Public

Quantitative assessment of central scheduling – FES 24 Update

Report by FTI Consulting for NESO

April 2025

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Report structure

Report conventions

- Unless stated otherwise, prices, revenues and costs are expressed in GBP and in 2024 real terms.
- Our FES22 Core Assessment presented results in 2022 real terms. In this FES24 Update Report we have scaled the results from the Core Assessment to 2024 prices to enable a comparison of findings.
- As the model is run in real EUR terms, we convert these values to GBP at an exchange rate of 1 GBP = 1.19 EUR.
- All present values are discounted to 2024, at a rate of 3.5%
- We have linearly interpolated between modelled years to derive values for intermediate years (e.g. 2027, 2028 etc.)

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Background and context

FTI Consulting's assessment of central scheduling builds on prior analysis of the case for and impact of co-optimised procurement

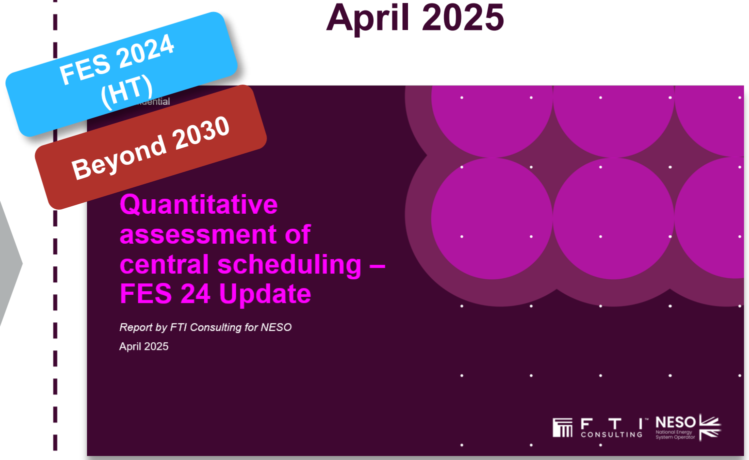
- In Summer 2024, the National Energy System Operator ("NESO") commissioned FTI Consulting ("FTI") to quantitatively assess the trade-off between an **earlier consideration of transmission ("Tx") network limitations** under **central scheduling** versus market participants' ability to **trade out their forecast errors** in the GB-wide wholesale ("WS") market until close to delivery under **self-scheduling.** This analysis has been conducted using generation and Tx assumptions aligned to **Future Energy Scenarios 2022 Leading the Way ("FES 22 LTW")** and **Holistic Network Development/Network Options Assessment 7 ("HND/NOA7")** respectively. We refer to this work as our "FES22 Core assessment".
- The scope of this assessment covered the **impact of introducing central scheduling under the current GB wholesale market design**, whether similar benefits could be delivered by **improvements to the balancing market ("BM")**, and how the case for central scheduling might change if GB moves to a **zonal wholesale market design.**
- This work built on **two reports previously prepared by FTI**, which qualitatively and quantitatively assessed the **case for and impact of co-optimised procurement** of energy, reserve and response services relative to the current sequential design. A key assumption underpinning this work was that the co-optimisation of energy and selected ancillary services ("AS") would be performed under central scheduling. However, the impact of central scheduling itself was not examined in those two reports, so FTI's assessment of central scheduling complements previous FTI work by direction evaluating the impacts of a potential transition from self-scheduling design to a central scheduling design.

This report

July 2024

March 2025

April 2025



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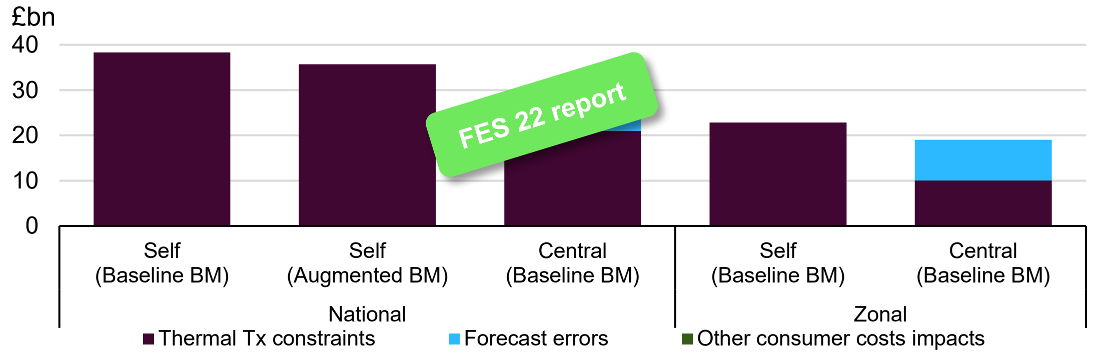
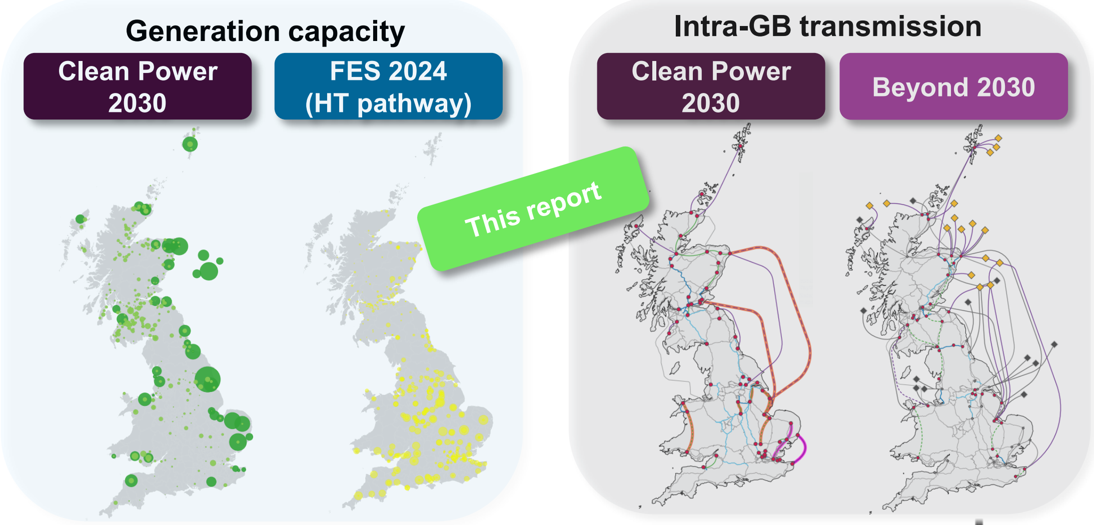
NESO has commissioned FTI Consulting to update the quantitative assessment of central scheduling using the latest generation/Tx forecasts

- Our "core" assessment (using FES22 input assumptions) found **significant consumer and socio-economic benefits** from a move to **central scheduling.** More cost-effectively resolving Tx constraints under central scheduling outweighed an increased cost of resolving forecast errors post-Gate Closure Time ("GCT").
- When considering a **national** WS market design, **consumer benefits of a move from self-scheduling to central scheduling** (totalling **£8.8bn** across **2030-2040**) were found to **exceed** the benefits that could be achieved through an **'Augmented BM**' **(£2.7bn** across **2030-40**), where incremental BM reform under self-scheduling is pursued as an alternative policy.[1]
- Transitioning from **national self-scheduling to zonal self-scheduling** was found to lead to higher consumer benefits than moving from national self-scheduling to national central scheduling (totalling £15.6 savings across 2030-2040). The **incremental benefit from central scheduling under zonal WS pricing, i.e. moving from zonal self-scheduling to zonal central scheduling, was less pronounced** than under national WS pricing **(£3.8bn**).
- Given the **importance of forecasted Tx congestion to the overall findings**, stakeholders expressed a preference to **update the model to the latest generation** and **Tx forecasts** (which can impact the volume of Tx congestion).
- In this context, **NESO** has **commissioned FTI** to **re-examine the case for central scheduling under an updated model,** aligned with the latest generation and Tx forecasts set out in **FES24**, **Clean Power 2030 ("CP2030")** and **Beyond 2030**.
- We have **agreed with NESO** to test how forecasted consumer and net GB impacts evolve under the updated generation and Tx assumptions for a **subset of the market designs** tested in the FES22 report, namely:
  - **National WS** pricing – **self-scheduling with Baseline BM**
  - **National WS** pricing – **central scheduling**
  - **Zonal WS** pricing – **self-scheduling (with Baseline BM)**
- This report should be read alongside FTI's core report jointly published with this document.
- Throughout this report, values are presented in 2024 prices and present values ("PVs") are discounted to the start of the modelling period (2030), using a discount rate of 3.5%. Modelled years were 2030, 2035 and 2040 and linearly interpolation is used for the intervening years.

Consumer costs incurred under self- vs central scheduling, £bn, PV 2030-2040





Notes: (1) An updated GBP/EUR exchange rate and a move from 2022 prices to 2024 prices cause the core assessment figures presented here to differ slightly to those presented in the core report.

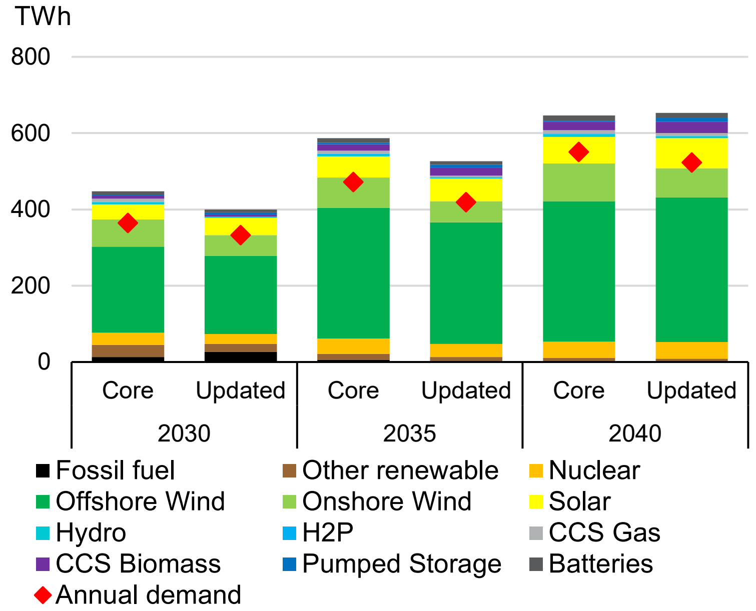
We have updated the generation and Tx outlook, but broader assumptions are unchanged from the previous assessment

Key modelling assumptions used in our quantitative analysis have been developed through extensive engagement with NESO and the Department of Energy Security and Net Zero ("DESNZ"), and we understand that, where possible, these reflect the same assumptions as in other quantitative assessments performed by DESNZ within the wider Review of Electricity Market Arrangements ("REMA") process.

Assumption	RECAP: Modelled in core scenario (in FTI's FES22 report)	Updated sensitivity
Generation & demand outlook	**FES 2022 LTW (GB), FES 22 EU Consumer transformation ("CT") (Europe)**	**CP2030** Further Flex & Renewable Energy Sources ("RES") (2030 GB), **FES 2024** Holistic Transition (2035 – 2040, GB), **Ten Year Network Development Plan ("TYNDP") 2024** Distributed Energy (Europe)
Interconnectors ("ICs")	Assumed **operational ICs** aligned with DESNZ REMA IC assumptions	Unchanged
Commodity prices	**Natural gas, hydrogen, oil and coal prices** follow DESNZ 2023 projections **Biomass price** calibrated using FES 2022 forecast capacity factors **Carbon price** aligned with forward estimates as of Q2 2024	Updated using **DESNZ and FES 2024 forecasts**
Modelled years	**2030, 2035, 2040**	Unchanged
Climate year ("CY")	**CY2013**	Unchanged
Transmission network	**HND + NOA7 Refresh** (contemporaneous with FES22) **Zonal boundaries** aligned with DESNZ REMA modelling (12 zone model)	**CP2030 and Beyond 2030** Zonal boundaries unchanged in the core scenario. A variant with more 'optimised' zones (with respect to the modelled scenario) was tested.
Balancing Mechanism ("BM") and pricing	**Participating technologies and pricing** developed with NESO and Ofgem **Penalty price** for IC redispatch aligned with NESO forecasted bid/offer prices	Unchanged
Forecast error between DA and GCT	**Demand:** calculated from national aggregate imbalance and sample of GSP forecast errors (provided by NESO) **Wind:** calculated using day-ahead ("DA") forecast and Final Physical Notifications ("FPNs") by windfarm (provided by NESO) **Solar:** calculated using forecast data from NESO and outturn data from Sheffield Solar	Unchanged

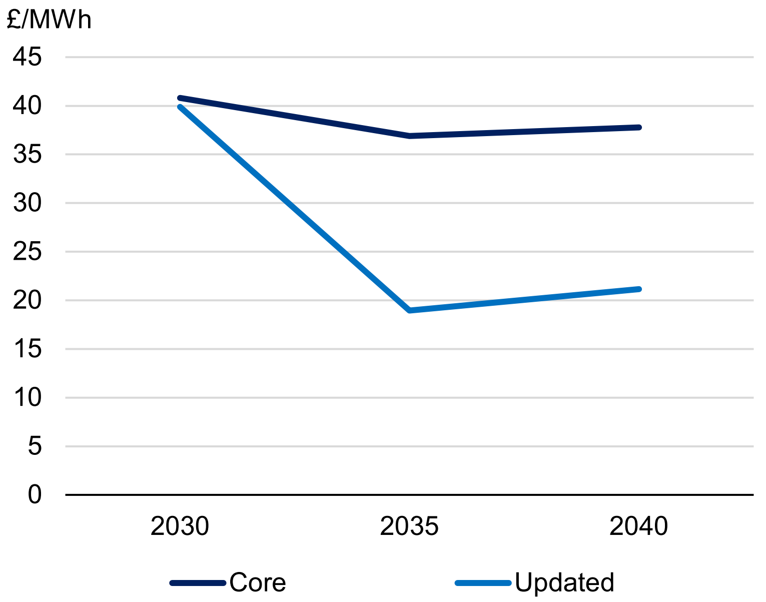
Lower demand and more RES curtailment reduces average WS prices in the FES24 scenario relative to the FES22 Core scenario, while increased Tx deployment reduces constraint volumes in later years

Annual generation and demand by technology, core and updated modelling, national pricing (TWh)



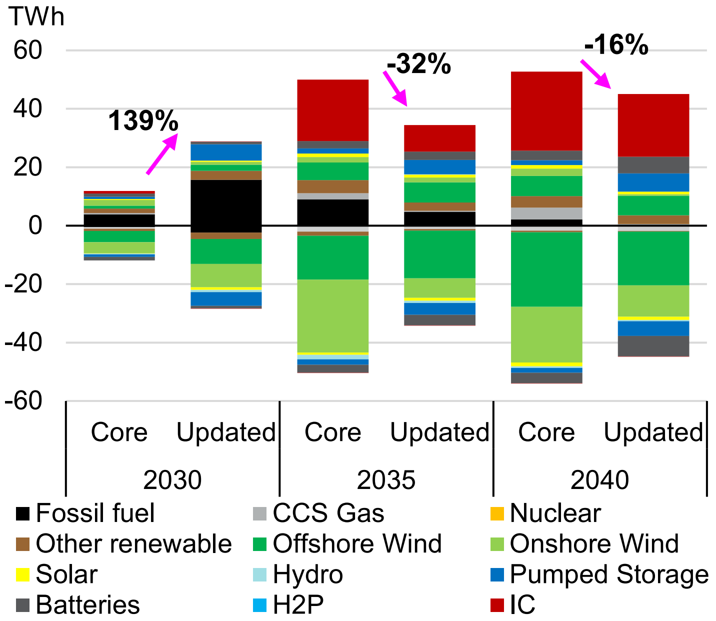
- Although installed RES capacity increases in the FES24 scenario (by 3-10% per year), annual realised RES output is lower in each modelled year in the updated scenario, caused by reduced GB electricity demand.
- This drives more economic curtailment of RES in the WS market in the updated scenario.

Annual average WS price, core and updated modelling, national pricing (£/MWh)



- The fall in GB demand in the updated scenario leads to lower average wholesale prices in 2035 and 2040.
- In 2030 the average WS price is similar under both scenarios. Even though there is less demand and more RES curtailment under the FES22 scenario, there is more fossil fuel generation which raises the WS price. This does not hold in 2035 and 2040.

Annual constraint volumes under self-scheduling, core and updated modelling, national pricing (TWh)



- Updating the modelled Tx network to align with CP2030 and Beyond 2030 increases modelled Tx congestion in 2030 (with CP2030 flagging some projects as likely to be delayed into the early-2030s)…
- …but lowers modelled Tx congestion in 2035 and 2040.
- Annual constraint volumes are more stable across the modelled period under the updated scenario, relative to the core (FES22) scenario.

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In our updated assessment, we assess the impact of central scheduling under national WS pricing, and the impact of a move to zonal WS pricing if self-scheduling is maintained

- This report evaluates the potential socio-economic benefit of transitioning from the current national self-scheduling arrangement to central scheduling, as well as the potential benefits of transitioning to a zonal WS market if self-scheduling is maintained. This therefore involves three model set ups:
  - A ‘Status quo’ with national wholesale pricing in place in a self-scheduled market and post-GCT balancing performed through a ‘Baseline BM’;
  - B National wholesale pricing with a centrally scheduled dispatch; and
  - C Zonal wholesale market design with self-scheduled dispatch.
- In our core assessment, we assessed the impact of introducing an ‘Augmented BM’ intended to reduced balancing costs under national self-scheduling; this is not assessed in this report, nor is the benefit of central scheduling with zonal wholesale pricing.

Our base zonal model (C1) uses DESNZ’s REMA zones; we also model a sensitivity (C2) for zonal with self-scheduling, using ‘optimised’ zonal boundaries that better align with the congestion patterns in the updated scenario.

Impact of central vs self-scheduling under national

Model	A National with self-scheduling	National with Augmented BM	B National with central scheduling	C Zonal with self-scheduling	Zonal with central scheduling
WS market design	National	National	National	Zonal	Zonal
Balancing Market	Baseline BM	Augmented BM	Baseline BM	Baseline BM	Baseline BM
Scheduling[1]	Self *(i.e. without thermal Tx constraints)*	Self	Central *(i.e. with all thermal Tx constraints)*	Self (i.e. with inter-zonal thermal Tx constraints but not intra-zonal Tx constraints)	Central
Resources scheduled relative to	National price	National price	Shadow nodal price[2]	Zonal price	Shadow nodal price[2]
Resources compensated based on	National WS/ID price	National WS/ID price	National price at DA, estimated ID price post-DA[3]	Zonal WS/ID price	Zonal price at DA, estimated ID price post-GCT
DA forecast error[4,5]	Intraday (“ID”) trading resolves aggregate imbalance	ID trading resolves aggregate imbalance	Imbalance resolved in BM	ID trading resolves GB aggregate imbalance	Imbalance resolved in BM

Not examined in this report

Impact of zonal design if self-scheduling is maintained

Not examined in this report

Notes: (1) The key difference in the modelling of self vs central dispatch lies in the consideration of thermal Tx constraints in the WS market schedule (all Tx constraints are considered under central scheduling at the DA stage while DA WS prices can be national or zonal). We do not model difference in portfolio (self-scheduling) vs unit-based bidding (central scheduling) or bidding formats – we discuss this simplification in Slide 15 of our core report; (2) Shadow nodal prices represent the implicit cost of supplying the marginal unit of generation/consumption at a particular node, with full consideration to the Tx network (i.e. as if there were a nodal pricing market design); (3) See Slides 55 and 56 of our core report for further detail; (4) We model different demand, solar, and wind generation between DA and GCT to mimic forecast error. See Slides 22 and 38 of our core report for more information; (5) We assume that all forecast errors are resolved pre-GCT under self-scheduling, which leads to conservative benefits of central relative to self-scheduling.

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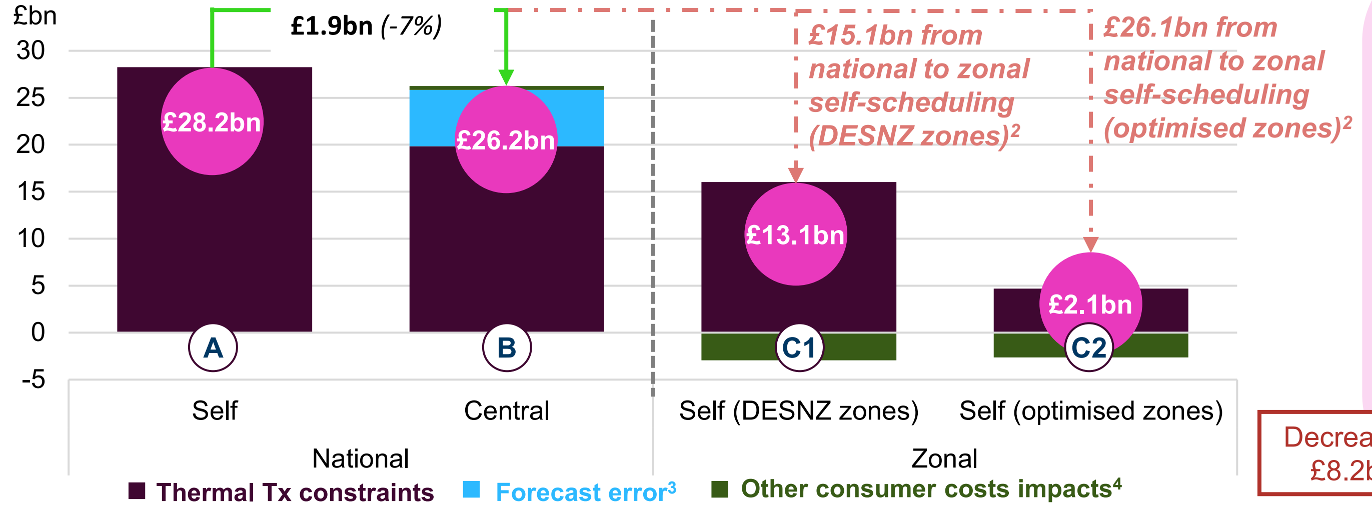
Overview of results

In the FES24 scenario, central scheduling reduces consumer costs, but zonal design reduces consumers costs much more significantly

GB consumer costs impacts under self- vs central scheduling, £bn, present value ("PV") 2030-2040[1]



- Under national WS pricing, a **move from self- to central scheduling** lowers aggregate consumer costs by **£1.9bn.**
- Alternatively, retaining self-scheduling but **transitioning to zonal WS pricing** would reduce consumer costs by **£15.1bn** when using the DESNZ zones. This is a slightly greater saving than in our core assessment, partly driven by higher intra-GB congestion rents.
- Further, using zones which align better with modelled congestion patterns increases the benefits of transitioning to zonal WS pricing to **£26.1bn.**

A → B **£1.9bn** A → C1 **£15.1bn** A → C2 **£26.1bn**

Decrease in consumer savings from £8.2bn in the FES22 modelling[5]

Small decrease in consumer savings from £15.6bn in the FES22 modelling

Key points

- As observed in the FES22 Core Assessment, the consumer benefits of central scheduling are a function of: (i) the scale of Tx constraints (with central scheduling delivering greater benefits in years with high constraint volumes and costs); and (ii) the scale of RES/load forecast errors (which increase costs under central scheduling).
- Under a national design, central scheduling leads to a reduction in aggregate consumer costs (£1.9bn for the modelled period of 2030-2040). This reduction is less significant than in the FES22 modelling, with a more ambitious Tx rollout in the updated assumptions post-2030 causing constraint costs under national self-scheduling to fall by more than the DA transfer payments required under central scheduling (see Slide 13). As noted in the core report, the benefits of central scheduling are highest in years where constraint costs under self-scheduling are relatively high.
- If considered as a potential alternative to central scheduling, introducing zonal wholesale design would reduce consumer costs by £15.1bn under the updated scenario. Under zonal WS pricing, improved price signals pre-GCT help reduce the cost of resolving Tx constraints without increasing the cost of resolving forecast errors.
- The magnitude of the modelled consumer savings of a move to zonal WS pricing is highly dependent on the zonal configuration used; by using 'optimised' zonal boundaries that align with the most-constrained boundaries observed in the FES24 model, the benefits of transitioning to zonal WS pricing could be increased to £26.1bn (see Slides 26-29).

Notes (1) DA WS costs are equivalent under self- and central scheduling when considering the WS market design (national or zonal) constant. (2) We do not assume any change in cost of capital or implementation costs under zonal pricing, nor other benefits of zonal pricing such as potential re-siting of new assets or reduced Tx investment. (3) Forecast errors represent the cost of adjusting to evolving forecasts of RES (solar and wind) and demand between DA and GCT under each market design. (4) Other consumer cost impacts include the changes in WS costs, Contract for Difference ("CfD") payments, and intra-GB congestion rents under zonal relative to under national pricing. The other consumer cost impacts of zonal pricing can be positive or negative on aggregate, and in the modelled scenario largely net off, combined providing a residual net benefit to consumers across the modelled period; (5) The impact of the updated scenario on the socio-economic welfare ("SEW") benefit from central relative to self-scheduling (both national) was less pronounced, i.e., £13.5bn (core) vs £9.1bn (updated) SEW benefits (see Slide 32).

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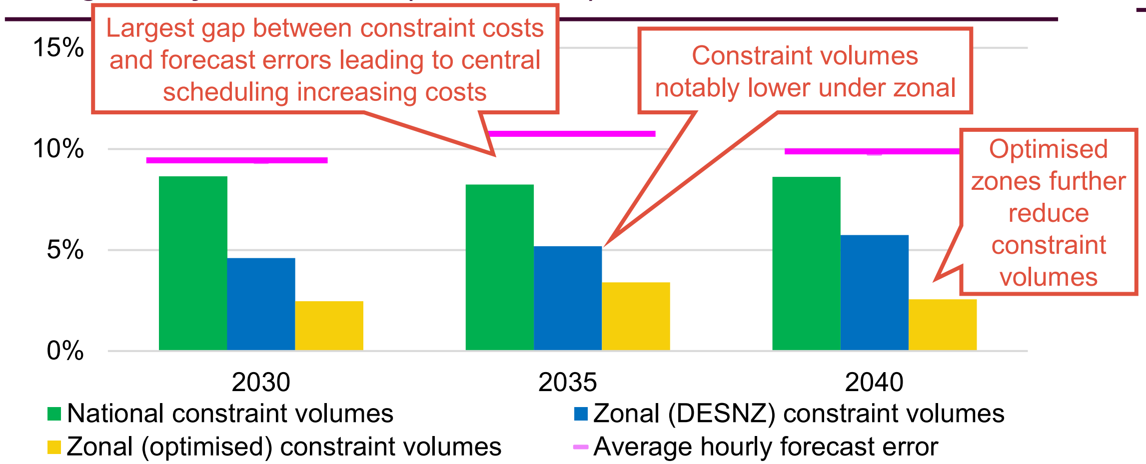
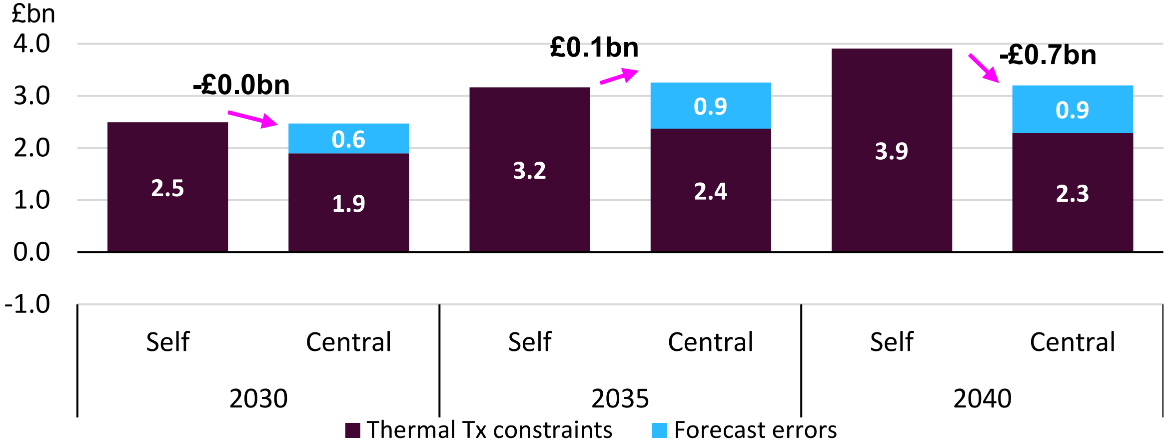
Central scheduling reduces the cost of resolving Tx constraints, but the benefit in 2030-35 is offset by the increased cost of solving forecast errors; zonal pricing delivers savings in all modelled years

- Tx constraints are resolved post-GCT under self-scheduling, whereas under central scheduling, Tx constraints are resolved at the DA stage and transfer payments are made to compensate generators for cost recovery and firm access.[1]
- In the updated scenario, constraint volumes relative to demand are relatively stable across the period for both national and zonal pricing, but are significantly lower under zonal in all years (and further lowered under the optimised zonal configuration).[2]
- With national pricing, consumer costs under self and central scheduling are relatively similar in 2030 and marginally higher in 2035. Tx constraints are relatively high leading to savings under central scheduling, but the cost of resolving forecast errors post-GCT under central scheduling is also sizeable. By 2040, RES deployment again outstrips Tx build, with central scheduling reducing consumer costs by £0.7bn in 2040.
- Consumer costs of resolving Tx constraints are significantly lower with zonal WS pricing, particularly when zones are more optimally aligned with congestion patterns, while the cost of resolving post-DA forecast errors through ID trading is minimal (as with national self-scheduling).

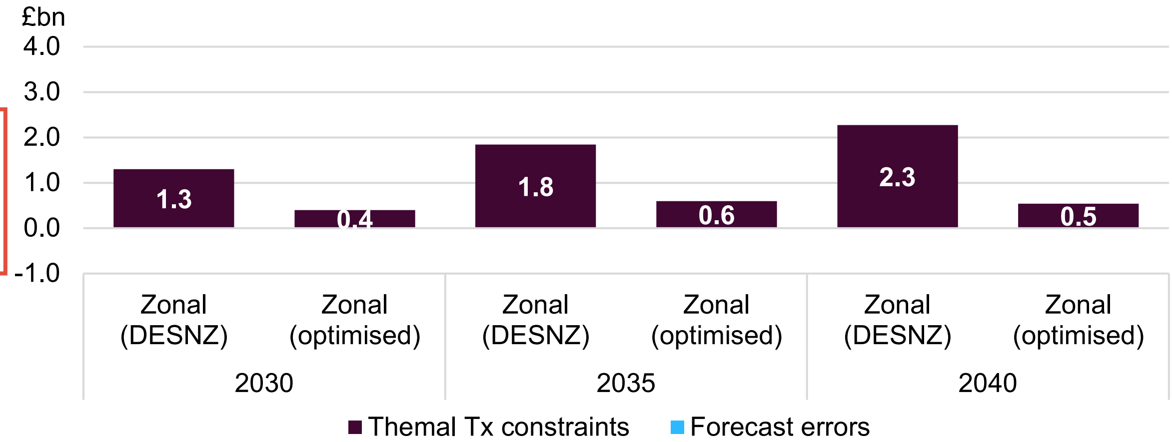
Constraint volumes under self-scheduling arrangements (% of demand) and average hourly forecast error (% of demand), 2030 - 2040[3]



Consumer costs of resolving thermal Tx constraints and forecast errors under self- and central scheduling with national WS pricing



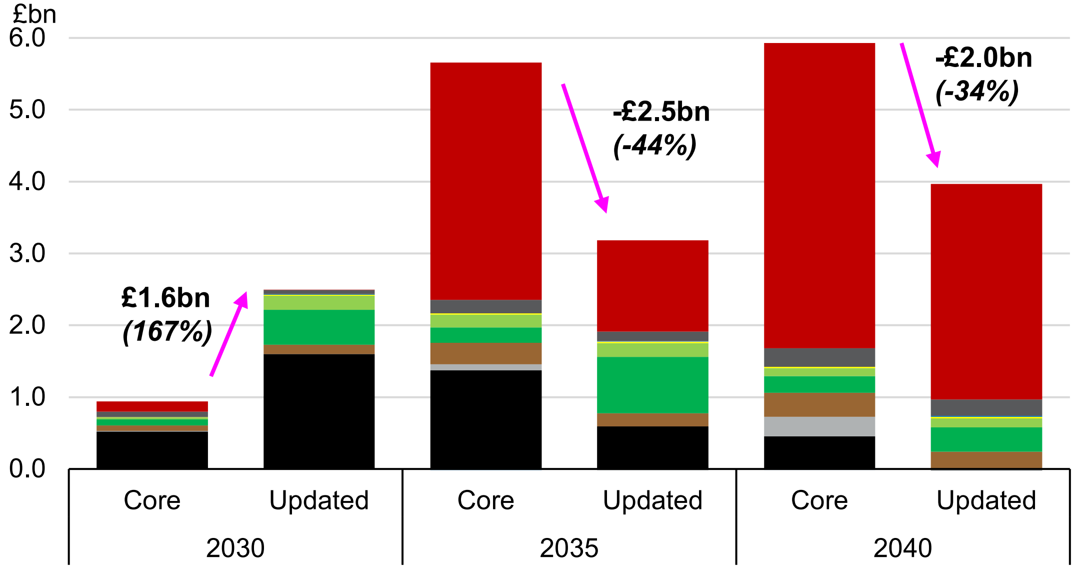
Consumer costs of resolving thermal Tx constraints and forecast errors under self-scheduling with zonal WS pricing, DESNZ and 'optimised' zones



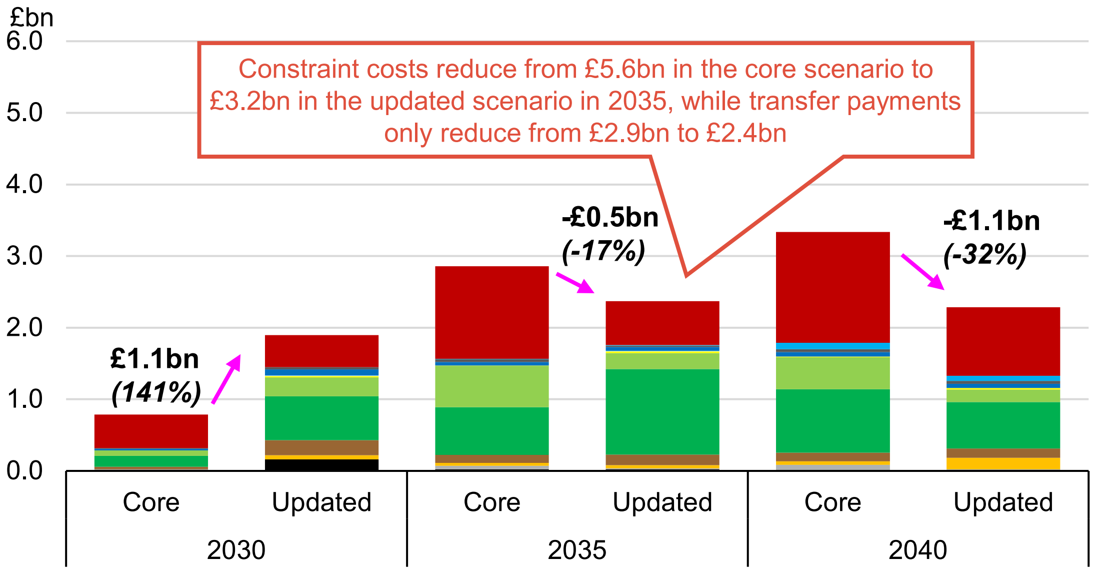
Note: (1) Post-GCT, small volumes of Tx constraints can surface under central scheduling due to forecast errors; (2) The total capacity of intermittent RES (and so the absolute forecast error) increases in 2035 and 2040, but increased demand means the average forecast error relative to demand remains stable; (3) The ratio of forecast errors and constraint volumes under National and Zonal should be read as a qualitative relationship – there is no direct linear relationship between these two indicators.

Consumer cost savings from central scheduling are lower in the updated scenario, as reductions in constraint costs under self in 2035-40 outweigh decreases in DA transfer payments under central

Cost of resolving Tx constraints in BM under self, core vs updated (£bn)



Cost of DA transfer payments to resolve Tx under central, core vs updated (£bn)



- The **updated Tx** deployment forecasts impact the volume and associated costs of resolving Tx constraints in all modelled years. Relative to the Core scenario, the **Updated scenario** sees **higher constraint costs** in **2030** and **lower in 2035-40**. Our core assessment showed that the benefits of central scheduling are greatest in years with high levels of constraint costs.
- In **2030**, under **self-scheduling**, significantly higher volumes of **fossil fuels** are **constrained-on** leading to an **increase** in **constraint costs**. Under **central scheduling**, these actions can be taken at **lower cost** – the '**cost recovery**' transfer payments made to **fossil fuel** units used in the **central schedule** are **lower** than the **constraint payments** made under **self-scheduling**. Additionally, instead of constraining on fossil fuels under self, **ICs** are **better scheduled** under **central**. However, **firm access** transfers made to Contract for Difference ("CfD") -supported RES units significantly **increase** – greater **Tx congestion** means the **volume** of **transfers increases**, but **higher assumed CfD strike prices**[1] also increase the average cost per MWh of firm access transfers. Consequently, while in 2030 constraint costs increase under the Updated relative to the Core scenario, this increase is nearly completely matched by increased DA transfers.
- In **2035** and **2040**, **constraint costs fall substantially** under **self-scheduling**. The significant increase in Tx deployment helps avoid some of the **highest-cost BM actions**, which more than **offsets** the **increased payments made to CfD RES**, particularly for offshore wind. Under **central scheduling**, DA transfer payments also **fall** but to a **lesser extent**. A large proportion of the DA transfer payments made under central are firm access payments to unscheduled CfD wind – the increased cost per MWh of these transfers largely offsets the reduced cost of 'cost recovery' payments made to ICs.

Note: (1) Average annual strike price for offshore wind is around £80/MWh in 2035 and 2040 in the updated scenario (due to updates to align with Allocation Round 6), and around £44/MWh in the core scenario.

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Consumer impacts of central scheduling under national wholesale pricing

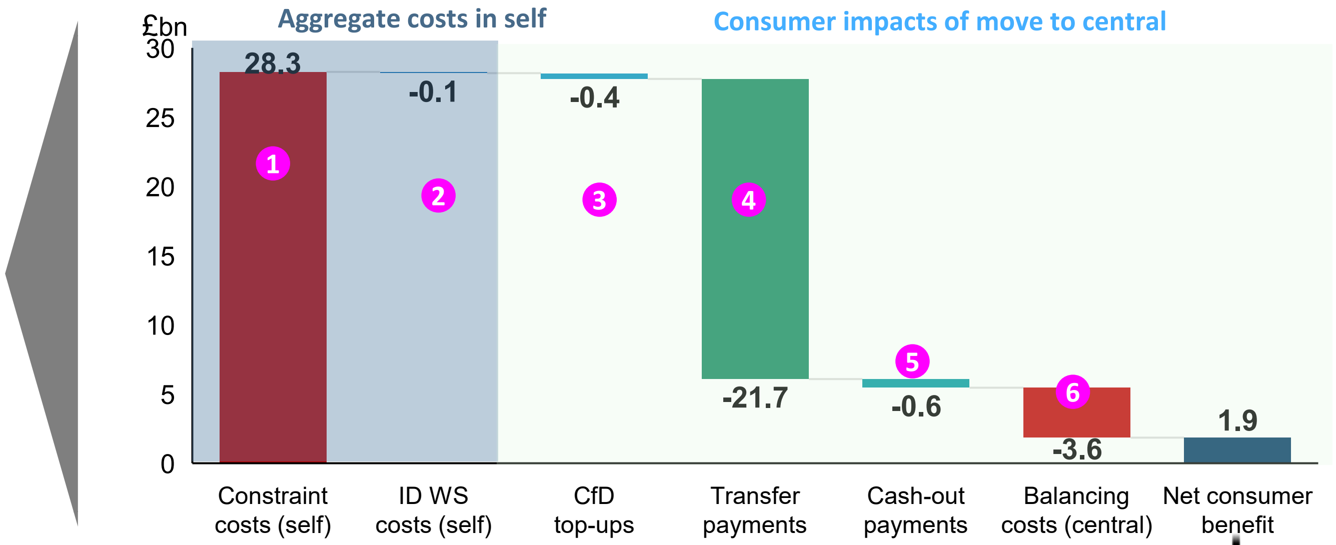
Public

In our updated assessment, consumer savings from central scheduling remain positive, as constraint costs (under self) are higher than transfer payments and balancing costs (under central)

- The net consumer impact of central scheduling (under national design) is composed first of the avoided **aggregate costs that would be incurred under self-scheduling** to resolve **thermal Tx constraints (BM constraint costs)** and **forecast errors (ID wholesale costs**[1]**)**, shown in the first two bars of the waterfall diagram on the right below (WS consumer costs are assumed to be unchanged under central scheduling, as noted in our core report). In addition, we adjust for the alternative costs that are instead incurred under central scheduling, namely DA transfer payments, post-DA transfer payments, cash-out payments and balancing costs. We also account for the impact of the central schedule on CfD top-ups.[2]
- We find an overall net consumer benefit of **£1.9bn between 2030-2040** from a transition from self to central scheduling under national WS pricing. The core driver of this net benefit is the **constraint costs** under **self-scheduling (£28.3bn)** being larger than the sum of **transfer payments (£21.7bn)** and **balancing costs (£3.6bn)** under **central scheduling**. The former is required to compensate units for the mismatch between the central schedule and the national WS price. The latter is due to the assumption that forecast errors at DA are resolved post-GCT under central scheduling; under self-scheduling these are resolved pre-GCT through ID trading at much lower cost, with even a slight benefit of £0.1bn due to net over-forecast of load.
- CfD payments are higher under central scheduling (£0.4bn) with more RES being eventually dispatched, while national WS prices are relatively low (see Slide 8). Finally cash-outs are a cost under central scheduling (£0.6bn) due to relatively generous cash-out prices (Slide 54 and Appendix 3 in the Core report) and a slight bias in generation under-forecasting at DA.

Aggregate consumer costs, national design, self vs central scheduling, £bn (2030-2040, PV 2030)[3]

Central scheduling net consumer benefits, national design £bn (2030-2040, PV 2030)[3]



Notes: (1) ID WS costs are calculated as the change in demand in the ID market relative to the DA market multiplied by the ID wholesale price. The change in demand can be positive or negative and hence the ID wholesale costs nearly net out; (2)The change in CfD top-ups between central and self-scheduling is limited as the DA WS price remains the same. However, the scheduled volumes of CfD-covered generation can be different under both setups leading to minor changes in CfD costs; (3) This chart does not include DA wholesale costs, which are assumed to be equal under both self- and central scheduling.

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Central scheduling delivers consumer benefits by more effectively resolving Tx constraints, but the difference in constraint costs relative to transfer payments is nearly matched by increased balancing costs

The consumer benefits of central scheduling are a function of:

1 **The scale of Tx constraints**
As constraint volumes and costs vary across the years, so too does the **benefit** of central scheduling.

2 **The scale of RES/load forecast error**
Forecast errors increase proportionally with deployment of RES capacity and increasing demand. Forecast errors **increase costs** under central.

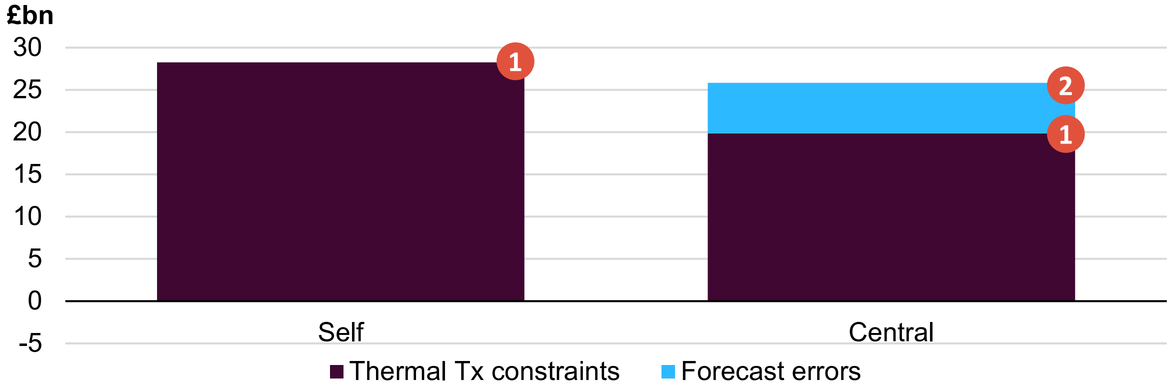
Central scheduling appears to be most beneficial if: (a) Tx deployment does not keep pace with RES expansion; (b) an ID market is introduced to help manage updated forecasts; and (c) ICs are scheduled using shadow nodal prices.

a) **Assumed network build.** In our updated assumptions, certain transmission projects have later delivery dates but the scale of transmission build out is more ambitious in later years. This decreases the benefits of central as the cost of resolving Tx constraints under self-scheduling are less significant

b) **Balancing arrangements to resolve forecast errors.** We assume that self-scheduling fully resolves forecast errors through ID trading, while central scheduling resolves all forecast errors post-GCT. Relaxing either of these assumptions, in particular the assumption that central is unable to resolve forecast errors through ID trading, would **likely improve the case of central scheduling**. Installed RES capacity is slightly higher in the updated scenario.

c) **Scheduling arrangements for ICs.** We model 'perfectly forecasted' explicit trading across all GB-Europe ICs for both self- and central scheduling. ICs are scheduled based on shadow nodal prices under central. The alternative approach, i.e. scheduling ICs in central using unconstrained national prices (as under self-scheduling) would likely very **significantly reduce the case of central**.

Consumer costs of resolving thermal Tx constraints and forecast errors under self- and central scheduling with National WS pricing



- The benefit of central scheduling is driven by **cheaper resolution of Tx constraints**, which happens at DA via the central schedule rather than post-GCT under self-scheduling.
- As shown above, in comparison to the sizeable cost under self-scheduling, the 'make whole' transfer payments made to producers at DA under central scheduling to resolve thermal Tx constraints **are significantly lower**. However, the costs under central have increased slightly relative to our core assessment, as explained in Slide 13.
- **Forecast errors are assumed to cost more to resolve under central** scheduling than under self (light blue). Under self-scheduling the cost to resolve forecast errors is negligible with ID trading resolving aggregate GB imbalances, while forecast errors are resolved via more costly post-GCT actions under central.
- Overall, **the aggregate constraint costs** incurred under **self-scheduling** are **greater** than the sum of **DA transfer payments** and **balancing costs** to resolve **forecast errors** required under **central scheduling**. However, this is **not the case in all modelled years** (see next slide).

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The updated scenario confirms that central scheduling provides benefits for consumers when the GB Tx network is heavily congested, but may not be beneficial when Tx constraints are modest

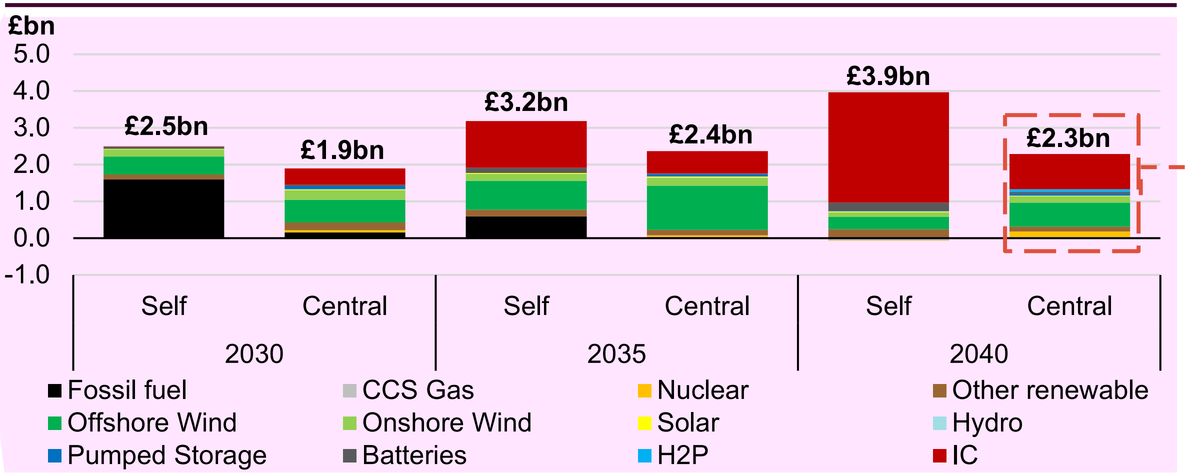
The consumer benefits of central scheduling are a function of:

The scale of Tx constraints
As constraint volumes and costs vary across the years, so too does the **benefit** of central scheduling.

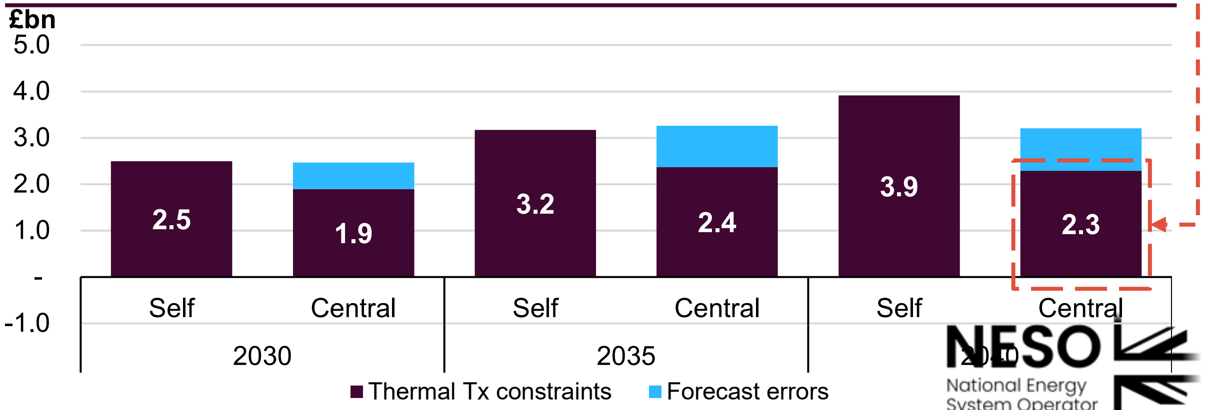
The scale of RES/load forecast error
Forecast errors increase proportionally with deployment of RES capacity and increasing demand. Forecast errors **increase costs** under central.

- The pattern of forecasted Tx constraints under the modelled scenario in GB leads to:
  - A **small positive benefit** of central scheduling in **2030**, when the difference between constraint costs under self (£2.5bn) and DA transfer payment under central (£1.9bn) nearly equates the cost for resolving forecast errors under central;
  - A small **disbenefit** of central scheduling in **2035**, given the assumed extensive Tx build in the updated modelling between 2030 and 2035. Tx build outpaces RES deployment in these years, meaning the benefit of cheaper resolving of Tx constraints under central scheduling (£3.2bn- £2.4bn = £0.8bn) is too small to make up for the increased cost of resolving forecast errors.
  - **Significant positive benefits** of **central scheduling** in **2040**, when thermal Tx constraint volumes are relatively high as the deployment of new RES capacity outpaces Tx build.
- Relative to the FES22 modelling, the **consumer benefit** of **cheaper resolving** of **Tx constraints** under **central scheduling** is **reduced** in the **updated scenario**. The **increased Tx congestion** observed in **2030**, driven by the **delays** to **HND/NOA7 Tx projects** flagged in **CP2030**, is **outweighed** by the **assumed extensive Tx deployment** in **2035** and **2040**.

Constraint costs under self-scheduling vs. DA transfer payments under central scheduling (£bn)



Aggregate consumer costs of resolving thermal Tx constraints and forecast errors under self- vs central scheduling1 (£bn)



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The cost to resolve forecast errors under central scheduling gradually increases over the modelling horizon, but not to the extent Tx constraint costs do

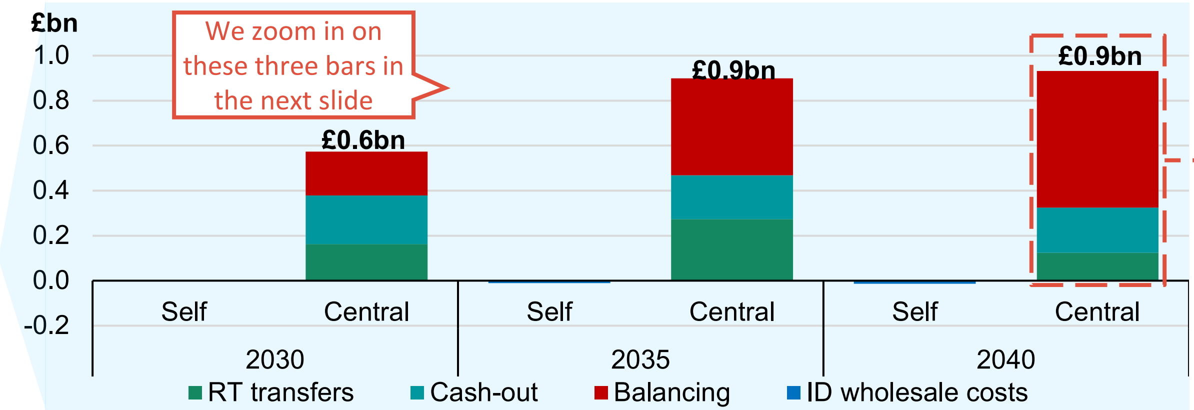
The consumer benefits of central scheduling are a function of:

The scale of Tx constraints
As constraint volumes and costs vary across the years, so too does the **benefit** of central scheduling.

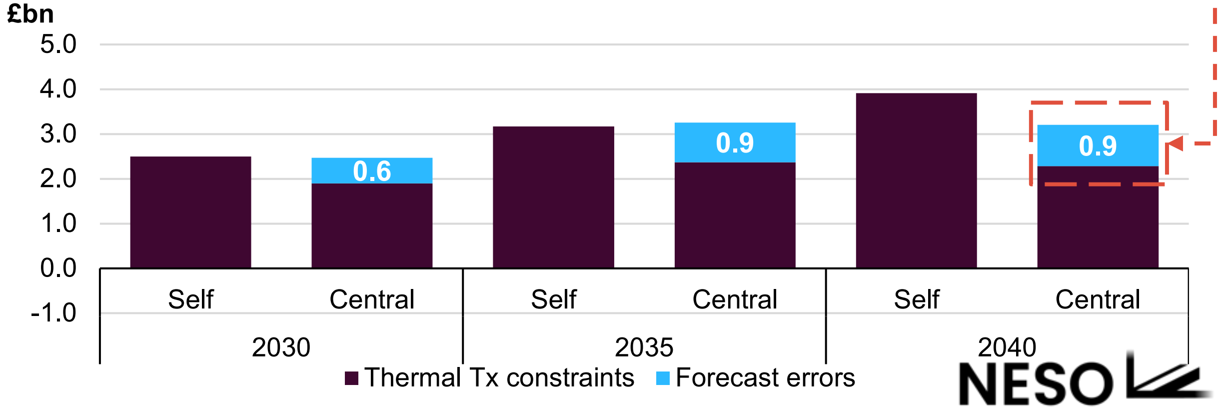
The scale of RES/load forecast error
Forecast errors increase proportionally with deployment of RES capacity and increasing demand. Forecast errors **increase costs** under central.

- Under **self-scheduling**, **forecast errors** are assumed to be **fully resolved** through **ID trading** before GCT at a **lower cost** than under **central scheduling**. Overall, the effect on ID WS consumer costs from demand imbalance is **minimal** in all modelled years, at -£0.3m in 2030 and -£14.2m in 2040.[1]
- Under **central scheduling**, we assume **no ID trading**, with all forecast errors centrally resolved via **cash-out payments**, **RT transfers** and **balancing actions**:
  - In the updated modelling, **balancing costs** remain the **key** post-GCT consumer cost under central scheduling. **Constraining-off** and **on** of marginal generators is required when RES/load **forecast errors** leave parts of the system **long** or **short**. Across each year, the same generators are regularly used for balancing in both directions, with a **net cost to consumers** (constraining-on actions generally cost more than constraining-off actions save). Increased **Tx capacity** has **slightly lowered net balancing costs** in the **updated assessment**.
  - The net cost to consumers of **cash-outs** and **RT transfers** is relatively **smaller than balancing costs**, with over- and under-forecasts of RES and load **largely offsetting** each other across each year. However, net cash-outs and RT transfers have both **slightly increased** in the updated assessment, due to **higher magnitude** of **RES forecast errors**, and an **increase** in the **spread** between the **average price paid** and **received** by NESO for these payments.

Cost of resolving forecast errors, self- and central scheduling (£bn)



Aggregate consumer costs of resolving thermal Tx constraints and forecast errors under self- vs central scheduling (£bn)

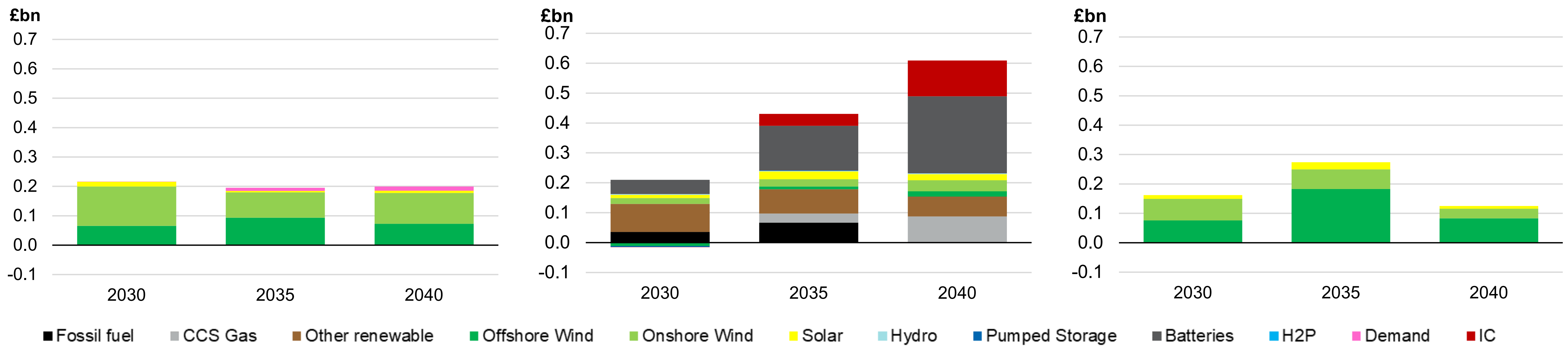


Notes: (1) Net ID saving is a consequence of minor over-forecasting of GB load at DA. See Appendix 1 of core report for more detail on ID WS costs.

Balancing costs account for the largest portion of post-GCT costs that arise from DA forecast errors under central scheduling

These three diagrams zoom in on the components of total cost to resolve forecast errors under central scheduling shown in previous slide

Central scheduling cash-out payments (£bn) | **Central scheduling balancing costs (£bn)** | **Central scheduling RT transfer payments (£bn)**



- If a change in generator output or load is caused by a unit's own forecast error, it receives or pays a cash-out payment.
- Net cash-out payments are positive; despite cash-out payments being required to and from NESO in relatively equal amounts (for over and under-forecasts), cash-outs from NESO (for under forecasting RES) are on average more expensive and therefore dominate over cash-outs to NESO (from over-forecasting RES).
- The magnitude of cash-outs is similar in the core and updated assessments, as although RES capacity has increased, lower GB demand means that forecast errors do not necessarily result in a change in a unit's dispatched output.

- Some NESO BM actions are still required under central scheduling to resolve energy imbalances (and Tx constraints created by energy imbalances). Although much lower than under self-scheduling, balancing costs are still material.
- Additional output is largely provided by batteries, ICs, and Carbon capture and storage ("CCS") gas. As seen in the core workstream, the net cost of constraining on these resources when forecast errors leave the system short outweighs payments to NESO from the constraining off of resources when the system is long.
- Post-GCT BM costs are slightly lower than in the core report, with reduced final demand and increased intra-GB Tx capacity.

- If a forecast error does not lead to a change in a unit's dispatched output, it instead receives/pays a transfer payment for the associated mis-forecast.
- In sum, RT transfers are slightly positive, compensating the additional output available from under-forecasting wind that is eventually not scheduled in RT.
- RT transfers are higher than in the core workstream, driven by a higher magnitude of forecast errors which require higher payments in RT. As these generators are not necessarily scheduled due to DA curtailment, this manifests in higher RT transfers (rather than higher cash-out payments).

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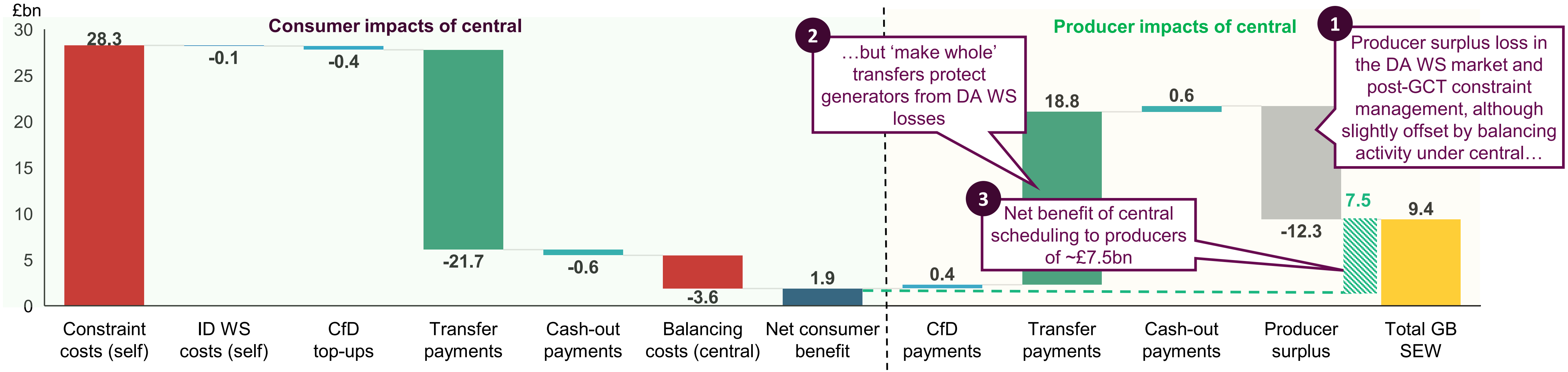
In our updated assessment, moving from self to central scheduling under national pricing leads to a GB SEW gain of £9.4bn

- In the previous slides, we examined the impacts on consumers from a move to central scheduling under national wholesale pricing in our updated assessment (£1.9bn). Below we show the impact of central scheduling on producers (£7.5bn) and total GB socioeconomic welfare ("SEW") (£9.4bn).
- Gross producer surplus[1,2] in the WS market and BM falls by £12.3bn under central (grey bar). The loss of producer surplus in the WS market is due to: (i) assets not scheduled under central scheduling that would have been in self-scheduling; and (ii) assets scheduled under central scheduling at a price below their SRMC. However, in both cases, the assets are compensated via transfer payments (£18.8bn).[3,4] Producer surplus is lost in the BM with fewer balancing actions required (typically loss of fossil fuel uplift). Cash-outs and CfD top-ups are equal and opposite on the consumer and producer side of the assessment.
- A net producer benefit of ~£7.5bn results, mostly driven by the aggregated transfer payments exceeding the gross producer surplus loss in the WS market and BM. This can be explained by assets being compensated when worse off at DA under central relative to self-scheduling, but not assumed to 'transfer back' rents for hours where they are better off under central scheduling (which is the policy choice modelled here, other policy choices are possible).[4]

Central scheduling total GB socioeconomic welfare benefits, national design £bn (2030-2040, PV 2030)



Notes: (1) £5.0bn of this loss is in the WS market and £7.3bn in the BM; (2) BM revenues to ICs are not assumed to contribute to producer surplus, as these are assumed to cover costs paid to generators in the connecting country to switch on in their respective BM to allow the reversing of ICs (i.e. there is no margin captured by the IC itself for the BM reversal); (3) Consistent with the treatment of IC revenues in previous GB SEW welfare assessments, half of the transfers paid to ICs are assumed to accrue to the 'connected country' half of the cable, hence transfer payments differ between producers and consumers; and (4) Transfer payments are mostly direct transfers from consumers to producers, except for ICs where a portion of the benefits is assumed to accrue to the connected country.

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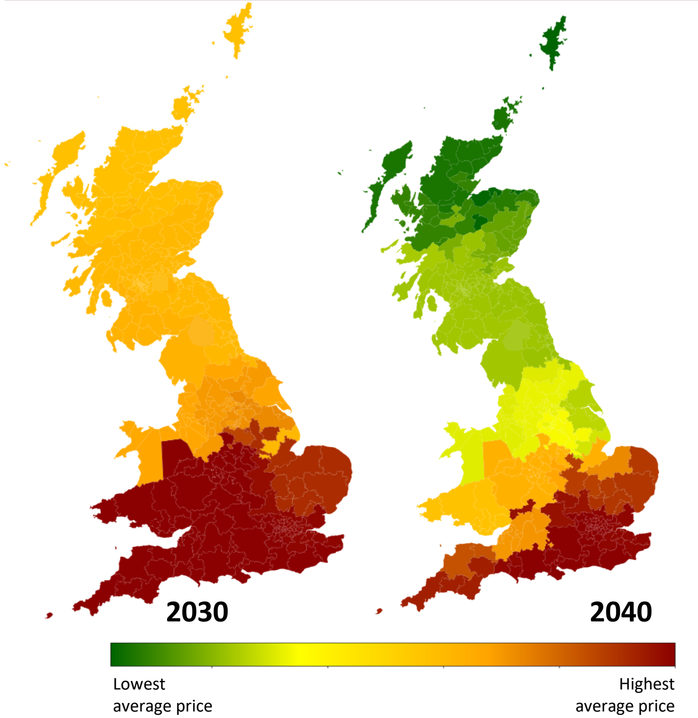
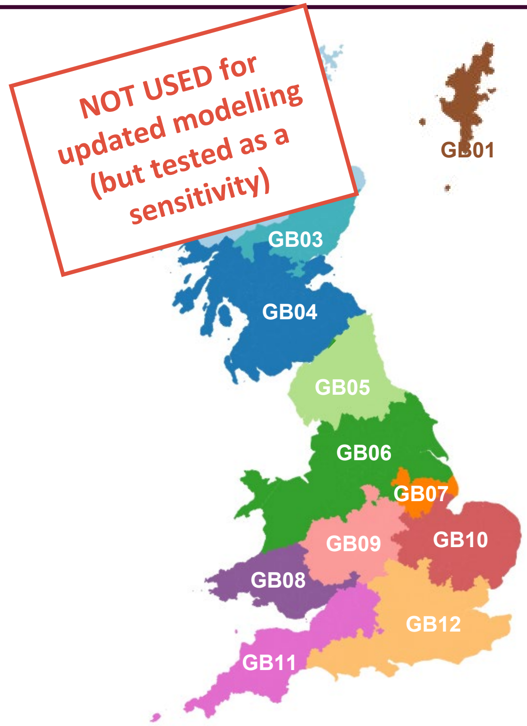
Consumer impacts of zonal pricing with self-scheduling (DESNZ zones)

Our zonal modelling is consistent with the DESNZ zones tested in REMA; these are not optimised for generator/Tx build in NESO's latest forecasts

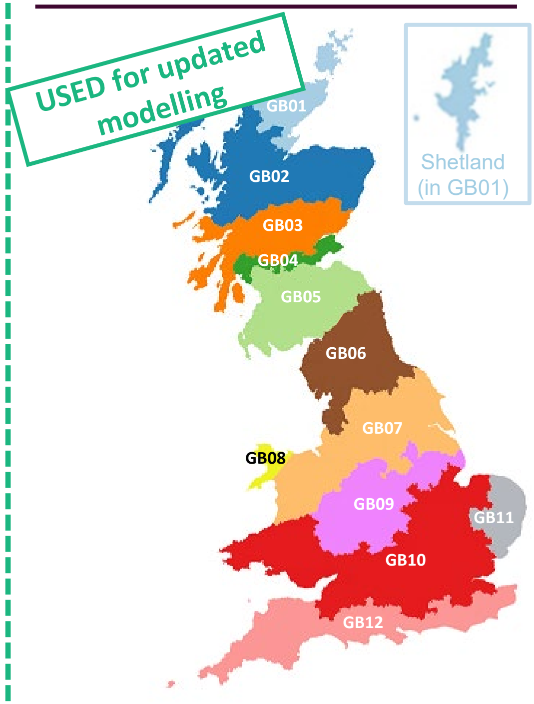
Nodal price heat maps in 2030 and 2040 in the updated model (FES24)[1]



'Optimised 12 zones' based on the most constrained boundaries in the FES24 nodal model



DESNZ REMA zones[2]

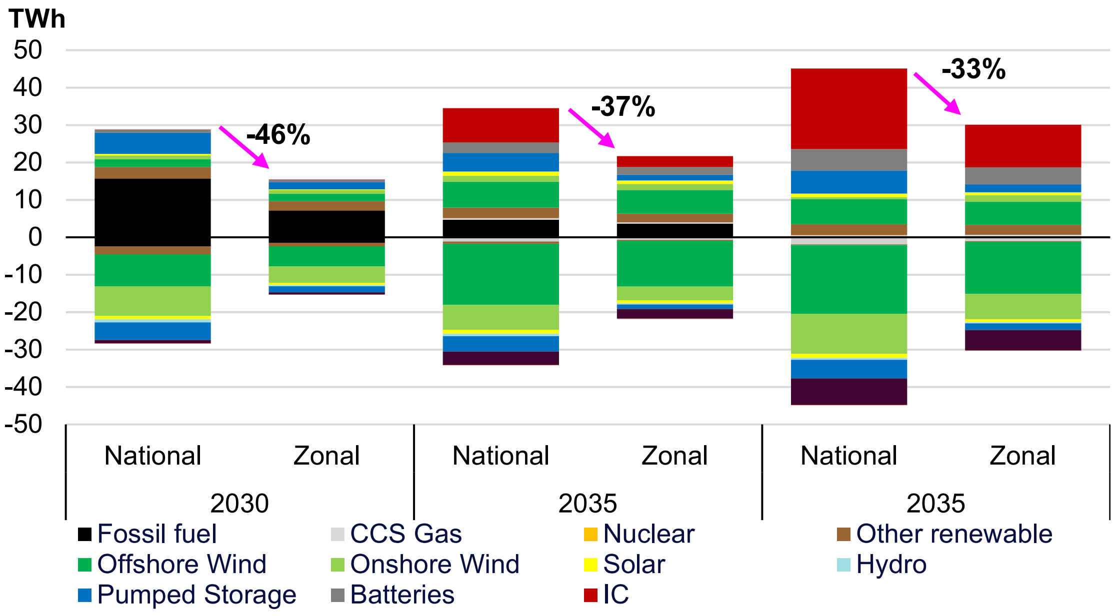


- Comparing modelled nodal WS prices can inform the choice of 'Optimised 12 zones'; where average nodal prices diverge across the year, persistent Tx constraints are likely to be present.
- FTI's 1,200+ node model aligns generator siting and Tx build at a detailed nodal level to NESO's latest forecasts in FES24, CP2030 and Beyond 2030…
- …and finds that the key constraint boundaries present in a system consistent with NESO's forecasts significantly differ from those currently used in the REMA analysis – fewer zones are required in Scotland (although Shetland should be a separate price zone) and an additional zone should separate South Wales from the Southeast.[3]

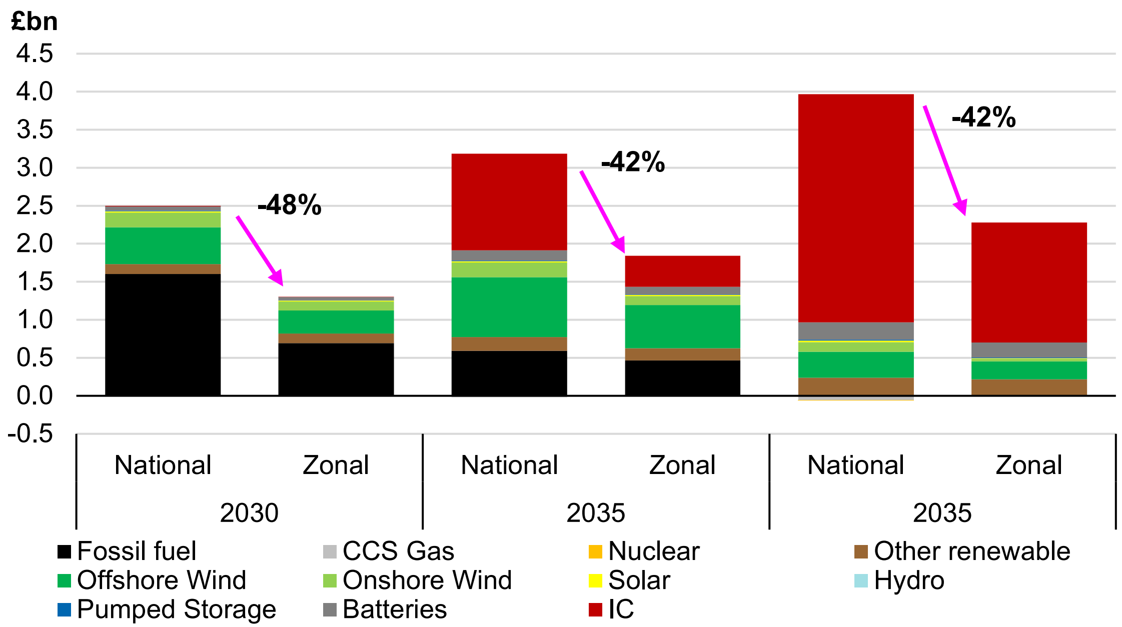
Notes: (1) From: FTI Consulting (2025). Impact of a Potential Zonal Market Design in Great Britain. Report for Octopus Energy (link). The nodal price maps use a dynamic scale, which ranges between the lowest and the highest observed annual average time-weighted price in each year to clearly illustrate the price difference in that year. (2) Shetland is included as part of GB01 under DESNZ's zones. (3) The above comparison of zones should not be interpreted as suggesting that the "optimised" zones are in any way "better" than DESNZ's REMA zones. Rather, we observe that matching the modelled zonal boundaries to the congestion observed in our model leads to reduced congestion, due to better zonal alignment.

Zonal WS pricing reduces Tx constraint costs by 42-48%, but DESNZ zonal boundaries leave material residual intra-zonal constraints

Total constraint volumes, National versus Zonal (updated scenarios) (TWh)



Total constraint costs, National versus Zonal (updated scenarios) (£bn)[1]



- Total constraint volumes under zonal (with DESNZ zones) are lower than under a national market, by between 33-46% per year. This is in line with the change in constraint volumes from national and zonal pricing under self-scheduling in our core assessment (23-43% decrease under zonal compared to national).
- The relative decrease is greatest in 2030, when better scheduling of assets under zonal leads to a significant decrease in the amount of fossil fuels that must be constrained on, and renewable generation that must be constrained off.
- In later years, constraining on of ICs is notably lower under zonal pricing as there is a significant decrease in scheduled exports in ICs connected to Southern zones which are (under national design) reversed in the BM.

- Total constraint costs under zonal are lower than under national, by between 42-48% per year. This is a more significant decrease compared to the decrease under zonal pricing relative to national pricing (both self-scheduling) in our core assessment (21-44% decrease under zonal compared to national). The smaller decrease in our core assessment was mostly caused by very low 2030 Tx constraint costs under national using HND/NOA7 Tx assumptions.
- The relative decrease is greatest in 2030, when better scheduling of assets under zonal leads to a significant decrease in the amount of fossil fuels constrained on.
- In later years, constraining on of ICs is notably lower under zonal pricing but imperfect zonal boundaries still leave sizeable constraints that must be resolved in the zonal BM.

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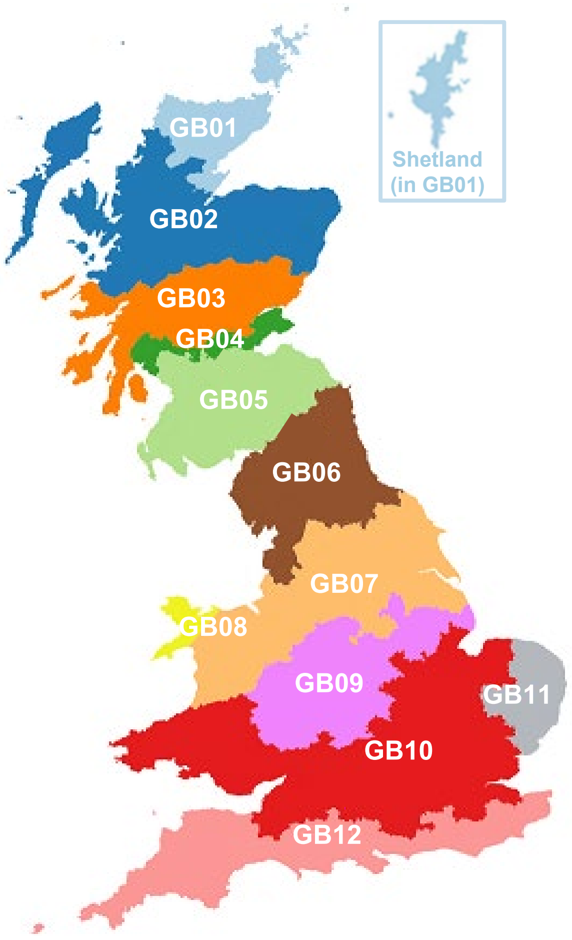
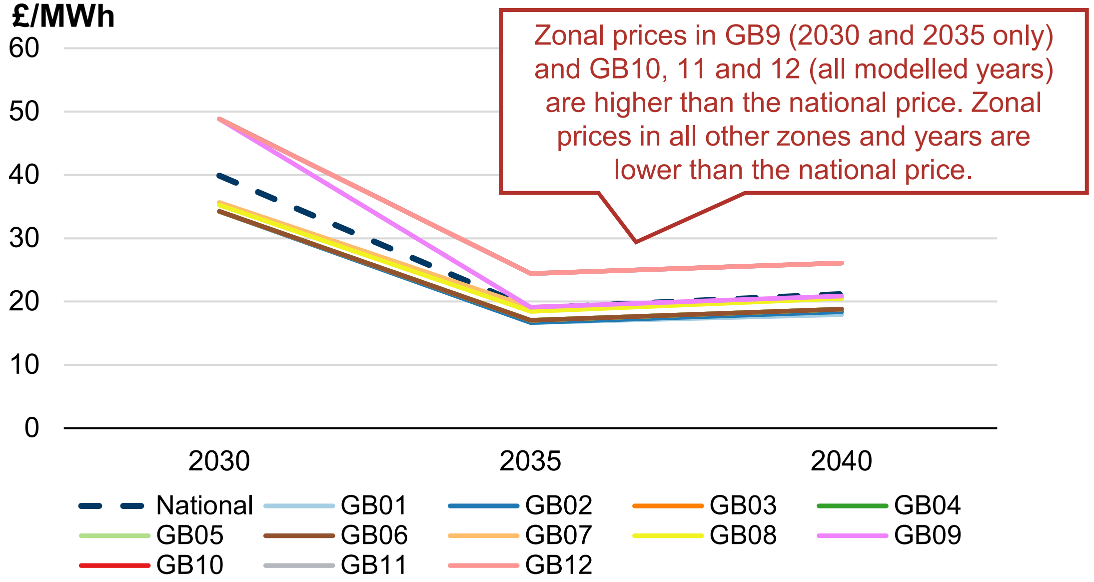
Notes: (1) Using zones that better align with the most constrained Tx boundaries in our modelling would lead to a greater constraint cost reduction, as shown on Slide 28 and in recently published FTI modelling for Octopus Energy (FTI Consulting (2025). Impact of a Potential Zonal Market Design in Great Britain. Report for Octopus Energy (link).

In the majority of zones, annual average wholesale prices are lower under a zonal WS market design than they are under national, but prices increase in zones with high demand



GB annual DA WS prices, National versus Zonal (updated scenarios) (£/MWh)



- As expected, across all years, modelled zonal DA WS prices in the majority of zones (GB01-GB08) are lower than the DA WS price under a national market. In GB09 the zonal DA WS price is also lower than the national price in 2040.
- Prices in the Southern zones (GB10-12) are higher than the national price in all modelled years, as is the zonal price in GB09 in 2030. This is due to less RES capacity outbuild and larger demand in those zones relative to the Northern zones.
- The increase in zonal prices in zones GB09-12 relative to the national price is greatest in 2030. Expensive fossil fuel units are regularly required to meet demand in these southern zones in 2030 and regularly set the zonal wholesale price. Under national pricing, these units are generally instead constrained on at higher cost in the BM post-GCT.
- Although most zones see a decrease in DA WS price under a zonal WS market, the average price paid per MWh in GB is slightly higher under zonal pricing, as zones with the highest DA WS prices are also those with the highest demand. This leads to higher DA WS costs under zonal WS pricing, although this is offset by other consumer savings achieved under a zonal WS market design (see next slide).

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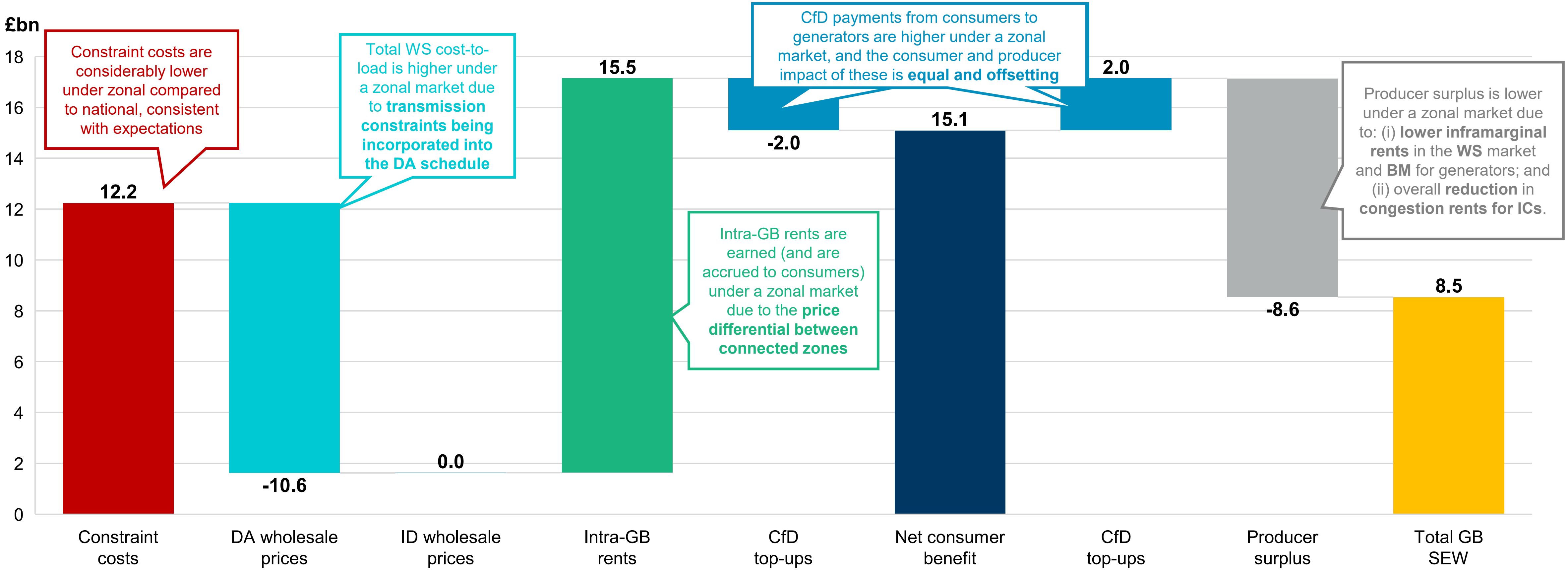
With the DESNZ REMA zones, there are £15bn of consumer benefits from a zonal market design under self-scheduling (PV 2030-40)

Net GB welfare impact of zonal pricing with self-scheduling, DESNZ zonal boundaries, (£bn, PV 2030-40)[1]

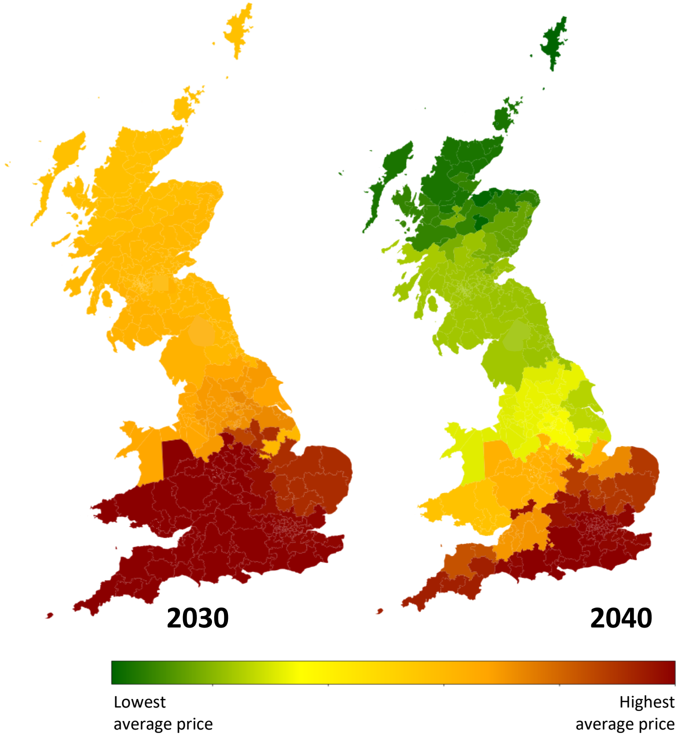


- Under self-scheduling, a zonal market design results in **£15.1bn of consumer benefits** relative to a national market design, under NESO's latest generation and Tx forecasts. **Net socio-economic welfare impact is £8.5bn**.
- However, the modelled boundaries between GB price zones are not optimally aligned with the most constrained Tx lines in the FES24 model. The next section tests the consumer and SEW impacts of self-scheduling with zonal pricing under an 'optimised' set of GB zones.

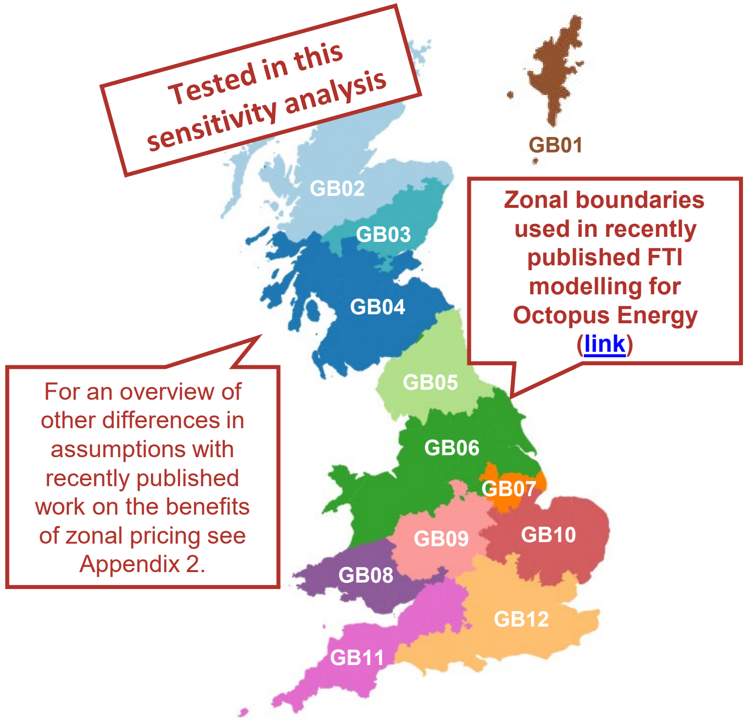
Consumer impacts of zonal pricing with self-scheduling ('Optimised' zones)

Our zonal modelling is consistent with the DESNZ zones tested in REMA; these are not optimised for generator/Tx build in NESO's latest forecasts

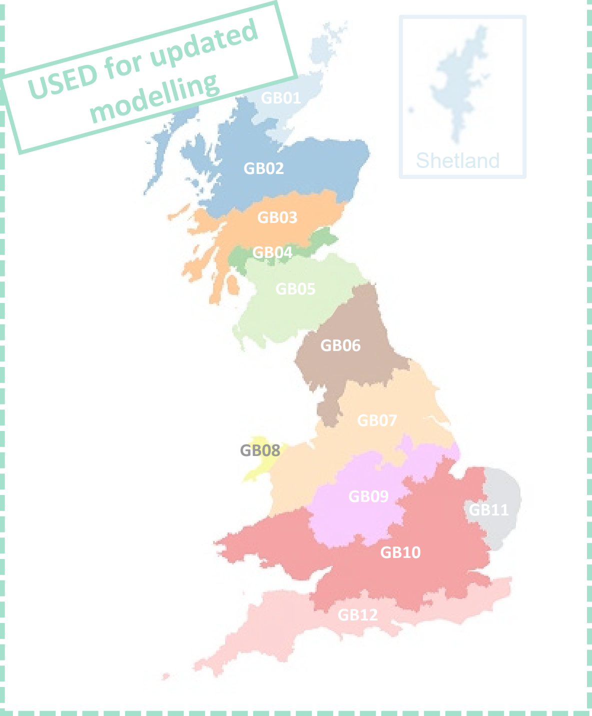
Nodal price heat maps in 2030 and 2040 in the updated model (FES 24)[1]



'Optimised 12 zones' based on the most constrained Tx boundaries in the FES24 nodal model



DESNZ REMA zones[2]



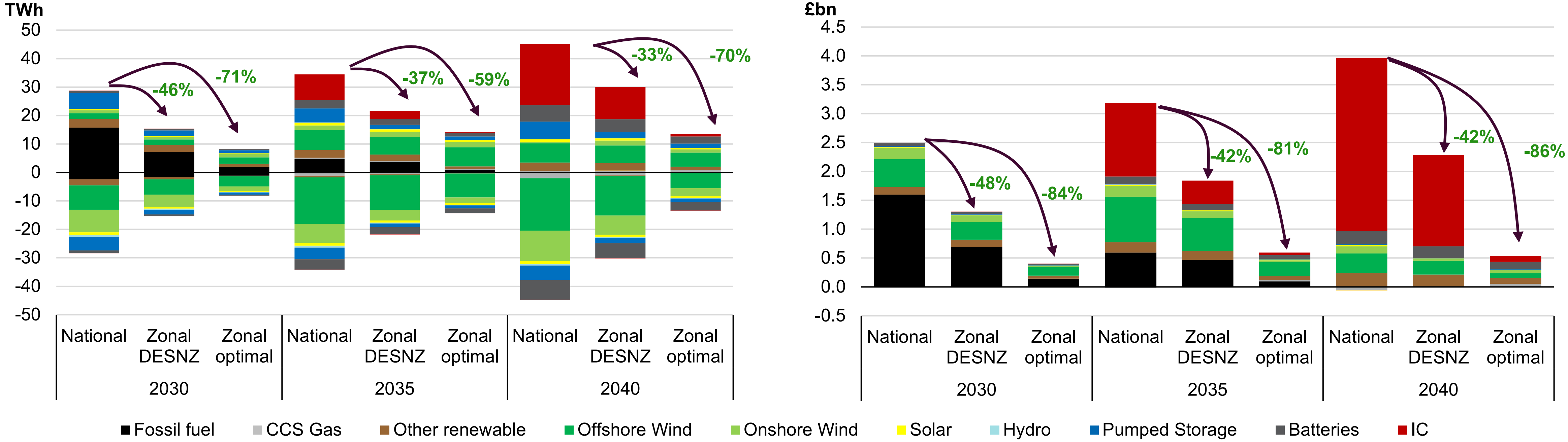
- We have tested the impact of repeating our zonal assessment but instead using an 'optimised' 12 zone model. These zones were created by establishing the key Tx constraint boundaries in FTI's 1,200+ node model (which aligns generator siting and Tx build at a detailed nodal level to NESO's latest forecasts in FES24, CP2030 and Beyond 2030).
- Key changes to the zonal configuration include separating Shetland from the rest of Northern Scotland, and placing London in a separate zone to Southern Wales and Somerset.
- As shown in the following slides, updating this zonal configuration greatly increases the observed benefits of a self-scheduled zonal relative to a self-scheduled national market.

Notes: (1) From: FTI Consulting (2025). Impact of a Potential Zonal Market Design in Great Britain. Report for Octopus Energy (link). The nodal price maps use a dynamic scale, which ranges between the lowest and the highest observed annual average time-weighted price in each year to clearly illustrate the price difference in that year. (2) Shetland is included as part of GB01 under DESNZ's zones.

Closer alignment of zonal boundaries to modelled congestion can further significantly reduce constraint volumes and costs under zonal

Total constraint volumes, National v Zonal (DESNZ zones) v Zonal (FTI zones) (updated scenarios) (TWh)

Total constraint costs, National v Zonal (DESNZ zones) v Zonal (FTI zones) (updated scenarios) (£bn)



- Calibrating the zonal boundaries to align with the most-constrained Tx boundaries in the model (and therefore aligned with the constraints created by the nodal-level generator siting in the FES24 model) significantly reduces the modelled volume of balancing actions. This is a function of aligning the modelling tool (and how the model "sees" congestion) with the delineation of the boundaries. While the zones FTI uses in this sensitivity perform "well" in FTI's own model, the same zones are likely to perform worse in DESNZ's own model, as the DESNZ model likely "sees" congestion differently.
- When using these updated zonal boundaries, zonal constraint volumes are **59-71%** lower than national constraint volumes, compared to **33-46%** when using the DESNZ zones.
- A similar trend is shown for constraint costs; when using the updated zones, zonal constraint costs are **81-86%** lower than national costs, compared to **42-48%** when using the DESNZ zones.
- These results indicate that using zonal boundaries that do not align with the constraints in the model leads to inflated estimates of constraints costs, i.e. the quantum of consumer and GB-wide-socio economic benefits of zonal is highly influenced by the choice of zones.

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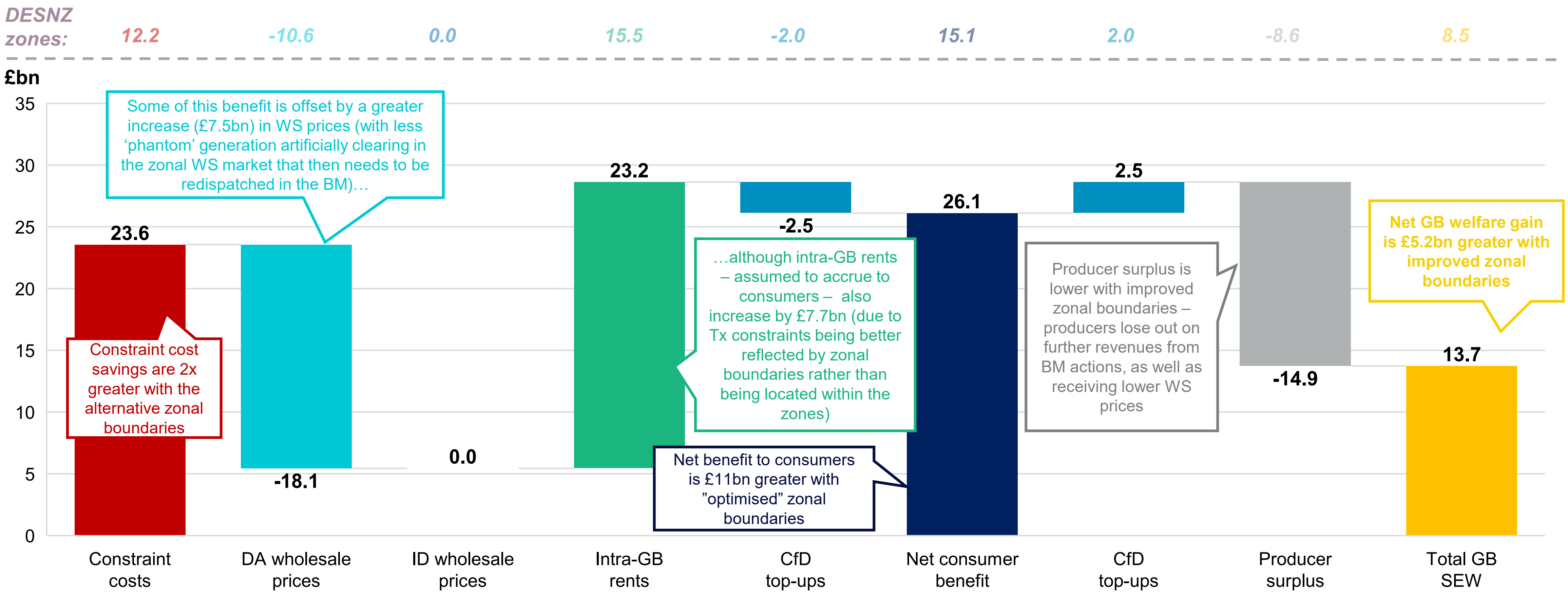
Relative to DESNZ zones, "optimised" zones increase consumer benefits with £11bn and GB SEW gains with £5bn (PV 2030-40)

Net GB welfare impact of zonal pricing with self-scheduling, FES24 "optimised" zonal boundaries, (£bn, PV 2030-40)



- Under self-scheduling, a zonal market design results in **£26.1bn of consumer benefits** relative to a national market design, under NESO's latest generation and Tx forecasts.
- Constraint cost savings are twice as large with the 'optimised' zonal boundaries, increasing the **net socio-economic welfare gain to £13.7bn**.

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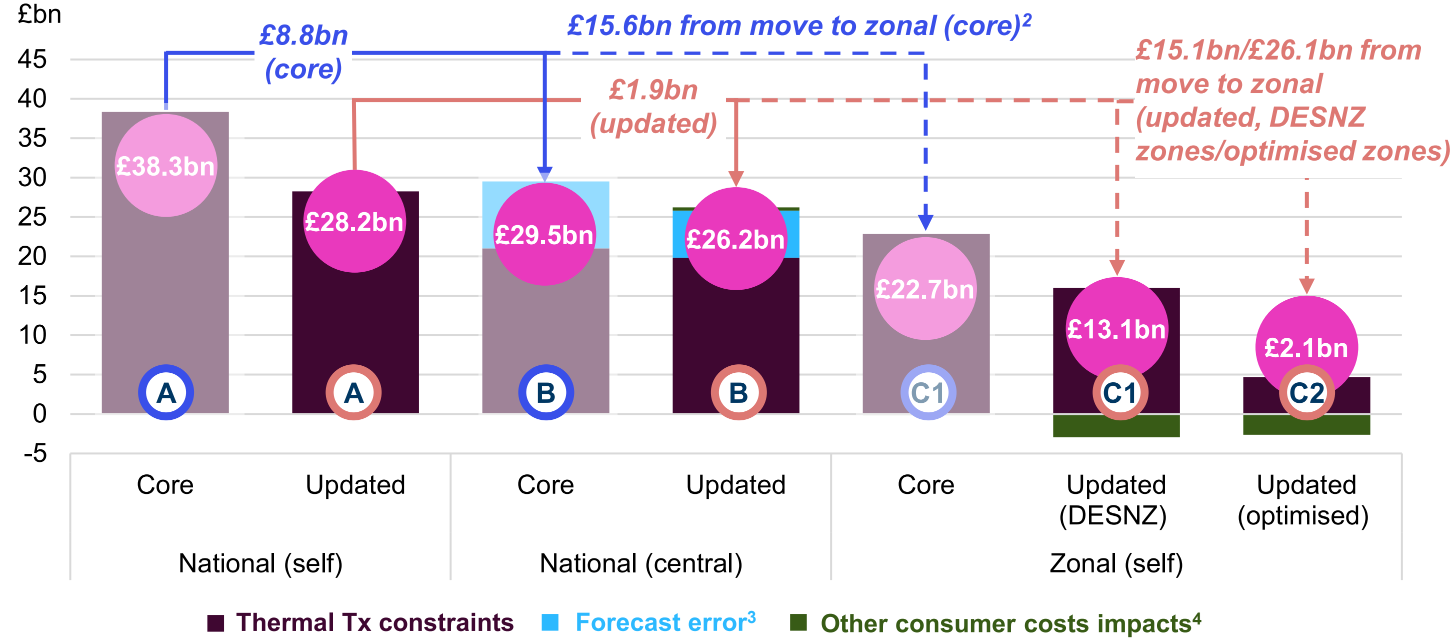
Appendix 1: Comparison of results from FES22 and FES24 scenarios

In our updated assessment, moving to a zonal WS design reduces GB consumer costs by £15.5bn, compared to £15.6bn in our core assessment

GB consumer costs incurred under self-scheduling, core and updated scenarios, £bn, PV 2030-2040[1]



Core	A → B	£8.8bn	A → C1	£15.6bn		
Updated	A → B	£1.9bn	A → C1	£15.1bn	A → C2	£26.1bn

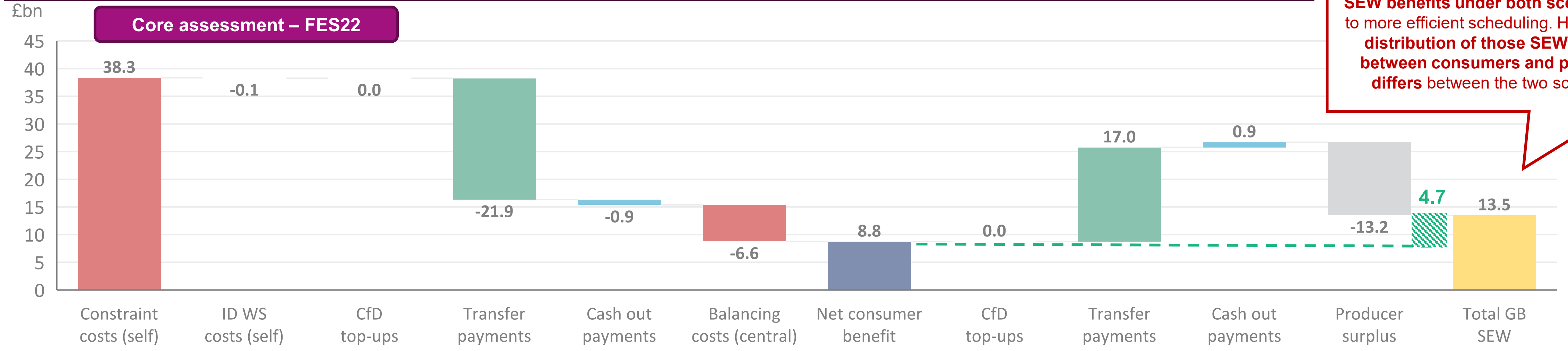
Key findings

1. In our core assessment, a move from self- to central scheduling lowered aggregate consumer costs by £8.8bn. In our updated assessment, this saving is reduced to £1.9bn.
2. The key drivers of the fall in consumer savings are: (i) reduced costs to resolve thermal Tx constraints under self-scheduling; and (ii) a small increase in the cost of DA transfer payments to assets not centrally scheduled.
3. The benefits to GB consumers of moving to a zonal WS design (as a potential alternative to central scheduling) were evaluated as **£15.6bn** in our core assessment, for the modelled period of 2030-2040. These benefits consisted of a **£15.5bn** reduction in costs of resolving thermal Tx constraints errors, and **£0.1bn** of other consumer savings (resulting from net change in WS costs, CfD payments and intra-GB congestion rents earned under a zonal market).
4. In our updated assessment, the benefits of moving to a zonal WS design are **slightly decreased to £15.1bn using DESNZ zones,** and **increased to £26.1bn using zones which align better with modelled congestion**.
5. The change in constraint costs in the updated scenario under both market designs reflects the impact of new Tx assumptions (Beyond 2030, compared to HND/NOA7 Refresh in the core scenario). These assumptions also impact the intra-GB rents earned under zonal.

Notes: (1) An updated GBP/EUR exchange rate and a move from 2022 prices to 2024 prices cause the core assessment figures presented here to differ slightly to those presented in the core report. (2) We do not assume any change in cost of capital or implementation costs under zonal pricing, nor other benefits of zonal pricing such as potential re-siting of new assets or reduction in Tx investment. (3) Forecast errors represent the cost of adjusting to evolving forecasts of RES (solar and wind) and demand between DA and GCT under each market design. (4) Other consumer cost impacts include the changes in WS costs, CfD payments, and intra-GB congestion rents. Under national pricing, only CfD payments can change between scheduling designs. The other consumer cost impacts of zonal pricing can be positive or negative on aggregate. These impacts are a more significant saving compared to in our core scenario. Lower average wholesale prices in the FES24 model under both national and zonal pricing lead to a smaller increase in CfD top-up costs under zonal pricing in the updated assessment relative to the core assessment. CfD impacts therefore net off less of the benefits of intra-GB rents earned under zonal in the updated scenario.

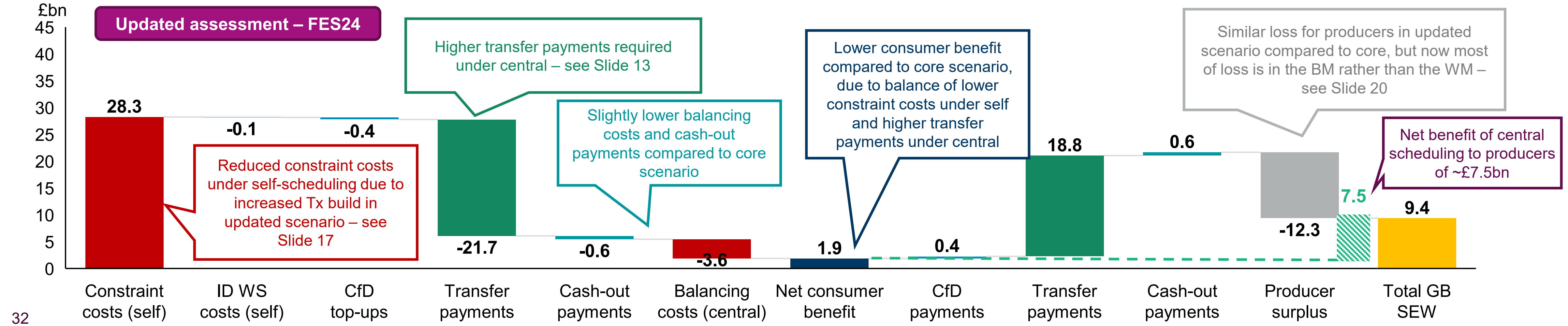
In our updated assessment, moving from self to central scheduling under national pricing increases GB SEW by £9.4bn, compared to £13.5bn in our core assessment

Central scheduling total GB socioeconomic welfare benefits, national design, FES22 scenario £bn (2030-2040, PV 2030)[1]



Central scheduling results in **significant SEW benefits under both scenarios** due to more efficient scheduling. However, the **distribution of those SEW benefits between consumers and producers differs** between the two scenarios.

Central scheduling total GB socioeconomic welfare benefits, national design, FES24 scenario £bn (2030-2040, PV 2030)[1]



Notes: (1) For comparability, core results have been updated to reflect the new exchange rate and price base used in our updated scenario, so may differ slightly to those presented in our core report.

Appendix 2: Comparison of key assumptions with recently published FTI modelling

Public

Differences in key assumptions reduce the modelled benefits of zonal relative to recently published FTI analysis

The majority of our assumptions in this report are even more conservative than those in FTI's published work for Octopus (shown as red arrows below), indicating that modelled consumer benefits in this report would be lower than those in the FTI report for Octopus

Assumption	FTI modelling for NESO (FES24 update)	Recently published FTI modelling for Octopus Energy (link)	Impact of NESO assumption on modelled benefits of zonal vs national relative to Octopus Energy study
Generation & demand outlook	**CP2030** Further Flex & RES (2030 GB), **FES 2024** Holistic Transition (2035 – 2040, GB), **TYNDP 2024** Distributed Energy (Europe)	**Identical**	0
Zonal boundaries	**DESNZ REMA zones**	**'Optimised 12 zones'** derived from the observed most-constrained Tx boundaries in FTI's nodal model, based on FES24 HT, CP2030 FF&R and Beyond 2030	↓↓
ICs	Assumed **operational ICs** aligned with DESNZ REMA IC assumptions	Similar assumptions to the NESO assessment, but slightly more GB-Europe interconnection capacity	↓
Commodity prices	**DESNZ and FES 2024 forecasts**	**CP2030 and FES 2024 forecasts**	≈
Transmission network	**CP2030 (2030) and Beyond 2030 (2035-2040)**	**Identical**	0
Horizon	**2030, 2035, 2040**	**2030, 2035, 2040, 2045, 2050**	↓ Due to shorter modelled period
Climate year	**CY2013 (Requested by NESO to align with FES)**	**CY2009 (Typically viewed as 'most representative' year by European regulators)**	≈
BM techs	**Run-of-river ("RoR") hydro** and **waste** allowed to participate in the BM	**RoR hydro** and **waste** unable to participate in the BM	↓
BM pricing	Penalty price for ICs set using an **annual average** of monthly **NESO forecasts** that consider the **cost of the marginal plant** in each **connected country** (£147/MW in 2030, £157/MW in 2035-2040)	Penalty price for ICs assumed equal to cost of a gas CCGT for all connected countries (£83/MW)	↑