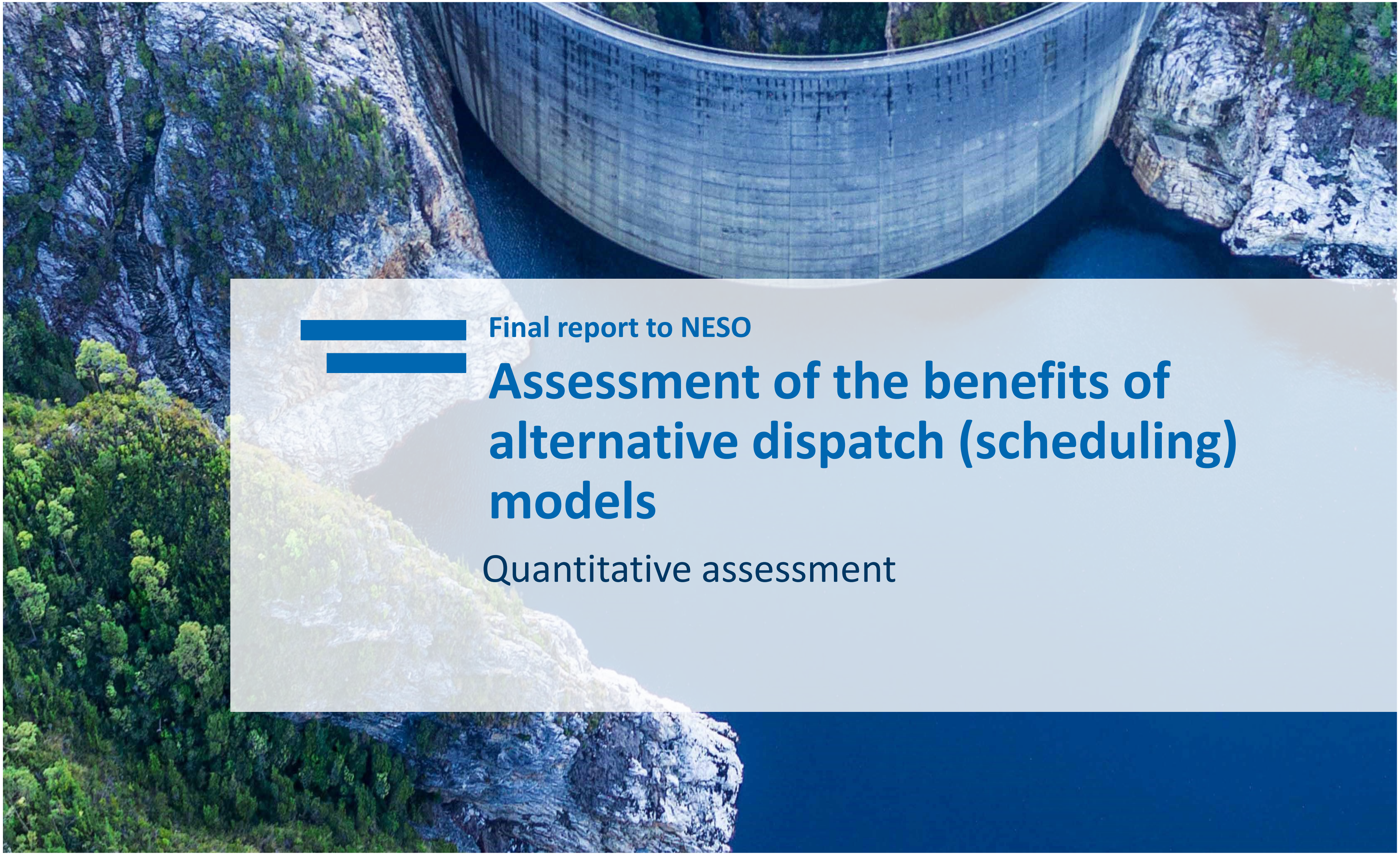

Final report to NESO

Assessment of the benefits of alternative dispatch (scheduling) models

Quantitative assessment

FTI CONSULTING

NESO

March 2025

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Section 1: Background and context

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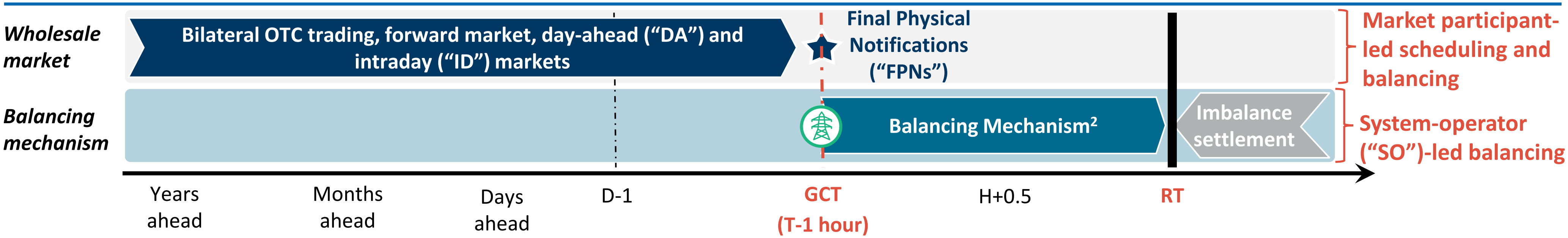
The current self-scheduled GB electricity market was designed to incentivise market participants to balance the system, with only residual NESO balancing

- GB's current electricity market design is based on the New Electricity Trading Arrangements ("NETA") design, implemented in 2001 when the system was dominated by a relatively small number of large fossil fuel generators. Its key features are:
  - It is a self-scheduling market, based on bilateral trading between generators and purchasers of energy (either over-the-counter ("OTC") or via power exchanges).
  - This trading assumes that electricity injected at any point in the network can be consumed anywhere in GB. Therefore, the wholesale ("WS") market, by design, does not take into account the physical limitations of the transmission ("Tx") network. The GB market assumes an unrestricted 'copper plate' network with a single national wholesale electricity price.
  - The original design was intended to facilitate competition among market participants (noting that at the time of the design being introduced, the system was dominated by a relatively small number of large fossil fuel generators) and to lead to price discovery.
  - Market participants are incentivised on a portfolio basis to produce or consume in line with the aggregate volumes they have sold or bought in the wholesale market, with imbalance charges ("cash-outs") penalising parties for deviations between their contracted volumes at market closure and their actual metered positions in real-time ("RT") measured over an imbalance settlement period ("ISP") of 30 minutes.
- Given the incentives that are in place for market parties, the National Energy System Operator ("NESO") was intended to fulfil the role of a **"residual balancer"**, only acting to ensure that Tx constraints and operating limits are respected via the Balancing Mechanism ("BM")[1] post-gate closure time ("GCT")[2] (originally designed as four hours before delivery, but now occurring one hour before delivery), in line with agreed Security and Quality of Supply Standards ("SQSS"). At the time of designing the current GB market, it was expected that this role would be relatively limited (which initially it was, as generation from renewable energy sources ("RES") was limited and its remit only covered England & Wales).

Simplified schematic of the GB electricity market design

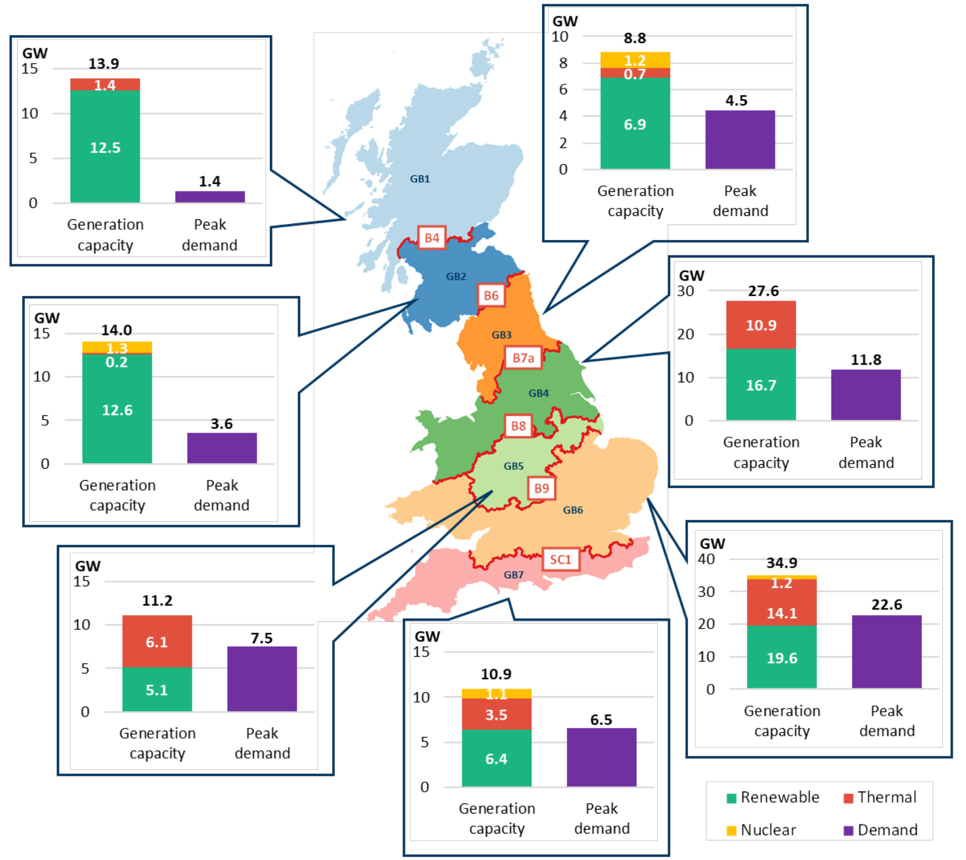


Notes: (1) The BM operates on a "pay-as-bid" principle, where market participants submit bids/offers to NESO reflecting the prices they are willing to accept to modify their electricity production/consumption. NESO then selects bids and offers in a merit order to ensure the system is balanced in RT while maintaining the stability and security of the system; (2) For simplicity, we have omitted discussion around the Capacity Market, ancillary services ("AS") and the interplay with other mechanisms such as Contract for Difference ("CfDs"). NESO is also able to undertake trading actions prior to GCT if it considers these actions to be lower cost than via the BM.

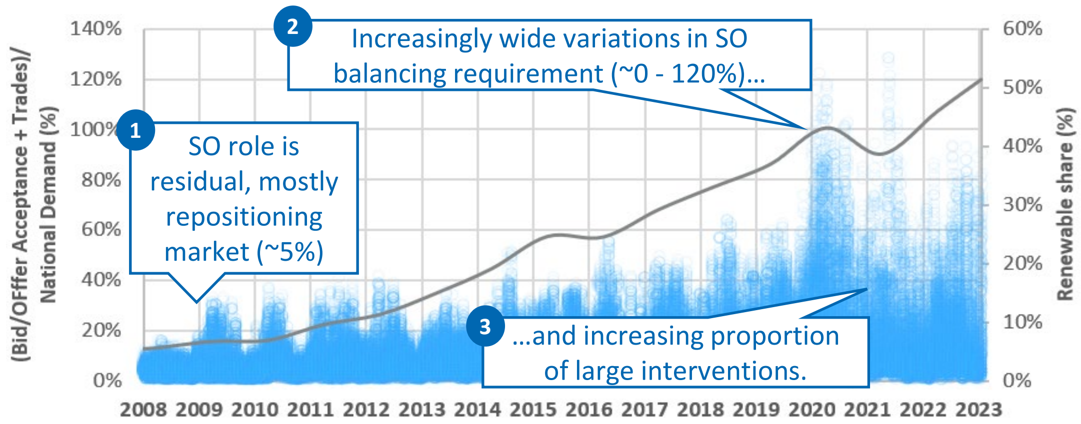
A rapid shift in how and where electricity is generated has significantly increased the volume of system balancing actions required from NESO

- Central to the NETA market design was the idea that the aggregate (self) schedule of planned generation, as created by the interaction of market participants, would ensure that the system was roughly balanced in each ISP period, with only residual system SO balancing required in RT.
- The NETA arrangements were **not designed** to accommodate the rapid change in both how and where electricity is produced and the resulting geographical mismatch between where electricity is generated and where it is consumed, especially given Scotland was not originally considered or part of the arrangements. This increasing mismatch is highlighted in the bottom-left chart.

Generation capacity and peak demand in GW per zone in 2025, FES 2022 Leading the Way ("LTW")[1]



Volume of balancing actions as proportion of national demand and renewable share of generation (2008-2023)[2]



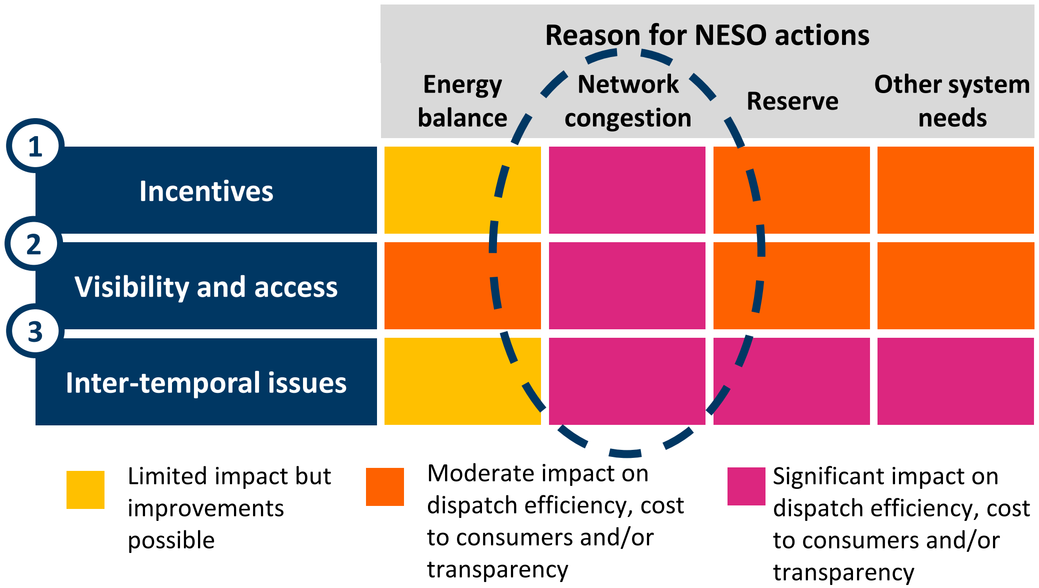
- The chart above illustrates that, contrary to the aims of NETA, over the last decade NESO has had to play an increasingly large role to ensure the system remains balanced in RT.
- NESO's balancing requirement has shifted in two key dimensions:
  - There is an increasingly wide variation in the volume of BM actions required, sometimes at ~0% and sometimes more than 100% of national demand.
  - An increasing proportion of interventions are very large, orders of magnitude higher than was required a decade ago.
- The role of NESO has therefore changed significantly: it can no longer be seen as a mere 'residual balancer' but rather as playing a key role in addressing the imbalances (often regional) in supply and demand on the GB system.

Source: (1) FTI analysis based on ESO's FES 2022 LtW. (2) Data provided by NESO.

In 2024 NESO commissioned a ‘case for change’ assessment, which confirmed that there is likely merit in altering the current market design

- In the context of the Review of Energy Market Arrangements (“REMA”) and the issue outlined in the previous slide, NESO commissioned a study to determine whether there might be a **case for change** to the current market arrangements.[1]
- This report highlighted three key limitations to the current market design:
  1. **Incentives:** incentives are not aligned with system needs and operational requirements;
  2. **Visibility and access:** lack of coherence between wholesale market and the BM due to limited NESO visibility and information access; and
  3. **Intertemporal issues:** Current dispatch mechanism is poor at optimising intertemporal constraints.

Key limitations with current market design identified in NESO case for change report[1]



- The report concluded that there is a case for change, and outlined two high-level approaches as potential routes for improvement:
  i. **Giving market participants improved incentives and information** to support system operation. The report suggests this could be achieved by, for example, shortening the ISP, zonal pricing, improving signals for AS procurement, increased BM participation, or increased information sharing.
  ii. **Formalising NESO’s role as “de facto central scheduler”** by giving it **greater control at an earlier stage**, allowing NESO to better coordinate unit commitment and operation of energy-limited units, as well as within-day positions.

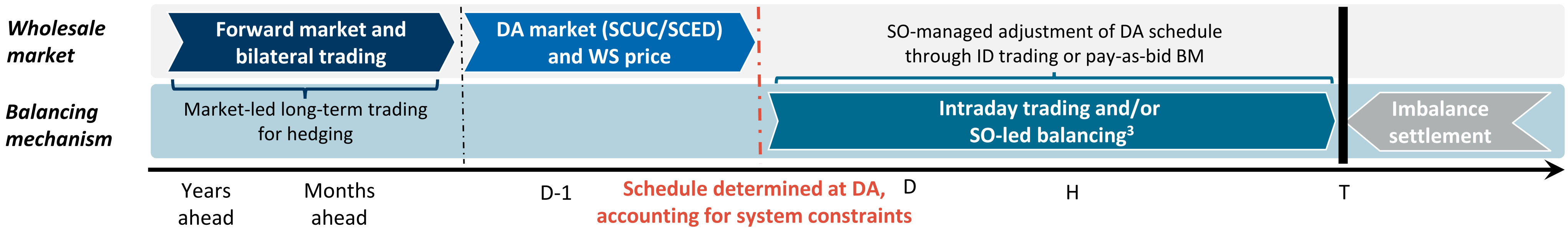
Source: (1) AFRY (2024) GB scheduling and dispatch – A case for change (link).

One identified solution is to formalise NESO's role as central scheduler and enable NESO to align the schedule with Tx limits at an earlier stage

Formalising NESO's role as central scheduler would allow NESO to coordinate the schedule in a manner consistent with system limitations at an earlier stage (i.e. optimise around Tx limitations) but potentially could reduce market participants' ability to adjust their schedules close to delivery. The key features of central scheduling typically include many of the following elements (though with variation across specific markets):

- Forward trading before the DA stage financially settled on the "unconstrained" DA market price (which can be national or zonal).
- Unit-based bidding, with market participants submitting separate ('multi-part') bids for each of their assets (e.g. separate start-up costs and running costs), reflecting the technical and economic parameters of those units individually.
- A DA schedule determined via a Security Constrained Unit Commitment and Economic Dispatch ("SCUC/SCED") model operated by the SO (incorporating Tx system constraints directly into scheduling decisions), i.e. DA schedule optimises around the 'system constraints that are known at DA', reducing the need for system balancing actions.[1]
- In forming the DA schedule, the SO can explicitly account for and price in network and intertemporal constraints, scheduling the units that meet these constraints at least-cost…
- …but a post-DA mechanism would be required to adjust/deviate the DA schedule in response to forecast errors and/or surfacing technical constraints. This could take the form of an ID auction or a centrally-managed SO-led mechanism.[2]
- As in the current GB system, a centralised BM would still be required, with the SO procuring and dispatching reserves and adjusting the central schedule to maintain grid stability.
- The "unconstrained" DA market price, paid by load to generation, is determined by clearing the WS market without considering any system constraints under national wholesale pricing or only thermal constraints between zones under zonal wholesale pricing.
- With WS and AS markets both centrally operated, the SO can co-optimise the procurement of energy and AS (or continue with sequential procurement).

Simplified schematic of a centrally scheduled electricity market



Notes: (1) In GB NESO activates energy balancing ("non-flagged") and system balancing ("flagged") actions in the BM. The latter resolve imbalances between supply and demand at GB-level (e.g. due to forecast errors) and the former resolve potential system constraints that are not reflected in the wholesale market (e.g. thermal constraints). In practice, both types of actions are performed to some extent jointly; (2) The need for compensation or "transfer" payments to certain generators under central scheduling is discussed in Section 3; (3) The approach to adjusting the central schedule post-DA varies across the jurisdictions that have implemented central scheduling. In the US, market participants can adapt their offer/bids for the RT market up to GCT (shortly before delivery) to reflect changing system conditions. In European markets, a series of ID auctions are typically held. We discuss these issues in further detail in Section 3.

In this context, NESO has commissioned FTI to quantitatively assess the potential benefits case for central scheduling

- A transition from the current self-scheduling design to a centrally scheduled one would be a fundamental change to the GB market design, with significant implications for all market participants.
- A key trade-off raised in the Case for Change consultation weighs the improved potential efficiency of a centrally-determined schedule that explicitly accounts for system constraints with the market-led resolving of supply and demand imbalances under the current self-scheduled design.
- In this context, NESO has commissioned FTI Consulting to assess quantitatively[1] the impact of introducing central scheduling under the current GB wholesale market design, whether similar benefits could be delivered by improvements to the BM, and how the case for central scheduling might change if GB moves to a zonal wholesale market design.
- Our work builds 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 AS would be performed under central scheduling.
- This report therefore complements previous FTI work by directly evaluating the impacts of a potential transition from self-scheduling design to a central scheduling design. The key topics and questions that this report covers are summarised in the table below:

Incorporating system constraints into the DA schedule	***How does the consideration of transmission constraints in the DA schedule affect consumer, producer and system outcomes?***
Limiting market-led response to changing information (e.g. forecast errors)	***What is more valuable: solving transmission constraints at DA under some form of central scheduling or allowing a market-led solving of net GB imbalances closer to delivery as per the status quo (and variants)?***
Comparing magnitude of benefits with potential reforms to the BM	***To what extent could amendments to the BM reduce redispatch costs (but possibly not volumes)?***
How the merits of central scheduling interact with potential locational pricing reforms	***How does the case for central scheduling change under a zonal wholesale market design compared to a national design?***

Notes: (1) Our work also builds upon the ~1,200-node model of the GB electricity market that was utilised in our previous work for NESO (see Slide 33).

Section 2: Overview of self- vs. central scheduling

We compare the status quo self-scheduling design with central scheduling and evaluate key trade-offs in the GB context

- **The current self-scheduling arrangement** in GB is designed to incentivise market participants to balance their contracted positions with their metered output around a single national WS price.
- However, the single national price is not a pre-requisite of self-scheduling arrangements. Indeed, while self-scheduling can be accompanied with national pricing (such as in GB and Germany) it can also be combined with zonal wholesale pricing (such as in the Nordics).[1]
- At its core, **central scheduling** considers Tx limitations and contingencies in the wholesale market via a so-called SCUC/SCED model. This model:
  - Is an optimisation that finds the least-cost schedule to meet expected demand, considering the costs and technical characteristics of all relevant units, Tx thermal limits and contingencies; and
  - Requires unit-based multi-part bids as inputs that reflect the technical features and characteristics of the assets and feed into the optimisation process.
- Central scheduling is often accompanied by nodal wholesale pricing (such as in many US markets and New Zealand), but this is not a necessary feature. Nodal prices are a natural output of SCUC/SCED, but variants of central scheduling can also be combined with national pricing (such as in Greece, Ireland, Poland, and previously England & Wales when the "Pool" was introduced in 1990) or with zonal pricing (such as in Italy).[2]
- In this report, we examine the potential for implementing central scheduling in the GB context. With DESNZ's second REMA consultation[3] removing nodal pricing from further consideration, for the purposes of this report, we assume that central scheduling in GB could only be combined with national or zonal WS pricing. Our "GB-style" central scheduling model draws upon real-world approaches to implementing central scheduling set out in this section.
- In the remainder of this section we discuss:

1. **An overview of the current self-scheduled GB electricity market, featuring market-led balancing up to GCT, with NESO then centrally managing the system to balance supply and demand in RT.**
2. **How central scheduling works in its typical form with nodal wholesale pricing, using the example of US markets**
3. **How central scheduling can also be combined with national or zonal pricing, using examples of EU markets**
4. **Overall comparison of different scheduling arrangements and identification of trade-offs**

Notes: (1) Under nodal pricing self-scheduling is typically allowed alongside centrally scheduled units. Self-scheduling units are price-takers of the nodal price at their node which is determined via a SCUC/SCED algorithm; (2) Combining a schedule based on a SCUC/SCED with national and/or zonal wholesale market design brings additional complications compared to combining Central scheduling with nodal design. We elaborate on these complications in the rest of this section; (3) DESNZ, 2024. Review of Electricity Market Arrangements. Second Consultation Document (link).

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Under the current self-scheduling GB design most market participants provide FPNs at GCT; NESO then ensures the schedule is physically feasible via the BM

Simplified schematic of the current GB electricity market design

Market-led balancing | **NESO balancing**

1. **Forward market and bilateral trading schedule** (Years ahead – Months ahead)
2. **Day-ahead auction: DA schedule[1] and wholesale price** (Noon D-1)
3. **Peer-to-peer continuous intraday trading and auctions** (Afternoon D-1)
4. **Balancing Mechanism** (GCT)
5. **Imbalance settlement** (T)

Submission of **Initial Physical Notification** ("**IPN**") gives NESO a first impression of the schedule[2]

Submission of **FPN** gives NESO visibility over expected output and consumption by BM unit[2]

1 – Forward market and bilateral trading schedule

- Market participants trade **long-term contracts**
- The primary objective is to **hedge** positions

2 – Day-ahead auction

- DA auction acts as the reference market for market participants to settle long-term contracts
- Covers **all hours** of the next day
- Bidding is conducted at the **portfolio-level** with simple or block bids
- There is **no consideration of thermal Tx constraints** by market participants

3 – Intraday trading and auctions

- **Continuous ID trading** occurs alongside several ID auctions
- This allows portfolios to **adjust their position** as more load and generation information (regarding expected consumption or production position in the forthcoming period) becomes available
- Participants are **incentivised to trade out imbalances** to avoid high cash-out payment, and periodically update their physical notifications ("PNs") to reflect changing conditions
- Closer to GCT NESO can countertrade with market participants and, in particular, interconnector ("IC") capacity holders to redispatch ICs to relieve intra-GB congestion.

4 – Balancing Mechanism

- In the BM, NESO instructs pay-as-bid BM units to resolve:
  - **net energy imbalance** due to market participants not trading out of their imbalances or making forecast errors within the BM timeframe ("**energy-flagged actions**")
  - **Tx constraints** that would occur from the wholesale schedule ("**system-flagged actions**")

5 – Imbalance settlement

- Settlement for parties that have a **short or long position at portfolio-level** (contracted vs physical production or consumption) per ISP (30-minute interval)
- Imbalance price paid/received on the difference in output is based on the **costliest 1MWh of non-flagged BM actions taken by NESO** in the same interval

Notes: (1) AS reservation markets are organised separately and can occur before or after the DA WS market; (2) IPNs and FPNs are asset-specific dispatch information provided by market participants before and at the time of GCT, respectively. Currently, market participants are only expected to follow "Good industry practice" when submitting FPNs (link). However, the net position of a market participant's portfolio at GCT is contractual.

The US implementation of central scheduling respects the network constraints from the DA stage and exposes all units to nodal prices at DA and RT

Simplified schematic of a "US ISO-style" market design with central scheduling and nodal pricing

1 Forward market and bilateral trading schedule

Years ahead — Months ahead

- Market participants trade **long-term contracts**
- The primary objective is to **hedge** positions **via hubs.**

2 Day-ahead market (SCUC/SCED) and nodal wholesale price

Noon D-1

- A DA **SCUC**/**SCED** is performed, covering **all hours** of the next day
- Bids are multi-part and unit-based
- Acts as the **reference market** to settle long-term contracts
- The DA schedule is determined by ISO **considering Tx limitations and contingencies**[1]
- **Nodal** DA WS prices are determined
- Schedule is financially binding, with units facing the **nodal RT price** for deviations between their DA commitment relative to their metered position.

3 Intraday ISO processes

- There is **no organised ID market/settlement.**
- ISOs have processes such as **Reliability Unit Commitments** ("**RUC**"), to make significant modifications to the schedule **before** the RT market. For example, when an outage occurs the ISO can commit additional units ahead of the RT market which would otherwise be **too slow** to respond on a short notice.
- Units can **adapt their RT market offers/bids prices** up to the GCT to better reflect changing system conditions (for example ID gas price swings).

GCT
RT offers/bids

4 Real-time market (SCED) and nodal RT prices

- RT market takes place on a **rolling basis**, typically producing RT nodal pricing per 5-15 minutes interval
- Potential supply-demand mismatches within the market time unit ("**MTU**") are solved via **frequency services outside of the RT market**.

T

5 Imbalance settlement

- Settlement for parties that have a **short or long position** (contractual vs physical production or consumption at each node) per RT settlement period
- Imbalances relative to the DA SCED (potentially including ID adjustments) are charged the **RT nodal price**.

Notes: (1) AS reservation markets are often co-optimised with the DA WS schedule.

Some EU countries run a SCUC/SCED directly after the SDAC to correct for Tx constraints while minimising the cost of deviations, i.e. "hybrid scheduling"

Simplified schematic of an EU market design with hybrid scheduling and zonal/national wholesale price[1]

1. Forward market and bilateral trading schedule	2. DA market and national/zonal wholesale price followed by a SCUC/SCED[2]	3. Peer-to-peer continuous intraday trading and auctions	4. Balancing Mechanism	5. Imbalance settlement
Years ahead / Months ahead	Noon D-1	Afternoon D-1	Gate Closure Time	T

1. Forward market and bilateral trading schedule

- Market participants trade **long-term contracts**
- The primary objective is to **hedge** positions.

2. DA market and national/zonal wholesale price followed by a SCUC/SCED[2]

- The **Single DA Market Coupling ("SDAC")** produces a **national/zonal WS price** covering **all next day's hours** and an "unconstrained" schedule
- The DA WS price is used to settle long-term contracts on
- A **DA SCUC/SCED** is run with unit-based multi-part bids respecting thermal Tx limits with the objective typically to minimise transfer payments (relative to the SDAC). The "integrated" schedule is binding.
- **Transfer payments** are required for units that are scheduled but "**out-of-the-money**" when only receiving the national/zonal WS price ("**cost recovery**") and units that are "**in-the-money**" but not scheduled in the SCUC/SCED ("**firm access**")

3. Peer-to-peer continuous intraday trading and auctions

- ID markets are in place in all the European countries that have central scheduling in place.
- Under **ID continuous markets there are typically** measures[3] in place to **avoid** units doing trades that would **create network issues** and require are-run of the SCUC/SCED
- Under **ID auctions,** the EU-wide ID auctions produce an unconstrained schedule, which is followed by a SCUC/ SCED **(as in DA)**[4]

4. Balancing Mechanism

- The BM is operated by the TSO **resolving mostly energy imbalances** due to **forecast errors** as the majority of **thermal Tx constraints are resolved at the DA stage**
- Additional thermal Tx constraints appear in the BM due to forecast errors, and need to be resolved by the TSO

5. Imbalance settlement

- Settlement for parties that have a **short or long position** (contractual vs physical production or consumption) per ISP
- Imbalances are charged at an **imbalance price**, typically based on the cost of **balancing actions**

Notes: (1) Art. 2(19) of Regulation (EU) 2017/2195 (EB GL) refers to Tx system operators ("TSOs") applying a central schedule combined with national/zonal prices as TSOs having an "integrated scheduling process" defined as "an iterative process that uses at least integrated scheduling process bids that contain commercial data, complex technical data of individual power generating facilities or demand facilities and explicitly includes the start-up characteristics, the latest control area adequacy analysis and the operational security limits as an input to the process". Examples are Greece, Italy, Ireland and Poland (Slide 6 of link); (2) Often AS reservation markets are co-optimised with the WS schedule; (3) An example are "feasibility intervals" in Italy, which are defined by the TSO in each run of the integrated scheduling process and are meant to allow market parties to trade and change the schedule of units in the continuous ID market, as long as the changes do not have a negative effect on system constraints; (4) Only "incremental" transfer payments relative to the transfer payments paid out at the DA stage would need to be paid out to avoid double payments.

Given that REMA has excluded nodal pricing, we describe a potential future GB central scheduling design that is loosely modelled on the EU-style precedent

- In this report, we are seeking to compare the current GB self-scheduling arrangements to a hypothetical future GB central scheduling design.
- We draw on the experiences of the US and EU markets as set out in the previous slides, and - given that REMA has excluded nodal pricing - we loosely base our model for such potential future GB central scheduling design on the EU precedent (rather than US precedent which would require nodal pricing). However, we adapt the European hybrid-style scheduling to the GB context.
- The table below summarises the key features of the three market designs. The following section of the report sets out in detail how we interpreted a potential GB central scheduling design and how this has been implemented in modelling terms (see Slide 26 for a summary).

Basis for assumed GB self-scheduled design | Basis for assumed GB central design

	Self-scheduling current GB	Central scheduling US-style	Hybrid scheduling EU-style	Assessment
DA energy scheduling	National scheduling[1], objective to max. welfare	SCUC/ SCED, i.e., nodal scheduling, objective to max. welfare	SCUC/SCED, i.e., nodal scheduling, typical objective to min. transfers[3]	**Quantified in this report**
DA wholesale pricing	National[1]	Nodal	National/Zonal	
DA transfer payments[2]	No	No	Yes, for cost recovery and firm access	
ID market	Yes, auctions and continuous	No organised market but SO has ID processes	Possible but unwinding DA SCUC/SCED schedule to be avoided	
RT dispatch	BM resolving energy imbalances and Tx constraints	RT market plus frequency services	BM mostly resolving energy imbalances	
WS bidding formats	"Financial" bidding formats (e.g., simple, block, and linked bids)	Multi-part bidding formats	"Financial" and/or multi-part bidding formats	**Not quantified, not feasible within existing power market modelling platforms given the underlying optimisation algorithms**
Bidding granularity	Portfolio bidding	Unit-based bidding	Unit-based bidding	
Pricing rule	Non-linear pricing	Linear pricing + uplifts[2]	Non-linear pricing	

Note: (1) Note that the modelling of self-scheduling under zonal pricing uses zonal scheduling at DA. (2) Transfer payments are explained in detail later in report (see Slides 42 - 46); (2) Uplifts are required under central scheduling because the WS price does not necessarily reflect all non-convex costs (e.g., start-up costs, no-load costs etc.) of all scheduled generators. Transfer payments are different as they can be required because the WS price can be even lower than the convex costs (e.g., fuel or opportunity cost) of the scheduled units; (3) As explained in Slide 26, the objective of the SCUC/SCED we run under central scheduling is to minimise total scheduling costs.

Section 3: High-level methodology and quantified cost components

High-level methodology

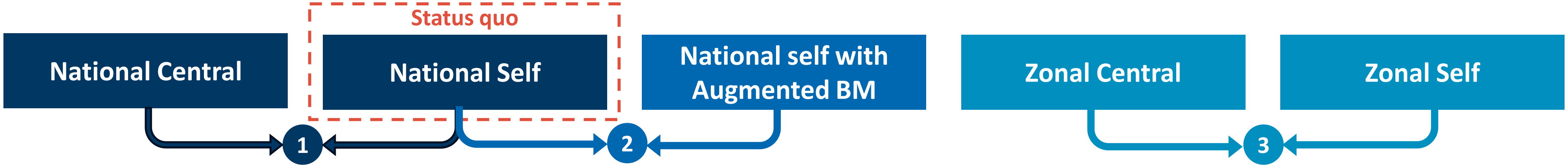
We test the case for central scheduling under three scenarios using five model setups

- This report evaluates the potential socioeconomic benefit of transitioning from the current self-scheduling arrangement to central scheduling by quantifying and comparing consumer and producer surplus under both scheduling designs. We perform this analysis under three scenarios for the period 2030-2040:

1. **'Status quo' with national wholesale pricing** in place for both the self- and central scheduling arrangements;
2. **National wholesale pricing** in place for both scheduling arrangements, but with an amended BM intended to reduce balancing costs under self-scheduling (an '**Augmented BM**'); and
3. **Zonal wholesale pricing** in place for both scheduling arrangements**,** with a Baseline BM.[1]

- Five distinct model setups are required to examine the three scenarios, as set out in the figure below:

Model setup overview



- These five model setups combine different scheduling arrangements (central/self), with different WS market designs (national/zonal), and therefore vary in terms of:
  - **The price used to <u>schedule</u> assets**, with self-scheduled assets scheduled relative to either a national or zonal WS price, while in the case of central scheduling, resources are scheduled based on a 'shadow nodal price' (i.e. considering all thermal Tx limitations).
  - **The price used to <u>compensate</u> assets**, which may differ from the prices used to schedule assets (and hence require additional "transfer" payments).
  - **The mechanisms for resolving forecast errors**: under self-scheduling, the aggregate net GB-wide imbalance arising from forecast errors (i.e. ignoring the impact of thermal Tx constraints) is resolved by market participants in ID markets, with the BM resolving Tx constraints only. Under central scheduling, all energy imbalances arising from forecast errors are resolved in the BM (but most thermal Tx constraints are resolved in the DA schedule).
- In addition, under the self-scheduling arrangement we compare a **'Baseline BM'** and **'Augmented BM'.**
- The details of the modelling assumptions across our five scenarios are summarised in the next slide.

Notes: (1) Although augmentations to the BM may be made in tandem with a transition to zonal pricing, we assume a 'Baseline BM' under our zonal assessment to isolate the impacts between the two potential policy directions.

We assess the potential benefits of central scheduling under different scenarios by comparing outcomes between model setups

- We can quantify the potential benefits of central scheduling under the three scenarios by comparing outcomes between our five different model setups.
- Model setups are differentiated via the following:
  - **Market design.** (N) National or (Z) Zonal;
  - **Balancing market.** (1) Baseline BM or (2) Augmented BM; and
  - **Scheduling.** (C) Central or (S) Self.

2 Impact of central relative to Augmented BM design

Model	N1C	N1S Status quo	N2S	Z1C	Z1S
WS market design	National	National	National	Zonal	Zonal
Balancing Market	Baseline BM	Baseline BM	Augmented BM	Baseline BM	Baseline BM
Scheduling[1]	Central *(i.e. with all thermal Tx constraints)*	Self *(i.e. without thermal Tx constraints)*	Self	Central	Self (i.e. with inter-zonal thermal Tx constraints but not intra-zonal Tx constraints)
Resources scheduled relative to	Shadow nodal price[2]	National price	National price	Shadow nodal price	Zonal price
Resources compensated based on	National price at DA, estimated ID price post-DA[3]	National WS/ID price	National WS/ID price	Zonal price at DA, ID price post-GCT	Zonal WS/ID price
DA forecast error[4,5]	Imbalance resolved in BM	ID trading resolves aggregate imbalance	ID trading resolves aggregate imbalance	Imbalance resolved in BM	ID trading resolves GB aggregate imbalance

1 Impact of central vs self-scheduling under national

3a Impact of central scheduling assuming zonal pricing

3b Impact of zonal design on the potential merits of central scheduling

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 while 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 on Slide 15; (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 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 for more information; (5) We assume that all forecast errors are resolved pre-GCT under self-scheduling.

We focus on the trade-off between earlier resolving of thermal Tx constraints under central scheduling and market-led solving of net GB imbalances under self

- As discussed in Section 2, by design the current GB self-scheduling arrangements include market-led GB-wide balancing up to GCT in the ID WS market, incentivised on the basis of a national wholesale price.
- Intra-GB Tx constraints are not considered by market participants in the WS market; instead, they are jointly managed by NESO alongside residual energy imbalances post-GCT in the BM.
- In this quantitative assessment, we examine two key impacts that a move to central scheduling could have in the GB context:

Earlier resolving of thermal Tx constraints on the GB network

- A key hypothesised benefit of central scheduling is that a central operator can significantly reduce system costs of final dispatch by optimising, on a unit-by-unit basis, the schedule around system needs at an earlier stage than the BM.
- By explicitly considering system constraints and reliability needs as part of the WS market schedule, a central operator could access a broader range of generators (e.g. those with longer lead times) and lower the cost to reposition ICs (and possibly other flexible assets), which would reduce the reliance on more expensive NESO actions nearer to RT.
- To test this effect, we **consider the impact of NESO resolving Tx constraints at different stages of the scheduling process** under self- and central scheduling.[1]

Hypothesis 1: Central scheduling resolves thermal Tx constraints more cost effectively and this is more beneficial than allowing market participants to resolve GB-wide imbalances until GCT.

Imperfect anticipation of generation and demand patterns at the DA stage

- However, a central operator's ability to reduce system costs would be limited by the extent to which demand and available supply were accurately forecasted at the time of determining the WS schedule.
- By determining a firm, physically feasible schedule at DA (rather than post-GCT), a centrally scheduled market may be less able to adjust the schedule in response to evolving demand and supply conditions in the hours leading up to delivery than market participants could themselves achieve under a self-scheduled market.
- To test this effect, **'forecast errors' are introduced for wind, solar and demand,** calibrated using historical data from NESO.

Hypothesis 2: Self-scheduling market participants resolve net GB-wide imbalances before GCT via the ID WS market, and associated savings outweigh the benefits of resolving thermal Tx constraints earlier.

Our assessment seeks to quantify which of these two effects dominates, and the extent to which this varies across national and zonal WS market designs.

Notes: (1) The volume of Tx constraints to be resolved in the "unconstrained" WS schedule at the DA stage under central scheduling does not necessarily differs compared to the volume of Tx constraints to be resolved under self-scheduling at GCT (minor differences might occur due to different wind, solar and consumption expected at DA vs at GCT).

The volume of constraints and forecast errors are the two key drivers of our analysis and these factors are likely to become more significant over time

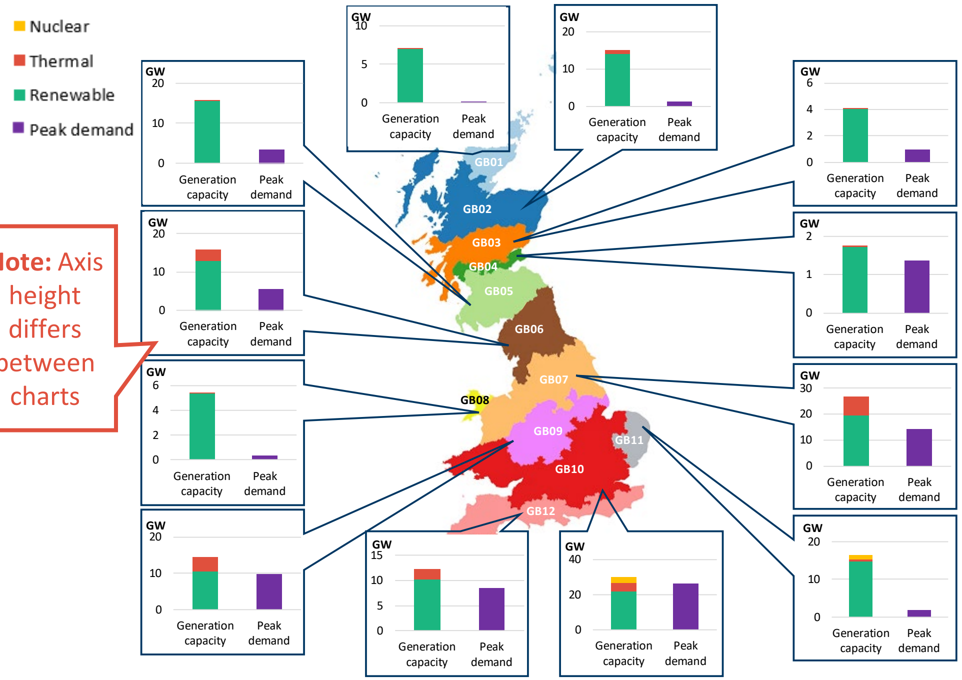
1 Increasing network constraints

- As shown in the top-right chart, there are **significant variations in the balance of peak demand and generation capacity across GB**, with excess volumes of supply relative to demand in the North (and vice-versa in the South). **This trend is expected to continue going forward.**
- This can, in part, be addressed by **building additional Tx**, allowing surplus supply in one region to displace more costly generation in another to meet demand. However, as shown in the bottom-right chart, even with NESO's Beyond 2030 recommendations for very significant Tx build-out, **significant constraints are expected to persist** on key boundaries, resulting in **high constraint management** costs in the BM.
- Other things being equal, **higher volume and cost of resolving thermal Tx constraints across GB would increase the estimated benefits of central scheduling relative to self**, as the value of resolving intra-GB congestion at an earlier stage, via a central planner, increases. Our methodology for assessing these costs is discussed in Slide 28.

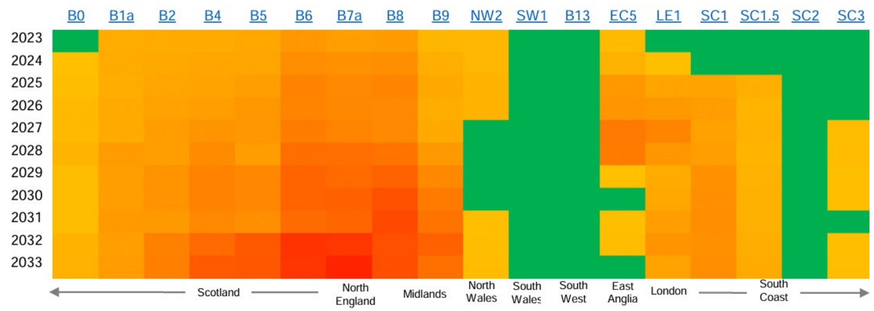
2 Increasing forecast errors

- **Demand and intermittent renewable capacity are assumed to significantly grow** across the modelled period, increasing forecast errors in absolute terms.
- Forecast errors per unit of demand/generation are a function of **weather patterns, demand patterns and forecasting capabilities**. These factors may act to increase or decrease absolute forecast errors in the future.
- Other things being equal, **more significant forecast errors (and hence energy imbalances) would increase the estimated benefits of self-scheduling**, as the value of those errors being resolved by market participants increases (relative to the SO resolving them post-GCT in central scheduling).
- We detail in the following slides how the quantum of forecast errors has been developed, calibrated and applied in our modelling.

Generation capacity and peak demand in GW per zone, 2030, FES 2022 LtW[1]



Excess flows beyond boundary capability with the Beyond 2030 recommended options applied[2]



Darker shading indicates greater congestion on the boundary

Sources: (1) FTI analysis based on ESO's FES 2022 LtW; (2) Electricity Ten Year Statement (ETYS 2023), ESO (link).

Imbalances between DA and GCT have been constructed using NESO data – we assume no change in forecast errors over time

Energy imbalances occur across GB primarily due to intermittent RES and demand mis-forecasting

- To examine the merits of central vs self-scheduling, we introduce **three sources of forecast error between DA and GCT**: wind, solar and GSP-level demand. We assume no further forecast errors post-GCT under both self- and central scheduling.[1]
- NESO has provided the following data on DA to GCT forecast errors:
  - i. For **wind**, NESO DA forecast and FPN by wind farm;
  - ii. For **demand**, historical national aggregate imbalance and a sample of GSP-level demand forecast errors;
  - iii. For **solar**, modelled forecasts and outturn data by DNO region.
- In **collaboration with NESO**, we have selected the most **representative forecast error profiles** from the respective datasets and developed **locationally-differentiated forecast error profiles for assets of each type on an hourly basis** (see Slides 37 and 38 for further detail).[2,3]
- We apply these forecast error profiles **equally** to **the initial DA forecast** in the **self-** and **centrally scheduled market designs**, creating an 'imbalance' for each asset, as shown for an example node in the figure to the right.
- Importantly, the **error profiles are fixed across the modelling horizon** to the **historically-observed** percentage point difference between DA forecast and final output/load for each asset, implying **no change in ability to forecast output/load over time**.
- To the extent that **forecasting abilities are expected to improve over time**, fixing error profiles to historical levels across the modelling horizon is a **conservative assumption** for the potential **benefits of central scheduling** (for which resolving imbalances is generally more costly than under self-scheduling in our modelling).
- However, should **forecasting abilities worsen**, for example due to **climate change-driven weather pattern changes**, assuming no change in the ability to forecast **may benefit the case for central scheduling.**

Illustrative application of error profiles at an example node

Example node

	Wind capacity factor	Solar capacity factor	Demand
DA forecast	70pp	20pp	60pp
	+	+	+
Imbalance	5pp	-2pp	-7pp
	=	=	=
GCT position	75pp	18pp	53pp

Notes: (1) Post-GCT forecast errors would, in theory, equally impact the self- and centrally scheduled market designs; in both cases, these 'last-minute' errors would be centrally resolved through the pay-as-bid BM. As such, we do not expect post-GCT errors to meaningfully impact the relative merits of the two scheduling designs and we apply this simplifying assumption equally across the self- and centrally scheduled setups; (2) Forecast error profiles for some solar DNO regions and wind GSPs appeared to show structurally biased errors, seemingly primarily driven by mid-year changes in installed capacity within the relevant regions being reflected at different points in time in each dataset. We worked with NESO to select the most representative error profiles from the relevant datasets and excluded DNO regions and wind GSPs with clear structural biases from the sampling database; (3) We note there are other potential data sources for RES and demand forecasts. However, we consider it most appropriate to use NESO forecasts given NESO would most likely rely on these if central scheduling were to be implemented. To the extent that improved forecasts of RES and demand might be available to NESO, using NESO's current forecasts would be a conservative assumption with respect to the potential benefits of central scheduling.

We compare scheduling designs by varying the point at which Tx constraints and energy imbalances are resolved ahead of real-time

To quantitatively assess the impact of introducing central scheduling, we vary the point at which Tx constraints and forecast errors are considered in the scheduling process, estimating the resulting cost of resolving each under self- and centrally scheduled market designs.

- Under self-scheduling, we assume that market-led self-balancing around a single national wholesale price adjusts to evolving forecasts through ID trading up to GCT. Thermal constraints are only considered post-GCT, resolved by NESO through the pay-as-bid BM.
- Under central scheduling, we assume that NESO explicitly considers system constraints when determining the WS market schedule (including ICs), reducing the need for post-GCT system-flagged balancing actions, although 'make whole' transfer payments would be required for some assets (see Slides 42-46).
- However, by setting the central schedule at an earlier stage, a centrally scheduled market could be more exposed to changes in the anticipated pattern of RES generation and demand. For the purposes of our assessment, we assume that all forecast errors would be resolved by the SO post-GCT.[1]

	Day-ahead	Intraday	Redispatch
Self-scheduling	▪ DA schedule ignores thermal Tx constraints and leads to a single GB **national unconstrained wholesale price**.	▪ Changes in forecasted demand/generation relative to DA are **resolved by the market via ID trading.**	▪ NESO adjusts schedule for Tx constraints through the BM **post-GCT**. ▪ Resolving thermal Tx constraints requires **constraint payments.**
Central scheduling	▪ DA schedule is determined in line with thermal Tx constraints, with assets scheduling according to shadow nodal prices. ▪ Schedule at DA **considers the thermal limits of the Tx network,** so limited thermal constraints need to be resolve post-GCT. ▪ 'Make whole' **transfer payments** required.	▪ As a modelling simplification, we assume no ID market under central scheduling (although central scheduling can be implemented alongside an ID market or ID SO-led processes (see Slides 13-14)). ▪ This is a conservative assumption in terms of the benefits of central scheduling, as all imbalances are assumed to be resolved in the last hour before RT in the BM (which is more costly).	▪ Change in forecasted demand/RES generation relative to DA **resolved by NESO** through the BM (instead of ID trading). ▪ Imbalance can also lead to (minor) thermal Tx constraints which are also resolved by NESO in the BM.

Scheduling **Transmission introduced** **Imbalance introduced**

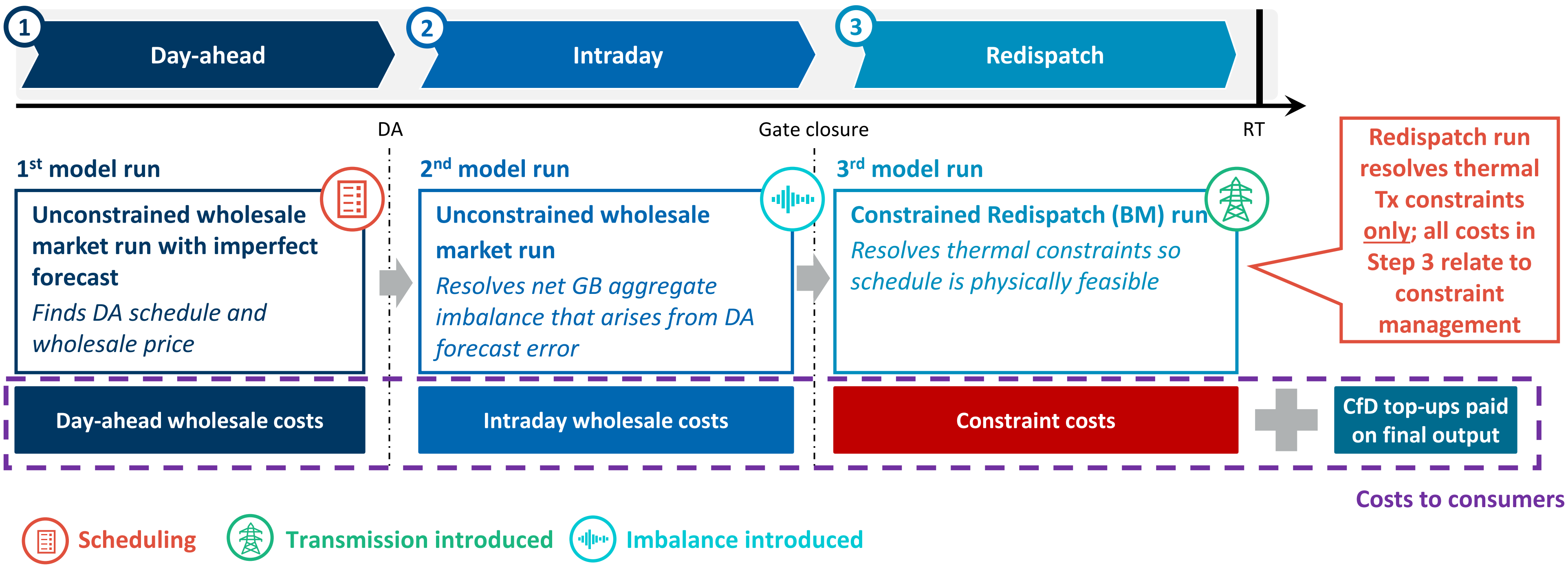
Note: (1) This is a conservative assumption with regards to the potential benefits of central scheduling. As noted in Slide 14, ID markets operate alongside the central schedule in some jurisdictions (such as Italy) and help the central schedule adapt to changing forecasts post-DA.

Under self-scheduling, forecast errors are resolved by market participants in 'intraday' wholesale markets; post-GCT actions resolve thermal Tx constraints only

The self-scheduled GB market is modelled via three steps:

1. **Day-ahead:** self-schedule determines the DA WS price based on **imperfect forecasting** of demand and intermittent RES output. **Tx constraints are ignored**. The **DA WS cost** is the DA price multiplied by forecasted GB demand at DA in each settlement period;
2. **Intraday:** ID trading is assumed to **fully resolve the net GB-wide imbalance** created by **forecast errors** in renewable output and demand. Changes in RES generation and demand receive/pay the **ID price** to adjust their positions, leading to **ID WS costs;** and
3. **Redispatch:** resolves **thermal Tx constraints only,** required as the **schedule at GCT may not be physically feasible** via the activation of system balancing actions. **Constraint payments** are made through pay-as-bid unit bidding in the BM.[1] All forecast errors (and hence energy imbalances) are assumed to have been resolved before this step begins.

Simplified self-scheduled market with forecast uncertainty at day-ahead



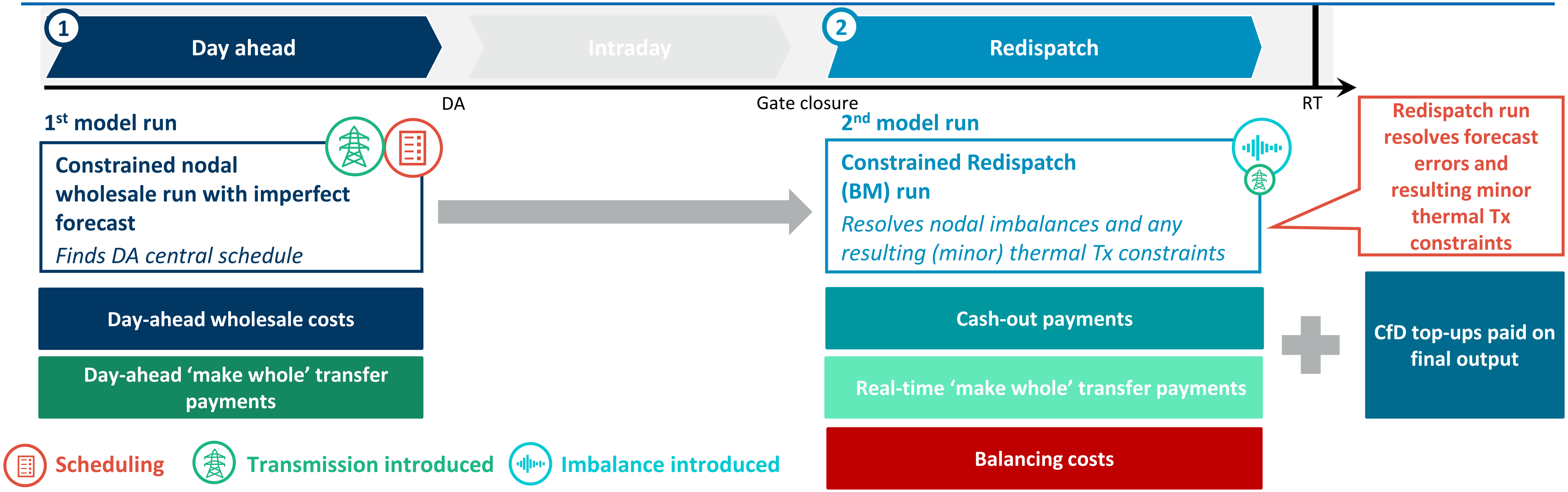
Note: (1) Under the modelled representation of self-scheduling, all energy imbalances are resolved before GCT and in the BM only system balancing actions are required to resolve Tx constraints. We refer to these costs as "constraint costs". Under central scheduling, most BM actions are deployed to resolve energy imbalances. Some minor Tx constraints can result from these energy imbalances. We refer to these costs as "balancing costs". Constraint management costs and balancing costs are jointly referred to as BM costs.

Under central scheduling, thermal Tx constraints are resolved at DA stage, with forecast errors (and associated minor thermal Tx constraints) resolved post-GCT

The centrally scheduled market is modelled with a DA and redispatch run, but we assume no ID trading:

1. **Day-ahead:** central schedule is determined accounting for **Tx constraints,** but generators are compensated relative to an estimated self-scheduled WS price (national or zonal depending on market design). **Transfer payments** are required to compensate units under certain conditions (e.g. when the WS price does not fully cover a centrally scheduled unit's costs) (see Slide 29);
2. **Redispatch:** we model three types of payments to market participants, which are required to resolve a combination of **forecast errors** and **thermal Tx constraints** (which arise solely because of the forecast errors; the bulk of thermal constraints are resolved in Step 1 above, see Slide 70). We differentiate between them as follows (see Slides 54-57 for more detail):
   - **Cash-out payments**: payments made when forecast error of a generator/demand node at DA causes a change in its own output/load in RT (i.e. no direct NESO intervention);
   - **RT transfers**: protect/penalise generators when a unit's forecast error does not change its output (for example, if a generator over-forecasts at DA, it pays back any DA transfer that it received for the 'missing' generation); and
   - **Balancing costs**: pay-as-bid balancing actions (i.e. energy balancing actions) when a unit's output changes for reasons other than its own forecast error. These are the costs of resolving residual energy imbalances and/or thermal Tx constraints arising directly from forecast errors.

Simplified centrally scheduled market with forecast uncertainty at day-ahead



In summary, our modelled potential future GB central scheduling design is loosely modelled on the EU-style precedent but is adapted for the GB context

- In describing a potential GB central scheduling design, we draw on the experiences of the US and EU markets as set out in Section 2.
- Given that REMA has excluded a nodal WS market design, we loosely base our model for the potential future GB central scheduling design on the EU precedent (rather than US precedent).
- However, we adapt the European hybrid-style scheduling to the GB context. The two most important adaptations are:
  i. We model US-style SCUC/SCED that minimises total scheduling costs at the DA stage and not a hybrid scheduling approach[1]
  ii. We do not model an ID market arrangement nor ID SO processes that are present in the US-style model.
- Both adaptations are conservative with respect to the potential benefits of central scheduling, i.e. hybrid scheduling would result in equal or lower transfer payments while an ID market would likely reduce the cost of resolving imbalances (as we are assuming that instead imbalances are resolved in the BM which is typically costlier).
- The table below summarises the key features of the four market designs.

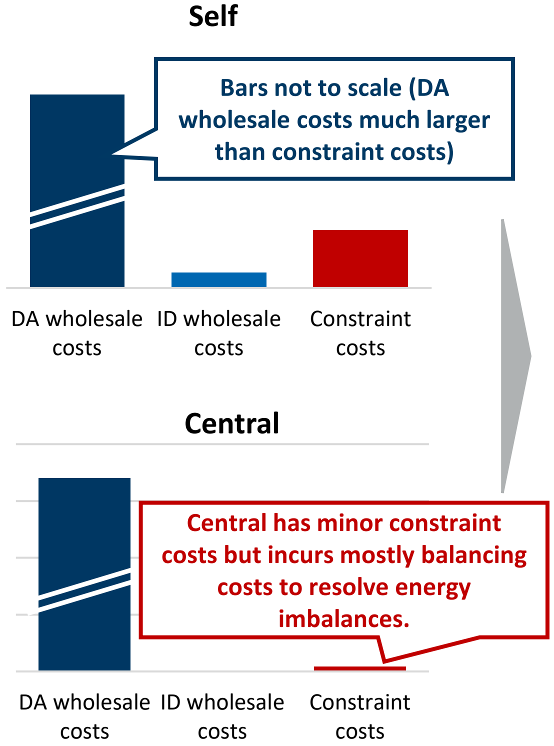
	Assumed GB self- design			Assumed GB central design
	Self-scheduling Current GB	Central scheduling US-style	Hybrid scheduling EU-style	Central scheduling GB-style
DA energy scheduling	National or zonal scheduling with objective to max. welfare	SCUC/ SCED, i.e., nodal scheduling, with objective to max. welfare	SCUC/SCED, i.e., nodal scheduling, typically with objective to min. transfers	SCUC/SCED, i.e., nodal scheduling, with objective to max. welfare
DA wholesale pricing	National/zonal pricing	Nodal pricing	National/Zonal	National/Zonal
DA transfer payments	No	Not required, as nodal WS price recovers full costs	Yes, for cost recovery and firm access	Yes, for cost recovery and firm access
ID market	Yes, auctions and continuous	No but system operator has ID processes	Possible but unwinding SCUC/ SCED schedule to be avoided	No ID market nor ID SO processes assumed
RT dispatch	BM resolving energy imbalances and Tx constraints	RT market plus frequency services	BM mostly resolving energy imbalances	BM mostly resolving energy imbalances

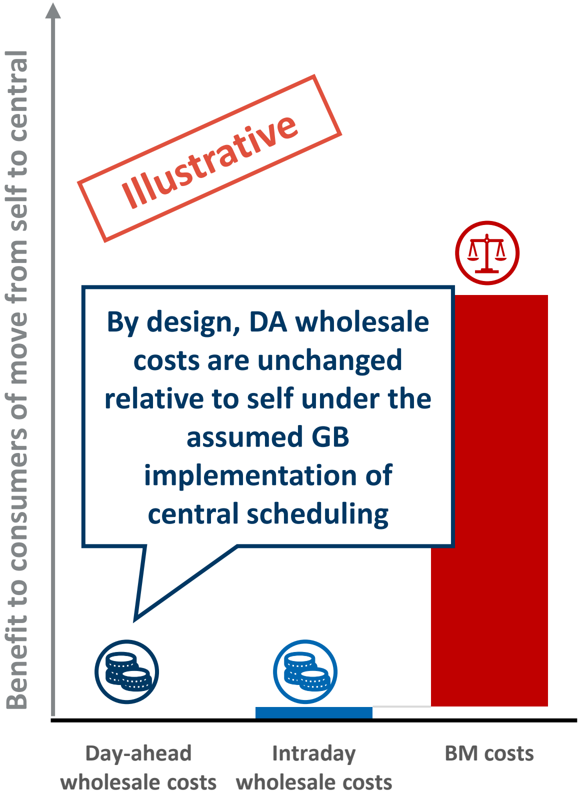
Notes: (1) Under hybrid scheduling, the SO's objective function is not to minimise the cost of production (i.e. seek the least-cost dispatch) but rather to minimise the cost of deviations from the unconstrained market schedule. However, the deployed modelling software (PLEXOS) is designed to find the least-cost dispatch. The functionality to model the hybrid approach is not a standard feature of PLEXOS. The decision to model central rather than hybrid scheduling does not reflect a preference for this approach but was made with NESO due to a low confidence that the existing modelling software could be recalibrated to accurately reflect hybrid scheduling within the required timeframe. In this respect, we model a lower bound for potential consumer savings, with central scheduling likely to lead to higher consumer costs relative to hybrid scheduling, but with lower underlying system costs.

Quantified cost components

Our assessment starts by quantifying the costs to consumers of resolving thermal Tx constraints and forecast errors under self-scheduling

- To quantify the potential socioeconomic benefits of a transition to central scheduling, our assessment begins by calculating the projected costs to consumers under self-scheduling: these are the **wholesale costs of meeting aggregate consumer load**, plus **costs to resolve Tx constraints**.[1]
- The **DA price** faced by consumers is the same under both self- and central scheduling. Our comparison of self- and centrally scheduled market designs therefore does not focus on DA WS costs.[2] This is illustrated in the figure below.
- Therefore, we focus on the following two components, which are additional consumer costs under self-scheduling compared to central scheduling:
  - **ID wholesale costs**; and
  - **Constraint costs**.





ID wholesale costs arise under self-scheduling due to demand forecast errors between DA and GCT.

- We assume additional demand that arises between DA and GCT will need to pay the modelled ID WS power price (thus increasing consumer costs) while a reduction in demand would receive the modelled ID price.
- As such, net ID WS costs can be positive or negative under self-scheduling and in general ID costs are a **small aggregate cost component** of self-scheduling in our modelling.

Constraint payments are required under self-scheduling due to **redispatch actions** needed to **resolve thermal Tx constraints**.

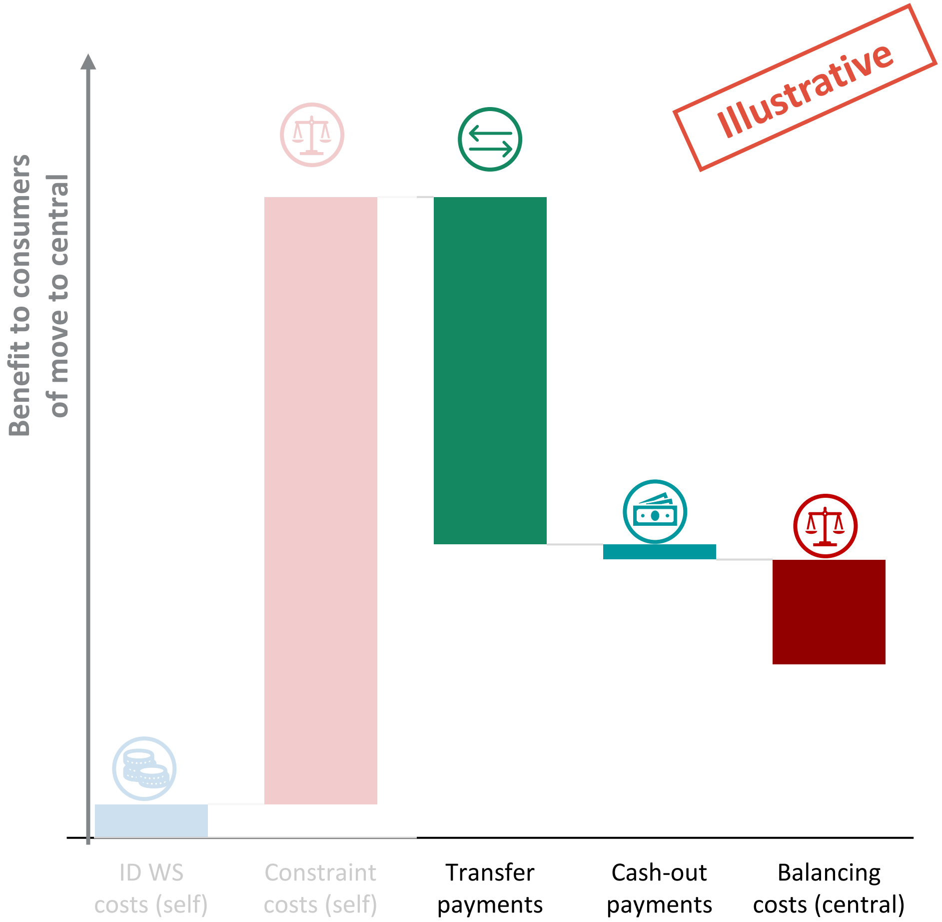
- Redispatch volumes **are significant** under self-scheduling, as the DA schedule does not account for thermal Tx constraints.
- Actions to resolve thermal Tx constraints are priced via a pay-as-bid BM. Our assumptions on BM bid/offer prices are shown in Slide 53.

Note: (1) We do not consider the costs of AS procurement ahead of time or costs to resolve potential voltage or stability constraints in the BM under either scheduling design; (2) However, wholesale price impacts are relevant when comparing between national and zonal wholesale market designs.

There are additional categories of consumer costs that arise under central scheduling and therefore reduce the benefits of central relative to self

The additional consumer costs under central scheduling are composed of the following three elements:[1]

- **Transfer payments**;
- **Cash-out payments**; and
- **Balancing costs**.



Transfer payments are made under the assumed implementation of central scheduling to compensate generators for certain outcomes relative to a **self-scheduled** market design (Slides 42-46). This is a policy assumption reflected in our modelling.

- Transfers are made when a unit is centrally scheduled but does not earn sufficient revenue from the unconstrained WS price to recover its short run marginal cost ("SRMC") (**cost recovery**) or is not centrally scheduled but would have been under self-scheduling (**firm access rights**). Transfer payments are always a cost to consumers, as the reverse payments are assumed to not occur; i.e. market participants that are better off under central compared to self for a given period are not assumed to be required to pay back any revenues (for example, if they are scheduled under central but not self, and the WS price is higher than the unit's SRMC).
- Under a zonal market design, transfer payments to GB Tx owners are also required to account for differences in intra-GB congestion rents (see appendix 4 for more information).

Cash-out payments are made when a unit/demand's forecast error causes its **position in RT** to **differ to its DA forecast**. The cash-out is priced at the ID self-schedule wholesale price (see Slide 55 for more information).

- Units that over-forecasted output at DA pay a cash-out payment to NESO for the output not delivered, and units that under-forecasted receive a cash-out payment for the extra realised output. **Net cash-out payments** may therefore be **positive or negative.** Net positive cash-outs represent a consumer cost.
- **Balancing costs** under central scheduling result from **BM actions** which are required to **solve residual imbalances** and any new **(minor) Tx constraints** created by RES/demand forecast errors.

Note: (1) CfD payments are a further consumer impact. These payments occur under both self and central scheduling and are a transfer between consumers and producers (see appendix 5).

Finally, we quantify the aggregate producer impacts under central scheduling (some of which are direct transfers from consumers)

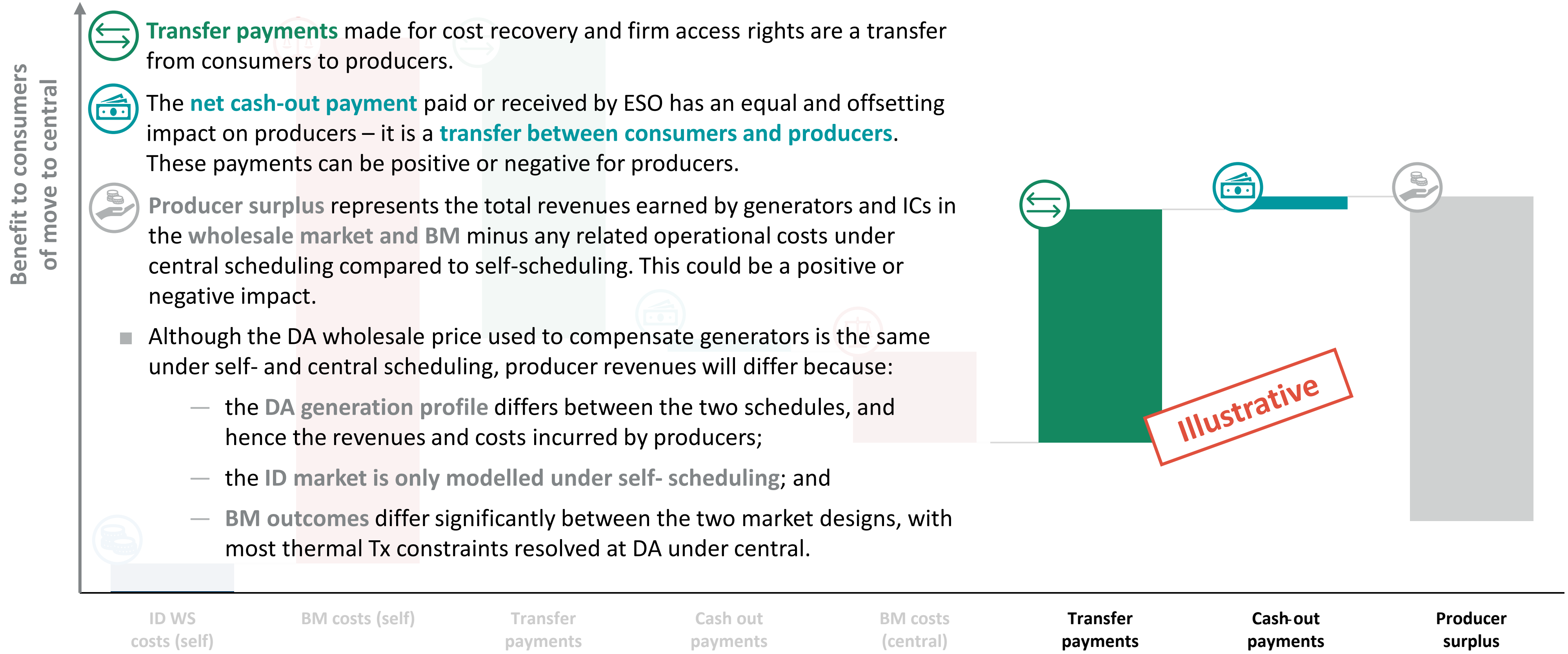
- The previous slides described the consumer impacts of a potential transition from self-scheduling to central scheduling.
- In addition to those, we assess the **aggregate producer impacts under central scheduling** compared to self-scheduling**.** These are composed of three elements:[1]
  - **Transfer payments**;
  - **Cash-out payments**; and
  - **Producer surplus**.

Transfer payments made for cost recovery and firm access rights are a transfer from consumers to producers.

The **net cash-out payment** paid or received by ESO has an equal and offsetting impact on producers – it is a **transfer between consumers and producers**. These payments can be positive or negative for producers.

Producer surplus represents the total revenues earned by generators and ICs in the **wholesale market and BM** minus any related operational costs under central scheduling compared to self-scheduling. This could be a positive or negative impact.

- Although the DA wholesale price used to compensate generators is the same under self- and central scheduling, producer revenues will differ because:
  - the **DA generation profile** differs between the two schedules, and hence the revenues and costs incurred by producers;
  - the **ID market is only modelled under self- scheduling**; and
  - **BM outcomes** differ significantly between the two market designs, with most thermal Tx constraints resolved at DA under central.

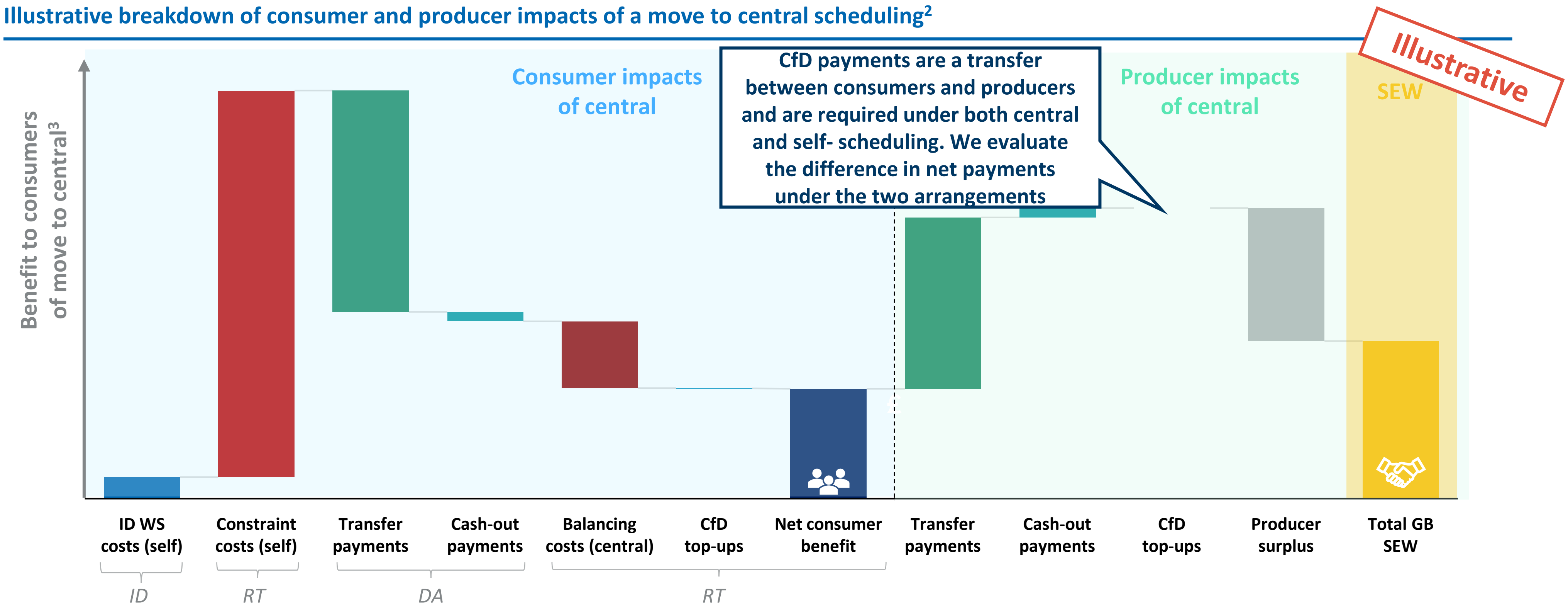


Note: (1) CfD payments are a further producer impact. These payments occur under both self and central scheduling and are a transfer between consumers and producers (see Slide 31).

Overall, our assessment allows us to establish net consumer and total socioeconomic impacts of central scheduling relative to self-scheduling

- Bringing all of this together, we reach an assessment of both **net consumer benefits** and **total socioeconomic benefits** of central scheduling compared to self-scheduling.
- We begin the assessment with **aggregate costs under self** (ID wholesale costs and constraint costs)[1] and compare these to payments under central.
- **Transfer payments** are mostly direct transfers from consumers to producers, except for interconnectors where a portion of the benefit is assumed to accrue to the connected country. **Cash-out and CfD payments** are both **equal and opposite** consumer/producer impacts.
- Constraint costs under self are **significantly higher** than balancing costs under central.
- **Producers** may make **higher or lower revenues and hence earn a higher or lower surplus** under central scheduling compared to self-scheduling, due to the different DA generation profiles observed under the two schedules as well as ID changes in generation under self.

Illustrative breakdown of consumer and producer impacts of a move to central scheduling[2]



Note: (1) As explained in Slide 28, we do not include DA wholesale costs as these are the same under both self and central scheduling; (2) "Total GB socioeconomic benefits" only considers the impact to the power system. Central scheduling is likely to impact other parts of the energy system, for example hydrogen, that are not captured in this assessment; (3) E.g. for 'constraint costs (self)', the benefit to consumers of a move to central scheduling is avoiding the constraint costs paid out in RT to resolve Tx constraints (noting that alternative costs are incurred in central).

Section 4: Model setup and key assumptions

FTI CONSULTING

We model a nodal-level representation of GB on the PLEXOS Integrated Energy Model platform, and this underpins our five model setups

Input assumptions

FES 2022 LtW

FES 2022 EU CT

Our pan-European model includes 19 countries and clears simultaneously across GB and Europe for each hour (critical in assessing the impact of interconnectors)

1 Transmission network

Includes over 1,200 Tx nodes in GB, current & future GB network topology with seasonal availability assumptions, and interconnectors (both connecting to GB and across Europe).

2 Demand

Includes hourly demand profile and flexibility assumptions

3 Generation capacity

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

4 Commodity prices

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

5 BM and CfD assumptions

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

Power Market Model

PLEXOS

Long Term Capacity Expansion model

Our power market modelling typically uses a long-term model to determine the optimal evolution of generation capacity (GW):

- Finds the lowest-cost combination of generation plants (of all technologies)…
- …that meets the minimum capacity margin…
- …constraints on CO2 and other emissions…
- …for each price zone

For this project, we have not used our capacity expansion model. Instead, we align generation/ storage capacity and location with FES 2022 LtW

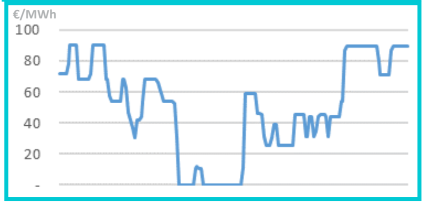
Short Term Dispatch Model

Takes capacity as given and determines optimal output of generation and storage (GWh):

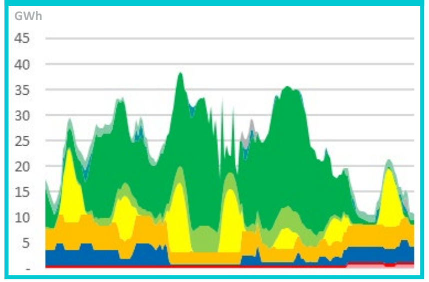
- Finds the least-cost dispatch profile of generation/ storage that meets demand…
- …on an hourly basis…
- …for each generating plant and storage unit…
- …for each price zone
- …subject to generator maintenance & outages…
- …with intra-GB Tx constraints used to estimated Balancing Mechanism outcomes

Hourly outputs for each modelled year

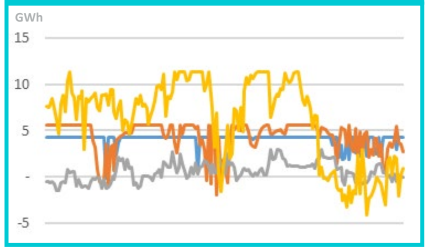
Wholesale power prices



Generation



Flows between countries



Example outputs

Generator revenues	Curtailment
Hourly wholesale prices	Wholesale costs

Key modelling assumptions have been developed in collaboration with NESO and DESNZ – these assumptions are constant under the five model setups

- Key modelling assumptions are presented in the table below.
- These have been developed through extensive engagement with NESO and DESNZ, and we understand that, where possible, these reflect the same assumptions as in other quantitative assessments performed by DESNZ within the wider REMA process.

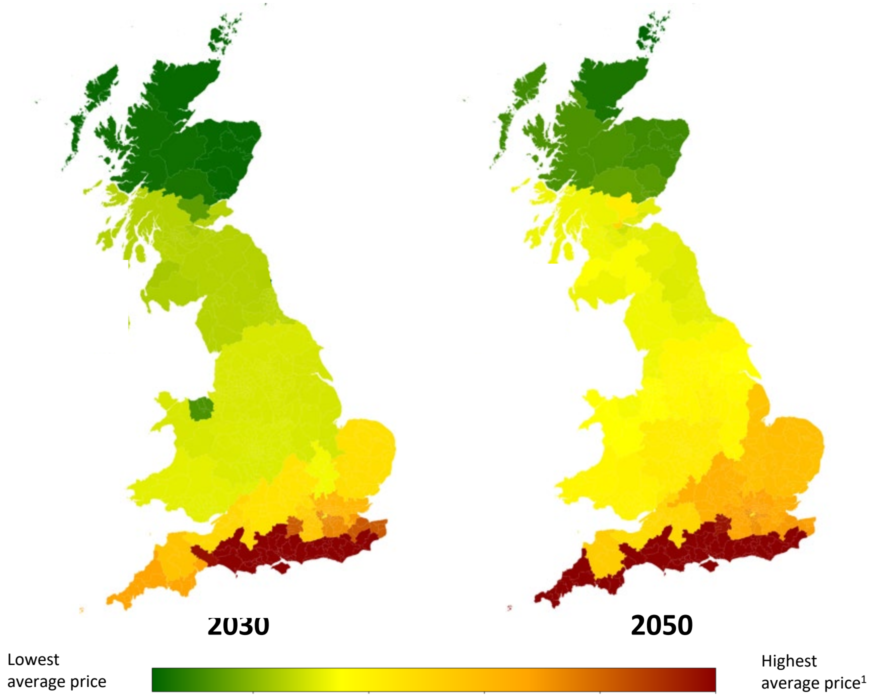
Assumption	Detailed description
Generation outlook[1,2]	**FES 2022 LtW (GB), FES 22 EU Consumer Transformation ("CT") (Europe)**
Interconnectors	Assumed **operational interconnectors** aligned with DESNZ REMA IC assumptions
Commodity prices	**Natural gas, hydrogen, oil and coal prices** follow DESNZ 2023 projections **Biomass price** calibrated using FES 2022 forecast capacity factors **Carbon price** aligned with forward estimates as of Q2 2024
Modelled years[3]	**2030, 2035, 2040**
Climate year ("CY")	**CY2013[4]**
Transmission network[1]	**HND + NOA7 Refresh** (contemporaneous with FES22) **Zonal boundaries** aligned with DESNZ REMA modelling (12 zone model)
Balancing market mechanism and pricing	**Participating technologies and pricing** agreed in collaboration with NESO and Ofgem **Penalty price** for interconnectors redispatch aligned with forecasted bid/offer prices provided by NESO
Forecast error between DA and GCT	**Demand:** calculated from national aggregate imbalance and sample of GSP forecast errors (provided by NESO) **Wind:** calculated using DA forecast and FPN by windfarm (provided by NESO) **Solar:** calculated using forecast data from NESO and outturn data from Sheffield Solar[5]

Note: (1) Updated generation and Tx forecasts have been published since this modelling exercise began, with FES 2024, CP30 and Beyond 2030 signalling a further acceleration of RES deployment and Tx build-out. FTI has agreed with NESO, and in response to stakeholder feedback, that there would be value in re-examining the benefits case of central scheduling under the updated assumptions – this is examined in a follow-up report to this one.; (2) FES 2022 published two European scenarios, EU CT and EU ST, with FES LtW (GB) partnered with EU CT; (3) The modelling period was agreed with NESO and DESNZ and is not necessarily indicative of potential timeframes to introduce a central scheduling market design. In selecting 2040 as the end year for our modelling, we considered a trade-off between assessing over more years and the level of uncertainty regarding key inputs in later years, such as generation capacity, storage, Tx and historical market fundamentals (commodity prices, demand, weather etc); (4) CY2013 is selected to align with NESO's choice of climate year used in the FES and NOA modelling exercises; (5) Sheffield Solar is a research group with a long-standing collaboration with NESO measuring national and regional solar outturn.

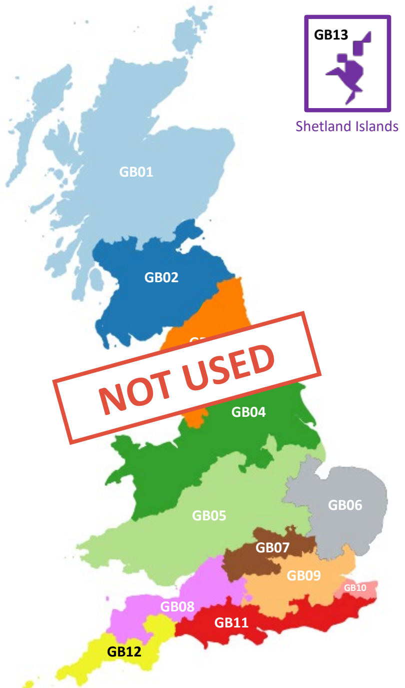
We have aligned our zones with those used by DESNZ throughout the wider REMA process

- The effectiveness of a transition to a zonal market design is dependent on the chosen zonal configuration. To ensure zones are properly calibrated when modelling a zonal market design, FTI has previously deployed its nodal model to find the most constrained boundaries over the forecast period.
- We find for the model used in this assessment, the zonal configuration in the middle chart below best reflects constraints on the network.
- However, to align with the same assumptions as in other quantitative assessments performed by DESNZ within the wider REMA process, for our assessment of the potential benefits of central scheduling under a zonal market design, we have instead used the zonal configuration in the bottom-right chart.
- This configuration of zonal boundaries is likely to result in higher thermal Tx constraints costs under zonal pricing than a more optimal configuration.

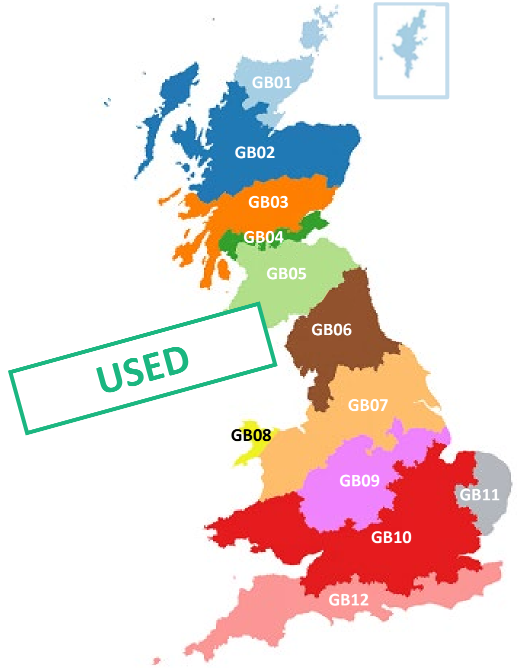
Nodal price heat maps in selected years – FTI model



13 zones reflecting most constrained boundaries in FTI's model



DESNZ REMA zones[2]

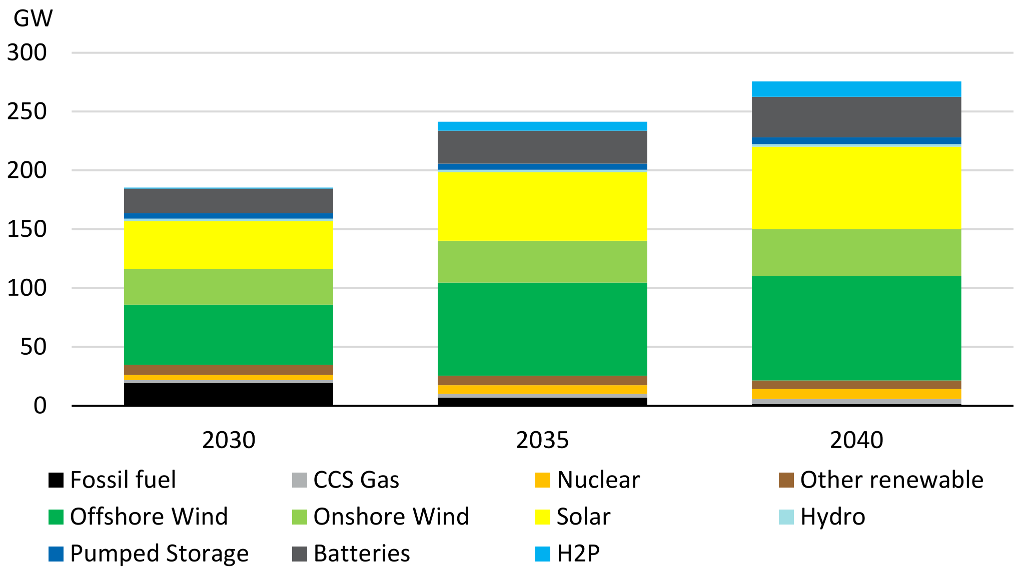


Notes: (1) The nodal price maps use a dynamic scale, which ranges between the lowest and the highest observed annual average price in each year to clearly illustrate the price difference in that year; (2) Shetland is included as part of GB01 under DESNZ's zones.

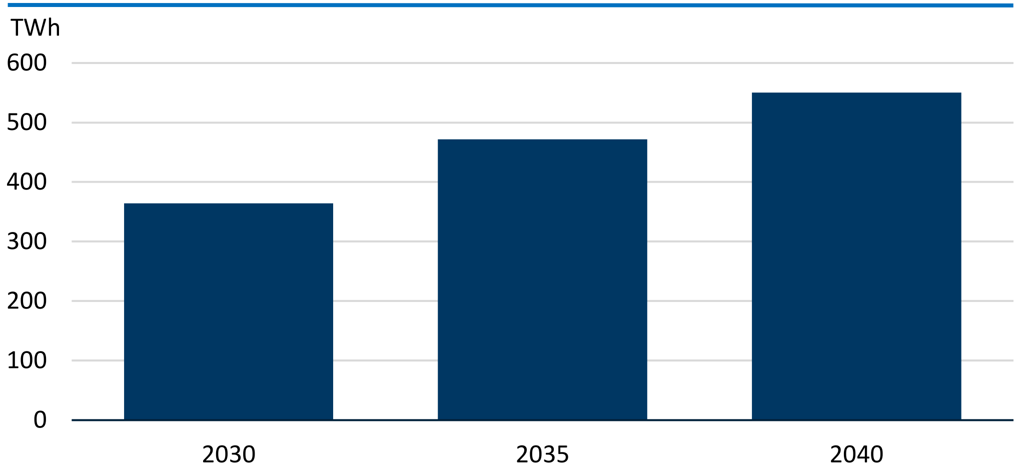
RES capacity and demand are forecast to increase significantly in GB under the FES 2022 LtW scenario

- In agreement with NESO, we have aligned our GB generation capacity and demand assumptions with the **FES 2022 LtW scenario**.
- The top chart shows the evolution of assumed generation capacity in GB across the modelling period under the FES 2022 LtW scenario:
  - The scenario assumes **significant growth in GB RES and storage capacity**, with wind & solar capacity forecast to grow from 122 GW in 2030 to 199 GW by 2040, and battery capacity to grow to 21 GW by 2030 and 35 GW by 2040.
  - In contrast, **fossil fuel capacity** progressively **declines** from 19 GW in 2030 to 2 GW in 2040.
  - Hydrogen-to-power ("H2P") capacity increases from 1 GW in 2030 to 13 GW in 2040.
- The bottom chart shows the assumed evolution of total annual GB power demand:
  - **Electrification** of heating and transport causes **annual electricity demand to increase significantly**, with a high penetration of price-responsive smart charging of electric vehicles.
  - Total annual electricity demand is **364 TWh** in **2030, 472 TWh** in **2035,** and **550 TWh** in **2040**.
- As explained in Slide 22, we assume **no improvement in RES and demand forecast accuracy.** Hence, forecast errors **increase proportionally** with RES capacity and demand. Since RES forecast errors are typically larger than demand forecast errors and there is more capacity for **wind** than **solar**, we see that the wind forecast error **greatly outweighs** the solar and demand forecast error. This is explained further in **Slides 37 and 38**.

Electricity generation capacity by technology, GB, FES 2022 LtW scenario, 2030 - 2040 (GW)[1]



Annual power demand, GB, FES 2022 LtW scenario, 2030 - 2040 (TWh)



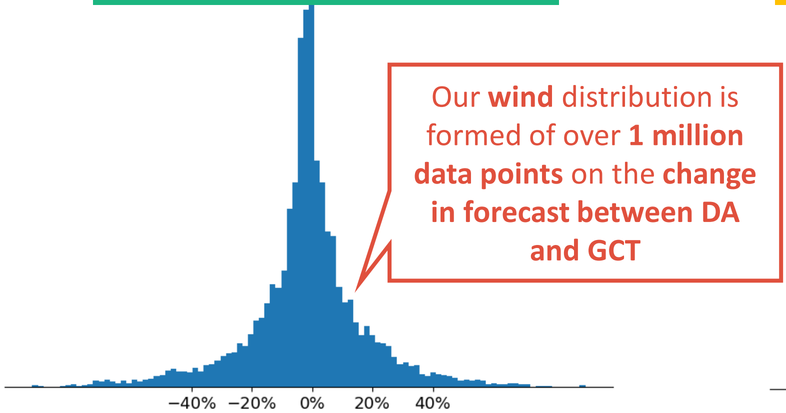
Note: (1) Other renewables includes biomass, CCS ("Carbon capture and storage") biomass, and waste.

We have worked with NESO to develop forecast error profiles for wind, solar and demand using historical data provided by NESO and Sheffield Solar

- As highlighted on Slide 22, we have worked with NESO to develop forecast error profiles for wind, solar and demand, based on historical data provided by NESO and Sheffield Solar. In collaboration with NESO, we have selected the most representative forecast error profiles from the respective datasets and developed locationally-differentiated forecast error profiles for assets of each type on an hourly basis.

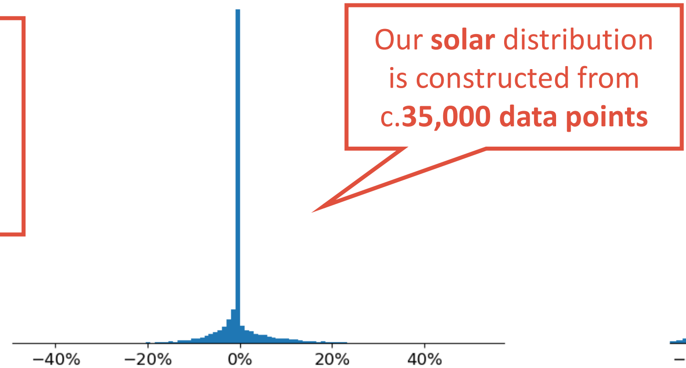
Histograms showing the distribution of samples used to form the wind, solar and demand imbalance profiles

Wind (% of GSP capacity)



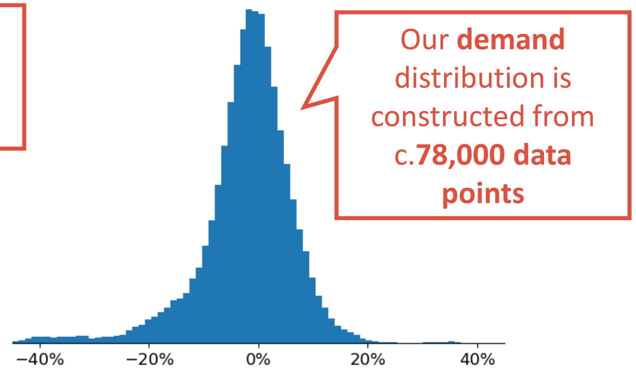
- For **wind**, we estimate a historical error profile for **each windfarm** based on **NESO's DA forecast** for that asset and **Elexon's FPN data** for the whole of 2023.
- We **map each windfarm** to its **nearest GSP** and calculate a **GSP-level wind error profile**.
- For each modelled windfarm, we apply the GSP-level imbalance profile from **one of the five GSPs closest to the asset** from a **sample of 26 GSPs.**
- Wind errors show the **widest variation**, with errors in a settlement period **regularly exceeding 20pp of installed capacity**.

Solar (% of DNO capacity)



- For **solar**, we estimate **DNO-level error profiles** by comparing **NESO's forecasts** close to the **DA auction** time with **outturn** solar modelled by **Sheffield Solar** (using data from the whole of 2023).
- **Structural data biases** mean that only **two DNOs** were deemed to have **representative error profiles**.
- For **each GB zone**, we construct an **annual solar error profile** by **sampling daily error profiles** from one of the two DNOs in the **relevant season** to preserve **time-of-day** and **seasonal trends**.
- Solar errors show **relatively little variation**, mostly clustered **between +/-10pp of installed capacity**.

Demand (% of peak demand)



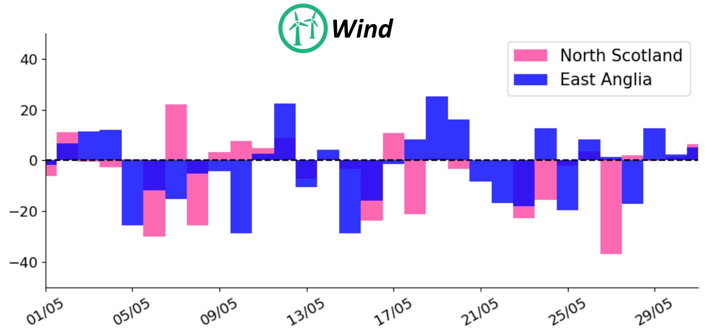
- For **demand**, **NESO** provided **DA forecast** and **actual demand** for **11 'demand-dominated' nodes** (i.e. with limited embedded generation) for March-Sept 2024.
- For each modelled GSP, we **randomly sample errors** from these 11 profiles, **clustering** the sampling **regionally** and **adjusting** to ensure **consistency** with the **historically-observed net GB imbalance**.
- Overall, demand errors are generally **clustered between +/-20pp** of **peak demand**.

Wind forecast error significantly outweighs solar and load errors; the impact on post-GCT costs is determined by the location and direction of errors

Total daily imbalance for wind, solar and demand in North Scotland and East Anglia, May 2030 (GW)

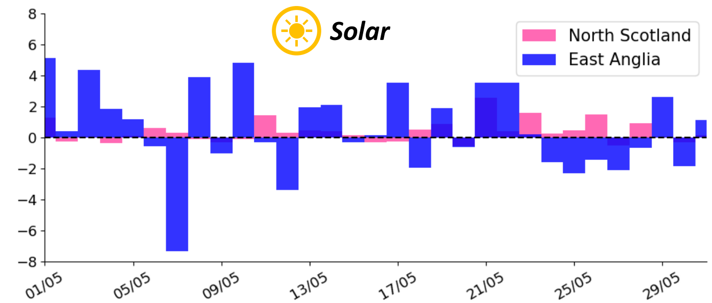
Net long *(more available energy post-GCT)*

Net short *(less available energy post-GCT)*



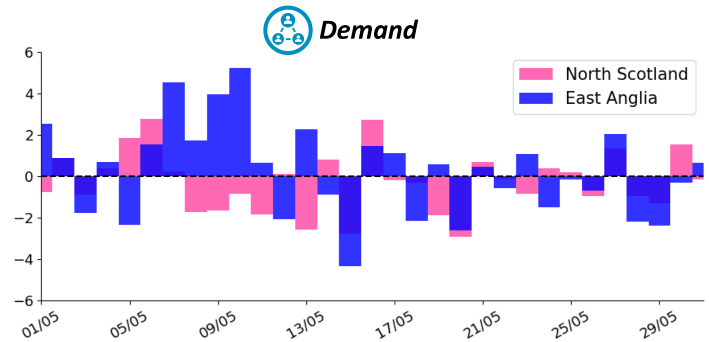
Net long *(more available energy post-GCT)*

Net short *(less available energy post-GCT)*



Net long *(more available energy post-GCT)*

Net short *(less available energy post-GCT)*



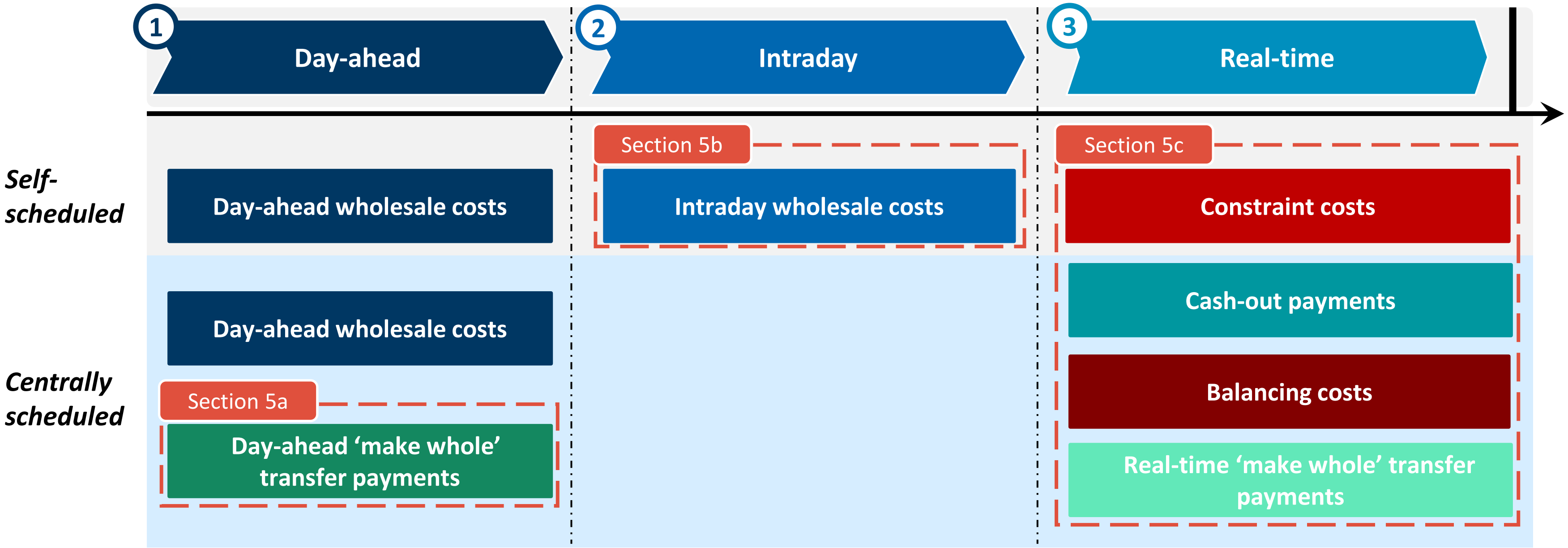
- The size and direction of historical forecast errors **vary significantly** across settlement periods and regions. The aggregate **wind** forecast error is an **order of magnitude greater** than for **solar** and **demand**.
- As shown in the lefthand graphs, forecast errors for demand, solar and wind can act in the **same** or **opposite directions** in North Scotland and East Anglia, with no discernible pattern.
- The **interaction between imbalances and constraint costs** depends both on the location of the imbalance and the scheduling arrangement.
- For example, a **positive imbalance** (e.g. higher wind output at GCT vs DA stage) in **Scotland could lead to:**
  - Under **self-scheduling**, scheduled Southern thermal generation to be turned down in the ID market with more wind available. However, the same thermal generators might be again constrained on in the BM. As such the **positive imbalance could lead to increased constraint costs**.
  - Under **central scheduling**, nearby units to be turned down in the BM (with some impact on BM costs), but limited need to constrain on alternative generation further south.
- Alternatively, a **negative imbalance** (e.g. lower wind) in Scotland could lead to:
  - Under **self-scheduling**, Southern thermal generation to be turned up in the ID market with less wind available. The **negative imbalance could reduce constraint costs**, with less wind constrained off in Scotland and thermal units scheduled earlier further south.
  - Under **central scheduling**, either reduced curtailment of nearby RES units or constraining on of nearby generation, with a **positive or negative impact on balancing costs**.

Section 5: Implementation of the methodology

We provide an in-depth overview of how we implement our methodology for the self and centrally scheduled market designs

- In this section we set out how the methodology is implemented to quantitatively test the self- and centrally scheduled market designs.
- In particular, we focus on the individual elements of the consumer and societal welfare assessment of a potential transition from a self-scheduling to a central scheduling arrangement, detailed on Slides 41-57:[1]
  - As shown in the diagram below, this is split into three subsections. These subsections are: (i) DA; (ii) ID; and (iii) RT.
  - Where appropriate, we complement our analysis with worked examples to provide the economic intuition behind our methodology.
  - Methodology assumptions have been developed in agreement with NESO. In instances where methodological assumptions appear to align with a specific policy stance on the detailed design of a centrally scheduled market, these should not be interpreted as recommendations on the final policy design, but rather modelling choices that have been made for the purpose of testing the case for central scheduling.
- DA wholesale costs are not discussed in detail. These are assumed to be the same under both scheduling arrangements as described in Slide 28.

Overview of the different modelled timeframes for both scheduling arrangements and relevant costs considered in the assessment



Note: (1) We also account for the change in CfD payments (driven by a change in final output) as part of our assessment of the change in consumer costs under central scheduling (see Appendix 5).

5a) Day-ahead

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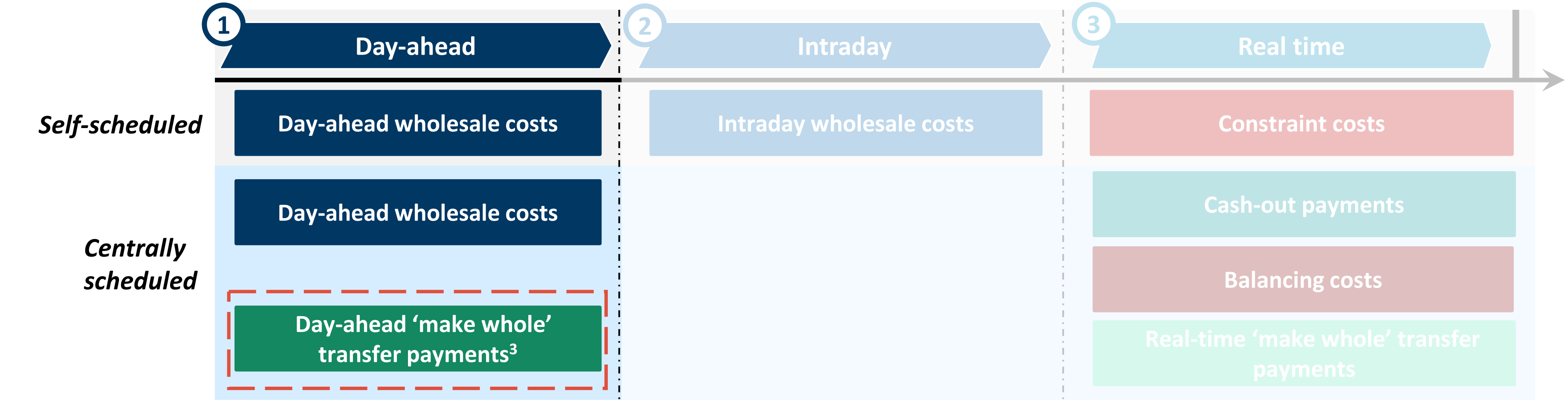
At day-ahead, wholesale costs are the same under self- and central scheduling, but transfer payments are required under a central schedule

- At DA stage under central scheduling, as under self-scheduling, consumers face the national unconstrained wholesale price. We assume the WS market clears at the same price under both scheduling designs, with WS costs therefore equal under the self- and centrally scheduled market designs.
- Similarly, generators face the national unconstrained wholesale price under both self- and central scheduling. However, under central scheduling, assets are scheduled to ensure compliance with Tx network constraints, with the schedule determined based on shadow nodal prices rather than national or zonal prices. Therefore, in a given hour, a generator may require compensation because:
  - They may be scheduled to generate at times when the unconstrained **national/zonal wholesale price does not cover their SRMC** ("cost recovery"); or
  - They **may not be scheduled to generate** at times when they would have been under self-scheduling ("firm access").
- As a result, under central scheduling, **'make whole' transfer payments** are required at the DA stage.[1]
- In this subsection, we outline the instances that would require a transfer payment under central scheduling and how they are priced within our model. We also describe how **transfer payments are applied to interconnectors** that are scheduled based on shadow nodal prices on the GB-side but continue to receive congestion rent based on the difference between the unconstrained GB wholesale price and the wholesale price in the connecting market.[2]

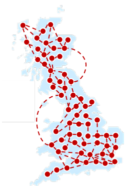
Overview of the different modelled timeframes for both scheduling arrangements and relevant costs taken into consideration in the assessment



Note: (1) We recognise there would be a significant degree of complexity in calculating transfer payments for storage assets under central scheduling given the difficulty in calculating hypothetical counterfactual revenues under self-scheduling (which would depend on the considered horizon). In this report, and recognising that storage is a relatively small share of total output (see Slide 59), we have made the simplifying assumption that transfer payments for storage assets are calculated on a weekly basis. For weeks where a storage asset earns less under central scheduling than they would have done under self-scheduling, they are paid the difference as a transfer payment. In practice, the specific methodology for compensating storage owners under central scheduling would need to be refined and calibrated to ensure appropriate risk-reward balance; (2) Scheduling interconnectors relative to the shadow nodal price in GB would provide significant operational complexities. FTI has identified sin subsequent work with NESO that there may be merits in examining the benefits case of a transition to central scheduling with ICs instead scheduled based on the national or zonal unconstrained wholesale price. (3) In practice, these transfer payments are, in the main, used similarly to constrained on and off payments in the BM under self, but are less costly as they are at DA.

We assume that generators will be compensated when worse off under central scheduling than they would have been under self-scheduling

A mismatch can arise between the prices determined by the central schedule and the price with which generators are compensated, as shown in the table below:

	Self-schedule	Central schedule
Schedule based on…	Unconstrained national wholesale price	Shadow nodal price 
Compensation based on…	Unconstrained national wholesale price 	Unconstrained national wholesale price 

Due to this mismatch between nodal scheduling and national compensation, some generator units will require 'make whole' transfer payments, under two scenarios:

Worked examples for a generator and an IC are provided in the following slides

Cost recovery:

- Asset is **centrally scheduled**, but the **unconstrained national price does not** cover its SRMC (as per its bid).
- To ensure it is not loss-making and hence unwilling to be centrally scheduled: **compensation = (SRMC – national price)*generation**
- This would typically be in **import constrained** regions.

Firm access rights:

- Asset is not **centrally scheduled**, but **would have been scheduled** under self-scheduling, firm access rights require the asset to be compensated the **equivalent profit as if it were scheduled**.
- **Policy choice**, not a necessary requirement to ensure the feasibility of a central schedule.[1]
- This would typically be in **export constrained** regions.

In hours where assets earn **higher revenue under central scheduling** than self-scheduling, we assume the asset **retains the additional revenue** (i.e. it is not netted off against transfer payments in other hours).

The need for 'make whole' transfer payments is driven by the combination of using a nodal schedule while retaining a national/zonal WS price. As explained in Slide 13 such compensations do not arise in the US-style design because scheduling and compensation are both made relative to nodal wholesale prices. However, "uplifts" can be paid in US nodal systems on top of the nodal WS price to allow generators to recover all their non-convex costs (which are typically not reflected in the nodal WS price).

Note: (1) However, not having firm access rights can result in disorderly bidding, whereby assets submit offers below their marginal cost to ensure there are scheduled. This can result in sub-optimal dispatch (for more detail see link).

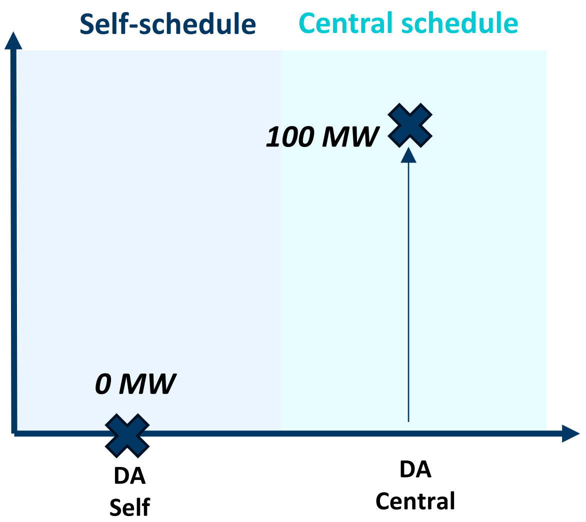
Worked example: Day-ahead 'make whole' transfer payments arise under two scenarios: cost recovery and firm access rights

Worked example 1: Cost recovery

- In this worked example, the prevailing wholesale price is £20/MWh.
- Under **self-scheduling**, a generator with an SRMC of £50/MWh offers into the wholesale market but is not "in merit" and therefore is not scheduled.
- However, the generator is scheduled to generate 100MW under **central scheduling**, but the prevailing wholesale price does not cover its SRMC.
- To recover costs, the generator receives a top-up transfer payment:

£(50-20)/MWh*100MW = £3,000

Wholesale price = £20/MWh
SRMC = £50/MWh
Cost recovery

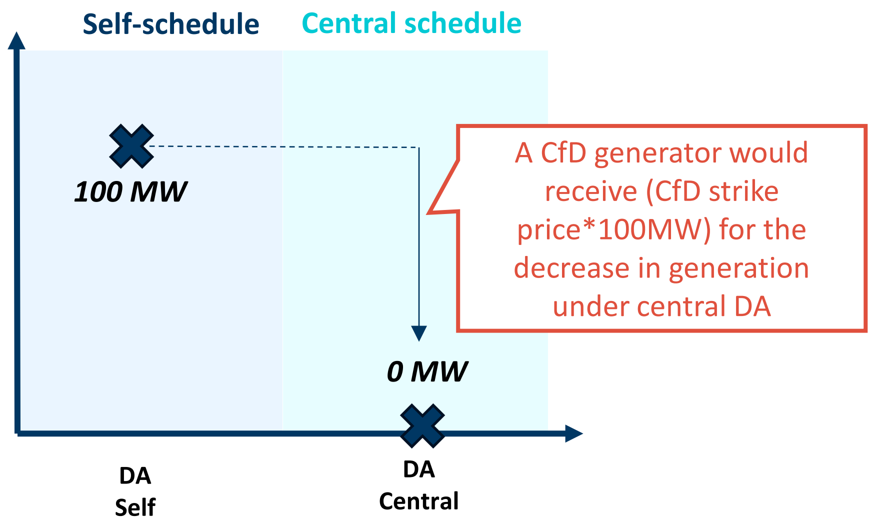


Worked example 2: Firm access rights

- In this worked example, the prevailing wholesale price is £20/MWh.
- Under **self-scheduling**, a generator with an SRMC of £5/MWh offers into the wholesale market at its SRMC and is scheduled to generate 100MW.
- However, the generator is not scheduled under **central scheduling** due to nearby Tx constraints.
- To recover lost profits, the generator receives a top-up transfer payment:

£(20-5)/MWh*100MW = £1,500

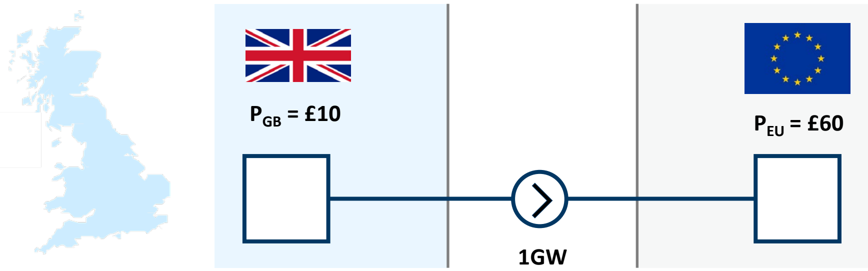
Wholesale price = £20/MWh
SRMC = £5/MWh
Firm access rights



Worked example: We assume ICs are centrally scheduled according to 'shadow' GB nodal prices, so ICs may require 'make whole' transfer payments

Self-scheduling

- In the example hour shown below, the prevailing (unconstrained) wholesale price in GB is £10/MWh, while in the connected European market the prevailing wholesale price is £60/MWh.
- Under self-scheduling, flows will be scheduled on the IC according to the wholesale price in both GB and the connected European market.
- The IC will therefore be scheduled to flow from the lower-priced market to the higher priced market (from GB to the connected European market in the example below).



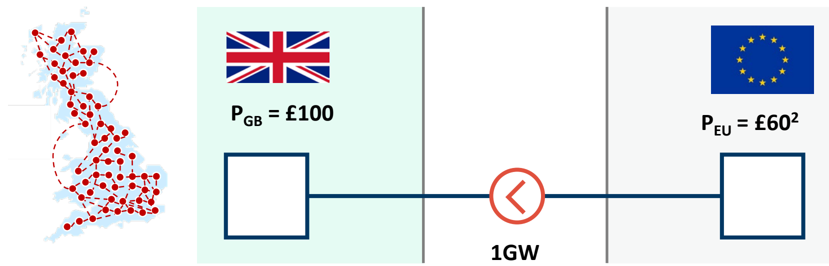
- Under self-scheduling, ICs are also compensated according to the same wholesale prices.
- In this example, the IC is scheduled to flow from GB to the connecting market and will earn £50,000 in congestion revenues.

Schedule price	**£10**	**£60**
Commercial price	**£10**	**£60**

Congestion revenues: 1,000MW * (£60 - £10) = £50,000[1]

Central scheduling

- Under central scheduling, assets are compensated according to the same DA wholesale price as under self-scheduling (the unconstrained national wholesale price). However, they are centrally scheduled according to shadow nodal prices.
- In the same example hour, with a prevailing national wholesale price of £10/MWh in GB and £60/MWh in the connected market, the shadow nodal price at the GB node the IC connects to is £100/MWh.
- As the shadow nodal price in GB is higher than the connecting market's wholesale price, the IC is now scheduled to flow towards GB (shown below).



- However, the IC is compensated according to the unconstrained GB national wholesale price.
- Therefore, in this example, the interconnector earns negative congestion rents.

Consequently, a transfer payment to the IC capacity holder of £100k (£50k for foregone DA revenue and £50k for losses from the scheduled flow) is required to make the IC capacity holder whole relative to self-scheduling.

Schedule price	**£100**	**£60**
Commercial price	**£10**	**£60**

Congestion revenues: 1,000MW * (£10 - £60) = -£50,000

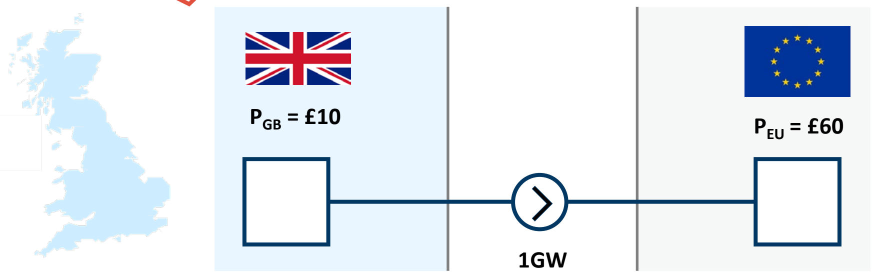
Note: (1) In this report we do not examine in detail the specific design of cross-border trading arrangements (such as explicit or implicit price coupling, or multi-region loose volume coupling ("MRLVC") and the interaction with market design (for example central scheduling or locational pricing). However, we recognise that there is a significant degree of complexity in aligning the selected market design with compatible cross-border trading arrangements. In this report, we make the simplifying assumption that all IC capacity is scheduled by market participants with perfect foresight under both scheduling designs. This means that any imperfections arising from explicit trading of IC capacity, as distinct from energy, are not evaluated. This approach is also, in modelling terms, akin to modelling implicit price coupling between GB and its European neighbours; (2) The additional demand provided by GB may cause the EU price to increase, in which case congestion revenues would be even more negative.

Worked example: However, IC revenues in some hours are the same under self- and central scheduling, with no transfer payment required

Self-scheduling

- Again, in this example hour the prevailing wholesale price in GB is £10/MWh, while in the connected European market the prevailing wholesale price is £60/MWh.
- The IC is scheduled to flow from GB to the European connected market according to the different wholesale prices in the two countries.

Note: Self-scheduling example is unchanged from previous slide



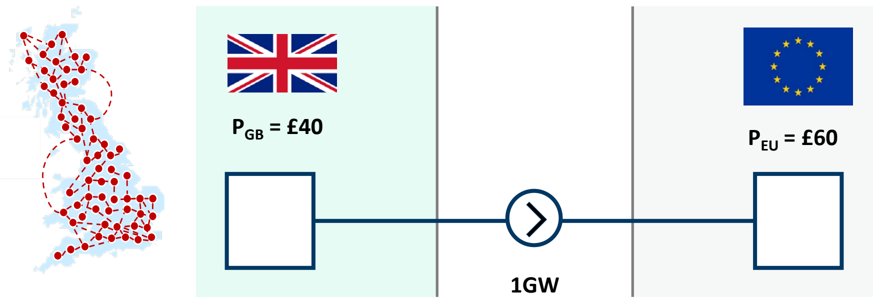
- The IC is then compensated according to the same wholesale prices as its schedule is based upon.
- In this example, the IC is scheduled to flow from GB to the connecting European market and earns £50,000 in congestion revenues.

	GB	EU
Schedule price	£10	£60
Commercial price	£10	£60

Congestion revenues: 1,000MW * (£60 - £10) = £50,000

Central scheduling

- In the same example hour, with a prevailing national wholesale price of £10/MWh in GB and £60/MWh in the European connected market, the shadow nodal price at the GB node the IC connects to is £40/MWh (rather than £100/MWh in the example on the previous slide).
- In this case, both the shadow nodal price (the price that determines the central schedule) and the 'unconstrained' wholesale price (the price that determines asset compensation) are lower than the EU price. Therefore, scheduled flows are equivalent under self- and central scheduling.



- Compared to the example on the previous slide, the IC is flowing in line with commercial prices (from the lower to the higher priced market).
- The IC thus earns the same as under self-scheduling, and no transfer payment is required.

	GB	EU
Schedule price	£40	£60
Commercial price	£10	£60

IC earns the same revenues under self and central, therefore no transfer payment is required.

Congestion revenues: 1,000MW * (£60 - £10) = £50,000

5b) Intraday

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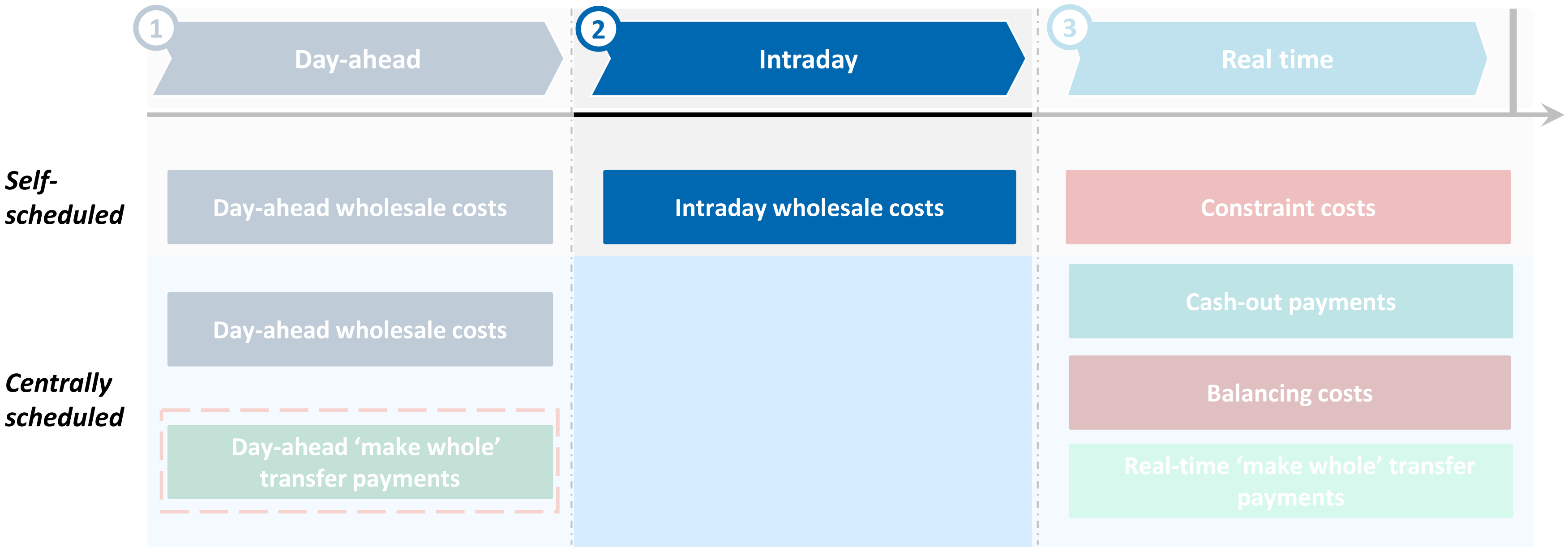
Under self-scheduling, forecast errors in RES output and demand are resolved via intraday trading, while we assume no intraday trading under central

- Due to **imperfect forecasting**, available intermittent RES generation (solar and wind) and demand may differ closer to delivery and in real-time from what was forecasted at DA.
- Under self-scheduling, buyers and sellers of power are assumed to balance their respective trade positions ID to resolve forecast errors as information regarding likely outturn improves, thereby solving **aggregate GB imbalance before GCT** (we assume no post-GCT errors under self-scheduling).
- **ID wholesale costs under self-scheduling** are computed as the incremental/decremental demand in ID (relative to DA) multiplied by the modelled ID wholesale price.
- In contrast, under central scheduling **we assume forecast errors and resulting imbalances are resolved after GCT** (see Section 5c for further detail).[1]
- In the next slide we provide further detail on the calculation of the ID wholesale costs under self-scheduling.

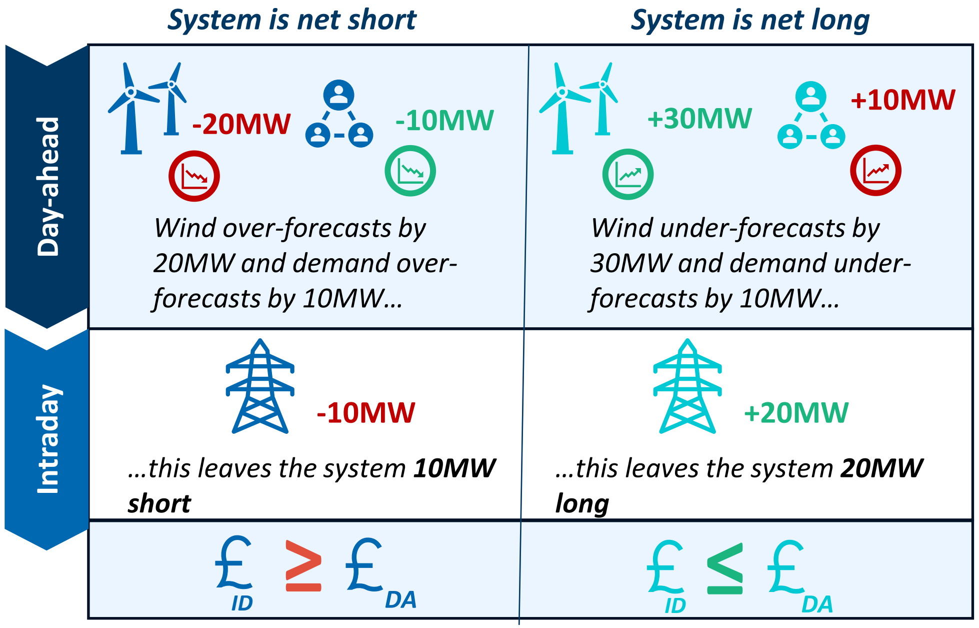
Overview of the different modelled timeframes for both scheduling arrangements and relevant costs considered in the assessment



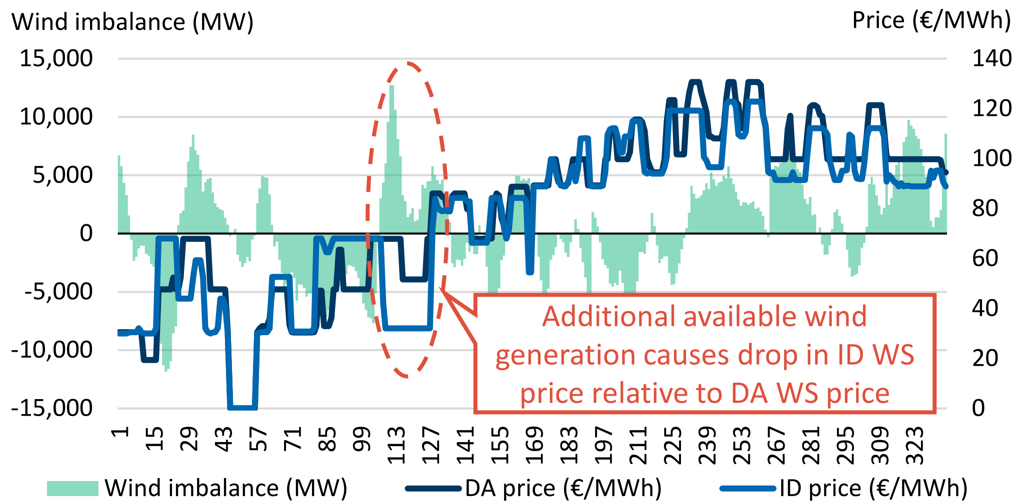
Note: (1) This is a conservative assumption with regards to the potential benefits of central scheduling. As noted in Slide 14, ID markets operate alongside the central schedule in some jurisdictions (such as Italy). Assuming that all forecast error-driven imbalances are resolved post-GCT in the BM, rather than through ID trading, likely overestimates the cost of adjusting the central schedule in response to improved information about likely outturn.

Incremental or decremental demand in intraday pays/receives the intraday wholesale price, which may be higher or lower than the DA wholesale price

- Due to differing mis-forecasts between demand and RES in a given hour, scheduled supply does not always equal demand at ID stage. If forecast errors mean that demand exceeds scheduled supply, **the system is considered to be net short.** The ID WS price is therefore likely to be higher than the DA WS price, with more expensive forms of generation required to be used to meet demand.
- Conversely, if forecast errors mean scheduled supply exceeds demand at ID, **the system is considered to be net long,** and the ID WS price is likely to be lower than the DA WS price.
- The top-right diagram provides example imbalances of supply and demand dynamics in the ID market and how these affect the ID price.
- This effect is borne out in our modelling results. The chart in the bottom-right shows, for an example two-week period, how wind imbalances affect ID prices in our modelling. For example, the circled orange period reflects a period where the expected wind generation increases in ID relative to DA which causes the ID price to fall relative to the DA price.
- Incremental/decremental demand in ID (relative to DA) pays/receives the ID price.
- This **encourages accurate DA forecasting:**[1]
  - at moments when the system is long (excess of generation or lack of demand), sellers will typically receive less for their electricity at ID than if sold at DA while buyers will pay less.
  - at moments when the system is short (lack of generation or excess demand), sellers will typically receive more for their electricity at ID than if sold at DA while buyers will pay more.



Hourly wind imbalance and effect on WS price, Jan 1 – Jan 14 in 2030



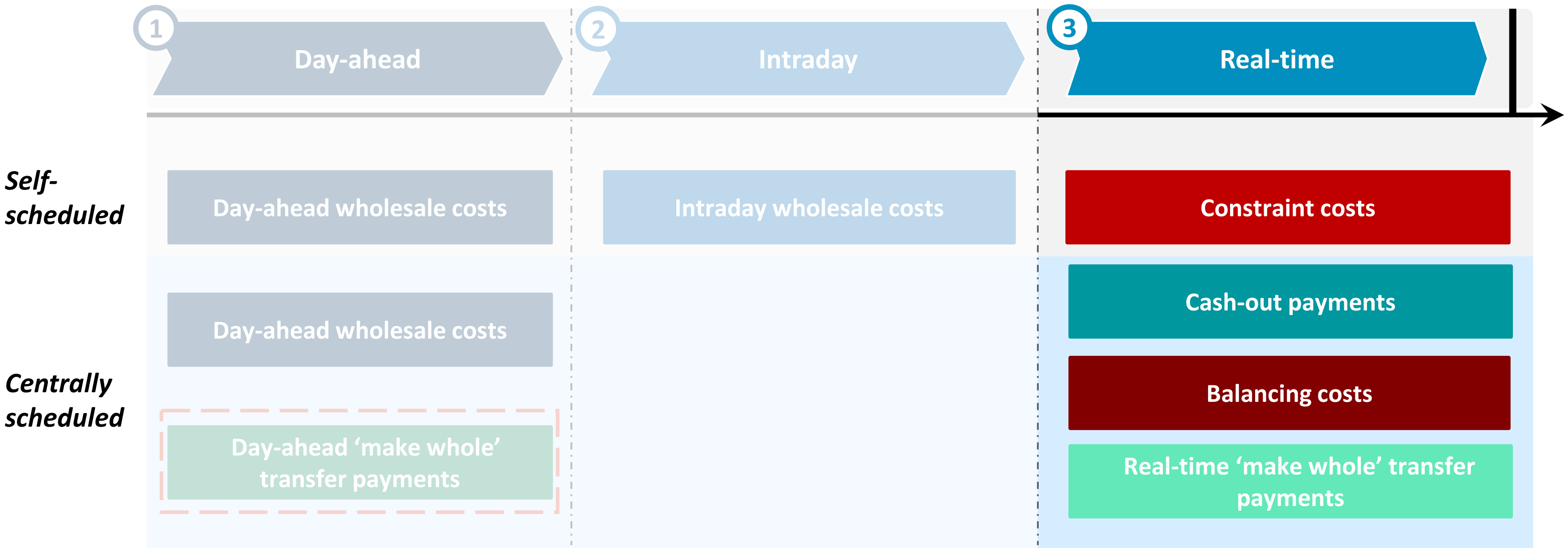
Note: (1) At least when considering that the system imbalance in ID is not predictable and market participants are risk-averse. We do not seek to capture the effects of any market participants deliberately seeking to be out of balance in this quantitative assessment.

5c) Real-time

Post-GCT, thermal Tx constraints are resolved under self-scheduling, while forecast errors are resolved under central scheduling

- Under **self-scheduling**, **thermal Tx constraints are resolved post-GCT via BM actions**, resulting in constraint management costs. By contrast, under central scheduling, Tx constraints have (in the main) been resolved at the DA stage (via transfer payments), at least for the expected generation and demand at the DA stage.
- However, unlike under self-scheduling, we assume that **under central scheduling balancing actions are required to resolve forecast errors in RT**. Different types of action have different associated costs, namely:
  - Balancing costs;[1]
  - Cash-out payments; and
  - RT transfer payments.
- In this subsection we describe the conditions in which these different types of payments arise, and how they are costed in our model.

Overview of the different modelled timeframes for both scheduling arrangements and relevant costs taken into consideration in the assessment



Note: (1) Balancing costs include actions in the BM to resolve the net imbalance created by forecast errors. Imbalances can also create thermal constraints but the volume of thermal constraints under central scheduling to be resolved in RT can be expected to be significantly smaller than under self-scheduling.

To calculate constraint costs under self-scheduling we model redispatch volumes and apply bid and offer price assumptions

- Under self-scheduling, Tx constraints are ignored in the DA/ID WS market; these constraints need to be resolved after GCT through BM actions.
- To model the resolving of Tx constraints in the BM, we first consider the final (unconstrained) ID schedule. We then use our nodal model ("the constrained redispatch run") to find the optimal schedule when accounting for Tx constraints, subject to technology-specific restrictions.[1]
- The difference between the ID schedule and the outcome of the nodal run is interpreted as redispatch volume and costed using assumed bid and offer prices. We provide more detail on this below and in the following slide.

Redispatch volumes

- To identify redispatch volumes under self-scheduling, we compare the unconstrained ID wholesale run and the constrained redispatch run that resolves thermal Tx constraints.

Scheduled volumes: Wholesale model run without intra-GB Tx constraints

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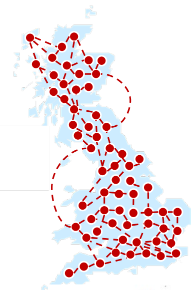
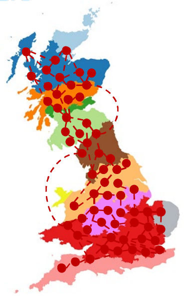
Scheduled volumes: wholesale model run with intra-GB Tx constraints

National



Zonal



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Bid and offer prices

- Differences in scheduled volumes represent RT BM actions that are required to resolve Tx constraints.
- Actions in the BM are priced as pay-as-bid and can result in payments either **by NESO to market participants** or **from market participants to NESO**.
- We apply bid prices for constrained off actions, and offer prices for constrained on actions, both of which vary by technology.
- **Uplifts** are included in the offer prices for some units, calibrated on **historical data,** including data provided by NESO. Given that these are based on observed data, they are likely to reflect a combination of **non-convex costs** (such as start-up and shutdown costs), but may also capture **market power**, insofar as that has historically been an issue in the BM.
- **BM actions are priced the same under self- and central scheduling**, and these **assumptions align with the current NESO methodology**, but total BM costs are higher under self-scheduling due to a higher volume of BM actions.
- The next slide provides detailed assumptions on the technologies active in the BM and bid/offer prices.

Note: (1) The redispatch run considers the generation and demand at GCT, i.e., after the ID market. Certain technologies' output in the redispatch run is fixed to its GCT position e.g., we assume that nuclear and skipped batteries cannot change their output post-GCT in the BM from their GCT position (see the next slides for more detail).

BM actions are priced equally under self and central scheduling, but the volumes and units called upon in the BM will differ in either case

- The table below shows assumed bid and offer prices for different technologies in the BM, formulated in agreement with NESO.
- These prices are applied for both resolving thermal constraints under self-scheduling and resolving energy imbalances under central scheduling.

Bid/offer prices used in the modelling of the Baseline BM

Baseline BM (NESO methodology)

Technology	Cost to NESO Bid (constrained off)	Cost to NESO Offer (constrained on)	
Fossil fuel	- Fuel cost - carbon cost	Offer uplift	+ Fuel cost + carbon cost
Renewable obligation certificate ("ROCs")	ROCs	(theoretical so no price assumed)	
Merchant renewables	£0	Offer uplift	
CfD renewables	CfD strike price – Wholesale price	Offer uplift	- CfD strike price
Batteries/Other storage	- Price Paid	Offer uplift	+ Price Received[1]
Interconnectors	Cost of reversing flow to export	Cost of reversing flow to import	
Biomass	- SRMC	Offer uplift	+ SRMC
Hydro (run-of-river)	£0 (but bids only clear after merchant RES)	(theoretical so no price assumed)	

Technologies not listed are assumed not to participate in our Baseline BM. We have also conducted an assessment using an **Augmented BM** which allows additional technologies, such as waste and hydrogen, to participate (see Slide 75).

Note: (1) Calculated as the average price paid/received across the week in the DA WS market.

- As set out on the previous slide, offer uplifts are applied to some technologies, intended to account for the non-convex costs (such as start-up and shutdown costs) that may be required for last-minute BM activation (but potentially also capturing historical market power).
- We assume no bid uplifts, implicitly assuming minimal operational cost of turn-down for units in the BM. This is a conservative assumption for the net cost to NESO of BM actions. Applying bid uplifts would be expected to increase modelled constraint costs under self-scheduling and balancing costs under central scheduling.

Fossil fuel

- Uplifts are aligned with average historical uplifts using data provided by NESO (see Slide 52). The offer uplift for thermal units is reduced from 72% to 60% in the Augmented BM (see Slide 76).

Interconnectors

- Flow reversals are modelled endogenously, with the cost calculated using an annual average of monthly NESO forecasts which consider the cost of the marginal plant in the connected country.

CfD wind

- Assumed strike price for CfD wind does not account for the recently raised strike price seen in the AR6 auction.
- Accounting for the raised strike prices would likely increase constraint costs under self-scheduling and transfer payments under central scheduling.

We have developed three 'rules' for allocating the post-GCT costs that arise from day-ahead forecast errors under central scheduling

- As discussed on Slide 51, unlike our modelled representation of self-scheduling with market-led resolution of forecast errors through ID trading, under central scheduling these errors must be centrally resolved by the system operator.
- Solving forecast errors in the BM results in three types of action, outlined below, with worked examples for each provided in the following slides.

Rules for allocating the costs of resolving forecast errors under central scheduling

1 Cash-out payments

Rule #1: If a change in generator **output** or **load** at a GSP is caused by **a unit's own forecast error**, it receives or pays a **cash-out payment**

- Cash-out payments compensate for any realised changed in output or load that is driven by an entity's own forecast error. For example, a windfarm that has under-forecasted at DA receives a cash-out payment if its additional available output is used in RT.
- We use the self-scheduling ID price to estimate the RT cash-out price under central scheduling (see appendix 3). This exposes generators to the same level of pricing risk/reward from over/under-forecasting in our modelled representations of self- and central scheduling.
- **We assume that any cash-out payment due to a unit would** first **repay** any 'make whole' **transfer received for the relevant output at DA.**[1]

2 Balancing costs

Rule #2: Any **change in generator output** that is **not a result of its own forecast error** should be priced as a **NESO BM action**, resulting in balancing costs

- Balancing costs are paid when a unit changes its output in response to an SO request. For example, a thermal unit may be called upon to increase output due to lower-than-expected wind output.
- Priced as a standard pay-as-bid balancing action (under Baseline BM assumptions).
- **BM revenues are not offset against DA transfers.**

3 Real-time transfers

Rule #3: If a **forecast error does not lead to a change** in a unit's output, it instead **receives/pays a transfer payment** for the associated mis-forecast

- RT transfers protect/penalise units when their forecast error does not change their final output (meaning no cash-out payment is made/received).
- For example, a windfarm that has under-forecasted at DA receives a RT transfer if its additional available output is not used in RT.
- As with cash-out payments, RT transfers are made based on the self- ID price.
- **RT transfers** first **repay** any 'make-whole' **transfers received at DA for the relevant output.**

Note: (1) While this exposes generators to some risk from over- or under-forecasting at DA, we implicitly assume that additional incentives through, for example, a best endeavours licence obligation, are placed on generators to accurately forecast available output at DA.

Self | Central | DA | ID | RT

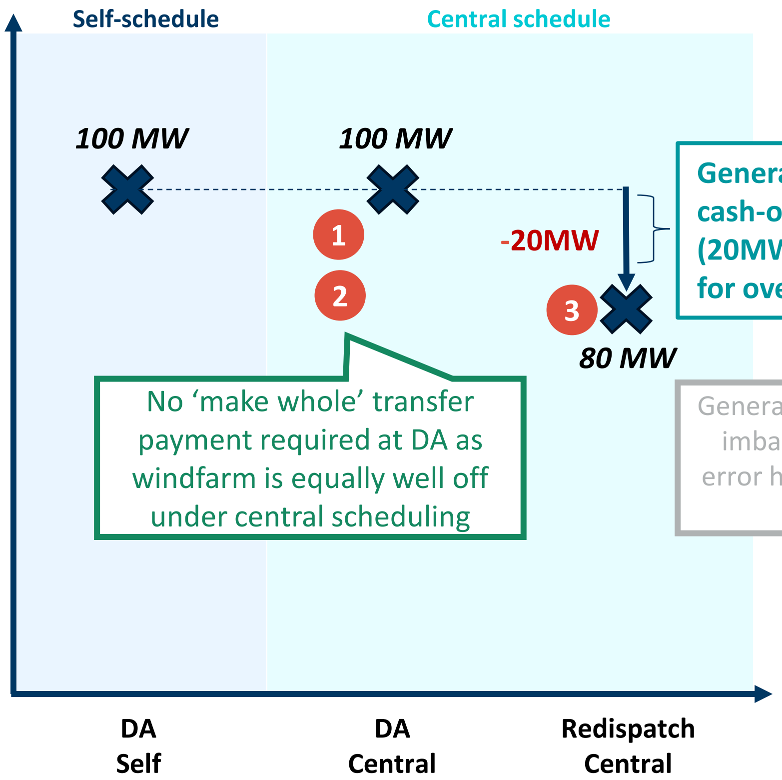
Rule #1: If a generator or demand GSP's forecast error leads to a change in its output or load, it receives/pays a cash-out payment

1 **Cash-out payments**

Worked example 1: A merchant windfarm is fully scheduled at DA under self- and central scheduling, but has over-forecasted its available output. Post-GCT under central scheduling, the windfarm must pay a cash-out price (i.e. repay the ID wholesale price) for the resulting fall in output.

Tech: Wind | **DA Central vs self :** Equal generation | **Forecast error:** Over-forecast

Wholesale price = €2/MWh
Intraday price = €3/MWh
Over-forecast = 20MW



	Volume	✖ Price	= Revenue
	MW	*€/MWh*	*€*
1 Wholesale market	100	2	200
2 Transfer payments	-	-	-
3 Cash-out	-20	3	-60
Outturn dispatch	80	-	140

ID price higher than at DA, meaning system was net short in the settlement period

As generator contributed to market being net short, revenue falls from mis-forecast (but no more than in the self-scheduled setup)

Rule #2: Any change in generator output that is not a result of its own forecast error should be priced as a NESO BM action, resulting in balancing costs

2

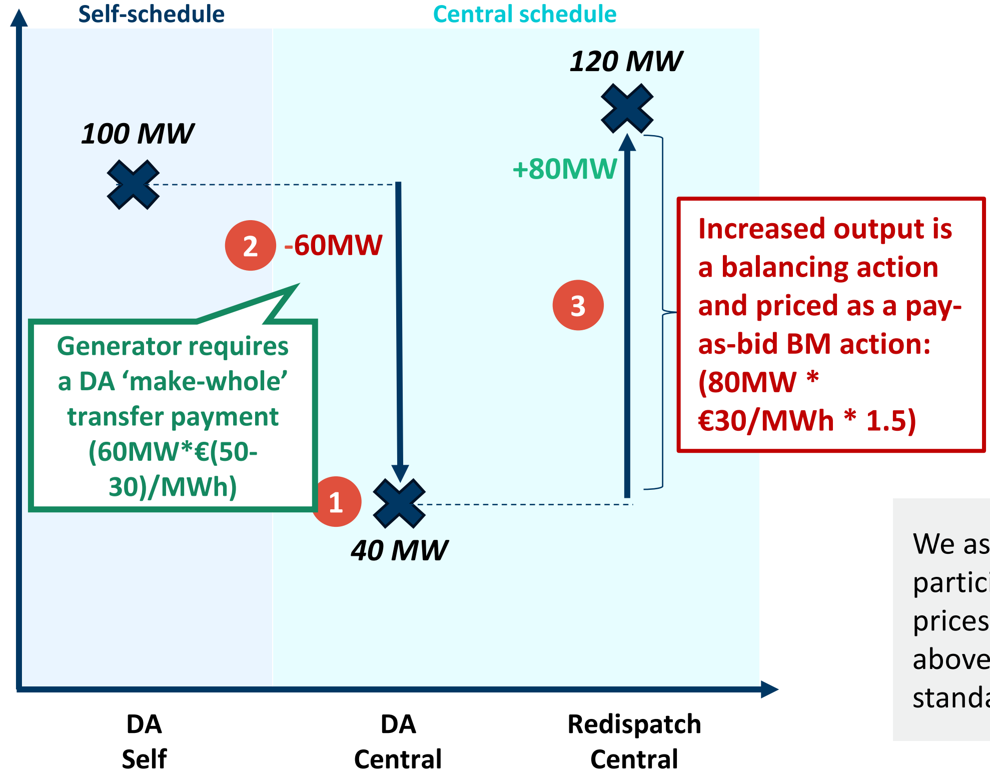
Balancing costs

Worked example 2: A merchant generator is fully scheduled at DA under self-scheduling but curtailed under central scheduling, requiring a 'make-whole' transfer. Post-GCT under central scheduling, the generator is activated in the BM to help resolve system imbalance. The unit retains the transfer received at DA and earns additional revenue in the BM.

Tech: Fossil fuel

DA Central vs self : Reduced generation

Forecast error: No forecast error



Wholesale price = €70/MWh
SRMC = €30/MWh, BM Uplift = 1.5x

		Volume	Price	Revenue
		MW	*€/MWh*	*€*
1	Wholesale market	40	70	2,800
2	Transfer payments	60	(70-30) *(Price-SRMC)*	2,400
3	BM	80	45 *(SRMC*uplift)*	3,600
	Outturn dispatch	120	-	8,800

We assume **BM revenues are not offset against DA transfers**, as if they were, BM participants would instead account for any foregone transfer payment in their bid/offer prices in the BM such that their **total revenues would be equal.** E.g. in the example above, the unit's additional output in the BM would not be profitable under the standard BM pricing if required to first repay DA make-whole transfer payments.

Self | Central | DA | ID | RT

Rule #3: If a forecast error does not lead to a change in a unit's output, it instead receives/pays a transfer payment for the associated mis-forecast

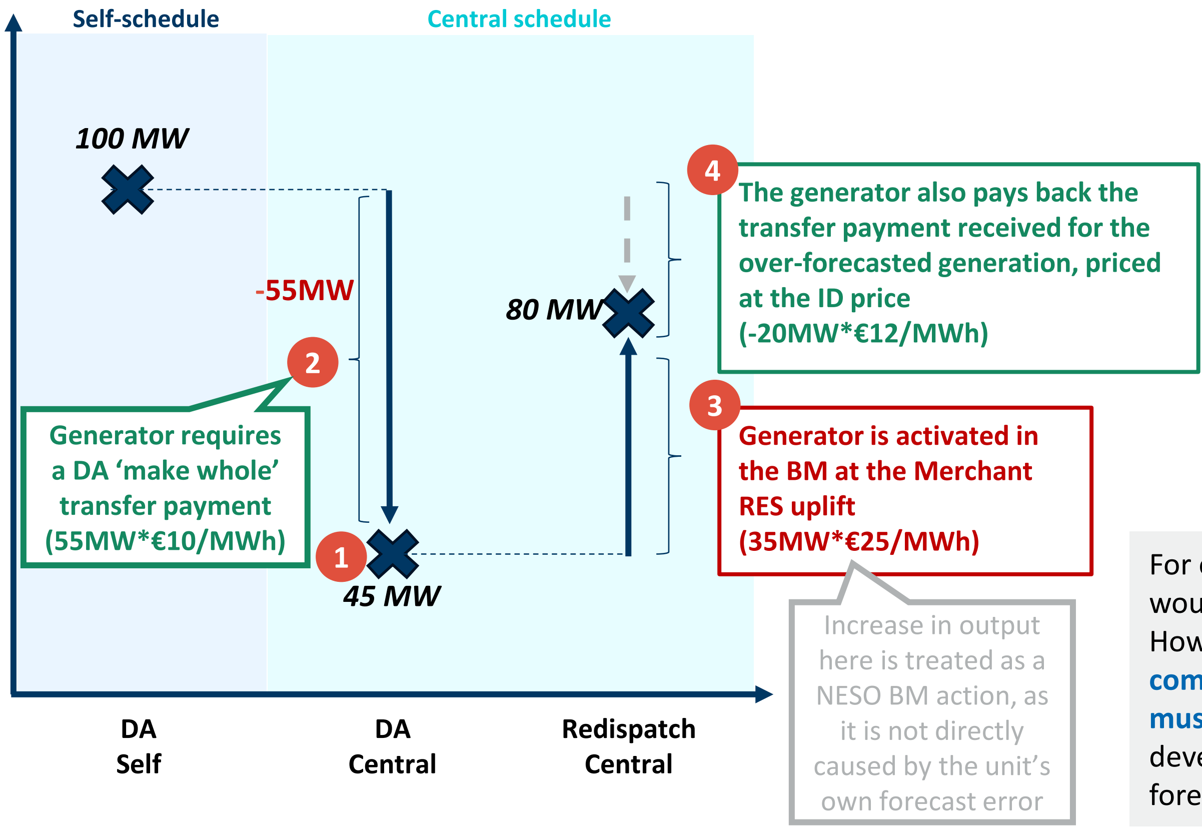
3

Real-time transfers

Worked example 3: A merchant windfarm in the North is scheduled less under central, had over-forecasted at DA, but is activated in RT. At DA, the windfarm receives a make-whole transfer for the reduced scheduled output under central relative to self (firm access). Post-GCT, the windfarm receives a payment for its increase in output but repays the make whole transfer received for (only) its over-forecasted DA output.

Tech: Wind | DA Central vs self : Reduced generation | Forecast error: Over-forecast

Wholesale price = €10/MWh
Intraday price = €12/MWh
Over-forecast = 20MW



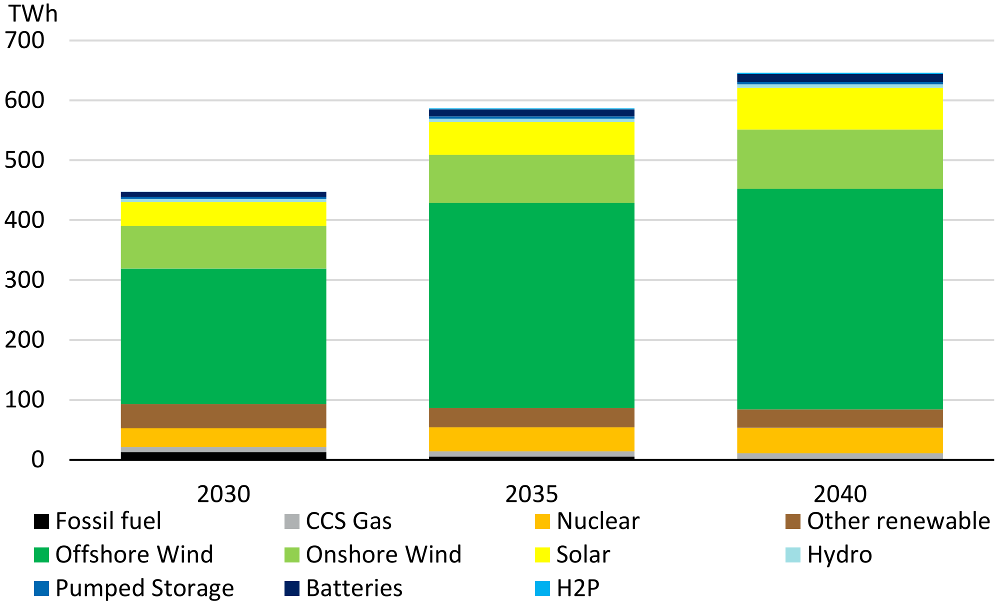
		Volume	Price	Revenue
		MW	*€/MWh*	*€*
1	Wholesale market	45	10	450
2	Transfer payments	55	10	550
3	BM	35	25	875
4	Transfer payments	-20	12	-240
	Outturn dispatch	135	-	1,635

For our calculation of RT transfers, we implicitly assume that NESO would have **full visibility of the potential output** of each asset. However, we acknowledge there are **certain operational complexities** that may make this difficult. The same assumption **must be made for deemed CfDs** to function, and certain developments, such as increased forecasting precision, are making forecasting of potential output **increasingly possible.**

Section 6: Results

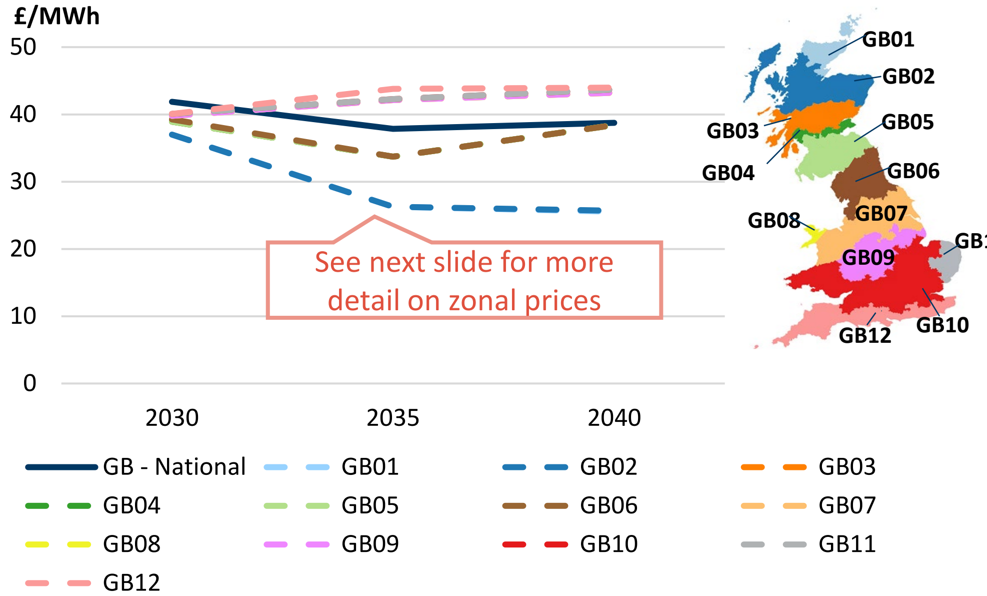
RES generation is expected to increase significantly between 2030 and 2040, although increasing demand means average wholesale prices remain stable

Annual DA scheduled generation by technology, self-scheduling, national wholesale pricing[1,2]



- As discussed in Slide 33, our pan-European model aligns generation capacity by technology with FES 2022 LtW and calculates generation on a unit basis for each hour.
- As shown in the chart above, increasing demand over the modelling period is largely met by **increased RES generation**.
- Fossil fuel generation makes up a small component of total DA wholesale generation in 2030 and reduces to almost zero by 2040.

Average time-weighted annual WS national and zonal prices over the modelling period and WS prices variability metrics (£/MWh)[3]



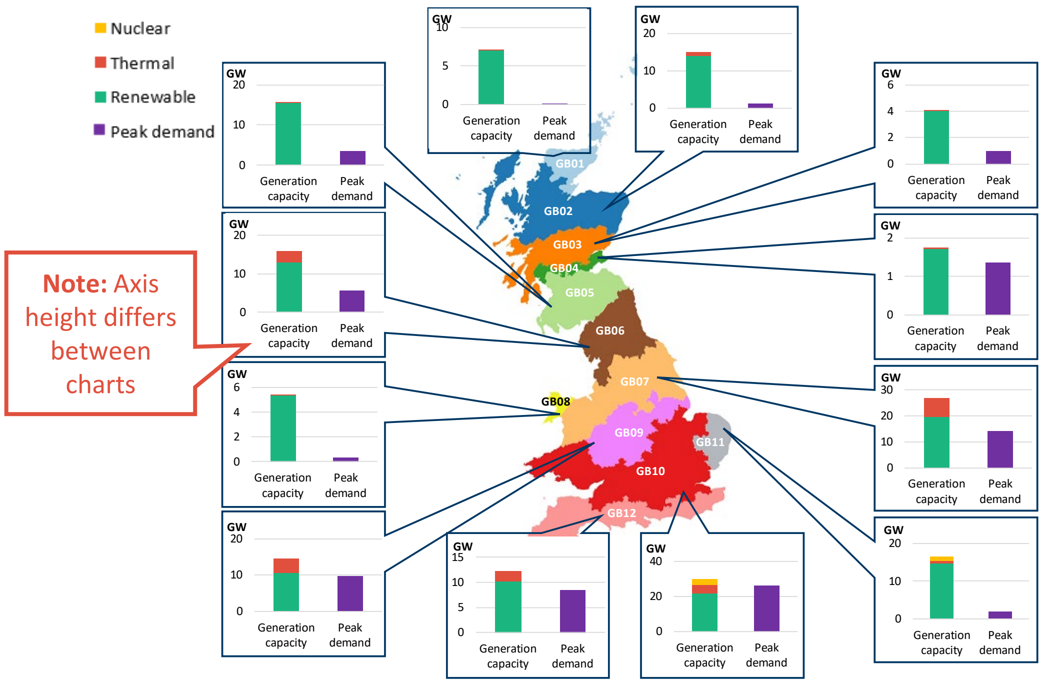
- The average time-weighted national WS price falls from £42/MWh in 2030, to £38/MWh in 2035 and slightly rises again to £39/MWh in 2040.
- The average time-weighted zonal WS prices in 2030 are very similar across zones and lower than the national average WS price for all zones.
- In 2035 and 2040, increasing Tx constraints lead to greater price divergence across zones, with Northern zones (GB06 and above) typically seeing lower average prices than under national pricing and the reverse for zones below GB06. We describe zonal price dynamics in more detail in the next slide.

Note: (1) Annual DA scheduled generation under central scheduling is slightly different than under self-scheduling due to less scheduled exports but follows the same trends of increasing generation across the modelling period, largely composed of RES; (2) Other renewable is composed of biomass, CCS biomass, and waste; (3) Annual average prices presented for all zones. However, some modelled zones, such as GB05 and GB06, have very similar prices across the year with minimal discernible difference in the chart (see heatmaps on next slide for further detail).

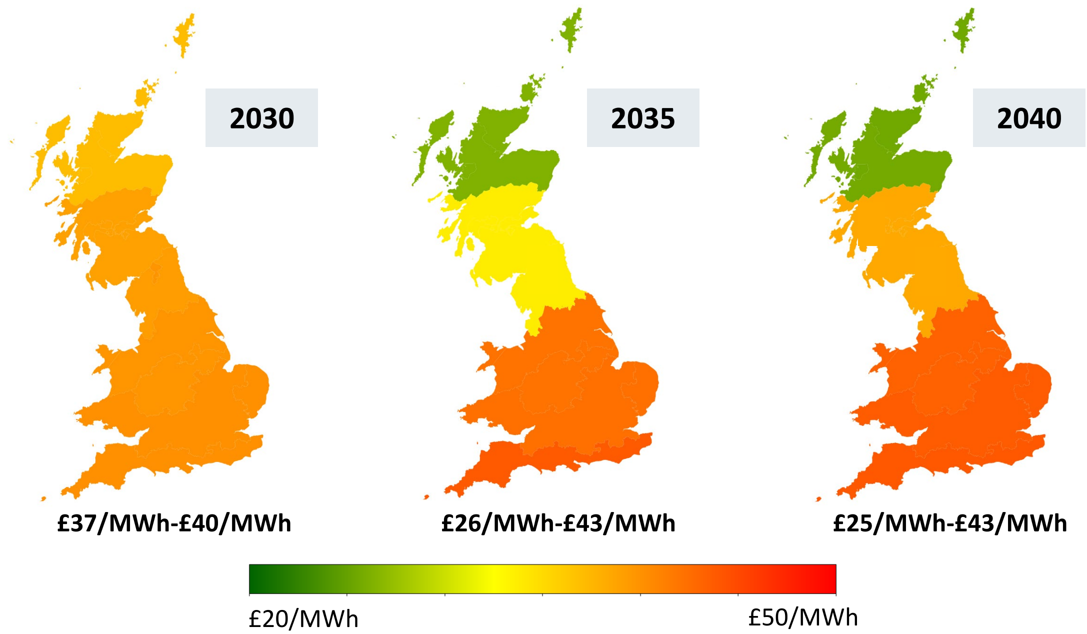
Zonal prices tend to be, on average, lower in the North of GB where electricity supply outstrips demand, while the opposite is true in the South

- As illustrated in the lefthand chart, generation capacity far outstrips peak electricity demand for a number of zones in the North of GB. These areas tend to be sparsely populated with low consumer demand, coupled with high offshore wind capacity.
- On the other hand, peak demand is closer to generation capacity for zones in the south. Given the majority of the GB population is situated in these areas, consumer demand tends to be higher, while comparatively less wind capacity is situated nearby.
- This dynamic of high generation supply and low demand in the North and vice-versa for the south (combined with inter-zonal Tx constraints) means average wholesale electricity prices tend to be lower in the North (as shown in the chart on the right).
- Prices are similar across zones in 2030 as Tx capacity is high relative to generation and demand, while prices diverge more across zones in 2035 and 2040 as RES generation capacity build accelerates relative to the speed of Tx build-out.

Generation capacity and peak demand in GW per zone, 2030, FES 2022 (LtW)[1]



Average annual zonal WS prices (time-weighted), 2030-2040 (£/MWh)

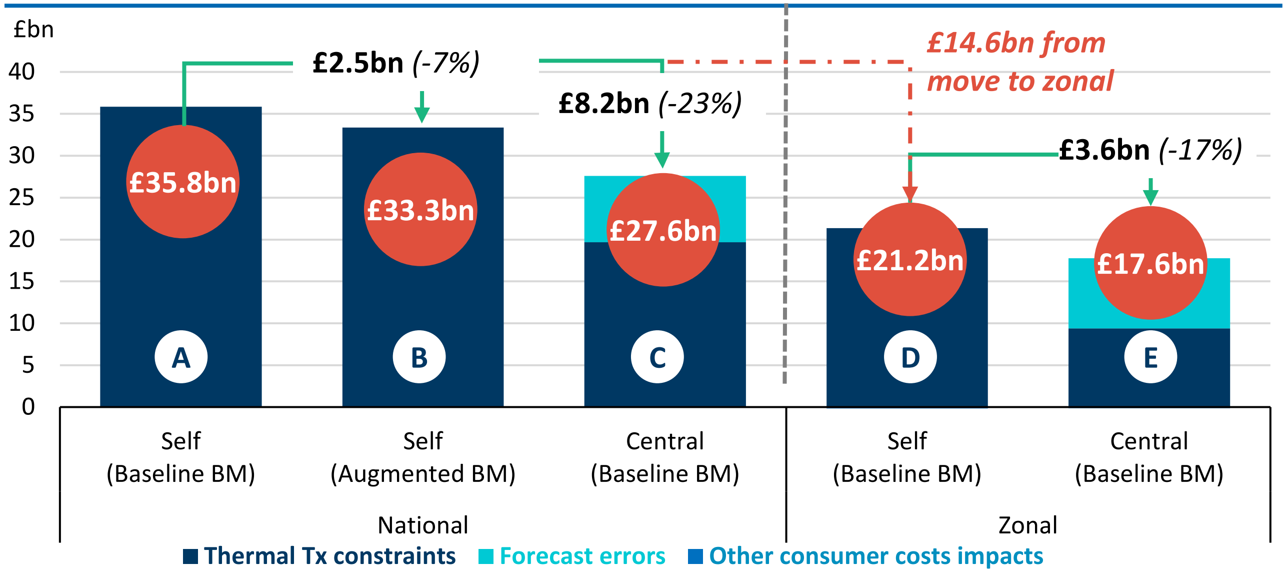


Sources: (1) FTI analysis based on ESO's FES 2022 (LtW).

Overview results

Central scheduling reduces consumer costs by £3.6bn-£8.2bn, but the largest reduction in consumer costs comes from introducing zonal design (£14.6bn)

Consumer costs incurred under self- vs central scheduling, £bn, present value ("PV") 2030-2040[1,2,3]



- Under **national** wholesale pricing, a move **from self- to central scheduling** lowers aggregate consumer costs by **£8.2bn**.
- Retaining self-scheduling with an improved use of thermal and storage assets in an **Augmented BM** would instead (i.e. as an alternative to central scheduling) reduce consumer costs by **£2.5bn**.
- Alternatively, keeping self-scheduling but **transitioning to zonal** wholesale pricing would reduce consumer costs by **£14.6bn.**
- Introducing **central scheduling under a zonal design** would provide a further incremental cost reduction of **£3.6bn**.

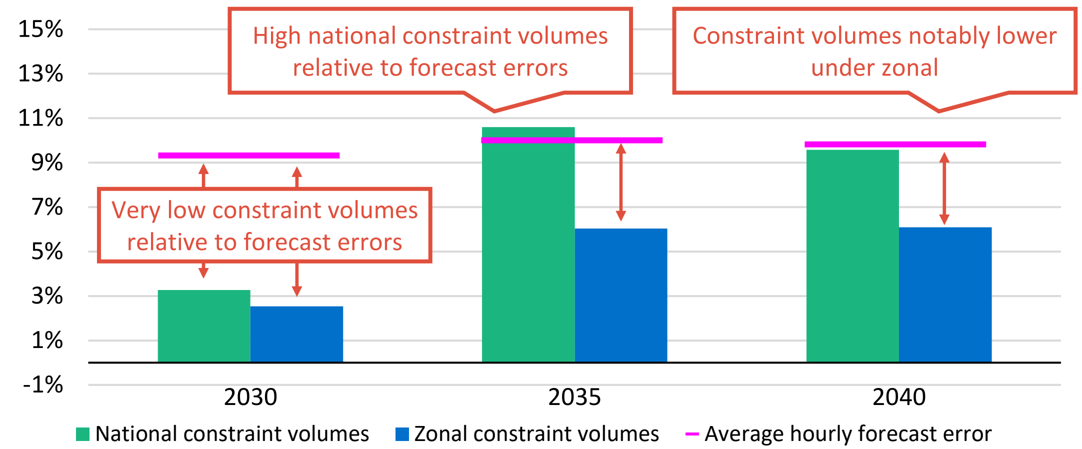
- **Key finding #1**: **Central scheduling leads to a reduction in aggregate consumer costs under national design** (moving from A to C, in the modelled period of 2030-2040). This confirms the hypothesis that solving Tx constraints at DA stage is, based on the modelled scenario, more valuable than solving GB-wide imbalances by market participants (i.e. the cost of resolving Tx constraints is higher than the cost of addressing forecast errors).
- **Key finding #2**: The **benefits of central scheduling are highest in years when congestion on the intra-GB Tx network is highest**. In one modelled year, where the modelled congestion is relatively low, central scheduling has higher consumer costs than self-scheduling. (This is detailed in Slide 63 below).
- **Key finding #3**: If considered as a potential alternative to central scheduling, introducing zonal wholesale design would reduce consumer costs by £14.6bn (in the modelled period of 2030-2040, on the basis of the scenario used).[1] Overall, under the scenario used in this analysis, **zonal design with self-scheduling would lead to £6.4bn** (D minus C) **lower consumer costs than national design with central scheduling** (i.e. moving from A to D saves more than moving from A to C).
- **Key finding #4**: **Introducing central scheduling remains beneficial under zonal design,** though its incremental benefit is less pronounced. Under zonal design central scheduling reduces costs by £3.6bn (from D to E), compared to £8.2bn under national design (from A to C), but is nevertheless positive for consumers.
- **Key finding #5**: **Augmentations to the BM process** could reduce consumer costs (£2.5bn in moving from A to B). However, this reform does not reduce consumer costs by a significant margin, and hence **cannot be seen as a credible alternative to either central scheduling or zonal design**.

Notes: (1) We don't assume any change in cost of capital nor implementation costs under central scheduling or zonal pricing. We also don't assume potential benefits of other market design changes that central scheduling could enable, such as the co-optimisation of WS scheduling and AS; (2) Forecast errors represent the cost of adjusting to evolving forecasts of RES and demand between DA and GCT under each market design; (3) Other consumer cost impacts include the changes in WS costs, CfD payments and 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 are small compared to other impacts.

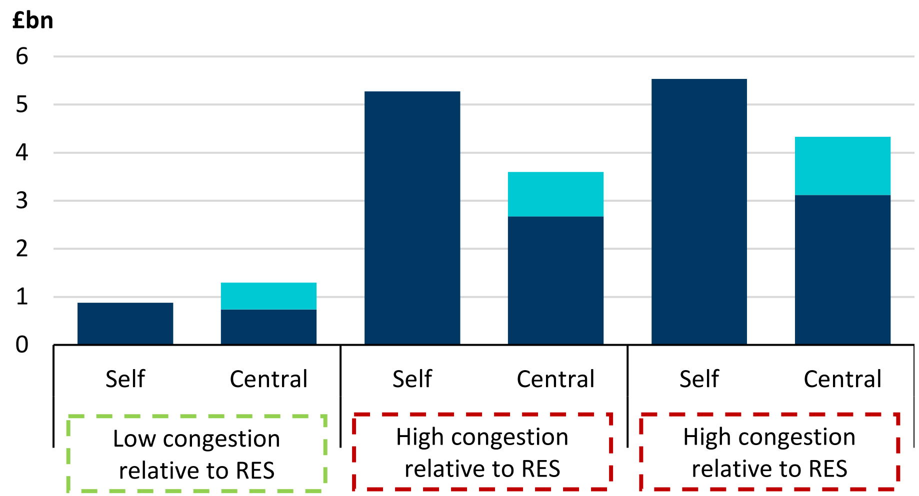
The benefits of central scheduling are driven by the underlying WS market design, the level of Tx congestion, and the size of forecast errors

- Under self-scheduling Tx constraints are resolved post-GCT. In the figure below we show how **constraint costs vary across the years and between national and zonal pricing**. Under central scheduling, Tx constraints are resolved at the DA stage and transfer payments are made to make up for cost recovery and firm access.[1]
- In 2030, Tx constraint volumes are relatively low compared to the size of the average forecast error, as shown in the figure below. **Zonal pricing further reduces constraint volumes**. **Tx constraint volumes increase significantly in 2035 and 2040** while average forecast error remains relatively stable.[2]
- Consequently, **consumer costs in 2030 are lower under self-scheduling, as the reduction in Tx constraint costs under central scheduling is outweighed by the increased cost of resolving forecast errors[3]** (under both national and zonal pricing). In 2035 and 2040, when **Tx constraint volumes increase substantially in the scenario we have modelled, the opposite is true**.

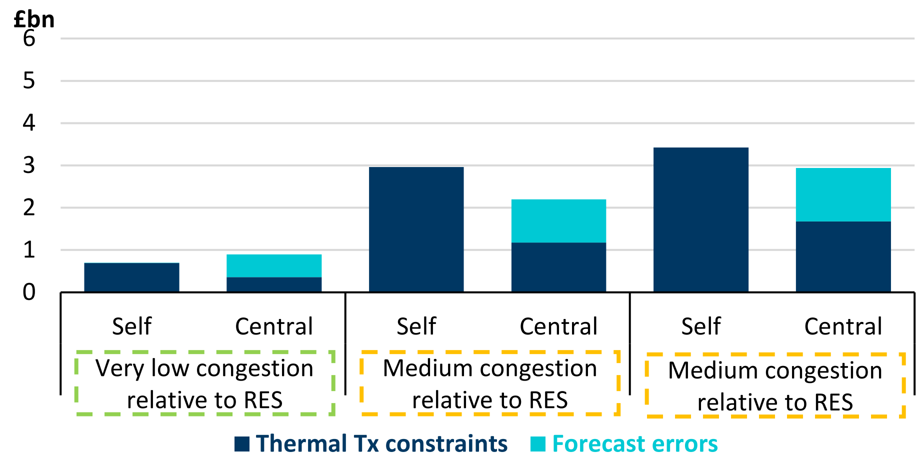
Constraint volumes under self-scheduling arrangements (% of demand) and average hourly forecast error (% of demand), 2030 - 2040[4]



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- and central scheduling with zonal WS pricing



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) Under self-scheduling DA forecast errors are resolved in the ID market just before GCT, while under central scheduling forecast errors are resolved post-GCT; (4) 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.

Our central scheduling benefits assessment relies on several key assumptions which may benefit from further analysis

Conservative assumptions: Factors which could lead to benefits being underestimated

- **No ID trading (central):** We assume no ID trading under central scheduling. However, ID trading may be possible under central scheduling, which would make the design more attractive.
- **Perfect ID trading (self):** All forecast errors are assumed to be resolved via ID trading under self-scheduling, likely underestimating balancing costs under self-scheduling.
- **No bid uplifts:** We do not consider bid uplifts ('downlifts') in the BM, reducing modelled balancing costs. As BM costs are much higher under self-scheduling, this assumption is conservative for the case for central scheduling.
- **No Inc-Dec gaming:** We do not model gaming between the wholesale market and BM under either design, but self-scheduling is arguably more prone to such gaming.[1]
- **Non-quantified benefits:** Broader potential benefits of central scheduling, such as increased SO asset visibility, market transparency and the co-optimisation of WS scheduling and AS, are not quantified.[2]

Uncertain impact: Could have positive or negative impact on estimate of benefits

- **Input assumptions:** Different inputs, such as capacity outlook and commodity prices, could affect the benefits case for central scheduling.
- **Forecast accuracy:** DA RES/load forecast accuracy is assumed constant across the modelling horizon. Should forecasting improve/ worsen over time, the benefits of central scheduling are underestimated/ overestimated.
- **Non-quantified impacts:** It is unclear how central scheduling would impact the required cost of capital for generators. We do not quantify this but note that the modelled market design includes 'make whole' transfer payments to limit revenue impacts on generators at DA.
- **NIV chasing:** Not modelled here, but subsequent FTI modelling for NESO found minimal impact of NIV chasing on balancing costs under self-scheduling with no consistent directional impact.
- **Number of zones and delineation:** The assessment uses a zonal design provided by DESNZ. Different zones (number or delineation) will impact the benefits of central scheduling under a zonal market design.[3]

Overestimation: Factors which could lead to benefits being overestimated

- **Nodal scheduling of ICs (central):** ICs are assumed to be scheduled perfectly relative to GB shadow nodal prices and WS prices in the connected country.[4] With explicit cross-border trading, WS price forecast errors by IC capacity holders could cause ICs to be misaligned with the 'optimal' GB schedule.
- **No transfer payment offer uplift (central):** We assume no offer uplifts in the DA market for units that are scheduled under central but not scheduled under self.[5] We make this assumption as the central schedule is set at DA while BM actions under self-scheduling are undertaken one hour or less before delivery. However, including offer uplifts for transfer payments would reduce the benefits case for central scheduling.
- **Portfolio scheduling (self):** Under both scheduling arrangements we model unit-based scheduling. Potential benefits from portfolio scheduling under self (mostly relevant for thermal units) are not modelled.
- **Non-quantified costs:** We do not measure implementation costs associated with a transition to central scheduling.

[1] Under self-scheduling portfolio owners can strategically position their assets at GCT in anticipation of how that positioning could lead to an increased need to resolve Tx constraints in the BM. The same portfolio owners would benefit from resolving those self-induced constraints. Under central scheduling, Tx constraints are resolved at the DA stage and the SO has visibility at asset-level. Rules must be put in place to avoid assets unwinding their positions relative to the central schedule. Policing the former is arguably harder than the latter.

[2] The co-optimisation of WS scheduling and AS was examined in a separate report prepared by FTI for NESO. PV consumer benefits for 2025-2035 were estimated £4.9bn.

[3] Deployed GB zones are not calibrated to modelled congestion boundaries, implying a conservative benefit estimate of a zonal market design (under the same scheduling approach).

[4] The interactions between cross-border trade arrangements and scheduling options are analysed in depth in a separate report prepared by FTI for NESO.

[5] By contrast, constrained on units in the BM under both scheduling arrangements are assumed to include an offer uplift, which is more relevant for self-scheduling due to higher BM volumes.

Consumer impacts of central scheduling under national wholesale pricing (with Baseline BM)

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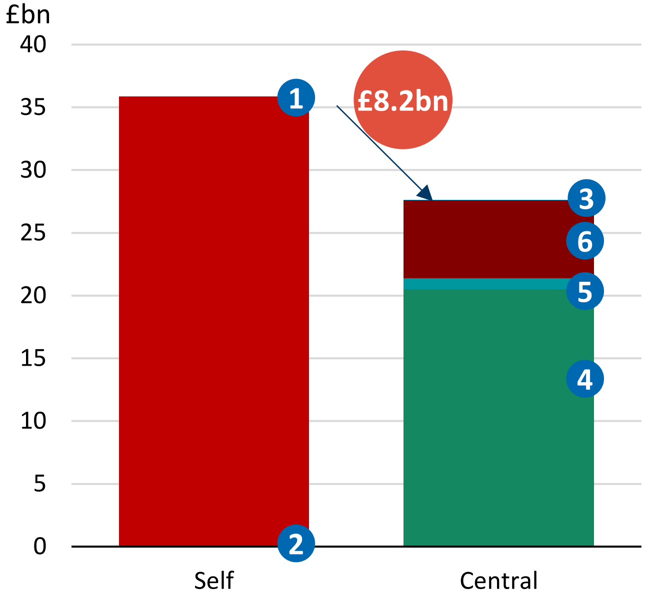
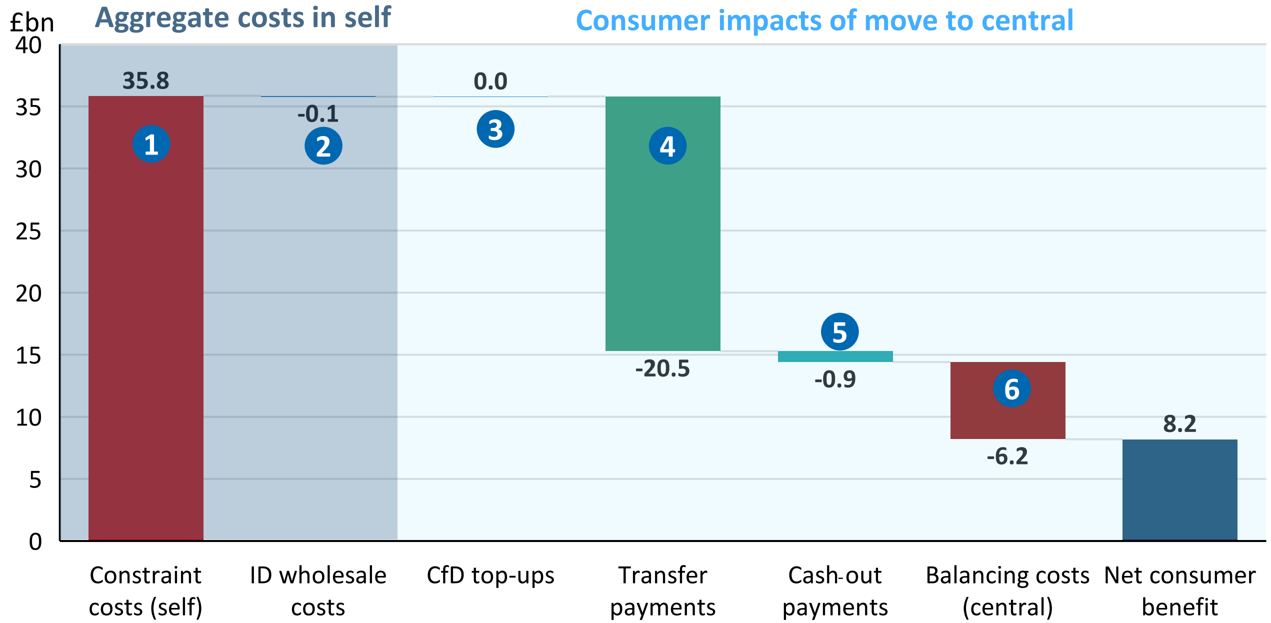
The consumer assessment accounts for costs of resolving Tx constraints and forecast errors under self- and central, accounting for changes in CfD top-ups

- The net consumer impact of central scheduling (under national design) is composed of the **aggregate costs incurred under self-scheduling** to resolve **forecast errors** (**ID wholesale costs**[1]) and **thermal Tx constraints (BM constraint costs)**. This is shown in the first two bars of the waterfall diagram below. As already noted, wholesale costs are assumed to be unchanged under central scheduling, with the central schedule retaining the same single (unconstrained) national wholesale price as in self-scheduling.
- In addition, we adjust for the **alternative costs incurred under central scheduling**, namely the **DA transfer payments** that enable the central schedule to **address thermal Tx constraints while retaining a single national wholesale price**, and the **post-DA transfer payments, cash-out payments** and **balancing costs** that enable the DA schedule to adjust post-gate closure to **updated forecasts of RES output and demand**. We also account for the impact of the central schedule on CfD top-ups.[2] This is shown in the four subsequent bars shown in the waterfall below.
- The diagrams below show the aggregate consumer costs incurred under the self and centrally scheduled designs and the net impact on consumers of a move to central scheduling (assuming national wholesale price and the Baseline BM).

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 wholesale 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 wholesale 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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Across the modelled period, the benefits of earlier addressing of Tx constraints under central scheduling outweigh the cost of later resolving of forecast errors

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 **core benefit** of central scheduling.

2 The scale of RES/load forecast error
Forecast error volumes increase in line with deployment of RES capacity and increasing demand. Forecast errors **increase costs** under the modelled central market design.

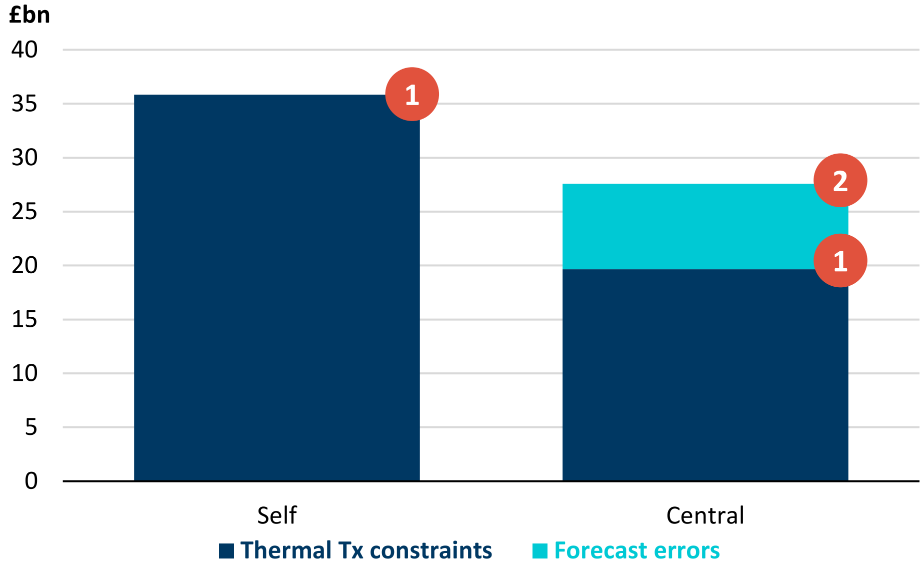
Central scheduling appears to be most beneficial if: (a) Tx deployment does not keep pace with RES expansion; (b) an ID market is introduced to help manage updated forecasts; and (c) ICs are scheduled using shadow nodal prices.

a) **Assumed network build.** We assume an ambitious network outbuild as per HND/NOA7 Refresh, hence delays in network outbuild can be considered more likely than accelerations. A delay in Tx outbuild would **significantly improve the case for central scheduling**.

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 (as discussed in Slides 23-25)**.

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 is driven by **cheaper resolution of Tx constraints**, which now happens at DA via the central schedule.
- 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, 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.
- Therefore, in years with low congestion, the cost to resolve forecast errors under central can **outweigh the benefit of reduced thermal Tx constraints under self**.

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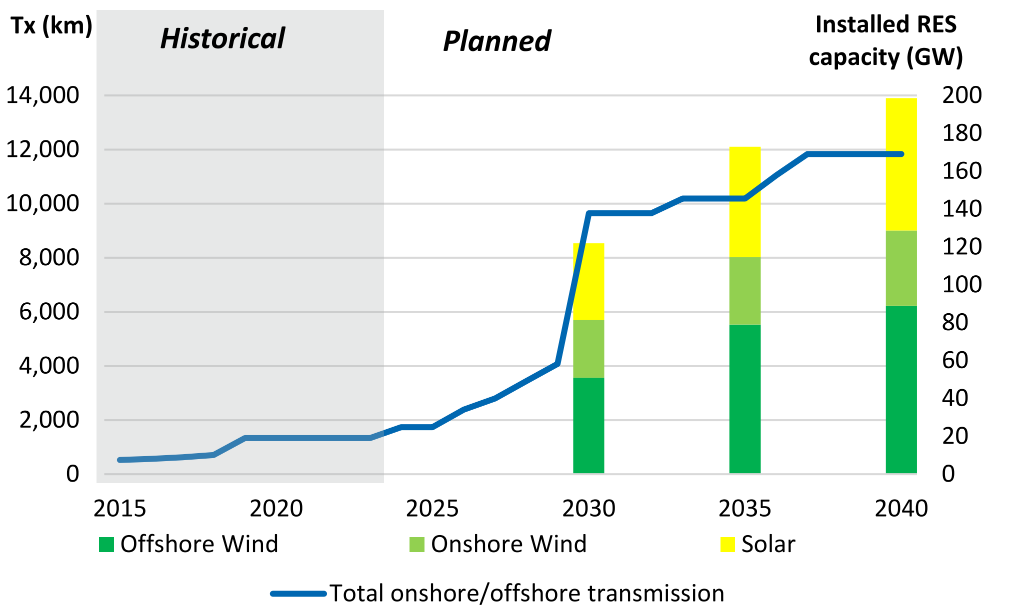
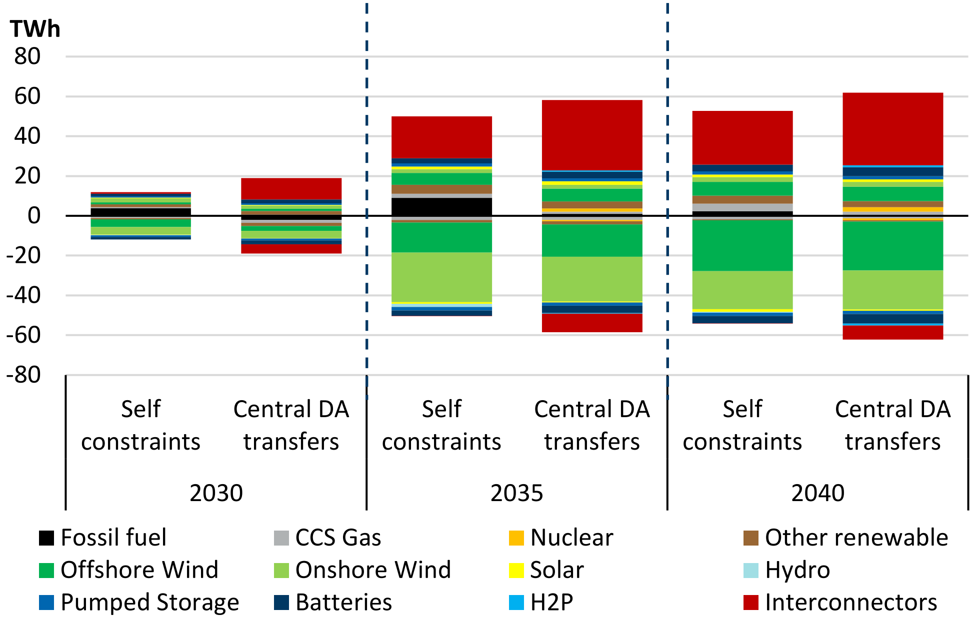
Modelled constraint volumes increase significantly across the 2030s, driven by increases in renewables capacity outpacing Tx outbuild

- Under the **HND/NOA7 Refresh Tx scenario**, a **significant** and **unprecedented** amount of **new Tx is delivered by 2030**, as demonstrated in the chart at the bottom-left. Further **Tx deployment slows across the 2030s** but remains **very high by historical standards**.
- Assuming no change to the current market design, **forecasted congestion volumes in our modelling follow this trend**: **Tx congestion** is comparatively **low** in **2030**, but the **pace (and siting) of RES deployment** assumed across the 2030s means **Tx congestion increases significantly** in **2035** and **2040** (despite significant continued grid investment by historical standards).
- The **volume of actions** to **resolve congestion** via **DA transfer payments** under **central** scheduling is in all years **slightly higher** than the **volume of congestion** resolved in the **post-GCT BM** under **self-scheduling**. In some hours, a higher volume of rescheduling actions, e.g., rescheduling of ICs (from import to export from GB) leading to **additional concurrent actions** in other parts of the network, can **reduce the overall cost of resolving congestion under central**.[1]
- When comparing the **technologies** active in **resolving Tx constraints**, in some hours where **unabated** and **CCS gas** are **constrained on** in the BM under self-scheduling, under central scheduling **ICs** are instead **scheduled** to **import** rather than **export** or other resources (e.g., **nuclear** and **batteries**) are centrally scheduled to generate at DA and paid transfer payments for cost recovery.[2]

Cumulative new Tx networks and uprates since 2015[3] (km) and forecasted RES deployment (GW)



Total congestion volumes under self-scheduling, and Tx-driven transfer volumes under central scheduling (TWh)

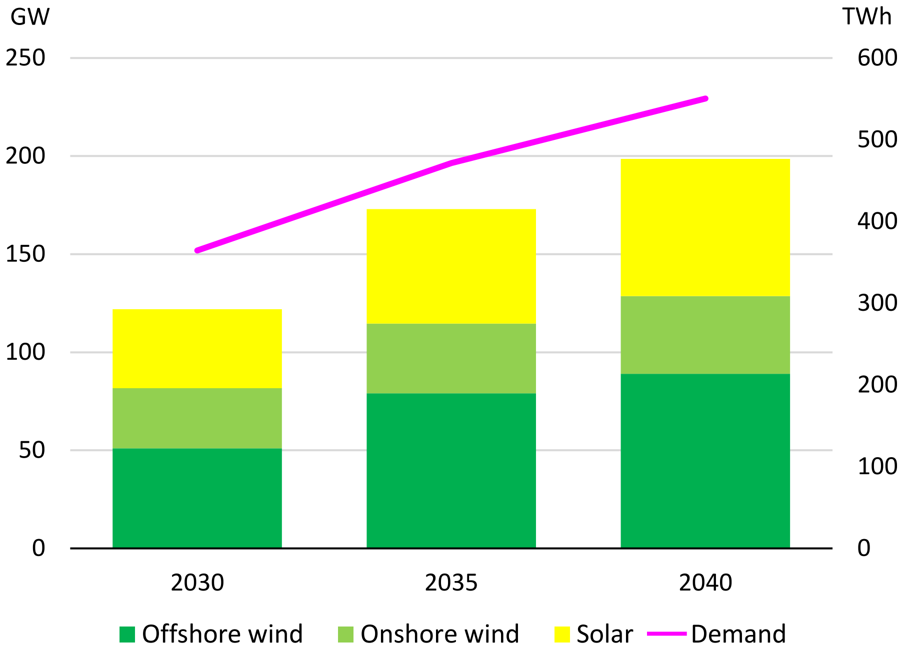


Notes: (1) While most "rescheduled" ICs are ICs in the South of GB that would have been scheduled to export based on the single national price but are centrally scheduled to import at DA, in some hours under central scheduling ICs that were scheduled to import based on the single national price are also "rescheduled" to export under a shadow nodal price (e.g., NSL). While this rescheduling reduces scheduling costs, it leads to higher total volumes of actions to resolve congestion; (2) Nuclear is assumed to not participate in the post-GCT BM under self-scheduling but can resolve system constraints under central scheduling if scheduled at DA given units have more advanced notice of the 'need' for their output; (3) Holistic Network Design, NG ESO, 2023 (link).

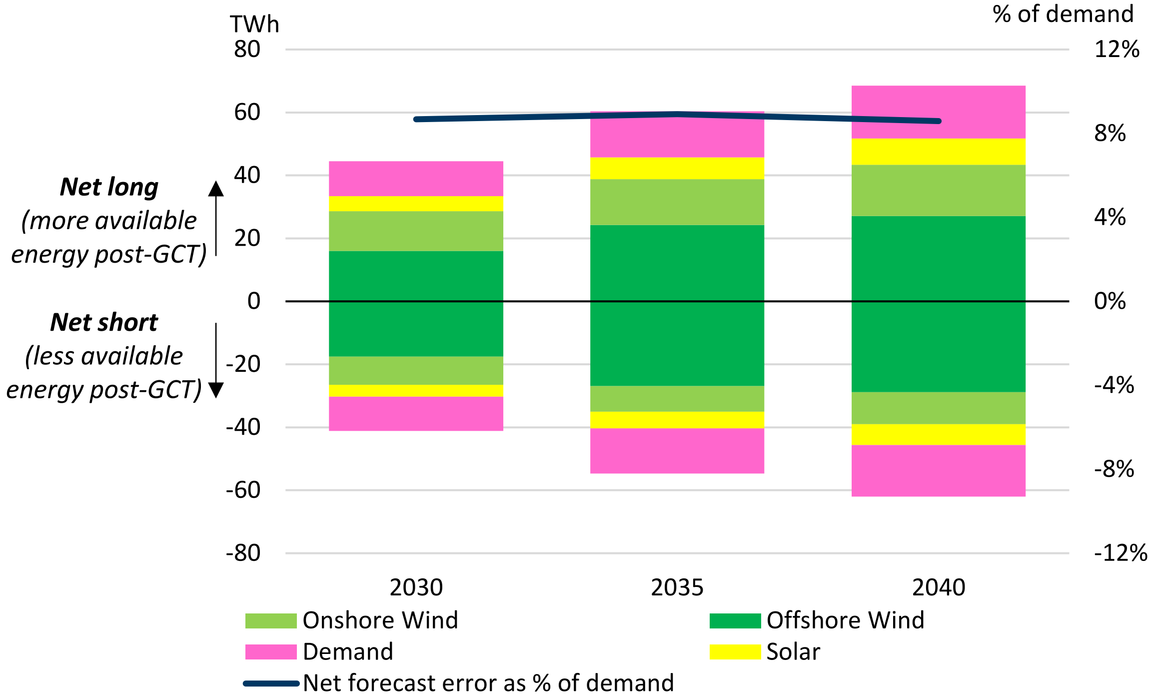
However, the volume of RES and demand forecast errors also increases, rising c.50% across the 2030s in line with increasing demand and RES deployment

- Our RES capacity and demand assumptions align with **FES22 LtW**, which projects a **substantial increase in RES capacity** across the **2030-2040** modelling horizon. **Demand** is also projected to **increase significantly**, **doubling between 2030 and 2040**.
- We calibrate **forecast errors** based on **historical data** and assume **no change in the accuracy** of RES or demand forecasts over time, with the **percentage errors** observed in the **historical NESO data assumed to hold constant in the future**.
- As a result, the total **volume of RES/demand forecast errors increases across the modelling horizon**, **rising c.50% across the 2030s** (from roughly gross 80 TWh in 2030 to more than 120 TWh in 2040). However, as the **scale of demand also increases substantially (**with high electrification assumed in FES22 LtW), forecast **errors as a proportion of total demand remain relatively stable**.
- The forecast errors observed in the historical data for **offshore** wind **outweigh** those of **onshore** wind, mostly due to the higher installed capacity of offshore wind. **Offshore** wind forecast errors **outweigh** those of **solar** and **demand** mostly due to the **higher relative forecast error per MW** of offshore wind installed.
- Overall, the **system is slightly more long than short**, i.e., on aggregate production is slightly under-forecasted and/or demand over-forecasted at DA.

Total installed wind and solar capacity and GB demand



Total volume of day-ahead vs delivery forecast error per technology (TWh)[1]



Notes: (1) Forecast errors are calculated as the change in generation/demand from the DA run to FPN due to mis-forecasting by an individual unit/GSP.

Central scheduling drives benefits for consumers when the GB Tx network is heavily congested, but may not be beneficial when Tx constraints are modest

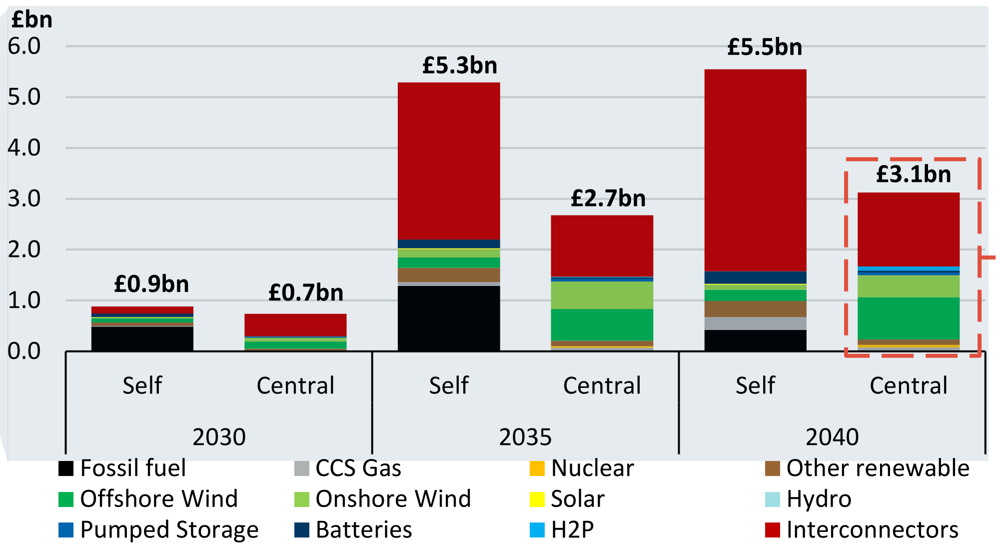
The consumer benefits of central scheduling are a function of:

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

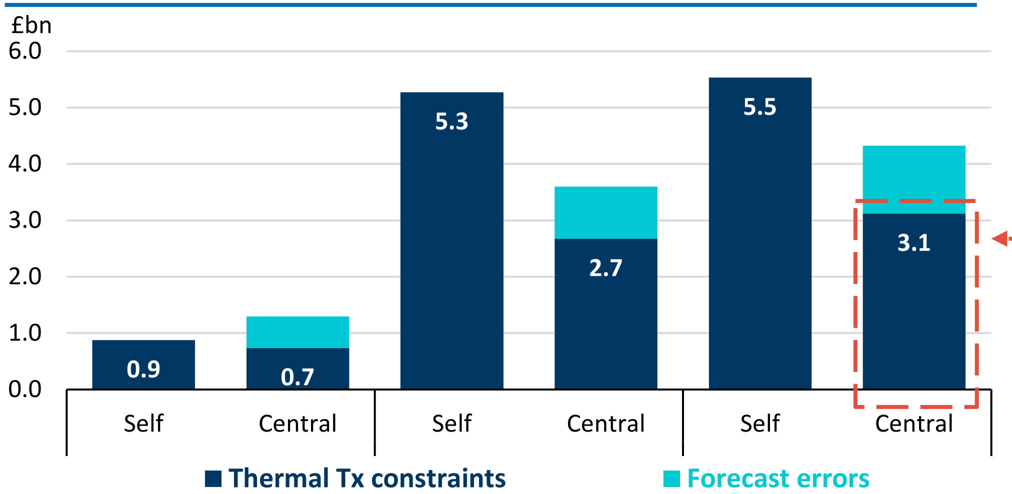
The scale of RES/load forecast error
Forecast errors increase proportionally with deployment of RES capacity and increasing demand. Forecast errors **increase costs** under central.

- The pattern of forecasted Tx constraints under the modelled scenario in GB leads to:
  - **Significant positive benefits** of **central scheduling** in **2035** and **2040**, when thermal Tx constraint volumes are relatively high as the deployment of new RES capacity outpaces Tx build.
  - A **disbenefit** of **central scheduling** in **2030**, given the assumed extensive Tx build in the late 2020s, as the benefit of cheaper resolving of Tx constraints under central scheduling is too small to make up for the increased cost of resolving forecast errors.
- Most consumer cost savings to resolve Tx constraints at DA (central) rather than post-GCT (self) are driven by:
  - Lower costs to reschedule ICs: “make whole” transfer payments are made to the IC capacity holders[1] while under self-scheduling a penalty price is paid to reschedule ICs.
  - Reduced reliance on fossil fuel generators: ICs are rescheduled or other resources such as nuclear and batteries are introduced in the DA schedule and paid an uplift, while an important share of the constraint costs under self-scheduling consists of relatively expensive fossil fuel generators.

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



Aggregate consumer costs of resolving thermal Tx constraints and forecast errors under self- vs central scheduling[1] (£bn)



Note: (1) In 2030, the volume of ICs being constrained on, i.e., switched from import to export, is very limited (hence very limited constraint costs attributable to IC actions).

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

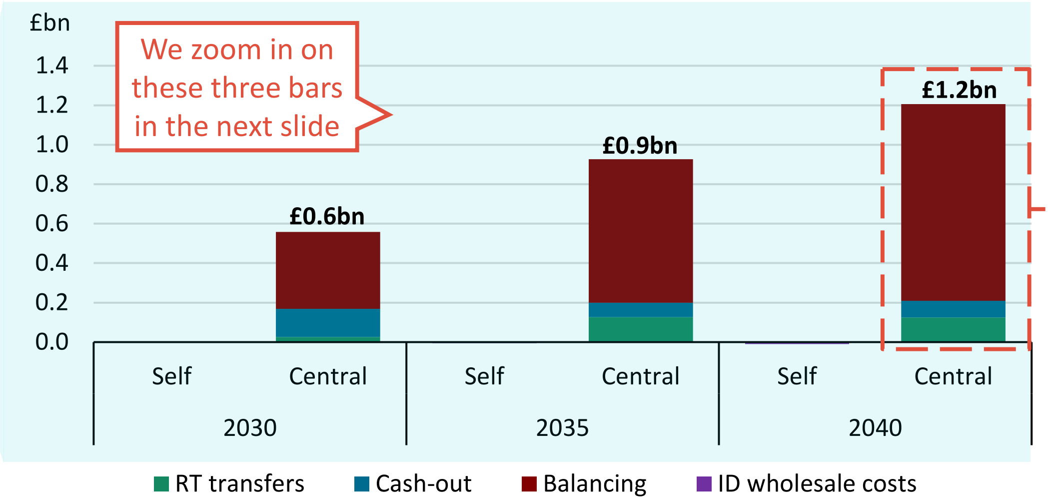
The consumer benefits of central scheduling are a function of:

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

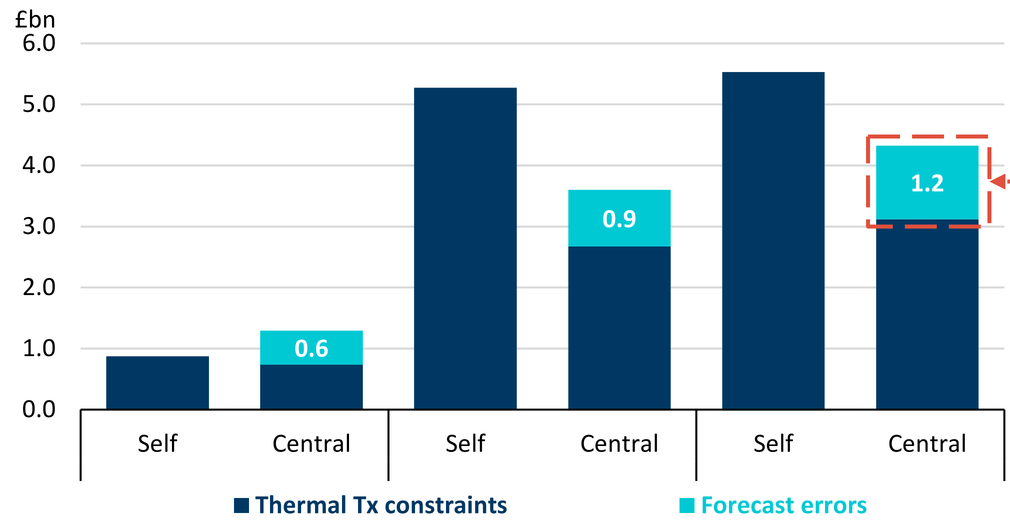
The scale of RES/load forecast error
Forecast errors increase proportionally with deployment of RES capacity and increasing demand. Forecast errors **increase costs** under central.

- Under self-scheduling, forecast errors are assumed to be fully resolved through ID trading before GCT and therefore at a lower cost than under central scheduling. Overall, the effect on wholesale consumer costs from demand imbalance is minimal in all modelled years, at -£1.0m in 2030 and -£16.4m in 2040.[1]
- Under central scheduling, to mimic the assumed "less efficient" trading of NESO (relative to the market) we assume no ID trading, with all forecast errors centrally resolved via cash-out payments, RT transfers and balancing actions (for a detailed breakdown, see the next slide).
  - The net cost to consumers of cash-outs and RT transfers is relatively minor, with over- and under-forecasts of RES and load largely offsetting each other across each year.
  - Forecast error-driven balancing costs are the key driver of consumer costs under central scheduling. When RES/load forecast errors leave parts of the system short, costly BM actions are required (though a much lower volume of actions is required than under self-scheduling as under central Tx constraints are already largely resolved at the DA stage).

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



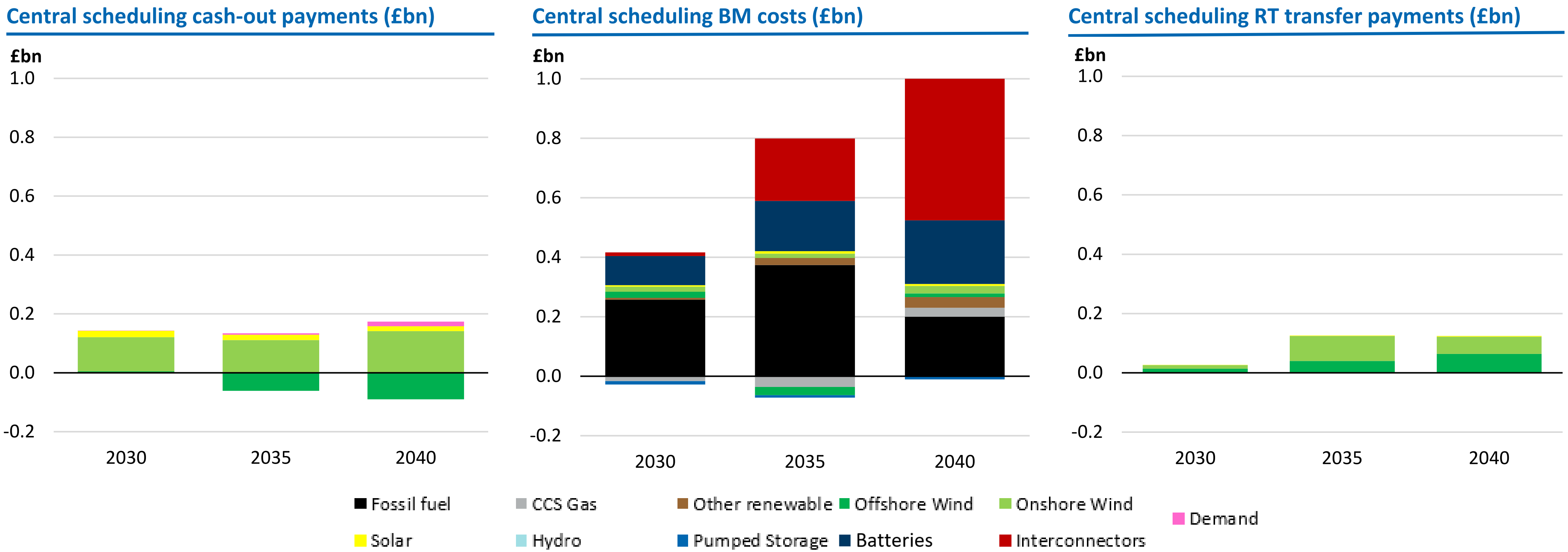
Aggregate consumer costs of resolving thermal Tx constraints and forecast errors under self- vs central scheduling[1] (£bn)



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

Constraint costs account for the largest portion of post-GCT costs that arise from day-ahead forecast errors under central scheduling

These three diagrams zoom in on the components of total cost shown in previous slide



- 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, with especially onshore wind tending to under-forecast in high-priced hours and receiving additional payments for increased output in RT.[1]
- However, the net balance of cash-out payments could change under a different CY.

- 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 fossil fuel generators. 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.

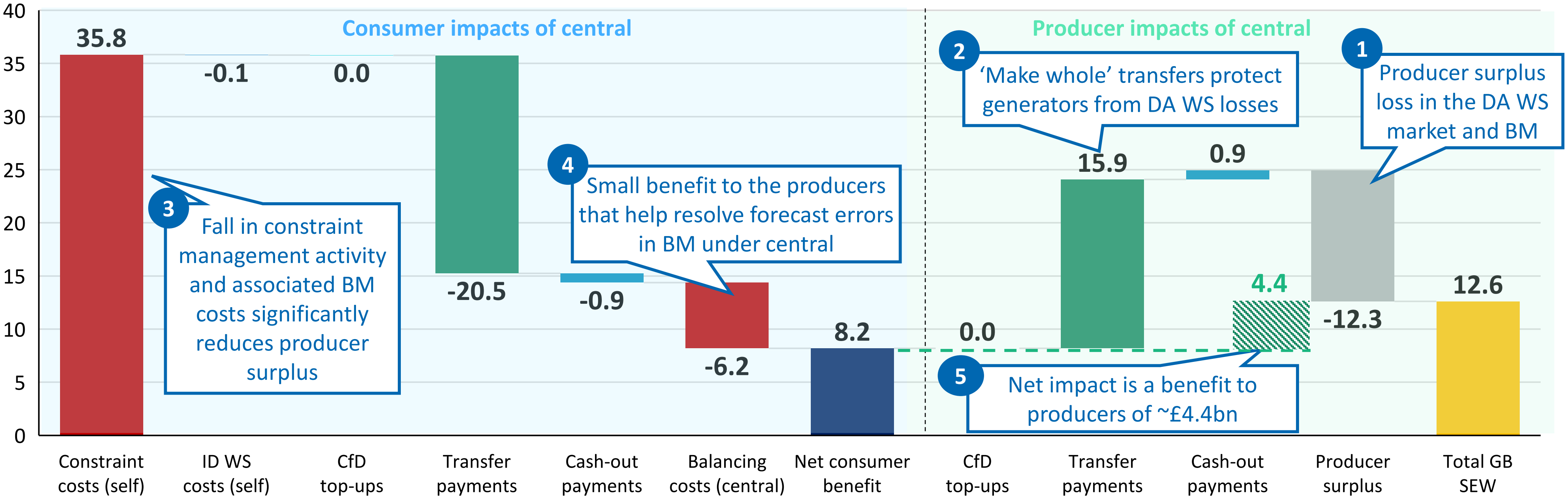
- If a forecast error does not lead to a change in a unit's output, it instead receives/pays a transfer payment for the associated mis-forecast.
- In sum, RT transfers are slightly positive, compensating the additional output available from under-forecasting wind that is eventually not scheduled in RT.

Notes: (1) For more details see Appendix 2.

Moving from self to central scheduling under national pricing increases GB SEW by £12.6bn, benefiting both consumers (£8.2bn) and producers (£4.4bn)

- In the previous slides, we examined the impacts on consumers from a move to central scheduling under national wholesale pricing (£8.2bn). Below we show the impact of central scheduling on producers (£4.4bn) and total GB socioeconomic welfare ("SEW") (£12.6bn).
- 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 (£15.9bn).[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 ~£4.4bn 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 scheduling relative to self, 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) £11.3bn of this loss is in the WS market, with £1.0bn loss for producers 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; (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 interconnectors where a portion of the benefits is assumed to accrue to the connected country.

Consumer impacts of central scheduling under national wholesale pricing (with Augmented BM)

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The Augmented BM assumes reduced offer uplifts on fossil fuels, removes battery skipping, and allows waste and H2P to participate

- NESO's 'case for change' assessment outlined two high-level approaches to improving the current scheduling and dispatch market arrangements: (i) augmenting the existing BM process; and (ii) formalising NESO's role as "de facto central scheduler" (see Slide 7).
- Although BM reform and a transition to central scheduling could be enacted concurrently, this report seeks to isolate the impact of each option and assess the comparative merits between the two. We therefore compare the costs to resolve thermal Tx constraints and forecast errors under self-scheduling **using an Augmented BM** (detailed below), which seeks to mimic the impact that potential policy reforms could have on the cost of balancing actions, against central scheduling **using a Baseline BM**, which assumes the BM continues to operate as it does today.

	Technology	Bid (constrained off)	Offer (constrained on)	
Baseline BM (NESO methodology)	Fossil fuel	- Fuel cost - carbon cost	1 Offer uplift	+ Fuel cost + carbon cost
	ROCs renewables	ROCs	(theoretical so no price assumed)	
	Merchant renewables	£0	Offer uplift	
	CfD renewables	CfD strike price – Wholesale price	Offer uplift	- CfD strike price
	Batteries/Other storage	- Price Paid	Offer uplift	+ Price Received[1]
	Interconnectors	Cost of reversing flow to export	Cost of reversing flow to import	
	Biomass	- SRMC	Offer uplift	+ SRMC
	Hydro (run-of-river)	£0 (but bids only clear after merchant RES)	(theoretical so no price assumed)	
3 Augmented BM	Waste	- SRMC	Offer uplift	+ SRMC
	Hydrogen (H2P)	- SRMC	Offer uplift	+ SRMC
	DSR	(theoretical so no price assumed)	Activation price assumed to be same as at DA	

Augmented BM assumptions

1 Reduced offer uplift

The Baseline BM assumes an offer uplift for fossil fuel plants of 60% above SRMC. This is calculated as the **mean** average of actual plant data provided by NESO.

The Augmented BM **reduces the assumed uplifts** and uses the **mode (i.e. most common)** uplift (36%), representing assumed **improved efficiency** of activation of thermal units in the Augmented BM.

2 Improve battery utilisation

The Augmented BM assumptions remove the **80% skip rate of 1h and 4h batteries** used in the Baseline BM.[1]

3 Broaden access to BM

Allow waste, H2P and DSR ("Demand-side response") participation. Waste is mid-merit, while H2 is used ahead of unabated gas (but with limited fuel available across the year).[2]

Notes: (1) Removing all battery skipping, although unlikely in practice, acts as an upper bound for the extent to which skipping could be reduced (and so reduce constraint costs); (2) In practice, industrial/household DSR is priced at the top end of the merit order and rarely activated in the Augmented BM.

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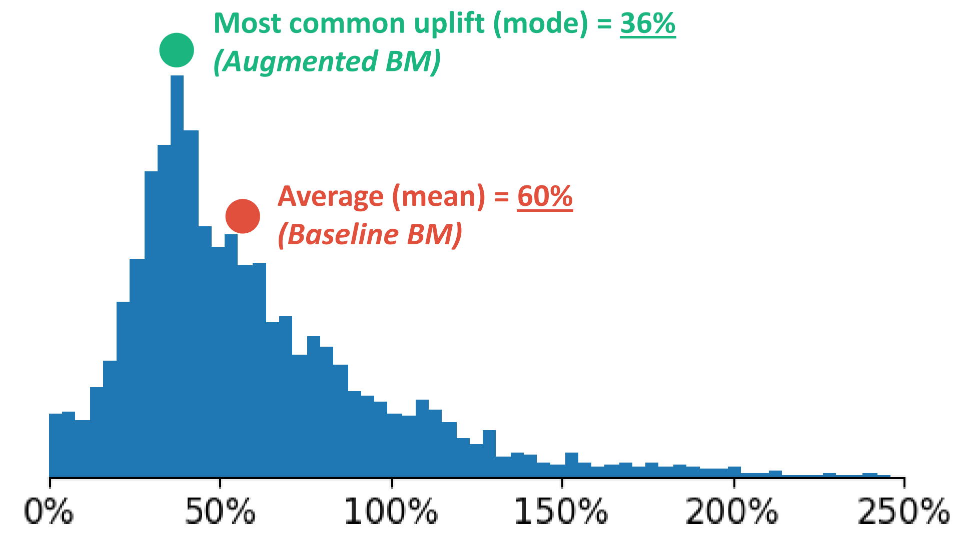
Thermal offer uplifts are aligned with the modal average from historical NESO data in the Augmented BM, versus the mean average for the Baseline BM

- In the Baseline BM, we apply a 60% price uplift above SRMC to fossil fuel offer prices, calibrated as the mean average combined cycle gas turbine ("CCGT") uplift observed in historical data for 2023 provided by NESO. Uplifts are intended to reflect start-up costs and any broader factors due to the nature of the pay-as-bid market of the BM.
- In the Augmented BM, we assume that broader policy reform (such as ID Balancing Reserve or locational procurement of reserve) reduces the cost of procuring thermal units to resolve thermal constraints...
- ...and lower the uplift for all thermal units to 36% in the Augmented BM. This is equal to the modal average, or the most common CCGT uplift from the 2023 NESO dataset, highlighted on the chart below.

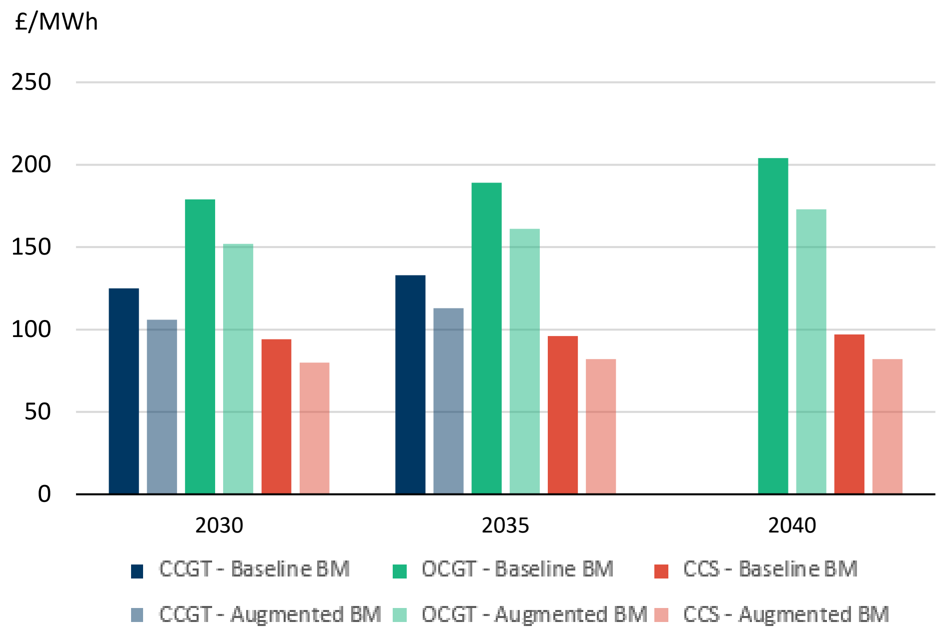
Distribution of CCGT offer uplifts above SRMC in accepted offers[1]



Source: (1) Historical BM bidding data across 2023 provided by NESO.

Assumed maximum offer price per technology for GB generators in BM modelling, 2030-2040 (£/MWh)

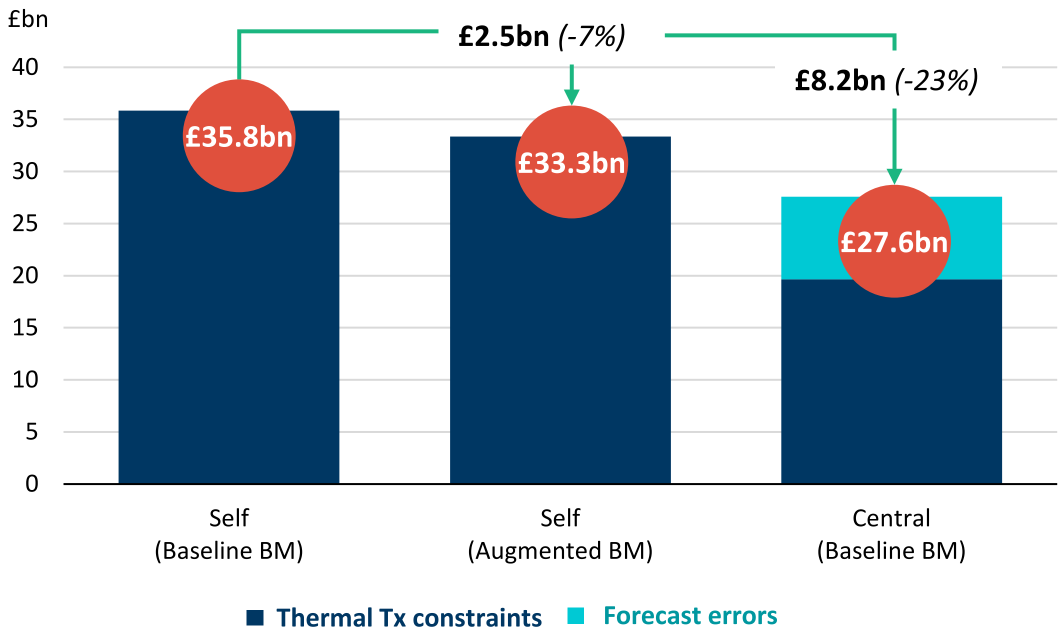
Category	2030	2035	2040
Baseline BM uplift (60%)			
CCGT	125	133	-
OCGT	179	189	204
CCS	94	96	97
Augmented BM uplift (36%)			
CCGT	106	113	-
OCGT	152	161	173
CCS	80	82	82



While an Augmented BM reduces consumer costs by £2.5bn compared to a Baseline BM, central scheduling would bring more substantial consumer savings

- Under self-scheduling and national WS pricing, the PV of 2030-2040 consumer costs to resolve thermal Tx constraints and forecast errors is estimated at £35.8bn.
- Improving the use of thermal and storage assets under self-scheduling via an Augmented BM (outlined in Slides 75-76) lowers this PV estimate by £2.5bn to £33.3bn.
- However, this remains substantially higher than estimated consumer costs of resolving thermal Tx constraints and forecast errors under central scheduling (by £5.7bn on a PV basis across 2030-2040).

Aggregate consumer costs of resolving thermal Tx constraints and forecast errors under self- vs central scheduling, national market design, £bn, PV 2030-2040



Baseline BM vs Augmented BM

- Expanding the potential use, and improving the efficiency of procurement of, thermal and storage assets in the BM reduces balancing costs across the modelled period.
- Relative to the Baseline BM, the cost of constraining on thermal technologies is reduced in the Augmented BM, but the relative importance of thermal units for balancing falls in later years.
- In 2035 and 2040, assumed improvements in the utilisation of other technologies allows the Augmented BM to avoid some costly balancing actions on ICs and fossil fuel units, reducing balancing costs by 4-13% in each year.

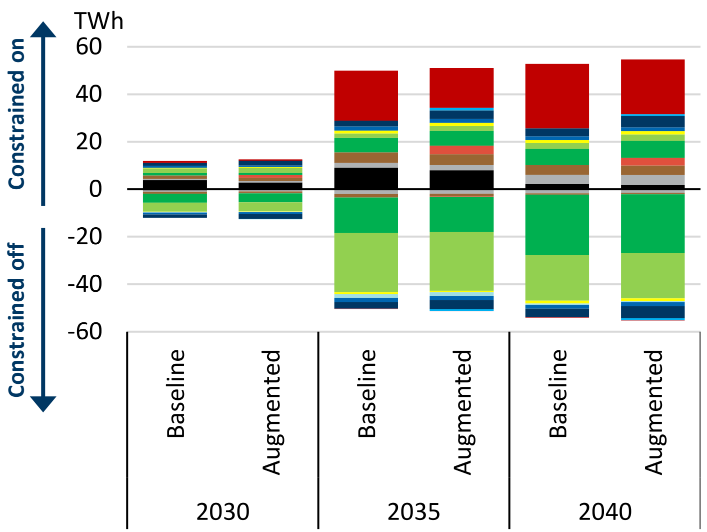
Augmented BM vs central scheduling as options to reduce consumer costs

- However, the wholesale (self-) schedule that the BM must adjust remains the same with an Augmented BM.
- While total consumer costs are reduced under the Augmented BM design, the reforms do not remove the underlying congestion volumes[1] (i.e. they only target the costs of the actions taken), replacing one BM action with another that still requires some (albeit assumed lower) cost of activation.
- The aggregate balancing actions taken under the Augmented BM are more costly than the DA actions (transfer payments) taken under central scheduling.

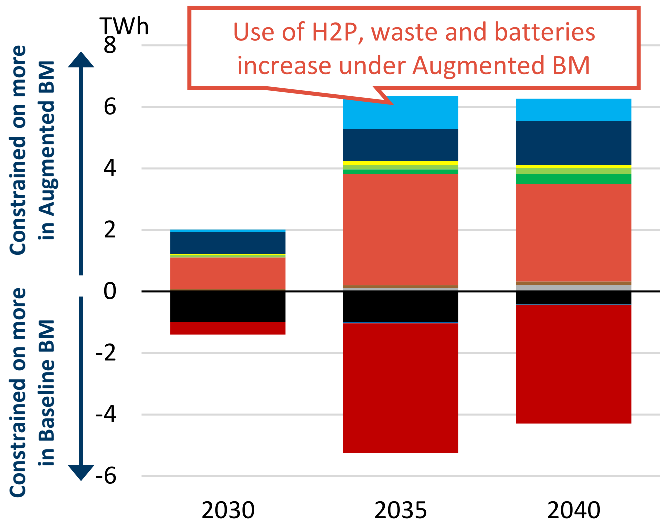
Notes: (1) Other than due to minor impacts of more batteries being utilised in the Augmented BM.

Waste, H2P, and increased battery volumes in the Augmented BM replace constrained on fossil fuel and IC volumes from the Baseline BM

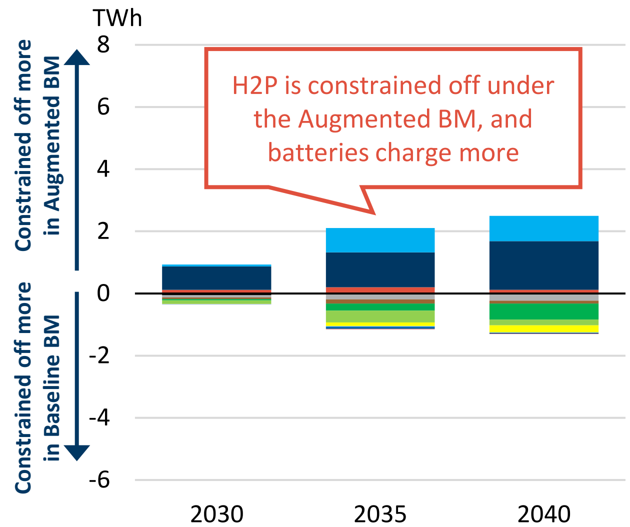
Total constrained on/off generation, self-scheduling, Augmented vs Baseline BM (TWh)[1]



Change in constrained on volumes, Augmented minus Baseline BM (TWh)



Change in constrained off volumes, Augmented minus Baseline BM (TWh)



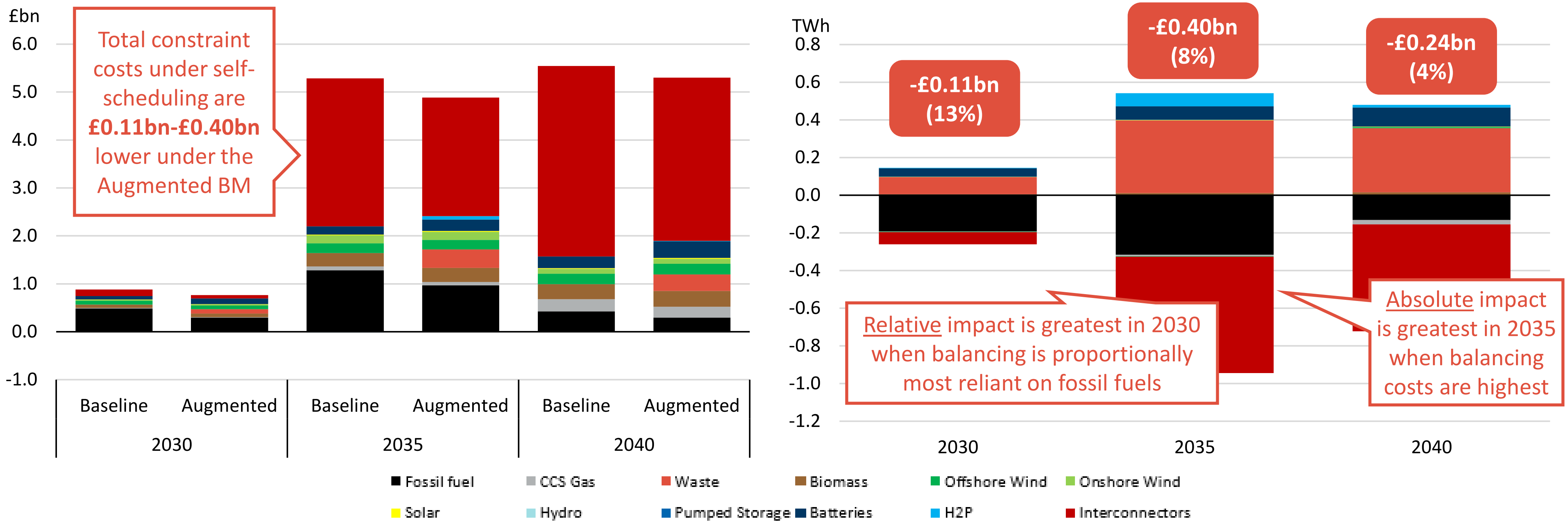
1	**Reduced fossil fuel uplift**	The reduced uplift above SRMC applied to thermal units reduces the cost of constraining on thermal units to resolve Tx constraints (though not the underlying volume of constraints), as detailed on the next slide.[2]
2	**Improve battery utilisation**	Improved battery utilisation leads to increased discharging and charging of batteries in the Augmented BM. Discharging (constrained on) displaces some thermal and IC actions that would have instead been taken in the Baseline BM, while increased charging (constrained off) helps reduce the constraining off of RES in some hours.
3	**Broaden access to BM**	The strongest volume effect is the constraining on of mid-merit waste generators, displacing some fossil fuel and IC actions taken in the Baseline BM. H2P units, as high-merit generators, follow a similar pattern for constraining on but with a lower volume effect. Notably, H2P units are also sometimes constrained off (either turned down before CCS gas or replaced by available battery supply).

Notes: (1) The additional battery capacity available is not only used to displace other BM technologies but can also lead to a slight increase in BM volumes to optimise redispatch over multiple time periods (while achieving an overall cost reduction). Concretely, the cost of the additional constraining on of batteries/RES (allowing for increased volumes of other batteries constraining off in the same settlement period) is lower than the BM cost that can be avoided in later settlement periods by discharging those batteries (that were previously charged in the BM) instead of constraining on an alternative BM technology (e.g., ICs or fossil fuel). As such constraint volumes can increase while overall constraint costs reduce; (2) In practice, a change in the fossil fuel uplift could lead to a change in the BM merit order and could potentially lead to an additional change in the composition of technologies resolving constraints.

The net impact of the Augmented BM is a fall in fossil fuel and IC costs, using lower-cost assets instead, with the lower thermal uplift further reducing costs

Total constraint costs, self-scheduling, Augmented vs Baseline BM (£bn)

Change in aggregate constraint costs, Augmented minus Baseline BM (£bn)

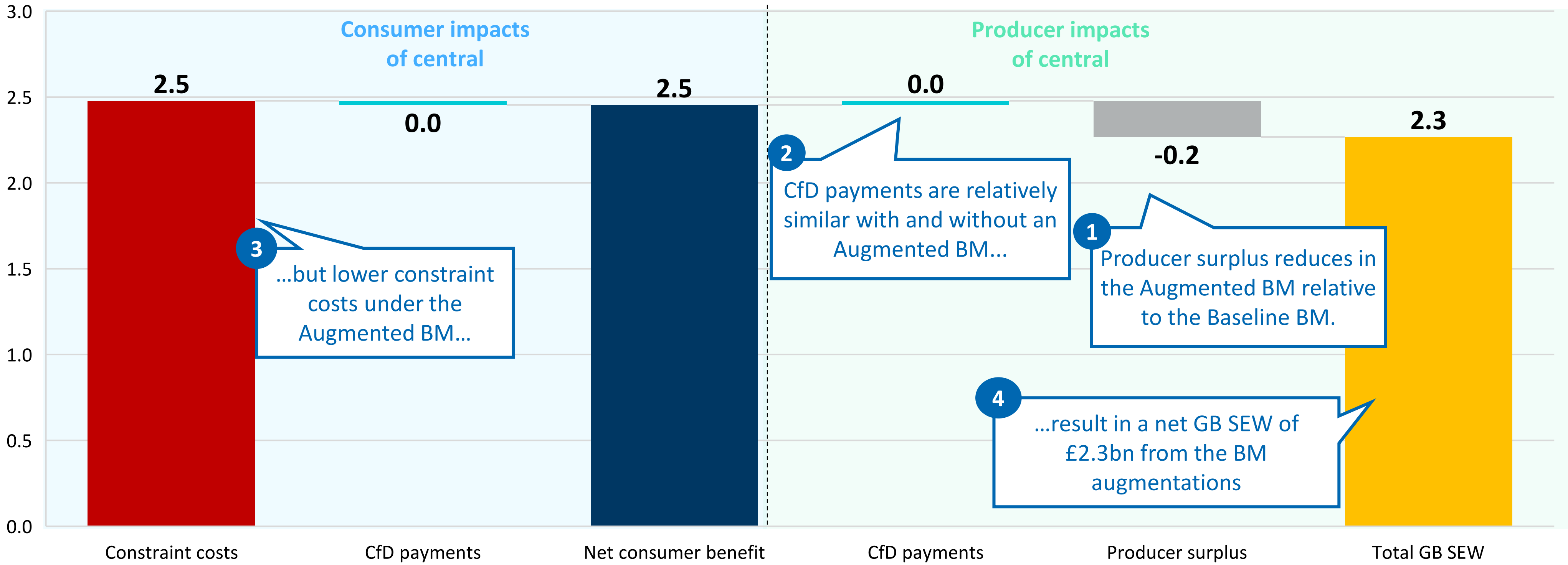


- Total constraint costs decrease in each modelled year under the Augmented BM, by £0.11bn in 2030, £0.40bn in 2035, and £0.24bn in 2040, with the introduction of lower-cost technologies and cheaper procurement of thermal units.
- The largest relative impact of the Augmented BM on constraint costs occurs in 2030, due to the relatively greater reliance on fossil fuels for balancing (made substantially cheaper by the reduced thermal uplift).
- The highest absolute impact of the Augmented BM on constraint costs occurs in 2035 when constraint volumes relative to demand are highest (see Slide 78). The cost decrease is primarily driven by the replacement of IC and fossil fuel actions with cheaper technologies (incl. improved use of storage), with the cost of thermal actions further reduced by the fall in thermal uplift.

Relative to self-scheduling with the Baseline BM, with the Augmented BM producer surplus falls by £0.2bn while GB SEW increases by £2.3bn

- Under self-scheduling with the Augmented BM, total constraint management costs are £2.5bn lower compared to self-scheduling with the Baseline BM. There is no material difference between CfD payments under the Baseline and Augmented BM, and thus the net consumer benefit of the Augmented BM relative to the Baseline BM under self-scheduling is £2.5bn.
- Producer surplus falls by £0.2bn, mostly due to a reduced use of fossil fuel generators in the BM and a reduced uplift for fossil generators.
- The producer surplus loss only represents a small share of the constraint cost savings, resulting in an overall net socioeconomic benefit of the Augmented BM of £2.3bn (implying that the modelled augmentations to the BM result in improved operational efficiency).

Self-scheduling Baseline BM vs self-scheduling Augmented BM, national design £bn (2030-2040, PV 2030)



Consumer impacts of central scheduling under zonal wholesale pricing

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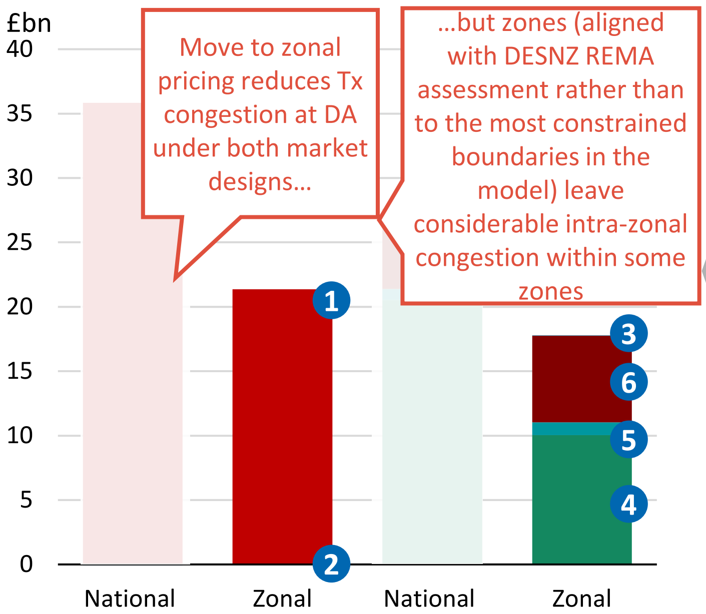
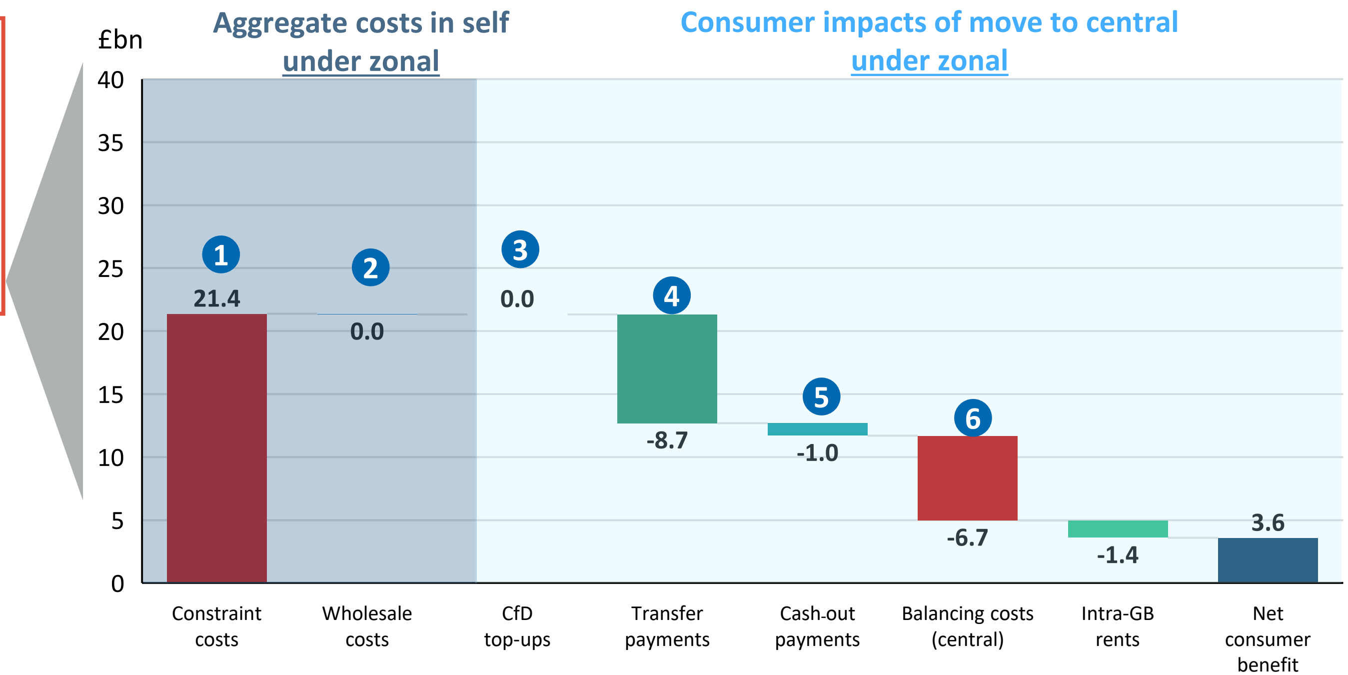
Central scheduling still provides substantial consumer benefits under a zonal design, but the incremental benefit is lower than under a national design

- As under a national wholesale market design, the net consumer impact of central scheduling under a zonal design consists of the avoiding of the **costs incurred** under self-scheduling to resolve **forecast errors** (ID wholesale costs[1]) and **thermal Tx constraints** (BM constraint costs), minus the alternative costs incurred under central scheduling (transfer payments, cash-out payments and balancing costs).
- However, when comparing consumer costs under central and self-scheduling under a zonal WS market design, differences in **intra-GB congestion rents also need to be accounted for.**[4] These are included within the DA transfers made to resolve Tx constraints in the central DA schedule (See Appendix 4).
- The diagrams below compare the aggregate consumer costs **under a zonal market design for both self- and central scheduling.**
- Central scheduling still delivers considerable consumer benefits relative to a self-scheduled zonal market by reducing the cost of resolving (intra-zonal) Tx constraints. However, as a self-scheduled zonal market already resolves a proportion of Tx constraints at DA, central scheduling has less incremental impact.

Aggregate consumer costs, self vs central scheduling, £bn (2030-2040, PV 2030)[3,4]



Central scheduling net consumer benefits, zonal design £bn (2030-2040, PV 2030)[3,4]



Notes: (1) ID WS costs are calculated as the change in demand in ID relative to the DA market multiplied by the ID WS price. Changes in demand can be positive or negative and hence the ID WS costs nearly net out; (2) Constraint costs under self-scheduling and balancing costs under central scheduling reflect the cost of resolving intra-zonal thermal Tx congestion; (3) This chart does not include DA WS costs, which are assumed to be equal under both self- and central scheduling; (4) Transfer payments under zonal pricing include payments to inter-zonal Tx owners, required as, while Zonal WS prices are the same under central and self-scheduling, flows on cross-zonal boundaries can be different as the DA schedule differs (impacting intra-GB congestion rents).

As with a national market design, central scheduling drives greater benefits for consumers under zonal pricing when the GB Tx network is heavily congested

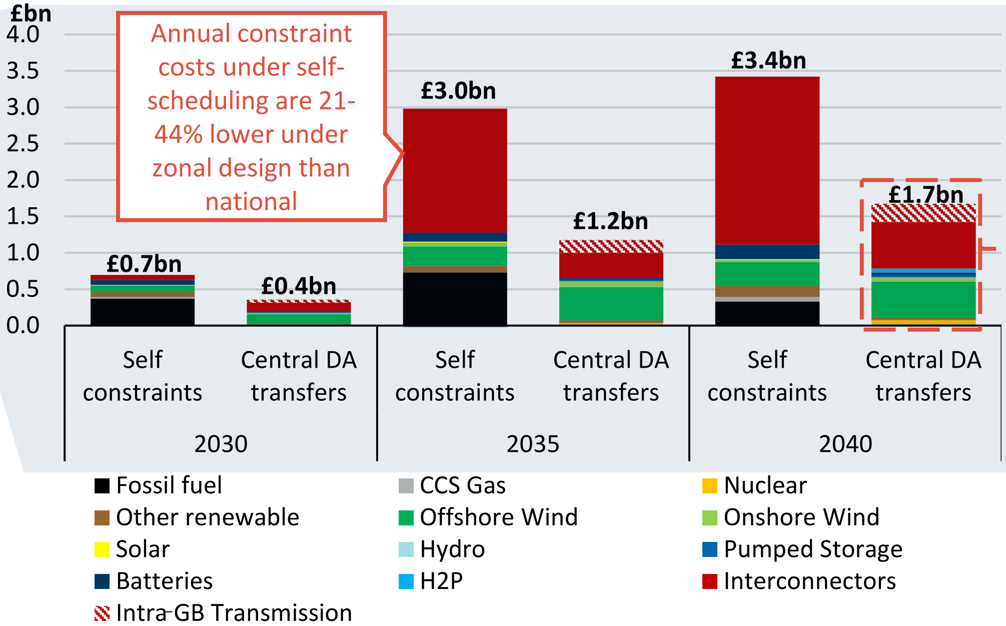
The consumer benefits of central scheduling are a function of:

The scale of Tx constraints

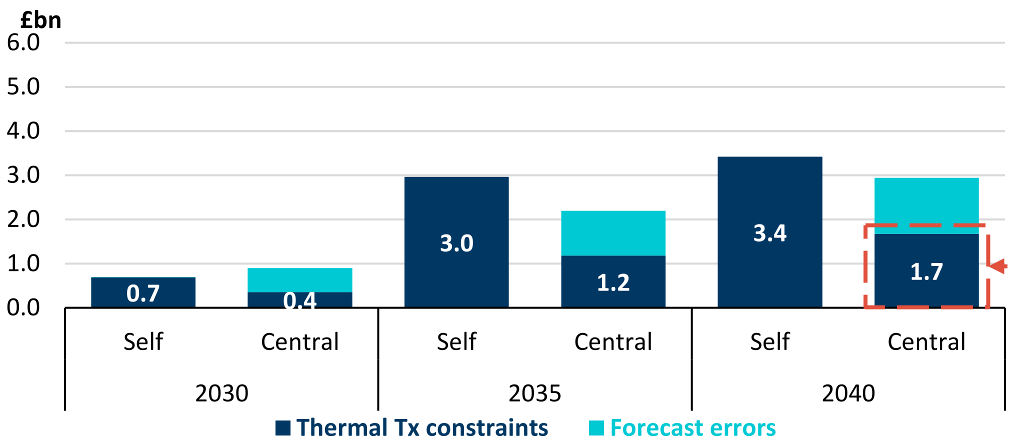
The scale of RES/load forecast error

- **Intra-zonal constraint costs** under self-scheduling are **significantly lower than** national constraint costs **under a national design** for each modelled year **(21-44%)**.
- **Central** scheduling still delivers **consumer benefits** in **2035** and **2040** under **zonal pricing** (when Tx congestion is at a 'medium' level – higher than in 2030 but lower than under national design, see Slide 63). In 2030, as under a national design, there is a **net disbenefit of introducing central scheduling** when Tx congestion is low.
- Even though total GB constraint costs with self-scheduling are lower under a zonal design than under national, **central scheduling continues to provide incremental benefits relative to a self-scheduled zonal design.** This is due to a **fall in Tx-driven DA 'make whole' transfers** (**46-56%** lower than under central national), driven by two factors:
- **First**, by virtue of zonal design implicitly **solving** some **Tx congestion at DA**, the **zonal self-schedule** is **closer** to the **system-optimal central schedule**, reducing the required **volume** of transfer payments.
- **Second**, DA 'make whole' transfers are **paid relative to zonal, rather than national, WS prices**, generally reducing the transfer cost. For example:
  - **North Scotland** has **significant wind** generation and **little demand**, leading to a relatively **low zonal price** (see Slide 60). Scottish wind farms that receive '**firm access' transfers** if they would be scheduled under self but not central receive **lower transfers for lost WS revenues** under zonal.
  - In contrast, **zonal WS prices** in the **South** of England tend to be **higher than under national pricing**. A **CCGT** plant in the South that would **not be scheduled** at DA **under self-scheduling** but **is under central** will likely require a **lower 'cost recovery' transfer** payment under zonal pricing.

Constraint costs under self-scheduling (Baseline BM) vs. transfer payments under central scheduling, zonal design (£bn)



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



Costs to resolve forecast errors under zonal are similar to those under national, but form a greater share of total consumer costs (relative to Tx constraints)

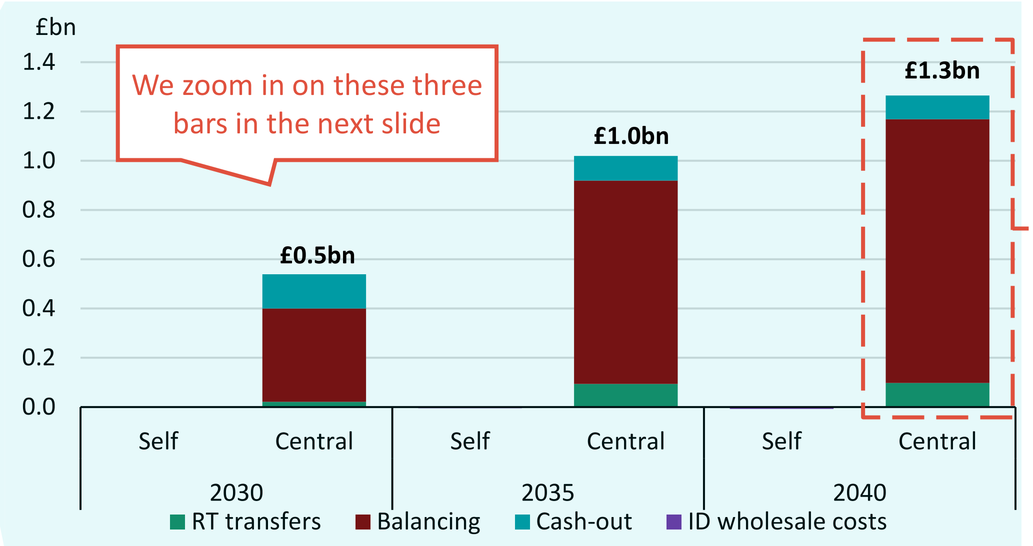
The consumer benefits of central scheduling are a function of:

The scale of Tx constraints

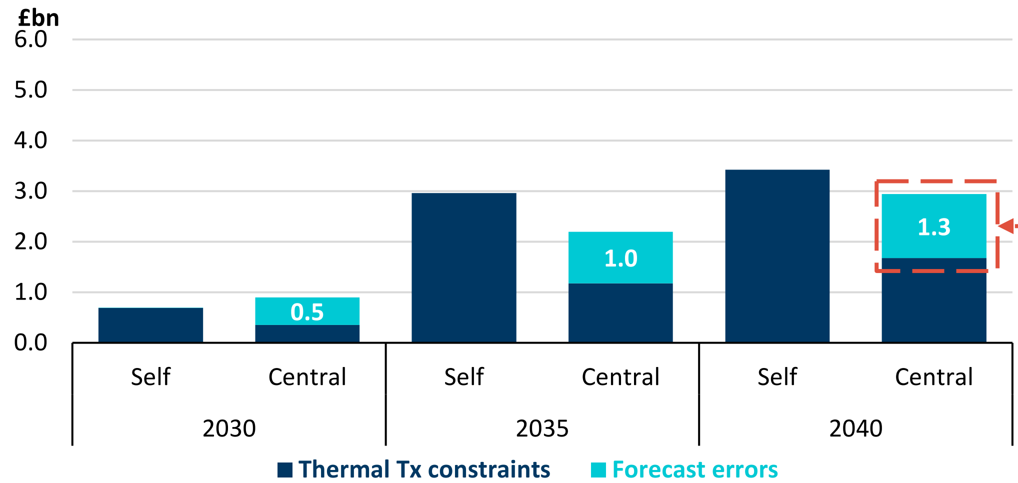
The scale of RES/load forecast error

- As in the national assessment, under self-scheduling with zonal pricing forecast errors are assumed to be fully resolved through ID trading before GCT, with minimal net cost to consumers.[1] Under central scheduling, the cost of resolving forecast errors is significantly higher.
- The annual cost of resolving forecast errors under zonal design with central scheduling is very similar to that under national design with central scheduling. This is because:
  - The central schedule under zonal pricing is similar to that under national pricing (there are minor differences, driven by different profiles of price-responsive consumer demand, e.g. smart charging of electric vehicles ("EV"), when facing a zonal, as opposed to national, WS price).
  - Forecast error profiles are identical in the national and zonal models.
- As under national pricing, the cost of resolving forecast errors under zonal design leads to a small disbenefit of central scheduling in 2030. However, in 2035 and 2040 this effect is outweighed by the consumer cost savings of improved management of Tx constraints.
- Overall, the cost of resolving forecast errors is relatively more important under zonal pricing (i.e. the light blue bar as a share of the total consumer costs is larger under zonal compared to national, see Slide 71), as a zonal WS design reduces the cost of resolving Tx constraints under both self- and central scheduling.

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



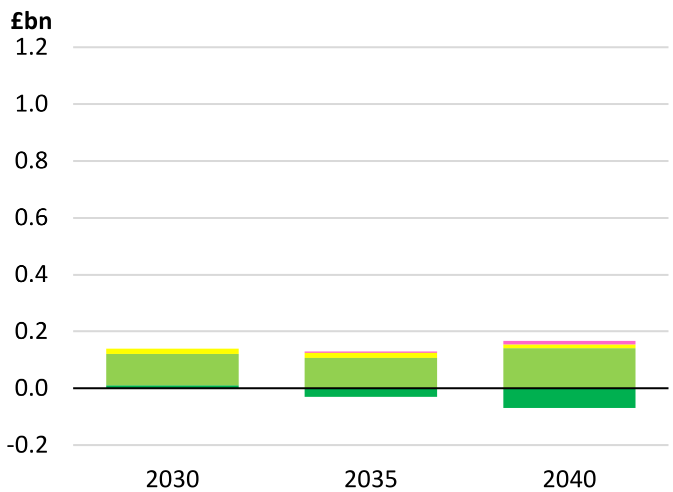
Aggregate consumer costs of resolving thermal Tx constraints and forecast error under self- vs central scheduling, zonal design (£bn)



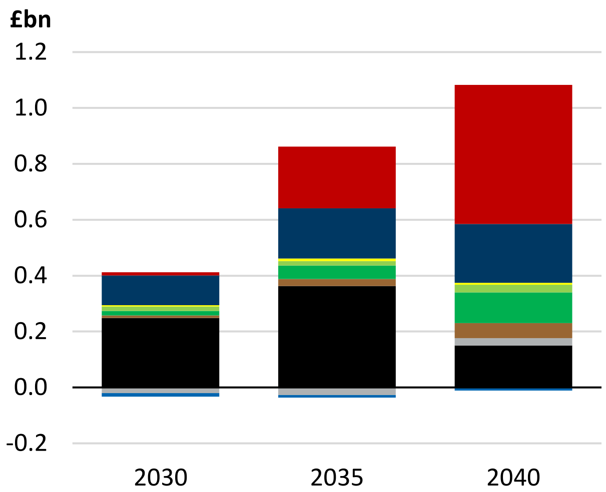
Notes: (1) While there are larger swings between the zonal DA and ID WS prices in zones with a high volume of renewables than observed in the national DA and ID WS prices (and vice-versa for zones with low volumes of renewables), these zones typically have lower demand (and so smaller demand imbalances) which limits the impact on consumers (see Slide 21).

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

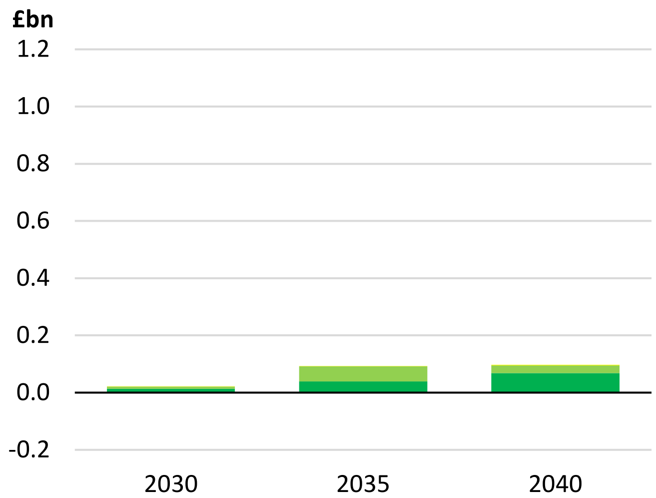
Central scheduling cash-out payments (£bn)



Central scheduling BM costs (£bn)



Central scheduling RT transfer payments (£bn)



Fossil fuel | CCS Gas | Other renewable | Offshore Wind | Onshore Wind | Demand | Solar | Hydro | Pumped Storage | Batteries | Interconnectors

- With zonal pricing, cash-out prices are paid relative to ID zonal prices (analogous to the ID national price under national pricing).
- However, when comparing total cash-out payments with the cash-out payments under national, the results are very similar.
- Net cash-out payments are slightly positive, with onshore wind tending to under-forecast in high-priced hours and receive additional payments for its increased output in RT.
- The balance of cash-out costs across technologies is to some extent driven by the CY modelled (CY 2013) – modelling a different CY could result in a different balance of cash-outs.

- Total (and technology-specific) BM costs to resolve forecast error-driven energy imbalances and resulting Tx constraints are very similar to those under national pricing (see Slide 72).
- The DA central schedule under zonal pricing is nearly identical to under national pricing, and the forecast error profile applied to each is the same.
- Minor differences are driven by: (i) the hours price-responsive demand consumes in at DA (see Slide 84), altering the total load the central scheduler must meet in each hour and; (ii) changes in opportunity cost of BM participation for batteries and CfD RES units that price BM actions relative to prevailing WS prices (see Slide 59), which are now zonal rather than national.

- Transfer payments are also paid out relative to zonal WS prices. In aggregate, this causes a slight fall in RT transfer payments under zonal pricing relative to under national pricing.
- However, as under national pricing, net RT transfers remain slightly positive. This is a policy-driven net transfer from consumers to producers to protect generators from the risk of forecast errors at DA, by providing 'make whole' transfers for the mis-forecasted output that is not used in RT by the central scheduler.

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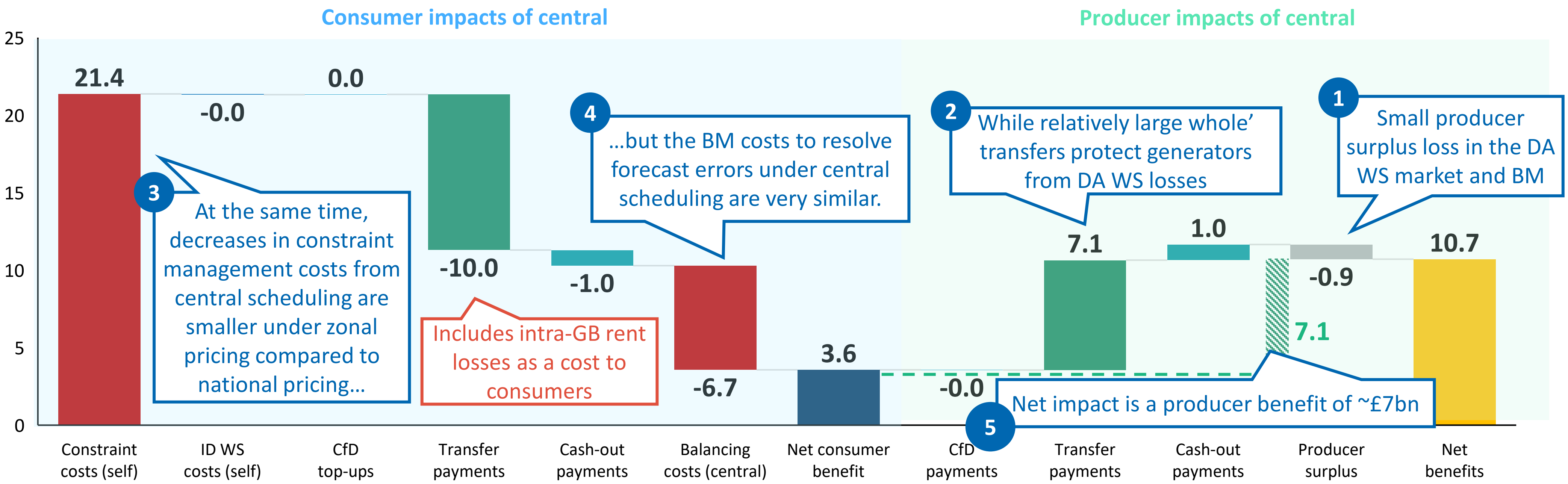
Moving from self to central scheduling under zonal pricing increases GB SEW by £10.7bn, with producers benefiting more than consumers

- Compared to under national pricing, producers see a larger net producer benefit from a move to central scheduling under zonal pricing (£7.1bn vs £3.6bn under national pricing). This can be explained by a relatively small gross producer surplus loss when moving from self to central scheduling under zonal pricing (£0.9bn)[1] while transfer payments to producers remain relatively large (£7.1bn). Gross producer surplus loss is relatively small because:
  - The decrease in Tx-driven constraint costs when moving from self to central scheduling under zonal (£21.4bn) is smaller compared to under national pricing (£35.8bn). This implies that producers active in the BM lose less revenue from the reduction in constraint management actions from a move to central scheduling under zonal pricing. At the same time, the increased forecast error-driven balancing costs in the BM when moving from self to central scheduling is similar under zonal relative to under national pricing (£6.7bn vs £6.2bn under national).
  - Under zonal pricing there are fewer instances where: (i) assets lose WS revenues because they are scheduled under self but not under central scheduling, or; (ii) assets are scheduled under central but loss-making. However, the same policy is in place that assets are compensated when worse off at DA under central scheduling relative to self but not required to 'transfer back' rents when they are better off under central scheduling.
- The total resulting GB SEW benefit of moving to central scheduling is lower under zonal pricing than under national pricing (£10.7bn under zonal vs £12.6bn under national).

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

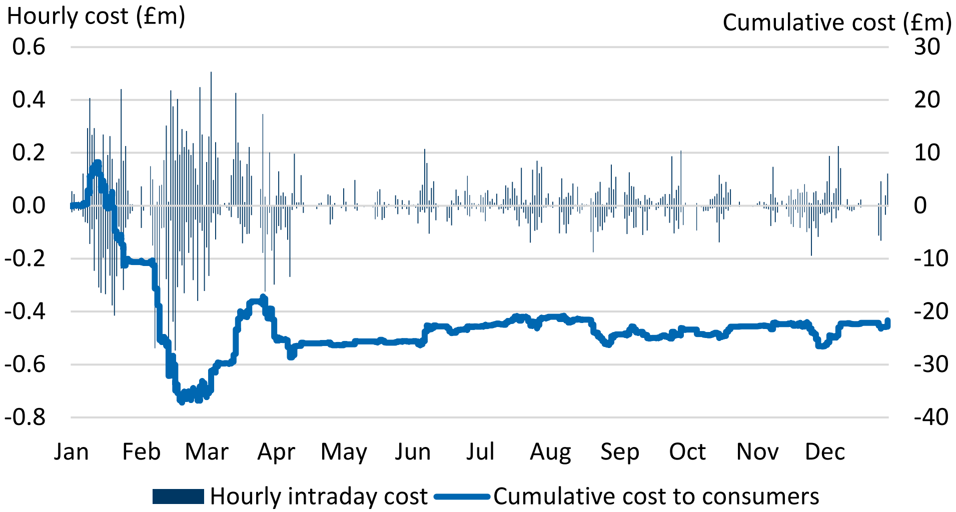


Notes: (1) This £0.9bn gross loss for producers consists of a £1.6bn increase in the BM under central scheduling but a £2.6bn loss in the WS market.

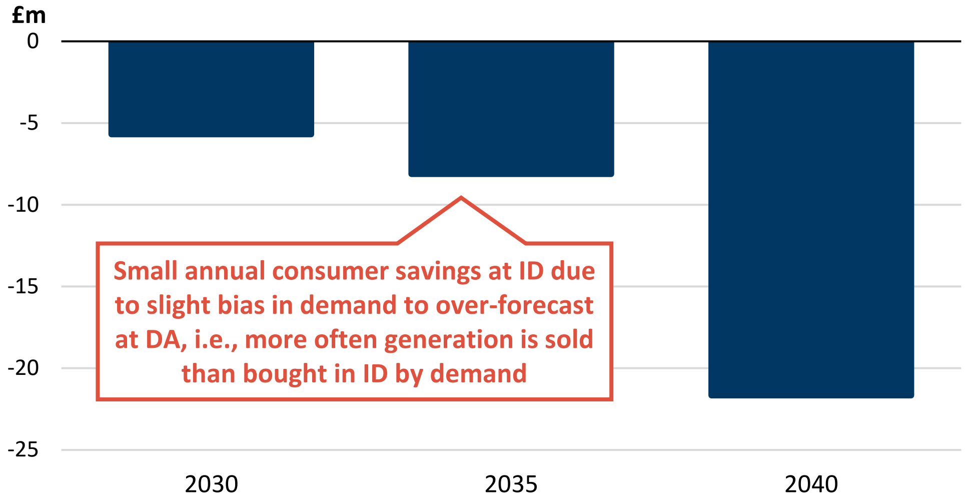
Appendices

Appendix 1: Under self-scheduling, the costs of resolving forecast errors ID broadly net out across the year, with a very low net consumer cost saving

Hourly and cumulative ID wholesale costs to consumers, 2040 (£m)



Net GB intraday wholesale cost per year (£m)



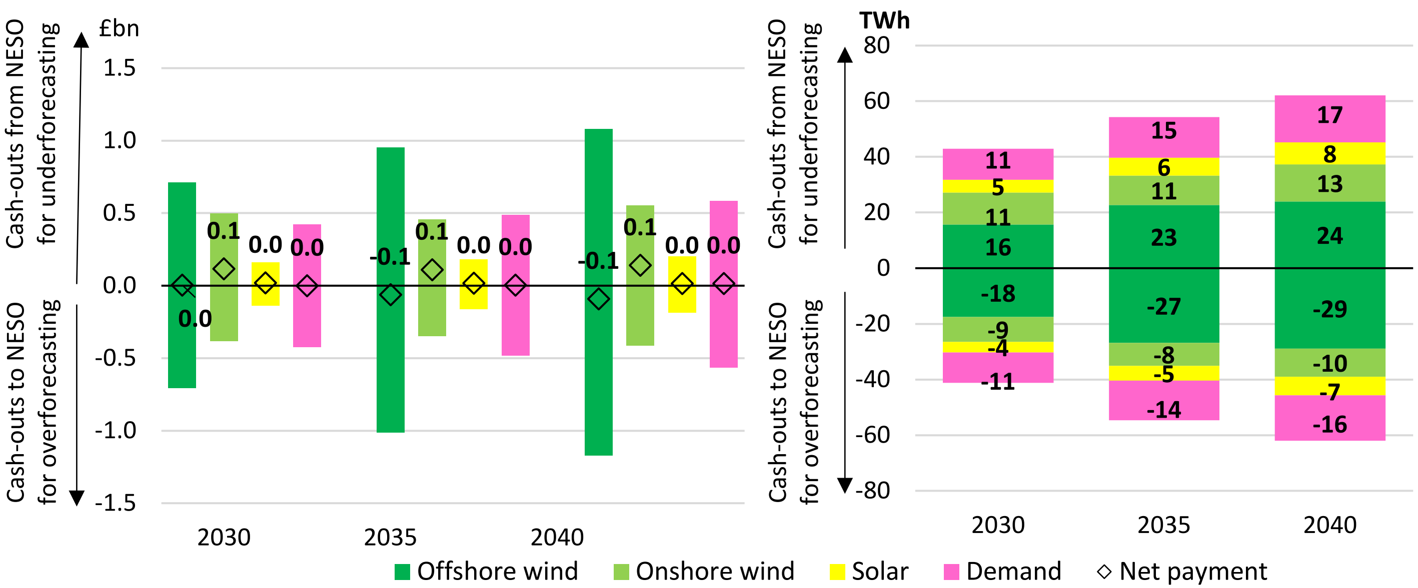
- Under self-scheduling, ID WS costs are calculated as the net change in demand across GB in each settlement period multiplied by the ID WS price.
- Due to differing mis-forecasts between demand and RES in a given hour, scheduled supply does not always equal demand at ID stage. If forecast errors mean that demand exceeds supply, the system is net short, and more power will be procured at ID. This constitutes a cost to consumers.
- Conversely, if forecast errors mean scheduled supply exceeds demand at ID, the system is net long, with demand selling generation purchased in excess in ID. This is assumed to be a saving for consumers (i.e. a negative cost).
- The top chart shows modelled hourly ID WS costs under self-scheduling, and the cumulative total across the year, for 2040.
- ID WS costs vary significantly by hour due to varying aggregate demand imbalances and volatility in the ID WS price.
- ID WS prices are not necessarily lower/higher when demand over/under-forecasts. This is because wind forecast errors are the dominating factor for ID WS price fluctuations and there is limited correlation between wind and demand forecast errors in the modelled scenario. Consequently, positive and negative ID WS costs largely net out across the year, with cumulative ID WS costs close to zero.
- The dataset used to construct demand imbalance profiles (calibrated using historical data as explained in Slide 37) has a slight bias to over-forecast at the DA stage. There is therefore slightly more power sold than bought at the ID stage, resulting in small ID WS cost savings for consumers.
- Overall, the effect on ID WS consumer costs from demand imbalance is minimal, estimated at £5.7m saving in 2030 (shown in the bottom chart).
- The ID consumer costs savings increase over the modelling period as total demand increases while the slight bias to over-forecast demand at the DA stage persists.

Appendix 2: Under central scheduling cash-out payments paid by NESO are almost equal to cash-out payments received by NESO

- If a **change in generator output or load** at a GSP is caused by **a unit's own forecast error**, it receives or pays a **cash-out payment**.
- Cash-out payments are **priced at the self-scheduled ID wholesale price (see Appendix 3).**

Central scheduling cash-out payments (£bn)

Total cash-out volumes (TWh)



Average cash-out price received/paid for under/over forecast (£/MWh)

		2030	2035	2040
Cash-outs from NESO for underforecasting	Offshore wind	45	42	45
	Onshore wind	43	43	42
	Solar	35	28	25
	Demand	38	33	35
Cash-outs to NESO for overforecasting	Offshore wind	40	38	41
	Onshore wind	43	42	41
	Solar	37	30	28
	Demand	39	34	35

- **Offshore wind generators** receive and pay the **greatest magnitude** of cash-out payments, with the **balance of payments to and from NESO being relatively equal** (see left chart). Overall, offshore wind over-forecasts slightly more often than it under-forecasts (see centre chart). However, the impact on cash-out payments is mitigated as the **average cash-out price when offshore wind over-forecasts tends to be lower** than when the wind under-forecasts (see the table).
- By contrast, onshore generators under-forecast more frequently than they over-forecast (see centre chart). Compounded by the fact that the average cash-out price is slightly higher in hours when onshore wind under-forecasts (is long)**, the net cash-out payments to onshore wind generators from NESO (on behalf of consumers) are positive.**
- Cash-out payments **to solar generators** are relatively small. This reflects the **lower generation volumes** of solar compared to wind, combined with the fact that in hours where there is significant solar imbalance, **the cash-out price is relatively low** (e.g. in the middle of the day).
- Demand **over- and under-forecasts in relatively equal amounts**, and the average **cash-out price is approximately the same** in both cases. A **slight bias towards over-forecasting** means that the net effect is a **small payment from NESO to consumers** in all years.

Appendix 3: There is a range of options to model the pricing of cash-outs, each with a trade-off between incentives and risk

Low degree of risk on generators but poor incentives to forecast accurately

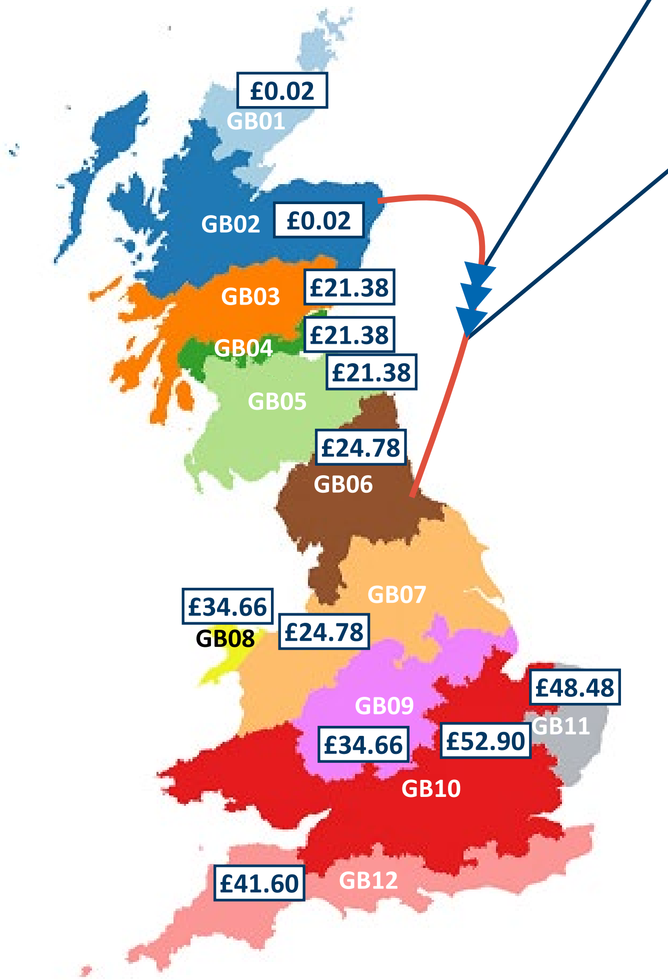
High degree of risk on generators but strong incentives to forecast accurately

	1	2	3
Cash-out price	**Day-ahead wholesale price**	**Intraday price**	**Highest accepted bid/offer from non-flagged BM actions ("imbalance price")**
Explanation	▪ Under-forecasted generation is paid the DA price and over-forecasted generation pays back the DA price ▪ Generators are indifferent to selling at day-ahead or being unbalanced post-GCT.	▪ Under-forecasted generation is paid the ID price and over-forecasted generation pays back the ID price ▪ Generators face the same price risk from forecast errors under central as the ID price risk under self-scheduling	▪ Under-forecasted generation is paid the imbalance price and over-forecasted generation pays the imbalance price ▪ Similar to status quo imbalance pricing used to settle differences between contracted positions and metered output
Advantages & disadvantages	✓ No risk to generators from mis-forecasting ✗ May incentivise mis-forecasting ✗ Leads to overly-generous payments to generators at the expense of consumers	✓ Incentivises generators to forecast accurately at DA ✓ Better reflects the value of power in RT than the DA WS price ✓ Places a reasonable degree of risk on generators but not as much as the imbalance price would do ✓ Reduces consumer costs relative to using the DA WS as the cash-out price	✓ Strong incentives to forecast accurately ✗ As imbalance prices can be volatile, this approach would place excessive risk on generators under central scheduling given the limited ability to rebalance assets in the ID timeframe as under the chosen modelling setup.

Modelling the cash-out price under central scheduling equal to the ID WS price under self-scheduling strikes a balance between incentivising accurate forecasting and preventing excessive generator risk

Appendix 4: Under zonal pricing, intra-GB congestion rents can diverge under self and central scheduling due to different flows across boundaries

GB zonal setup and zonal prices in an example hour

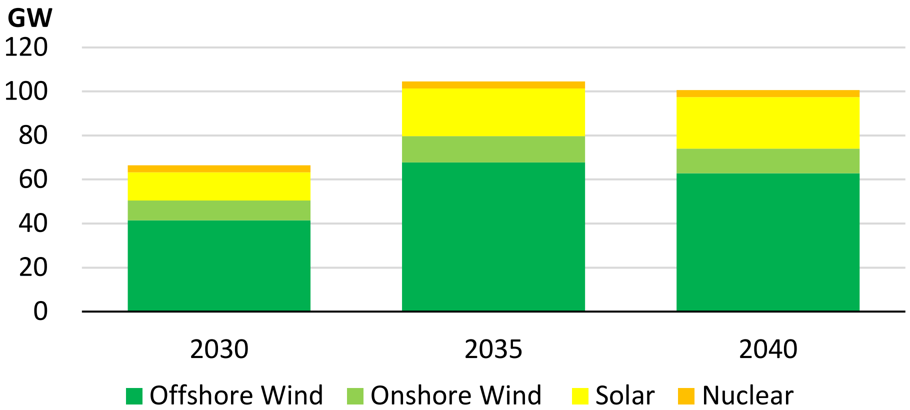


- Suppose, in a **given hour**:
  - The wholesale price of electricity in **GB02** is **£0.02/MWh**;
  - The wholesale price of electricity in **GB06** is **£24.78/MWh**; and
  - There exists **a Tx cable** of **2.0GW** connecting GB02 and GB06.
- Equivalent as for ICs, congestion rent is collected on the 2.0GW intra-GB Tx link as electricity from GB02 is sold to consumers in GB06 at a higher price than was paid to the generators in GB02. Assuming no losses:
  - Paid to producers in GB02 = 2,000MW * £0.02 = £40
  - Paid by consumers in GB06 = 2,000MW * £24.78 = £49,560
  - Congestion rent = £49,560 - £40 = £49,520
- Under central scheduling, similar to ICs, inter-zonal Tx will sometimes be scheduled to flow in a direction **counter to commercial incentives** (see Slide 82), and congestion rents on Tx between two GB zones can be **negative**. Overall, intra-GB congestions are expected to be lower under central scheduling.
- In these instances, Tx owners are due a **transfer payment** equal to the difference between the congestion rent under central and under self-scheduling.
- Currently the onshore TOs are regulated, such that they receive a regulated return on their investments which, everything else equal, would not be impacted by different intra-GB congestion rent. Hence, we assume that the transfer payment incurred for differences in intra-GB congestion rent is refunded to consumers via reduced Tx tariffs.
- However, in case onshore Competitively Appointed Tx Owners would become more prevalent in the future, the transfer payments would likely (depending on the exact business model) be kept by CATOs and not refunded to consumers.

Appendix 5: Our assessment of the consumer impacts from CfDs relies upon our assumptions on CfD capacity projections and future CfD regime design

- CfDs are government-backed agreements that provide electricity generators with price risk protection by guaranteeing a "strike price" for the power they sell.
- If an asset is scheduled in the reference market (typically being the DA WS market as assumed in our modelling) and the reference price falls below the strike price in a given hour, generators with a CfD contract receive a top-up; if prices exceed the reference price, they instead pay back the difference.
- In our assessment, to forecast the impact on CfD payments from a transition to central scheduling, we make assumptions on both the capacity of electricity generation with a CfD contract, and the methodology for forecasting strike prices.

Projected capacity of CfD holders



- We assume the following technologies have a CfD contract:
  - Existing projects with CfD contracts;
  - All existing, planned, and future offshore wind projects;
  - 50% of future onshore wind and solar projects; and
  - Hinkley Point C.
- All are assumed to have a 15-year contract length.
- Other technology types are excluded due to immateriality and/or uncertainty.

Methodology for calculating the CfD top ups

- **Strike price:**
  - For existing and planned offshore wind we use historical auction strike prices.[1]
  - For future offshore wind, and onshore wind and solar, we assume a strike price equal to the average levelised cost of energy forecasts from DESNZ.[2]
  - We assume the same strike price across GB and market design (national and zonal). In practice, this might lead to different total CfD payouts based on capacity factors and constraint risk.
- **Reference price & generation volume:**
  - We calculate hourly prices for each market and generation volume by generator (see Slide 33 for more information on our modelling approach).[3]

Notes/Sources: (1) Not including projects from the recent AR6 auction; (2) Electricity generation costs 2023, DESNZ (link); (3) In practice, the reference price for our zonal assessment could be defined in a number of alternative ways (e.g. a national price or hub price). For simplicity, we have assumed that the zonal price is the reference price.

Glossary

Glossary

AS	Ancillary Services	LtW	FES 2022 Leading the Way
BM	Balancing Mechanism	MTU	Market time unit
Cash-out payment	Compensation for any realised changed in output or load that is driven by an entity’s own forecast error	MRLVC	Multi-Region Loose Volume Coupling
CCGT	Combined cycle gas turbine	Net long	More demand than supply
CCS	Carbon capture and storage	Net short	More supply than demand
CfD	Contract for Difference	NETA	New Electricity Trading Arrangements
Client / NESO	National Grid Electricity System Operator	NOA	Network Options Assessment
Constraint costs	Paid when a unit changes its output in response to an SO request	OTC	Over-the-counter
CS	Central scheduling	PV	Present value
CT	Consumer Transformation	REMA	Review of Electricity Market Arrangements
CY	Climate year	RES	Renewable energy sources
DA	Day-ahead	ROC	Renewable Obligation Certificate
DESNZ	Department for Energy Security and Net Zero	RT	Real-time
DNO	Distribution network operator	RT transfer payment	Protect/penalise units when their forecast error does not change their final output
DSR	Demand-side response	RUC	Reliability Unit Commitments
FES	Future Energy Scenarios	S&D	Supply and demand
FPN	Final physical notification	SCUC/SCED	Security Constrained Unit Commitment and Economic Dispatch
FTI	FTI Consulting LLP	SDAC	Single Day-ahead Market Coupling
GCT	Gate closure time	SEW	Socioeconomic welfare
GSP	Grid supply point	Shadow nodal price	The prices used for scheduling assets under central scheduling (output of the SCUC/SCED) but not necessarily used to compensate assets
HND	Holistic Network Design	SO	System operator
IC	Interconnector	SQSS	Security and Quality of Supply Standards
ID	Intraday	SRMC	Short-run marginal cost
IPN	Initial physical notification	Transfer payment	Compensate generators that are worse off under central scheduling than self-scheduling
ISO	Independent system operator	TSO	Transmission system operator
ISP	Imbalance settlement period	Tx	Transmission
LT model	Long-term model	WS	Wholesale

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