Industry engagement

Quantitative Assessment of Self and Central Scheduling

Modelling methodology

FTI CONSULTING

NESO

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NESO has commissioned FTI to assess the merits of central vs. self-scheduling and how this may interact with other reforms (e.g. zonal pricing, BM reforms)

Introduction

- As part of the 'Dispatch' workstream in DESNZ's Review of Market Arrangements ("REMA"), NESO has completed a 'Case for Change' which identified potential benefits to taking a more centralised approach to scheduling of resources for energy and ancillary services.[1]
- NESO has since engaged FTI to assess the merits of centralised dispatch compared to self-dispatch under the current national market design as well as how this may interact with other key potential market reforms on locational pricing and improvements to the Balancing Mechanism ("BM").[2]
- An overview of the core workstreams of this project are set out on the right side.

This presentation

- This presentation summarises our methodology and key assumptions for the main workstream (#1). It is structured as follows:
- Overview of the approach (Slides 4-6)
- Key modelling assumptions (Slides 7-10)
- Modelling of forecast errors (Slides 11-13)
- Payment flows under self-scheduling (DA and post-DA) (Slides 14-15)
- Payment flows under central scheduling (DA and post-DA) (Slides 16-19)
- Overall cost-benefit assessment (Slides 20-21)

Project workstreams

1 **Impact of central vs. self-scheduling under a national wholesale market**

How does consideration of Tx constraints at DA stage affect wholesale prices and consumer/system cost outcomes?

What is more valuable: solving Tx constraints at DA or allowing the market to solve net GB imbalances closer to delivery?

2 **Self-scheduling with an Augmented BM under a national wholesale market**

To what extent could amendments to BM methodology reduce redispatch costs (but possibly not volumes)?

3 **Impact of central vs. self-scheduling under a zonal wholesale market**

How does the case for central scheduling change under a zonal wholesale design compared to national design?

Sources: (1) NESO, Scheduling and Dispatch Options Webinar, July 2024. (2) DESNZ, REMA: second consultation, May 2024.

Overview of approach

We will assess wholesale and BM outcomes across the three quantitative workstreams using five model set-ups

2 Impact of augmenting status quo BM design (N1S, N2S)

Model	N1C	N1S Status quo	N2S	Z1C	Z1S
Market design	National	National	National, with augmented BM	Zonal	Zonal
Scheduling[1]	Central *(i.e. accounts for Tx constraints)*	Self *(i.e does not account for Tx constraints)*	Self	Central	Self
Resources scheduled relative to[2]	Shadow nodal price	National price	National price	Shadow nodal price	Zonal price
Resources compensated based on	National price at DA, national cash-out price post gate closure	National WS/ID price	National WS/ID price	Zonal price at DA, zonal cash-out price post gate closure	Zonal WS/ID price
Day-ahead forecast error[3]	Imbalance resolved in BM	Intraday trading resolves GB aggregate imbalance	Intraday trading resolves GB aggregate imbalance	Imbalance resolved in BM	Intraday trading resolves GB aggregate imbalance
Transmission constraints resolved at	Predominantly DA	Resolved in BM	Resolved in BM	Predominantly DA	Resolved in BM

1 Impact of central vs self-scheduling under national (N1C, N1S)

3a Impact of central vs self-scheduling under zonal (Z1C, Z1S)

3b Impact of zonal design on the merits of central vs self-scheduling

● Workstream

Notes: (1) The key difference in the modelling of self vs central scheduling lies in the consideration of transmission constraints in the wholesale market schedule (all network constraints are considered under central scheduling while prices can be national or zonal). We do not model difference in portfolio (self-scheduling) vs unit-based bidding (central scheduling) or bidding formats. (2) Core and sensitivity interconnector scheduling methodology under central is yet to be finalised with NESO. (3) We assume that all forecast error is resolved pre-gate closure under self-scheduling.

We will examine perceived trade-offs between intraday balancing under self-scheduling and resolving Tx constraints at day-ahead under central scheduling

Under the modelled representation of self-scheduling, the market solves forecast error-driven supply and demand imbalances via intraday trading, while thermal constraints are assumed to be resolved by NESO after gate closure. In the modelled representation of central scheduling, we assume that NESO solves thermal constraints in the DA central schedule, but imbalances are not resolved until closer to delivery.

Simplified modelling assumptions	Day-ahead	Intraday	Post-Gate Closure
Self-scheduling	▪ DA schedule ignores Tx constraints ▪ …with market clearing based on imperfect forecasts of demand and RES output	▪ Change in RES/load forecasts lead to imbalances. GB imbalances are assumed to be resolved by the market via intraday trading.[1]	▪ ESO adjusts schedule for transmission constraints through the pay-as-bid BM.
Central scheduling	▪ DA schedule determined in-line with Tx constraints ▪ Schedule at DA considers the thermal limits of the transmission network but clears based on imperfect forecasts of demand and RES output (these errors are identical to the self-scheduling above).	Assumption: No intraday market under central scheduling to resolve imbalances Conservative modelling assumption that likely overestimates the burden to the SO of resolving forecast errors under central. Other centrally scheduled markets (e.g. in Italy) have different forms of intraday trading.	▪ Imperfect anticipation of the pattern of generation and demand at day-ahead creates imbalances and some new Tx constraints (but fewer than under self). ▪ ESO continues to adjust schedule for transmission constraints through the pay-as-bid BM.

Legend

Scheduling — Transmission introduced — Imbalance introduced

Notes: (1) We assume 'perfect balancing' under self-scheduling, such that all forecast errors are resolved prior to gate closure. This is a simplification that enables us to isolate the role of the market balancing under self-scheduling relative to central scheduling (i.e. for both market designs we ignore any further imbalance created in the final hour before delivery).

Key modelling assumptions

The model is calibrated to FES 2022 Leading the Way, with key assumptions updated to align with market developments and DESNZ REMA modelling

Key proposed assumptions for quantitative assessment

GB scenario	FES 2022 LTW
Europe scenario	FES 22 EU CT
Interconnectors	Aligned with DESNZ REMA modelling
Commodity prices	Oil, gas and coal aligned with DESNZ 2023 assumptions. Others are forward prices as of Q2 2024.
Modelled years	2030, 2035, 2040
Climate year (“CY”)	CY2013 (agreed with NESO)
Transmission network	HND + NOA7 Refresh (contemporaneous with FES22) Zonal boundaries aligned with DESNZ REMA modelling

‘Baseline’ BM assumptions are the same for self and central scheduling, with key cost assumptions aligned to NESO estimates

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
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)	
Waste	No participation		
Hydrogen (H_2P)	No participation		
DSR	No participation		
Nuclear	No participation		

Current NESO BM methodology

Baseline BM pricing assumptions have been developed based on NESO methodology

Baseline percentage **offer uplift for thermal units** is estimated by **comparing historic offer prices of gas generators** with their **historic SRMCs** (data provided by NESO).[1]

Cost of **reversing interconnector flows** from their WS position is driven by the **expected marginal generator in the connected country that is required to increase output in response**. **NESO** has provided estimated **reversal costs per MW** out to 2035 (we extend the per MW cost for 2035 to 2040).

We introduce a **skip rate** (aligned to a range of internal and external metrics, provided by NESO), to a **subset of assets in the baseline BM** by fixing a proportion of their output to their day-ahead outcome.

BM actions are priced the same under self and central scheduling… but the volumes and units called upon in the BM will differ.

Note: (1) This offer uplift is calculated by comparing historic offer prices of gas generators with their historic SRMCs (provided by NESO). It is intended to reflect uplifts in the BM offer price on top of the SRMC, which includes other costs, such as start costs and the uplift due to the nature of the pay-as-bid market of the BM. Since we are estimating this uplift over the SRMC based on historical data, it could include the effect of market power, if this has been an issue historically in the BM.

Self | Central

DA | ID | RT

We will also run an 'Augmented BM' sensitivity for self-scheduling with cheaper thermal use, reduced unit skipping and broader technology access

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

(2) applies to all rows from Fossil fuel to DSR.

Current NESO BM methodology | Augmented BM

Augmented BM

1 Reduced offer uplift[1]

We propose to show the impact of a **range of reduced uplifts**, representing **improved efficiency** of activation of thermal units in the Augmented BM.

2 Improve asset utilisation

Remove all unit skipping in the Augmented BM.

3 Broaden access to BM

Allow **waste, H2P and DSR** participation. **Waste is mid-merit**, while H2 is used ahead of unabated gas (but with limited fuel available across the year).

- The Augmented BM is intended to illustrate the impact that BM design improvements could have under self-scheduling (e.g. ID balancing reserve, wider access for resources).
- Our proposed alterations for the Augmented BM below focus on prices (uplifts) and volumes (range of technologies) as proxies for possible future BM augmentations.

Modelling of forecast errors

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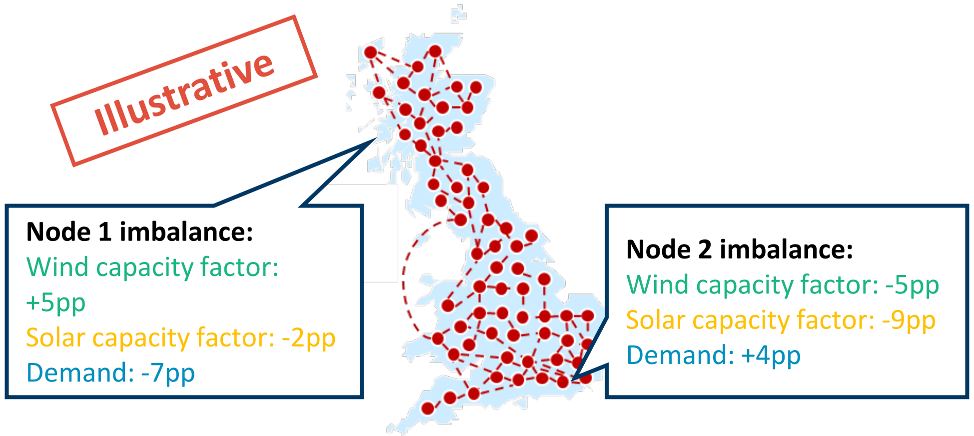
We introduce forecast errors, calibrated from NESO data, to assess the cost of solving ID forecast changes under central compared to ID trading under self

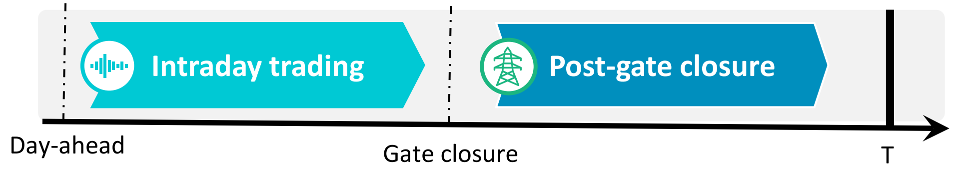
Energy imbalances occur across GB primarily due to RES and demand mis-forecasting

- NESO has provided the following data on DA to GC forecast errors:
  i. For wind, NESO DA forecast and FPN by wind farm;
  ii. For demand, national aggregate imbalance and a sample of GSP-level forecast errors;
  iii. For solar, NESO DA forecast and Sheffield Solar PV outturn for a subset of DNO regions.[1]
- Wind forecast errors are the most significant, followed by solar and demand.
- To examine the merits of central vs self-scheduling, we introduce **three sources of forecast error into the model between DA and gate closure**: wind, solar and demand at the GSP level, as illustrated below.[2]

Illustrative nodal imbalances created by RES/load DA forecast error

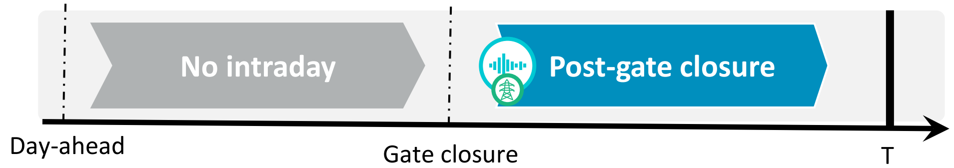


Self-schedule is assumed to resolve the imbalance created by these forecast changes 'intraday' pre-gate closure



- Under self-scheduling, the **net aggregate GB imbalance is modelled as being resolved via 'intraday' trading (i.e. pre-gate closure)…**
- …but the impact on final balancing costs is uncertain. The final schedule at gate closure may still not be technically feasible and 'intraday' trading to solve the net GB imbalance **may alleviate or exacerbate thermal constraints.**

Central schedule is assumed to resolve the imbalance created by these forecast changes post-gate closure

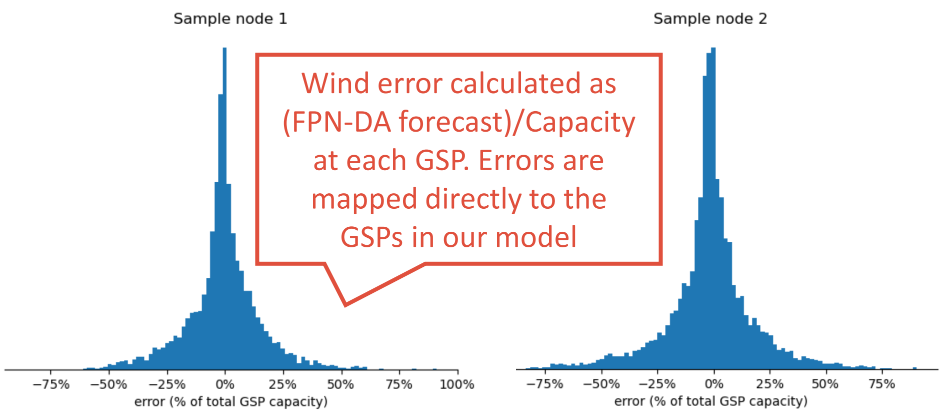


- Under central scheduling, forecast errors by generators lead to units receiving/paying a cash-out for changes in position in real time…
- …while the remaining **residual nodal imbalances are modelled as solved through constraint management actions at additional cost to NESO.**
- This additional cost is an important consideration when assessing the potential benefits of central scheduling.

Notes: (1) Sheffield Solar is a research group with a long-standing collaboration with NESO measuring national and regional solar outturn. (2) The day-ahead schedule clears with an imperfect visibility of RES and load patterns under both market designs. We introduce revised (improved) forecasts between day-ahead and gate closure, solved via intraday trading under self-scheduling and post-gate closure under central scheduling. We assume that all forecast errors are resolved pre-gate closure under self-scheduling.

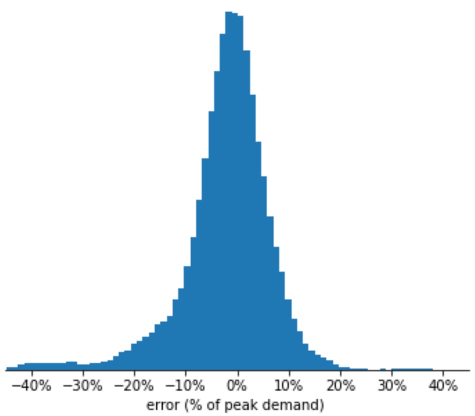
Wind forecast error significantly outweighs load error, with the impact on post gate closure costs determined by the location and direction of the error

Selected GSP wind error histograms (% of capacity)



Wind error calculated as (FPN-DA forecast)/Capacity at each GSP. Errors are mapped directly to the GSPs in our model

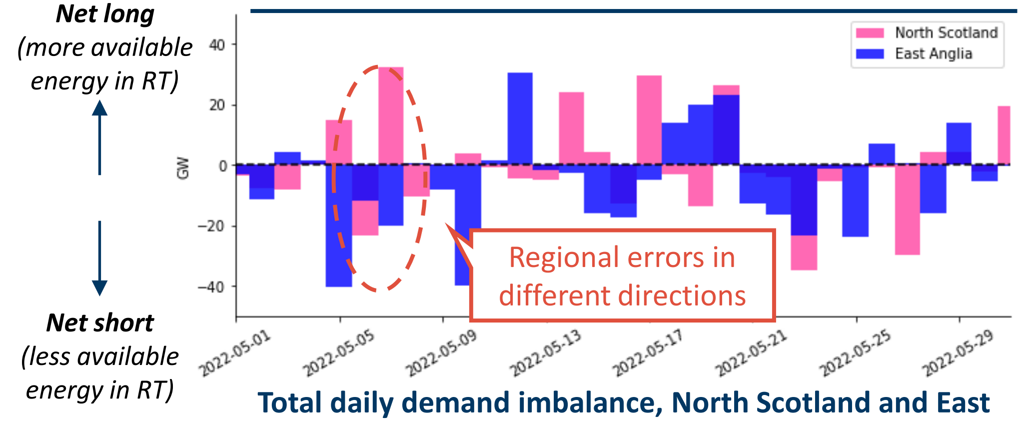
Distribution of forecast errors for sample of 'demand-dominated' nodes (% of peak demand)



- NESO provided a sample of forecast errors for 11 'demand-dominated' nodes (i.e. nodes with minimal embedded generation) for March-Sept 2024.
- We formed a distribution of these GSP-level errors…
- …and sample this distribution (clustered regionally) to apply errors to the GSPs in our model.

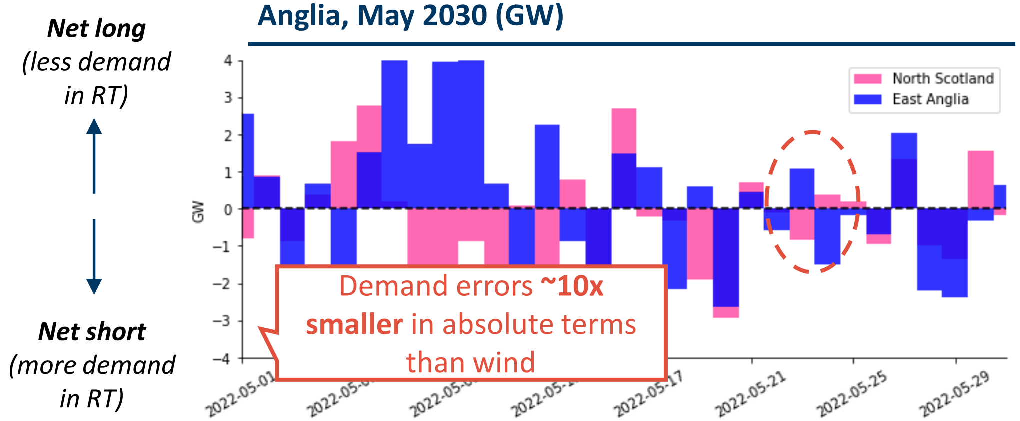
Our demand error distribution is constructed from c.**78,000 data points**

Total daily wind imbalance, North Scotland and East Anglia, May 2030 (GW)



Regional errors in different directions

Total daily demand imbalance, North Scotland and East Anglia, May 2030 (GW)



Demand errors **~10x smaller** in absolute terms than wind

- Size and direction of historical forecast errors vary significantly across settlement periods and regions.
- For example, as shown above, demand and wind imbalances can act in the same or opposite directions in North Scotland and East Anglia, with no discernible pattern.
- Cost impact of the imbalance in each period depends on the location, e.g. higher wind in Scotland may increase constraint costs, while lower demand elsewhere in England could reduce costs.

Self-scheduling: payment flows at DA and post-DA stages

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

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

Wholesale market

Day-ahead → Intraday → Post-Gate Closure

Day-ahead | Gate closure | H | T

Model S1

Unconstrained wholesale market run with imperfect forecast

Finds DA self-schedule and wholesale price

Model S2

Unconstrained wholesale market run

Resolves net GB aggregate imbalance (but schedule still may not be physically feasible)

Model S3

Constrained Redispatch (BM) run

Resolves thermal constraints only

Post-gate closure run assumed to resolve Tx constraints only; all costs are constraint management.[1]

Day-ahead wholesale costs

- Day-ahead wholesale market clears ignoring Tx constraints…
- …and based on imperfect forecasts of demand and RES output

Intraday wholesale costs

- Change in load and generation in intraday markets pays/receives the intraday wholesale price…
- …which is primarily influenced by the 'post-day-ahead forecast error' change in RES output

Constraint management costs

- Constraint management costs under self-scheduling solved in the usual way with pay-as-bid unit bidding in the BM
- All forecast errors are assumed to have been resolved by market participants before constraint management process begins

CfD top-ups paid on final output

Scheduling | Transmission introduced | Imbalance introduced

Central scheduling: payment flows at DA and post-DA stages

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Self | Central

DA | ID | RT

Under central scheduling Tx constraints are resolved at DA, with forecast errors resolved post-gate closure; constraint costs are reduced, but other costs arise

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

Wholesale market

Day ahead → Intraday → Post-Gate Closure

Day-ahead | Gate closure | H | T

Model C1

Constrained nodal wholesale run with imperfect forecast

Finds DA central schedule wholesale price

Model C2

Constrained Redispatch (BM) run

Resolves nodal imbalances and any resulting (minor) thermal constraints

Post-gate closure run resolves imbalances and Tx constraints caused by the imperfect anticipation of the pattern of generation and demand at day-ahead (in turn driven by the forecast error); imbalance generates cash-out payments, real-time transfers, and constraint management costs

1 **Payments are required when the DA Central outcome differs from DA Self…**

Day-ahead wholesale costs

Day-ahead 'make whole' transfer payments

Day-ahead 'make whole' transfer payments discussed further on Slide 18

Real-time transfers and cash-out payments are required under central scheduling in place of intraday trading (see Slide 19).

2 **…and when the RT Central outcome differs from DA Central**

Constraint management costs

Cash-out payments

Real-time 'make whole' transfer payments

\+ **CfD top-ups paid on final output**

Scheduling | Transmission introduced | Imbalance introduced

Notes: (1) We assume 'perfect balancing' under self-scheduling, such that all forecast errors are resolved prior to gate closure. This is a simplification that enables us to isolate the role of the market balancing under self-scheduling relative to central scheduling. (2) This is a policy choice agreed with NESO for the purposes of the quantitative assessment.

Assets are compensated when they are worse off at day-ahead under central scheduling compared to self-scheduling

There is a mismatch between the prices determined by the central schedule, and the price with which generators are compensated…

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

Due to this mismatch between shadow nodal scheduling and national compensation, some generators require 'make whole' transfer payments:

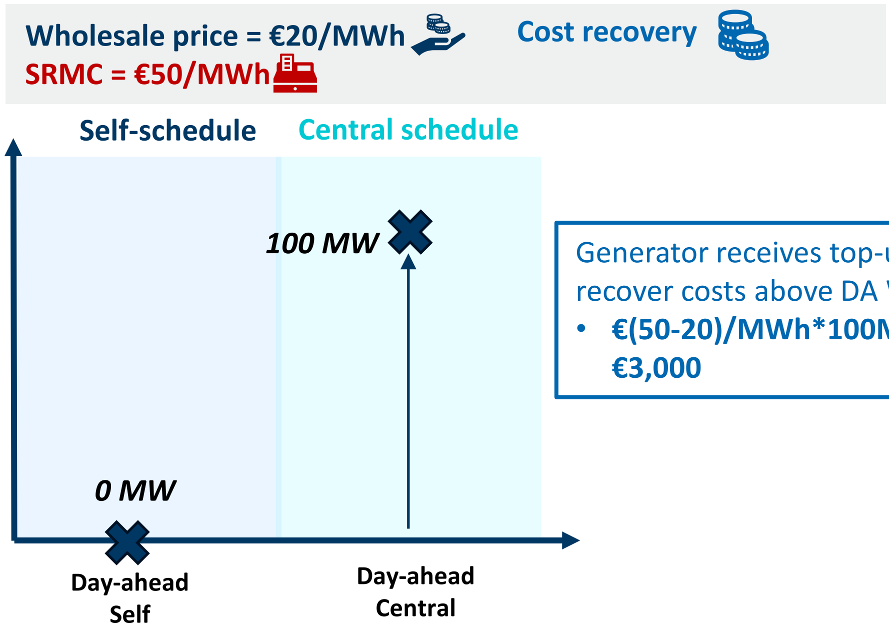
Cost recovery:

- Asset is **centrally scheduled**, but the **unconstrained national price does not** cover their SRMC
- To ensure they are not loss making, **compensation = (SRMC – national price)*generation**

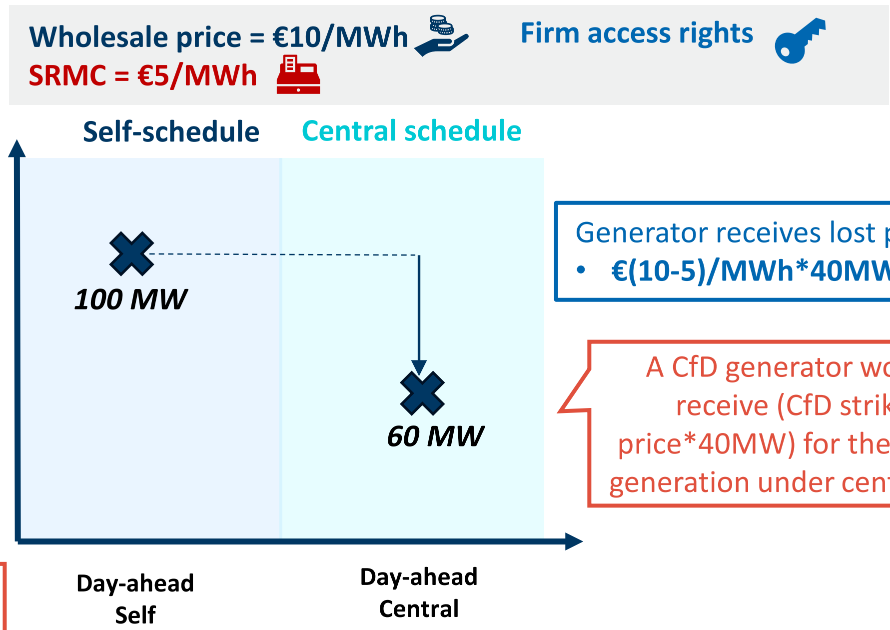
Firm access rights:

- Asset is not **centrally scheduled**, but **would have been** under self-scheduling (less prevalent with zonal pricing)
- Firm access rights require the asset to be compensated the **equivalent profit as if it were scheduled**.

We have agreed with NESO to model firm access rights for all units



Generator receives top-up to recover costs above DA WS price:
- **€(50-20)/MWh*100MW = €3,000**



Generator receives lost profits:
- **€(10-5)/MWh*40MW = €200**

A CfD generator would receive (CfD strike price*40MW) for the fall in generation under central DA

Self | Central

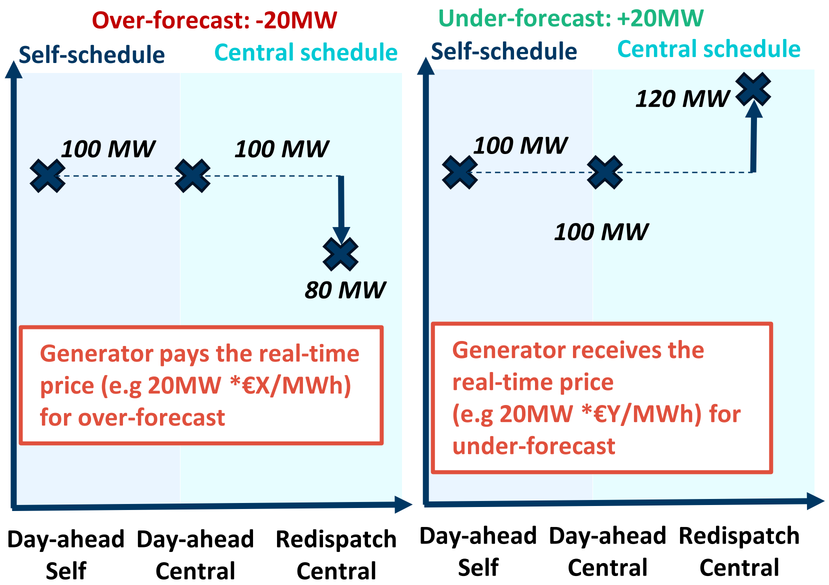
DA | ID | RT

We have developed three ‘rules’ for allocating the post-gate closure costs that arise from day-ahead 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**

Tech: | DA Central vs self : | Forecast error:

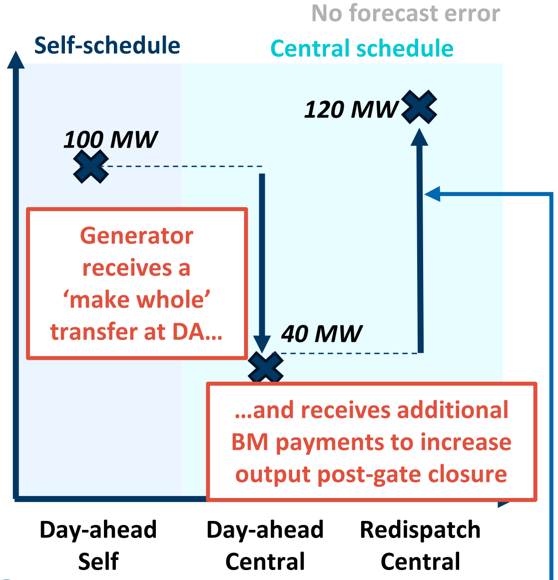


As the self-scheduling model assumes no forecast errors post-GC, and the imbalance profiles are the same under self and central scheduling, we use the self-scheduling intraday price as a proxy for the RT cash-out price under central.

2 Constraint 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 constraint costs

Tech: | DA Central vs self :

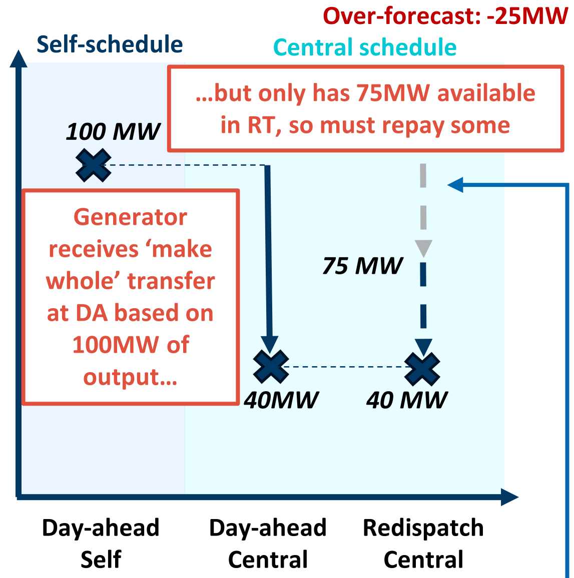


1 **BM revenues are not offset against DA transfers** (otherwise units would internalise the lost transfer in their BM bid/offer pricing)…

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[1]

Tech: | DA Central vs self : | Forecast error:



2 …but **real-time transfers** and **cash-out payments should** first **repay** any ‘make whole’ **transfers received at day-ahead.**[2]

Note: (1) This mechanism for payment/re-payment of real-time transfers would rely on the ability of NESO to effectively measure the ‘true’ final output that each unit could have provided. (2) In practice, this exposes generators to relatively little risk from over- or under-forecasting at DA, meaning 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.

Overall cost-benefit assessment of central vs self-scheduling

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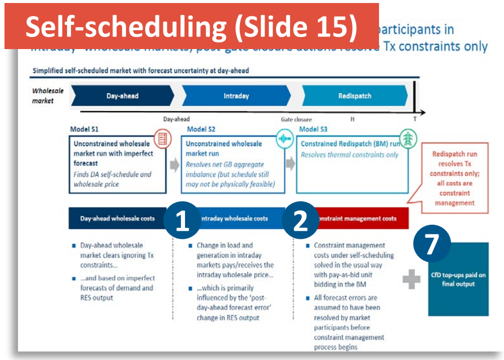
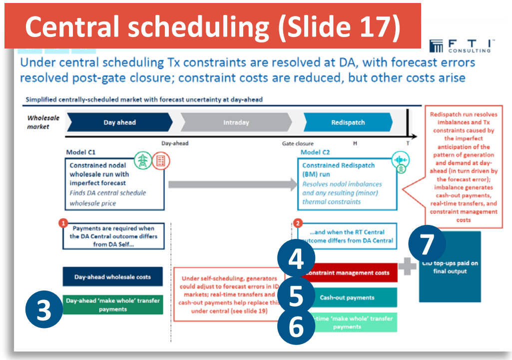
The quantitative assessment will capture a range of consumer and producer impacts of central scheduling to estimate net GB socioeconomic welfare

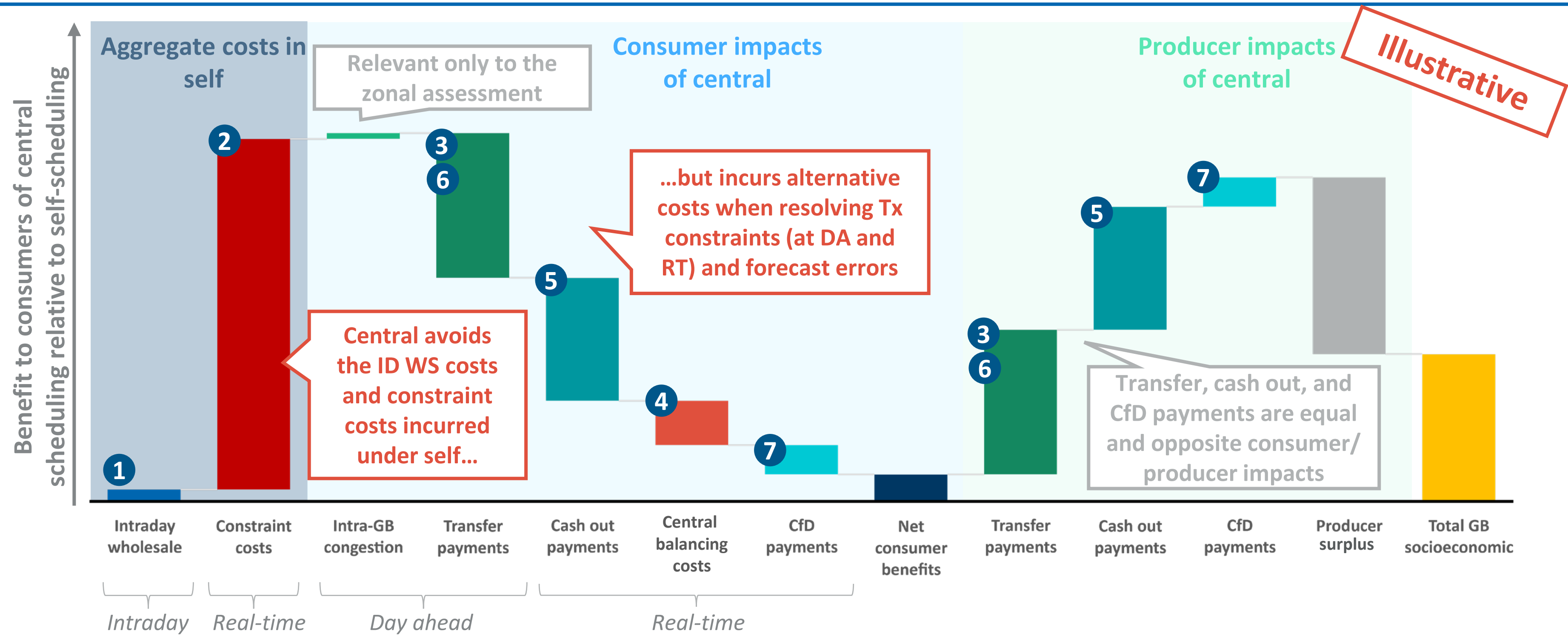
Day-ahead wholesale costs are unchanged between the modelled central and self-schedules





- **WS1** will test the **case for central scheduling** under the current **national wholesale market** design
- **WS2** will repeat this assessment, but with an **Augmented BM** in the **self-scheduled model** that reduces constraint costs
- **WS3** will test how the **case for central scheduling changes** under a **zonal** wholesale market design compared to a national design

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



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