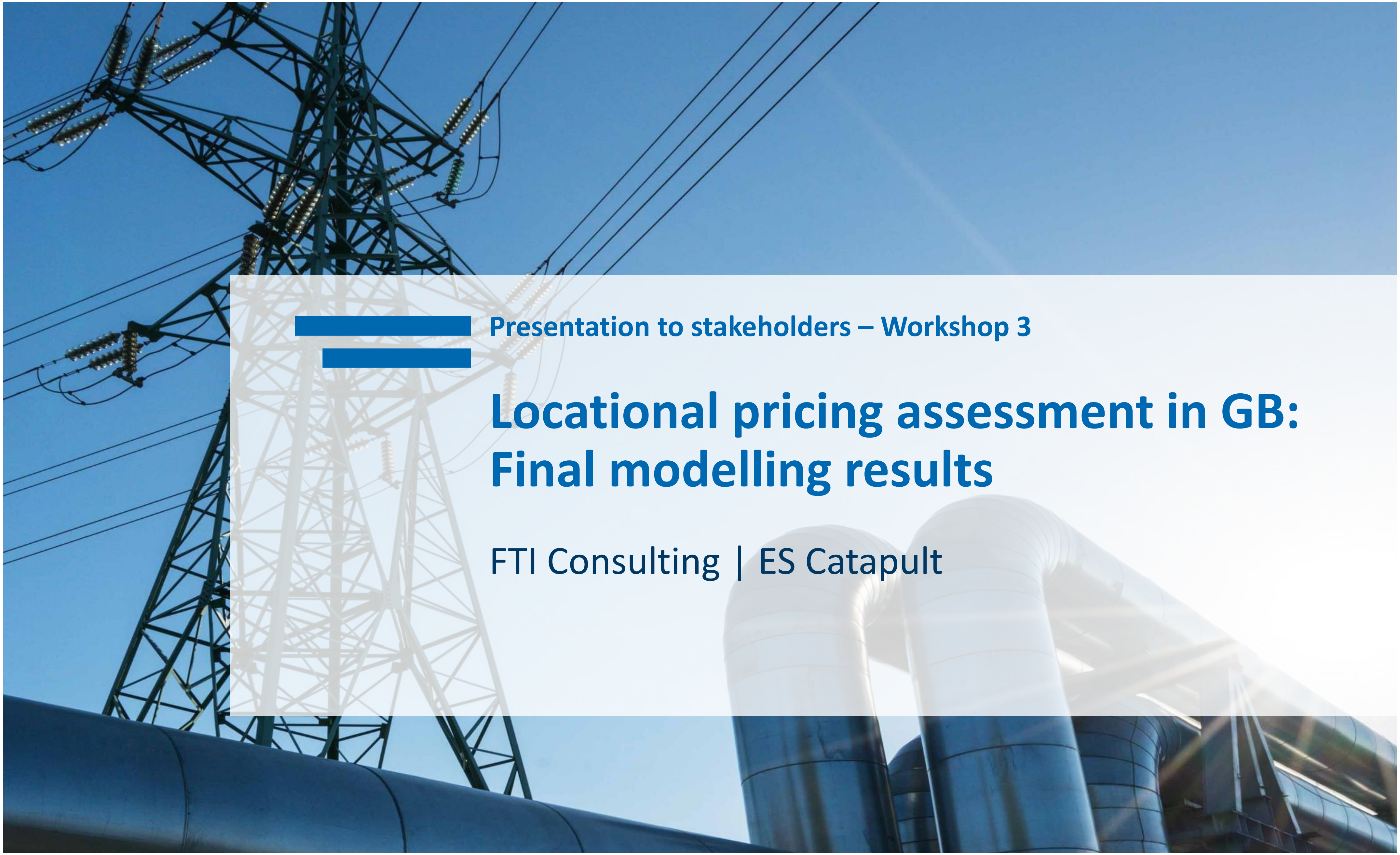

Presentation to stakeholders – Workshop 3

Locational pricing assessment in GB: Final modelling results

FTI Consulting | ES Catapult

6 June 2023 – London
13 June 2023 – Glasgow

Welcome

ofgem

Housekeeping

Breaks

- We will have two breaks this afternoon

Hybrid event

- 3 Q&A sessions with questions from the room and online. Online attendees, please use slido codes below.
- www.slido.com

Q&A Session #1 **Code: 2270 806**	**Q&A Session #2** **Code: 6648 199**	**Q&A Session #3** **Code: 4036 143**

In our final workshop, FTI Consulting and ES Catapult present our assessment of the costs and benefits of introducing a more locational GB power market

Project Leads

Project Lead

Jason Mann

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GB Market Expert

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Bill Hogan


Scott Harvey


Susan Pope


Ken Ditzel


Mitch DuRebis

EU Market Experts


Fabien Roques


Yves Le Thieis

Project Partners – Energy Systems Catapult


Ben Shafran


George Day


Guy Newey

In person *Dialled-in*

Agenda for today’s workshop

Introduction and purpose of the workshop	13:30	10 mins	ofgem
Topic 1: Recap on assessment approach	13:40	10 mins	FTI Consulting
Topic 2A: Modelling outputs on the status quo market design	13:50	10 mins	FTI Consulting
Topic 2B: Modelling outputs on the locational market designs	14:00	20 mins	FTI Consulting
Q&A	14:20	20 mins	FTI Consulting, ofgem
BREAK	14:40	20 mins	
Topic 3: Wider system impacts (incl. financing costs)	15:00	20 mins	FTI Consulting
Topic 4: Overall cost benefit assessment	15:20	20 mins	FTI Consulting
Q&A	15:40	20 mins	FTI Consulting, ofgem
BREAK	16:00	15 mins	
Topic 5: Key sensitivities	16:15	5 mins	FTI Consulting
Topic 6: Flexible resources and transmission investment signals	16:20	25 mins	FTI Consulting
Q&A	16:45	20 mins	FTI Consulting, ofgem
Next steps	17:05	10 mins	ofgem, Catapult Energy Systems

Topic 1: Recap on assessment approach

In the context of REMA, Ofgem commissioned FTI and ES Catapult, to undertake a cost benefit assessment of a more locational GB power market

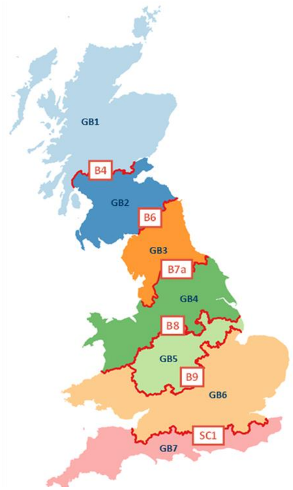
As part of this we have developed a locational market model of the GB power market allowing us to compare market outcomes between market designs…

National

Uniform price clears across entire market

GB | Germany

Zonal

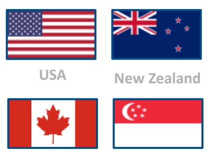


*System divided into **seven zones** with individual prices*

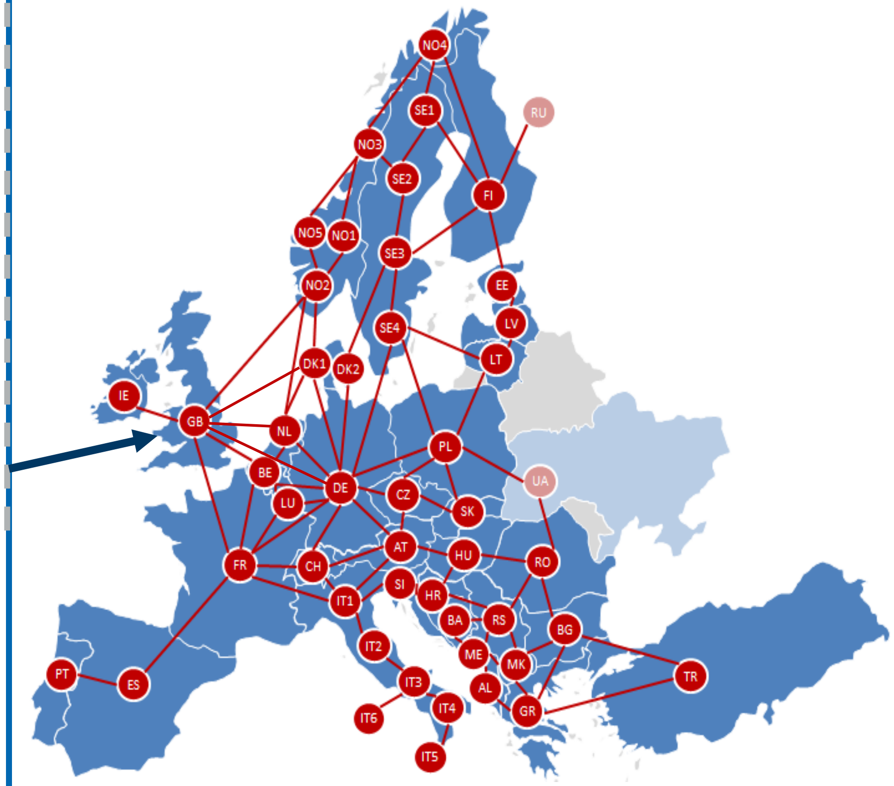
Australia | Sweden | Norway | Italy

Nodal

*System divided into **c.850 "nodes"** with individual prices*



USA | New Zealand | Canada (Ontario) | Singapore



… and we have also assessed wider system impact of implementation costs, financing costs and liquidity

Today's presentation delivers our final assessment results, assessing the following key impacts of locational wholesale electricity pricing

Type	Effect	Covered today
Short-run impact ***(Operational)***	**Changes in wholesale prices** (lower in export-constrained areas and higher in import-constrained areas)	✓
	Reduced cost of congestion to be borne by consumers	✓
	More efficient dispatch across all resource types including **flexibility resources**	✓
	Surplus revenues from congestion rent (and losses)	✓
	Operational impacts from central dispatch system relative to the BM	
Long-run impact ***(Investment)***	Greater incentives for **generation and storage to site** at more efficient locations	✓
	Greater incentives for **demand to site and/or grow** at more efficient locations	
	Improved signals for **transmission development** (due to transparent wholesale prices between different nodes)	✓
Costs / Other	Changes to **CfD payments**	✓
	Other **policy interactions**	
	ESO system implementation costs	✓
	Market participant implementation costs	✓
	Changing **risk profiles** of market participants including **financing cost**	✓

Our assessment supports seven conclusions which we explore throughout this workshop in further detail

1. **Significant consumer benefits** modelled between 2025 and 2040 in a nodal market between £28bn and £51bn
2. **All consumers in each GB region are expected to benefit**, although some cohorts more than others
3. Moving to locational pricing would reduce emissions faster – we estimate between 25 and 100 MtCO2 less would be emitted between 2025 and 2040. Applying **DESNZ's carbon values, increases socioeconomic welfare increases by a further £4.3bn to £17.9bn**
4. Our modelled **benefits of locational pricing are (arguably) conservative** – we assume no demand re-siting, no change to total generation capacity by type, and no change to transmission build out
5. Our two **sensitivity scenarios**, shows moderate reductions in benefits, but **still produces significant net benefits**
6. **Flexibility resources**, particularly interconnectors but also batteries and vehicle charging, are utilised more effectively, recognising constraints on the network
7. **Potential significant savings in transmission** – as locational pricing delivers market signals that improves operational and siting decisions, the need for greater transmission investment is reduced

Our overall approach remains unchanged from our previous workshops (in May, August and October 2022)

Locational granularity

National market | **Zonal market** | **Nodal market**

Proposed Modelling scenarios

Scenario 1: Leading the Way

Scenario 2: System Transformation

Key inputs

1 **Transmission capacity**

Includes current & future network topology, and seasonal availability assumptions

2 **Demand**

Includes annual demand, profile and flexibility assumptions by type and location

3 **Generation capacity**

Includes build-out assumptions, plant technical characteristics and renewable capacity profiles

4 **Commodity prices**

Includes price projections for a set of commodities (CO_2, gas etc)

5 **Balancing mechanism and Contracts-for-Difference assumptions**

Includes BM bid and offer prices and capacity constraints, and projected CfD capacity and future regime design

Power Market Model PLEXOS

Long Term Capacity Expansion model

For the zonal and nodal market designs only – the LT model determines the optimal evolution of generation capacity (GW):

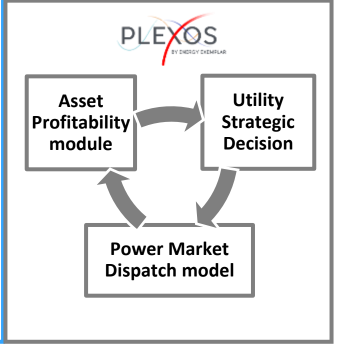
- Finds the lowest-cost combination of generation plants (of all technologies)…
- …that meets the minimum capacity margin,…
- …constraints on CO_2 and other emissions…
- …for each price zone

For the national market design, we will align total capacity and location with the FES scenarios

Short Term Dispatch Model

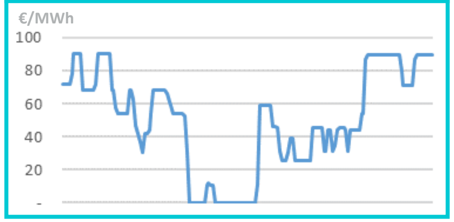
Takes capacity from the Long Term model as given and determines the optimal output of generation (GWh):

- Finds the least-cost dispatch profile of generation…
- …that meets demand…
- …on an hourly basis…
- …for each generating plant…
- …for each price zone

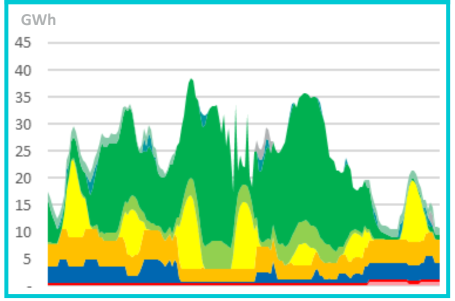


Hourly outputs for each modelled year

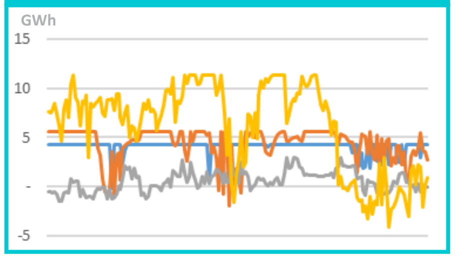
Wholesale power prices



Generation



Flows between zones



6 ***Additional quantitative analysis***

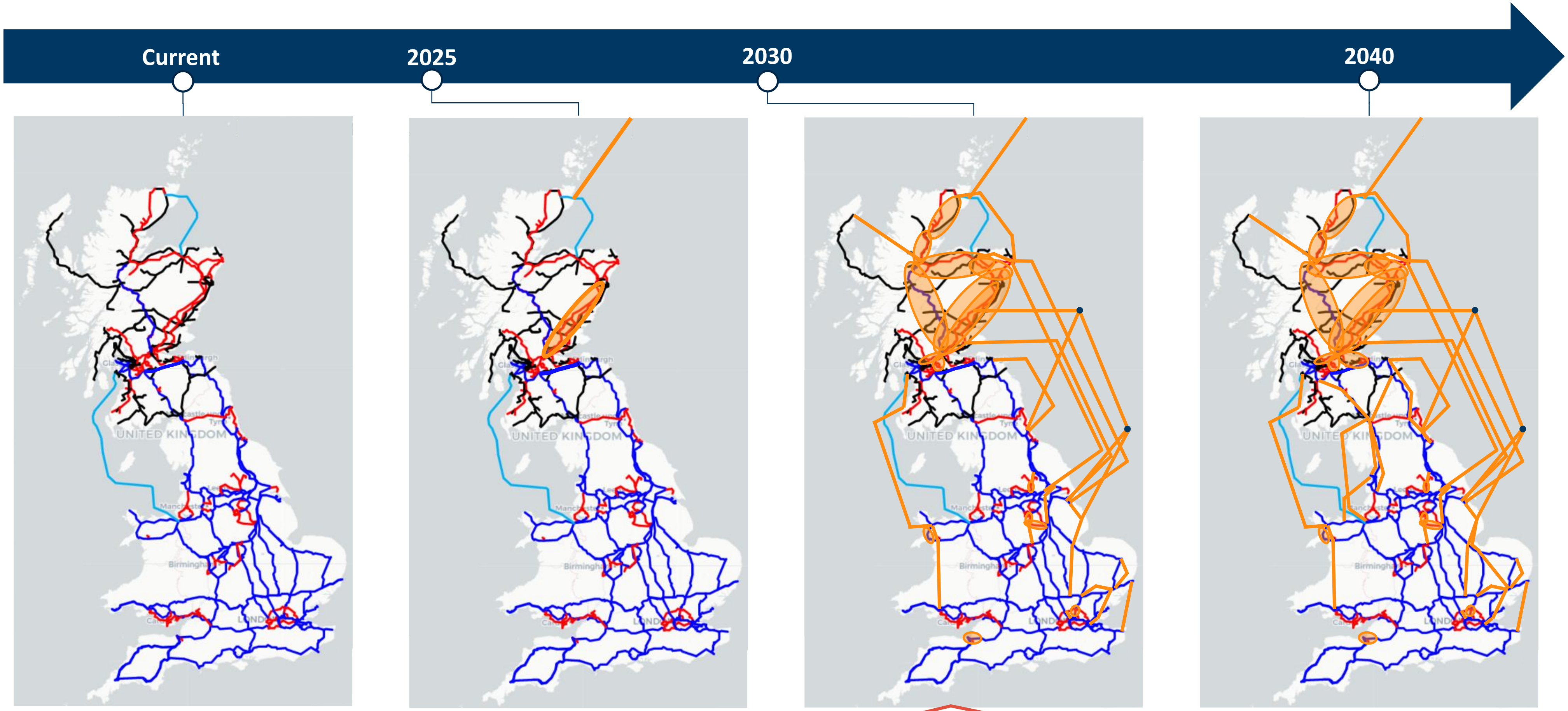
Wherever possible, we have relied on public datasets predominantly from the ESO and ENTSO-E…

Topic	Datasets used
GB transmission	nationalgridESO ETYS 2021, NOA 21/22, NOA 21/22 Refresh
Demand level	nationalgridESO FES 2021
Demand profiles	entsoe Pan-European Climate Database
Demand flexibility	FTI CONSULTING (adapting assumptions from nationalgridESO FES 2021)
Generation capacity and location	nationalgridESO FES 2021
Technical characteristics	entsoe Pan-European Market Modelling Database; Bloomberg NEW ENERGY FINANCE; European Commission EC Technology Pathways: 2020 Reference scenario
Climate profiles	entsoe Pan-European Climate Database
Build limits	nationalgridESO FES 2021; THE CROWN ESTATE Offshore wind leases; Department for Business, Energy & Industrial Strategy CfD Auction, Clustering, H2 strategy

… and have previously discussed and developed these assumptions with stakeholders, and agreed them with Ofgem

The evolution of the transmission network is an external input based on ETYS and NOA, and is the same for all market design variants

Transmission build-out for the LtW (HND) scenario – diagrams illustrate a portion of the transmission lines in our model



- The HND scenario has an additional and accelerated network build between 2025 and 2030
- The equivalent NOA7 scenario has a more gradual build out profile up to 2040

Legend: Existing 400kV line | Existing 275kV line | Existing 275kV line | Existing offshore HVDC | New circuit | Circuit uprating

Sources: ETYS, NOA 2021/22 Refresh, HND

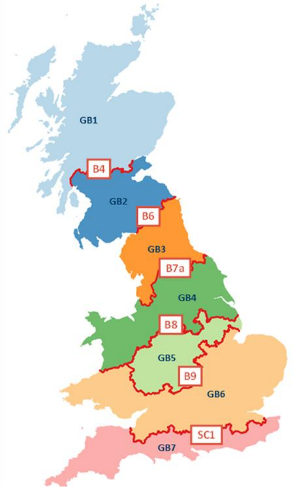
1:Projects on the map only include new offshore circuits, new 400kV onshore circuits and circuit uprating to 400kV. Other projects, such as thermal upgrades are not indicated on these maps

Together with a map of each generating unit, this forms a detailed representation of the GB electricity system, organising around c.850 nodes

Nodal

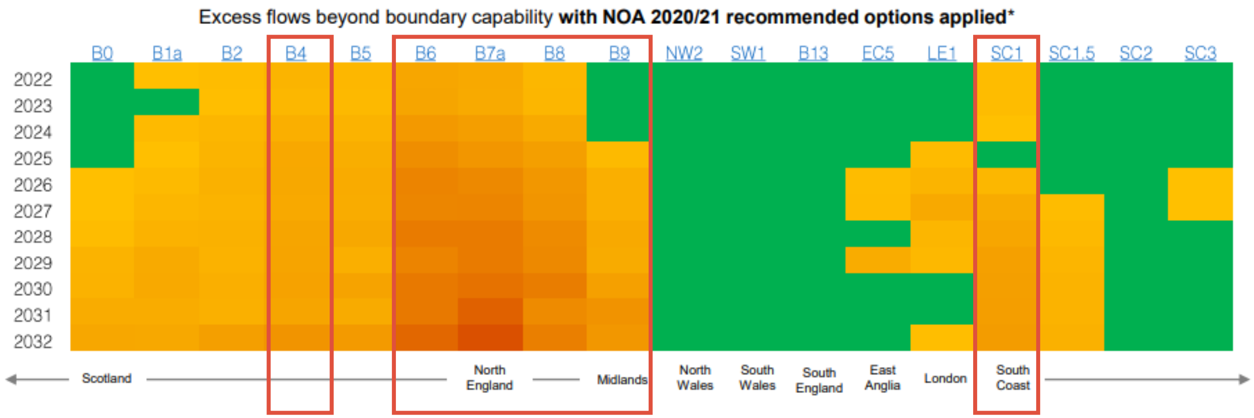
System divided into ***c.850 "nodes"*** *with individual prices*

Zonal



System divided into ***seven zones*** *with individual prices*

For our zonal model, these nodes are then grouped into 7 zone based on the most constrained boundaries as per ESO forecast



- List of boundaries used:
  1. B4: SSEN – SP transmission border;
  2. B6 SP – NGET transmission border;
  3. B7A – Upper North of England
  4. B8 – North of England to Midlands
  5. B9 – Midlands to South of England
  6. SC1 – South Coast

Source: ETYS 2021, page 7

Our assessment varies the market designs for three different scenarios, while holding the generation, demand and transmission assumptions constant

1 SCENARIO 1: Leading the Way (NOA7)

Market design	National	*Vs*	Zonal	*Vs*	Nodal
Generation / demand	LtW	*Vs*	LtW	*Vs*	LtW
Transmission	NOA7	*Vs*	NOA7	*Vs*	NOA7

2 SCENARIO 2: Leading the Way (HND)

Market design	National	*Vs*	Zonal	*Vs*	Nodal
Generation / demand	LtW	*Vs*	LtW	*Vs*	LtW
Transmission	HND	*Vs*	HND	*Vs*	HND

3 SCENARIO 3: System Transformation

Market design	National	*Vs*	Zonal	*Vs*	Nodal
Generation / demand	SysTr	*Vs*	SysTr	*Vs*	SysTr
Transmission	NOA7	*Vs*	NOA7	*Vs*	NOA7

National

The national market design forms the counterfactual against which the zonal and nodal markets are assessed against. We assume no further policy reforms.

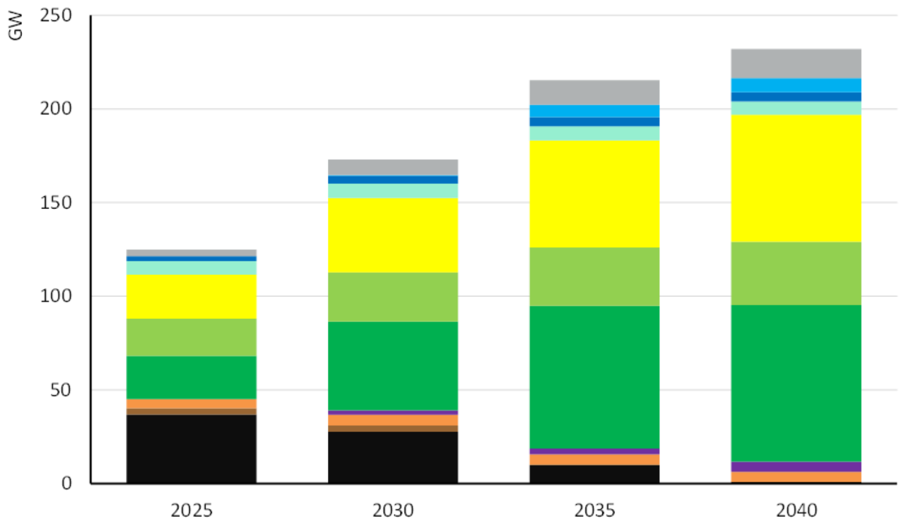
Topic 2a:
Modelling outputs on the status quo market design

Under **LtW (NOA7)**, the majority of fossil fuel generation capacity is retired across all zones by 2035, with significant increases in renewables

LtW is the ESO's **most ambitious scenario** for decarbonisation, involving:

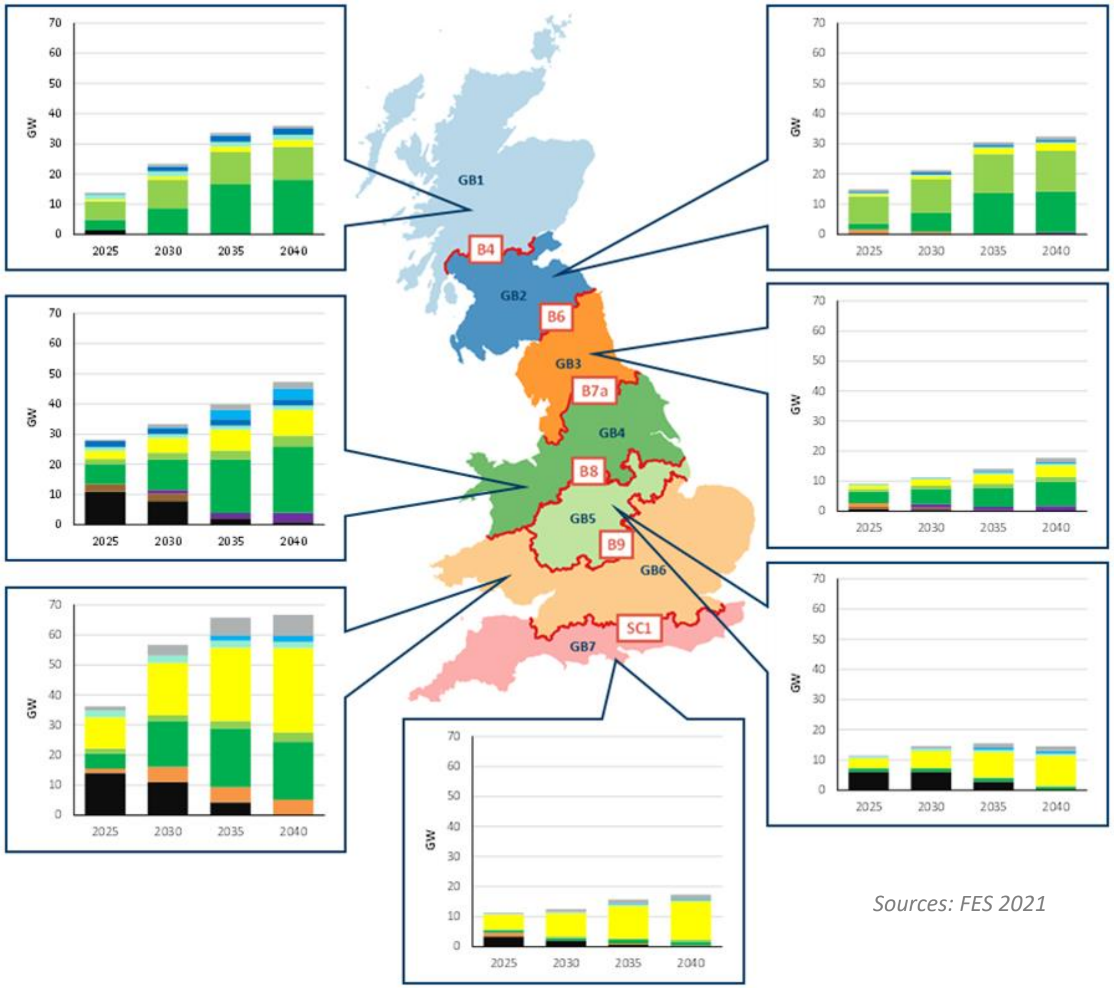
- **Early phase-out of existing fossil fuel generation** and no new additions beyond 2025;
- Rapid deployment of **intermittent renewables**;
- Early adoption of **new generation technologies**, such as Small Modular Reactors and hydrogen;
- Introduction of **carbon negative generation technologies;** and
- **High level of storage capacity and increased interconnection** between GB and other electricity markets

Aggregate GB installed capacity under LtW



Sources: FES 2021

Installed capacity grouped by zone under national market design – LtW (NOA7)

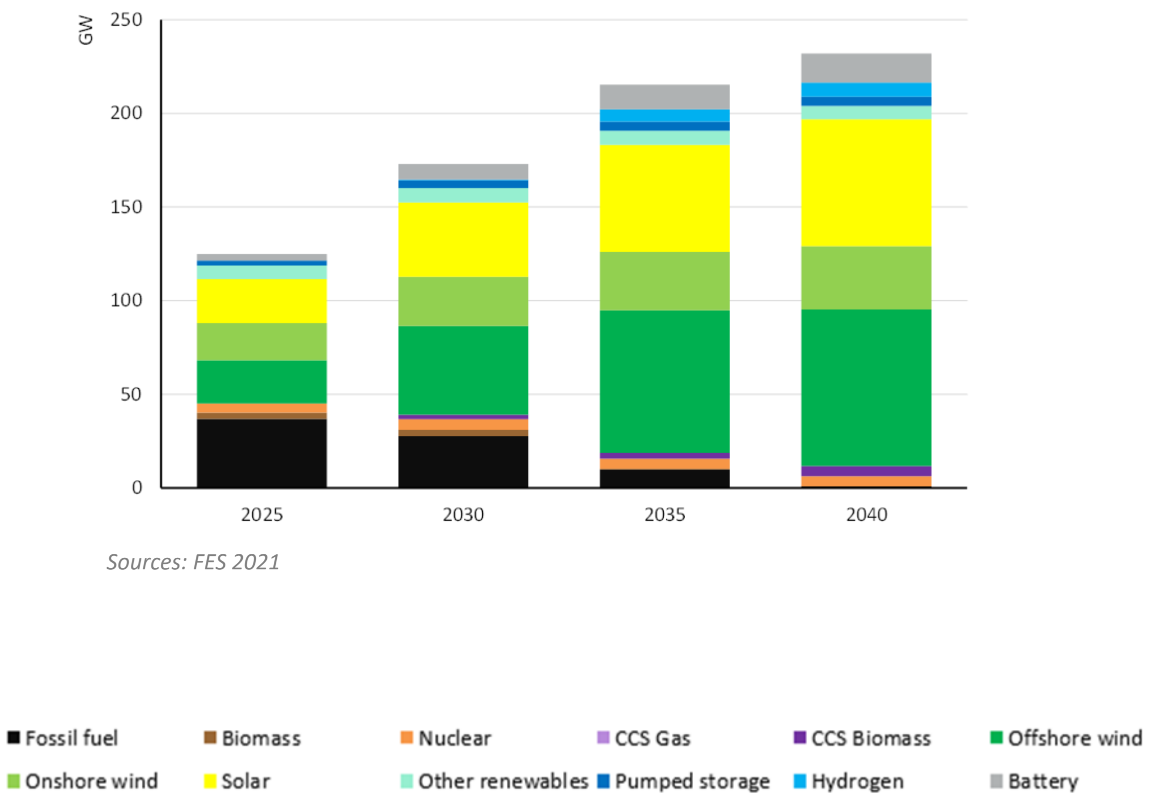


Sources: FES 2021

Fossil fuel | Biomass | Nuclear | CCS Gas | CCS Biomass | Offshore wind | Onshore wind | Solar | Other renewables | Pumped storage | Hydrogen | Battery

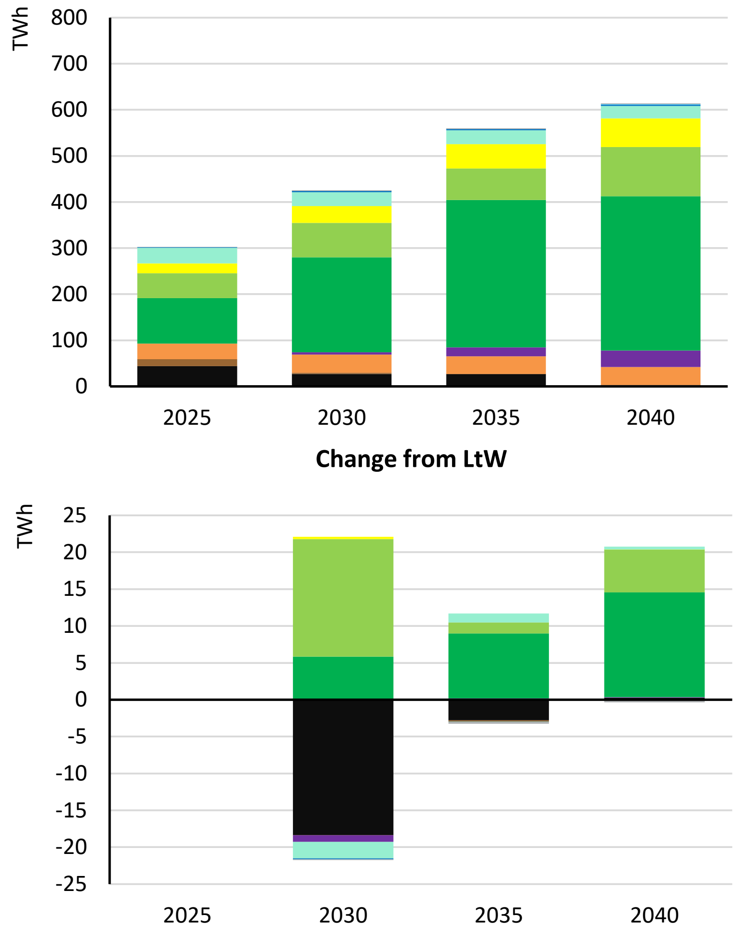
Under the **Leading the Way (Holistic Network Design)** scenario, greater transmission capacity enables more demand to be met by wind generation

Aggregate GB installed capacity under LtW



Sources: FES 2021

Generation under a national market design – LtW (HND)

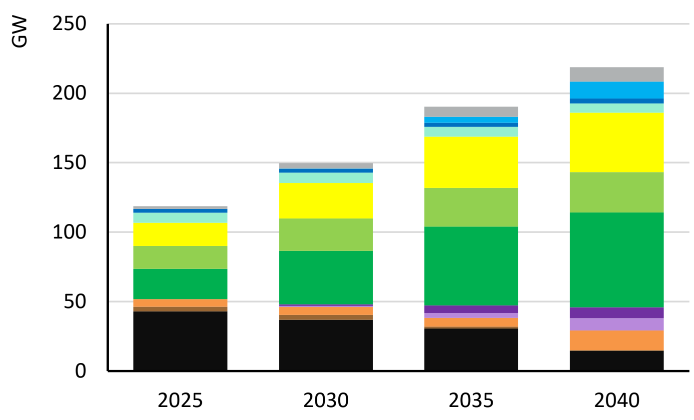


Sources: FTI Consulting

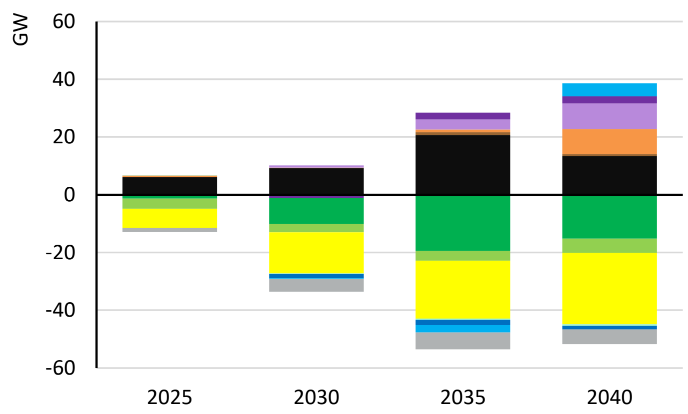
- **Installed capacity** is the same under the LtW (NOA7) and LtW (HND) scenarios.
- Greater and accelerated build-out of transmission capacity enables **more wind generation to be conveyed to meet demand**…
- …this leads to **20TWh** more onshore and offshore wind generation in 2040.

The **System Transformation** scenario represents a slower transition to Net Zero, with lower wind and solar capacity in lieu of more fossil fuel generators

Installed capacity under a national market design – SysTr (NOA7)

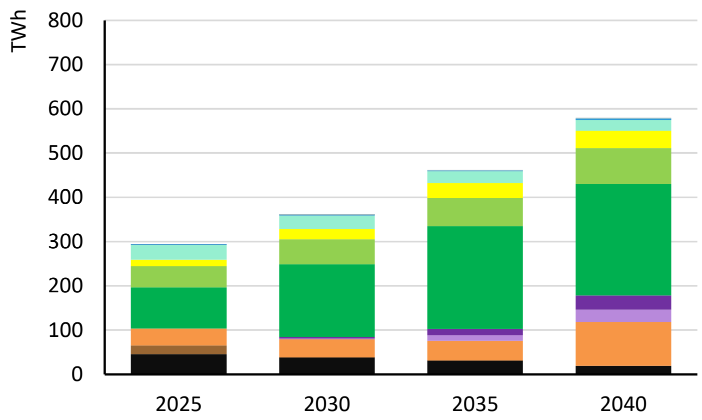


Change from LtW

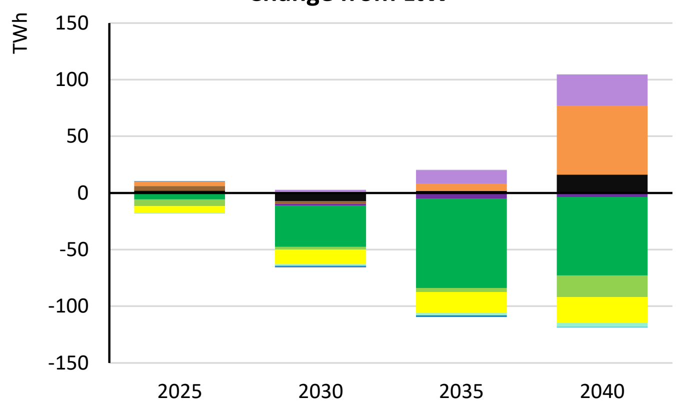


Sources: FES 2021

Generation under a national market design – SysTr (NOA7)



Change from LtW



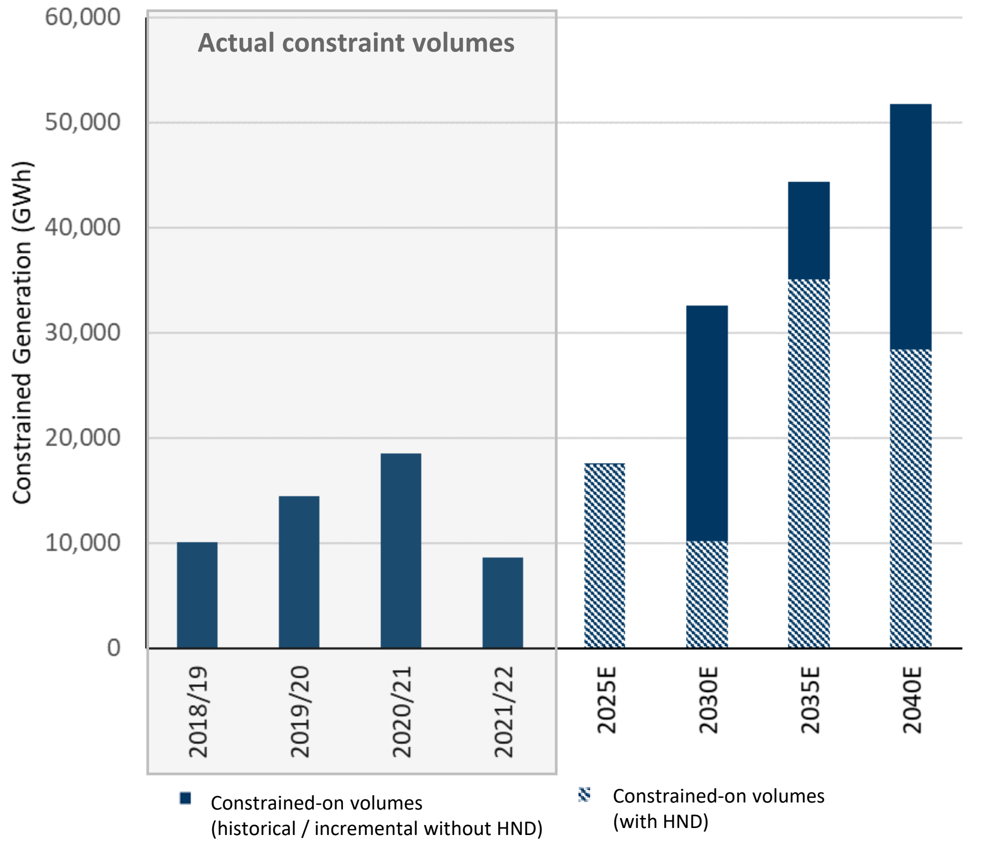
Sources: FTI Consulting

Fossil fuel | Biomass | Nuclear | CCS Gas | CCS Biomass | Offshore wind | Onshore wind | Solar | Other renewables | Pumped storage | Hydrogen | Battery

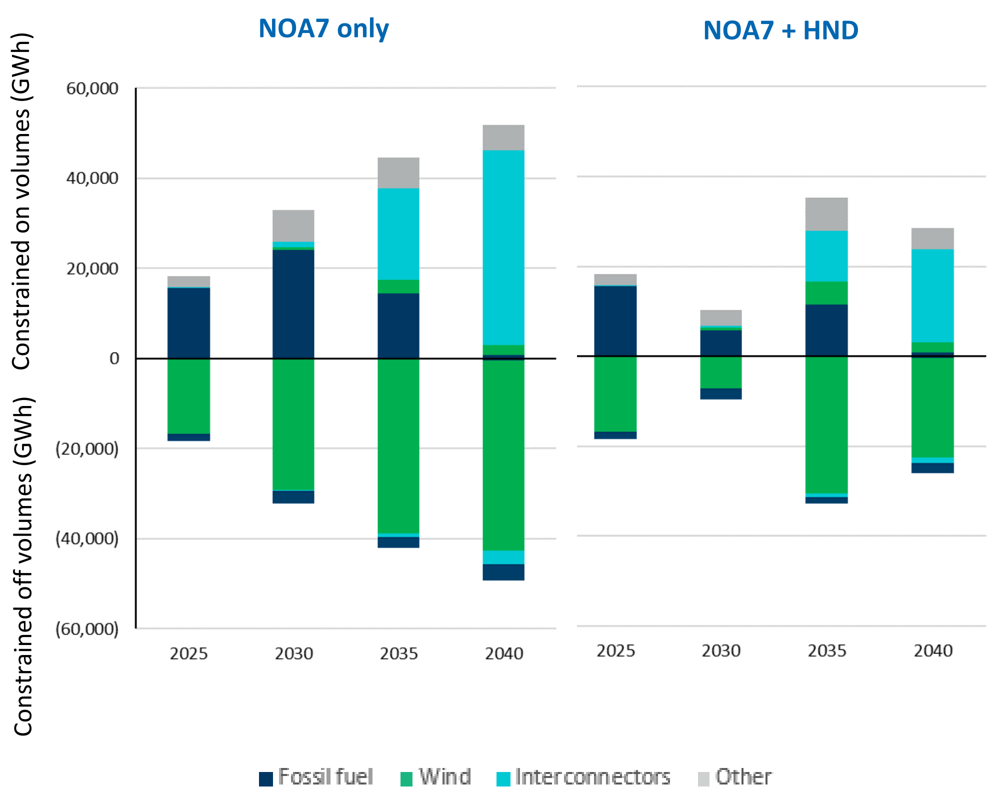
- Compared to the LtW (NOA7) scenario, the SysTr scenario has **61TWh more nuclear generation** and **44TWh more fossil fuel generation** (including CCS gas) in 2040…
- …in lieu of lower renewable deployment with **23TWh less solar generation** and **88TWh less onshore and offshore wind generation** in 2040.

As part of the status quo market assessment, we needed to assess constraint management cost – constrained on and off volumes increase in all scenarios

Actual and modelled constrained on volumes (National design, GWh/year)



Breakdown of constrained on/off volumes by technology (GWh/year)



- Our modelling results show congestion volumes increasing to **c.51TWh by 2040.**
- Given the additional transmission under HND, the rate of increase in congestion volumes is lower under an alternative HND scenario to **c.28TWh by 2040**.
- The increase in congestion volume arises mostly from constrained-off **wind** generation.
- As expected, curtailment is **reduced under the HND scenario.**

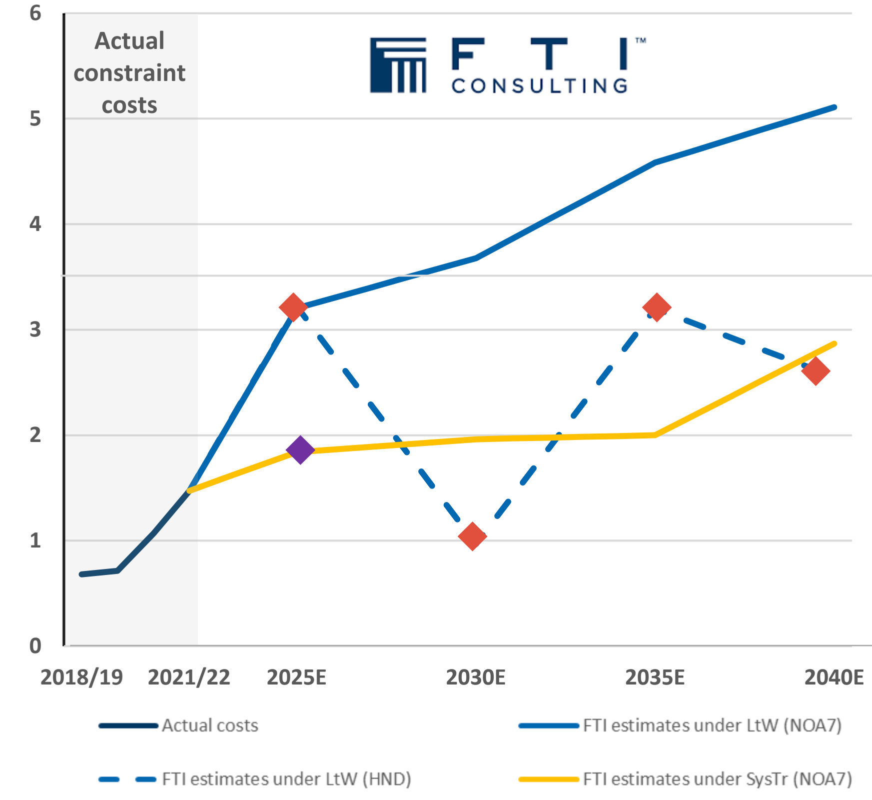
In previous workshops we discussed our BM assumptions with stakeholders; we have verified our methodology with the ESO and agreed with Ofgem

Technology	Cost to ESO Bid	Cost to ESO Offer
Fossil fuel	- Fuel cost - carbon cost	Offer Uplift + Fuel cost + carbon cost
Biomass	- Fuel cost	Offer Uplift + Fuel cost
CCS Biomass	Carbon price – Fuel cost	Offer Uplift + (Fuel cost – carbon price)
ROCs renewables	ROCs[1]	(theoretical only so no price assumed)
CfD renewables	CfD strike price – Wholesale price	(theoretical only so no price assumed)
Merchant renewables	£0	Offer Uplift
Batteries	- Price Paid	Price Received + Offer Uplift
Other Storage Technology	- Marginal Value	Marginal Value
Hydrogen generation H_2	- Marginal Value	Marginal Value
Interconnector	Cost of reversing flow €130 / €100[2]	Cost of reversing flow €130 / €100[2]

1- The number of ROCs will depend on technology. For simplicity, we assumed 1.9ROCs for OfW and 0.99ROCs for Onshore which is the average per technology from BEIS [link]
2 - Cost of reversing flow of €130 assumed in 2025 and 2030

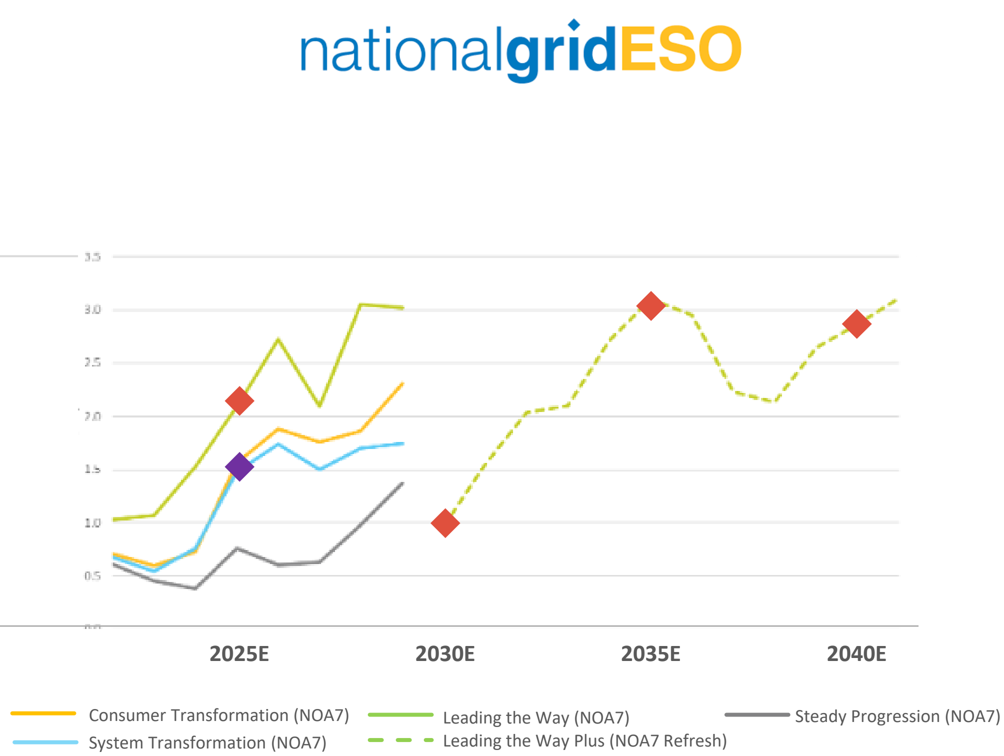
Our updated estimate (with and without HND) maintains a significant increase in constraint costs post-2030, in line with the ESO's August revised forecast

Constraint cost estimates, Leading the Way, 2018-2040, £bn



Source: FTI analysis

ESO constraint costs, NOA7 + HND, 2022-2041, £bn

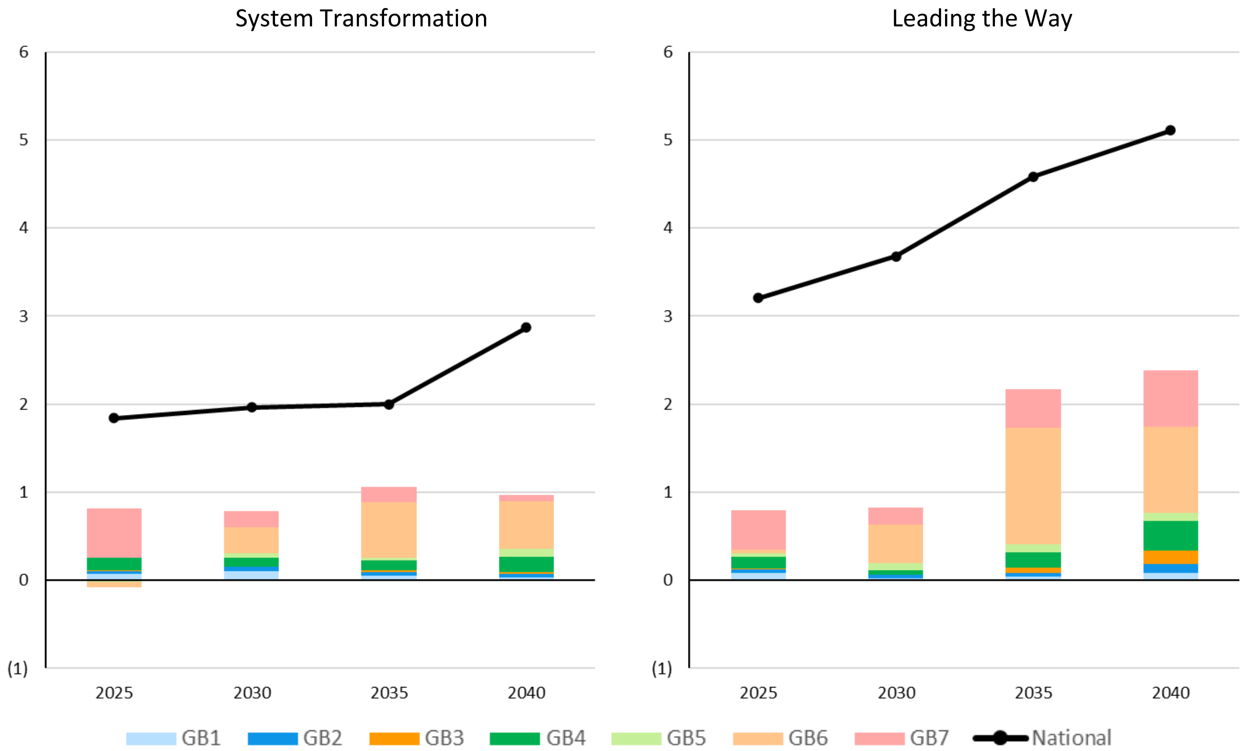


Source: ESO (2022) Modelled Constraint Costs – August 2022 (link)

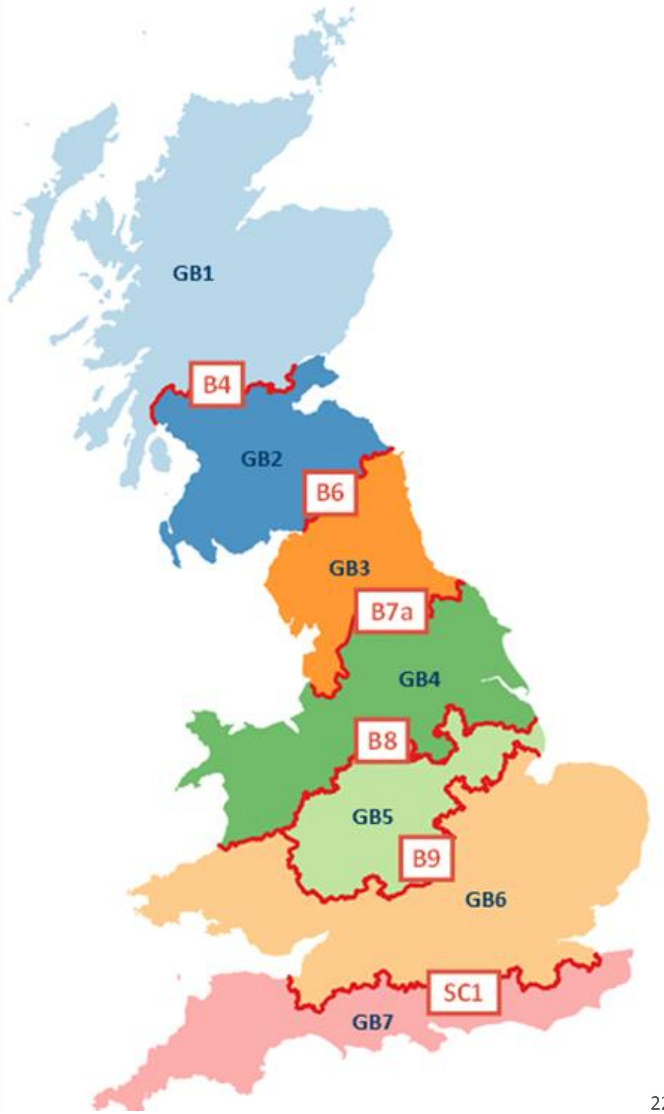
- Our assessment indicates that constraint cost under the national market design option could **exceed £4bn by 2035**.
- **HND transmission projections** would slow down the increase in constraint cost by 2035 to just under £3.5bn.
- This broadly **follows the trajectory of the latest ESO forecasts** of NOA7 + HND congestion costs published in August 2022…
- … albeit ours are higher (which could be explained by our more locationally granular approach to assessing constraint volumes).
- **SysTr** constraint costs are tend to be lower at £2bn - £3bn p.a. (reflecting greater volumes of predominantly nuclear, generation in the south).

A move to zonal market design would reduce the overall level of constraint management costs – although the impact lessens over time

Constraint cost estimates, Leading the Way and Sys Trans, NOA7, 2025-2040, £bn



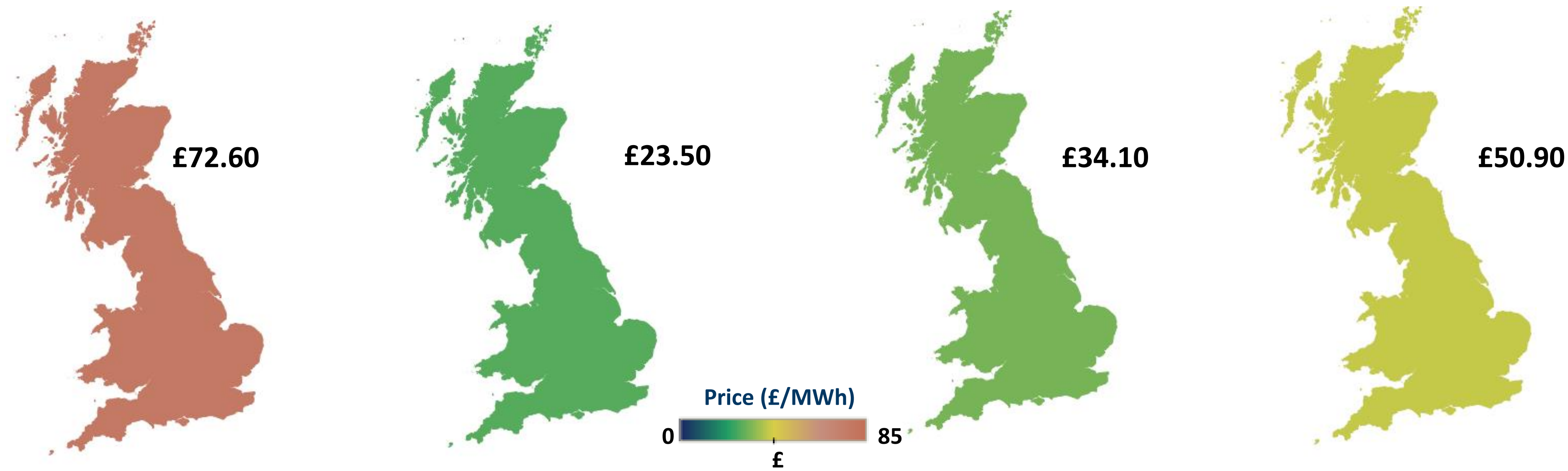
Source: FTI analysis



- Under the zonal market design option constraint cost projections up to 2030 are **lower than costs currently observed under national market design**.
- Post 2030, LtW zonal constraint costs are forecasted to **increase to above £2bn.**
- Increasing constraint costs in GB6 and GB7 zones illustrate the need for policymakers to consider and evaluate the **benefits of re-zoning as the system evolves**.

Pressure on wholesale prices is expected to ease in 2030 but increase again due to increased electrification, limited flexibility options and high carbon prices…

2025 | **2030** | **2035** | **2040**



2025

A load-weighted annual average wholesale prices are **expected to be high** in 2025…

….reflecting **higher gas prices** in a system that is still **reliant on fossil fuels.**

2030

These are **expected to fall significantly** by 2030…

…as **pressure on gas prices** is **expected to ease**…

…and **more renewable capacity** is built.

2035

Power prices **trend upward** again in 2035…

…as **increased electrification** drives electricity demand…

…and rising carbon prices increase the cost of some flexible generation.

2040

Wholesale prices continue to increase into 2040…

…reflecting **high carbon prices** and **fewer options for flexibility** as gas capacity becomes increasingly limited…

…with GB exposed to **higher prices in other countries** due to **increased reliance on ICs**.

… we compare these prices across the three market designs, while holding input assumptions constant

Source: FTI analysis

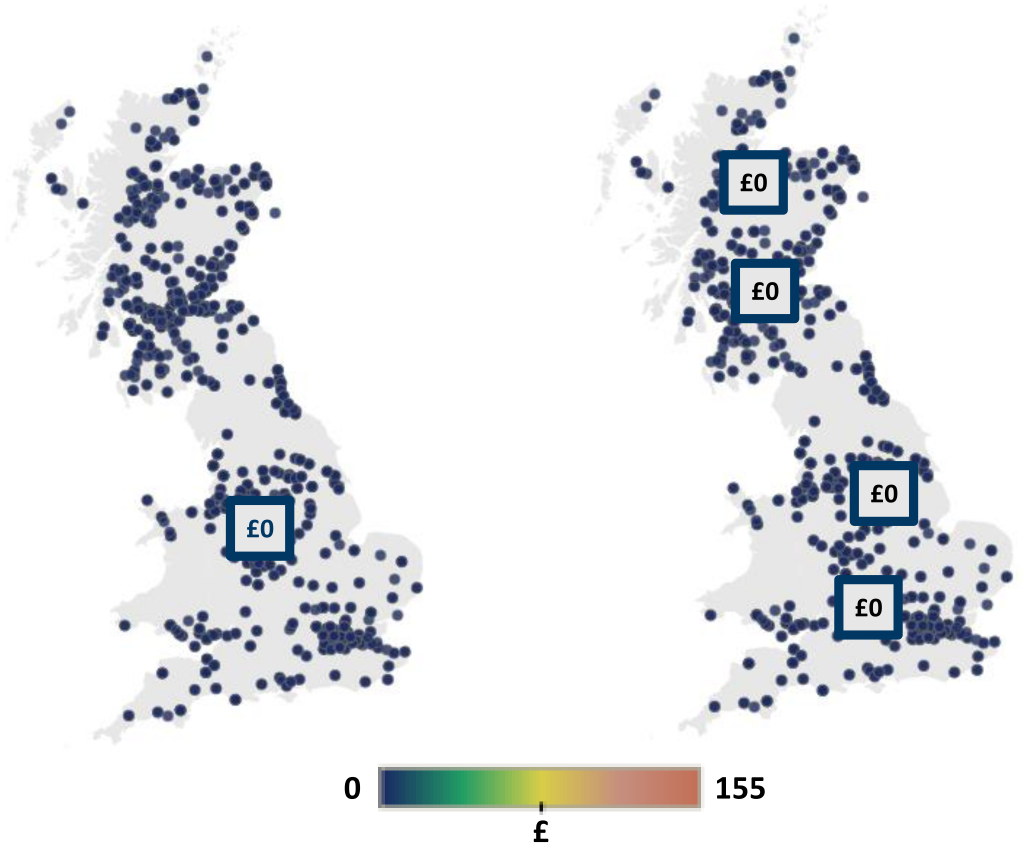
Topic 2b:
Modelling outputs on the locational market designs

Pricing outcomes

In our assessment, wholesale electricity prices vary under each market design – we show example hours below when wind output is very high…

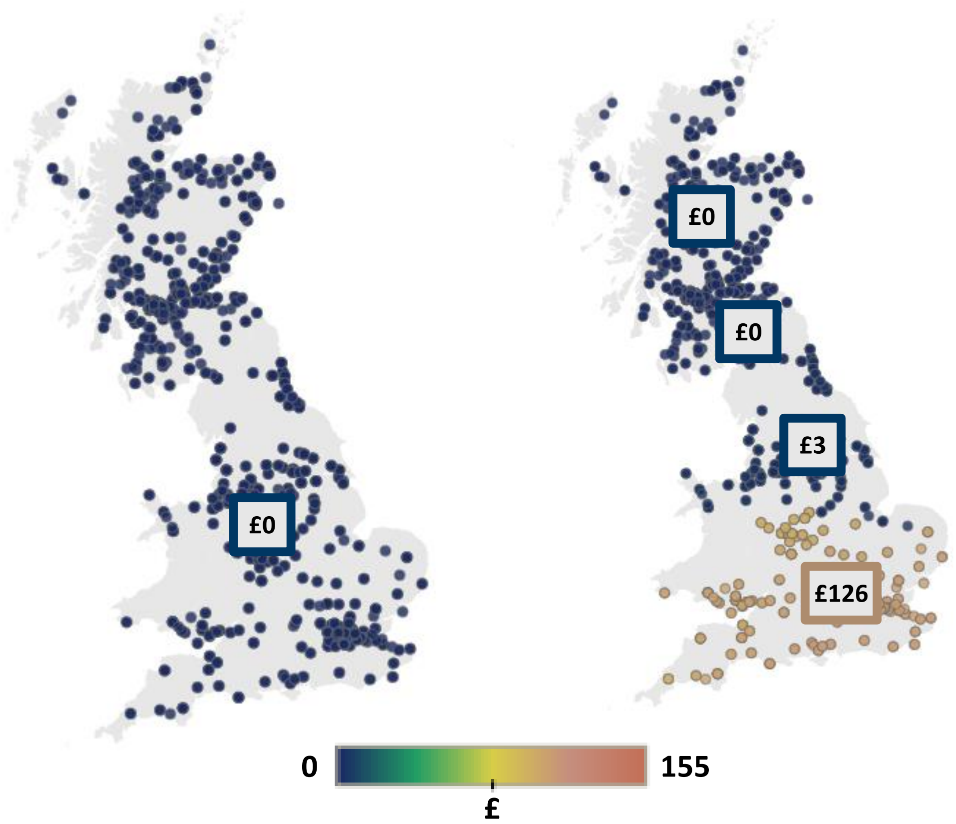
1 *Example of a very high wind hour across GB (29th Sept 2040 – 12:00)*

National | **Locational**



2 *Example of a very high wind hour in Scotland and northern England (10th Dec 2040 – 17:00)*

National | **Locational**

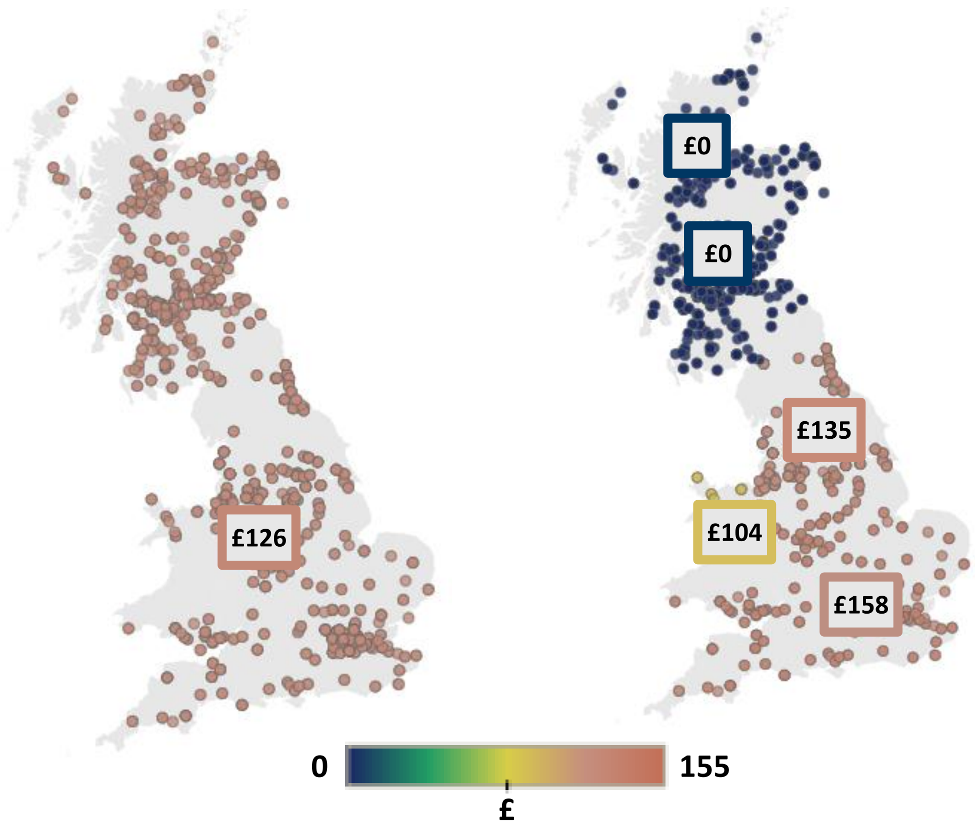


Source: FTI Consulting

… and also show example hours when wind output is lower

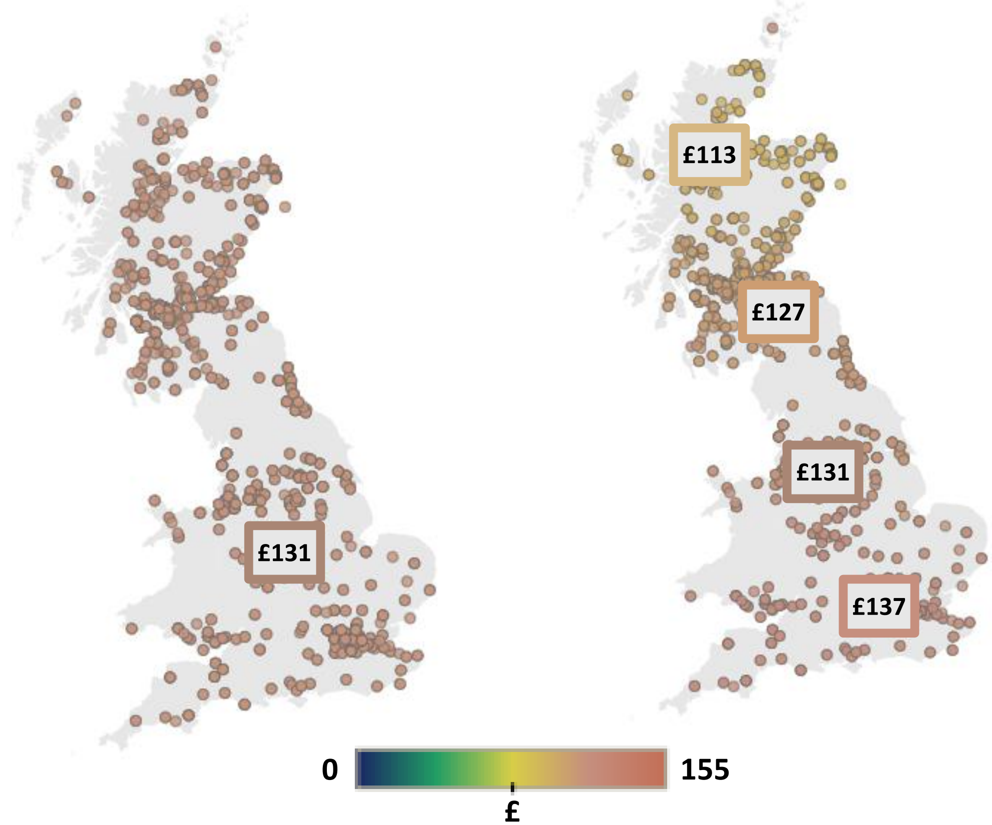
1 *Example of a moderately high wind hour in Scotland and northern England (17th Jan 2040 – 17:00)*

National **Locational**



2 *Example of a low wind hour in Scotland and northern England (27th Feb 2025 – 08:00)*

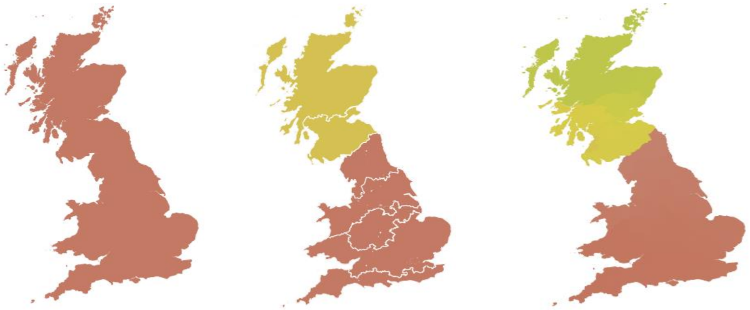
National **Locational**



Source: FTI Consulting

Average wholesale power prices across the three market design options are influenced both by 'macro' trends and by the locational granularity

2025 – Load weighted annual average wholesale prices, £/MWh

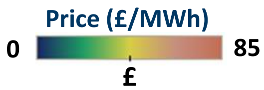


	National	Zonal	Nodal
LtW (NOA7)	£72.60	£47.40 - £79.30	£37.40 - £81.30
LtW (HND)	£72.60	£47.50 - £79.40	£37.40 - £81.40
SysTr (NOA7)	£75.00	£53.90 - £76.90	£42.90 - £80.10

2030 - Load weighted annual average wholesale prices, £/MWh

	National	Zonal	Nodal
LtW (NOA7)	£23.50	£17.40 - £29.20	£13.80 - £31.00
LtW (HND)	£23.50	£21.00 - £24.90	£18.50 - £27.40
SysTr (NOA7)	£25.70	£20.40 - £28.20	£17.20 - £31.00

2035 - Load weighted annual average wholesale prices, £/MWh



	National	Zonal	Nodal
LtW (NOA7)	£34.10	£31.80 - £37.80	£24.90 - £43.10
LtW (HND)	£34.10	£31.10 – £37.00	£25.70 - £42.30
SysTr (NOA7)	£29.90	£25.80 - £31.40	£22.80 - £35.00

2040 - Load weighted annual average wholesale prices, £/MWh

	National	Zonal	Nodal
LtW (NOA7)	£50.90	£45.40 - £50.90	£37.0 - £58.70
LtW (HND)	£50.90	£43.00 - £48.90	£37.50 - £56.40
SysTr (NOA7)	£30.20	£27.60 - £32.20	£21.20 - £38.40

- Moving from national to locational widens the range of prices observed, as Tx congestion and losses (in nodal design) are reflected in wholesale price
- The price spread is generally greater for LtW than for SysTr due to the higher demand, different technology mix, greater penetration of variable renewables and two-way assets (interconnectors and batteries)

Generation capacity re-siting

In our locational models, overall gen capacity by technology are unchanged, but new capacity sites in response to locational price signals, up to a limit

Re-siting assumptions for new build capacity*, subject to limits to proxy for real-life constraints

Technology	Assumption
Onshore Wind	• England: No new onshore wind • Total capacity at any node can be max 2x FES21
Offshore Wind	• Offshore wind responds, but respects historical ARs and resource availability (wind speeds, seabed leases)
Solar	• Total capacity at any node can be max 2x FES21
Battery	• New capacity can locate on any node with battery capacity in FES21 subject to a 400MW p.a. limit
H2 generation	• New capacity can locate at nodes with H2 CCGTs as specified in FES21 and nodes around H2 clusters
CCS Biomass	• Location optimised across clusters and nodes corresponding to clusters identified in government strategy

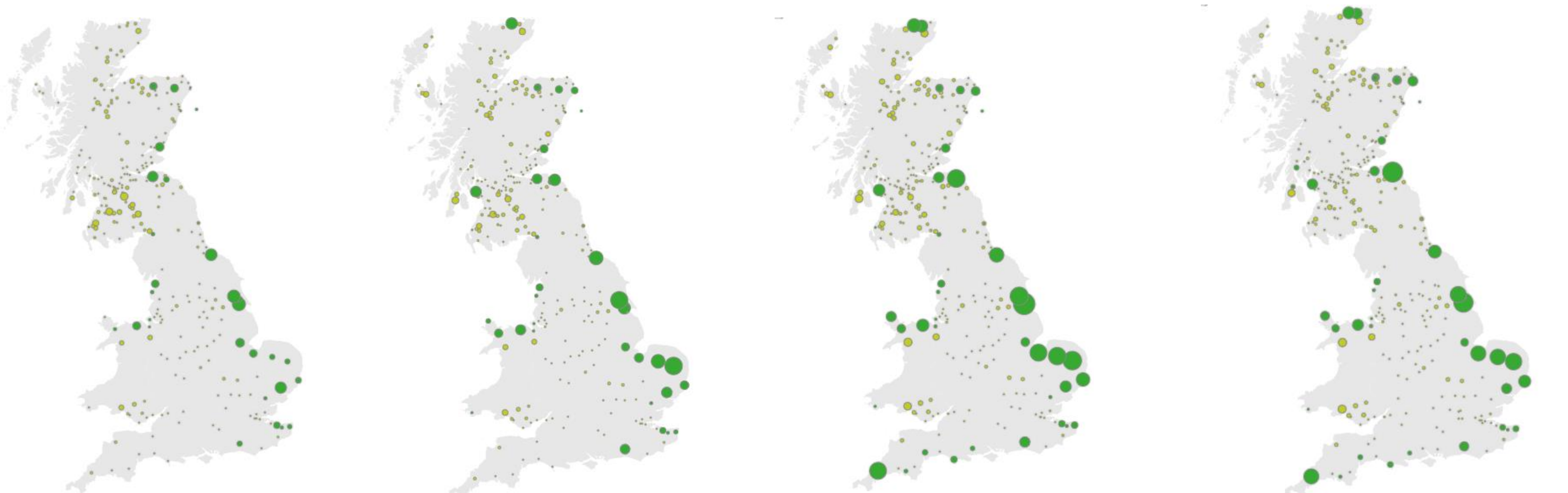
Technology	Assumption
Fossil fuel	• No resiting allowed (fixed as per ESO sources)
Nuclear	
Biomass	
Hydro and pumped storage	
Interconnectors	

Note: we assume all projects in development do not resite. This includes projects that are due to be completed by 2030 in FES which considers some, but not all of the ScotWind projects.

Approximately a third of projected wind capacity resites under a **nodal market**, in response to more granular pricing signals (NOA7)

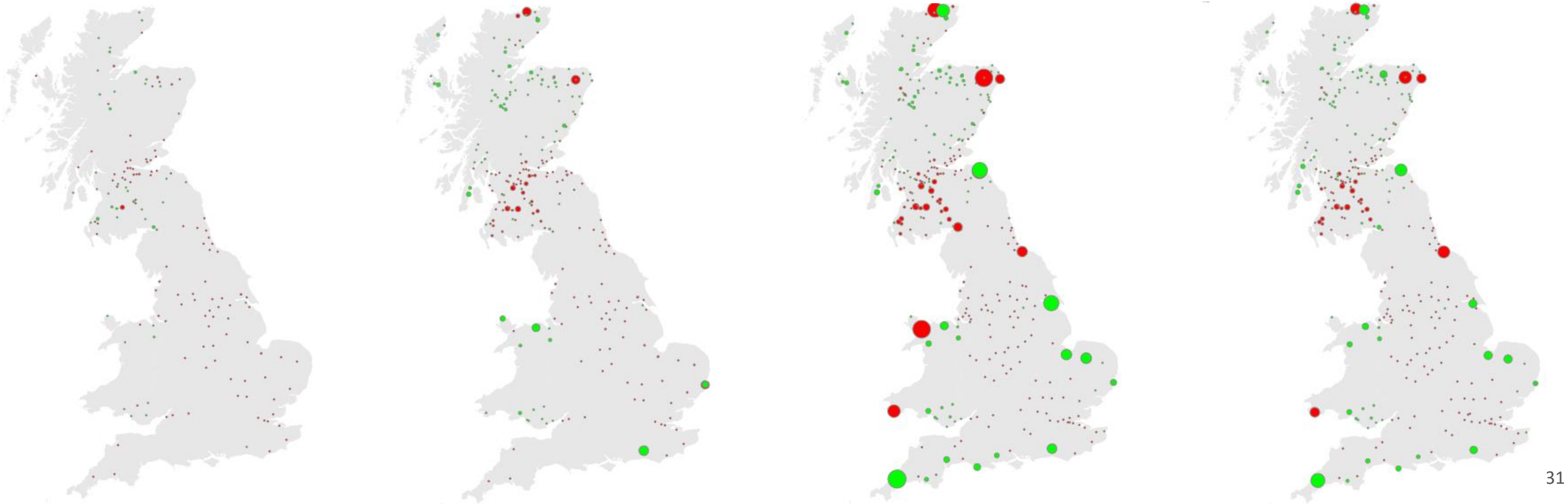
	2025	2030	2035	2040
Installed Capacity	**43GW**	**74GW**	**107GW**	**117GW**

Increase in capacity of offshore wind in Humber and East Anglia



Cumulative capacity with a change in location	**2GW**	**8GW**	**32GW**	**35GW**

In comparison to the national market, we can observe a reduction in installed wind capacity in Scotland, North West of England and North Wales



● **Decrease relative to national model** ● **Increase relative to national model** ● **Offshore wind** ● **Onshore wind**

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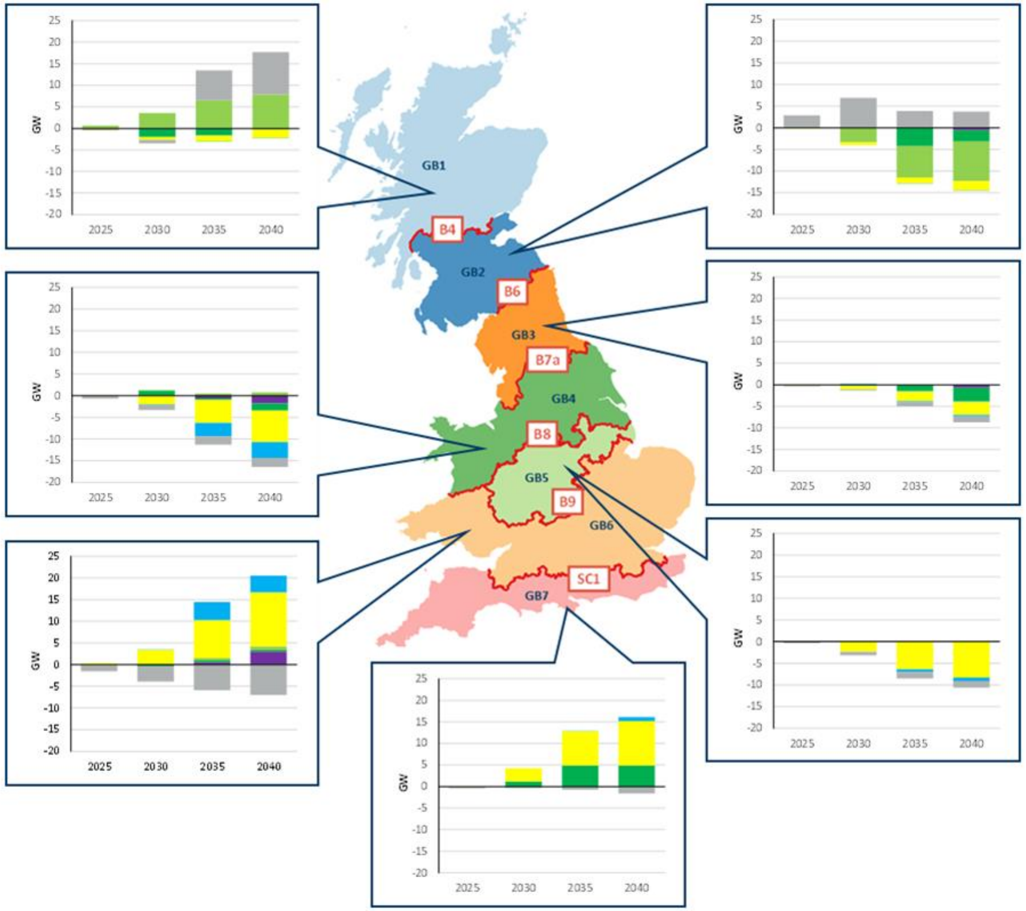
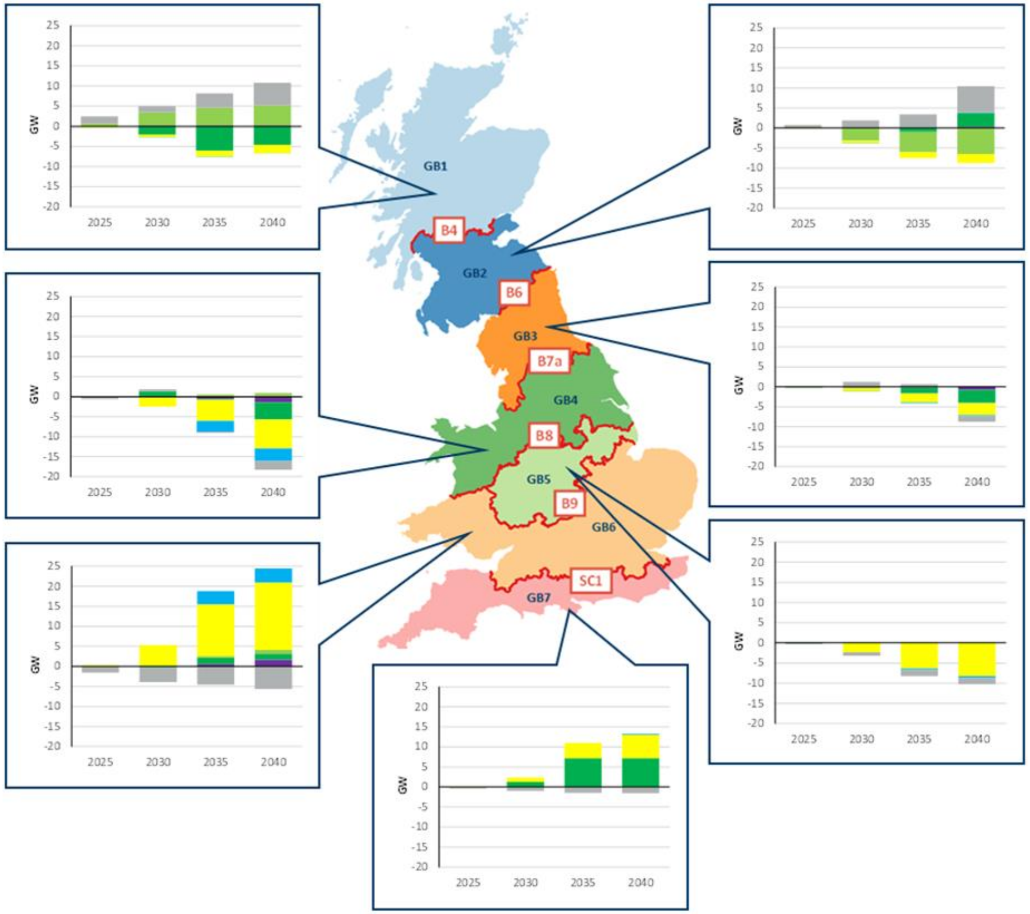
We set out the impact of locational signals on re-siting **new-build generation capacity and storage assets**, while keeping total capacity by tech fixed

ZONAL: change in location of generation capacity between zonal and national market design – LtW (NOA7)



NODAL: Change in location of generation capacity between nodal and national market design – LtW (NOA7)

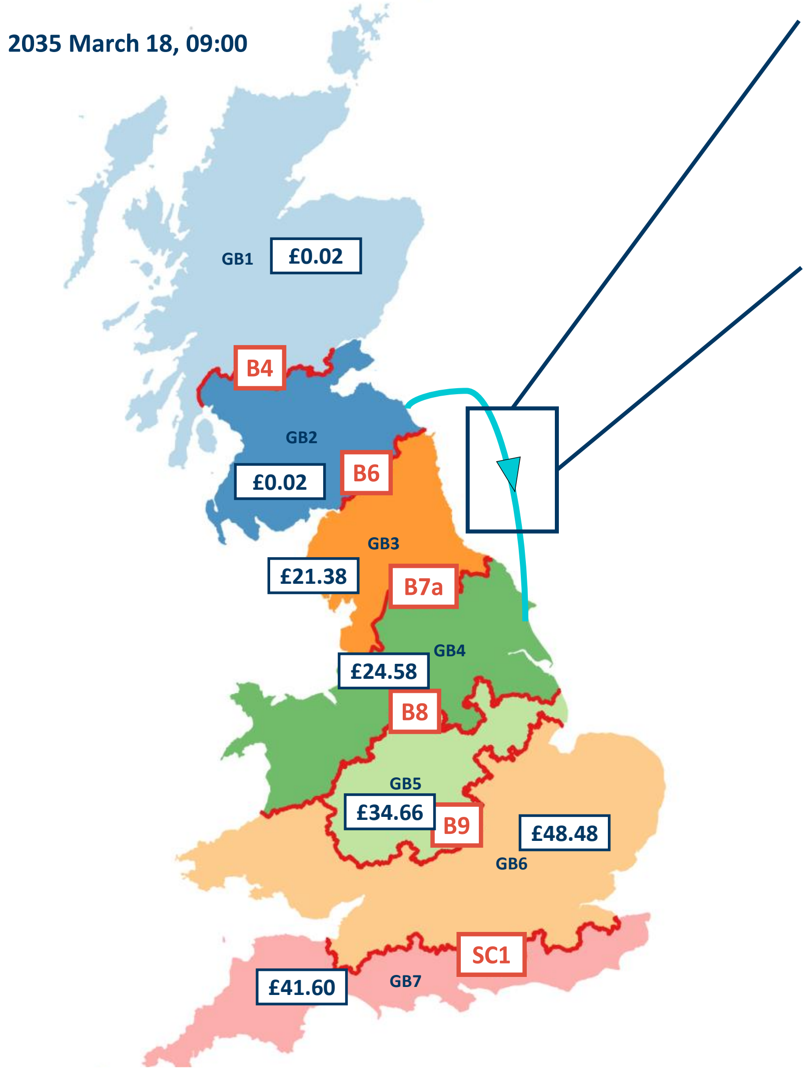


Fossil fuel | Biomass | Nuclear | CCS Gas | CCS Biomass | Offshore wind
Onshore wind | Solar | Other renewables | Pumped storage | Hydrogen | Battery

- In both the zonal and nodal market designs, **significant solar capacity and some offshore wind capacity resites** from Scotland / northern England to southern England.
- The majority of projected **large-scale battery capacity resites** with a significant proportion moving to Scotland and some moving within zones in southern England in the nodal model

Intra-GB congestion rents

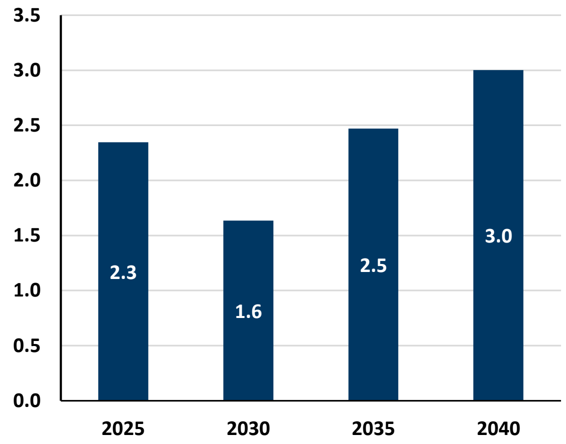
Congestion rents are earned on the wholesale electricity price differential between the two price zones they are connecting



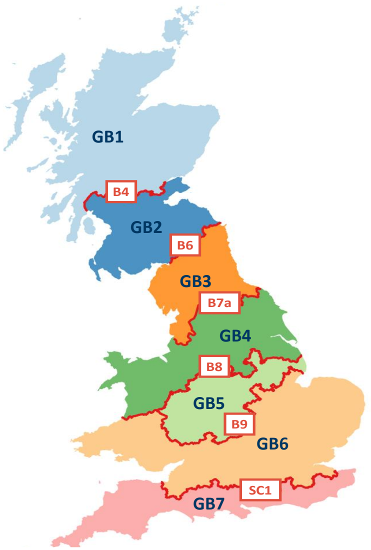
- Suppose, in a **given hour**:
  - The wholesale price of electricity in **GB2** is **£0.02/MWh**;
  - The wholesale price of electricity in **GB4** is **£24.58/MWh**; and
  - There exists **interconnection capacity** of **4.4GW** connecting GB2 and GB4.
- Assuming no losses, in settlement, this results in a rent of £108,064 (4.4GW*£24.56/MWh) in this hour.
- We refer to these revenues as **congestion rents, which arise on all zone boundaries** under a zonal market and **between all nodes on the network** under a nodal model. **Congestion rents do not exist under the national model.**
- They are equivalent in concept to congestion rents in **interconnectors**

In zonal and nodal markets, congestion rents arise in the settlements process from price differentials between connecting price zones or nodes…

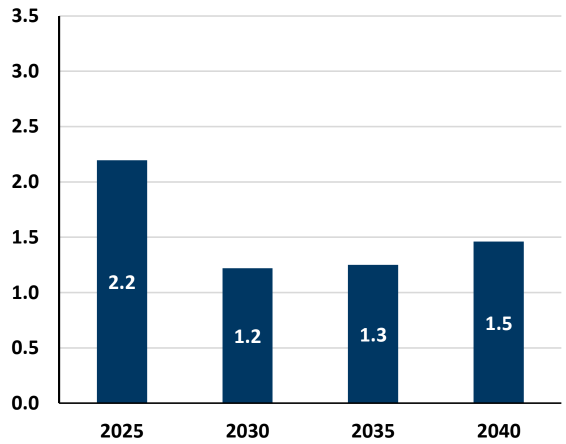
Nodal congestion rents (£bn/year)



- In **nodal markets**, congestion rents and loss surpluses are earned on **all transmission lines between nodes**.
- We estimate these revenues to be between **£1.6bn** and **£3.0bn** across the modelled years



Zonal congestion rents (£bn/year)



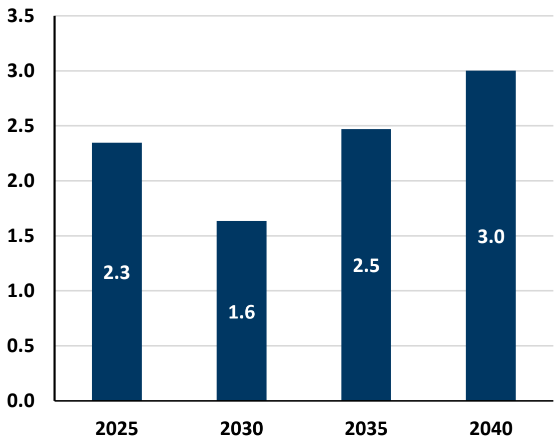
- In **zonal markets**, congestion rents are only earned on **inter-zonal transmission lines**.
- We estimate these revenues to be between **£1.2bn** and **£2.2bn** across the modelled years…
- … reflecting lower zonal spreads relative to nodal spreads

…and are typically used to reduce transmission costs (to the benefit of consumers), although other uses are possible

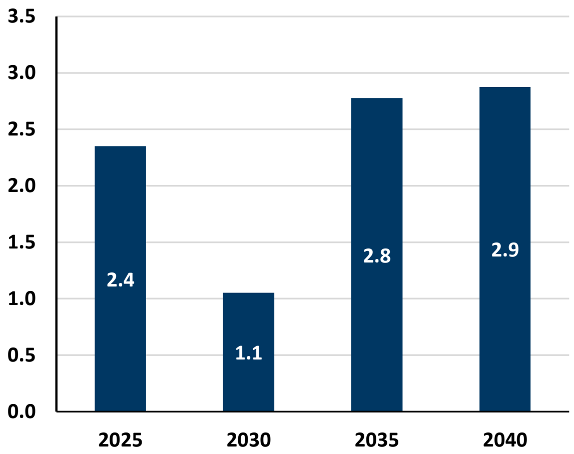
Other scenarios have different forecasted congestion rent values due to differences in prices as well as flows across each line or zonal boundary

Nodal congestion rents (£bn/year)

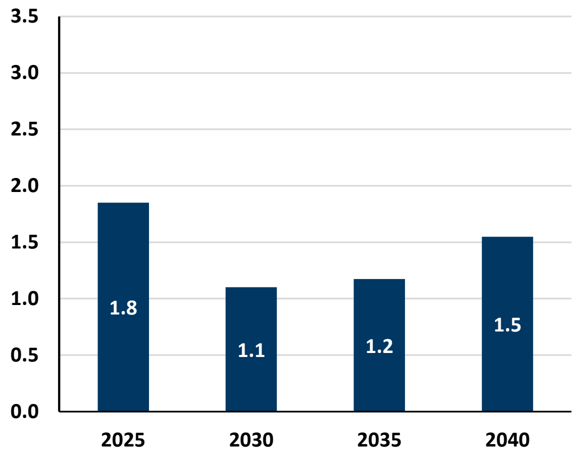
Leading the Way (NOA7)



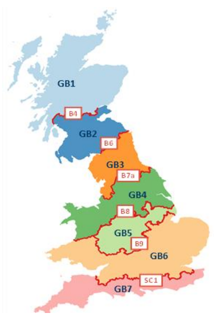
Leading the Way (HND)



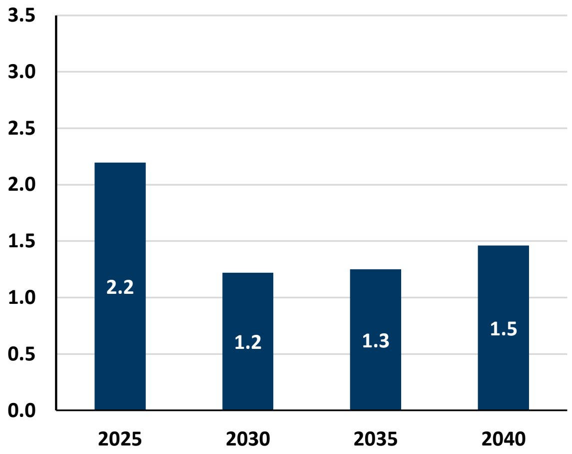
System Transformation



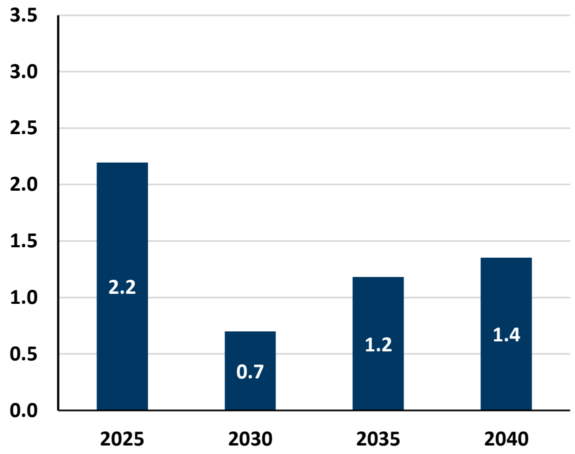
Zonal congestion rents (£bn/year)



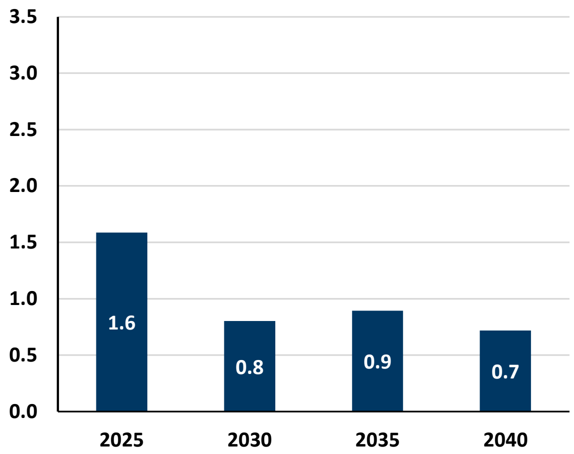
Leading the Way (NOA7)



Leading the Way (HND)



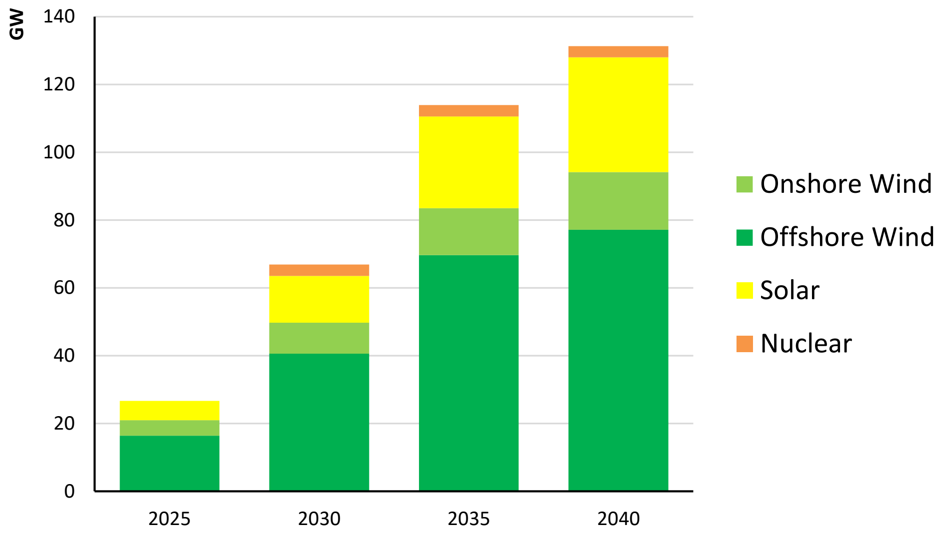
System Transformation



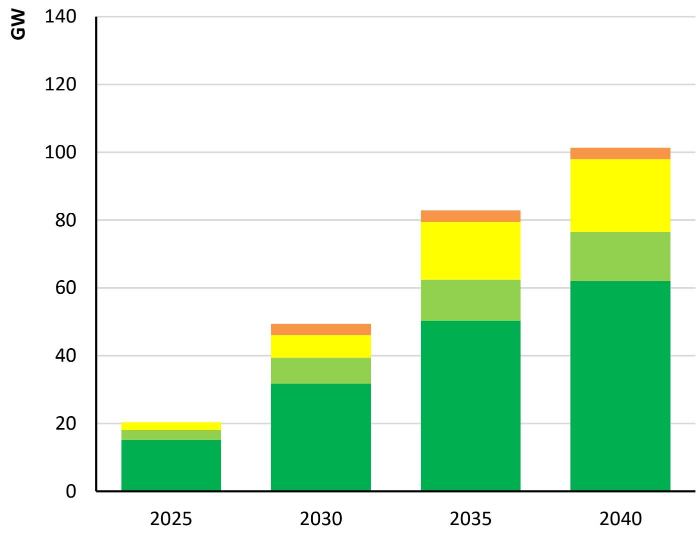
CfD analysis

To assess the impact of locational markets on CfDs, we were required to make two key assumptions – (1) first, on the profile of evolution of CfD capacity…

Assumed projected capacity of CfD holders (LtW)



Assumed projected capacity of CfD holders (SysTr)



Sources: FES 21, BEIS Generation Cost Report 2020, FTI analysis

Technologies included:

(1) Existing projects with CfD contracts
(2) All proposed offshore wind projects awarded CfDs in AR1-4
(3) Hinkley Point C
(4) All future offshore wind projects
(5) 50% of future solar projects
(6) 50% of future onshore wind projects

All other technology types are excluded due to immateriality and / or uncertainty.

FTI assumptions based on limited data sources.

50% assumption selected as a mid-point to reflect increasing participation in Auction Rounds, and increasing potential for merchant investment.

Flexing these assumptions (e.g. assuming 60% which might increase CfD support payments) would:

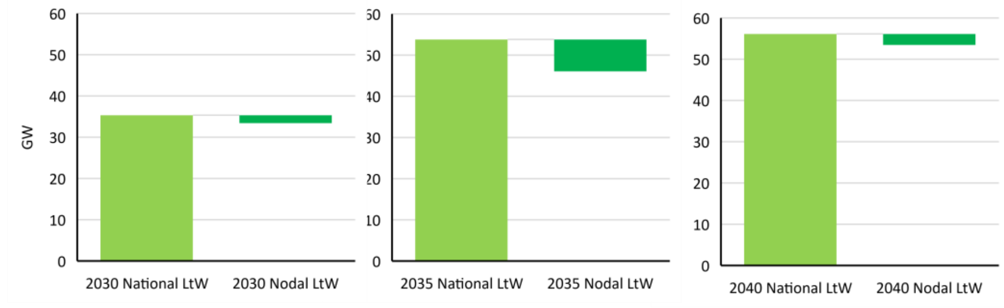
1. Have **no net impact on socioeconomic welfare** (transfer between producers and consumers)
2. Increase the **constraint cost estimate** due to increase in BM bids, and constrained off payments (increasing the benefits of locational pricing)

…and (2) second, on the future CfD regime design

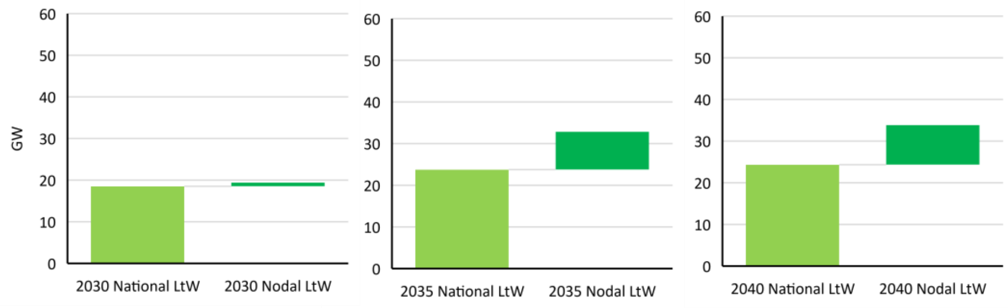
Re-siting of CfD generation capacity

- Future CfD design would have a **locational element to incentivise efficient re-siting** (to benefit from locational price and to reduce curtailment)
- An example of such a design is for CfD auctions to be designed to **reduce support payments instead of strike prices**[1]

Onshore and offshore wind capacity resiting in Scotland - LtW (NOA7)



Onshore and offshore wind capacity resiting in southern England - LtW (NOA7)



Sources: FES 21, BEIS Generation Cost Report 2020, FTI analysis
Note: Different design options are available to benefit from locational prices. While we have explored potential CfD designs with DESNZ and Ofgem, it remains outside of our scope to consider the detailed mechanics of such designs.

Methodology for calculating the CfD support payments

- CfD support payments are calculated for each unit modelled
- We set out our assumptions below

CfD support payments = (**Strike price** − **Reference price**) × **Generation volume**

Strike price
- **BEIS LCOE figures**
- We assume the same LCOE across all locations. In practice, this might differ based on resource factors and constraint risk

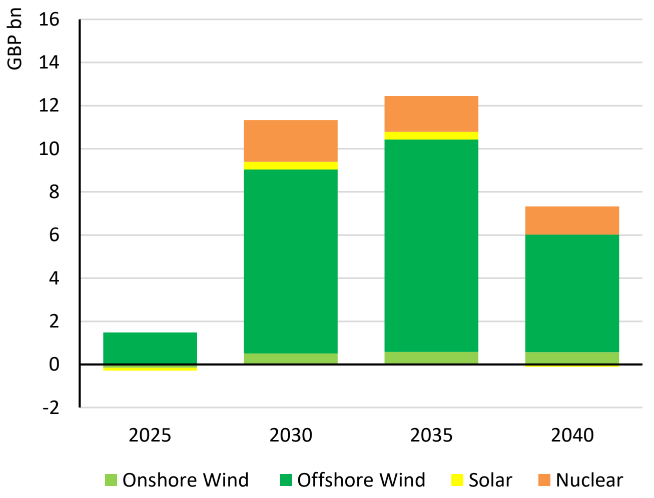
Reference price
- Output from model
- **Zonal / nodal price assumed** for simplicity[1]

Generation volume
- Output from model
- **Generation volumes** are based on **redispatch volumes**

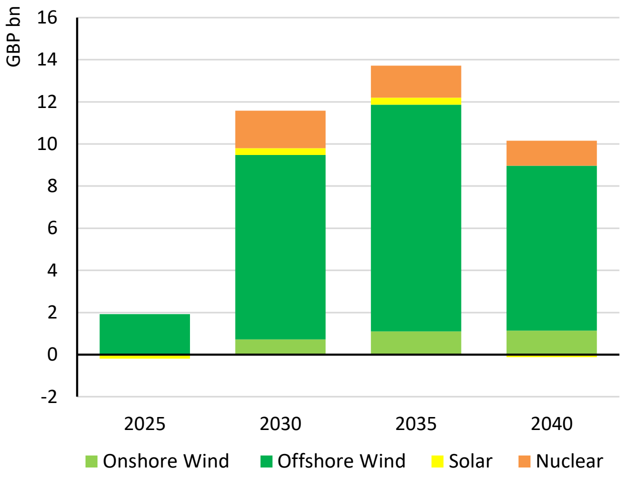
Note: In practice, the reference price could be defined in a number of alternative ways (e.g. a hub price or national price + FTRs to node). For simplicity, we have assumed that the reference price would be based on the individual nodal price.

Under a **nodal market**, total CfD support payments (across 2025-2040) would increase relative to a national market…

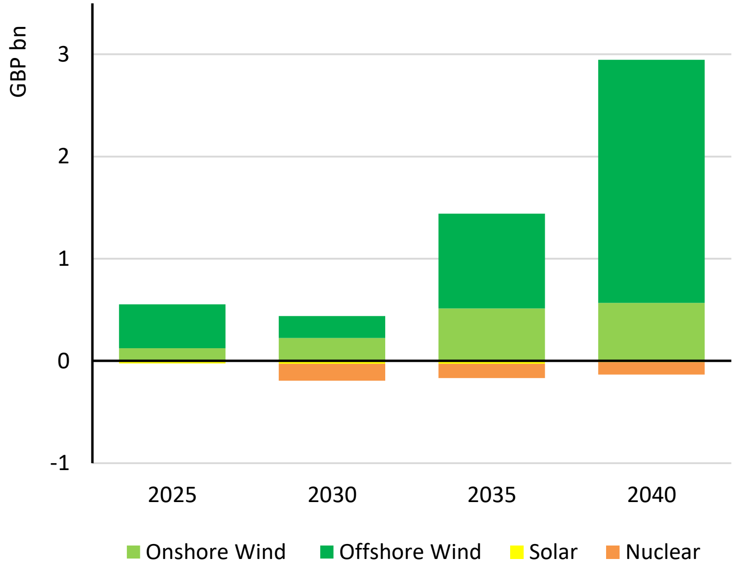
CfD difference payments (National) (£bn)



CfD difference payments (Nodal) (£bn)



CfD difference payments (Nodal – National) (£bn)



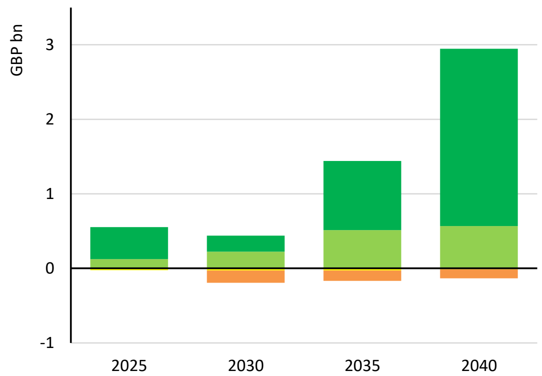
- We estimate that CfD difference payments will steadily increase under a nodal market reaching up to **c.£3bn in 2040**.
- This is driven predominantly by **lower wholesale prices** particularly in northern GB, and in part by a moderate increase in generation volumes.
- CfD support payments for **Hinkley Point C falls** due to an increase in average wholesale prices in that locality.

… we undertake the same analysis for the zonal market, and for each scenario

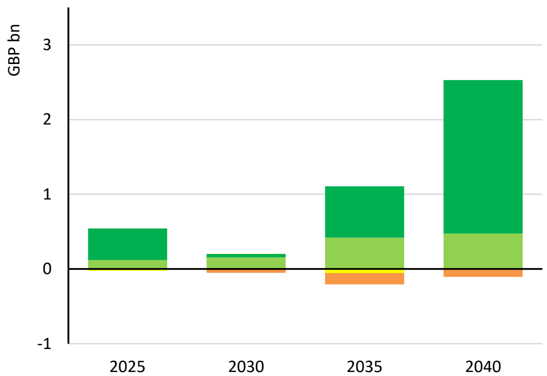
Note: We have not considered the potential savings from the lower cost of RAB-based financed projects

Transitioning to locationally granular prices under LtW (NOA7) increases the CfD payments by the largest magnitude, followed by LtW (HND) and SysTr

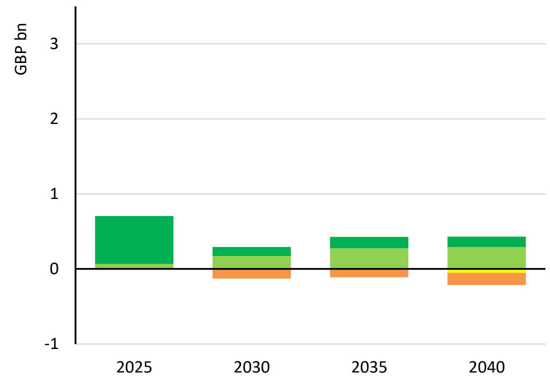
CfD payments for LtW (NOA7), relative to National LtW (NOA7)

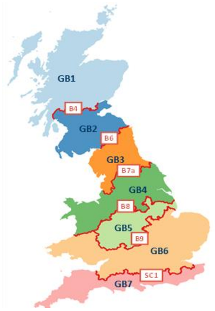


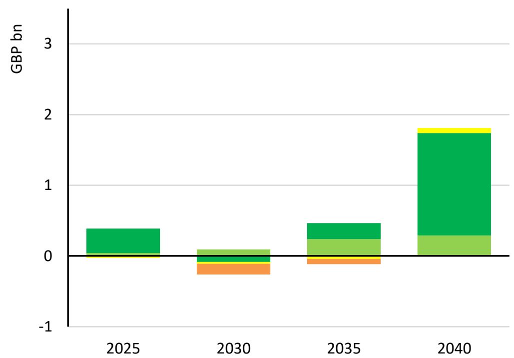
CfD payments for LtW (HND), relative to National LtW (HND)

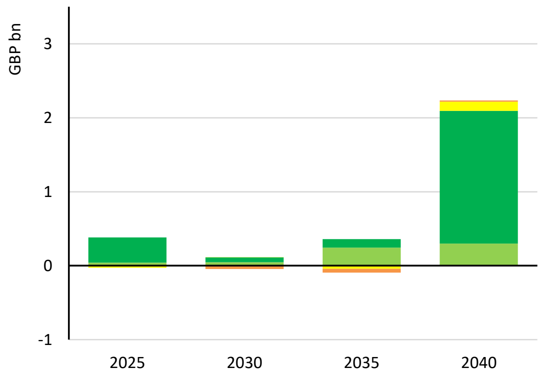


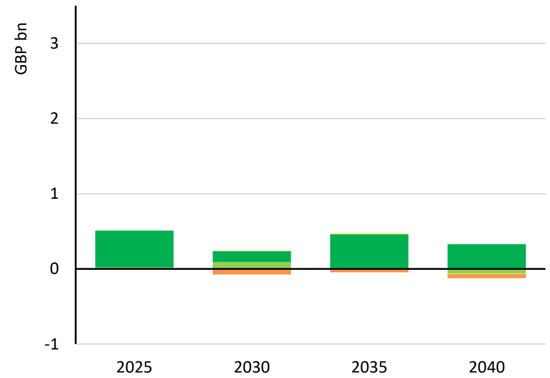
CfD payments for SysTr (NOA7), relative to National SysTr (NOA7)











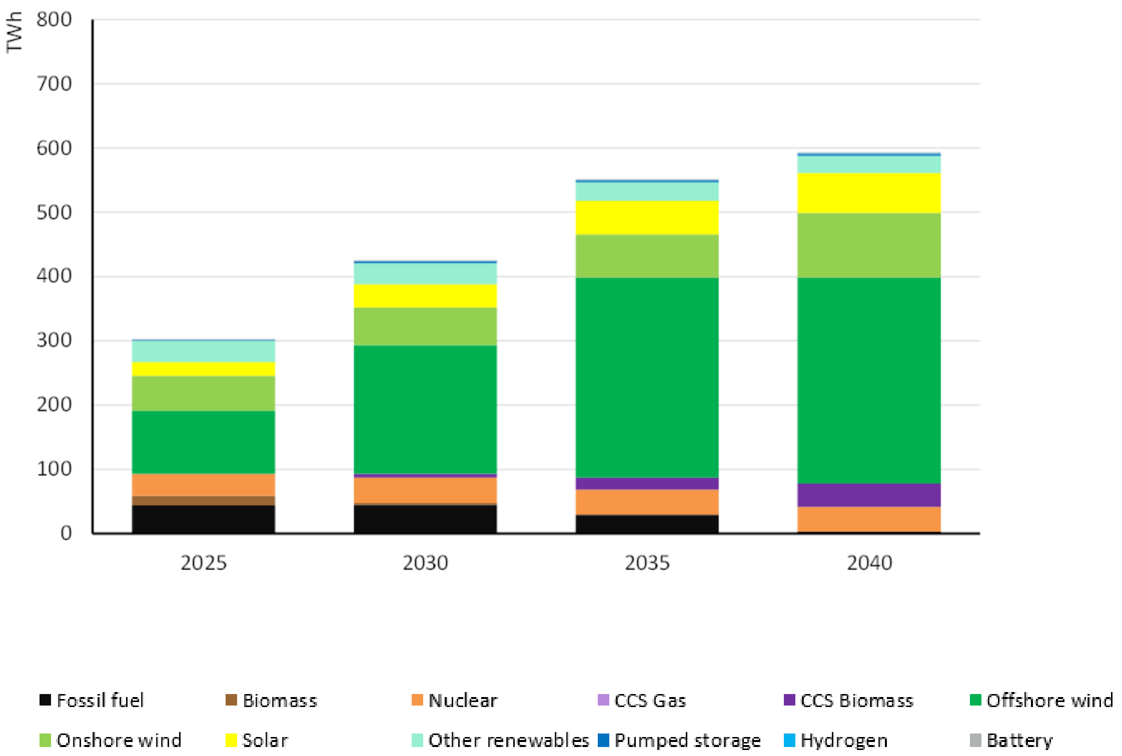
Onshore Wind | Offshore Wind | Solar | Nuclear

EmissionsA & curtailment

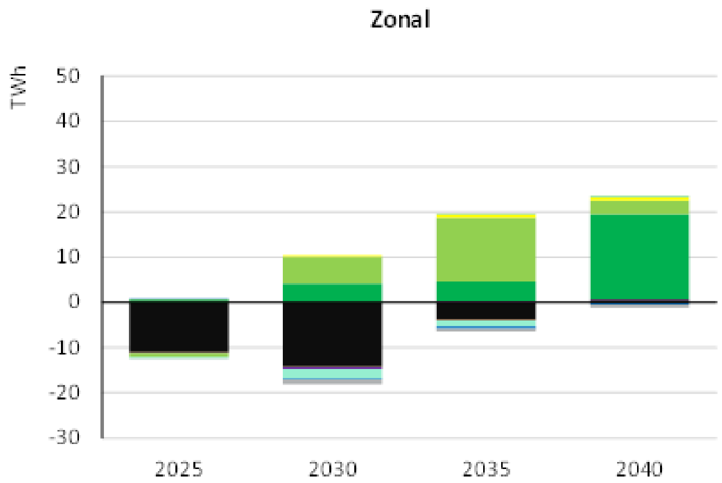
We estimate that locational pricing would **significantly reduce power generation from fossil fuel generators** and **increase windfarm generation**

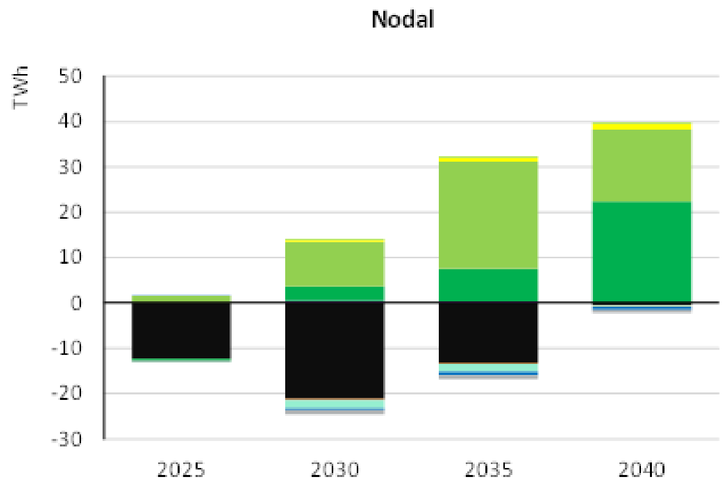
- In early years, improved price signals enable **imports through interconnectors to displace some fossil fuel generation.**
- In later years, more efficient dispatch and improved siting incentives enable **exports of wind generation otherwise curtailed**.

Post-redispatch generation mix under national market design – LtW (NOA7)



Changes in generation mix relative to post-redispatch national generation mix – LtW (NOA7)

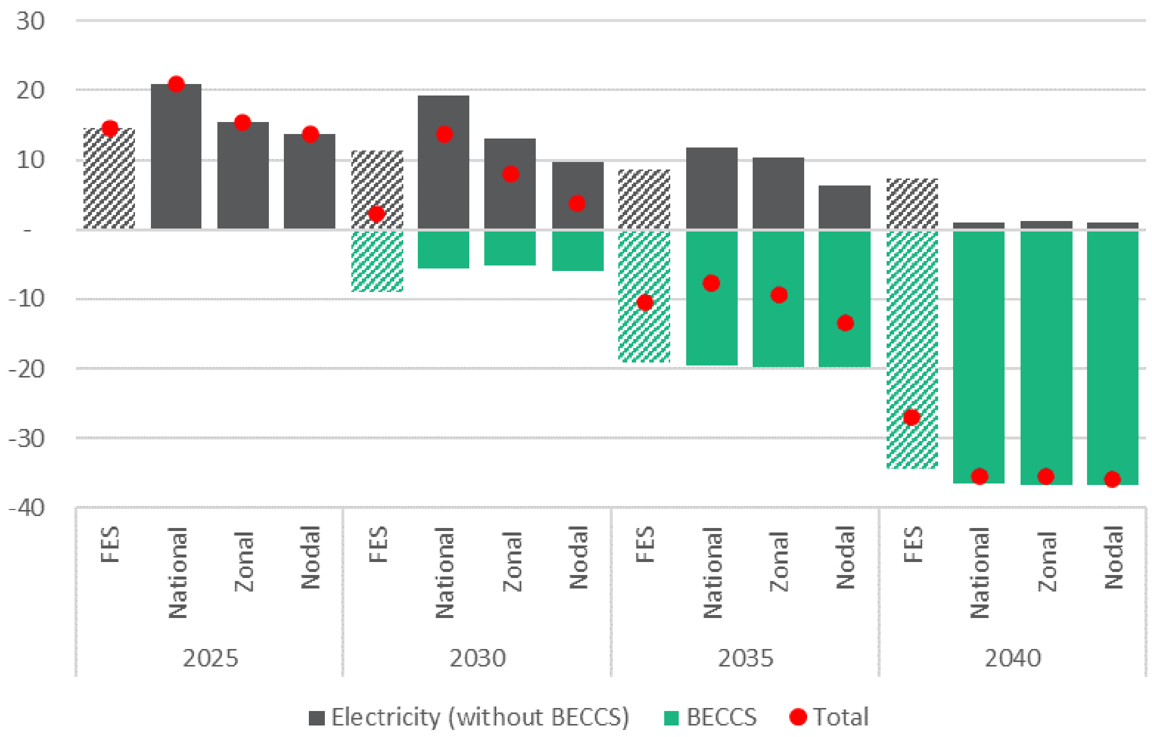




Source: FTI Consulting

Emissions reductions occur faster and earlier under nodal and zonal than under national

Emissions - Leading the Way (NOA7), million tonnes*



Total emissions (2025-2040), million tonnes

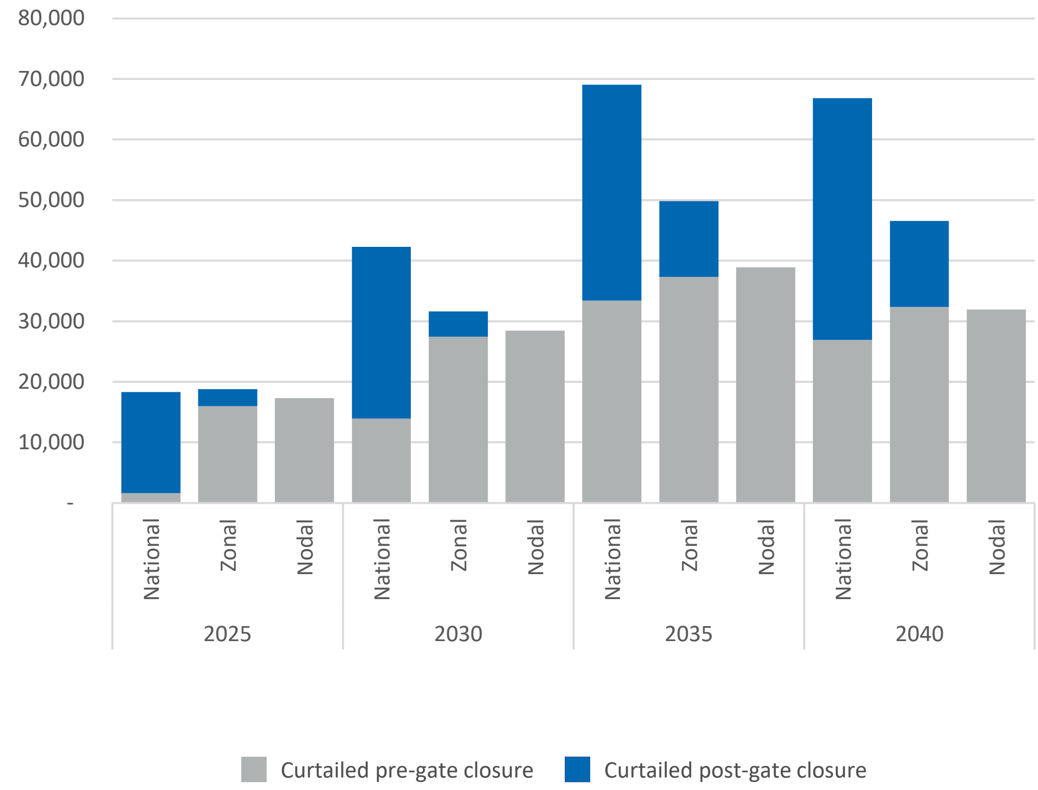
	National	Zonal	Nodal
LtW (NOA7)	-14	-67	-114
LtW (HND)	-55	-81	-120
SysTr (NOA7)	55	30	-32

- Under LtW, **locational pricing leads to a faster decarbonisation** due to more efficient dispatch and optimal siting
- According to our modelling, both the **national and zonal models decarbonise slower than the FES assumptions, missing the carbon budget targets**. This is only achieved in the **nodal model**.
- By 2040, all market designs produce **similar level of emissions**
- The monetary and societal value of these emissions are discussed later.

Notes: Our estimates exclude emissions from waste plants, as they are currently not part of the UK carbon trading scheme. They are included in the FES estimates leading to a minor discrepancy between the estimates.

Our analysis also indicates reduced renewables **curtailments** under nodal and zonal market design when compared against national

Wind curtailment - Leading the Way (NOA7), GWh

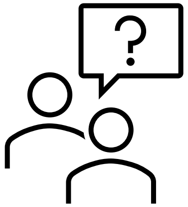


Total wind curtailment (2025-2040), TWh

	National	Zonal	Nodal
LtW (NOA7)	812	603	485
LtW (HND)	591	510	426
SysTr (NOA7)	677	636	502

- Locational pricing helps to **reduce wind curtailment**, as it utilises resources more efficiently, particularly on **interconnectors**, **flexible demand** and better **locational signals for siting**
- In the national market, **18TWh of wind generation expected to be curtailed in 2025** (equivalent to the annual output of c.3,000 wind turbines) and **70TWh by 2035** (c.11,000 wind turbines)

Q&A Session #1



Please follow this link and use the following code:

https://www.slido.com/

Session 1: 2270 806

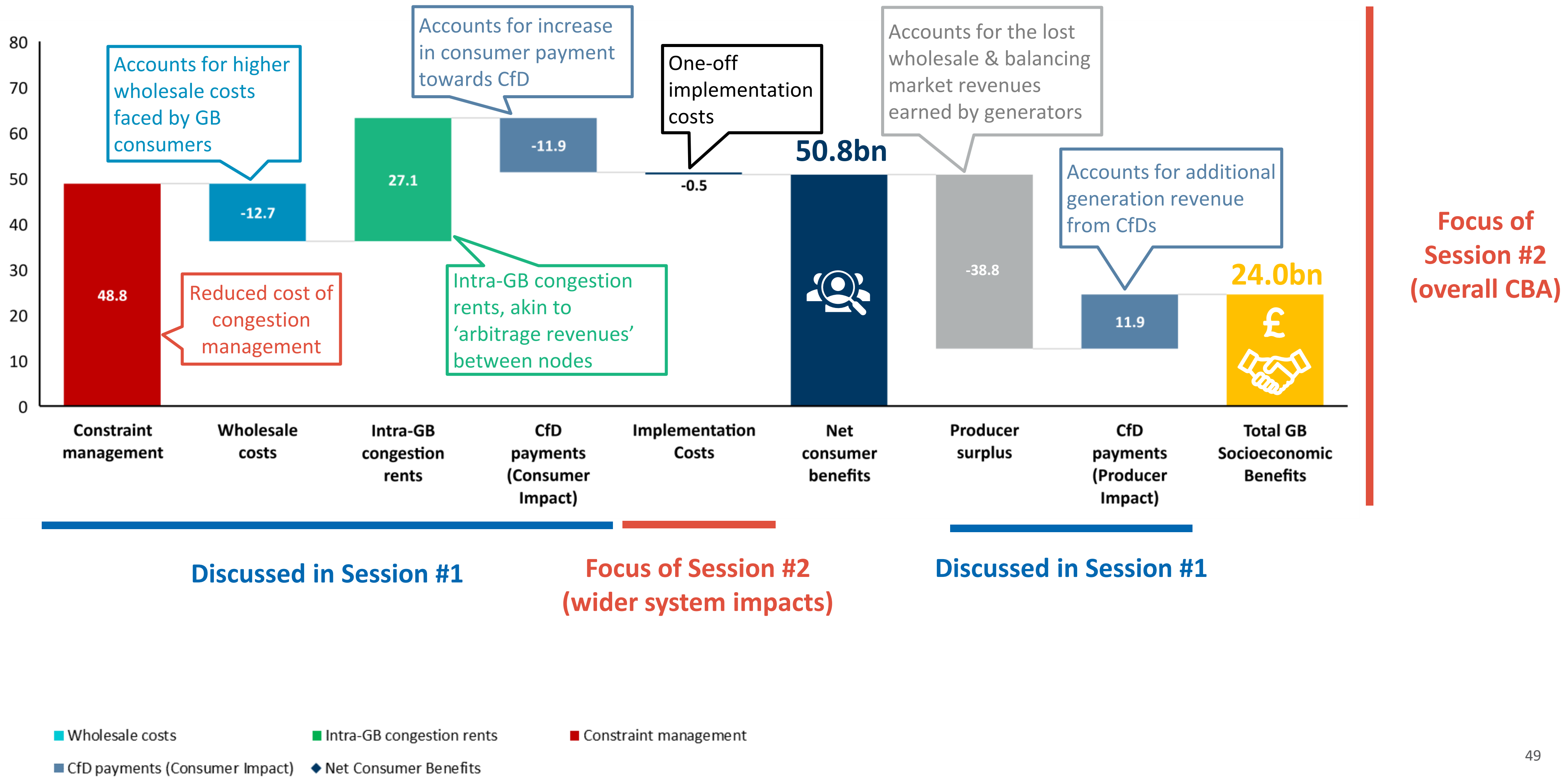
Break #1

Session #2

In this session, we build up each block of impact of locational pricing from the previous session to calculate the aggregate CBA for our assessment

Breakdown of consumer surplus and welfare (£bn, Present Value 2025-40, Nodal – National, Leading the Way NOA7)

Price basis for NPV estimation is 2024.



Topic 3: Wider system impacts

Wider system impact:
Implementation costs

We estimate that introducing a more locational power market would incur implementation costs of c.£500m across ESO and other market participants

ESO implementation costs

- One-off costs to the SO to enhance processes
- IT and software systems to operate in a nodal / zonal market

+

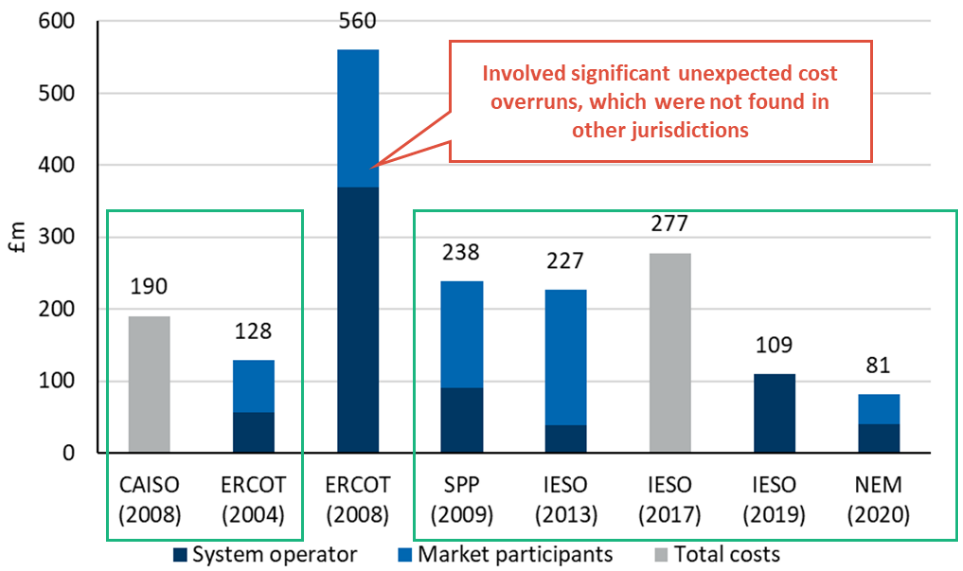
Market participant costs

- One-off costs to update systems and capabilities of market participants to operate in a nodal / zonal market

Our assessment of these costs is based on three sources

1 **Implementation costs incurred or estimated in cost-benefit analyses of locational pricing in other jurisdictions**

Our assessment of implementation costs from international case studies (£m, 2022 prices) indicates that all but one jurisdiction incurred costs under £300m.



2 **Interviews with system vendors and market participants**

HITACHI SIEMENS

High-level conservative estimate of £40m - £60m

Market participants did not identify any unique challenges that might cause GB to differ from other jurisdictions.

3 **Discussions with the ESO to understand required steps for implementation**

6 key areas that would require considerable change:
Data exchange, Metering, Optimisation processes (for day-ahead market, ancillary services and network configuration), Settlement processes, Real-time processes Automation processes to maintain system frequency.

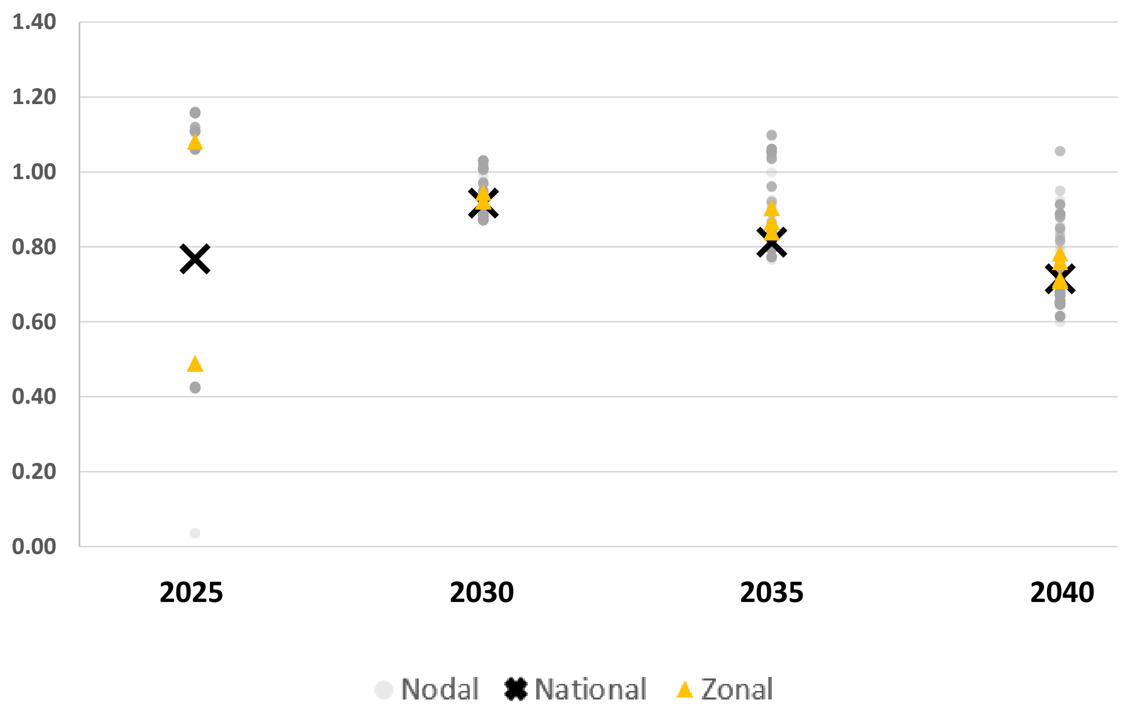
Wider system impact:
Impact on financing costs

We have found limited evidence that moving to nodal or zonal pricing will impact the cost of capital for market participants

	Summary of view	Evidence
Risk assessment	▪ Risks may change for market participants depending their location, but the magnitude and direction of the **overall impact on beta, cost of debt and gearing is uncertain..** ▪ … and could move in either direction, if at all	▪ **Cost of debt:** largely depend on support mechanisms, such as CfDs for wind/solar and RAB mechanism for nuclear. Expect **limited change in price risk**. ▪ Within the CAPM framework, **impact on beta** (and in turn the cost of equity) will largely depend on the correlation of returns with general market conditions. – This could fall if returns become less correlated to fossil fuel prices… – …but could also increase if electricity prices become more correlated with demand.
Stakeholder input	• **General perception** amongst market participants is that they might expect some increase in risk and WACC… • … but difficult to separate overall revenue / risk impact from the non-diversifiable risk impact… • … meaning we have assigned **limited evidential weight** to these claims	• Report by Frontier Economics (sponsored by SSE, RWE and Greencoat Capital) • Report by Strathclyde University (supported by SSE and ScottishPower) • Bilateral discussions with wind investors and battery investors
International evidence	▪ We found limited direct evidence examining the impact of locational pricing on WACC, in particular in previous CBAs. However the indirect evidence shows that **locational pricing has become more popular** in liberalised markets over time… ▪ …and that **investment in generation capacity** does not appear to be hindered by locational pricing and is often complemented by geographical factors and/or policy mechanisms.	

Our modelling suggests limited impacts of locational pricing on average hour-to-hour price volatility

Volatility of each node and zone in each modelling year, LtW (NOA7)



Average volatility, LtW (NOA7)

Average ***(min, max)***	**2025**	**2030**	**2035**	**2040**
National	0.77	0.92	0.81	0.71
Zonal	0.66 *(0.49, 1.08)*	0.93 *(0.92, 0.95)*	0.87 *(0.84, 0.90)*	0.74 *(0.71, 0.78)*
Nodal	0.78 *(0.04, 1.16)*	0.92 *(0.87, 1.03)*	0.84 *(0.77, 1.10)*	0.70 (0.60, 1.06)

- In our modelling, the **inter-temporal (hour-by-hour) volatility is often higher** in locational market designs than the national market design.
- However, this cannot be assumed to be always the case, and will differ by location.
- In locational markets, this **risk can typically be hedged** using financial transmission rights or equivalent financial derivative products.

Note: Volatility is calculated based on the log prices to normalise the non-normal distribution of prices
Source: FTI Consulting

While our base case assumes no change to the cost of capital, we test a sensitivity to assess the impact of the following WACC uplifts

	Price risk	Volume risk	Rationale	Assumed uplift
RAB financing *Non-HPC nuclear; CCS*			• Market participants that are RAB financed are **guaranteed a return on investment**… • ….and therefore will **not be affected** by the potential change in price or volume risk…	**0bps**
Contract for Difference *Wind; Solar; HPC*			• CfDs provide price certainty **for debt financing** in the **first 15 years**, but some volume risk to generators located behind constraints • Cost of equity impact for CfD holders is likely minimal as the beta of renewable assets have **limited correlation with the market**. Returns to equity are mostly derived beyond 15 years. • A 50bps uplift is considered as a midpoint between limited and high risk exposure.	**50bps**
Merchant *Merchant renewables; Thermal*			• Merchant market participants may experience a change in their risks… • …and the direction and magnitude of the impact will largely depend on whether the market participant is located in an **area of high demand relative to supply (likely decrease)** or areas of **low demand relative to supply (likely increase).** • Some market participants will also benefit from **reduced volatility of BM revenues**. • We assume a 50bps uplift for merchant technologies.	**50bps**

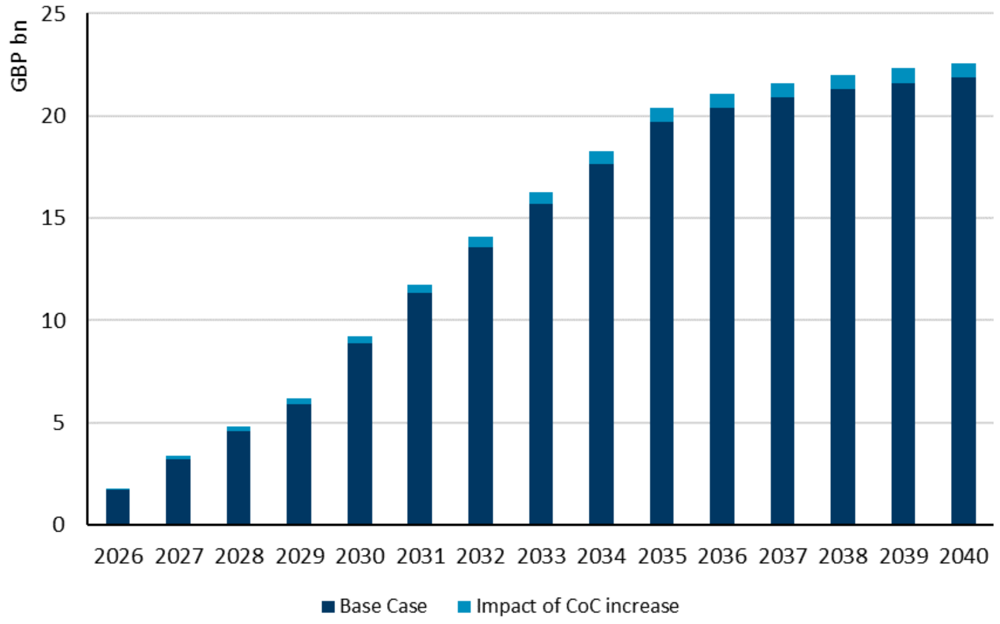
Cap and Floor
Interconnectors
			• Like other merchant technologies, interconnectors and batteries may also experience a change in their risks that affects their bankability.
			• However, both interconnectors and batteries are exceptions in that they could **benefit from the greater price arbitrage opportunities** due to the additional price and volume risk. Additionally:
			  • For interconnectors, floor arrangements provide revenue certainty for debt financing in the first 25 years.
			  • Some feedback provided by the battery developers indicated lower risk
			• Therefore, we apply 0bps uplift for both **interconnectors** and **large-scale batteries**
			• We apply a 0bps uplift for **BTM batteries** as their **capital costs are unlikely to be affected** by wholesale prices.
				0bps

Batteries *Large scale*				**0bps**
Batteries *BTM*				**0bps**

The impact of an increase in the cost of capital in our sensitivity scenario affects our base case by £7.45bn over the modelling period of 2025-2040

RAB financing *Non-HPC Nuclear; CCS*	0bps
Contract for Difference *Wind; Solar; HPC*	50bps
Merchant *Merchant renewables;*	50bps
Cap and Floor *Interconnectors*	0bps
Merchant *Large scale batteries*	0bps
Merchant *BTM batteries*	0bps

Annual financing cost in the Base Case (£bn)



Impact of WACC uplift over 2025-2040 is £7.45bn.

As an extreme sensitivity, a uniform WACC increase of the follow negates consumer benefits:

	Nodal Pricing	Zonal Pricing
LtW (NOA7)	341 bps	206 bps
LtW (HND)	229 bps	125 bps
SysTr (NOA7)	256 bps	139 bps

Applied across impacted technologies, across the modelling period

Wider system impact:
Liquidity

Contrary to popular perception, we are not aware of liquidity issues in nodal markets, particular with the development of trading hubs

1 **Perceived liquidity in national markets**

- While many consider wholesale markets in national-type markets to be liquid, we highlight a considerable proportion of trades do not reflect the physical realities of the network…
- …meaning some liquidity in these markets are illusory – and may need to be unwound or counter-traded in the BM

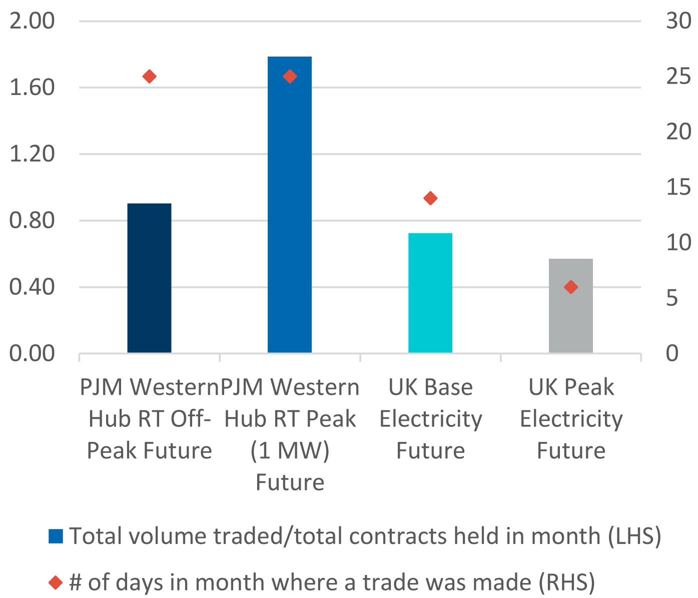
2a Nodal markets in the US rely on liquid **trading hubs…**

- Trading hubs are **market exchanges which represent a group of nodes**, allowing participants to hedge against the uncertainty of future prices
- Allows for both bilateral trading and exchange-traded products. Latter **negates the need to find a counterparty** and **allows all market participants** easier access unlike in national market designs.
- FTRs can then be used to hedge between nodes and trading hubs.
- PJM's trading hubs considered one of the most liquid exchanges in the world

2b …and a high level analysis of exchanges shows **no evidence of liquidity issues**

- As a measure of liquidity, we have analysed forward trading volumes on electricity future exchanges for the following:
  - Measure #1: The total number of trades made in a month as a proportion of the total available stock (defined as open interest)
  - Measure #2: the number of days in that month where trade was made

Total volume traded as a proportion of total contracts available in Sept 2022 (for Dec 2023 delivery)



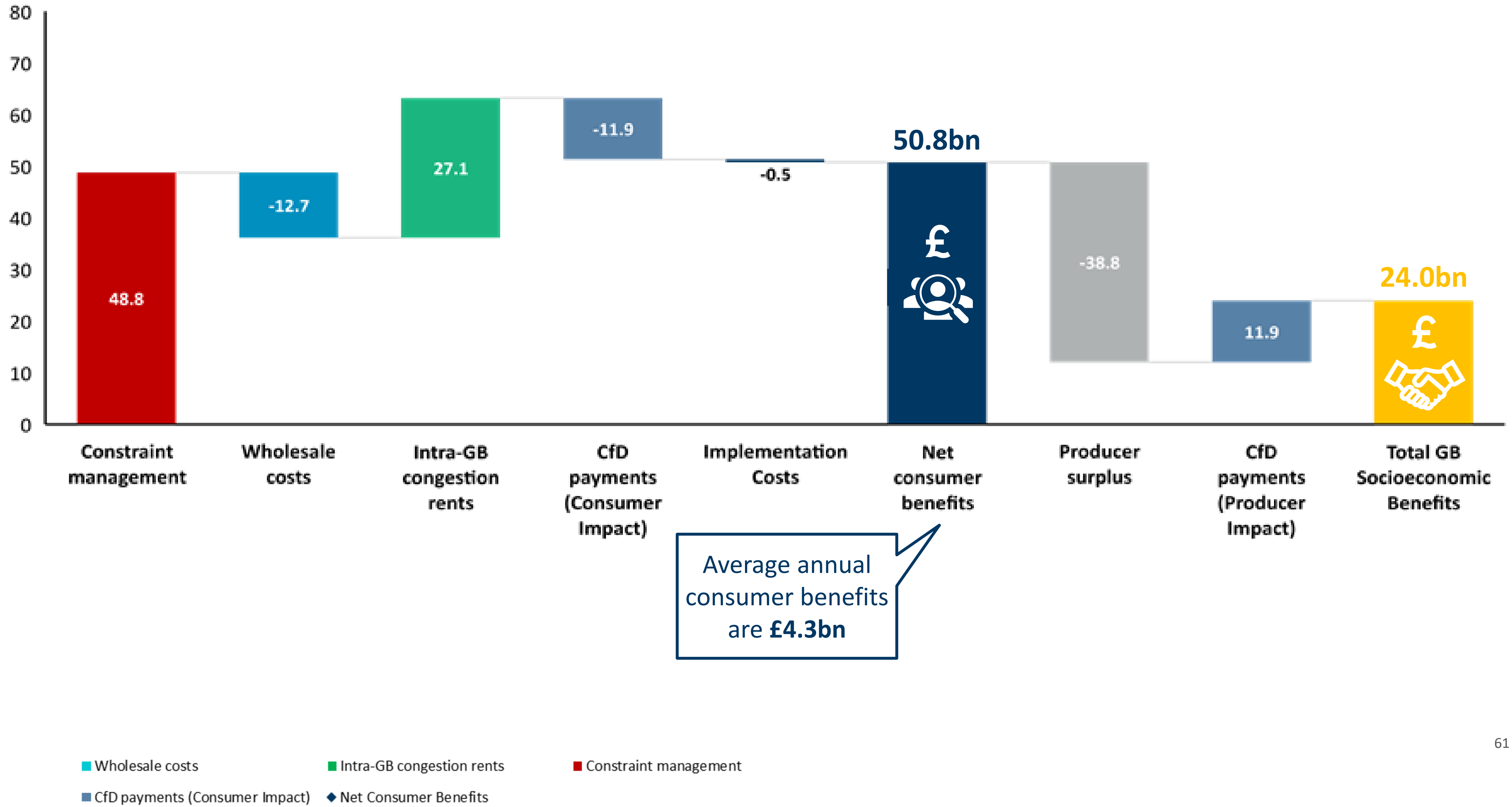
Source: The ICE (product codes are OPJ, PDA, UBL, UPL)
Note: Each product has slightly different contract definitions (size, pricing and relevant hours)

Topic 4: Overall cost benefit assessment

Consumers benefit significantly from locational pricing, through transfers from generators to consumers and greater operational and locational efficiency

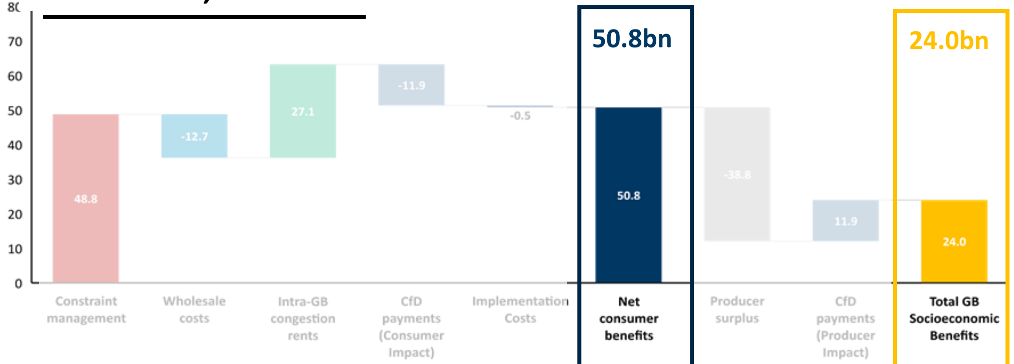
Breakdown of consumer surplus and welfare (£bn, Present Value 2025-40, Nodal – National, Leading the Way NOA7)

Price basis for NPV estimation is 2024.

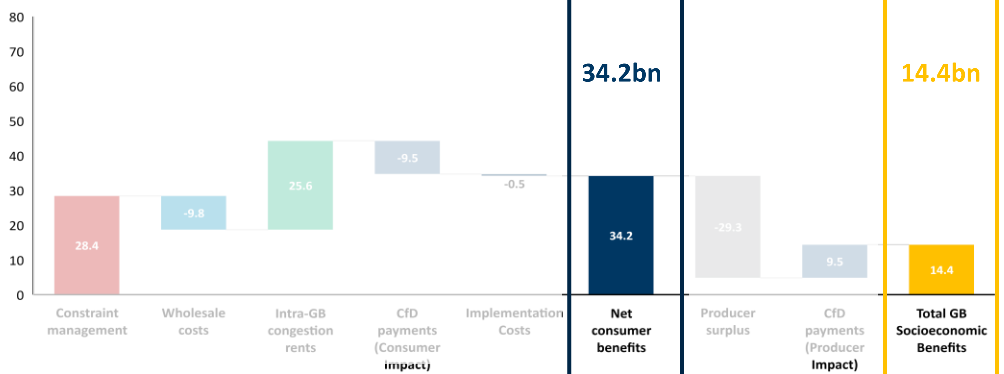


Our analysis indicates transitioning to more locationally granular pricing increases consumer and GB socioeconomic welfare under all six scenarios

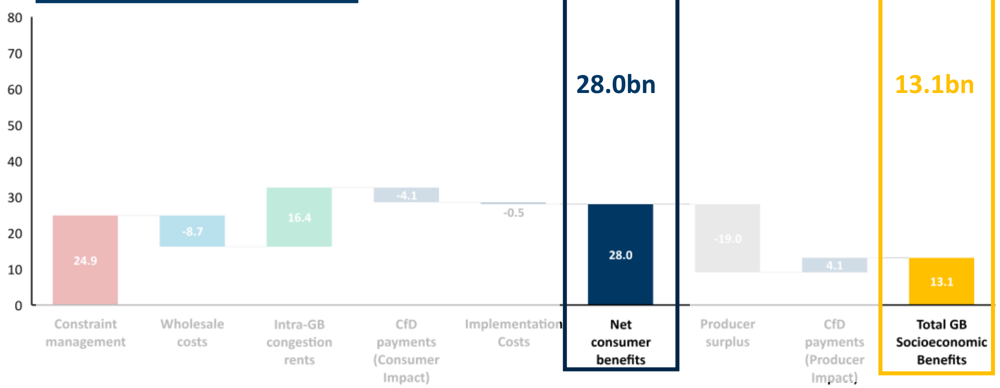
LtW NOA7, Nodal



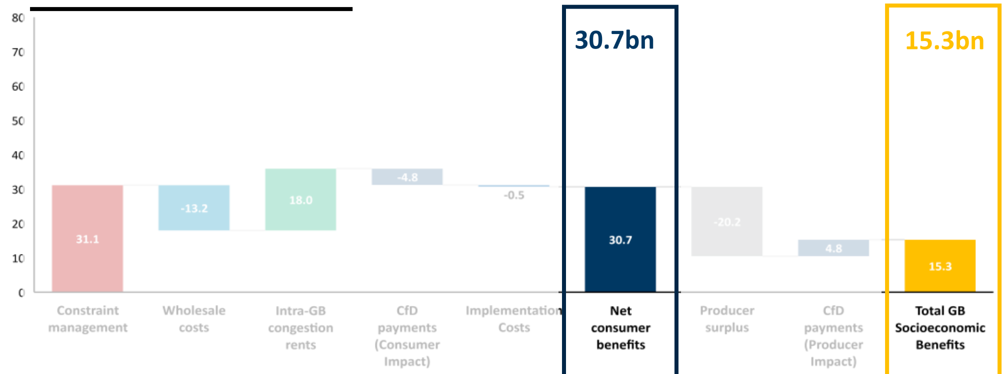
LtW HND, Nodal



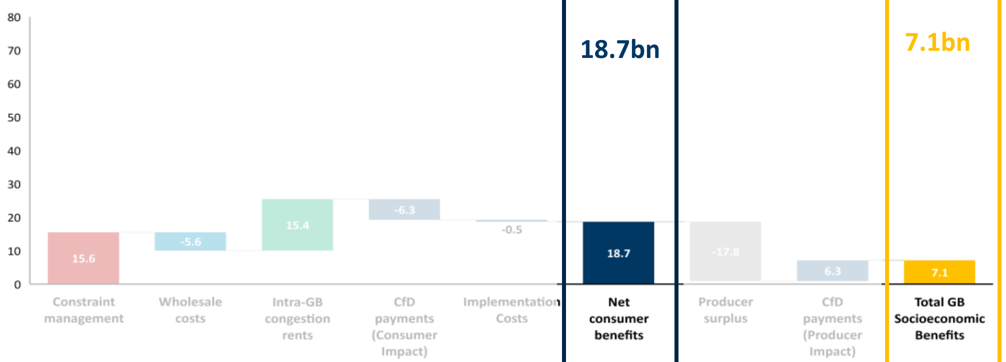
Sys Tr, Nodal



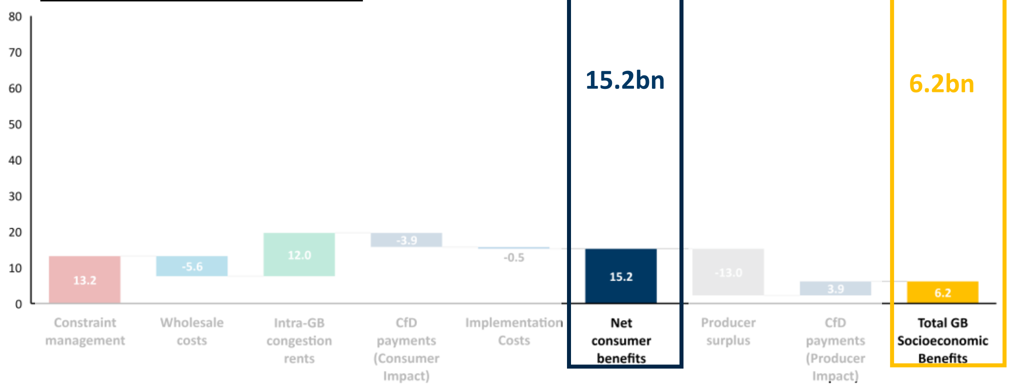
LtW NOA7, Zonal



LtW HND, Zonal

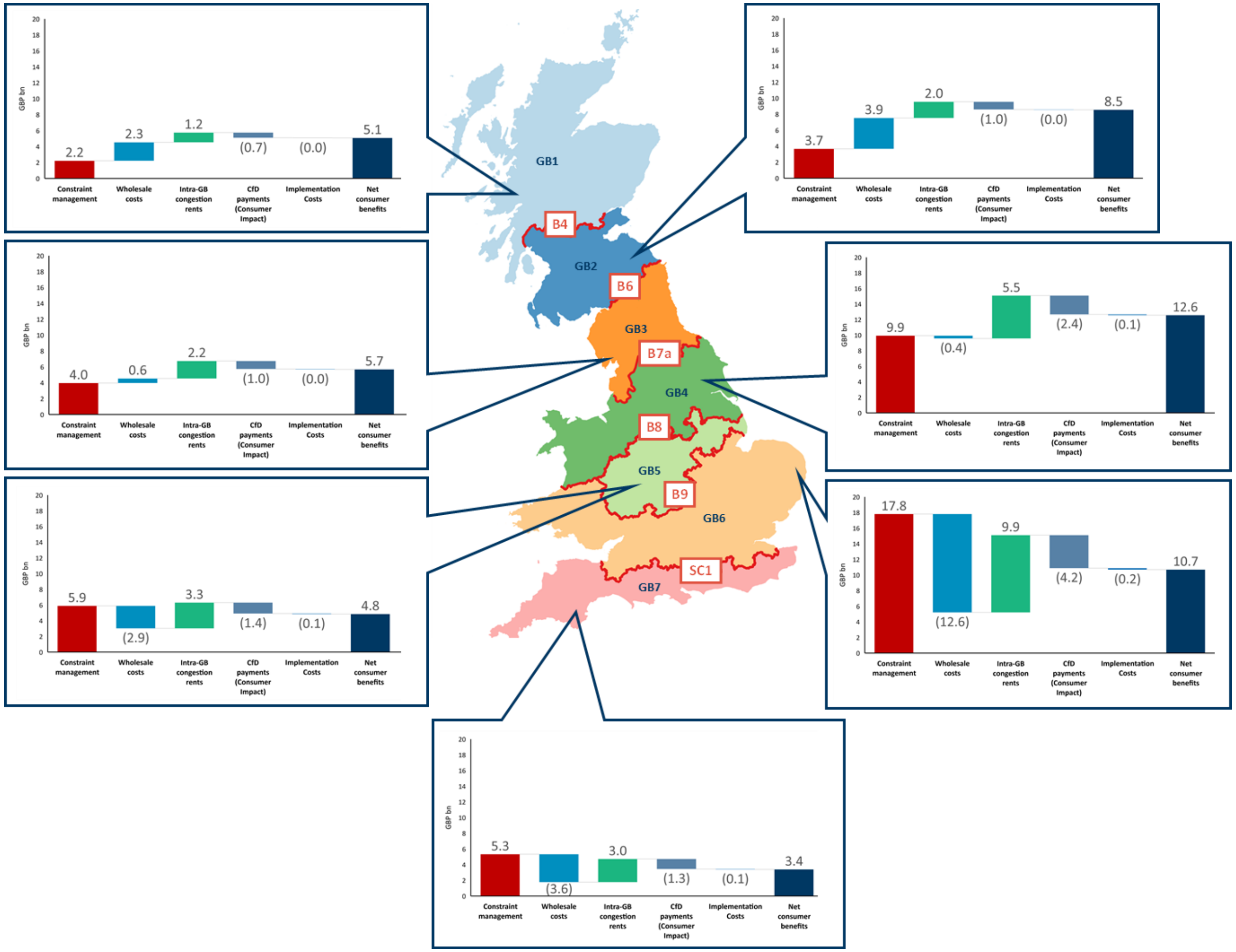


Sys Tr, Zonal



Consumers in all regions are expected to benefit from locational pricing, those in Scotland and northern England are estimated to benefit the most

Breakdown of consumer surplus and welfare (£bn, Present Value 2025-40, Nodal – National, Leading the Way NOA7)



Scotland

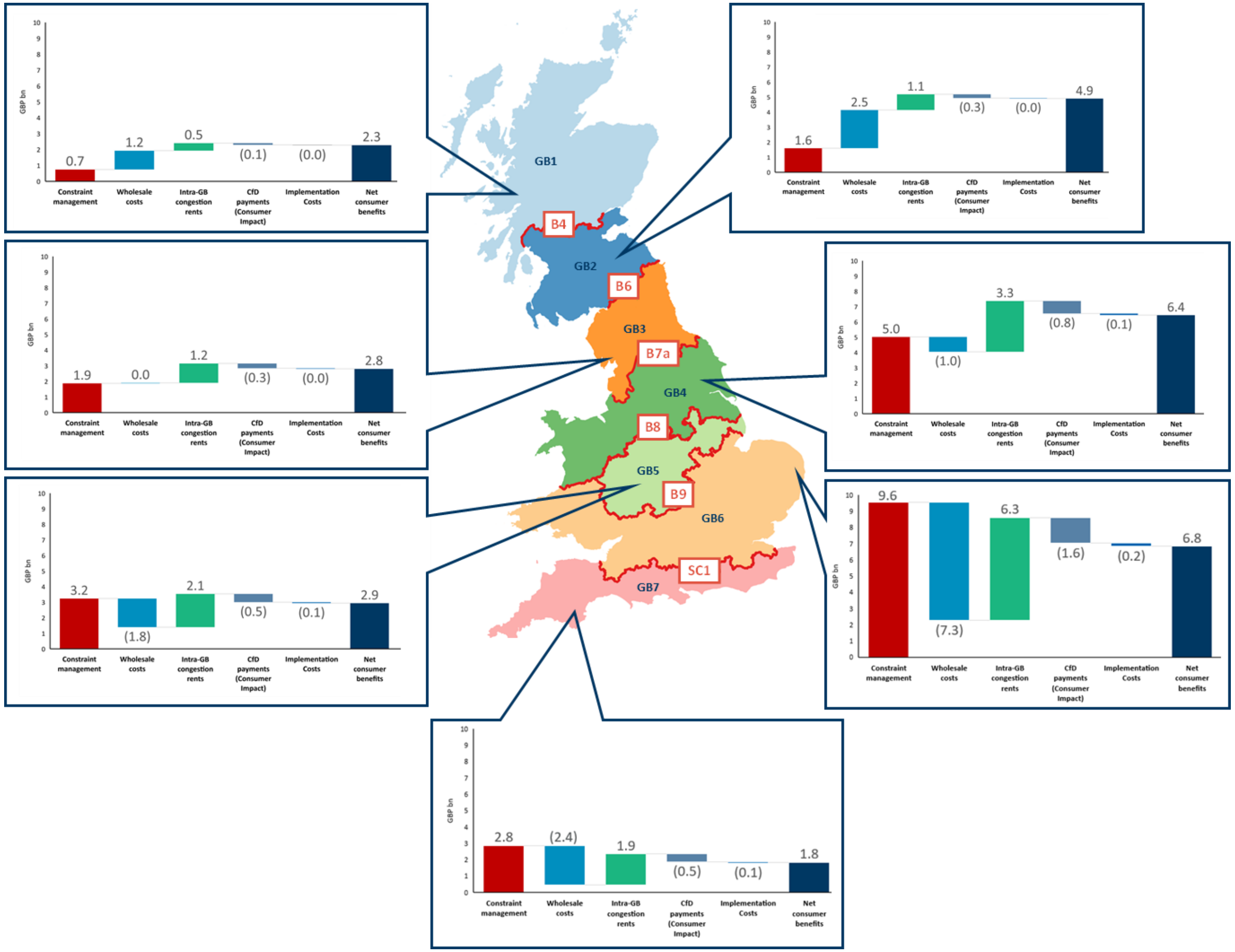
Scottish consumers are expected to **receive over 25% of total consumer benefits**, while they only account for c. 8.5% of the population in Great Britain

Southern England and Wales

The **south of Wales and England** account for more than **half of the total electricity demand** in GB currently. Despite this, only around **28% of the benefits** are accrued to consumers in these zones

We see a similar distribution of locational consumer benefits under System Transformation, albeit to a different extent

Breakdown of consumer surplus and welfare (£bn, Present Value 2025-40, Nodal – National, System Transformation NOA7)



Scotland

Scottish consumers are expected to **receive over 25% of total consumer benefits**, while they only account for c.8.5% of the population in Great Britain

Southern England and Wales

The **south of England & Wales** account for more than **half of the total electricity demand** in GB currently. Despite this, only around **31% of the benefits** are accrued to consumers in these zones

Transitioning to nodal pricing would reduce the wholesale cost of electricity by 9% - 20% depending on scenario

Breakdown of wholesale costs and comparison to consumer benefit (Nodal – National, Leading the Way NOA7, 2025 - 2040)

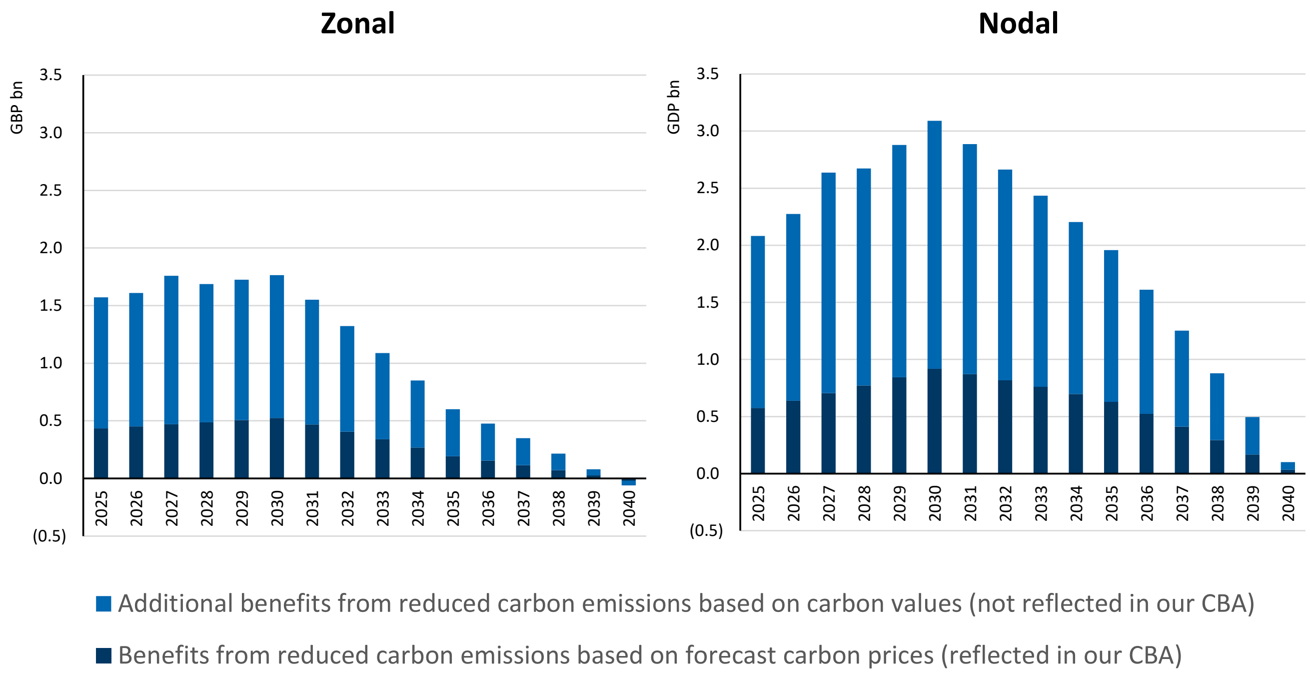
Item	**2025**	**2030**	**2035**	**2040**	**Total**
	GBPmn	*GBPmn*	*GBPmn*	*GBPmn*	*GBPmn*
Electricity wholesale cost	21,978	8,976	15,836	27,420	272,254
Constraint management cost	3,199	3,663	4,573	5,123	66,143
Total wholesale component of the cost of electricity	**25,176**	**12,639**	**20,409**	**32,543**	**338,397**
CfD costs	1,205	11,332	12,450	7,220	144,186
Total wholesale component of the cost of electricity (+ CfDs)	**26,382**	**23,971**	**32,859**	**39,763**	**482,582**
Consumer benefit from nodal market	4,586	3,465	4,387	5,178	68,551
Nodal consumer benefit relative to cost of electricity	*18%*	*27%*	*21%*	*16%*	*20%*
Nodal consumer benefit relative to cost of electricity (+ CfDs)	*17%*	*14%*	*13%*	*13%*	*14%*

**£mn figures are undiscounted*

	Consumer benefit relative to cost of electricity	**Consumer benefit relative to cost of electricity (incl. CfDs)**
LtW (NOA7)		
Nodal pricing	20%	14%
Zonal pricing	12%	8%
LtW (HND)		
Nodal pricing	15%	10%
Zonal pricing	8%	5%
SysTr (NOA7)		
Nodal pricing	15%	9%
Zonal pricing	8%	5%

The overall CBA does not consider DESNZ's societal carbon values – significant consumers benefits arise when they are included

Annual benefits from reduced carbon emissions, LtW (NOA7)



Total (discounted) additional benefits, £bn

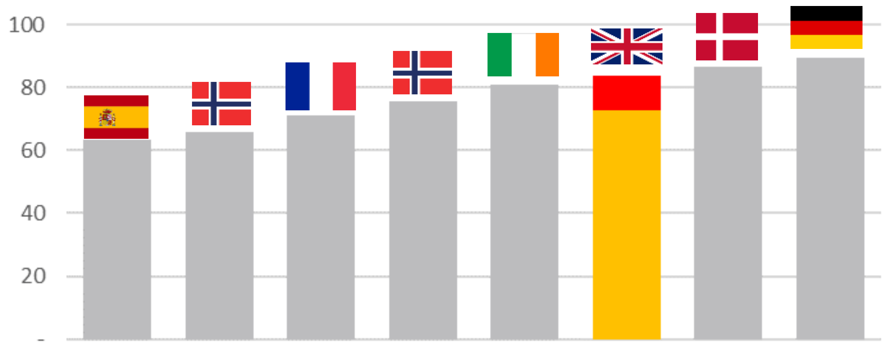
	Zonal	Nodal
LtW (NOA7)	9.7	17.9
LtW (HND)	4.9	11.7
SysTr (NOA7)	4.3	15.0

- Our quantitative assessment includes the **monetary benefits from reduced emissions based on forecast carbon prices**
- Forecast carbon prices are typically lower than DESNZ's societal carbon values
- When carbon values are considered, the **additional benefits to socioeconomic welfare increases by £4.3bn to £17.9bn** (discounted) over the modelling period

Average wholesale prices are lower under nodal market for all GB consumers - Scotland & N. England having the lowest wholesale prices in all of W. Europe

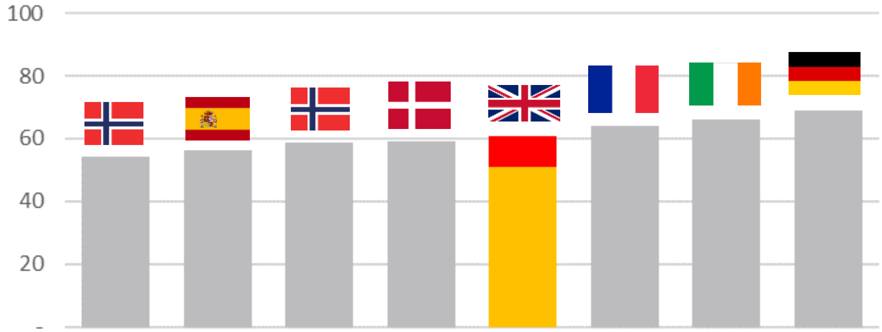
Under national market arrangements, GB has one of the highest wholesale electricity market prices among W.European countries

Average national wholesale prices, 2025 (£/MWh)



- In the short-term, GB is likely to have **one of the highest wholesale prices in Western Europe** under the national market design after accounting for balancing costs…
- …making GB less competitive in industries which require electricity as an input and leading to high domestic customer bills.

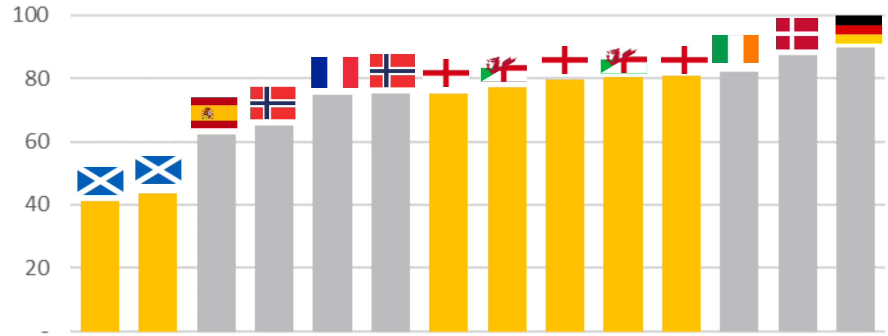
Average national wholesale prices, 2040 (£/MWh)



- Despite significant investment in renewables between today and 2040, **we forecast GB wholesale electricity prices remain average across Western European countries…**
- **…**due to significant balancing costs eroding the benefits of investments in renewable energy sources.

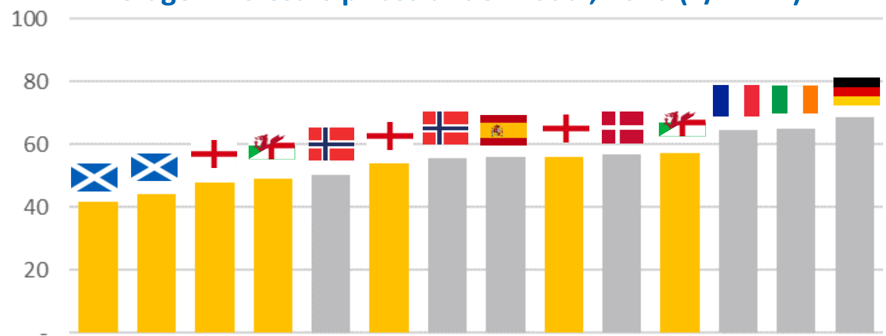
In contrast, under nodal, Scottish would have the lowest wholesale prices in W. Europe, with prices in the rest of GB also decreasing

Average wholesale prices under nodal, 2025 (£/MWh)



- In the short-term, **Scottish wholesale prices decrease below Northern Norwegian and Spanish prices under a nodal market design**, due to the significant wind capacity already in Scotland.
- Prices in the rest of GB would be similar to Western European wholesale prices, due to the more efficient dispatch compared to the national market design.

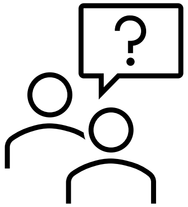
Average wholesale prices under nodal, 2040 (£/MWh)



- **More efficient siting and dispatch under the nodal market leads to a larger decrease in wholesale electricity prices by 2040**, than under the national market.
- We forecast Scottish, Northern English and Northern Welsh wholesale prices to be among the cheapest in Europe, while wholesale prices in South England and South Wales would likely be lower than in France or Germany.

*** GB Prices include constraint cost recovered through BSUoS (indicated in red). The cost of renewable support mechanisms are not included for any country – these costs may be significant**

Q&A Session #2



Please follow this link and use the following code:

https://www.slido.com/

Session 2: 6648 199

Break #2

Session #3

The results presented in the previous session are based on several key assumptions, many of which we consider to be very conservative

Conservative assumptions

Factors which could lead to benefits being underestimated

- **Fixed transmission build:** does not vary across market designs (although less transmission is likely to be required in locational markets)
- **Fixed capacity mix:** change in technologies between national and locational could further increase efficiency and reduce costs of achieving Net Zero
- **No demand re-siting:** we have not allowed demand re-siting or inward investments which could unlock further efficiency benefits
- **Additional operational benefits:** CBA does not account for operational benefits from centralised scheduling and other dispatch benefits

General limitations

Could have positive or negative impact on estimate of benefits

- **Re-siting assumptions:** assumptions on technology siting were developed in discussion with stakeholders
- **No other reforms assumed:** assessment based on the current market structure and policy landscape
- **Choice and design of zones:** alternative zone delineation could change the outcome of analysis
- **No change in cost of capital:** assumed no change to cost of capital

Overestimation

Factors which could lead to benefits being overestimated

- **Locational investment signals from other policies:** we assume in the counterfactual that no policy absent of market reform can replicate the impact of locational wholesale pricing on investment signals
- **Consumer exposure:** assumed all consumers are fully exposed to locational pricing

Academic evidence on the movement and growth of energy-intensive industries in lower electricity price areas

Kahn and Mansur (2013), 'Do local energy prices and regulation affect the geographic concentration of employment'

Academic evidence on the re-siting of new generation in response to zonal market reform

Lundin (2021), 'Geographic price regularity and investments in wind power: Evidence from a Swedish electricity market splitting reform'

We explore a few key sensitivities around assumptions to provide useful insights on our results and their implications

Conservative assumptions

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Explored below

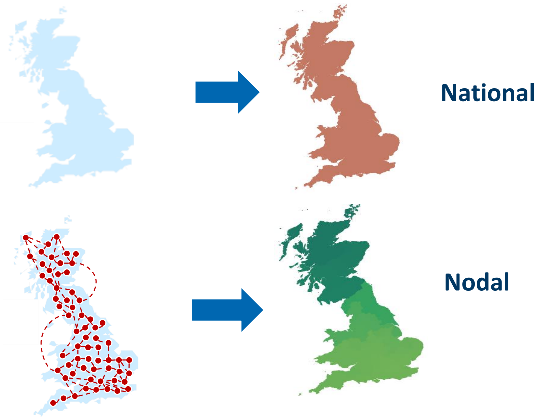
Topic 5: Key sensitivities

Dispatch-only sensitivity

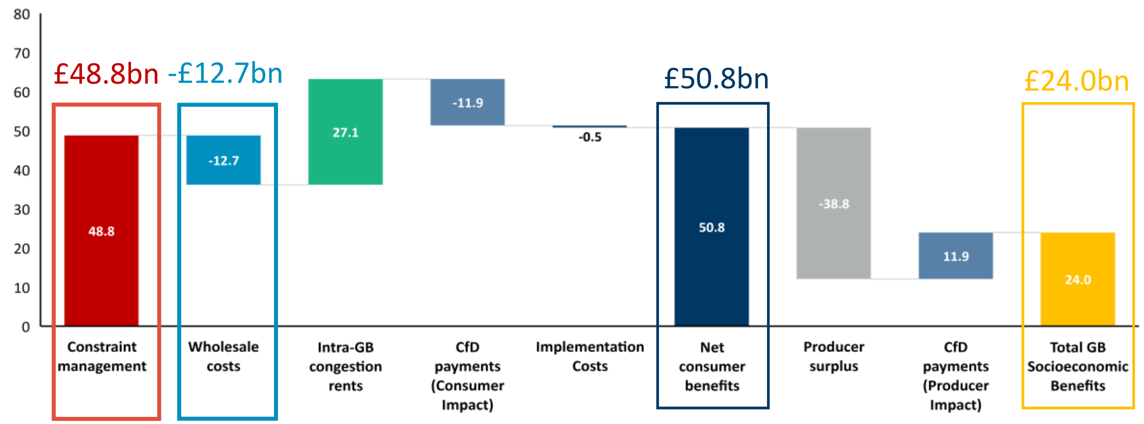
Our **dispatch-only sensitivity** uses siting decisions from the nodal run in order to isolate the benefits caused by operational price signals and not re-siting

- This sensitivity considers capacity siting decisions under the nodal pricing model run for our national pricing model run.
- This is in response to stakeholder comments to test the view that certain centralised policies could produce efficient locational siting in lieu of nodal pricing.

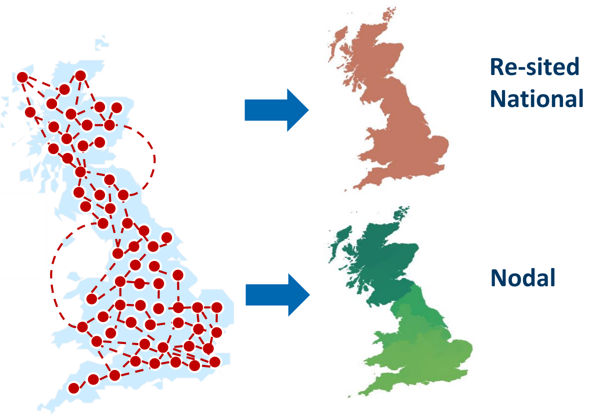
Leading the Way NOA7



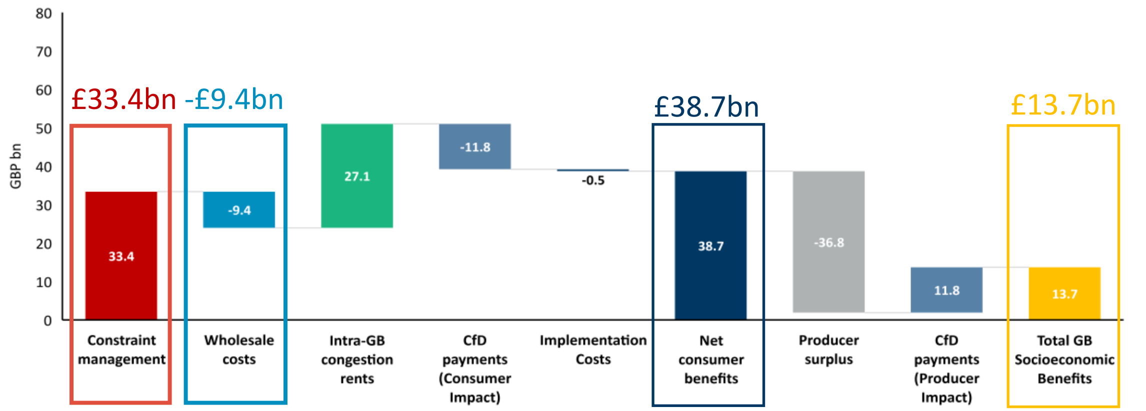
ORIGINAL: Welfare assessment (£bn, Present Value 2025-40, Nodal – National, LtW NOA7)



Dispatch-only sensitivity



SENSITIVITY: Welfare assessment (£bn, Present Value 2025-40, Nodal – National, LtW NOA7)



- The difference in consumer surplus is driven in large part by a **drop in constraint costs (c.32%)** in the sensitivity, as re-sited capacity reduces constraints.
- As **prices are higher** in the national sensitivity, they are closer to the nodal prices faced by consumers, leading to **lower consumer benefits.**

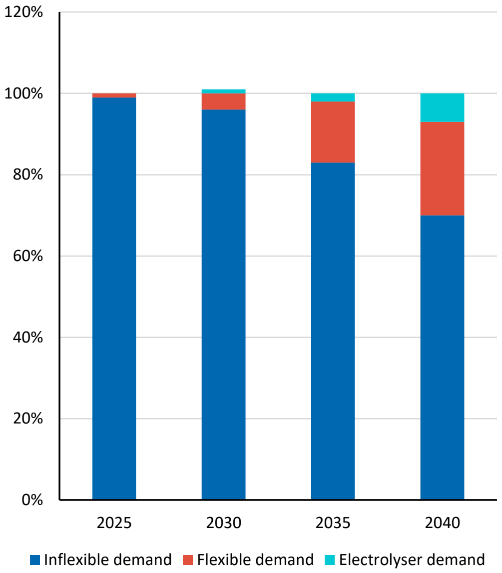
Load-shielding sensitivity

Our **load shielding** sensitivity tests the impact of shielding consumers from the locational price, while retaining locational pricing on the supply-side

Overview

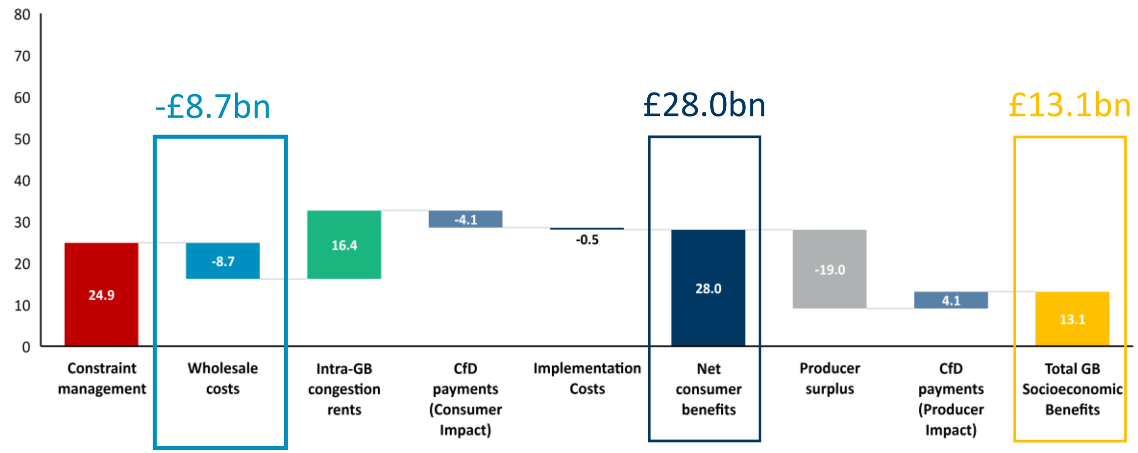
- In certain nodal markets, some types of consumers are exposed to a uniform zonal price.
- This sensitivity tests the impact of **exposing consumers to a uniform national price in a nodal market design.**
- In this sensitivity, we assume:
  - All domestic, industrial and commercial consumers (incl. EVs and heat pumps) are **shielded from the nodal price.**
  - All electrolysers and batteries **receive the nodal price.**
- Due to model limitations, all generator and storage units are treated in the same way, as such, **all BTM batteries and V2G assets receive the nodal price.**
- This sensitivity uses the **SysTr scenario** as the LtW scenario relies heavily on BTM batteries and V2G.

Demand profiles across SysTr (NOA7)

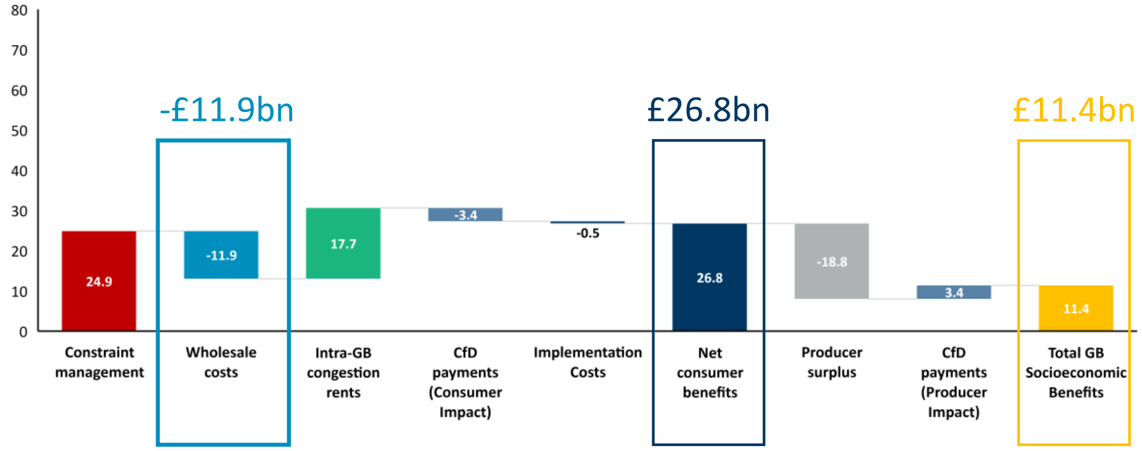


- **Inflexible demand:** Not price responsive
- **Flexible demand:** Price responsive EV and heat pump demand affected by load shielding.
- **Electrolyser demand:** Price responsive electrolyser demand – not affected by load shielding

ORIGNAL: Welfare assessment (£bn, Present Value 2025-40, Nodal – National, SysTr NOA7)



SENSITIVITY: Welfare assessment (£bn, Present Value 2025-40, Nodal – National, SysTr NOA7)



Sensitivity results in the following inefficiencies:

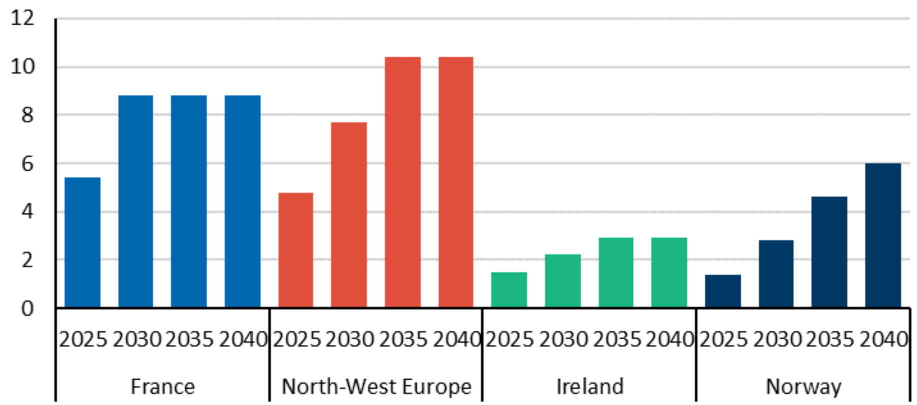
- Increase in average annual wholesale prices
- Increased cost of meeting demand
- (but partially offset by increased intra-GB congestion rents decreased CfD support payments)

Topic 6: Flexibility resources and Transmission Investment

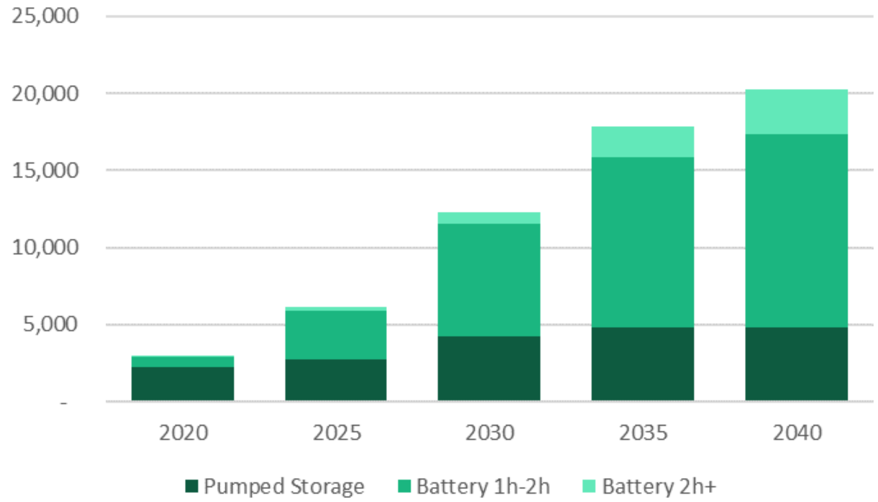
Flexibility Resources

New flexible assets (e.g. batteries, interconnectors and EVs) are integral to the FES scenarios – the market design impacts how they are scheduled to operate…

Interconnector capacity, LtW scenario, GW

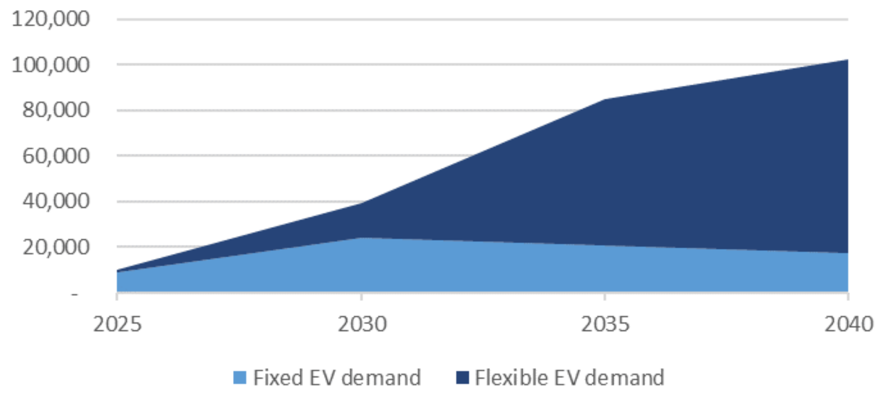


Battery capacity, LtW scenario, MW

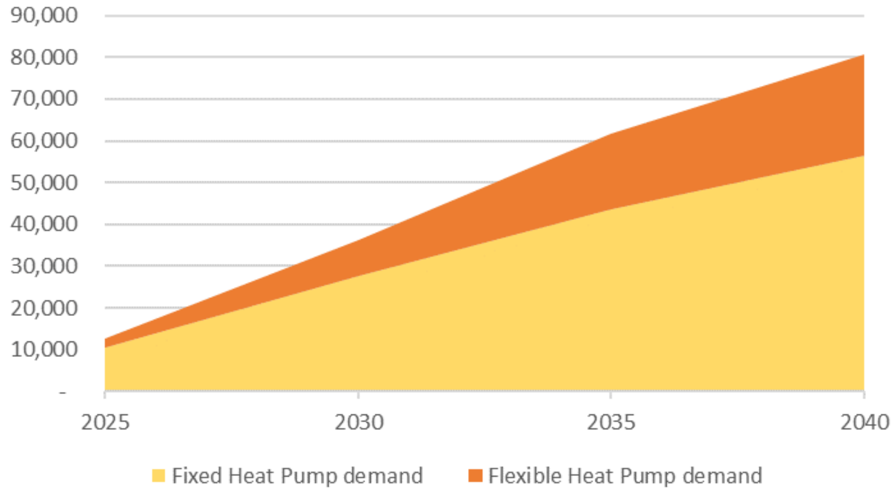


Smart demand

EV demand, LtW scenario, MWh



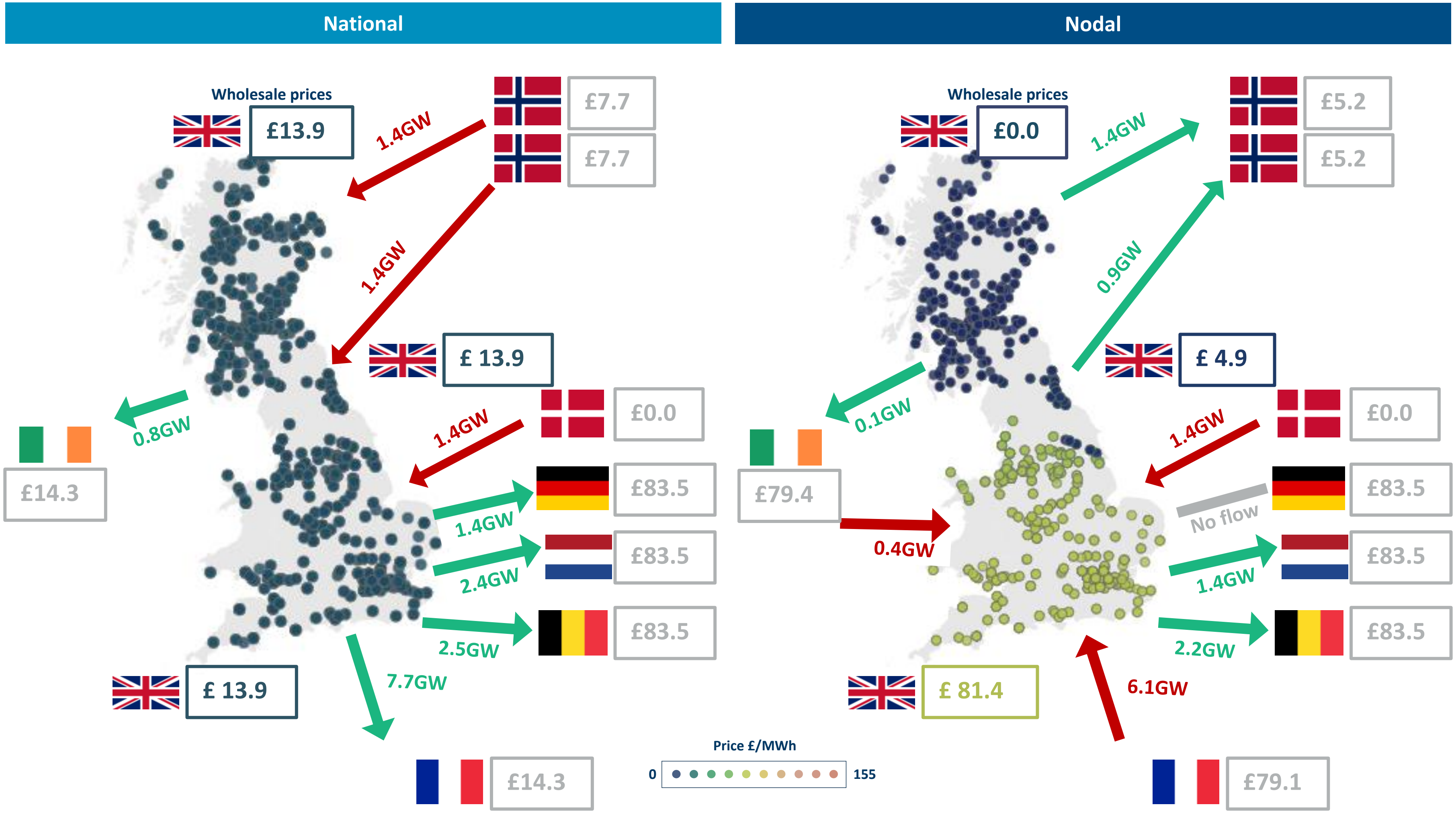
Heat pump demand, LtW scenario, MWh



Nodal pricing would change how the market schedules interconnector flows between GB and connected countries

Example of the impact of nodal pricing on interconnectors

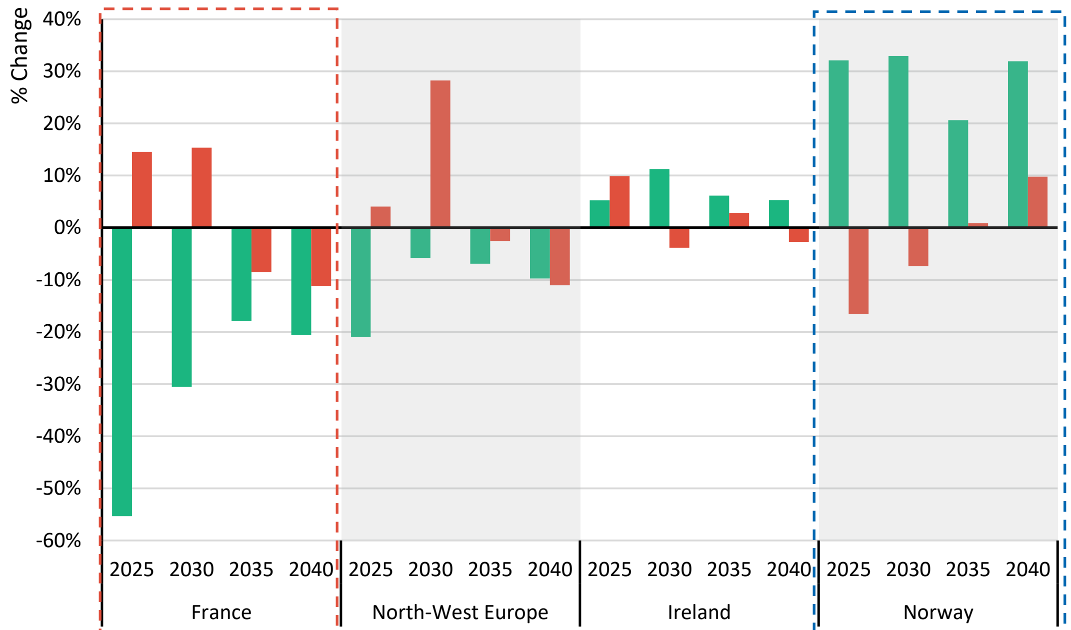
Snapshot – 09/03/2030 @8am



Source: FTI Consulting
Note: We follow ENTSO-E's methodology model which includes consideration of the transmission network between NI and ROI

Over a year there are significant differences in the way the market schedules interconnector flows, particularly between GB to Norway and GB to France

Change in interconnector flows (nodal relative to national)



	France 2025	France 2030	France 2035	France 2040	NWE 2025	NWE 2030	NWE 2035	NWE 2040	Ireland 2025	Ireland 2030	Ireland 2035	Ireland 2040	Norway 2025	Norway 2030	Norway 2035	Norway 2040
*Net change to **exports** (TWh)*	-7	-13	-9	-10	-5	-3	-5	-6	+0	+1	+1	+1	+1	+3	+3	+6
*Net change to **imports** (TWh)*	+3	+2	-1	-2	+0	+2	-0	-1	+0	-0	+0	-0	-1	-1	+0	+1

Exports Imports

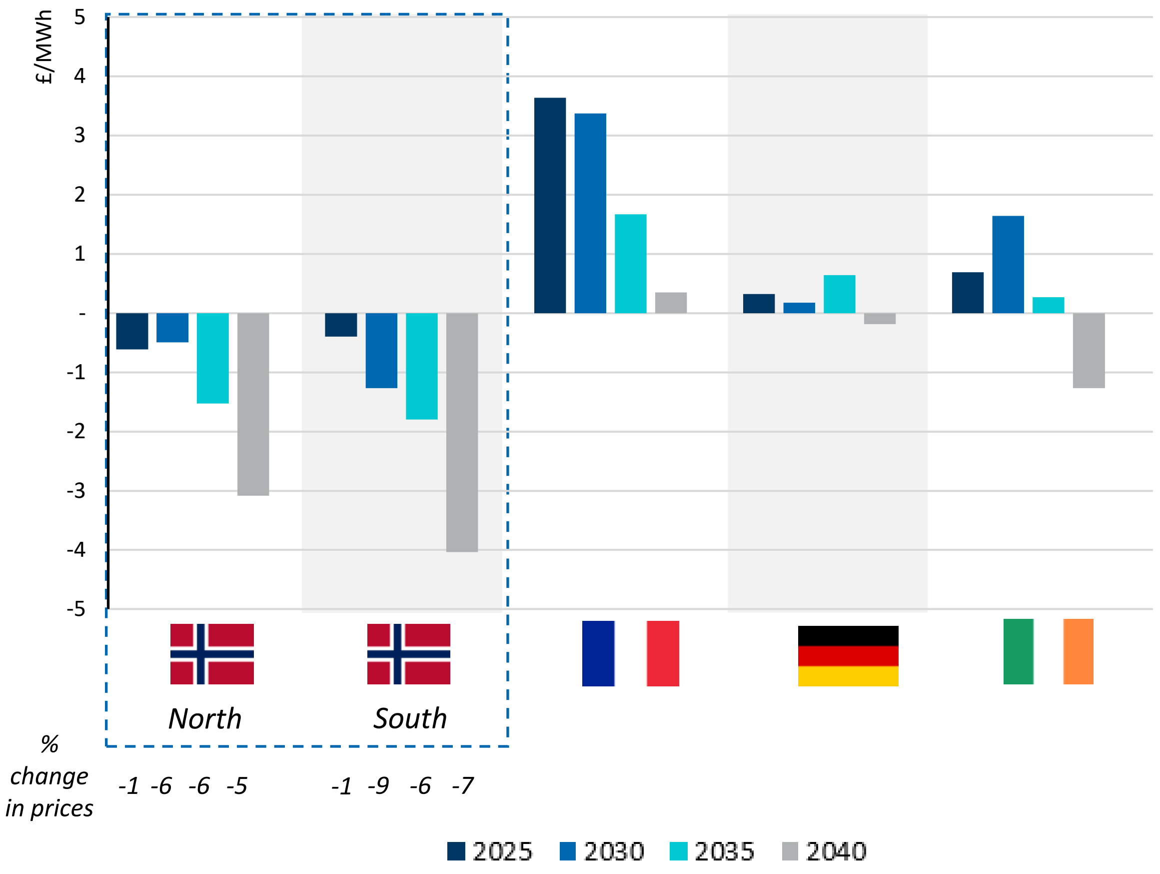
- Large increase in exports to Norway due to the location of the landing point of the two interconnectors.
- Nodal prices account for the value of congestion and allow **surplus wind generation to be exported** that would otherwise be constrained off.

- The opposite effect occurs in interconnectors to France, where there is high exports under the current market design.
- Nodal prices limit exports, and, indeed, imports would displace plant that is currently constrained on in GB market.
- Reduced flows in latter part of forecast period as a result of greater price convergence between southern England and France.

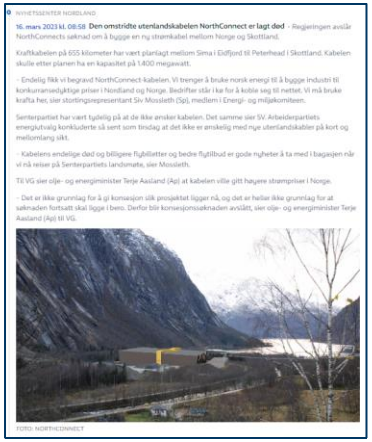
Source: FTI Consulting

Changing interconnector flows impact prices in neighbouring countries and, potentially, the political narrative in surrounding countries…

Change in connected country prices



- Some Norwegian stakeholders resistant to greater interconnection due to upward pressure on Norway prices...



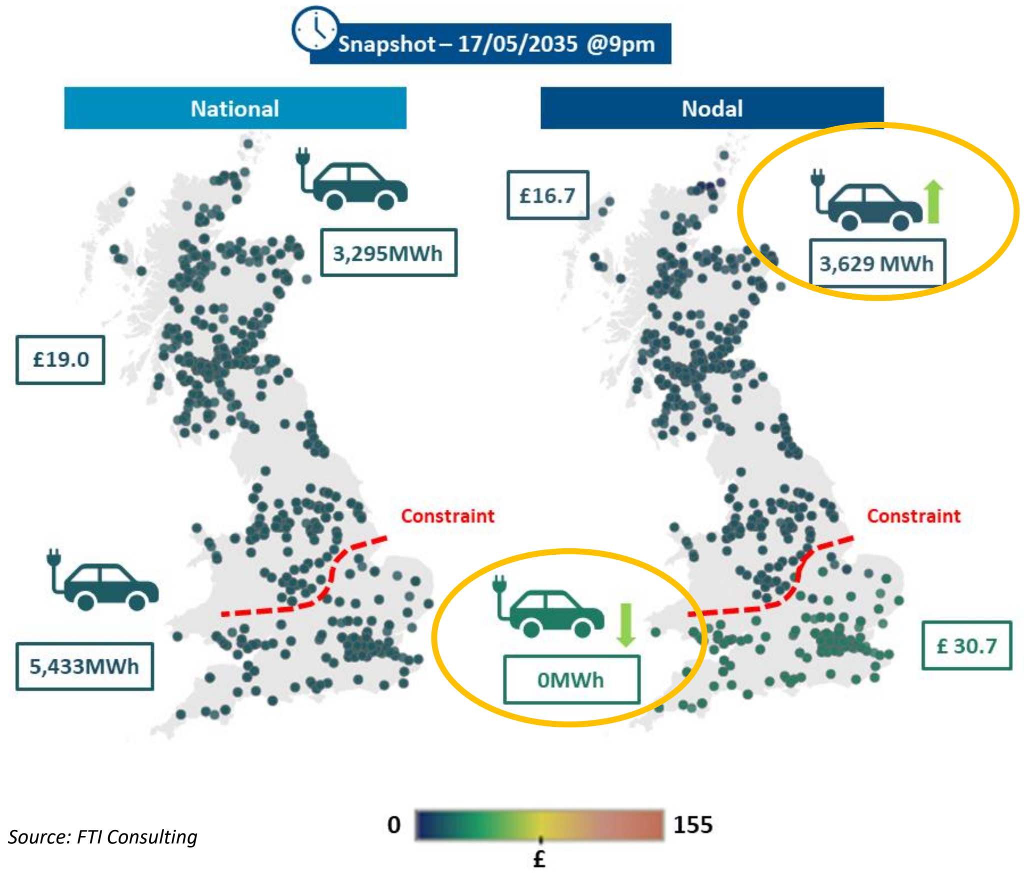
"We finally got the NorthConnect cable buried. We need to use Norwegian energy to build industry at competitive prices in Nordland and Norway….We must use our strength here"
Siv Mossleth,
Norwegian MP Centre Party

Source: Norwegian Broadcasting Corporation

- …but locational pricing in GB means Scotland, with frequently low prices, would export a greater volumes of electricity to Norway (and put downward pressure on prices there).
- Potentially significant better usage of Norway's 87TWh of reservoir storage – consistent with "Battery of Europe" concept.

The timings of when consumers would charge their flexible EVs differs in a nodal market relative to the status quo

Snapshot of impact on EV charging[1]



Source: FTI Consulting

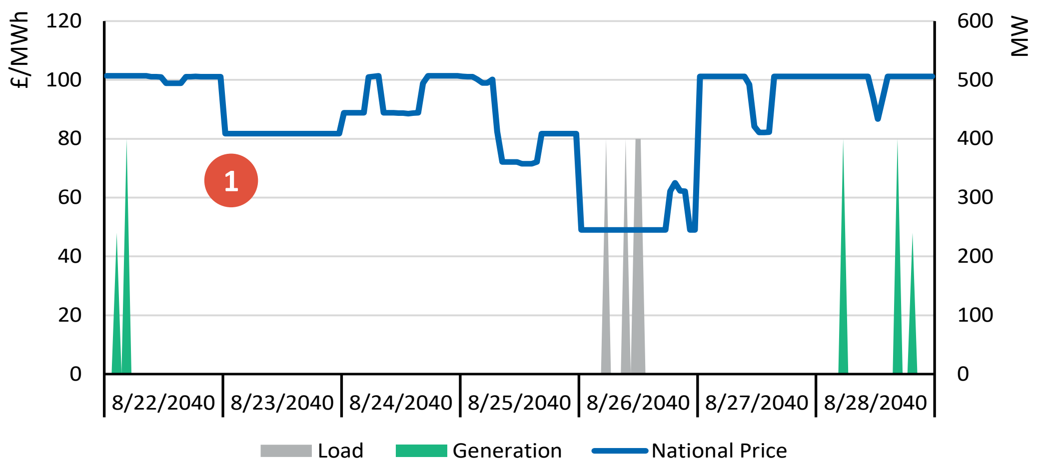
- In the FES, the use of EVs as a flexibility resource is expected to increase…
- … which could support system balancing under the efficient price signals…
- … or conversely, exacerbate consumer cost if wholesale price signals do not accurately reflect the needs of the system.

In 2035, the % of hours where flexible EV loads at each node were scheduled to run in an opposite manner in the nodal market relative to national (i.e. on in one and off in the other) was **28%[2]**

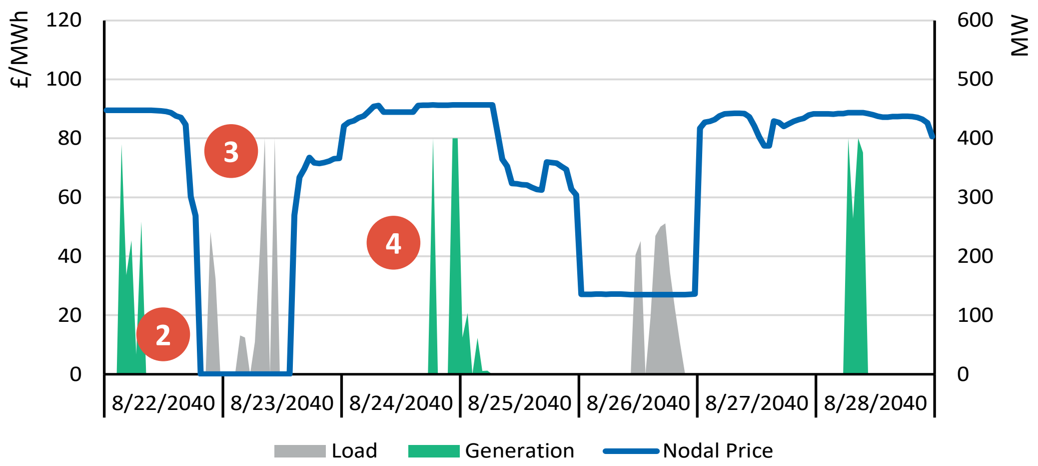
Note 1: DSR is impacted in a similar way to EVs in our assessment – we do not consider changes to both (1) overall demand and (2) resiting of demand.
Note 2: This figure takes into account amount of generation and storage capacity in each node so that it will only reflect changes to wholesale electricity market conditions and not capacity. There might be some other factors not related to wholesale prices that cause EVs to operate differently (e.g. local generator outages or extended periods of £0 prices) but we do not consider them to be material.

Locational pricing enables storage assets to better respond through the market to the availability and need for power in the connected region

Hourly profile for Ardmore 4hr battery, National model (LTW), Aug 2040



Hourly profile for Ardmore 4hr battery, Nodal model (LTW), Aug 2040



1 Single national price is relatively stable, with insufficient price differential for battery cycling…

2 …but nodal pricing reflects there is an excess of supply in the local area, with some RES curtailment.

3 With local price signals, battery is able to charge at low cost, reducing system curtailment in the process…

4 …and release the power to the system when local prices (and the need for power) rise in later hours.

In 2035, the % of hours where batteries (in aggregate)[1] were scheduled to run in an opposite manner in the nodal market relative to national (i.e. charging in one and off or discharging in the other) was **23%**

Note: 1-2 hour duration batteries only. Unlike the analysis in EVs, we aggregate each unit of batteries as one object – this is because our market modelling software treat different battery units indifferently on occasion (when conditions are equal) leading to arbitrary decisions on which battery should generate and/or consume

Transmission investment signals

To date our assessment on market design has considered different market designs while holding generation and transmission constant…

Assessing benefits of nodal market design under LtW

Market design	National	*Vs*	Zonal	*Vs*	Nodal
Generation / demand	LtW	*Vs*	LtW	*Vs*	LtW
Transmission	NOA7	*Vs*	NOA7	*Vs*	NOA7

Assessing benefits of nodal market design under LtW HND

Market design	National	*Vs*	Zonal	*Vs*	Nodal
Generation / demand	LtW	*Vs*	LtW	*Vs*	LtW
Transmission	HND	*Vs*	HND	*Vs*	HND

To date our assessment on market design has considered different market designs while holding generation and transmission constant…

Assessing benefits of nodal market design under LtW

Market design	National	Vs	Zonal	Vs	Nodal
Generation / demand	LtW	Vs	LtW	Vs	LtW
Transmission	NOA7	Vs	NOA7	Vs	NOA7

Assessing benefits of nodal market design under LtW HND

Market design	National	Vs	Zonal	Vs	Nodal
Generation / demand	LtW	Vs	LtW	Vs	LtW
Transmission	HND	Vs	HND	Vs	HND

Market design	National	Vs	National
Generation / demand	LtW	Vs	LtW
Transmission	NOA7	Vs	HND

Assessing benefits of HND under national market design

Market design	Nodal	Vs	Nodal
Generation / demand	LtW	Vs	LtW
Transmission	NOA7	Vs	HND

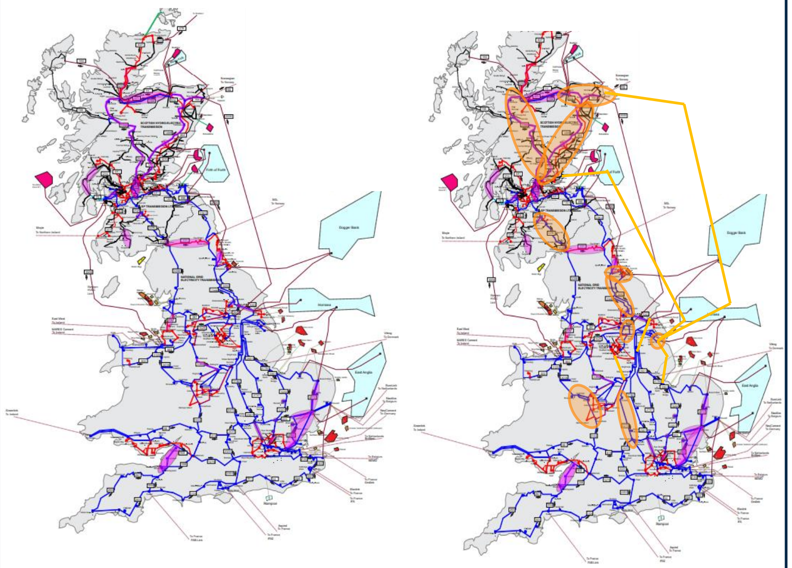
Assessing benefits of HND under nodal market design

But, with the introduction of HND scenario, can also assess benefits of more transmission under different market designs

The HND transmission scenario overlays greater volumes of transmission at accelerated pace against the Leading the Way generation background

LtW Transmission Grid scenarios - 2030

NOA7 scenario **HND scenario**



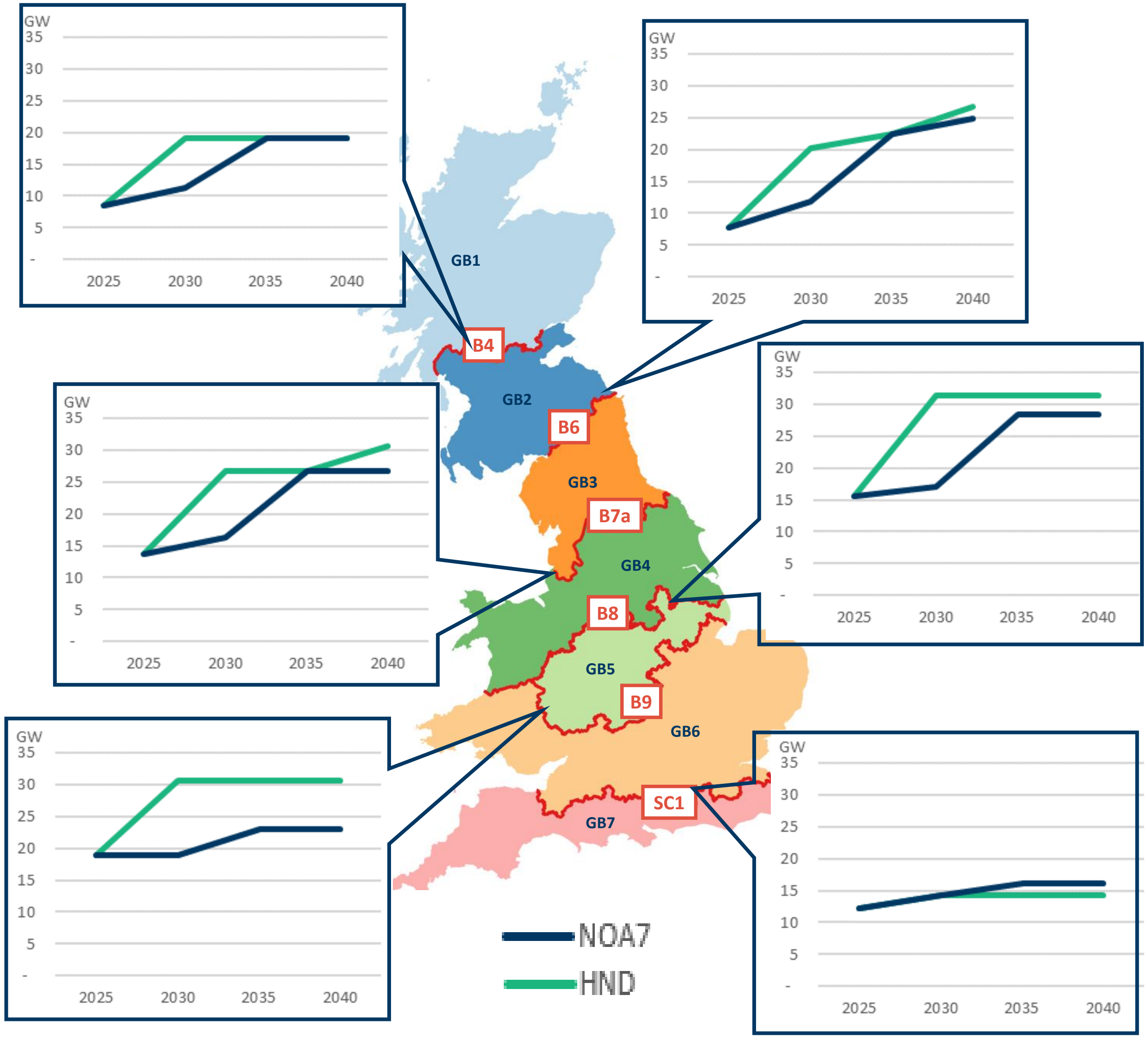
Source: ESO; FTI Consulting
Note: HND scenario map edited by FTI, based on ESO info (may not be exhaustive)

400kV **275kV** **132kV**
DC **Reinforcement**
Additional HND reinforcement

Relative to NOA7, HND has:

- Accelerated roll-out of transmission by 2030
- Additional transmission in Midlands

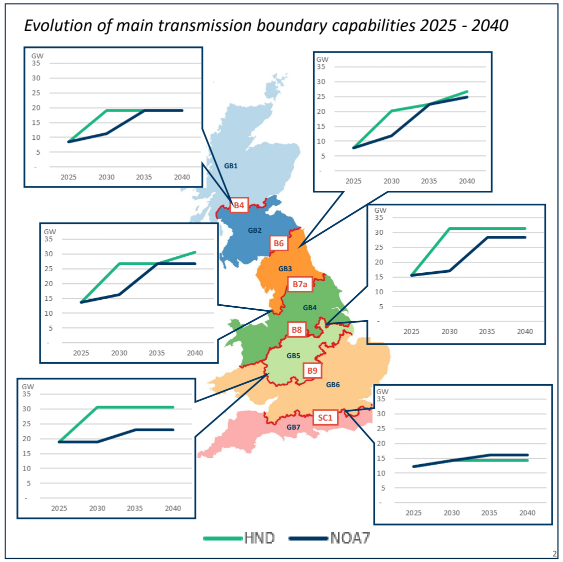
Evolution of main transmission boundary capabilities 2025 - 2040



Source: FTI analysis

The choice of market design fundamentally impacts the way in which benefits of transmission investments are evaluated

2 different transmission scenarios



2 different transmission scenarios

National market

Approach to assessing benefits of increase transmission

- Impact of transmission investments is to reduce transmission constraints…
- …therefore benefits of a transmission investment are reduced transmission constraint costs incurred by ESO.

Examples of assessment approach

- ESO Network Options Assessment Methodology

Nodal market

Approach to assessing benefits of increase transmission

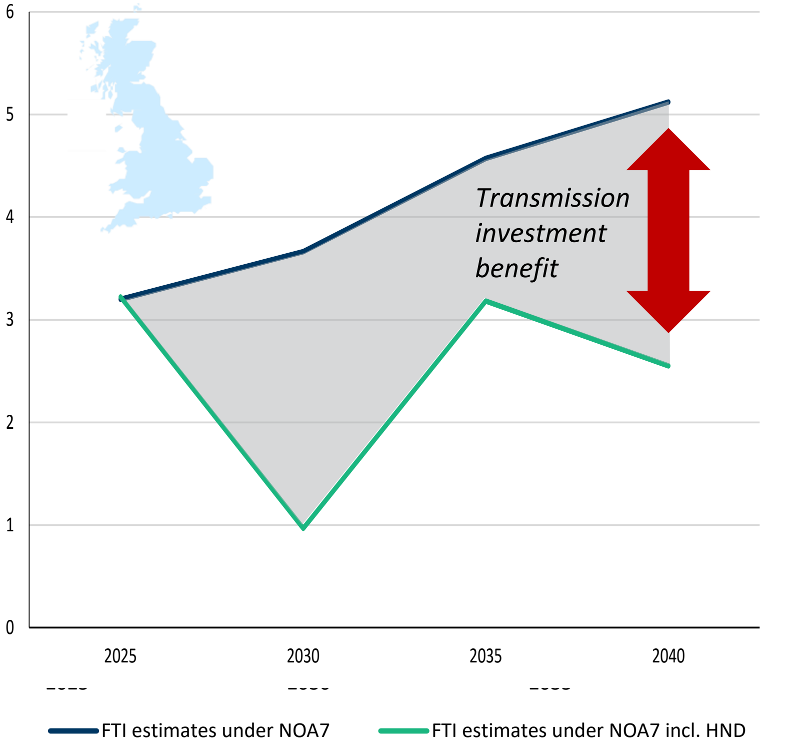
- There are no constraint costs for the ESO to mitigate
- Impact of transmission investment instead is on nodal prices
- In exporting regions of the network, prices tend to increase…
- …in importing regions prices are lower.
- Therefore need to assess impact of change in prices on consumers and producers to evaluate overall benefits

Examples of assessment approach

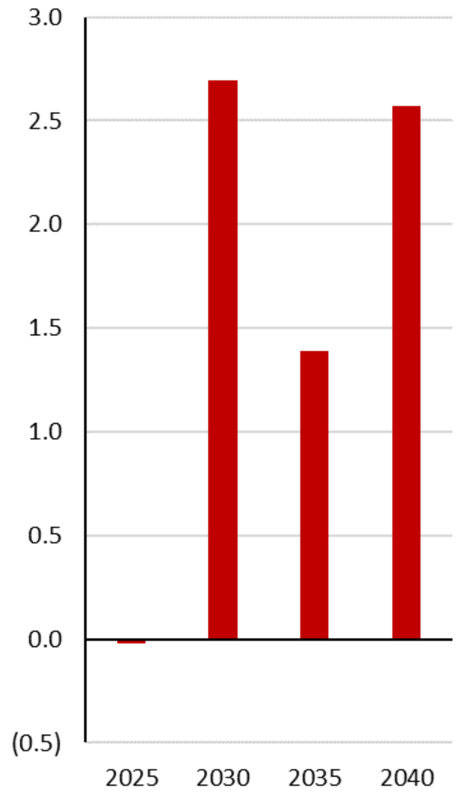
- Ofgem C&F interconnector CBAs (of sorts)
- MISO (USA)
- New Zealand

For national pricing, the benefits of the incremental transmission investment in HND would be evaluated at c£28bn over the 2025 – 2040 period…

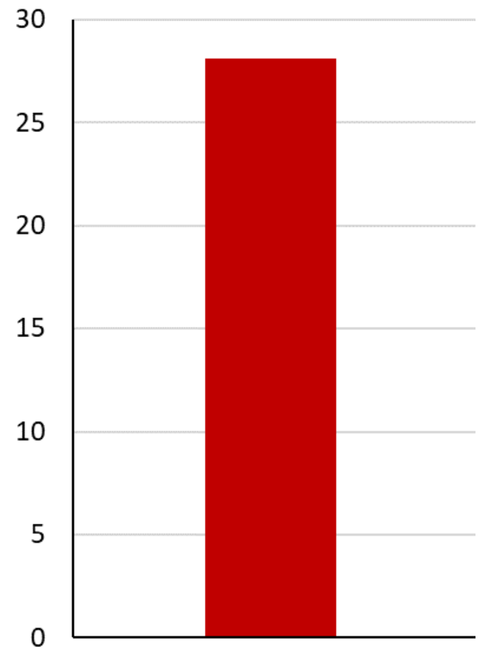
FTI estimates of constraint cost estimates, Leading the Way NOA & and LtW HND, 2025-2040, £bn



Difference in constraint costs, £bn



Total benefit of incremental HND investment under national market design 2025 – 2040 , £bn



Benefits of National LtW (HND) relative to National LtW

Annual results interpolated and aggregated for the 15 year modelling period.

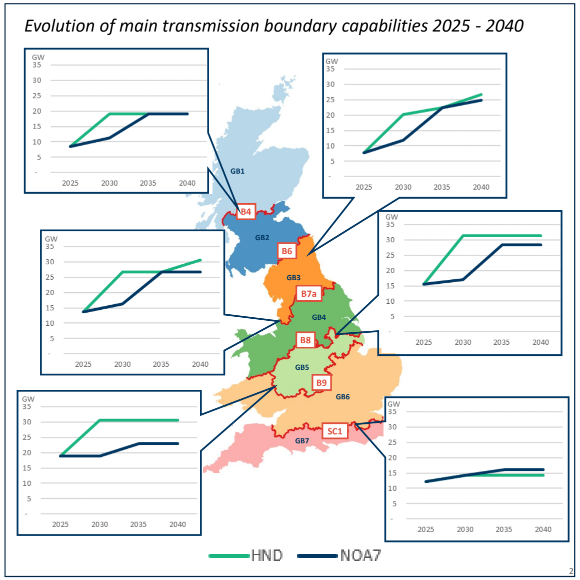
Source: FTI analysis

Note: we show undiscounted values for the purposes for this comparative analysis

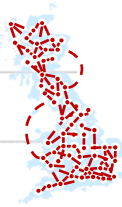
…this is in line with the ESO approach as set out in its published methodology

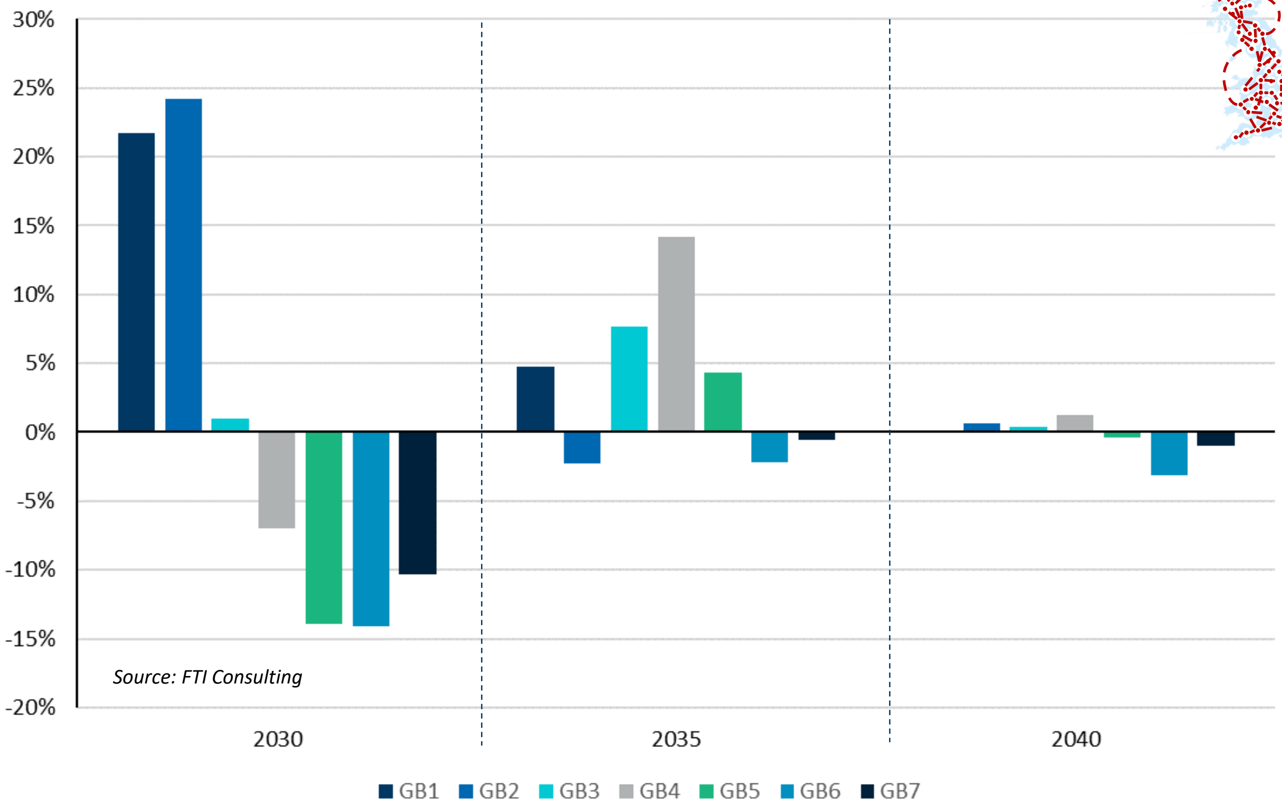
See: https://www.nationalgrideso.com/document/174231/download

The incremental transmission investment from HND in this assessment results in changes to the nodal prices…



Percentage change in average annual nodal prices (grouped by zones) due to incremental HND transmission investment relative to HND





- In **2030** significantly more North-South transmission in HND relative to NOA7.
- Leads to 2030 prices increasing in North and decreasing in south (in line with expectations)

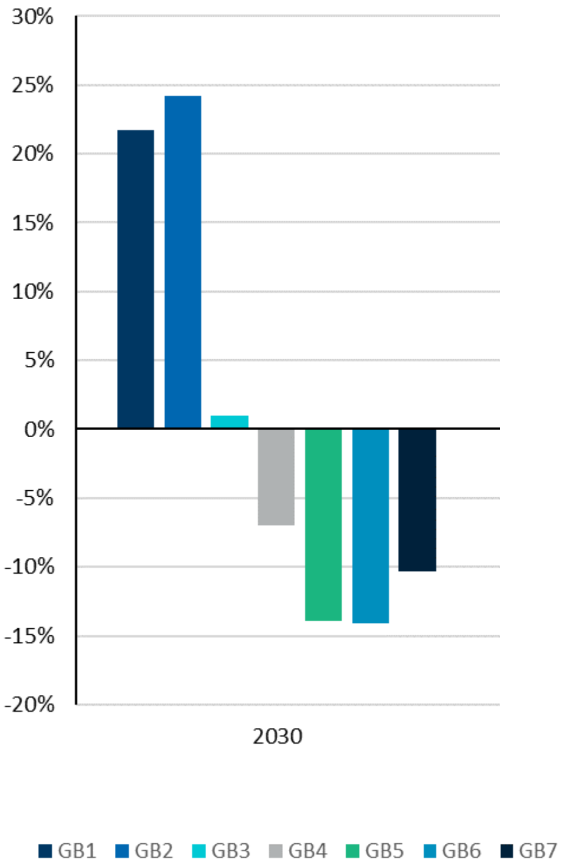
- By **2035** most NOA7 build has caught up with HND although 7GW+ in Midlands
- HND prices higher Midlands northwards, and lower in south

- By **2040**, persistently lower prices in south as a result of additional transmission

This results in varying consumer and producer benefits across regions due to HND under the nodal pricing regime…

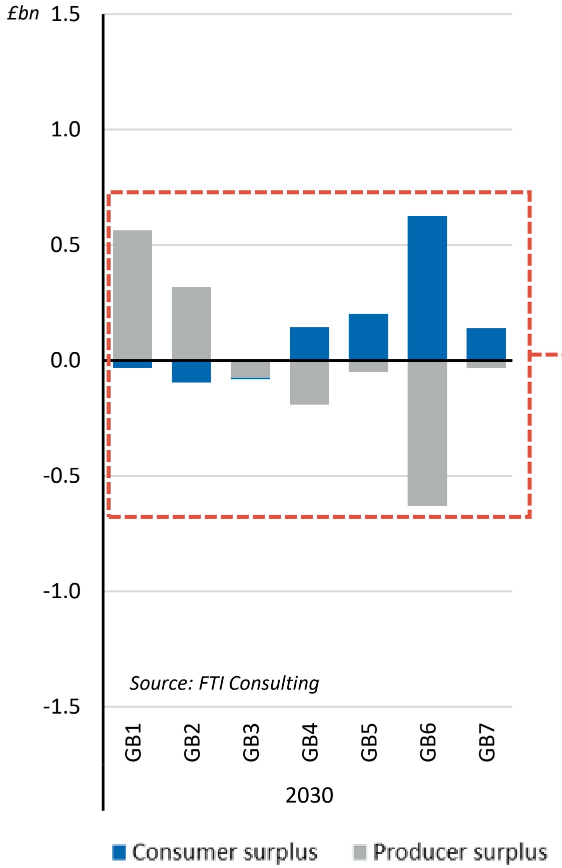
Prices changes as a result of HND for 2030….

Percentage change in average annual nodal prices (grouped by zones) due to HND, 2025



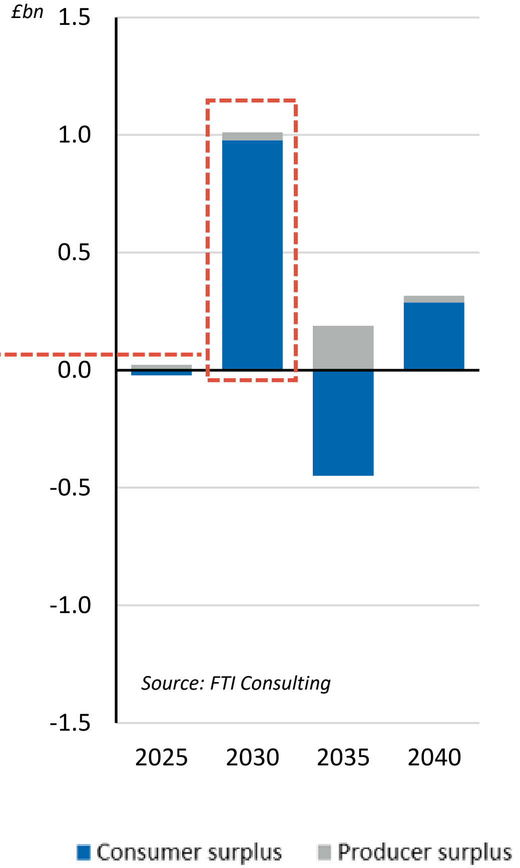
…which impact consumers and producers differently by region….

Consumer price benefit and change in producer surplus by region 2025, £bn

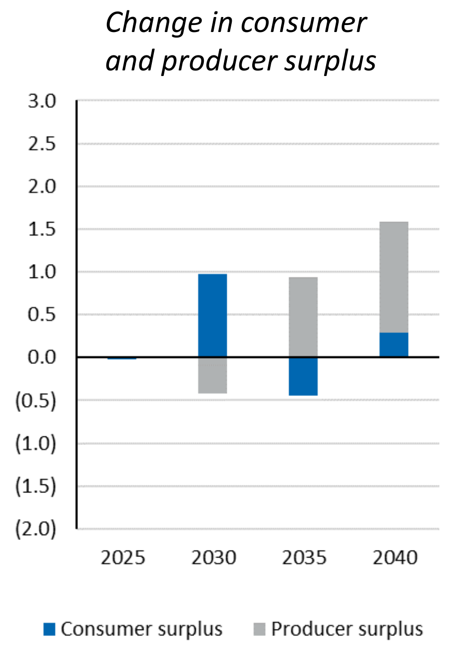


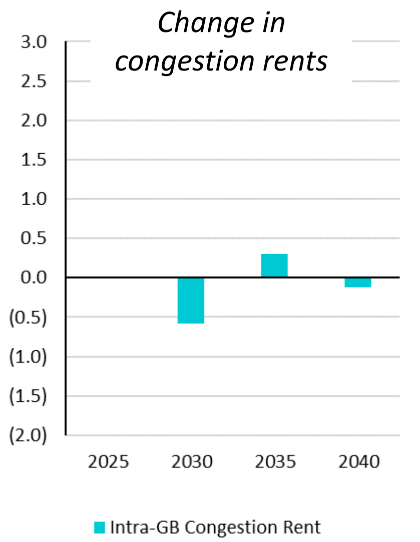
…and aggregate to evaluate the overall change in consumer and producer surpluses

Aggregated consumer price benefit and change in producer surplus 2025 - 2040, £bn

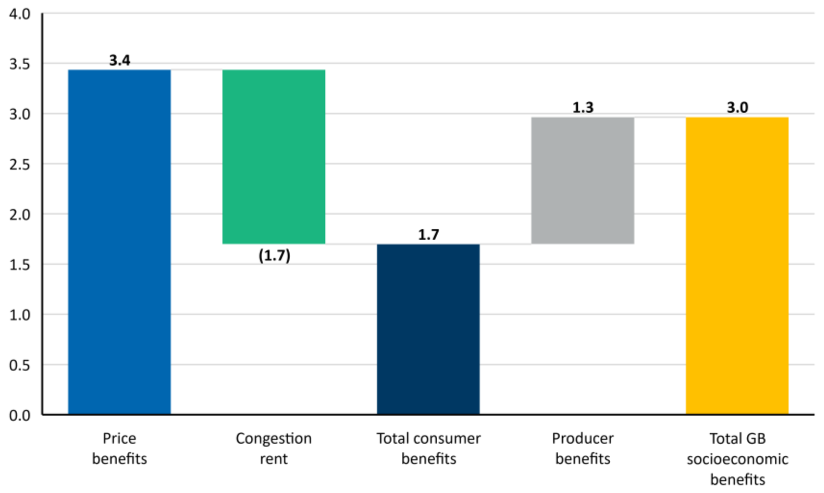


… and the overall impact on socioeconomic benefits in a nodal market design





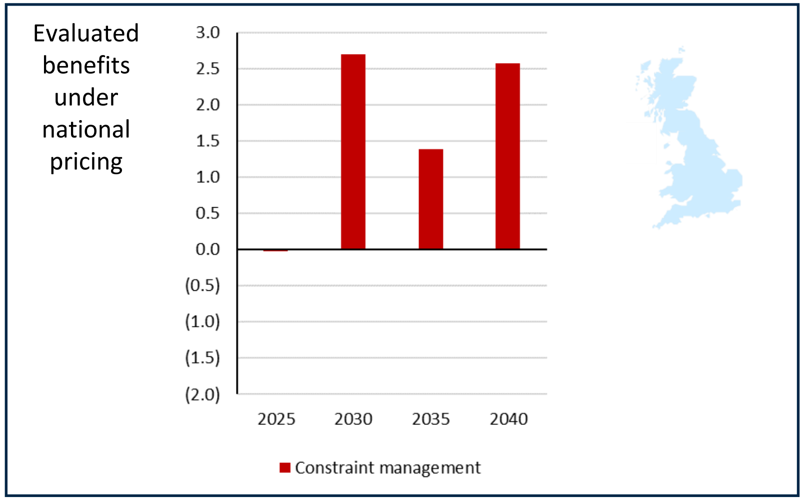
Total benefit of incremental HND under Nodal pricing market design 2025 - 2040, £bn

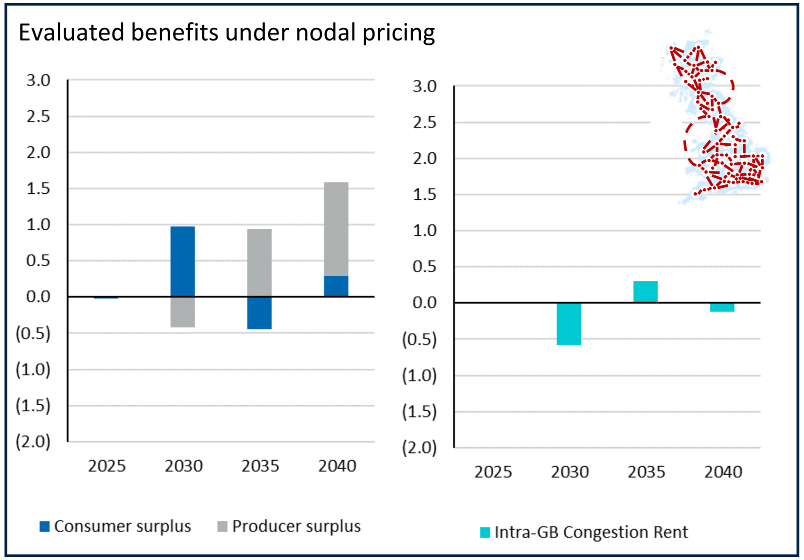


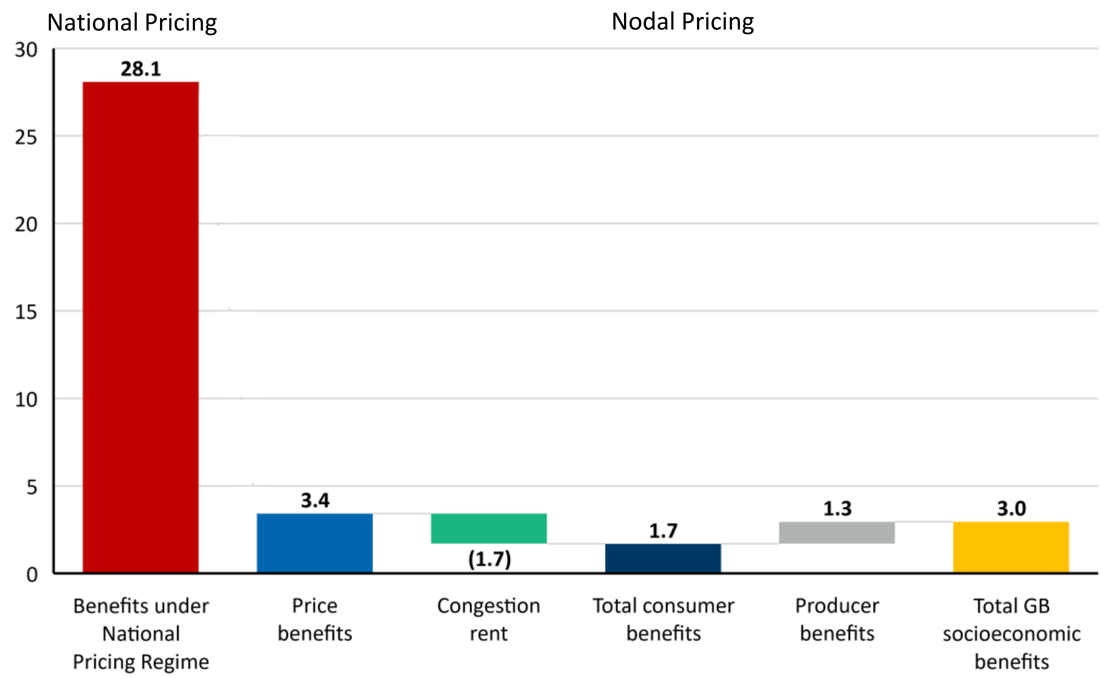
Annual results interpolated and aggregated for the 15 year modelling period.

Benefits of incremental transmission investment are lower under a nodal pricing regime

Total benefit derived from HND under the National Pricing regime and the Nodal pricing regime, £bn







- Clearly very significant difference between two benefits assessments…
- …albeit exactly same level of incremental transmission and same overall volume of generation capacity…
- … so we have worked with Ofgem and ESO to understand drivers of difference

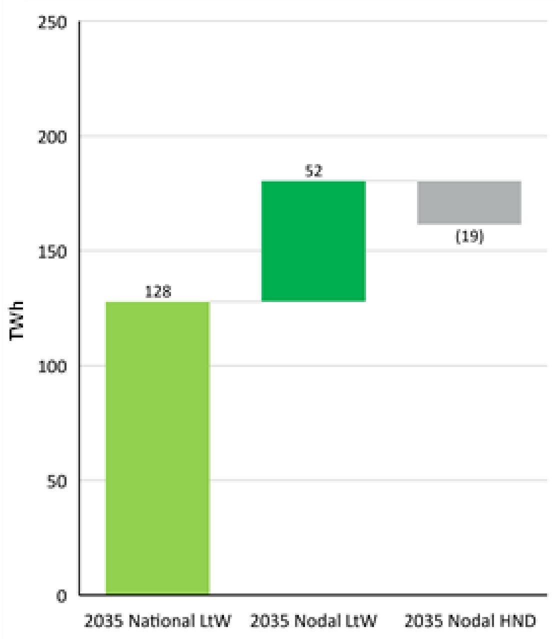
The significant reduction in benefits of transmission enhancement found in our modelling under nodal pricing can be attributed to three main reasons

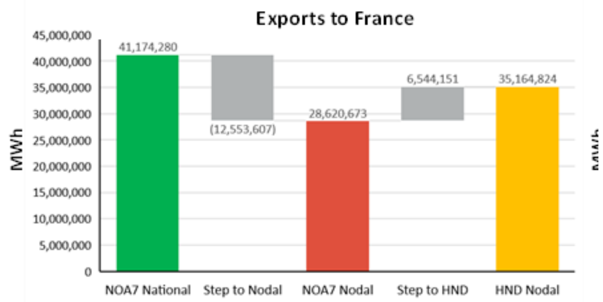
1 Forecasting congestion costs

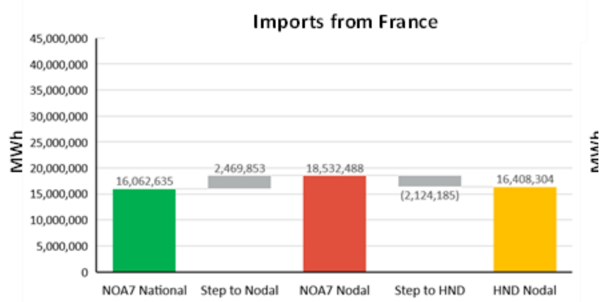
2 Change in generator siting and output

3 Change in interconnector flows and use of other flexible assets

Technology	Cost to ESO Bid	Cost to ESO Offer
Fossil fuel	- Fuel cost - carbon cost	Offer Uplift + Fuel cost + carbon cost
Biomass	- Fuel cost	Offer Uplift + Fuel cost
CCS Biomass	Carbon price – Fuel cost	Offer Uplift + (Fuel cost – carbon price)
ROCs renewables	ROCs[1]	(theoretical only so no price assumed)
CfD renewables	CfD strike price – Wholesale price	(theoretical only so no price assumed)
Merchant renewables	£0	Offer Uplift
Batteries	- Price Paid	Price Received + Offer Uplift
Other Storage Technology	- Marginal Value	Marginal Value
Hydrogen generation H_2	- Marginal Value	Marginal Value
Interconnector	Cost of reversing flow €130 / €100[2]	Cost of reversing flow €130 / €100[2]







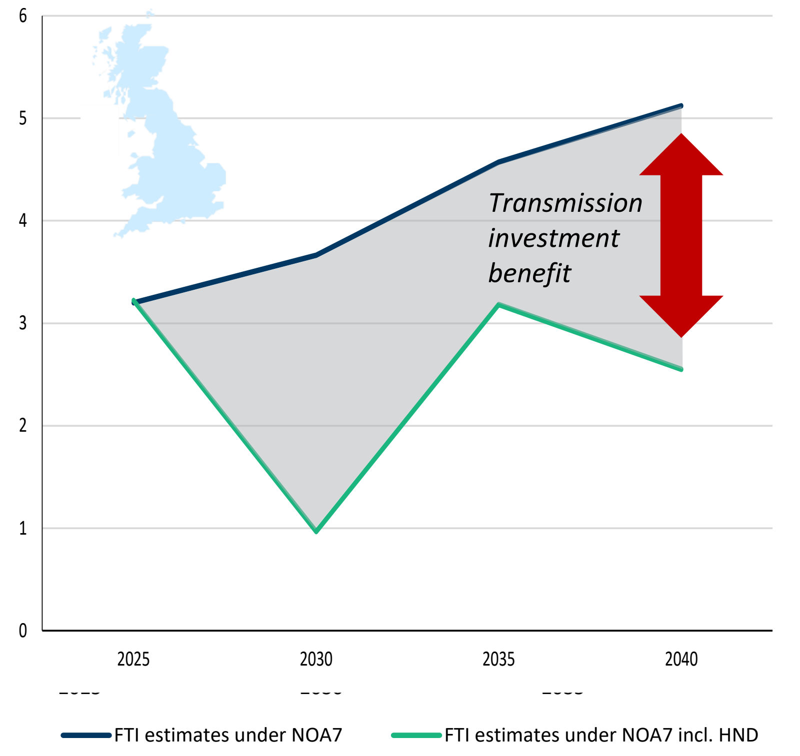
Assumptions on balancing mechanism bid and offers feed into the transmission investment benefits assessment

Assumptions on BM bids and offers

Technology	Cost to ESO Bid	Cost to ESO Offer
Fossil fuel	- Fuel cost - carbon cost	Offer Uplift + Fuel cost + carbon cost
Biomass	- Fuel cost	Offer Uplift + Fuel cost
CCS Biomass	Carbon price – Fuel cost	Offer Uplift + (Fuel cost – carbon price)
ROCs renewables	RO Cd	(theoretical only so no price assumed)
CfD renewables	CfD strike price – Wholesale price	(theoretical only so no price assumed)
Merchant renewables	£0	Offer Uplift
Batteries	- Price Paid	Price Received + Offer Uplift
Other Storage Technology	- Marginal Value	Marginal Value
Hydrogen generation H_2	- Marginal Value	Marginal Value
Interconnector	Cost of reversing flow €130 / €100²	Cost of reversing flow €130 / €100²

- BM bids and offers feed into evaluation of congestion costs…
- …but assumptions mean prices used in forecasts deviate from marginal costs (e.g. offer uplifts and CfD payments)…
- …and means consumer transfers in BM (e.g. constrained off payments and uplifts to constrained on generators) feed into case for transmission.
- Hence current NOA approach evaluates from consumer perspective not conventional socio-economic…
- …whereas our nodal evaluates from standard socioeconomic assessment

FTI estimates of constraint cost estimates, Leading the Way NOA & and LtW HND, 2025-2040, £bn



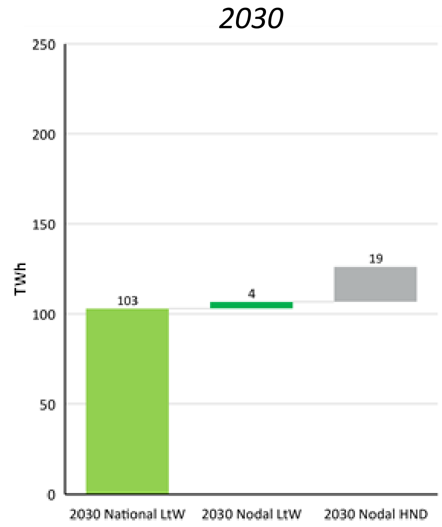
The ESO had, independent of our analysis and findings, recently identified this issue internally as part of their review of the Network Options Assessment methodology and are currently considering this issue

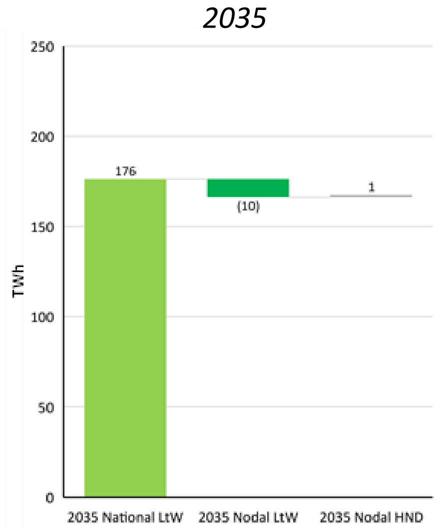
See NOA methodology | ESO (nationalgrideso.com)

Change in siting impacts output by wind and solar resources in each of the regions

More **wind and solar generation** in south given assumptions on generation re-siting as a result of nodal pricing signals…

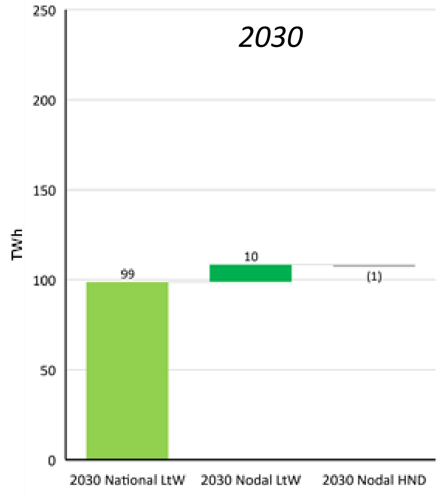
Scotland
Change in solar and wind production

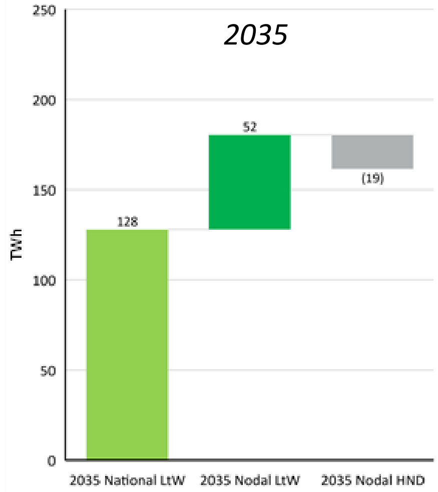




- Slight reduction in RES output in 2035…
- …given assumptions in generation re-siting

Southern England
Change in solar and wind production





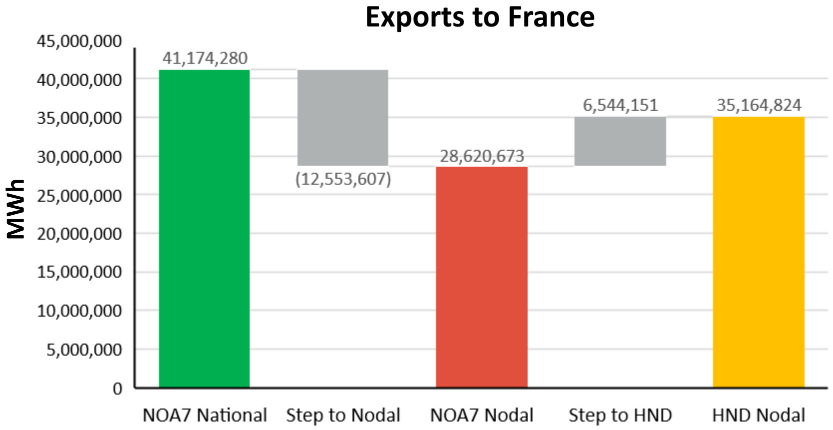
- Greater volumes of wind and solar generation in south of England as a result of transition to nodal pricing..
- This is due to our assumptions on re-siting…
- …and also to improved wholesale price signals to flexible demand assets

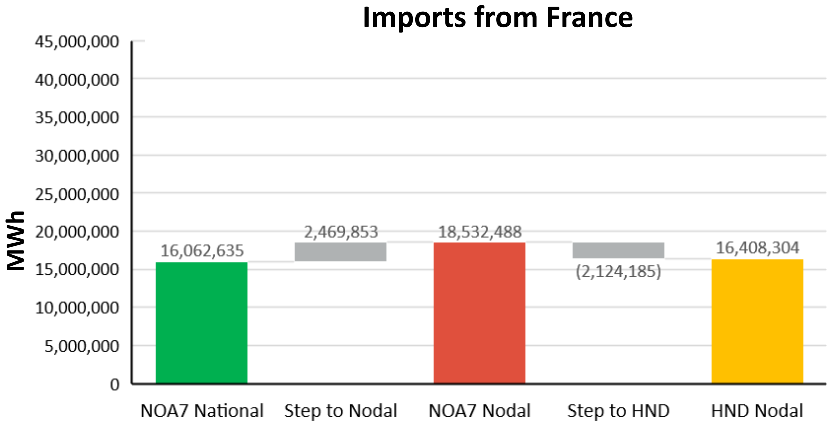
…means new transmission investment between north and south is overlaid on a less constrained system and therefore, all else equal, less beneficial

Nodal pricing significantly reduces congestion on the GB system by sending price signals that alter market scheduled IC flows (esp for France and Norway)

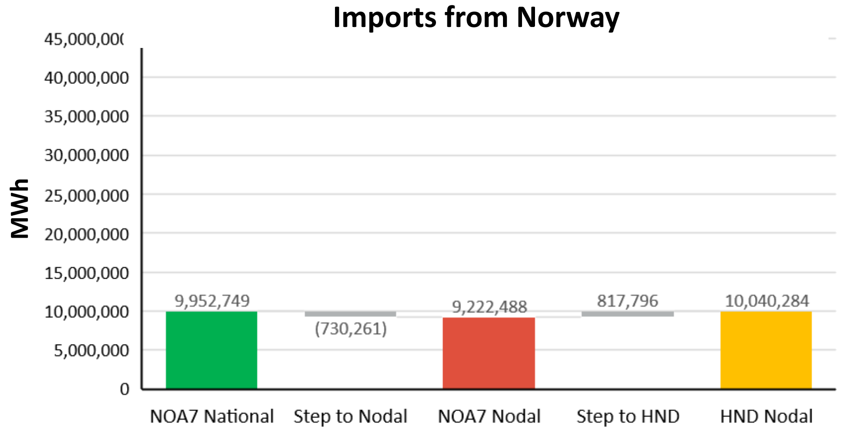
Differences in the projected IC flows in 2030 under national and nodal market designs, before and after HND (MWh)

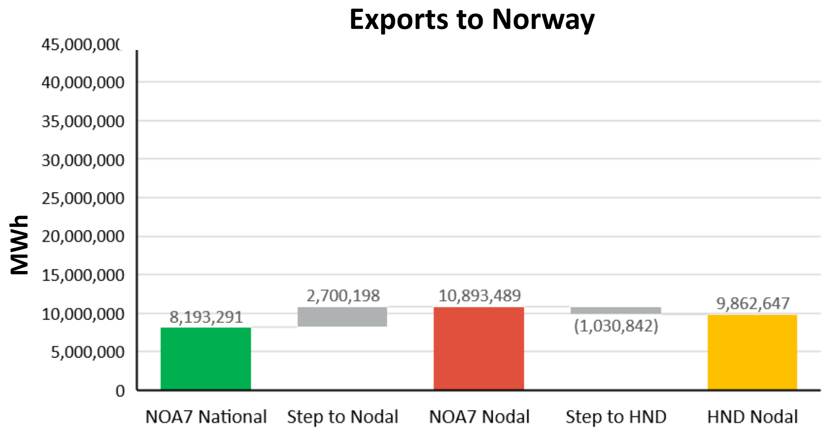
Higher nodal prices in the south result in reduced net flows to France (i.e. less exports and more imports)….





…but lower prices in north result in higher net flows to Norway (i.e. more exports and less imports)





As well as investment signals, nodal pricing has an operational impact - it encourages the market to flow electricity to the most constrained parts of the network. In turn, as the system is less constrained, any incremental transmission enhancements will have less benefit

To close, we highlight **seven conclusions** from our assessment

1. **Significant consumer benefits** modelled between 2025 and 2040 in a nodal market between £28bn and £51bn

2. **All consumers in each GB region are expected to benefit**, although some cohorts more than others

3. Moving to locational pricing would reduce emissions faster – we estimate between 25 and 100 MtCO2 less would be emitted between 2025 and 2040. Applying **DESNZ's carbon values, increases socioeconomic welfare increases by a further £4.3bn to £17.9bn**

4. Our modelled **benefits of locational pricing are (arguably) conservative** – we assume no demand re-siting, no change to total generation capacity by type, and no change to transmission build out

5. Our two **sensitivity scenarios**, shows moderate reductions in benefits, but **still produces significant net benefits**

6. **Flexibility resources**, particularly interconnectors but also batteries and vehicle charging, are utilised more effectively, recognising constraints on the network

7. **Potential significant savings in transmission** – as locational pricing delivers market signals that improves operational and siting decisions, the need for greater transmission investment is reduced

Q&A Session #3

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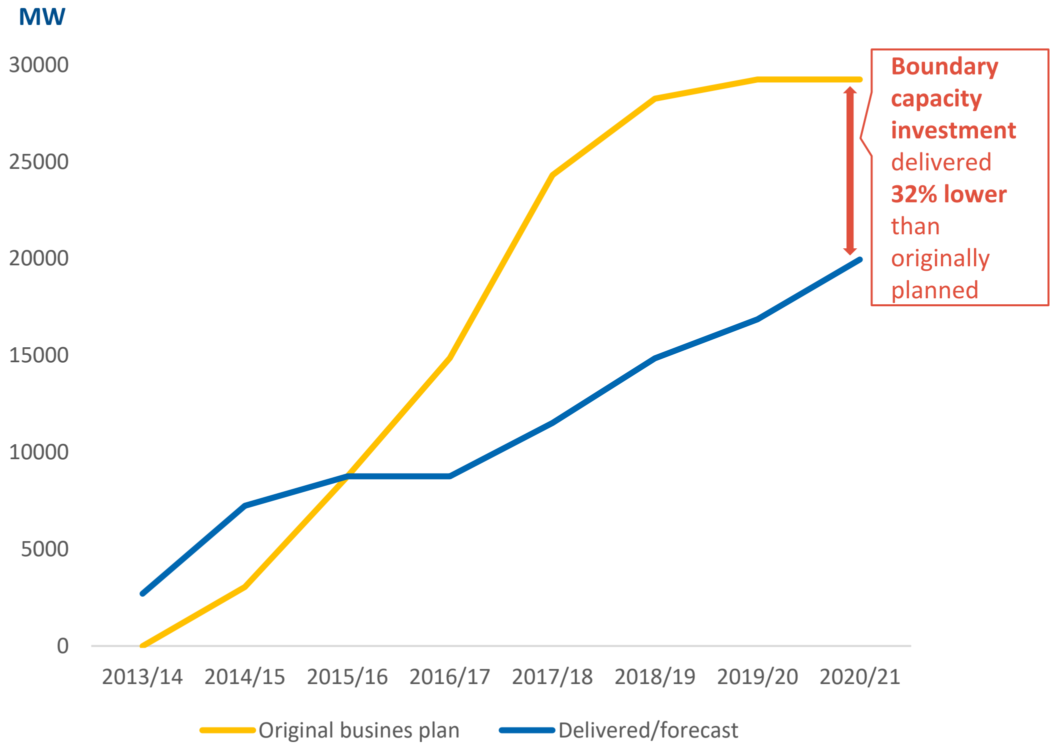
Appendix 1: Methodology detail

An 8-fold increase in the delivery of large transmission reinforcement is required to meet the capacities identified in ESO's HND

Historically, delivery of the new capacity has significantly lagged the initially proposed requirements

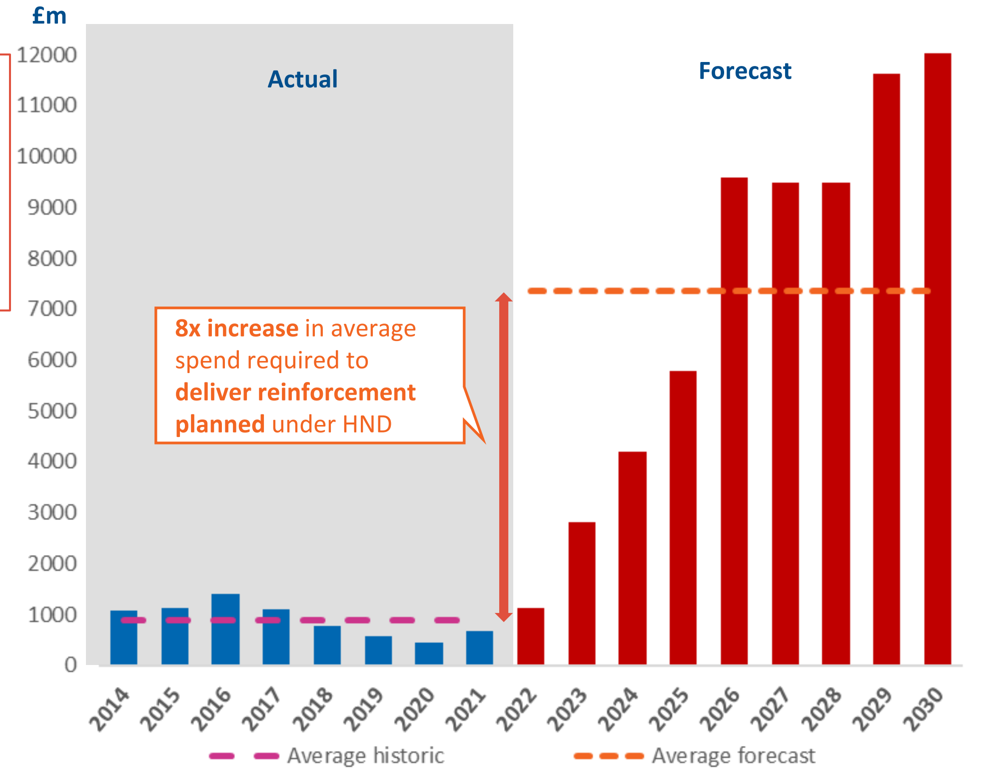
Comparison of planned vs. actual delivery of boundary reinforcement projects in GB over RIIO1



Sources: Ofgem - RIIO1 Performance summary documents; TOs Annual Performance Reports; FTI analysis.

Transmission reinforcement required to meet the 2030 generation target requires an increase of 8x the average annual spend across all TOs

Comparison of average annual expenditure to delivered planned NOA7+ and HND reinforcements



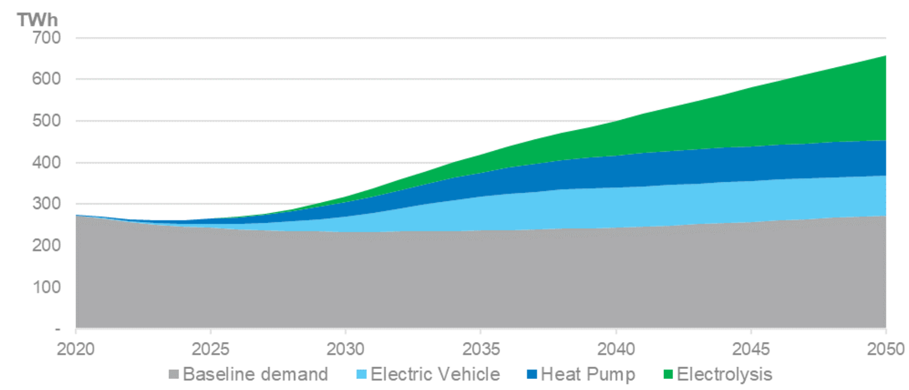
Sources: Ofgem-RIIO Performance report; RIIO T2 PCFM; ESO-Pathway to 2030 Holistic Network Design and NOA Refresh; FTI analysis.

Demand projections are based on FES21 LtW, including the flexibility behaviour of different technologies, excluding demand portability

A **We split customer demand[1] into four components. Total annual demand for each of these components, in each scenario, is set exogenously, using the local demand as defined in FES2021 (GSP demand level)**

- Baseline demand
- Electric vehicles
- Heat pumps
- Electrolysers

FES21 Leading the Way - demand forecast (TWh)



B **Demand profiles for each of these components are based on the Pan European Market Modelling database (PEMMDB)[2]. These profiles are optimised by the model, using flexibility assumptions developed based on FES21**

DSR	▪ Two tier of DSR included in the model, each of them activated at different price levels ▪ Capacity of DSR and price levels are based on FES21
Electric vehicles	▪ A quarter of EVs optimise demand across ten hours a day day to minimise cost, consuming at times when power is cheapest ▪ Remaining 75% of EVs follow a fixed hourly demand profile peaking late at night (i.e. most charging happens overnight)
Heat pumps	▪ 50% of heat pumps optimise demand within each day to minimise cost, with climate profiles varying heating demand across the year ▪ The proportion of flexible units follows the proportion of flexible heat pumps units in use according to FES21
Electrolysers	▪ Electrolyser capacity and annual demand is fixed to FES21 (implying load factors of c.11-31%) ▪ The model optimises the demand profile within the year

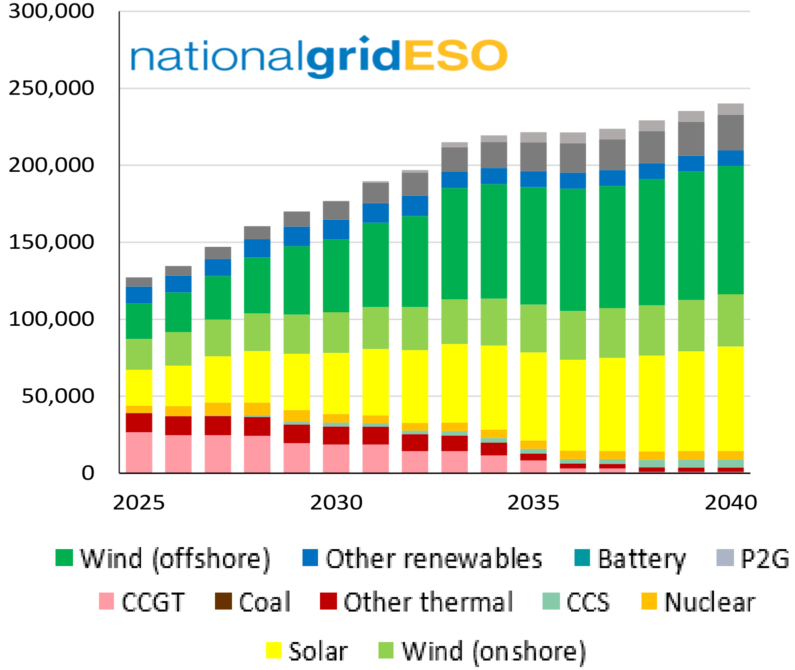
C **Demand from the power sector (e.g. battery and pumped storage) is optimised endogenously by the model. The installed capacity of these technologies is fixed to FES21**

1: Customer demand excludes demand from the power sector (e.g. power plant own consumption).
2: The PEMMDB is published by ENTSO-E and is the basis of the TYNNDP modelling

Generation capacity forecasts are based on FES21 Leading the Way scenario, and the mix stays the same across market designs

National model assumes capacity follows FES21

Total GB capacity (MW), FES21 Leading the Way



- Total generation capacity per technology is based on the FES21 data
- Siting is based on FES21 regional breakdown (at nodal granularity)

Capacity under nodal and zonal design also follows FES21[1], but we allow the following technologies[2] to re-site, subject to limits

Technology	Limits
Onshore Wind	• England: No new onshore wind • Wales and Scotland: New capacity can locate on any node/zone with onshore wind capacity in FES21 • Total capacity at any node can be max 2x FES21
Offshore Wind	• Offshore wind responds, but respects historical ARs and reflecting local resource availability (wind speeds)
Solar	• Total solar capacity at any node can be max 2x FES21
Battery	• New capacity can locate on any node with battery capacity in FES21
CCS Biomass (CCS BIO)	• New capacity can locate at nodes which are part of CCUS clusters
Hydrogen generation (H_2)	• New capacity can locate at nodes with Hydrogen CCGTs as specified in FES21 and nodes around H2 clusters

- Keeping the same capacity mix is a conservative assumption for alternative market design options, as more granular pricing could potentially trigger a change in the capacity mix
- This approach allows a direct comparison across the three locational designs under consideration
- Restricting new build to (mostly) locations with prior new build is arguably also conservative, as it limits the optimisation of siting

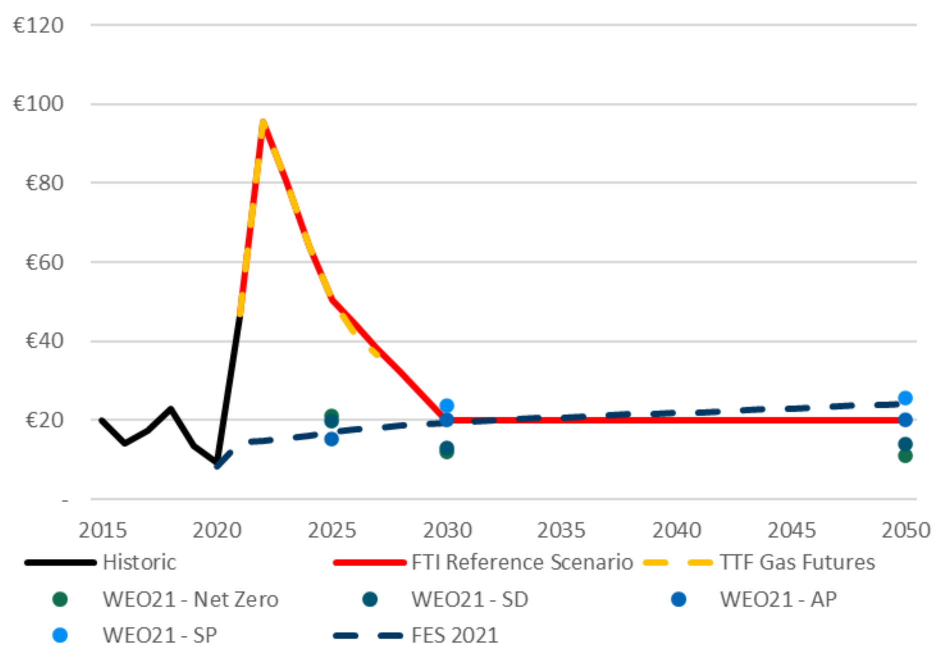
1: Small changes of <2% are allowed for Biomass, CCS biomass and Hydrogen generation, reflecting resource availability in line with FES21
2: All other technologies, including fossil fuel, biomass, nuclear, pumped hydro, hydro and interconnectors remain sited in identical locations across national, zonal and nodal designs.

Commodity price assumptions are based on future curves and long-term benchmarks to reflect recent market development

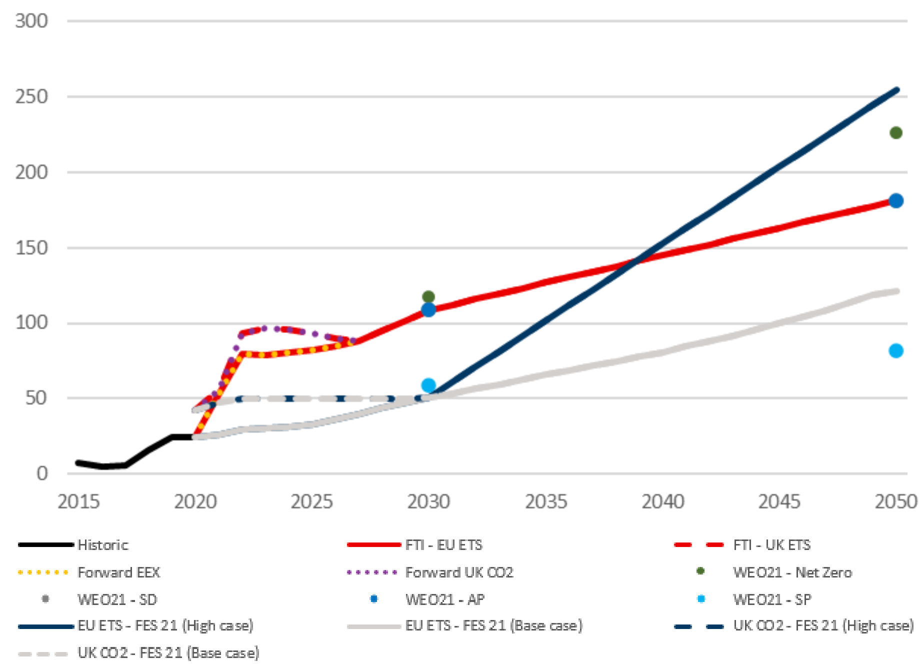
Commodity price forecasts (mainly gas and carbon) are the main determinant of the short-run marginal costs of thermal power generators, and thus wholesale energy prices

Gas	▪ Follows forward curves up to 2025 and World Economic Outlook ("WEO") long-term forecasts from 2030[1]
Carbon	▪ Similarly based on mix of future curves and long-term benchmarks from the WEO ▪ Includes adjustment for Carbon Price Floor in UK, until convergence with Continental Europe in late 2020s[2]
Other	▪ Coal, biomass and oil also relevant ▪ Same approach used with respect to future curves and long-term benchmarks

Gas price forecast (€ per MWh)



Carbon price forecast (€ per MWh)



1: The forecast gas prices rely on 2021 and early 2022 data sources, as tested with stakeholders and agreed with Ofgem.
2: We have considered market impact from forecasted carbon prices, but not policy-administered carbon values intended to reflect the full societal cost of carbon

We model constraint management costs by applying balancing mechanism bid and offer prices to our constrained generation model run

The BM has several unique features in the national and zonal market designs

- The SO must balance on a locational basis
- The SO trades with market participants on a pay-as-bid basis
- The SO is the only counterparty

Given this, we undertook two model runs per scenario

- The unconstrained model run assumes no constraints on the network due to transmission
- The constrained (or "redispatch") accounts for the physical reality of the transmission network
- We apply assumed BM bid and offer prices to differences in generation between the two model runs

Constrained on costs = Constrained on generation × Offer price

Constrained off costs = Constrained off generation × Bid price

BM bid and offer prices have been developed using historical behaviour, as well as forecasts of fuel and carbon costs for different technologies[1]

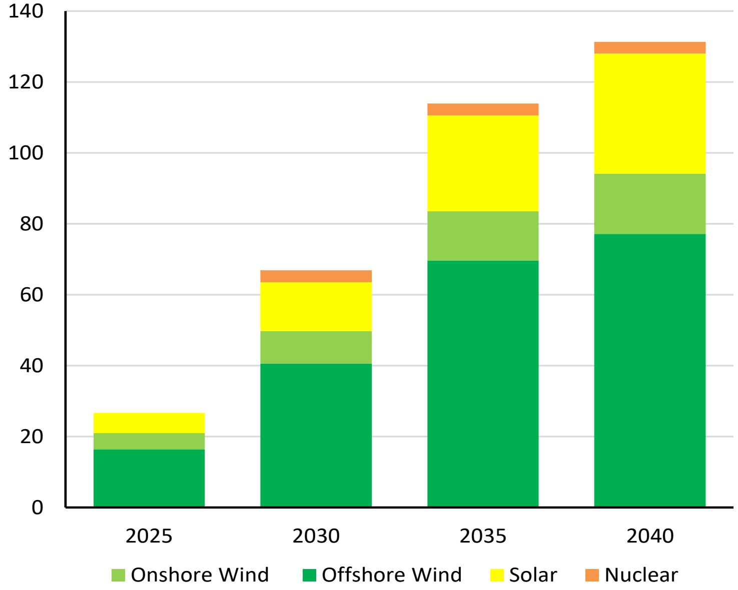
Technology	Cost to ESO Bid	Cost to ESO Offer
Fossil fuel	- Fuel cost - carbon cost	Offer Uplift + Fuel cost + carbon cost
Biomass	- Fuel cost	Offer Uplift + Fuel cost
CCS Biomass	Carbon price – Fuel cost	Offer Uplift + (Fuel cost – carbon price)
ROCs renewables	ROCs[1]	(theoretical only so no price assumed)
CfD renewables	CfD strike price – Wholesale price	(theoretical only so no price assumed)
Merchant renewables	£0	Offer Uplift
Batteries	- Price Paid	Price Received + Offer Uplift
Other Storage Technology	- Marginal Value	Marginal Value
Hydrogen generation H_2	- Marginal Value	Marginal Value
Interconnector	Cost of reversing flow €130 / €100[2]	Cost of reversing flow €130 / €100[2]

Note: We assume that Demand Side Response, nuclear, hydro (run-of-river) and small-scale thermal do not participate in the balancing mechanism.
1: The number of Renewable Obligation Certificates ("ROCs") will depend on technology. For simplicity, we assumed 1.9 ROCs for offshore wind and 0.99 ROCs for onshore wind, the average per technology from DESNZ (link).
2: The cost of reversing flow is assumed to be €130 in 2025 and €100 in all other years.

Our approach to Contracts-for-Difference costs is based on the evolution of CfD generator capacity and assumptions of future CfD regime design

We assume CfD contracts will be available, in part or fully, across four technologies

Projected capacity of CfD generators under LtW (GW)



This includes:

- **Existing projects with CfD contracts;**
- **All proposed offshore wind projects awarded CfDs in Auction Rounds 1 to 4;**
- **Hinkley Point C;**
- **All future offshore wind projects;**
- **50% of future solar projects; and**
- **50% of future onshore wind projects 1**

Our constrained generation model estimates generation profiles for each of these projects, allowing us to estimate the cost of CfD support on consumers

Cost estimated as:

CfD support payments = ∑ (Strike price – reference price) * generation volume

Where:

	National market	Zonal market	Nodal market
Strike price	• Based on DESNZ's levelized cost of electricity estimates ("LCOE") • Use arithmetic average across range of LCOEs by technology type • Assume same LCOE across all locations		
Reference price	National price	Zonal price	Nodal price
Generation volume	Constrained model output (i.e. redispatch model run)	Actual output	

1. This assumption is due to limited available information and represents a balance given the trend of increasing numbers of CfD contracts being awarded over the last four Action Rounds and potential for more merchant investments. Amending the assumption would lead to a pure transfer between producers and consumers.

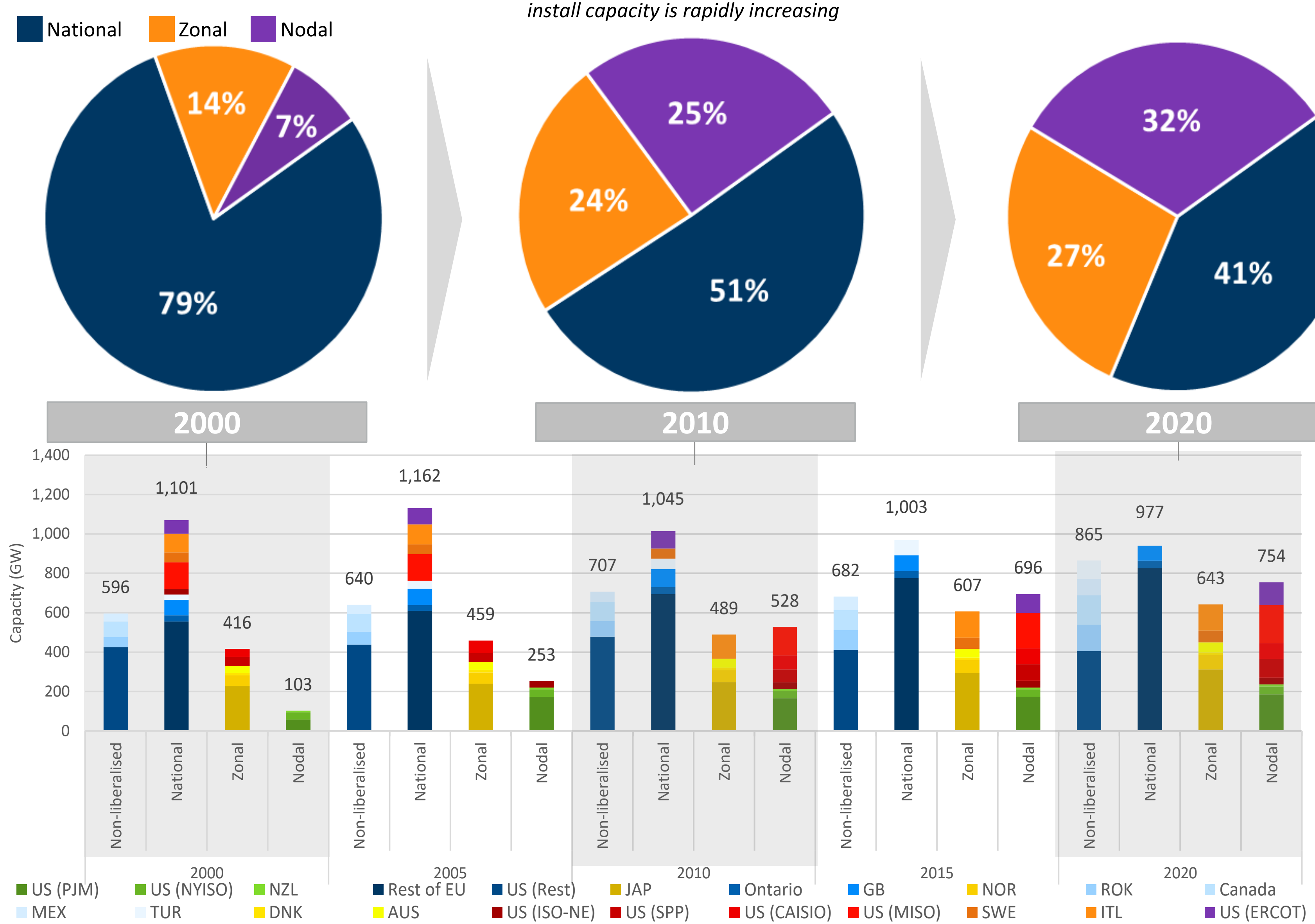
Appendix 2: Wholesale electricity market designs in other developed energy markets

CATAPULT Energy Systems
FTI CONSULTING

Developed countries are increasingly moving towards locational pricing, with no reversals regarding decisions to increase the locational granularity of prices

Share of market design options across the OECD[1] countries

Greater proportion of markets in developed economies are moving towards more granular locational pricing while the total install capacity is rapidly increasing



Notes: (1) chart includes OECD member countries (as of 2000) except Iceland. Sources: IRENA, CAISO, NYISO, ERCOT, MBIE NZ, Potomac Economics, IESO, DUKES, FERC, SPP, ISO-NE