Presentation to stakeholders – Workshop 2b

Updated modelling results

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20 October

Welcome

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Re-cap on scope

The UK Government's first Review of Electricity Market Arrangements consultation is now closed. The REMA programme is considering a wide range of options for updating GB electricity market arrangements to meet our 2035 target– decarbonisation of our power sector by 2035.

Alongside providing advice on the case for change and full suite of options, we are undertaking an assessment of zonal and nodal market designs for GB.

Approach

1. Identify (i) simplified market designs to model and (ii) how these markets could operate in GB
2. Economic modelling to provide a quantitative benefits analysis of different market designs
3. Assess likely implementation requirements and costs
4. Distributional impact assessment and potential mitigations (and impact on benefits)

Outcomes

System modelling and analysis:

1. Supports BEIS decision-making on whether zonal and nodal market design should be short-listed for further consideration
2. Advances sector-wide market reform debate and capability in considering reform options

Timeline

March: FTI / Catapult project kick-off with Ofgem

26 May: First stakeholder session on modelling methodology, assumptions, and policy interactions

01 June: Workshop summary and Call for Input published (closed 26 June)

07 July: Holistic Network Design published

18 July: FES 2022 published

18 July: REMA consultation published

25 Aug: FAQ published online

30th Aug: Second stakeholder session, interim results (based on NOA6), approach to cost of capital and liquidity

20 Oct: Today's session with updated modelling results (based on NOA7 refresh)

Final workshops ~ Nov-Dec covering:

- Final modelling results across LtW and SysTran including sensitivities
- Mitigations and transitional measures and distributional impacts.

Publication of findings Q1 2023

Decision to include HND as part of modelling exercise pushes original timeline to the right

Housekeeping

- Focus for today's session is presentations from FTI covering updates to the **modelling methodology and preliminary CBA results for the Leading the Way Scenario with and without Holistic Network Design.** This will be followed by an **Ofgem-led session which will present our thinking to-date on the market arrangements required to facilitate locational pricing.**

- **Same format as the last session –** presentation and Q&A as opposed to small break-out groups and discussion

- Attendees are welcome to use the **chat function for clarification questions–** we don't plan to respond to questions during the presentations but instead seek to address them at the end of each session

- **Chatham House Rule –** if we publish an overview of key discussion points, views will not be attributed

- **Break** at 15:30 for 10 mins

Today's workshop will be delivered by Ofgem's Wholesale Market Reform Te supported by FTI Consulting and ES Catapult

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Agenda for today's workshop

Welcome, purpose of session and housekeeping	14:00 – 14:10	10 mins
Session 1: Methodology and assumptions update	14:10 –14:25	15 mins
Session 2: Updated modelling results	14:25 –15:15	50 mins
Q&A	15:15 – 15:30	15 mins
BREAK	15:30 – 15:40	10 mins
Session 3: Cost-benefit analysis results	15:40 – 16:05	25 mins
Q&A	16:05 – 16:15	10 mins
Session 4: Potential market arrangements	16:15 – 16:40	25 mins
Q&A	16:40 – 16:50	10 mins
Wrap up, thanks and next steps	16:50 – 17:00	10 mins

Methodology and assumptions update

We have made several refinements to our modelling approach, partly basec your feedback from the August workshop

	#	Area	Refinement
A **Planned** model refinements	1	**Model design**	Integration with **pan-EU model**
	2	**Transmission**	Incorporated all **NOA7 projects**
			Modelled a new scenario which includes **ESO's Holistic Network Design ("HND** transmission investment plan
			Applied **N-2 contingency constraints** and moved ratings from **post-fault to pre-**
	3	**Generation**	**Added generator outages** to the model
B Model refinements following **stakeholder feedback**	1	**Onshore wind siting**	**Onshore wind can now be built** in E&W up to the FES21 capacity in each node
	2	**Offshore wind siting**	**Offshore wind siting decisions limited** to be more consistent with likely availab of offshore sites
	3	**Battery siting**	Updated our capacity expansion model to use a **more granular timescale for optimising battery siting**
	4	**Bidding in the BM**	Updated **storage and hydrogen offer price** assumptions
	5	**Impact on financing costs**	Updated impact on financing cost assessment
	6	**Liquidity**	Extended measures of liquidity analysis in the futures market

Today's presentation focuses on the same subset of the full impacts as the previous workshop, as well as a further assessment of costs

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 price signals to incentivise **generation and storage to site** at more efficient locations	✓
	Greater price signals to incentivise **demand to site** 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 costs	✓
	Changing **risk profiles** of market participants including **financing cost**	✓

Updated results from August Workshop

Additional assessments presented today

As a recap, the evolution of the transmission network is an exogenous input based on ETYS and NOA, and is the same for all market design variants

2022

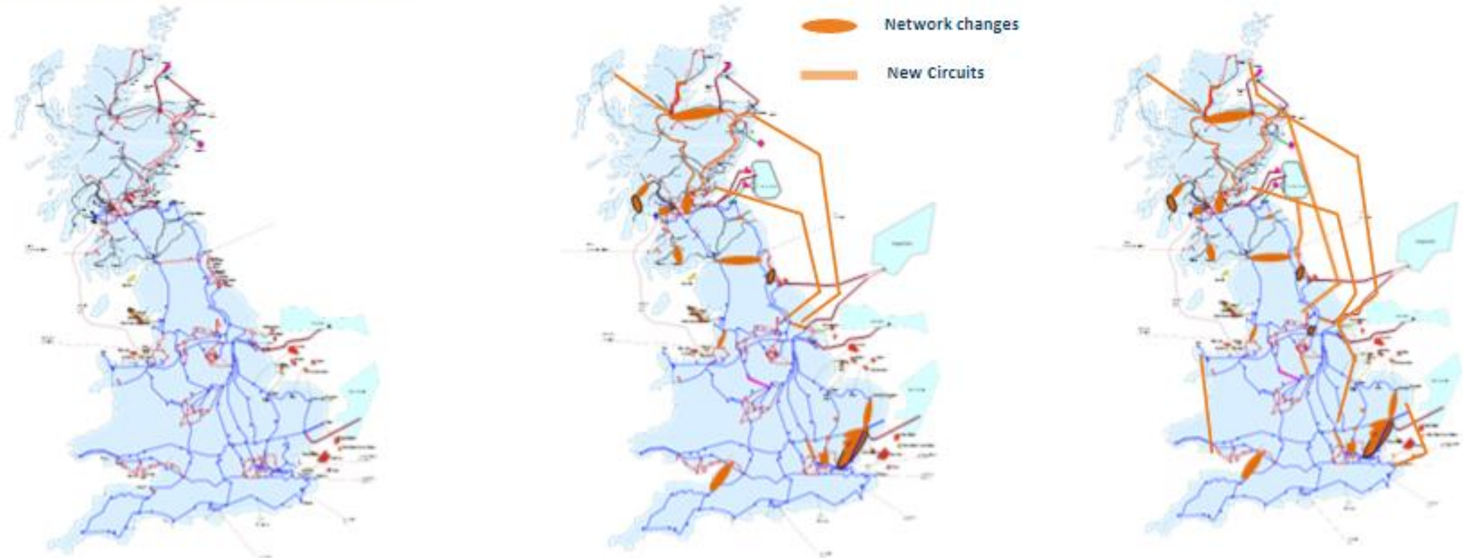
- **Current network** as defined in ETYS21
- **112GW of capacity** across 20 boundaries

2031

- ETYS21, based on NOA6 (LtW), has been **updated with the NOA7 recommendations** with the in-service date prior to 2030
- **Up to 200GW of capacity** across 20 main boundaries in NOA7

2041

- ETYS21 updated with the **NOA7 recommendations**
- **c.230GW of capacity** across 20 main boundaries



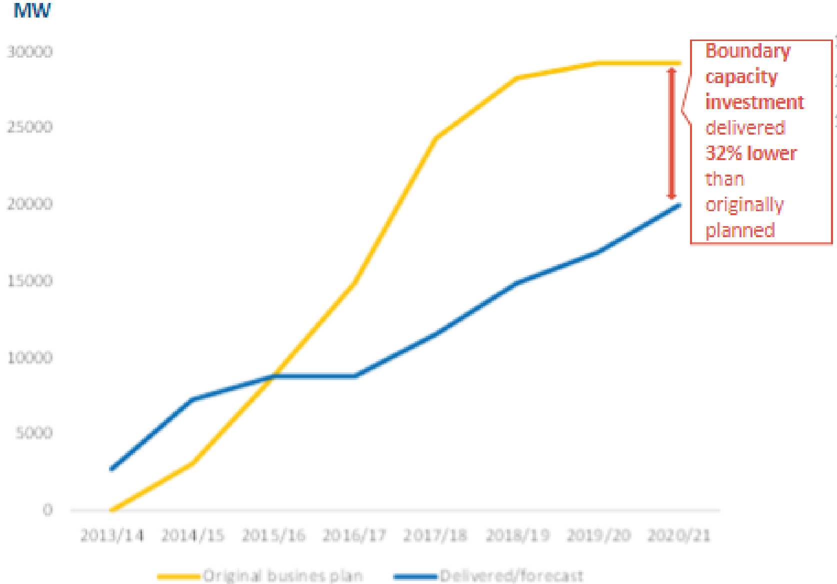
We have also modelled a separate scenario which incorporates the additional transmission investment under ESO's Holistic Network Design approach

E N E R G Y

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

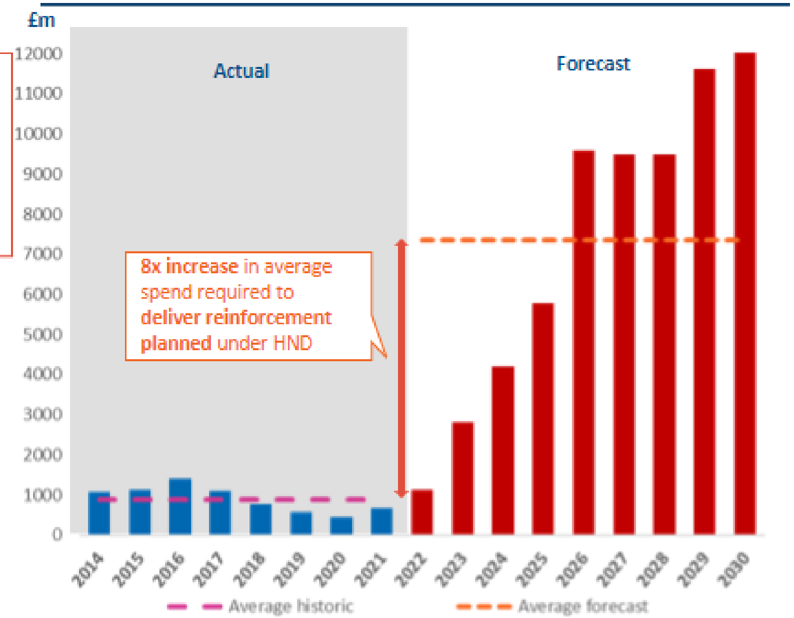
Comparison of planned vs. actual delivery of boundary reinforcement projects in GB over RIIO1



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.

Our overall modelling approach remains unchanged from our previous workshop

Baseline geographical set-up of FTI's power market model

Single national price	Zonal pricing	Nodal pricing
Uniform price clears across entire market	*System divided into **seven zones** with individual prices*	*System divided into **c.850 "nodes"** with individual prices*

Weaker locational signals — *Stronger locational signals*

Our modelling is based primarily on public sources including FES 2021, NOA7, ETYS, and ENTSO-E data

Updated modelling results

Updated modelling results:

Long-term capacity expansion results

National design | Zonal design | Nodal design

For the **national market design**, generation is sited as defined by FES21

Wind Capacity 2030

Offshore wind   Onshore wind

Solar 2030

Solar

Battery 2030

Battery

For the **nodal market design**, the capacity is reallocated in response to different price signals while keeping the total capacity by technology constant

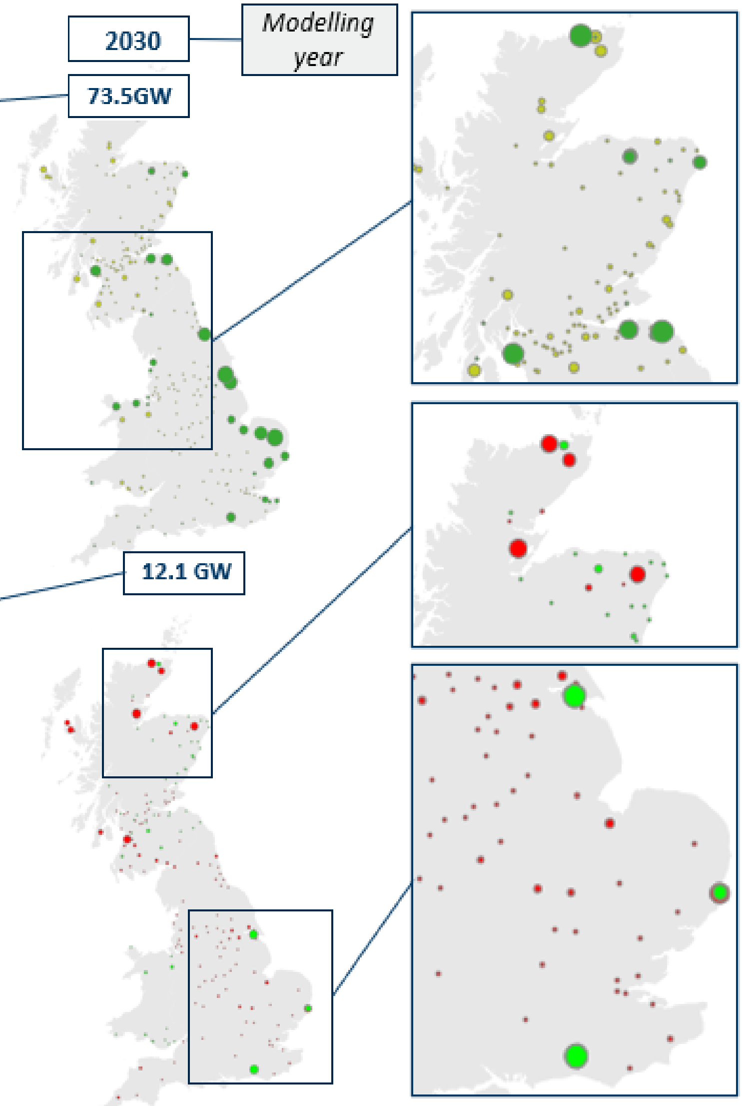
Installed Capacity

The total installed capacity in the modelling year

Cumulative capacity location change

The capacity change represents the change in location of installed capacity between the national and nodal models

The larger the circle, the greater the capacity or capacity change represented



The circles represent installed capacity with different colours for each technology as indicated in legend

Red circles represent a decrease in capacity at the node relative to the national model

Fluorescent green circles represent an increase in capacity at the node relative to the national model

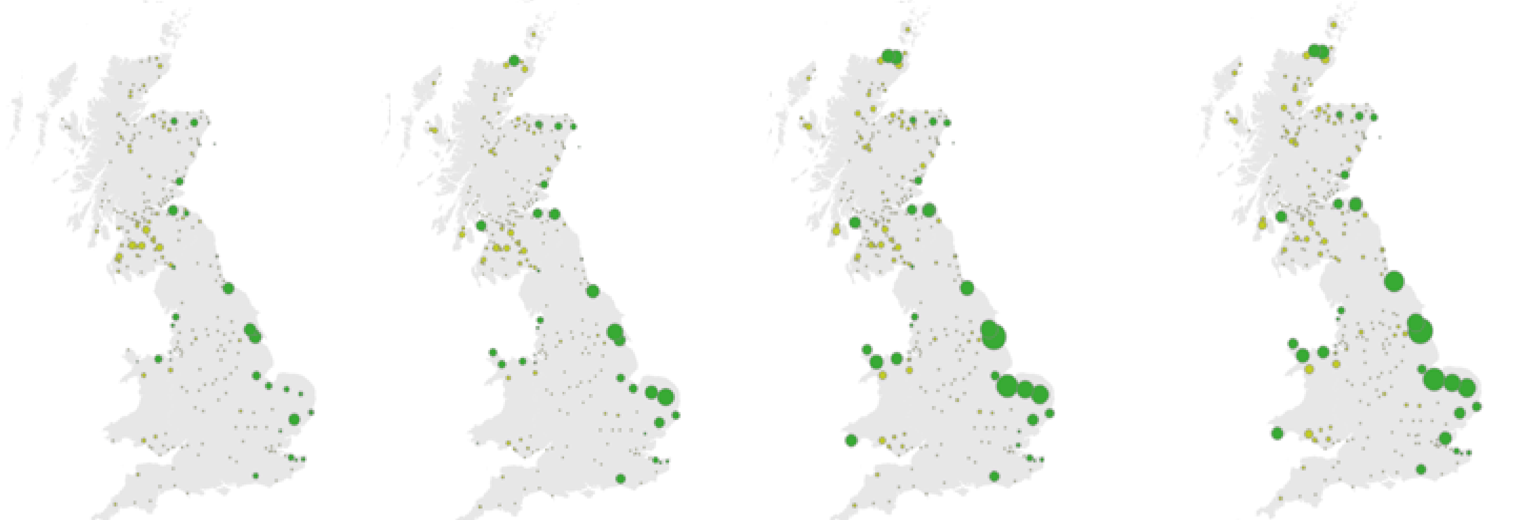
● Decrease relative to national model ● Increase relative to national model ● Offshore wind ● Onshore wind

National design | Zonal design | **Nodal design**

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

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

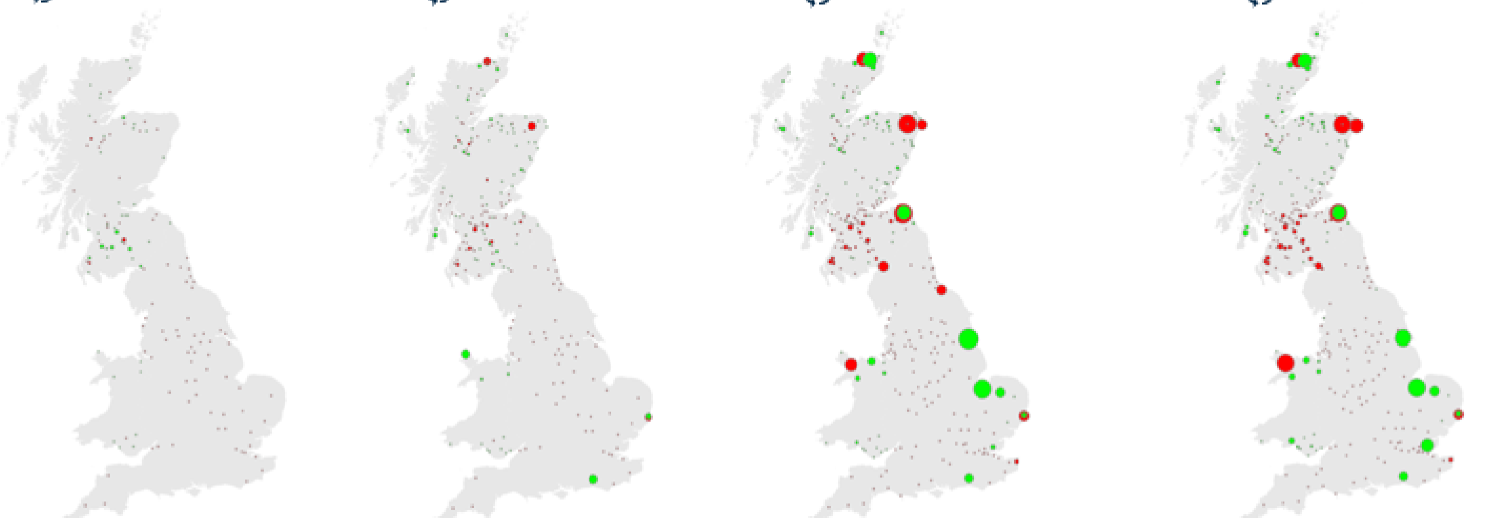
Increase in capacity of offshore wind in Humber and East Anglia



Cumulative capacity with a change in location

2025	2030	2035	2040
2GW	8GW	30GW	33GW

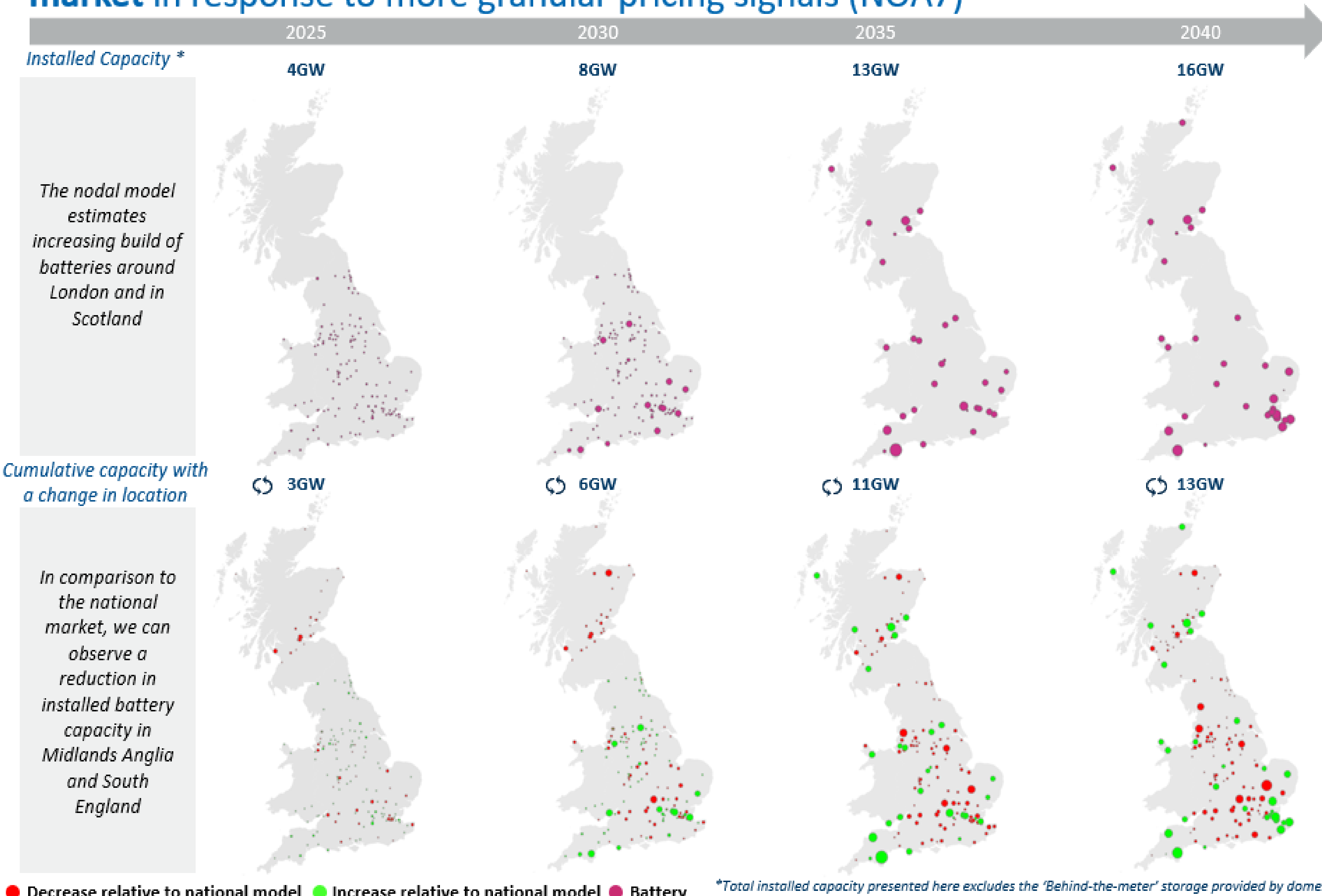
In comparison to the national market, we can observe a reduction in installed wind capacity in Scotland, North West of England and North Wales



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

National design | Zonal design | **Nodal design**

The majority of projected large-scale battery capacity re-sites under a **nodal market** in response to more granular pricing signals (NOA7)



*Total installed capacity presented here excludes the 'Behind-the-meter' storage provided by domestic batteries and V2G (0.4GW in 2025 to 72GW in 2040), which do not re-site in the nodal expansion model.

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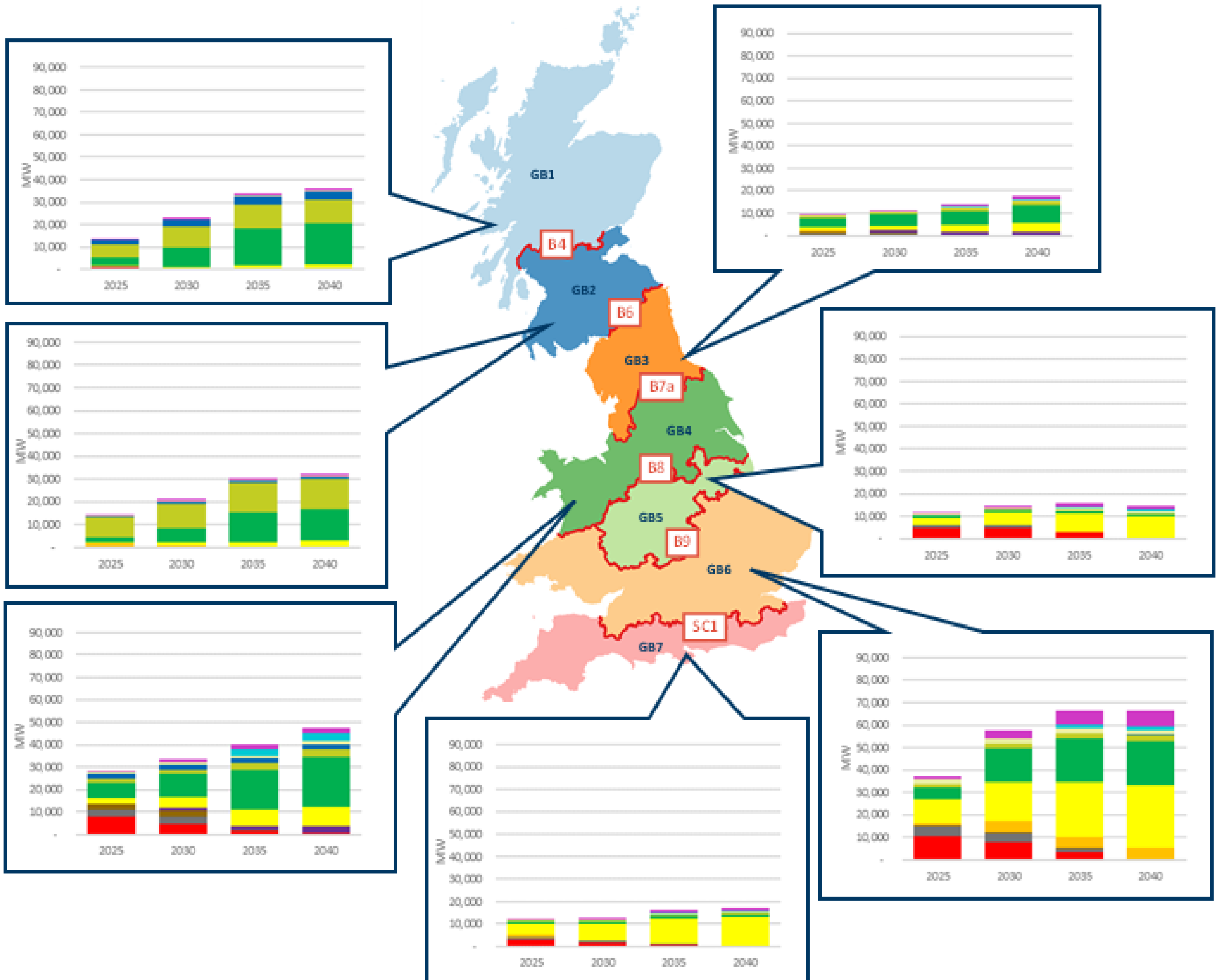
The evolution of generation capacity under the **national market design** as per FES21 assumptions is displayed below



- Capacity for each technology allocated to individual node on the system as per FES 21 assumptions
- Each node, based on geographical location allocated to defined zones. Capacity on the diagram represent the sum of all the nodal capacity within the zone

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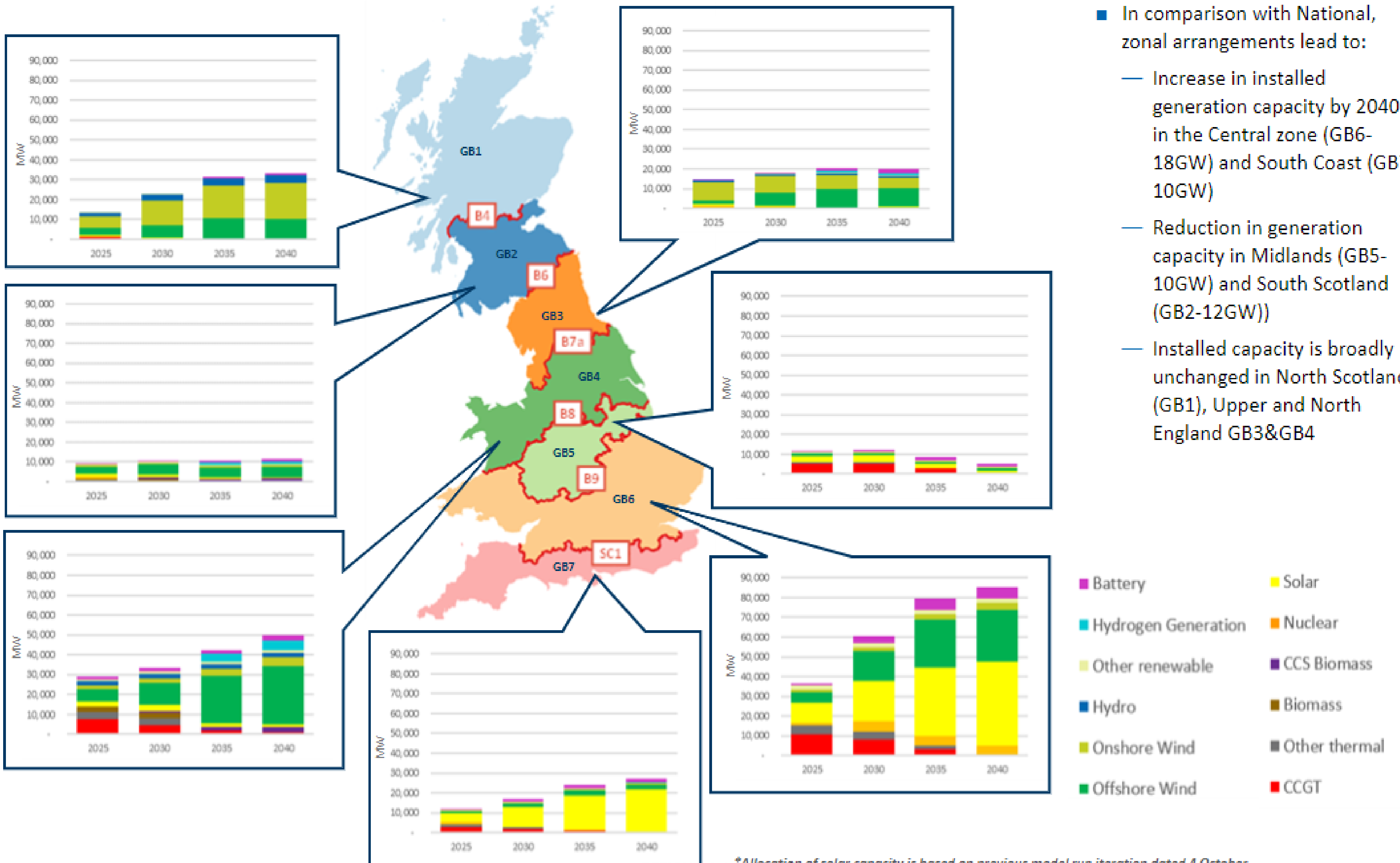
Similar to our nodal assessment, we have modelled the projected evolution of generation capacity in a **zonal market design**



- In comparison with National, zonal arrangements lead to:
  - Increase in installed generation capacity by 2040 in the Central zone (GB6-18GW) and South Coast (GB7-10GW)
  - Reduction in generation capacity in Midlands (GB5-10GW) and South Scotland (GB2-12GW))
  - Installed capacity is broadly unchanged in North Scotland (GB1), Upper and North England GB3&GB4

*Allocation of solar capacity is based on previous model run iteration dated 4 October

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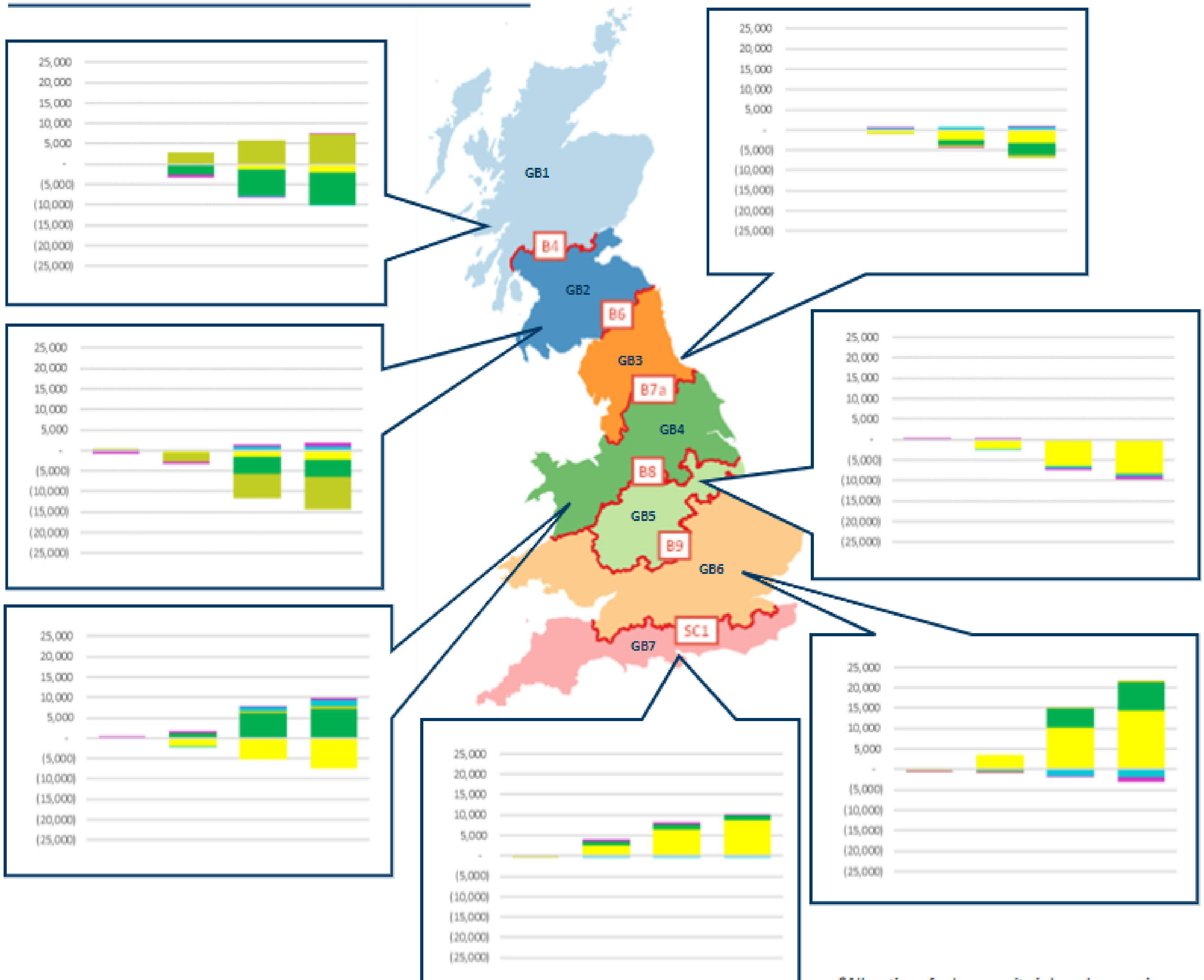
Under the **zonal model**, wind (onshore and offshore) and solar capacities relocate across the GB zones

Difference in capacity relative to national model (MW)



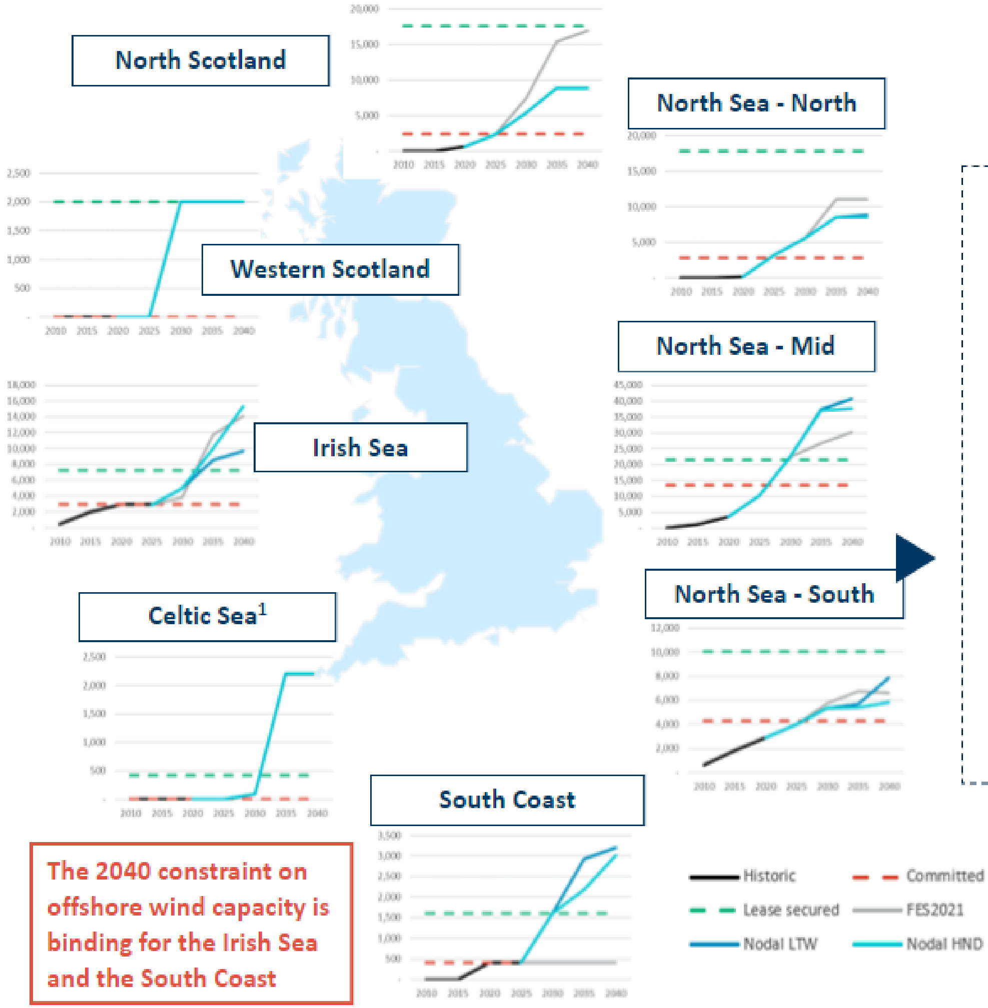
Battery
Hydrogen Generation
Other renewable
Hydro
Onshore Wind
Offshore Wind
Solar
Nuclear
CCS Biomass
Biomass
Other thermal
CCGT

- Results from modelling of zonal arrangements suggest:
  - Onshore wind re-allocates from South to North Scotland (GB2 to GB1)
  - Offshore wind capacity shift from Scotland to North England and North Wales (GB4) and Central (GB6)
  - Only marginal movements in battery capacity across the zones
- Majority of solar generation* locates in the south (GB6 & GB7)

*Allocation of solar capacity is based on previous model run iteration dated 4 October

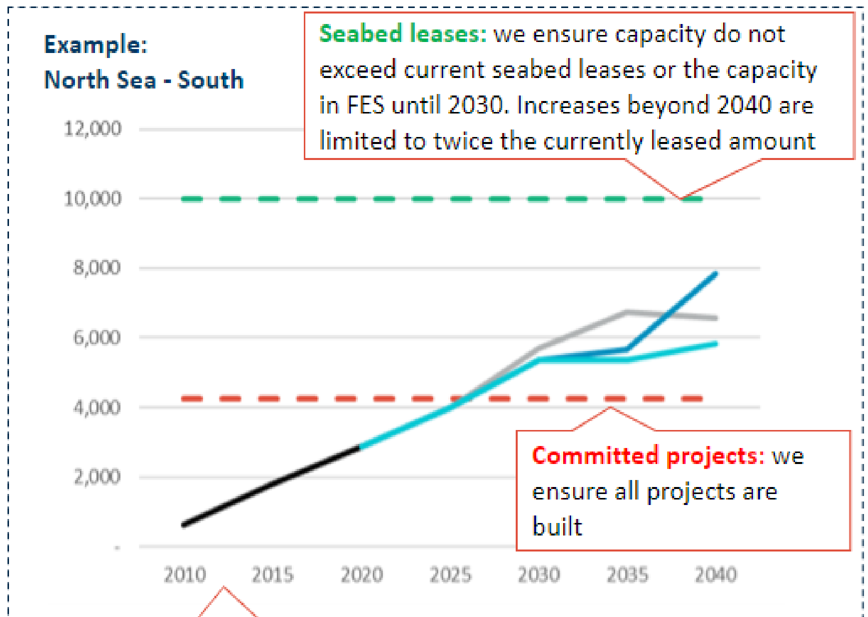
As a cross-check, we have assessed the plausibility of the offshore wind build-out in the nodal model against projects in the pipeline in each offshore zone

- We have grouped existing wind farm projects and wind farms in the model to offshore regions



The 2040 constraint on offshore wind capacity is binding for the Irish Sea and the South Coast

- We have used these offshore regions to compare offshore wind build-out to:
  - **Committed projects** (under construction or awarded under a CfD contract)
  - **Seabed leases** (currently awarded)



Generation capacity under FES, **nodal (NOA7)**, and **nodal (NOA7 + HND)** scenarios

1: *The 2040 limit for the Celtic Sea is increased to 5GW, as the Crown Estate is due to hold auction for 4GW floating wind in this area in 2023*

Updated modelling results: Detailed price outcomes

Wholesale prices

National design | Zonal design | Nodal design

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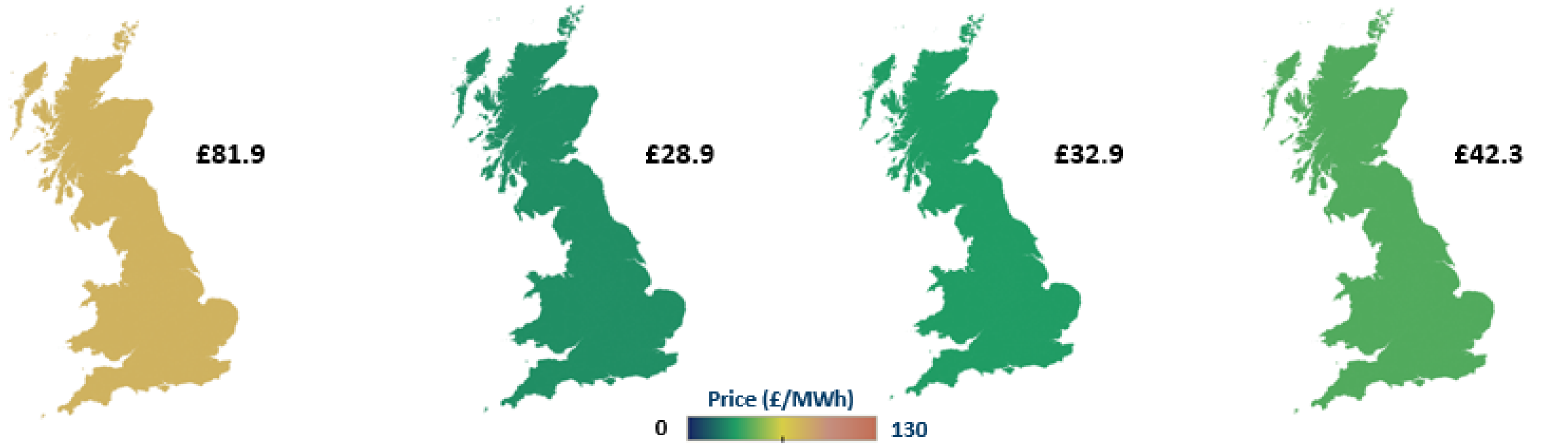
Pressure on wholesale prices is expected to ease in 2030 but increase again due to increased electrification, limited flexibility options and high carbon prices

2025	2030	2035	2040



2025

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

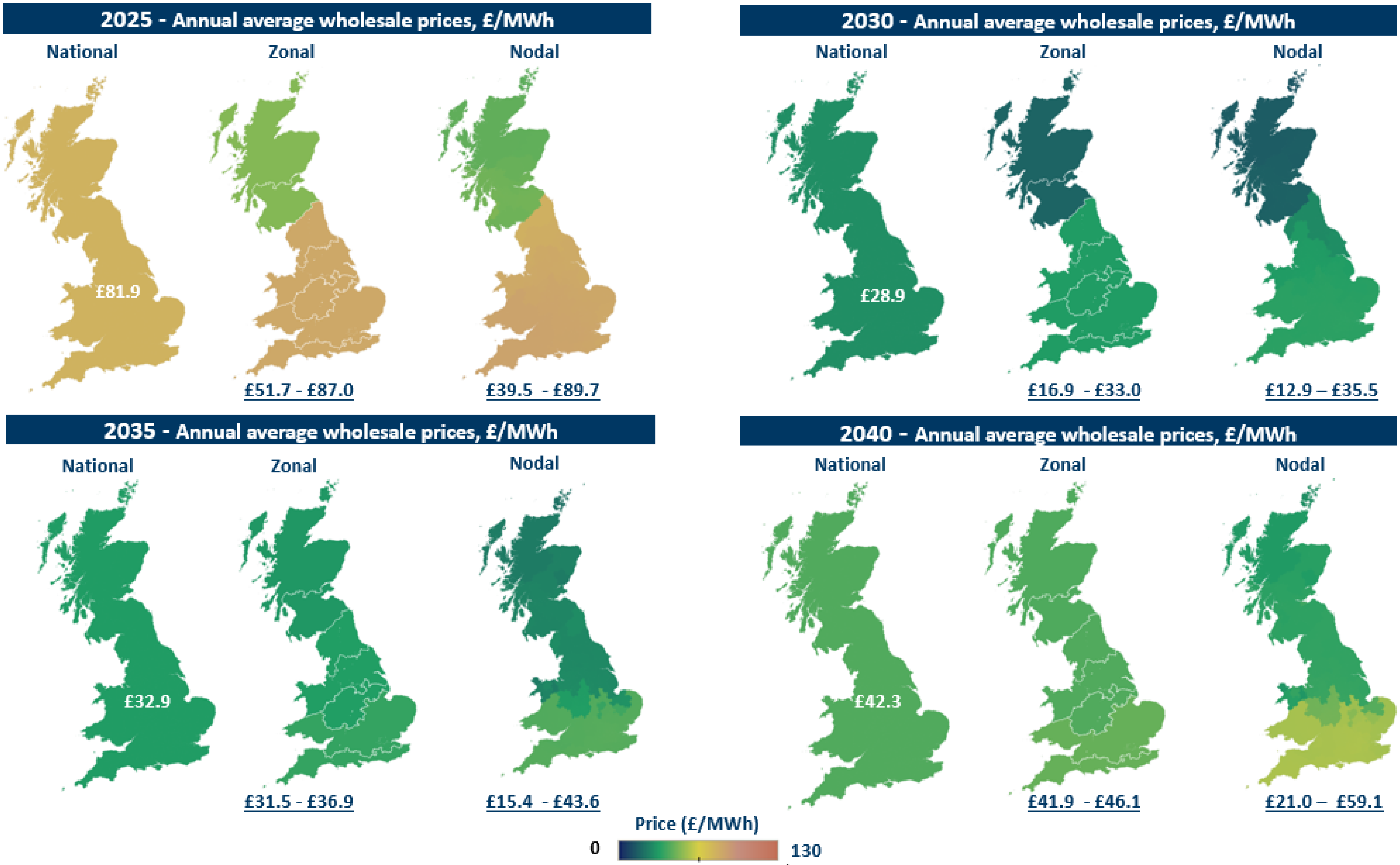
Wholesale prices continue to increase into 2040…

…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 for flexibility**.

Note: A load-weighted annual average wholesale prices would produce similar results: £87.8 in 2025, £32.7 in 2030, £33.7 in 2035, and £42.3 in 2040

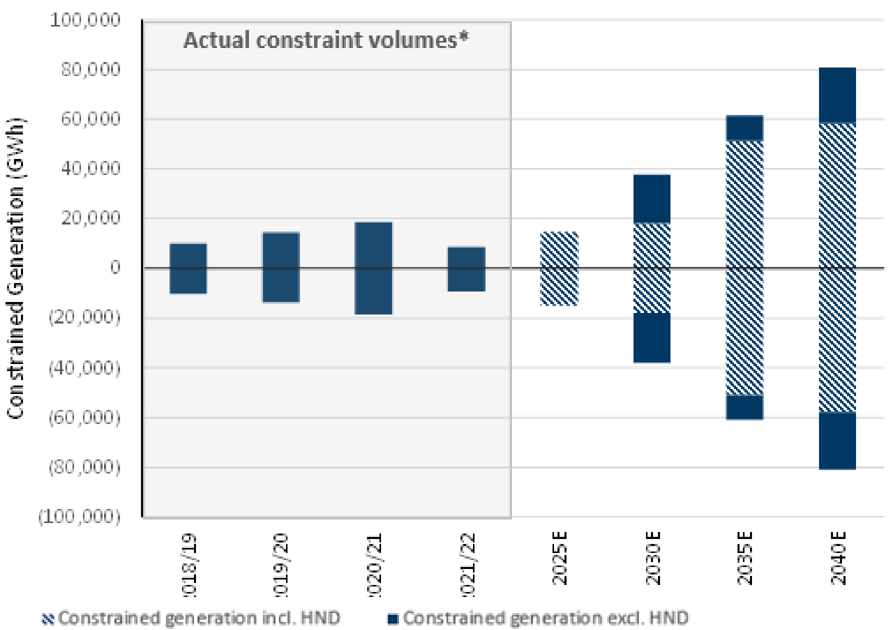
Average wholesale power prices across the three market design options are influenced both by 'macro' trends and by the locational granularity



Updated modelling results:
Constraint management costs

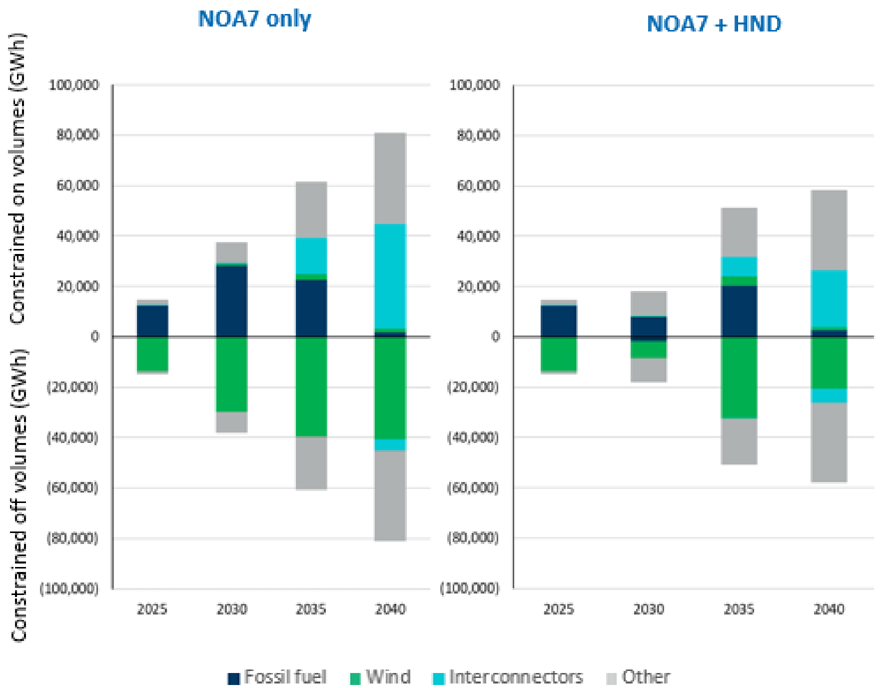
We have updated our assessment of constrained on and off generation and include the results of an additional scenario with ESO's HND

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



*Source – ESO Data Portal.

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



- Our modelling results show congestion volumes increasing to **c.80TWh** by 2040 (or c.15% of total generation).
- The rate of increase in congestion volumes is lower under an alternative HND scenario to **c.60TWh** by 2040.
- As indicated in the last workshop the **constraint volumes increased in 2025 & 2030 driven by the inclusion of HND reinforcements**, outages and N-2 security criteria.

- The increase in congestion volume arises mostly from constrained-off **wind** generation.
- As expected, **curtailment is reduced** under the HND scenario.

Our constraint cost assumptions for batteries and hydrogen generation now include a bid and offer spread, other assumptions are unchanged from August

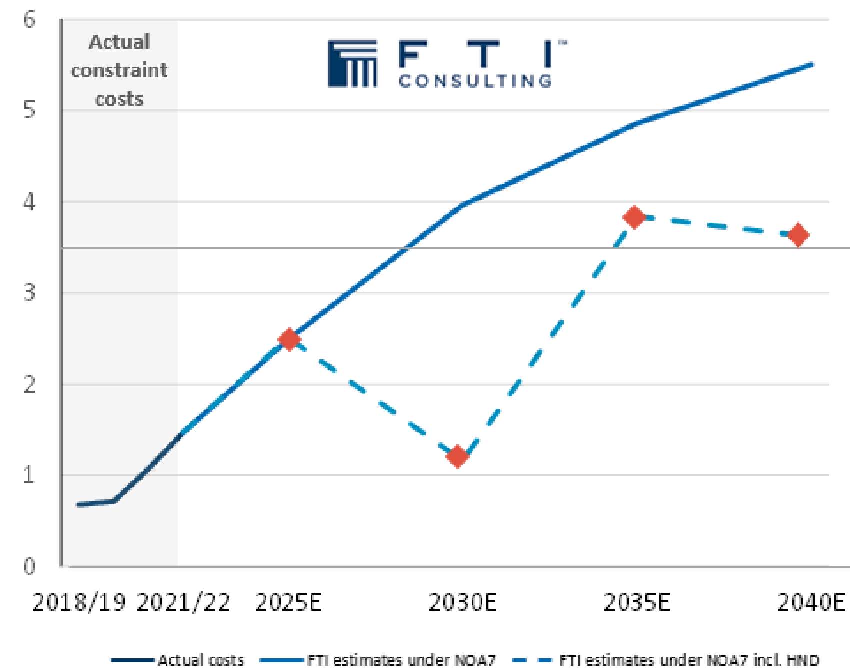
Technology	Cost to ESO Bid	Cost to ESO Offer	Additional assumptions
Fossil fuel	- Fuel cost - carbon cost	Offer Uplift + Fuel cost + carbon cost	• Multiplier uplift calculated using historical offer prices and historical commodity prices
Biomass	- Fuel cost	Offer Uplift + Fuel cost	• 50% of the Absolute fossil fuel offer uplift as a proxy
CCS Biomass	Carbon price – Fuel cost	Offer Uplift + (Fuel cost – carbon price)	• 50% of the Absolute fossil fuel offer uplift as a proxy
ROCs renewables	ROCs*	(theoretical only so no price assumed)	-
CfD renewables	CfD strike price – Wholesale price	(theoretical only so no price assumed)	-
Merchant renewables	£0	Offer Uplift	• 20% of the Absolute fossil fuel offer uplift as a proxy
Storage technologies	- Marginal value	Offer Uplift + Marginal value	• Marginal value calculated by Plexos • 50% of the absolute fossil fuel offer uplift as a proxy
Hydrogen generation H_2	- Marginal value	Offer Uplift + Marginal value	• Marginal value calculated by Plexos • 50% of the Absolute fossil fuel offer uplift as a proxy
Interconnector	Cost of reversing flow €130 / €100**	Cost of reversing flow €130 / €100**	• Integrated with our pan-EU model

*- 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]
** - Cost of reversing flow of €130 assumed in 2025 and 2030

Technologies not participating in the BM	Demand side response	Nuclear	Hydro (run-of-river)	Small-scale thermal

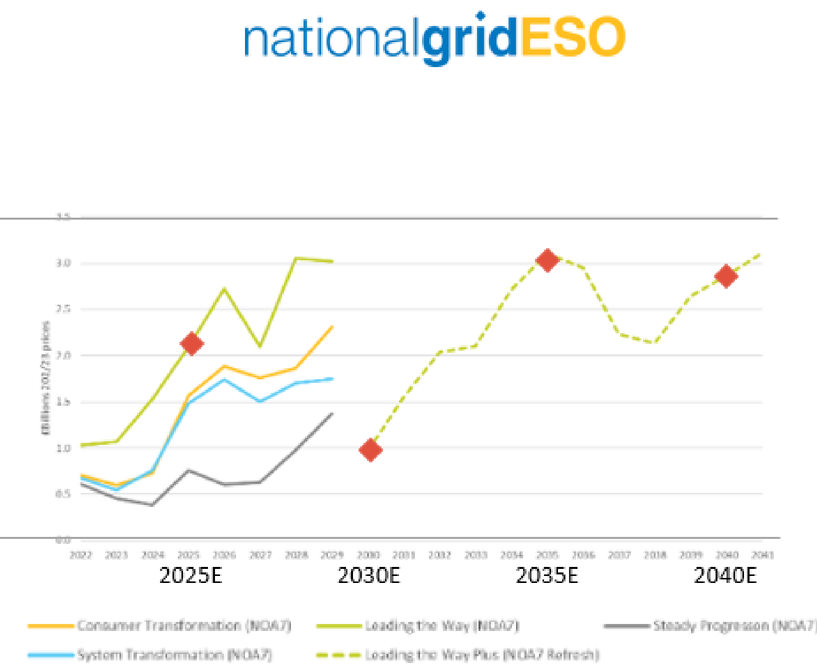
Our updated estimate (with and without HND) maintains a significant increase in constraint costs post-2030, in line with the ESO's August revised forecast

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)

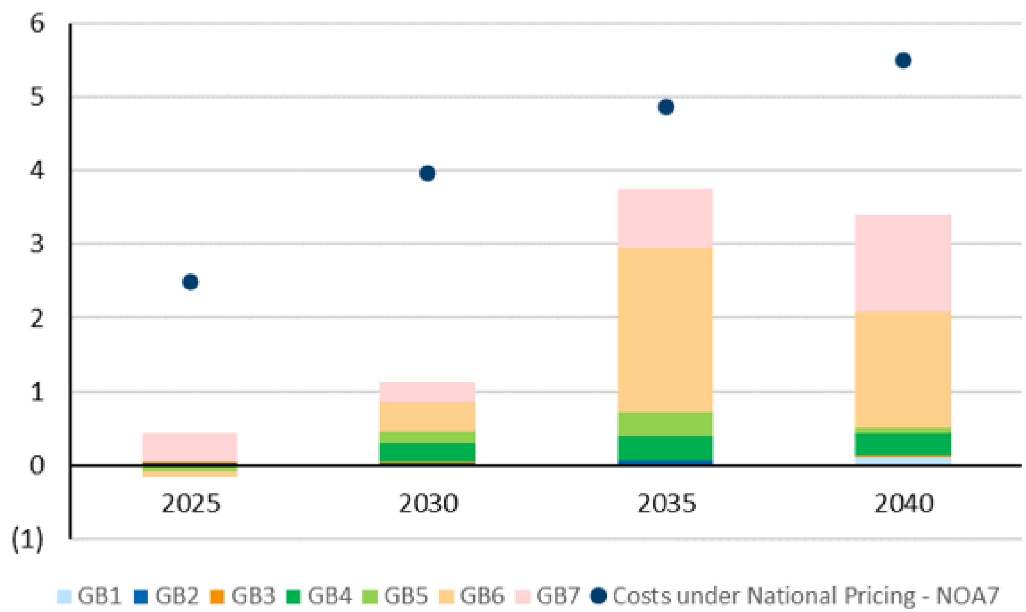
- Our **updated assessment** indicates that constraint cost under the national market design option **could exceed £5bn by 2035.**
- **HND transmission projections** would slow down the increase in constraint cost by 2035 **to just under £4bn.**
- This broadly follows the trajectory of the latest ESO forecasts of NOA7 + HND congestion costs published in August 2022…
- … albeit ours are c.20-25% higher (which could be explained by our more locationally granular approach to assessing constraint volumes).

Constraint management costs

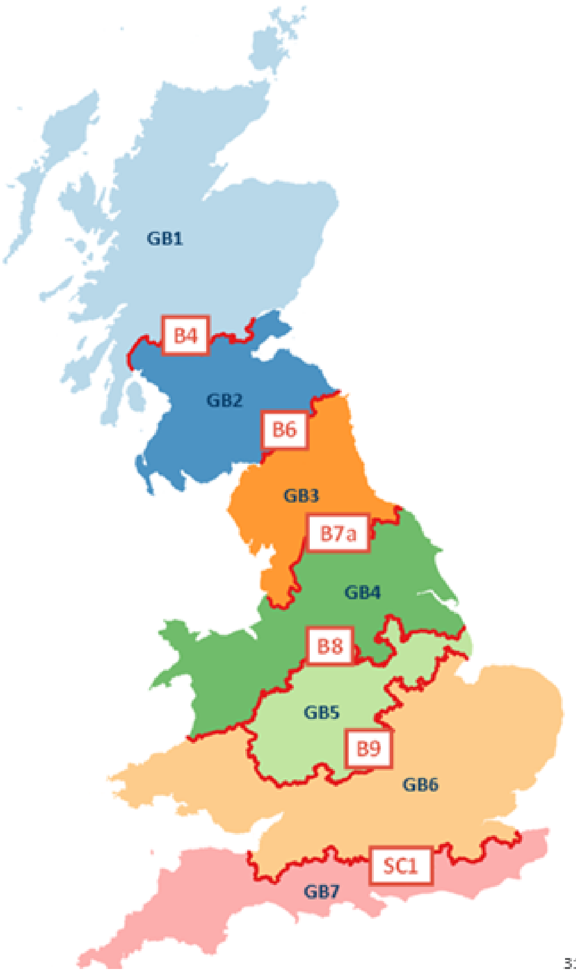
National design | Zonal design | Nodal design

Under zonal design, constraint management costs could be lower in period up to 2030 after which they are projected to increase to near £4bn

Constraint cost estimates, Leading the Way, 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 constraint costs are **forecasted to increase to just under £4bn** and broadly stay at that level for the remainder of the modelling period.
- GB6 and GB7 zones illustrate the need for policymakers to consider and evaluate the benefits of **re-zoning** as the system evolves.

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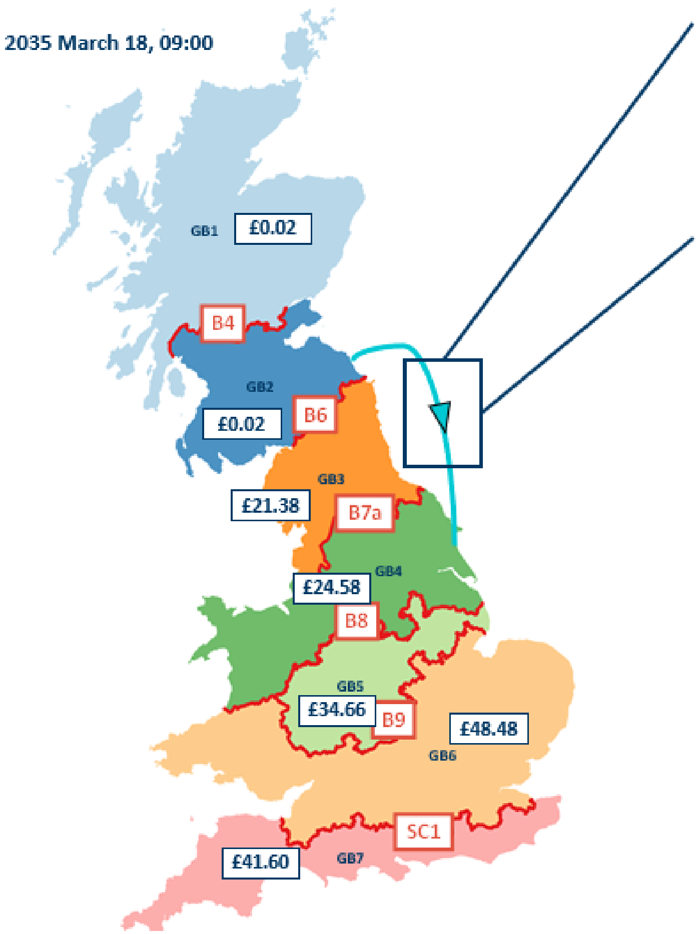
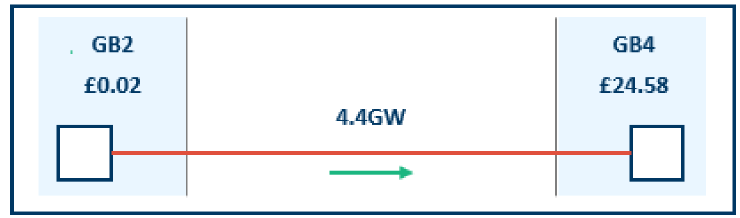
Updated modelling results:
Intra-GB congestion rents

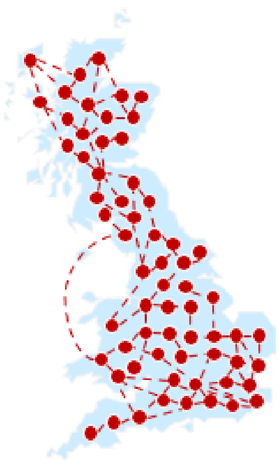
Transmission owners would earn congestion rents, based on the wholesale electricity price differential between the two price zones they are connecting



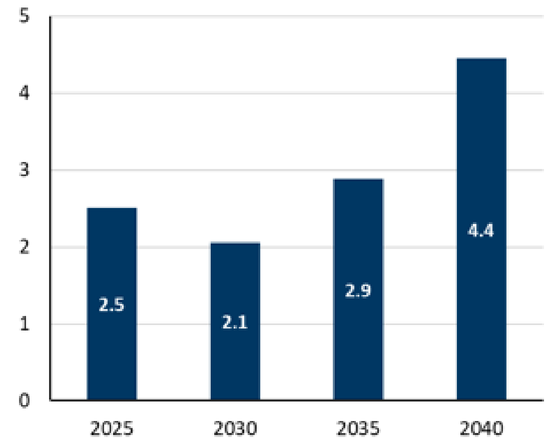


- Suppose, in a **given hour**:
  - The **wholesale price** of electricity in **GB2** is **£0.02/MWh**;
  - The **wholesale price** of electricity in **GB4** is **£24.58/MWh**; and
  - There exists **interconnection capacity** of **4.4GW** connecting GB2 and GB4.
- Assuming no losses, in settlement, 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.**
- The rights to these rents are so-called "financial transmission rights"…
- …they are equivalent in concept to congestion rents in **interconnectors**

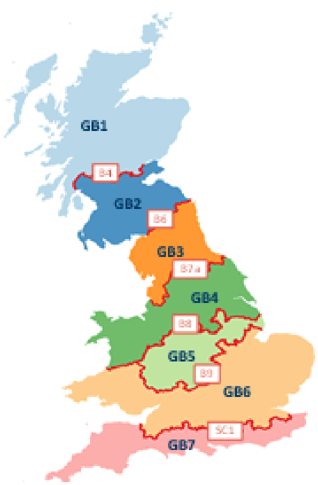
In zonal and nodal markets, congestion rents arise in the settlements process from price differentials between connecting price zones or nodes



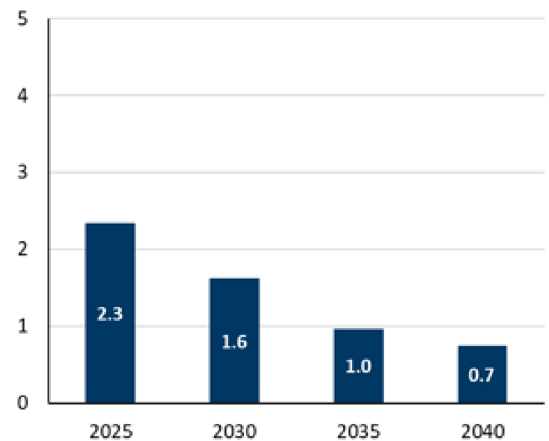
Nodal congestion rents (£bn/year)



- In **nodal markets**, congestion rents and loss surpluses are earned on all transmission lines between nodes.
- We estimate these revenues to be between **£2.1bn** and **£4.4bn** 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 **£0.7bn** and **£2.3bn** across the modelled years...
- ... reflecting lower zonal spreads relative to nodal spreads

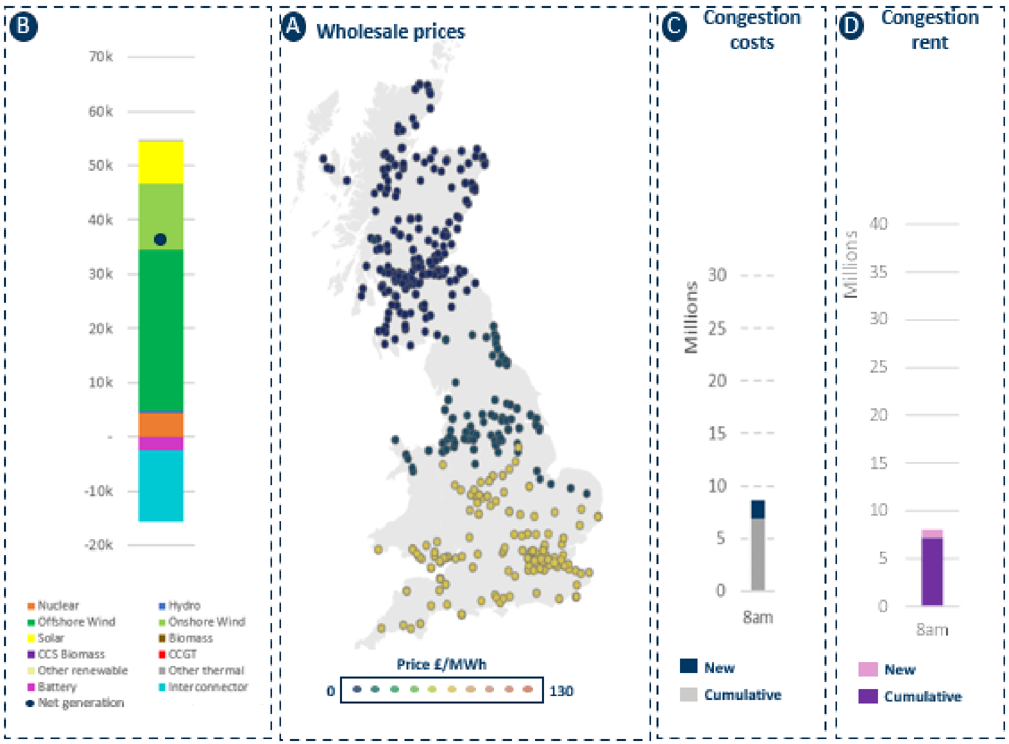
Congestion rents **arise in the settlement process** and we assume that they would, as a default option, be **used to reduce transmission costs** (ultimately borne by consumers).

We therefore treat **congestion rents** as a **net benefit to GB consumers...**

...in practice, **alternative options** for distribution congestion rents are possible, e.g. by allocating FTRs to other stakeholder as part of a transition process (this has not yet been considered in our analysis).

Updated modelling results:
Snapshot of nodal model results

Introduction to detailed nodal price outcomes:
Presentation of the wholesale prices, generation mix and congestion costs



A Wholesale prices

1. Each circle represents a node on the system
2. The colour of the circle represents the wholesale price in £/MWh

B Generation mix

1. Bar chart next to the map represents the generation mix in the same hour as the wholesale prices
2. Colour of the bar segment represent relevant technology as indicated in the generation mix legend
3. Height of the bar represents the capacity of the technology that generates at the time (negative figures reflecting IC exports)

C Congestion cost

1. Bar chart next to the map represents the cumulative congestion costs on the day up to and including the hour shown
2. Colour of the bar segment differentiates between current hour (dark blue) and the cumulative prior hours on the same day (grey)

D Congestion rent

1. Bar charts represent the cumulative congestion rent between all nodes on the network under a nodal model, or between zone boundaries under a zonal market. This represents net benefit to GB consumers

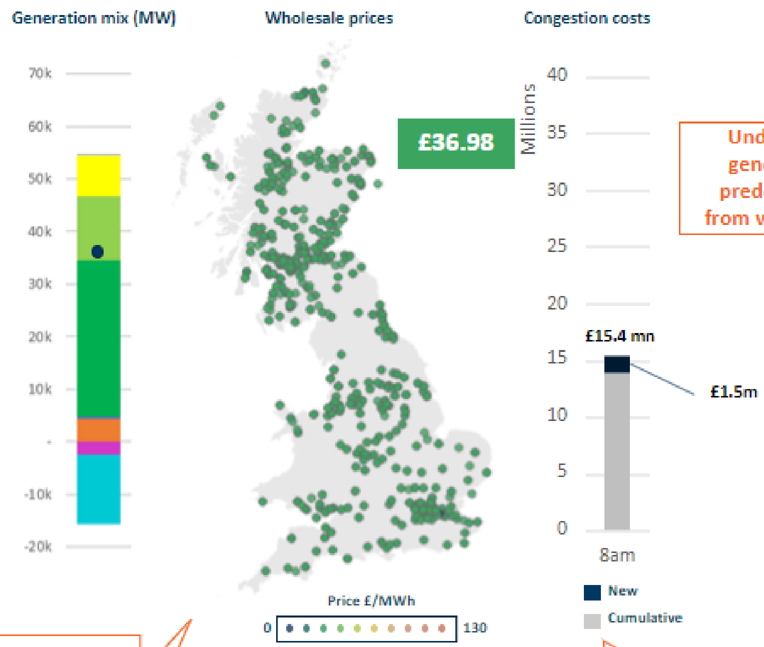
Snapshot – 30/03/2030 @8am

National design | Zonal design | Nodal design

With high volumes of RES generation across GB, wholesale prices are lower under national, but the cost of meeting demand under national design is higher

8am

National



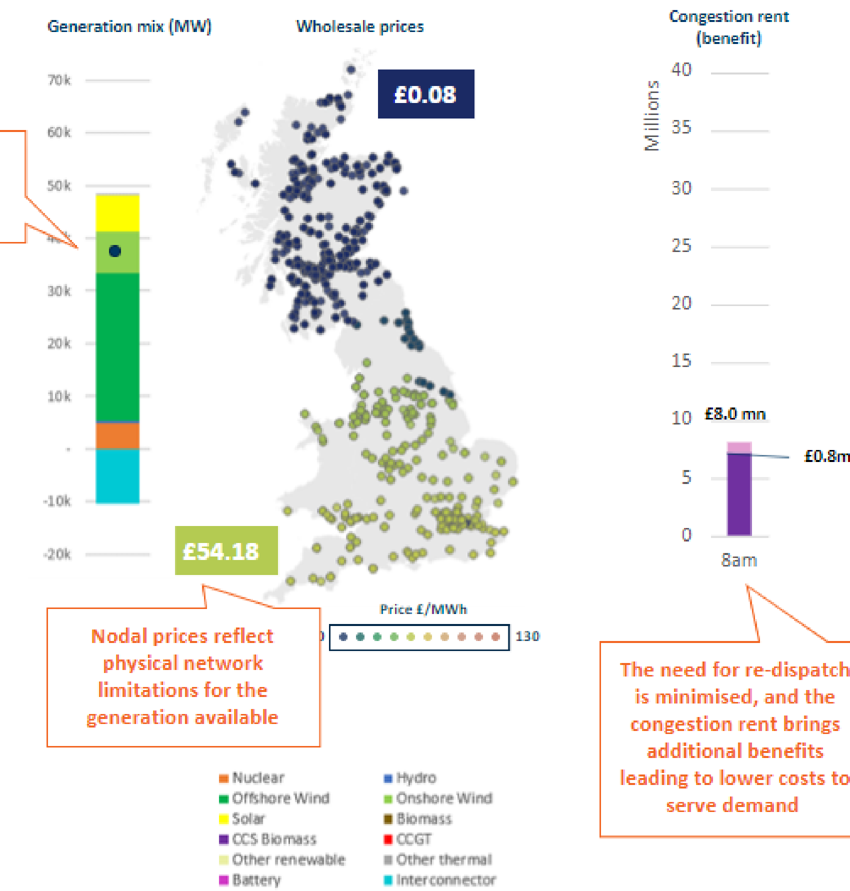
The wholesale price under national pricing is lower due to large volumes of low marginal cost generation

However, network capacity limitations require large volumes of re-dispatch …

… which leads to £1.5m of congestion cost

Under nodal, generation is predominantly from wind & solar

Nodal



Nodal prices reflect physical network limitations for the generation available

The need for re-dispatch is minimised, and the congestion rent brings additional benefits leading to lower costs to serve demand

Snapshot – 30/03/2030 @8pm

National design | Zonal design | Nodal design

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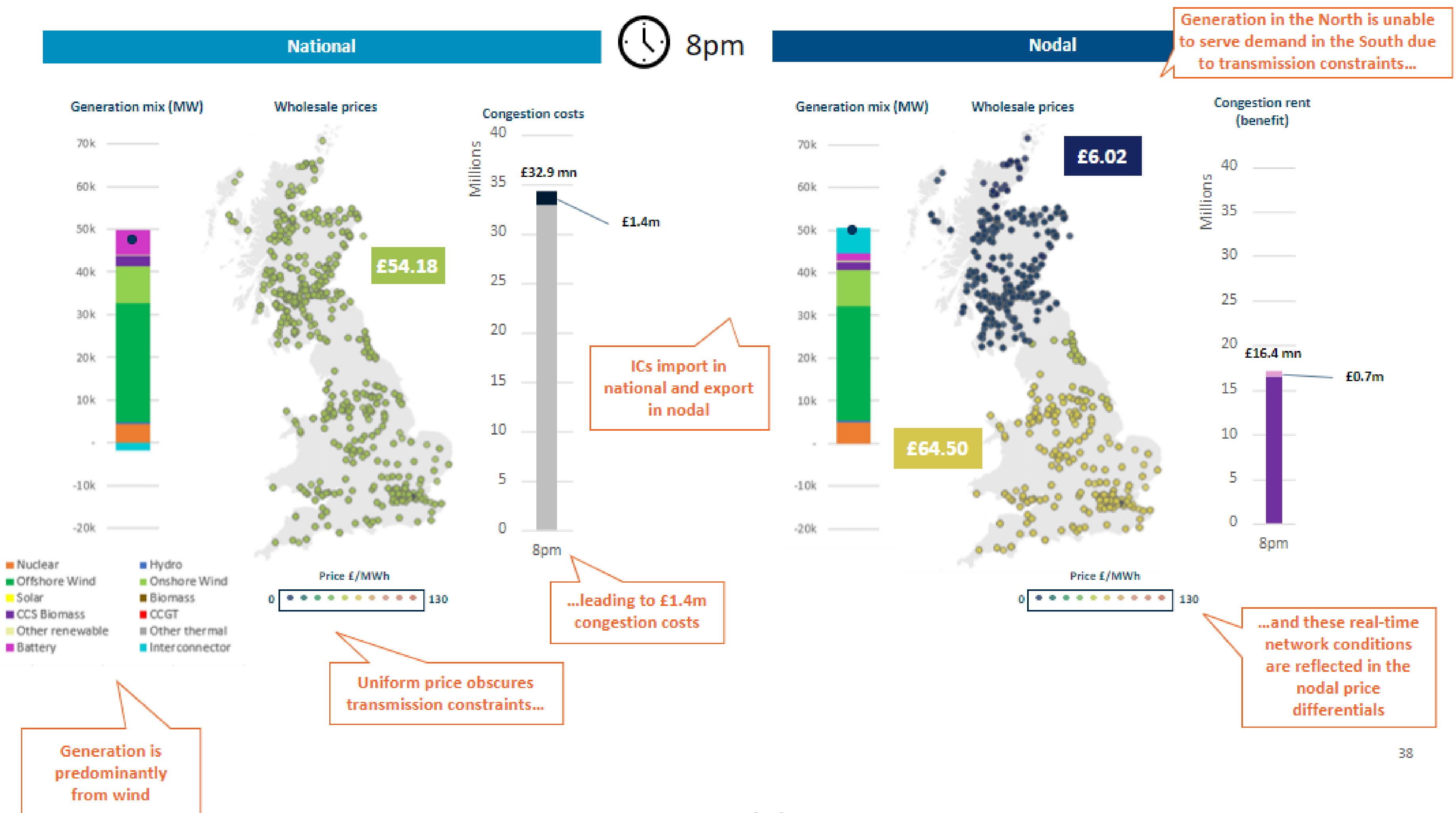
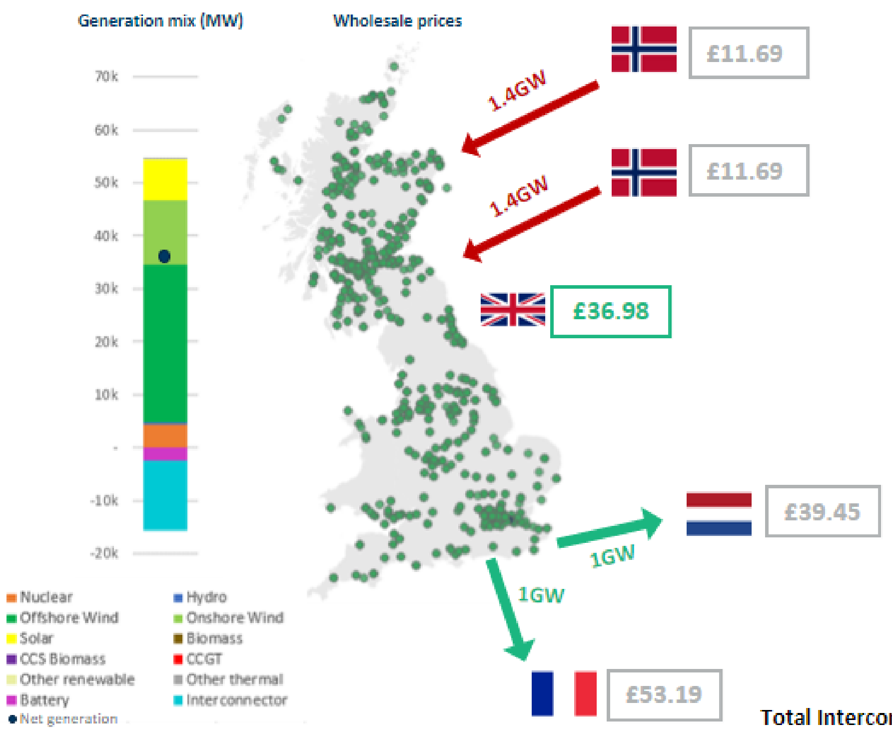
Nodal prices reflect the real-time transmission network constraints, whereas these are obscured in a national price



Interconnector flows respond differently to price signals in the nodal market which could alleviate constraints

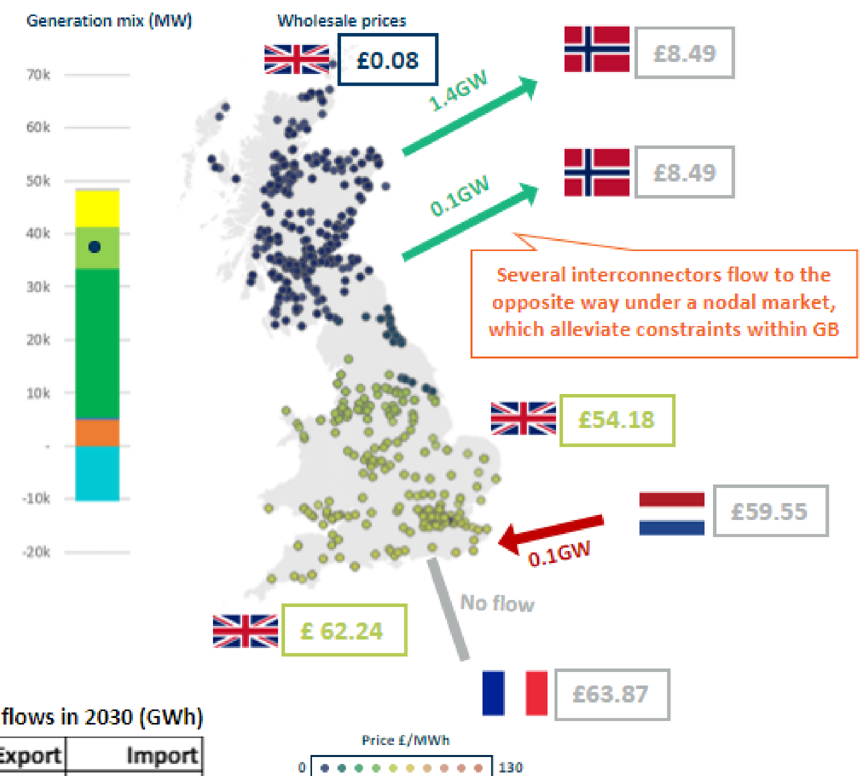
8am

National



CCGT generation required to balance the system

Nodal



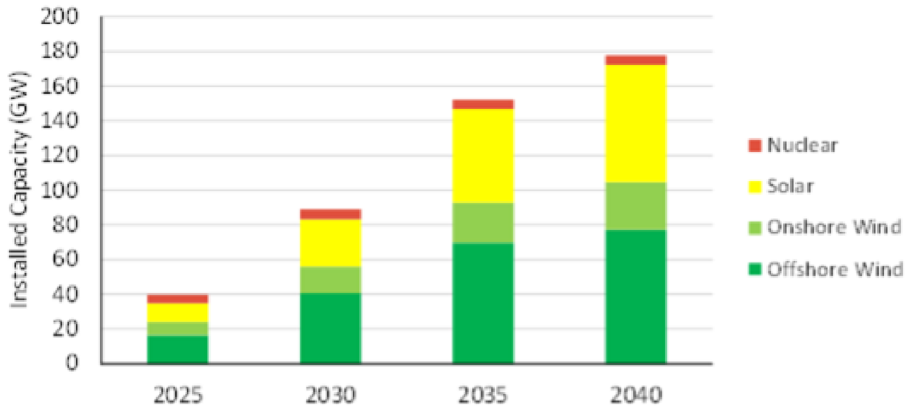
Total Interconnector flows in 2030 (GWh)

	Export	Import
National	96,680	43,944
Nodal	82,614	48,415

Updated modelling results:
CfD analysis

Our methodology in assessing the cost of CfDs is based on our CfD capacity projections and assumptions on the future CfD regime design

Projected capacity of CfD holders



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

FTI assumptions based on limited data sources

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

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

Methodology for calculating the CfD top ups

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

Assumptions for calculating CfD difference payments

BEIS LCOE figures	Nodal price	Output from model
• BEIS LCOE figures provide an **independent and consistent view**; • a **simple average** is taken across the range of LCOEs by tech type.	• **Nodal price assumed** for simplicity[1]	• **Generation volumes** are based on **unconstrained model** output (prior to ESO re-despatch)

We assume the **same LCOE across all locations.** In practice, this might differ based on capacity factors and constraint risk

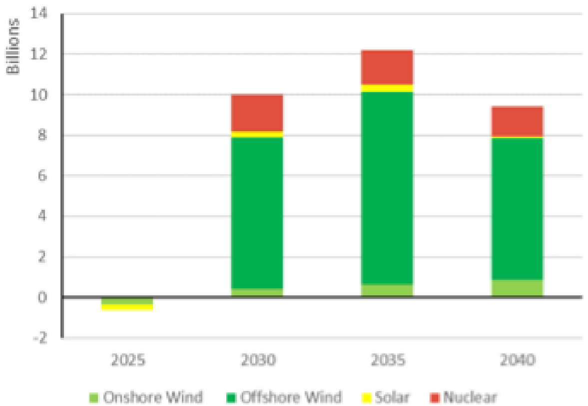
Note: In practice, the reference price could be defined in a number of alternative ways (e.g. a hub price or national price + FTRs to node). For simplicity, we have assumed that the reference price would be based on the individual nodal price.

CfD impact

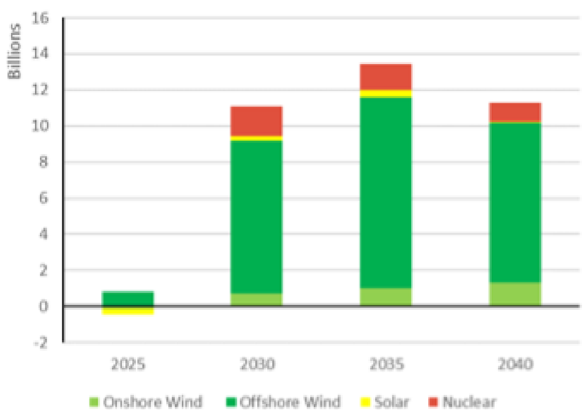
National design | Zonal design | **Nodal design**

Our calculations show that a **nodal market** would increase total CfD difference payments (across 2025-2040) relative to a national market

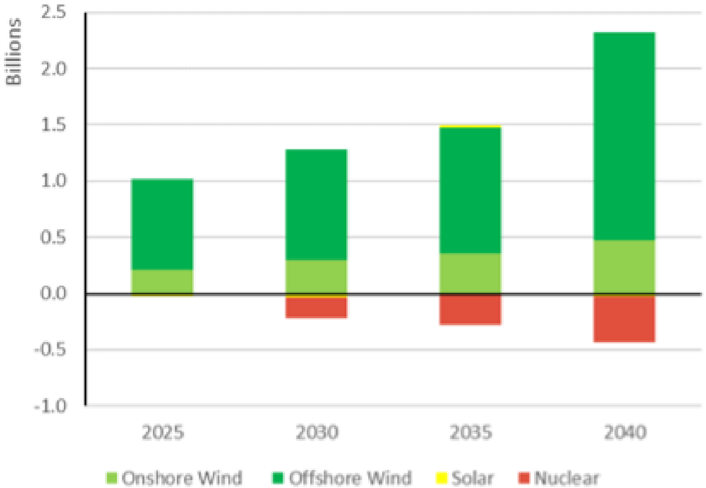
CfD difference payments (National) (£bn)



CfD difference payments (Nodal) (£bn)



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



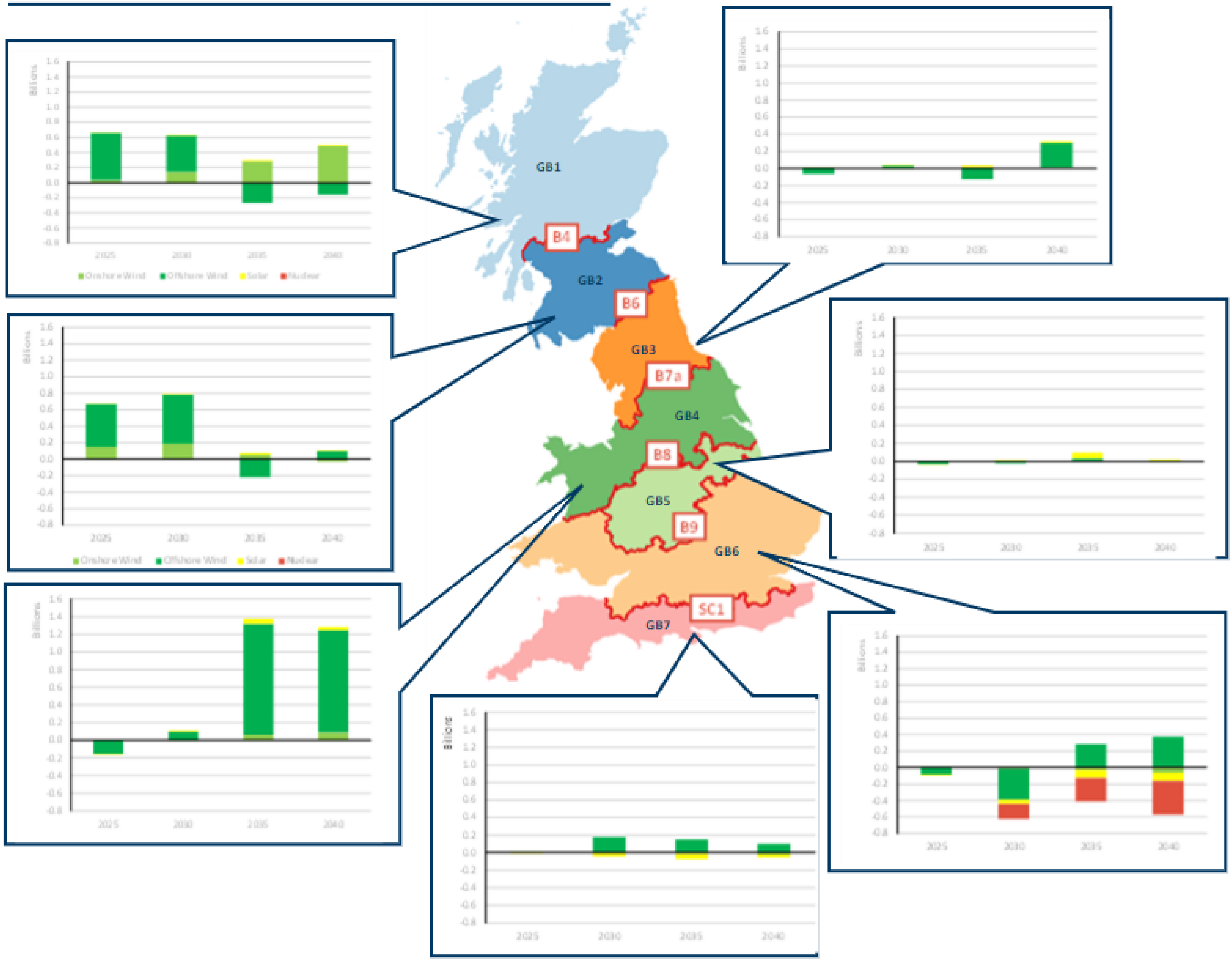
- We estimate that CfD difference payments will steadily increase under a nodal market reaching up to **c.£2bn** in 2040.
- This is driven predominantly by lower wholesale prices particularly in the North, and in part by a moderate increase in generation volumes.
- CfD difference payments for **Hinkley Point C falls** due to an increase in average wholesale prices in that locality.

We observe similar results for the HND scenario

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

In line with wholesale price changes, Northern generators receive higher CfD payments with nodal pricing, whereas payments to Southern generators decrease

Difference in CfD payments relative to national model (£bn)

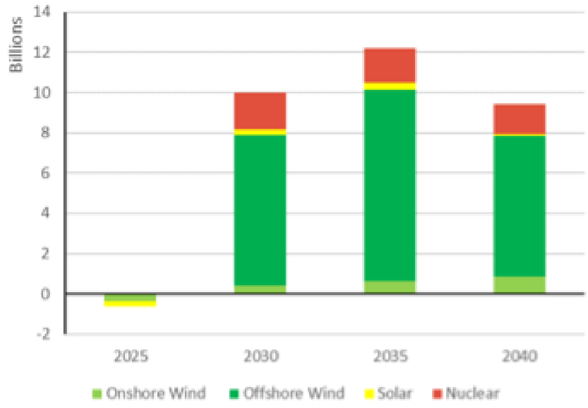


- Generators in most regions see an increase in CfD payments with largest increase observed in **GB4 (£2.3bn)** driven by greater level of installed offshore wind capacity and increase in volume of energy produced.
- Scottish wind generation in **GB1 & GB2** also see a significant increase (**£1.6bn** offshore and **£1.3bn** onshore).
- **GB6** is the only zone where CfD difference payments are lower under nodal market driven by higher wholesale prices. Notably, CfD payments to HPC also reduces **(£0.85bn)**.

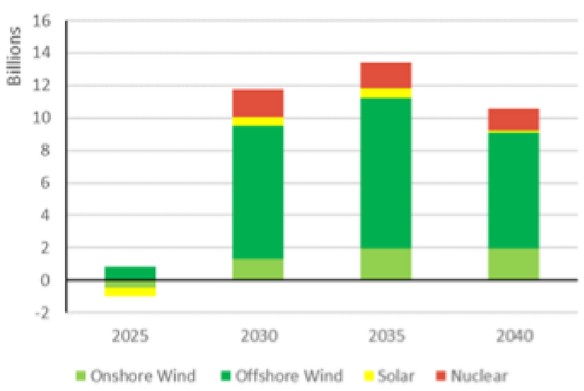
Onshore Wind
Offshore Wind
Solar
Nuclear

Similar to nodal, a **zonal market** would increase total CfD difference payments relative to a national market, albeit with different levels of impact to each tech

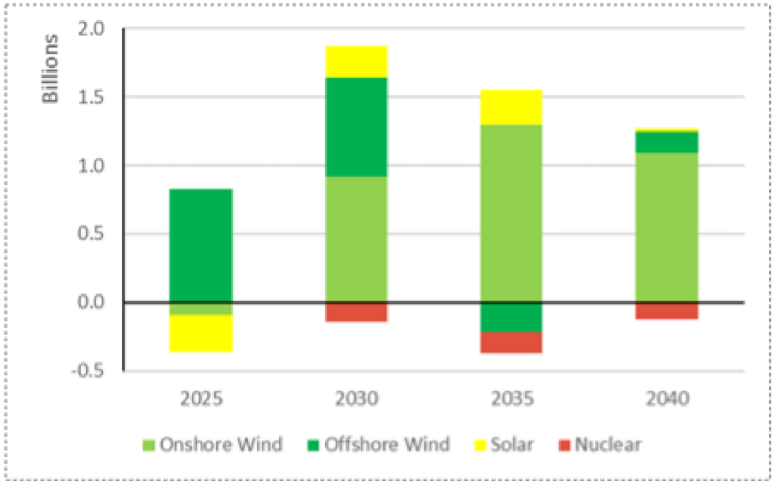
CfD difference payments (National) (£bn)



CfD difference payments (Zonal) (£bn)



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



- Under the zonal market model, we estimate that CfD difference payments will reach up to **c.£1.7bn** in 2030 and then steadily reduce to **£1.1bn**.
- This is driven predominantly by lower wholesale prices, particularly in the GB1 zone where the bulk of onshore wind capacity is sited.

The same analysis for the HND scenario produced similar results

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

Updated modelling results:
Implementation cost

We triangulate from several sources to provide an indicative estimate of a range of implementation costs

One-off implementation costs predominantly consists of the two items below…

System implementation costs — One-off costs to enhance ESO and/or Elexon processes, new IT & software systems and capabilities

Market participant implementation costs — One-off costs to update system and capabilities of market participants

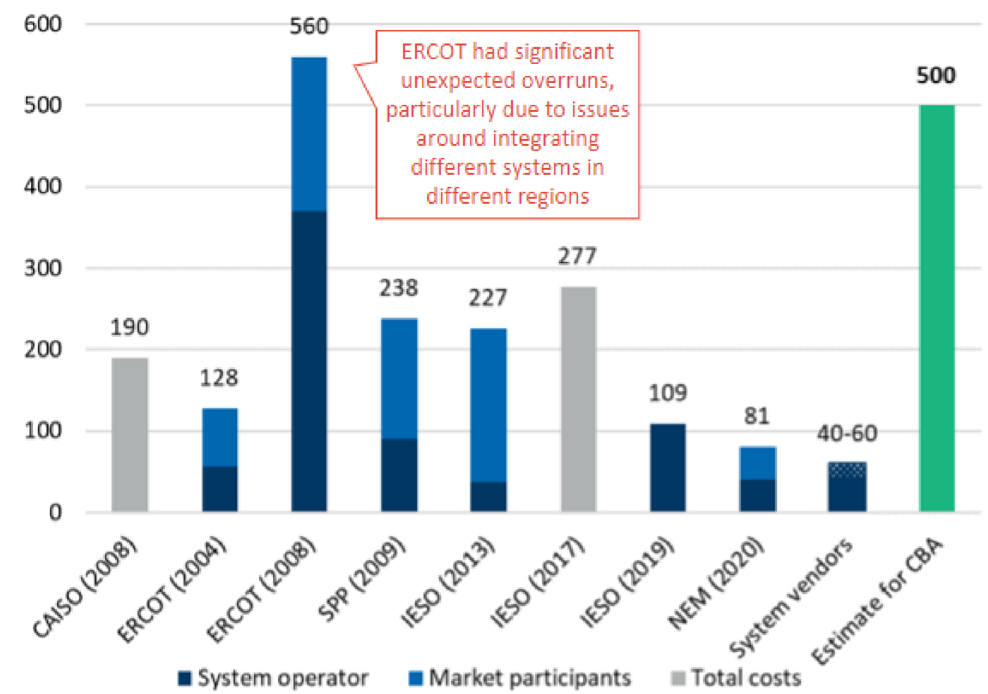
Approaches

1. **Conversations** with ESO to understand cost of running existing systems
2. **International case studies,** including recent (IESO) and older examples (ERCOT, CAISO)
3. **Direct conversations** with system vendors & market participants

ESO was not in position to provide an estimate of costs at this stage

International case studies indicate one-off implementation costs of £81m to £560m and are consistent with system vendor estimates

Implementation costs from international case studies (£m)



Notes: 2019 IESO and ERCOT were conducted mid-implementation.
Source: RIIO2 BP2 – Annex 3, CAISO, ERCOT, SPP, IESO, Hard Software.

Assumptions

- We **adjust market participant costs** based on the **relative installed capacities** of the jurisdiction (in the year the CBA was conducted) and in GB as at 2021.
- As a conservative assumption, we assumed **no additional investment** is required under the **National market design**.

Limitations

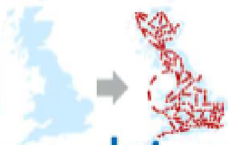
- We **do not adjust SO costs** for relative installed capacities. This implicitly assumes that system costs are **not proportional to the size of the electricity market** in each jurisdiction.
- This is a high-level analysis and we have not adjusted the implementation costs for **differences in the level of reform required** in each jurisdiction relative to GB. This is outside the scope of our work.

For the purposes of this CBA, we assume implementation costs of *£500m*, which is at the upper end of our estimated range[1]

Note: For our zonal CBA, we maintain our conservative assumption of £500m implementation costs.

Cost-benefit analysis results

National → Nodal design (NOA7)



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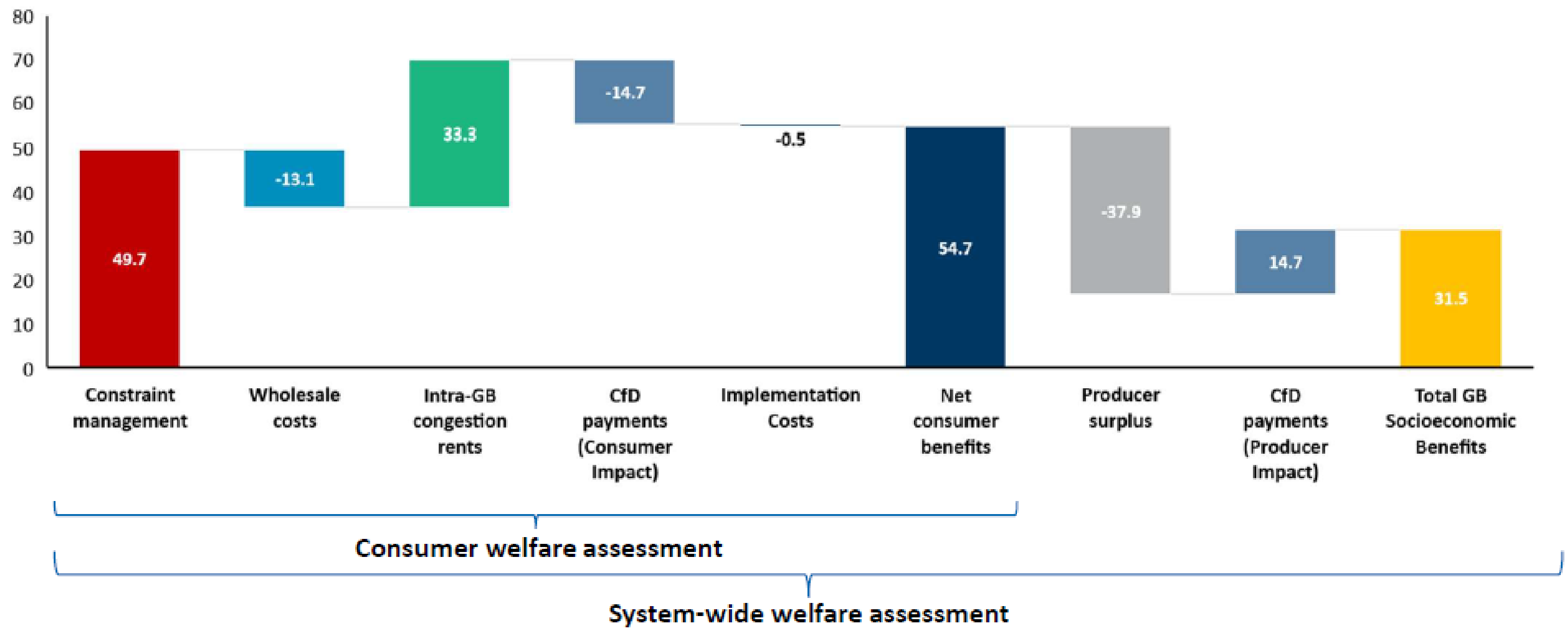
Our analysis shows a **nodal market** produces a net consumer benefit of £55bn and socioeconomic benefits of £31bn over the 2025-40 modelling period

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



Our assessment is based on several key assumptions, some of which are conservative…

- Keeping the same capacity mix – more granular pricing could potentially trigger a change in the capacity mix.
- Commodity prices based on 2021 trends – higher fuel prices would affect pricing outcomes and constraint costs
- No demand portability – demand may relocate in response to greater price signals in locational market designs

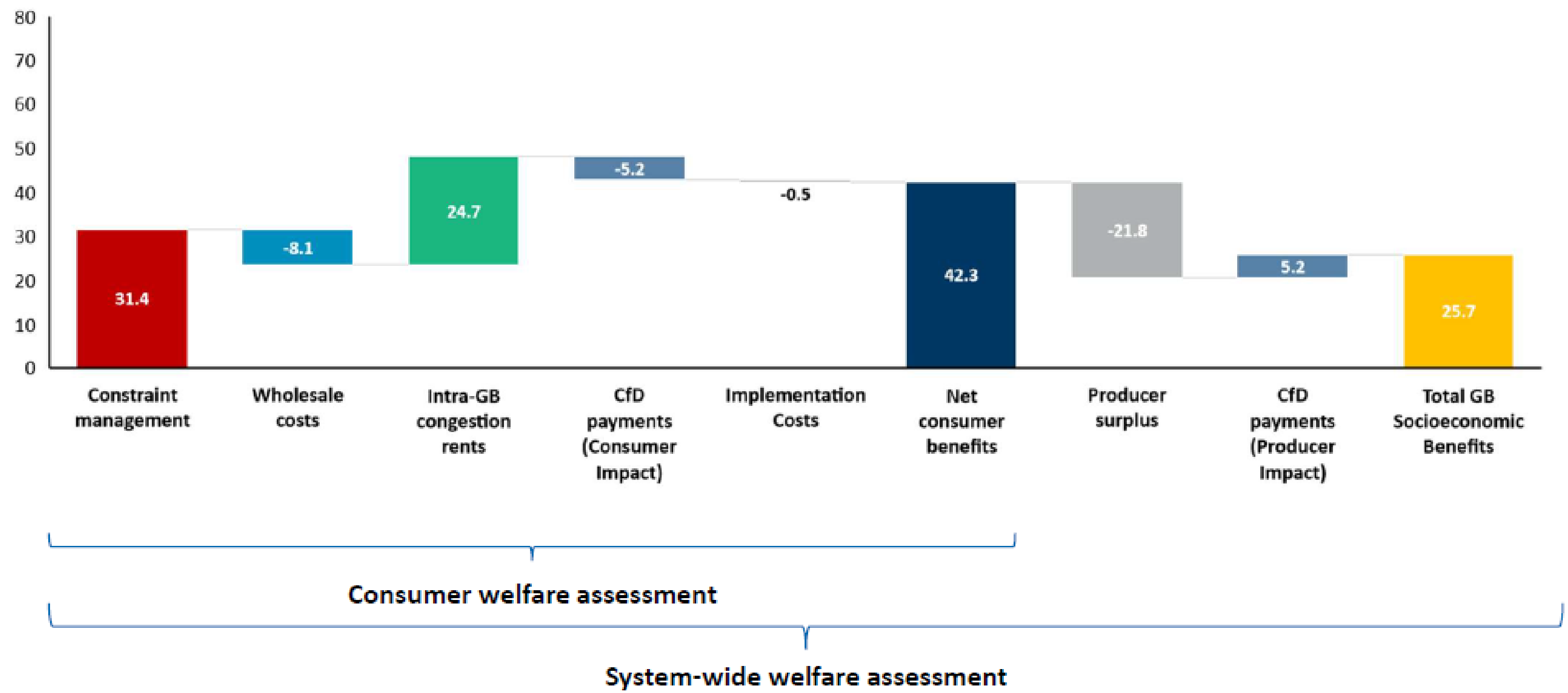
… while others may reduce total socioeconomic benefit

- Demand shielding – policymakers could "shield" consumers from experiencing locational wholesale electricity prices
- Transitional measures – measures to mitigate impact of locational pricing on market participants will represent a transfer of consumer benefits to producers

National → Nodal design (NOA7+HND)

Under the HND scenario, a **nodal market** would continue to deliver a net consumer benefit of £42bn and socioeconomic benefits of £26bn

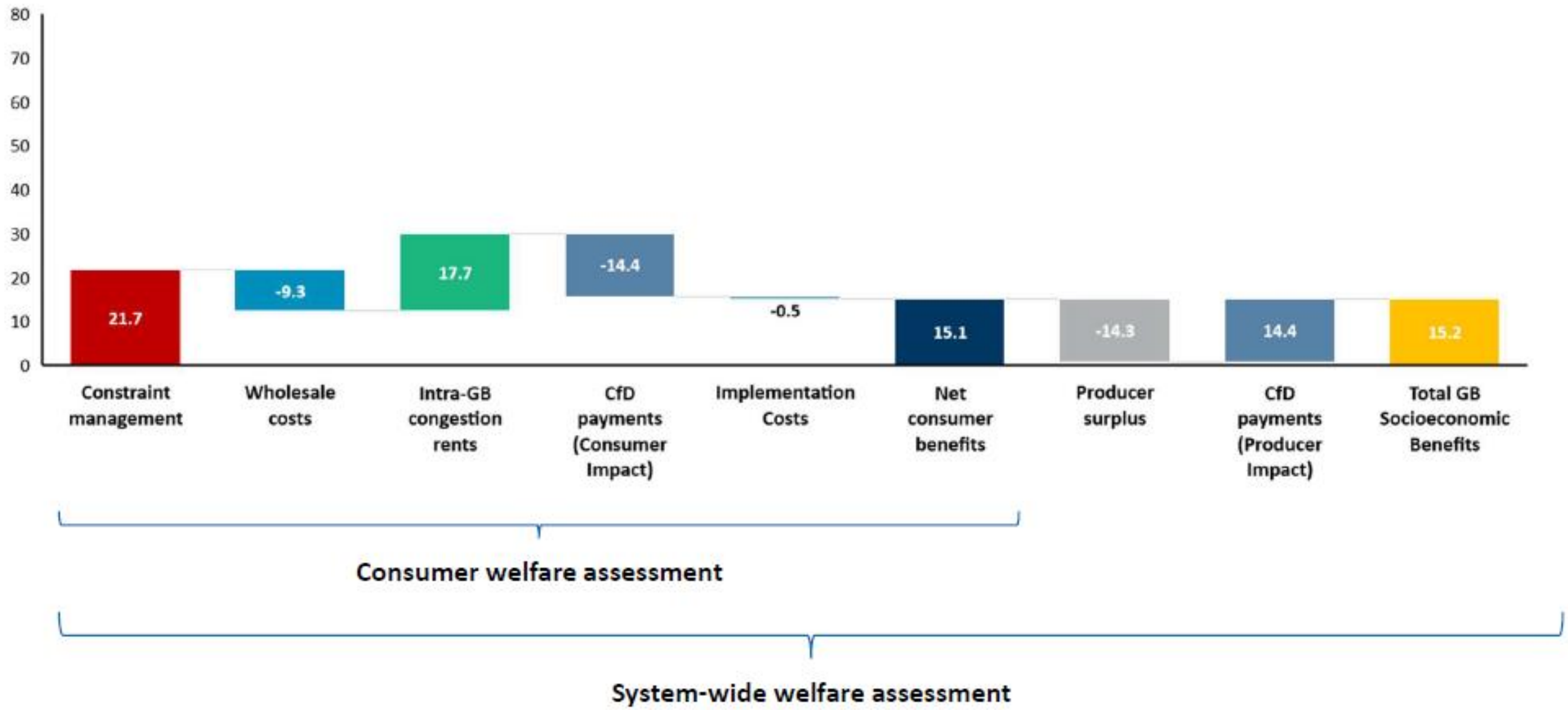
Breakdown of consumer surplus and welfare (£bn, Present Value 2025-35, Nodal – National, NOA7 + HND)



National → Zonal design (NOA7)

Our analysis shows that a **zonal market** would produce a net consumer benefit of £15bn and socioeconomic benefits of £15bn over the 2025-40 modelling period

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



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For the **next workshop** and our **Final Report**, we will include results for the System Transformation scenario, further sensitivities, and mitigation options

1 Current scenarios

- For the **Leading the Way** scenario (both **NOA7** and **NOA7 + HND**)
  - Finalise assumptions based on stakeholder feedback
  - Final round of model debugging and checks; undertake final runs

2 Further scenarios

- **System transformation** scenario
- Impact of **load shielding**
- Potential additional sensitivity (TBD)

3 Additional analysis

- Assess further **distributional impacts**
- Consider potential **transitional and implementation** measures

Workshop 3

Final report

Additional analysis

Additional analysis:
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

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**
- In particular, the **impact on the cost of debt** will largely depend on **support mechanisms**, such as CfDs for wind/solar and RAB mechanism for nuclear. We expect **limited change in price risk** for market participants that are supported by such mechanisms.
- Within the CAPM framework, the **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

- We have **not received substantiated quantitative evidence** from stakeholders, but the **general perception** amongst market participants is that they might expect some **increase in risk and WACC** from locational pricing
- However, based on several conversations with investors, the **magnitude on the impact** on WACC is **highly uncertain.**
- As a sensitivity, we assume an uplift to the WACC by **50bps for merchant market participants.**

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** appears to be driven by factors other than market design, in particular the **geographical characteristics** of a region and **policy incentives.**

For the sensitivity on the impact on financing cost, our methodology involves the following four steps

1 Estimating capacity profile

- Based on the same **FES capacity assumptions** used in our modelling
- To delineate between new capacity and retired capacity, we have assumed that **5% of existing capacity** is expected to **retire** each year

This has **minimal impact** on the results

2 Converting capacity to capex

- Based on **capex costs** for each technology from **externally verifiable sources.**[1]
- We calculate the financing costs for each asset in each year based on the following assumptions:
  - Straight line depreciation over an asset life of 25y for solar and wind, 15y for batteries and 40y for other technologies
  - Base WACC of 7% across all technologies

The base WACC **does not affect the incremental impact** in our assessment of a possible increase in financing costs.

3 Estimating WACC changes

- We have assessed the effects of a **tiered increase in the WACC** depending on each technology type and their exposure to regulatory risk.
- **This is set out in the next slide.**

4 Applying WACC to profile

- We have applied the change in WACC **across the whole modelling period of 2025-2040.**
- In practice, a proportion of the WACC uplift may be transitionary.

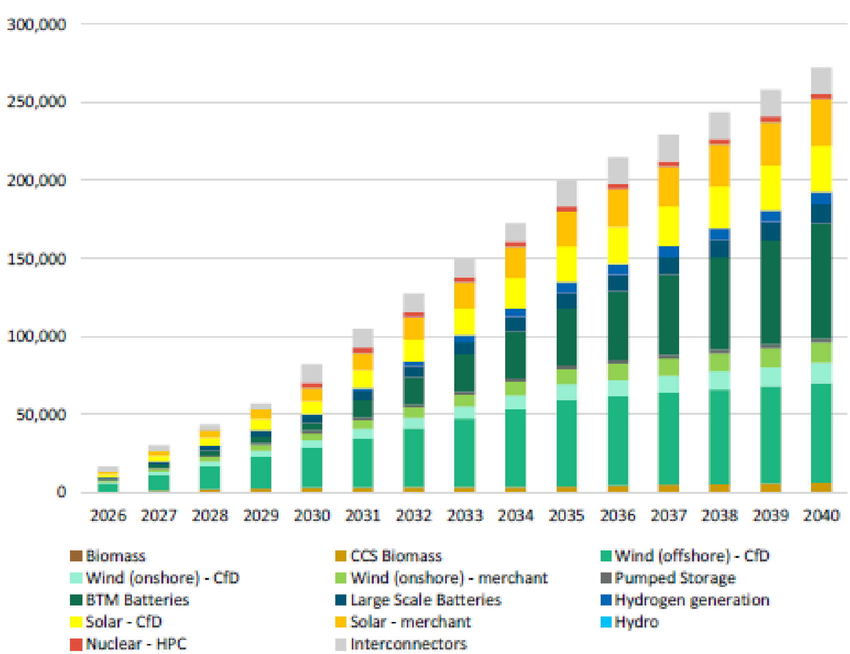
Note: (1) These are: (i) European Commission ASSET study on Technology Pathways in Decarbonisation Scenarios; and (ii) BEIS Electricity Generation cost report.
(2) includes offshore wind (CfDs), interconnects (Cap & Floor), and batteries (benefits from volatility)

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

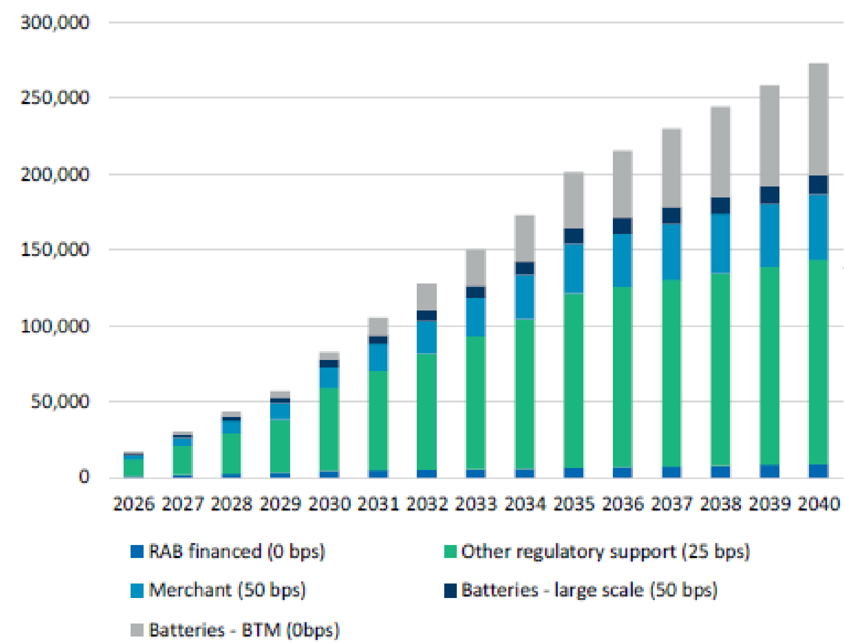
	Price risk	Volume risk	Rationale	Assumed uplift
RAB financing *Non-HPC nuclear; CCS*	↔	↔	• Market participants that are RAB financed are guaranteed a return on investment… • ….and therefore will not be affected by the potential change in price or volume risk…	0bps
Contract for Difference *Wind; Solar; HPC*	↔	↑	• Market participants with regulatory support are protected against some change in risk. • CfDs provide price certainty for debt financing in the first 15 years, but some volume risk to generators located behind constraints • Floor arrangements provide revenue certainty for debt financing in the first 25 years • 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. • For assets with a C&F, the cap serves to limit returns to equity. • A 25bps uplift is considered as a midpoint between limited and high risk exposure.	25bps
Cap and Floor *Interconnectors*	↑	↑↓		
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
Batteries *Large scale*	↑↓	↑↓	• Like other merchant technologies, batteries may also experience a change in their risks that affects their bankability. • However, batteries are exceptions in that they could benefit from the greater price arbitrage opportunities due to the additional price and volume risk… • Notwithstanding these potential additional benefits, we apply the same 50bps uplift to the WACC as other merchant market participants.	50bps
Batteries *BTM*	↔	↔	• We apply a 0bps uplift for BTM batteries as their capital costs are unlikely to be affected by wholesale prices.	0bps

We based capacity expansion on the FES capacity assumptions

Capacity expansion by technology by year (MW)



Cumulative expansion by type of regulatory arrangements (MW)



On a cumulative basis, this implies an capacity increase of:

- 9 GW for RAB financed market participants (e.g. CCS and SMR)
- 134 GW for market participants covered by regulatory support such as CfDs, C&F
- 43 GW for merchant market participants (e.g. merchant renewables and biomass)
- 86 GW for batteries (of which 74GW are behind-the-meter (BTM) batteries)

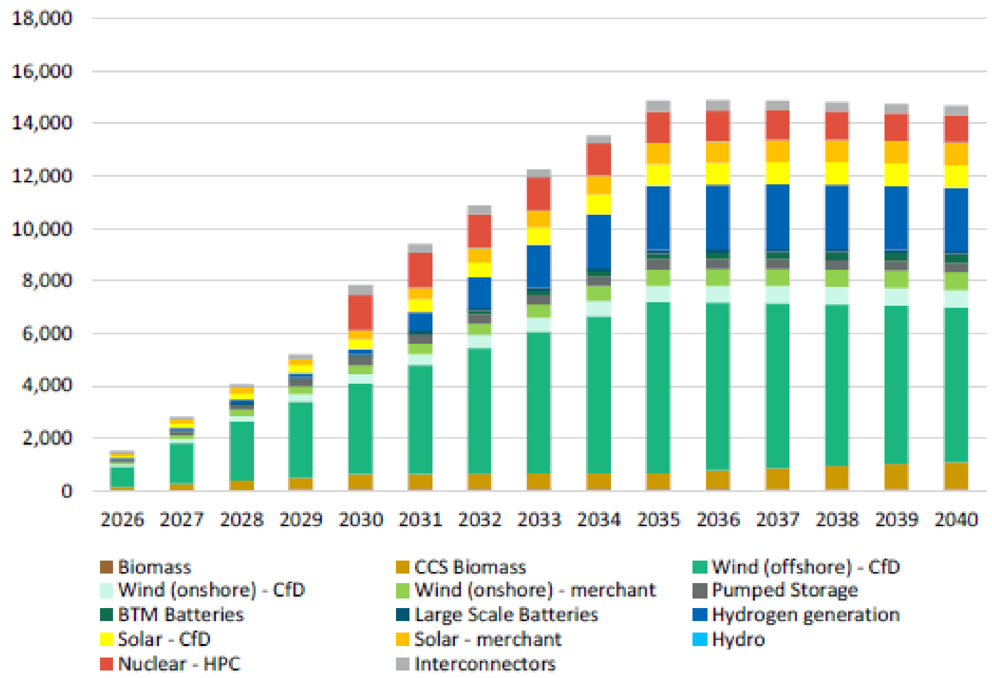
Source: FES2021 (Leading the Way)

Financing costs in the Base Case assume a uniform WACC and a straight line depreciation of Capex investment over the asset life for each technology

Asset life and estimated cost by technology

	Economic asset life (years)	Estimated 2035 cost per MW (£'000)
Biomass	40	1,689
CCS Biomass	40	3,157
Wind (offshore) - CfD	25	1,920
Wind (onshore) - CfD	25	1,048
Wind (onshore) - merchant	25	1,048
Pumped storage	40	2,896
BTM Batteries	15	104
Large Scale Batteries	15	231
Hydrogen generation	40	5,068
Solar - CfD	25	571
Solar - merchant	25	571
Hydro	40	2,293
Nuclear	40	5,792
Interconnectors	25	N.A

Annual financing cost in the Base Case (£m)



Straight line depreciation assumed

Estimated based on the expected project costs of individual interconnectors

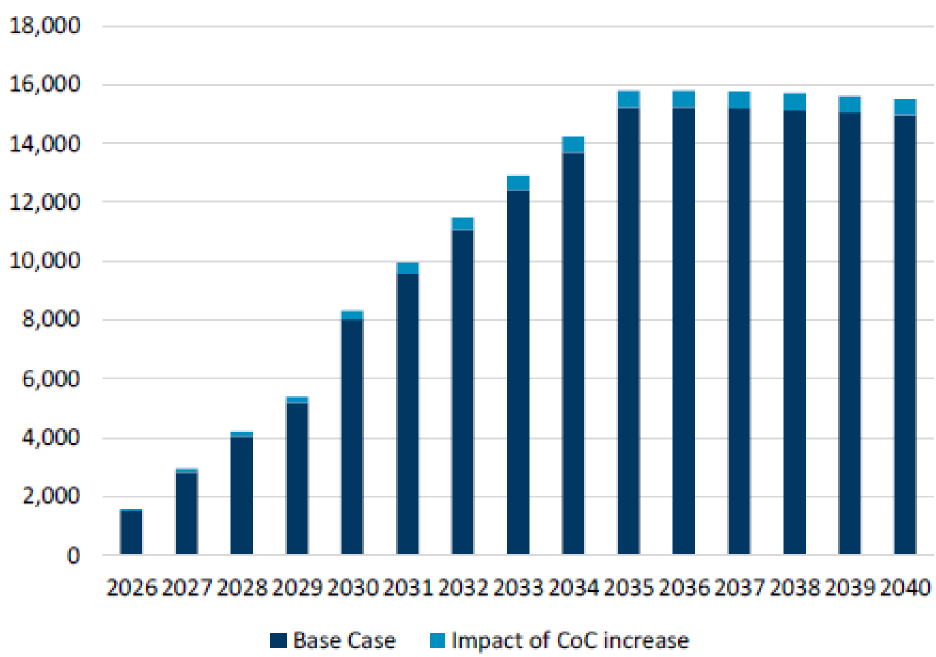
We use a base WACC of 7% which does not affect the incremental impact on financing costs.

Source: FTI analysis; Cost data is derived from European Commission's ASSET study (2018). Interconnector costs based on individual expected project costs.
Note: Capex investment in each year is calculated as the product of the increase in capacity in that year and the estimated cost per MW.

The impact of an increase in the cost of capital in our sensitivity scenario affects our Base Case by £6.0bn over the modelling period of 2025-2040

RAB financing *Non-HPC Nuclear; CCS*	0bps
Contract for Difference *Wind; Solar; HPC* **Cap and Floor** *Interconnectors*	25bps
Merchant *Merchant renewables; Thermal*	50bps
Merchant *Large scale batteries*	50bps
Merchant *BTM batteries*	0bps

Annual financing cost in the Base Case (£m)



Impact of WACC uplift over 2025-2040 is £6.0bn.

- As an extreme sensitivity, a uniform WACC increase of:
- 240bps is required to negate **all consumer benefits** from nodal pricing;
- 138bps is required to negate **all welfare benefits** from nodal pricing.

Applied across all technologies, across the modelling period

Additional analysis:
Liquidity

Based on energy futures exchanges, nodal markets have trading hubs which has a comparable degree of liquidity as GB

Concerns expressed by some stakeholders

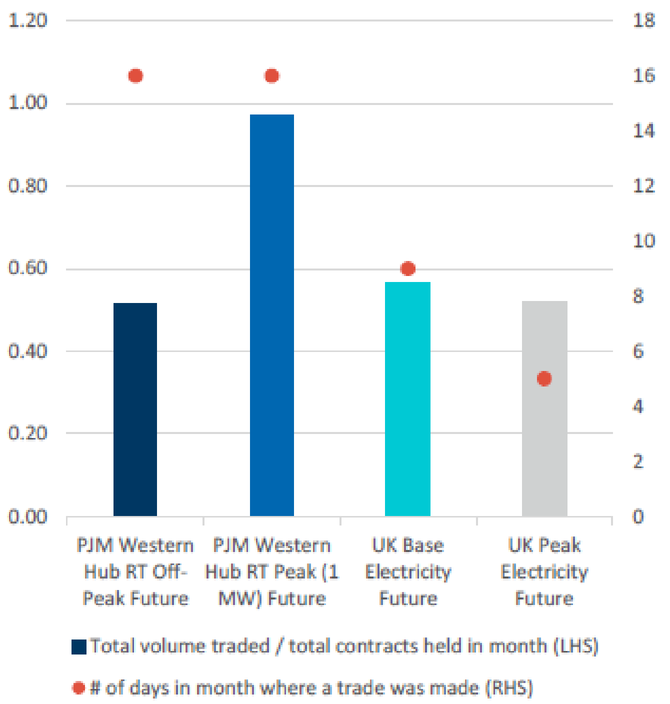
- **Lower liquidity** is predominately related to **trading in futures** and not short-term.
- **The frequency at which the trades occur** in the market should be considered in addition to trading volumes.

- As a measure of liquidity, we have analysed forward trading volumes on **electricity future exchanges** for the following:

  1. **Measure #1:** The total number of trades made in a month as a proportion of the total available stock (defined as open interest)
  2. **Measure #2:** the number of days in that month where trade was made

- The comparable products we have assessed are:
  - UK baseload and peakload electricity futures
  - PJM Western Hub Real-Time off-peak and peak futures
- The evidence we found is that **nodal markets have comparable liquidity to GB power markets** based on our assessment on electricity futures.*
- This could a potential option for GB, where **trading is not constrained at a particular node**, but rather via **liquid hubs…**
- … and market participants will manage **price differentials** between the hub and their node **via FTRs**.

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)

*(Note this does not include trades within vertically-integrated entities nor bilateral contracts).

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