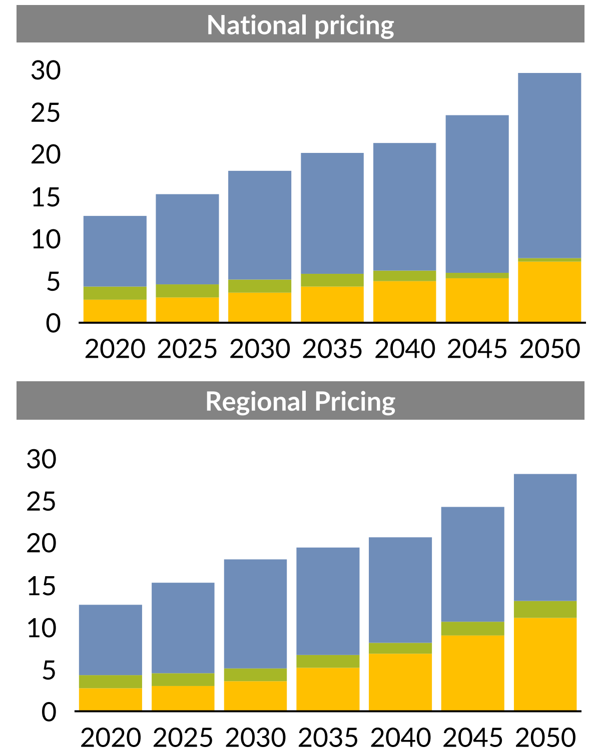
Solar PV capacity, GW



Offshore wind capacity, GW



Onshore wind capacity, GW

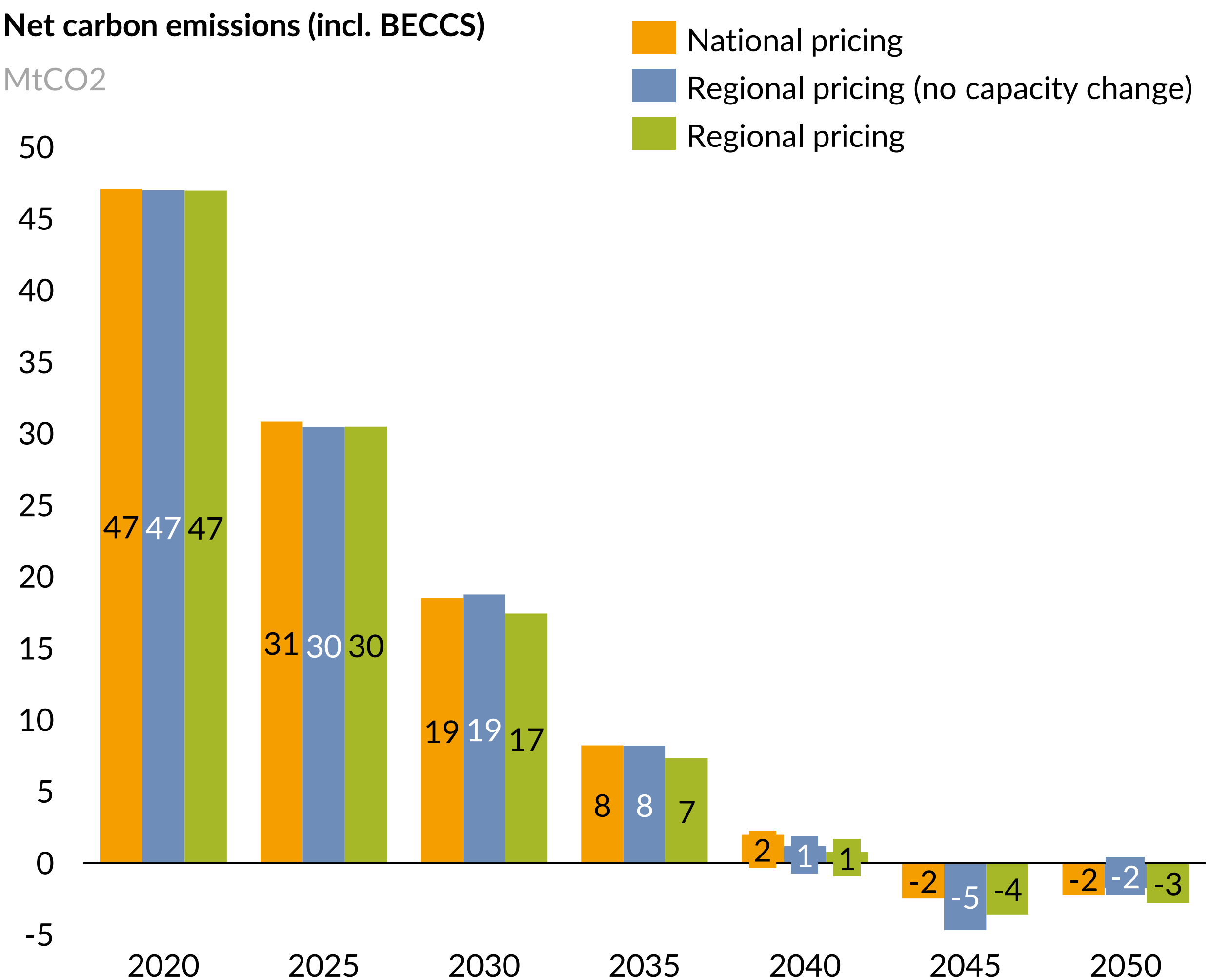


- The introduction of Regional Pricing sees up to 8.4 GW floating offshore wind by 2050 in the Southern Price Zone. Floating Offshore Wind can be used in deeper water depths and so can be constructed over a wider area of seafloor, increasing potential capacity in busy maritime areas.
- Up to 5GW more solar is built in the Southern Price Zone under full regional pricing.
- Regional pricing sees onshore wind building in the Southern Price Zone over the Northern Price Zone. This has the effect of reducing curtailment for constraint management purposes. Changes to planning regulations would be required to facilitate this.

1. Chart updated to reflect correct installed capacities.

Source: Aurora Energy Research

Additional emissions reductions of 1.0 MtCO2e p.a. could be achieved with regional pricing



- Introducing regional pricing results in slightly decreased carbon dioxide emissions across the forecast horizon.
- This is due to increased renewable build-out in the southern and central price zones, which faces fewer grid constraints as it is located closer to demand centres, and so is curtailed less frequently.
- This results in more generation from renewables and therefore lower carbon dioxide emissions.

Source: Aurora Energy Research

Report details and disclaimer

Publication	Prepared by	Approved by
Impact of locational pricing in Great Britain - Research commissioned by Policy Exchange	Anna MacDonald (anna.macdonald@auroraer.com) Sahasrajit Ramesh Emma Woodward Jordan Banting Sally Jones	Felix Chow-Kambitsch (felix.chow@auroraer.com)

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