ESO

REMA Dispatch Options Webinar Pre-read

July 2024

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1 Introduction and context

ESO has been asked by DESNZ to lead the 'Dispatch' workstream in its 2nd phase of REMA. We have previously published AFRY's 'Case for Change' on Scheduling & Dispatch, which provided a qualitative account of issues in current Dispatch arrangements. ESO additionally published its response to AFRY's work.

We are now in the 2nd 'Options Identification' phase. This webinar is to get industry feedback on the seven Dispatch models we have identified for evaluation in the REMA programme. We are asking:

- Have we identified the right spectrum of models?
- Are the distinctions between models clear?
- Have we identified the right hypothesised pros/cons of each model that would need to be validated in REMA?

This pre-read document sets out the strawman models we have identified so far to help attendees familiarise themselves with the content before the discussion.

1.1 What are scheduling and dispatch, and why are they important?

Scheduling, dispatch, and re-dispatch are the steps for determining when units will operate and at what level, while ensuring their operation respects the physics of the electricity network in real-time:

- **Scheduling** covers the start-up and shut-down decisions about units. Scheduling can start months or years ahead with forward trading, and is refined to around 24 to 4 hours ahead of real-time.
- **Dispatch** covers decisions about the exact output level and profile of units. Dispatch is refined towards real-time, when more detailed information and forecasts are known.
- **Re-dispatch** is changes to the dispatch made in real-time, or just before, to make sure that the needs of the system are met (balancing, constraints, inertia, voltage etc.).

Re-dispatch frequently entails 'turning on' a unit that would not have otherwise cleared in the wholesale market, and therefore tends to increase consumer costs. Re-dispatch also leads to wider system inefficiency: in electricity markets, price signals for close to real-time delivery are critical for incentivising efficient market behaviour, as market parties' expectations of these 'spot prices' underpin forward trading and investment decisions. High re-dispatch impacts market parties' ability to accurately forecast the spot price, reducing system efficiency in both operational and investment timescales.

The extent to which re-dispatch is required depends on how well the scheduling and dispatch meet the physical needs of the system: **better scheduling and dispatch** → **less re-dispatch**. A key question in REMA is whether significantly changing how scheduling and dispatch are done to minimise re-dispatch is better or worse for the system as a whole, when considering REMA's wider objectives.

1.2 What are the current and future issues with GB's dispatch arrangements?

Re-dispatch volumes and resulting costs have risen significantly in recent years as shown in the Figure below. This rise has been driven by the large quantities of new generation and interconnectors that have connected in congested areas of the network. A renewable-led generation mix has an inherently more variable output, and the changing nature of generation and demand has increased the volume of system operator interventions to maintain system security.

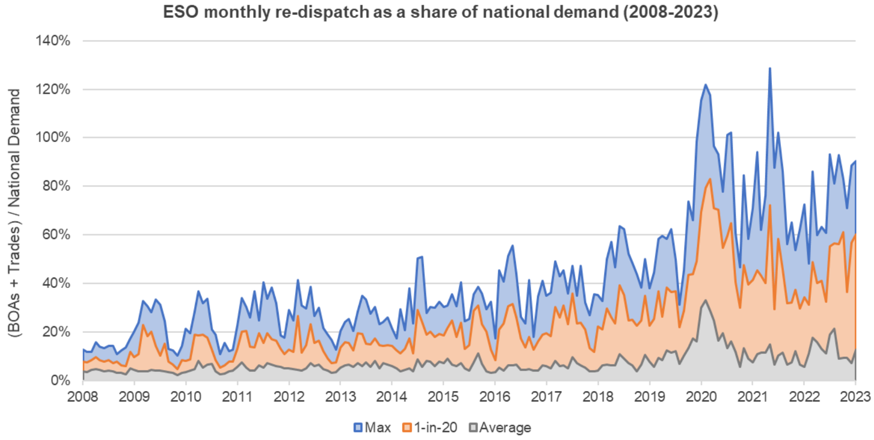

Figure 1: ESO monthly redispatch as a share of national demand, 2008-2023

Significant redispatch volumes were not envisaged when the current market framework was established. Inefficiencies and distortions are arising as the volume and overlap of balancing actions in real-time disrupts parties' expectations of spot prices.

Afry's "ESO Scheduling and dispatch: A case for change" identified three key issues facing GB's dispatch arrangements:

1. Incentives: the current energy markets do not provide scheduling incentives in line with system needs and operational requirements
2. Visibility and access: ESO has incomplete visibility of market outcomes and limited access to some resources which impacts coherence between wholesale market and balancing actions
3. Intertemporal issues: the current dispatch mechanism does not facilitate effective optimisation of costs and unit constraints over time

1.3 ESO process to develop dispatch models

ESO was asked to identify options and preferred models for dispatch under both a national and a zonal wholesale market pricing structure as part of Phase 2 of the REMA programme.

Beginning in January '24, the dispatch workstream is progressing over three phases:

1. **Problem statement**: establishing what issue should any reform of dispatch seek to address
2. **Identifying possible options**
3. **Developing a shortlist and recommendation of options**

This webinar aims to capture stakeholder feedback on phase 2 – identification of possible options.

2 Constructing dispatch models

The models we have so far identified are strawmen intended at this stage to facilitate discussion within the REMA Programme and to highlight important trade-offs. These models are not detailed designs as significant optionality remains to be refined at a later stage.

2.1 Building blocks

The dispatch models are built around two major design decisions:

1. The 'scheduling structure' that determines how units prepare to dispatch
2. The status of the real-time market (RTM)

The models also vary according to the form of pricing used (national or zonal). The range of building blocks and options identified are presented in Figure 2.

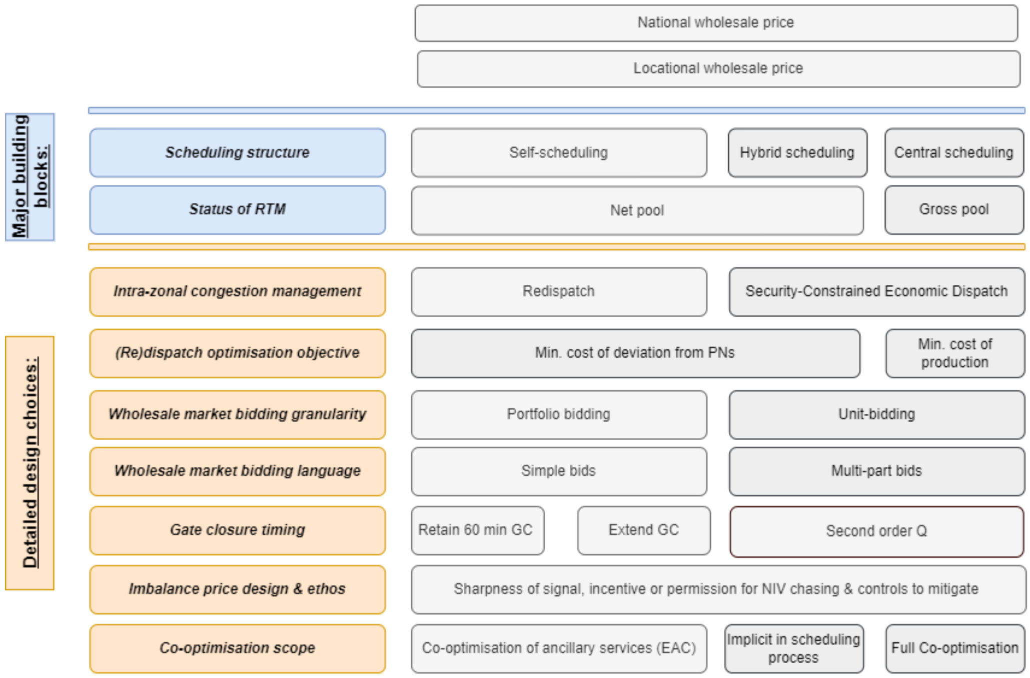

Figure 2: Dispatch mechanism building blocks as identified by the ESO.

Below we provide further detail on the major building blocks and detailed design choices.

2.1.1 Major building blocks

What is the scheduling structure?

Whether the market is 'central scheduling' or 'self-scheduling' reflects the underlying market philosophy: central scheduling allows a more significant role for the SO, who tends also to be the Market Operator (MO). A single algorithm optimises asset cost and technical data together with system operation information such as forecasts to produce a theoretically optimal dispatch.

Under self-scheduling, asset owners choose when and how to run their 'portfolios' (groups of units) in the wholesale market. The System Operator steps in, generally as late as possible, to correct market positions that risk system security.

In practice there is some overlap: for example, all US Central Dispatch markets allow 'self-scheduling' – where parties declare their intended output but become price takers.

What is the status of the real-time market?

This building block defines whether a participant's energy imbalance is 'gross' or 'net' of their existing bilateral contracts. The GB market is a 'net pool': Buyers and sellers can contract directly for the physical delivery of electricity, without reference to a central market. Imbalances are the difference between a party's net contract position and their net physical output. Their calculated imbalance volume will be the basis for any imbalance penalties/payments. Moving GB to a 'gross pool' would mean that all bilateral contracts before the real time 'physical' market are not accounted for in settlement. Instead, bilateral contracts would be financial 'contracts for difference' referenced against the real-time price. The distinction is important since it informs what types of forward hedging contracts are used. It also has implications for how physical transmission capacity is allocated in zonal markets.

2.1.2 Detailed Design Choices

Table 1: Summary of dispatch models detailed design choices

Category	Options	
Intra-zonal congestion management	Redispatch	Security Constrained Unit Commitment / Security Constrained Economic Dispatch

Defines how the System Operator ensures that the production and consumption of electricity respects network capacity and constraints	• Market participants are allowed to dispatch without being limited by the internal capacity of the zone they are in. • If the resulting flows would cause congestion (i.e. not secure), then the SO would take actions to re-dispatch unit(s) to a different level to resolve the congestion.	• An optimisation problem which combines bids from market participants with models of the network • In theory, SCUC/SCED finds the optimal scheduling and dispatch of participating assets so that the power system delivers maximum social welfare while respecting physical and security constraints.
Central Dispatch optimisation objective	**Minimise cost of production**	**Minimise cost of deviation from market schedule**
Sets the starting point of the "Central Dispatch" algorithm	• Effectively starts from scratch, with all units assumed at zero output. • It takes in bids for production or consumption and uses these to find the lowest cost solution to dispatch all units at a secure position that meets the demand. • It does this without regard to any (financial) trades that the market has undertaken ahead of the algorithm being run.	• Starts from the market's traded position, with units assumed at their notified position (e.g. PNs). • It takes in bids for incremental or decremental production or consumption and uses these to find the lowest cost solution to re-dispatch units to a secure position that meets the demand. This is similar to the way the BM works.
Wholesale market bidding granularity	**Unit bidding**	**Portfolio bidding**
Whether bids in the wholesale market are required to relate to a particular unit or not	• Unit bidding means that a market participant submits separate bids for each of their assets, reflecting the technical and economic parameters of those units individually. • Unit bidding is usually done through 'multi-part bids'	• Portfolio bidding does not require the bids to relate to a particular asset or assets • Under portfolio-level balancing, market participants can choose which assets to dispatch to optimise for their sold volume and plant availability • Portfolio bidding is usually done through 'simple bids'
Wholesale market bidding language	**Simple bids**	**Multi-part bids**
The structure of bids used on exchanges where wholesale market trading takes place.	• Simple bids are made up of a single price and volume for producing or consuming energy in a given period. • There is no explicit way for market participants to use simple bids to reflect the technical parameters and associated fixed costs of individual units, such as minimum on or off time and start-up costs	• Multi-part bids explicitly include the technical details and prices for units, including the start-up, no-load, shut-down costs as well as prices and volume
Gate closure timing	**Retain 60 minutes**	**Extend gate closure**
The lead-time before a Settlement Period at which a BMU must confirm their intended schedule to the System Operator	• A short gate closure length allows the market to reposition units until a much later stage, allowing them more flexibility to deal with changes, but it reduces the planning horizon for the SO to address operability challenges in real-time.	• A longer period between gate closure and real-time typically provides better visibility to the SO which could enable better planning and scheduling of units, but may prevent flexible resources from adjusting to market imbalances near real-time.
Imbalance price design & ethos	**Sharpness of price signal, permission to NIV chase, and controls to mitigate**	
Covers how sharp the imbalance price signal is, whether market participants are permitted or incentivised to undertake "NIV chasing", and controls to	• A dual imbalance price has a different price for those who cause and those who help to solve imbalance. A single imbalance price ensures that the reward for helping reduce the imbalance is equal to the penalty for causing the imbalance • In GB, BMUs are theoretically not allowed to NIV chase (i.e. deliberately change their output away from their traded position with the aim of receiving a cash out payment). Non-BMUs have no restrictions (intended or actual) on changing their planned output, as they are not captured by the BM rules around PNs or Gate Closure; they are fully permitted to NIV-chase	

mitigate unhelpful behaviour			
Co-optimisation scope	**Ancillary services**	**Implicit in scheduling**	**Full co-optimisation**
Covers which products can be co-optimised with each other: these typically span energy (wholesale), transmission capacity (constraints), and Ancillary Services (such as reserve and response)	• Allows providers to simultaneously bid to provide one or more of the services, removing the need for them to estimate the clearing price and opportunity costs of entering each the market for each individual product. • There is no co-optimisation of these Ancillary Services with energy or transmission	• With a 'hybrid' model, the co-optimisation still has the opportunity to look at all three elements of energy, transmission, and Ancillary Services, but is much more limited in its scope	• Central Dispatch offers the opportunity to co-optimise all three elements of energy, transmission, and Ancillary Services, as all of the market clearing, Ancillary Services procurement and dispatch happen in one place with understanding of network capabilities

These building blocks are typically found in one of two groups:

(i) a net pool with self-dispatch and portfolio-bidding, or
(ii) a gross pool with central dispatch and unit-bidding

There are, however, some jurisdictions [e.g. Ireland] that use a third "hybrid" model

(iii) net pool with central dispatch and unit bidding

Ultimately, units' generation profiles are always determined by the prices market parties submit and the physics of the network; the difference is how that outcome is achieved.

We have created seven high-level strawman dispatch models from these building blocks. As stated, these are not refined models but instead illustrate the spectrum of options available:

Table 2: Overview of strawman dispatch models

Wholesale price	Pool type	Dispatch type	Bidding	Additional key design features	Model ref.
National	Net	Self	Portfolio	Extended Gate Closure	National 1a
				Revised balancing incentives	National 1b
		Hybrid	Unit	n/a	National 2
	Gross	Central		n/a	National 3
Zonal	Net	Self	Portfolio	n/a	Zonal 1
		Hybrid	Unit	n/a	Zonal 2
	Gross	Central		n/a	Zonal 3

3 Counterfactual

To enable effective assessment of potential REMA reforms, it is important to establish what reforms which may impact dispatch efficiency are already being delivered or are being planned.

During the initial ESO options scoping process, we defined a list of planned or in-flight reforms that will have an impact on dispatch efficiency. These include ancillary services reform recently delivered by ESO, such as Balancing Reserve, and industry-led code modifications such as GC0117 which is seeking to harmonise BMU size thresholds across Scotland, England, and Wales.

In addition to our Counterfactual scenario, we have identified options for reform under a ‘Counterfactual +’ scenario. Counterfactual+ options are defined as potential reforms which could be delivered by ESO or industry independent of wider REMA policy reform or significant influence from DESNZ or Ofgem. The reforms include closer to real-time and locational reserve and response procurement, more local constraint markets, and information imbalance charges. ESO has not undertaken full assessment of these Counterfactual + reforms and the inclusion of a particular proposal does not necessarily mean ESO intends to pursue it.

Table 3: Counterfactual and Counterfactual + scenarios

	Counterfactual	Counterfactual +
Network build	New transmission build to increase network capacity	
Ancillary service reform	Balancing Reserve	Closer to real time reserve and response procurement
	Co-optimisation of reserve & response	Locational procurement of Reserve & Response
	‘System’ ancillary services products (e.g., stability)	New constraint management solutions
	Reserve reform	More Local Constraint Markets
		Maximising boundary transfer for constraints
		Improved Net Transfer Capacity (NTC) process
Code reform & interconnectors	Lower mandatory MW threshold for new BMUs	Final Physical Notification (FPN) Accuracy / Info imbalance
		DNO/TO Metering enhancements
		Maximum Export Limit / Stable Export Limit definition clarification
		Separating subsidy payments from BM bids/offers
		Portfolio ramp limits for Balanced Responsible Parties
		Standardised interconnector trading
		Ramping limits for interconnectors
BM & ESO systems reform	Open Balancing Platform launch	
	State of Energy of energy limited assets	

4 Model definitions

This section provides a detailed description of the dispatch models we have identified. For each model we give a high-level description, its component building blocks, a market timeline, and its hypothesised advantages and disadvantages.

4.1 National Model 1a: self-scheduling with extended gate closure

National Model 1a represents evolutionary change to current dispatch arrangements. It varies from the counterfactual by extending the current 60-minute Gate Closure (GC) to 4-6 hours before delivery. Market participants would continue to decide when to schedule on a portfolio basis. Energy would be settled according to a single national wholesale price and imbalances according to a single imbalance price.

This model attempts to address the 'inter-temporal' issues identified in AFRY's Case for Change by extending the time for the Balancing Mechanism to optimise over. Fixing Physical Notifications several hours ahead of real time means ESO scheduling decisions would not compete with wholesale market scheduling decisions. Since demand and renewable forecasts would continue to evolve between an earlier gate closure and real time, the quality of PNs at that earlier gate closure would probably be less accurate than today.

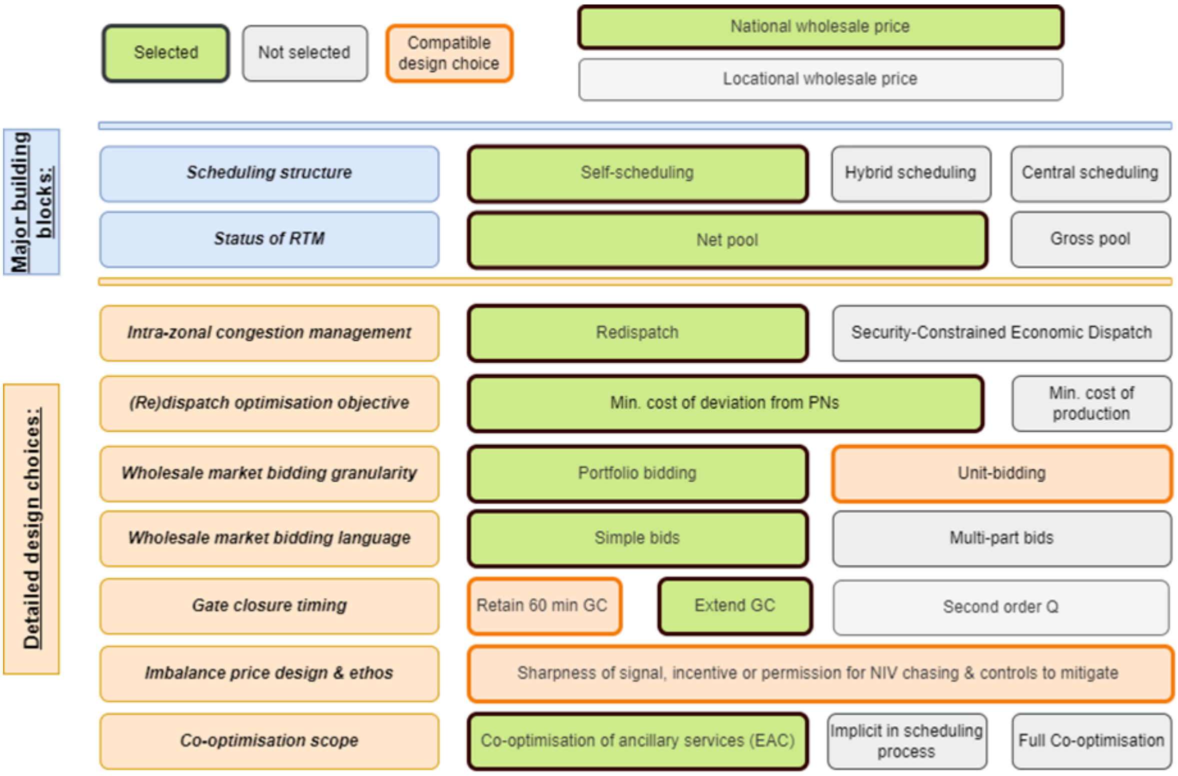

Figure 3: National self-scheduling with extended gate closure building blocks

Market timelines would remain similar to the status quo. Market participants would continue to trade under the current arrangements, with bilateral and organised markets open until Gate Closure. The SO would procure ancillary services at the day-ahead stage and then would monitor and plan for upcoming balancing periods. After Gate Closure, the SO would send redispatch instructions if necessary.

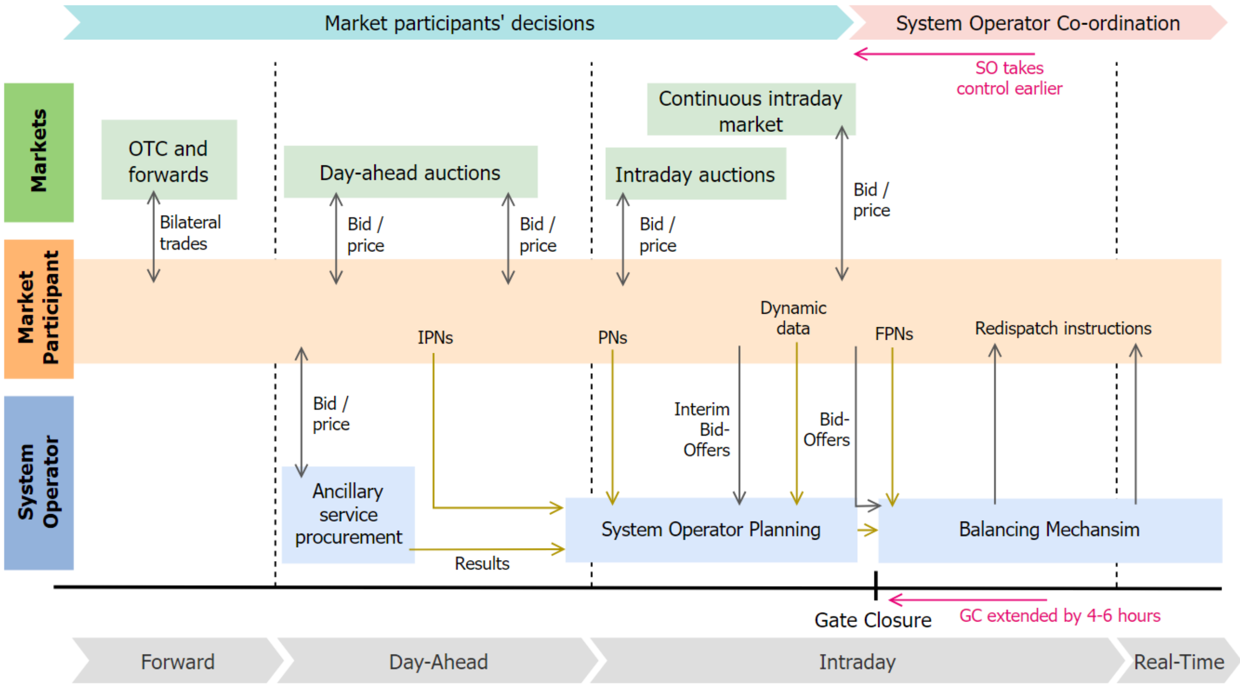

Figure 4: National self-scheduling with extended gate closure market process

We have so far identified the following potential advantages and disadvantages:

Hypothesised advantages	Hypothesised disadvantages
• Extending gate closure **provides more time** for redispatch decisions, potentially **allowing better management of intertemporal issues by ESO and reducing uncertainty** • **Self-dispatch is retained**, giving portfolio owners freedom to optimise between their assets • **Implementation is expected to be less complex** and disruptive than other options • We expect this model to be **fully compatible with current cross-border trading arrangements** • National pricing and self-dispatch **would allow existing structures for forward physical trading to remain**, potentially avoiding any **increase in wholesale collateral requirements**	• Absence of wholesale locational incentives means **market continues to produce infeasible dispatch**, leading to high redispatch • Extending gate closure **would likely not improve operational efficiency** as market would achieve a less accurate position • **Renewables are likely to be exposed to more imbalance risk** since output would continue to change after trading ends • **Possible poor utilisation of flexible resources** which cannot respond to close to real-time imbalances • **ESO would,** de facto, **have greater balancing responsibility** which contradicts objectives of self-dispatch design • Portfolio trading may **inhibit competition by disadvantaging smaller players who have fewer assets** • Market clearing algorithm and simple bids for self-dispatch may be **limited in ability to represent asset's intertemporal constraints** • **Identifying market power exploitation would be more challenging** under portfolio settlement

	and would continue to rely on ex-post investigation • Separation of MO and SO would **limit the scope for benefits of co-optimisation** • **Algorithmic dispatch has risks** such as long time to solve

4.2 National Model 1b: National self-scheduling with stronger balancing incentives

This model also represents evolutionary change to dispatch; however, instead of giving the SO greater control earlier it aims to:

a) give market participants stronger incentives to self-balance ahead of Gate Closure, reducing real-time re-dispatch and system-balancing

b) incentivise more liquidity and competition in intra-day markets and the Balancing Mechanism, helping to lower operational costs

Key features include: re-instating a dual-imbalance price; alignment of Gate Closure timescales for BM and market trades; shorter settlement periods facilitating a “quasi-PAC” (Pay-As-Clear) Balancing Mechanism for energy actions; mandatory participation for all assets over 1MW, and; more data available to the ESO about traded positions and to the market about BM data submissions over time.

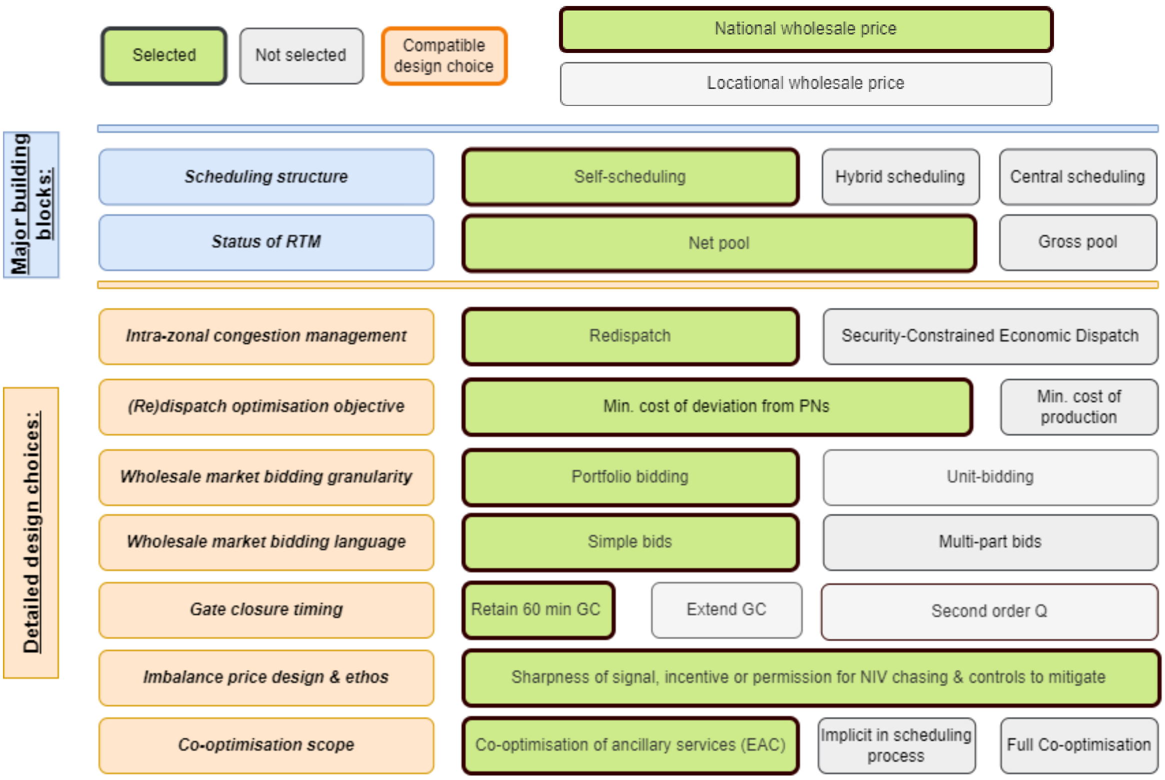

Figure 5: National self-scheduling with stronger balancing incentives building blocks

Market timelines would remain the same as the status quo. Market participants would continue to trade as under current arrangements, with bilateral and organised markets open until Gate Closure at 60-min ahead. The only difference is the balancing incentives market participants face.

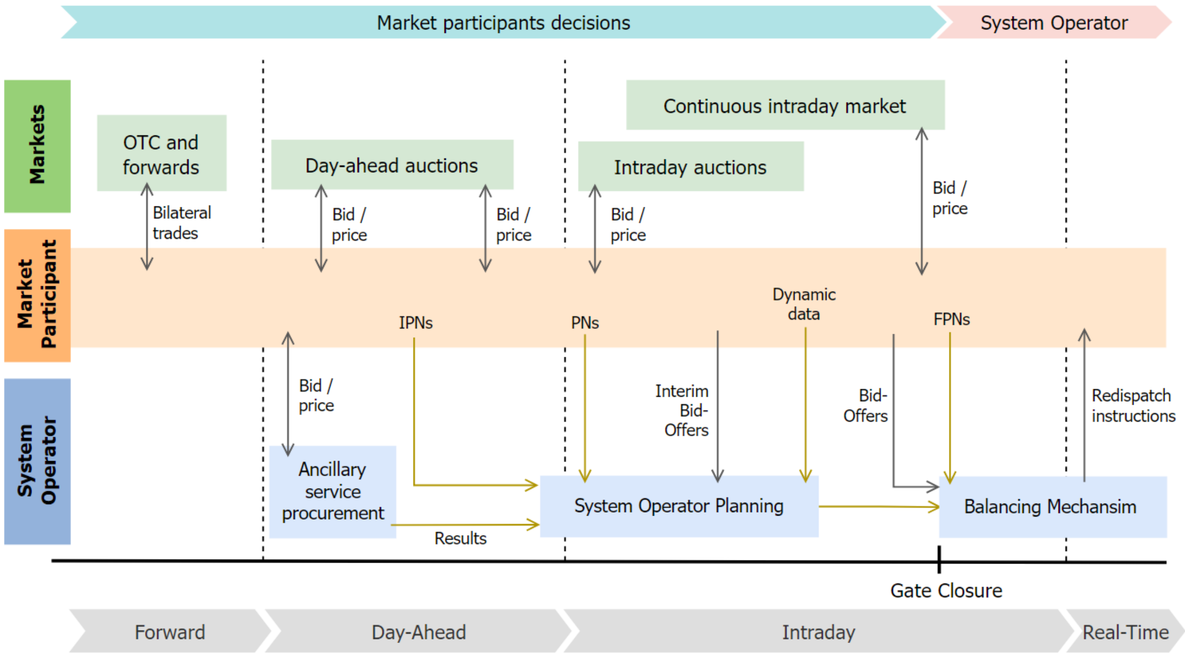

Figure 6: National self-scheduling with stronger balancing incentives market process

We have so far identified the following potential advantages and disadvantages:

Hypothesised advantages	Hypothesised disadvantages
• This model could incentivise parties to achieve a balanced position, **reducing both uncertainty in redispatch timescales and redispatch volumes** (see AFRY Case for Change) • **Shorter settlement periods would increase arbitrage opportunity for flexible assets** and provide stronger incentives **for trading to match the profile** of more **flexible demand and generation** • Re-pricing energy-flagged actions to the better of the imbalance price and the BOA price (akin to a Pay-As-Clear BM) **may address the visibility and access issue** from the Case for Change **by making the BM more attractive** • **Self-dispatch is retained**, giving portfolio owners freedom to optimise between their assets • **Implementation for dispatch processes may be less** disruptive than other options • We expect this model to be **fully compatible with current cross-border trading arrangements** • National pricing and self-dispatch **would allow existing structures for forward physical**	• Absence of wholesale locational incentives means **market continues to produce infeasible dispatch**, leading to high redispatch • **Significant implementation complexities** from 5-minute settlement periods. • **Higher barriers for small, flexible assets** to participate in system balancing due to the additional requirements of the BM compared to NIV chasing • Market clearing algorithm and simple bids for self-dispatch may be **limited in ability to represent asset's intertemporal constraints** • **Exposure to dual imbalance prices** may **increase risk** for market parties • Portfolio trading may **inhibit competition by disadvantaging smaller players who have fewer assets** • **Identifying market power exploitation is more challenging** under portfolio settlement and relies on ex-post investigation • Separation of MO and SO **limits the scope for benefits of co-optimisation** • **Algorithmic dispatch has risks** such as long time to solve

trading to remain, potentially avoiding any **increase in wholesale collateral requirements**.	

4.3 Zonal Model 1: Self-scheduling

Zonal Model 1 retains self-dispatch while introducing zonal pricing. The combination of major building blocks and detailed design choices replicates many of the current arrangements in GB, including portfolio bidding (limited by zone) in a net pool and 60-minute gate closure. Because zonal pricing will reduce re-dispatch volumes, this model could also be compatible with a potential future move to shorter gate closure – but further work is needed. This model broadly resembles the operation of the power market in the Nordics.

Under zonal pricing, market parties lose firm access to the transmission network outside their zone. New mechanisms would be required for managing transmission access in operational timescales: the SO would be required to calculate available transmission capacity on the zone boundaries, and a price coupling algorithm such as EUPHEMIA would be required to allocate flows across available capacity within GB. Significantly more volumes would therefore be traded under the central 'market coupling' process compared to today.

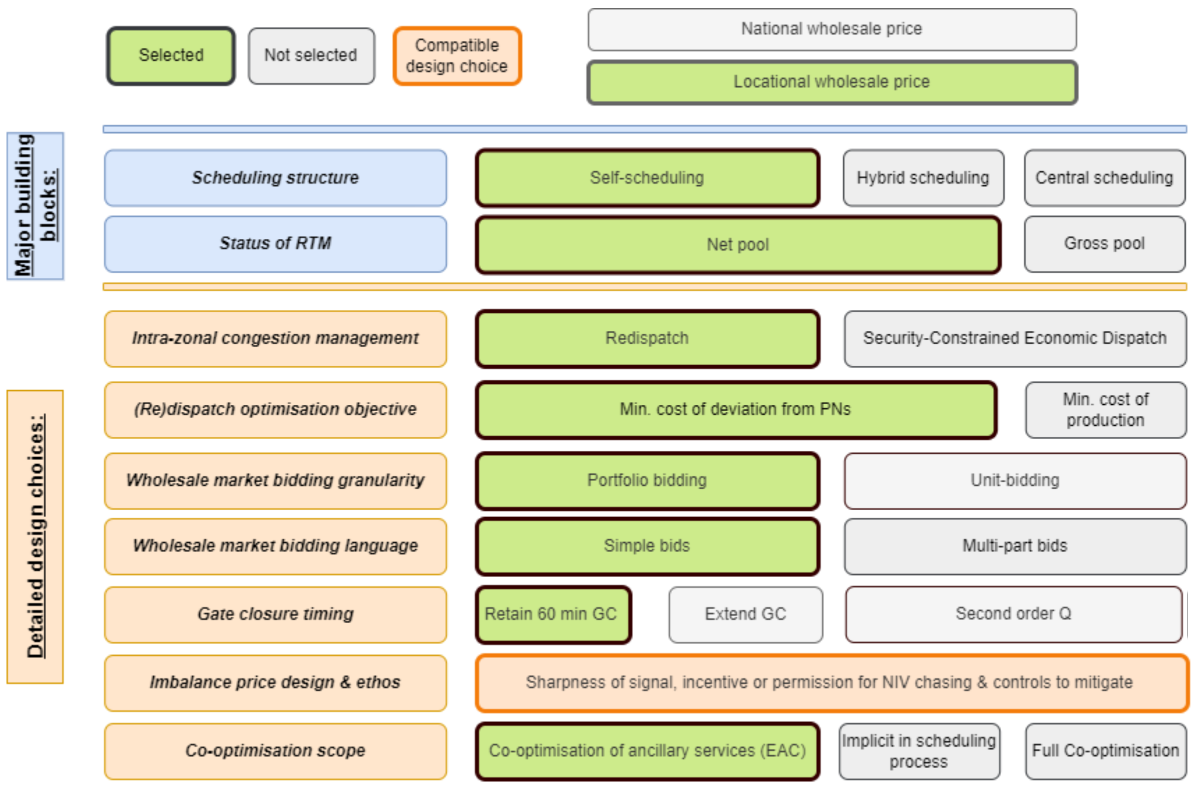

Figure 7: Zonal self-scheduling building blocks

Market timelines would remain similar to the status quo. Market participants would continue to trade as under current arrangements, with bilateral and organised markets open until Gate Closure. The main differences are:

- The SO would calculate the available transmission capacity between zones and release this capacity to the wholesale market.
- The DA and ID auctions would now need to account for boundary limits when clearing the market. As such, they would become price coupling auctions.

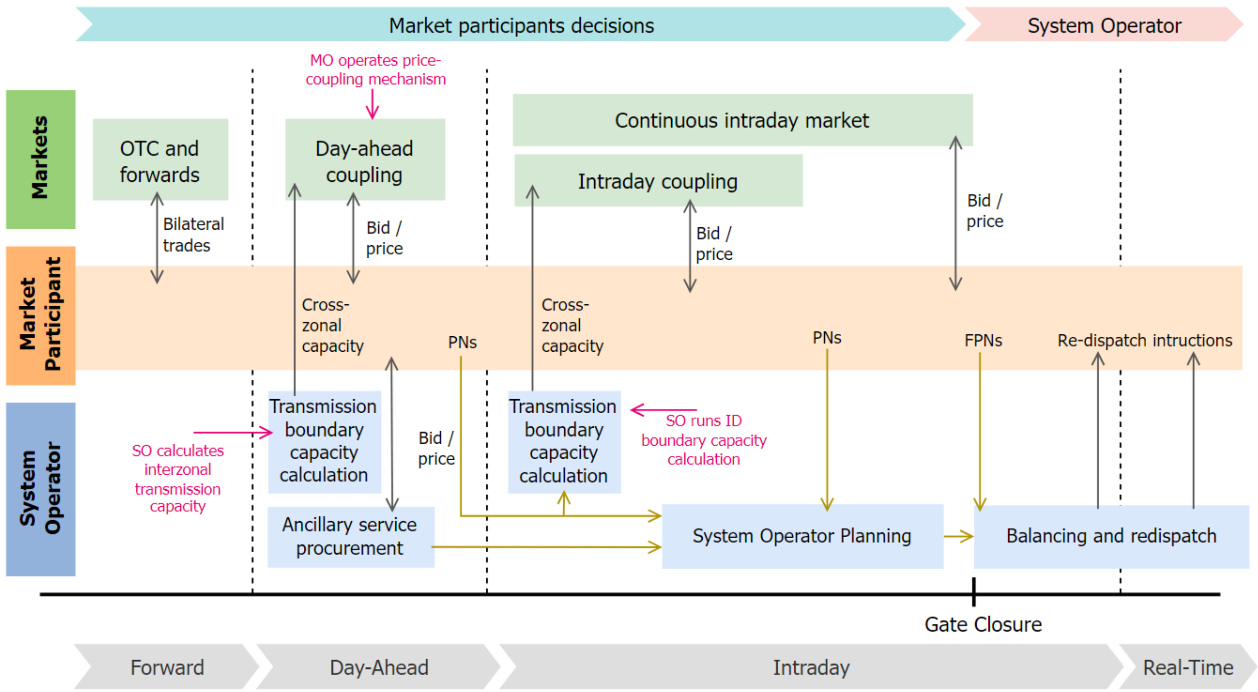

Figure 8: Zonal self-scheduling market process

We have so far identified the following potential advantages and disadvantages:

Hypothesised Advantages	Hypothesised Disadvantages
• Locational signals from **zonal pricing would significantly improve the efficacy** of scheduling and dispatch decisions to respect network capability, avoiding costly redispatch • Portfolio owners would **retain freedom to optimise their assets within a zone** and between zones with no congestion • Retaining self-dispatch would avoid some **implementation complexity** compared to other options, particularly for **cross-border trading arrangements** • Zonal pricing could **reduce scope for market power exploitation** given consistent price signals at different timeframes • Locational price signals should enable **efficient investment decisions** • **Potentially increased liquidity in spot markets** because a) intraday markets get **more liquidity for re-balancing portfolio within zone**; b) marginal generators currently priced out of national market may be more competitive under zonal arrangements.	• **A significant change** that would be complex to implement and would expose some market players to new risk • Portfolio trading may **inhibit competition by disadvantaging smaller players who have fewer assets** • **Identifying market power exploitation would be more challenging** under portfolio settlement and continues to rely on ex-post investigation • Potential impact on collateral requirements due to move from **physical to financial forward trading** for interzonal trade • Separation of MO and SO expected to **limit the scope for benefits of co-optimisation** • Market clearing algorithm and simple bids for self-dispatch may be **limited in ability to represent asset's intertemporal constraints** • Uncertain zonal price differences when contracting between zones **dampens incentives for forward trading, so could reduce liquidity**

• **Some opportunity to co-optimise transmission capacity allocation** for energy and balancing between zones.	• Potential for **inefficient allocation of interzonal capacity** at different timeframes • **Algorithmic dispatch has risks** such as long time to solve

4.4 National Model 2: Central dispatch with hybrid scheduling

In this model, GB maintains a national wholesale price, but reforms dispatch arrangements drawing inspiration from the Irish hybrid 'central scheduling' approach.

Market participants would trade physical energy at day-ahead (DA) and intraday (ID), in markets separate from the SO-run balancing market. (In Ireland they are operated by power exchanges). They would notify cleared volumes from these markets to the SO. Forward trading before the DA/ID markets would be financial. This model is a net pool since physical contracts can be traded before the balancing market.

The SO would run an optimisation algorithm to account for network constraints in the scheduling process. The optimisation objective would be to minimise the cost of units deviating from their schedules. The SO could explicitly optimise asset inter-temporal constraints in a way that the current Balancing Mechanism does not allow. This design would require a move from portfolio bidding to unit bidding.

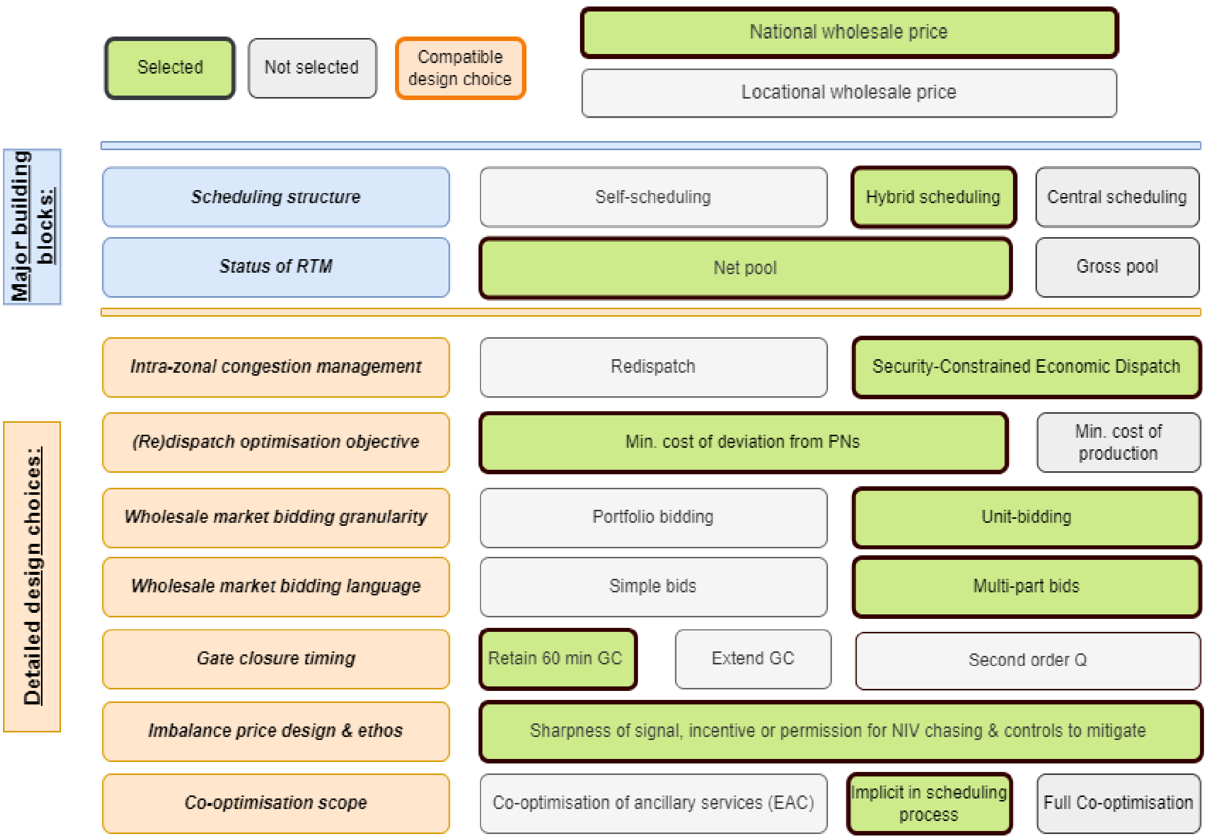

Figure 9: National central dispatch with hybrid scheduling building blocks

A key change of this model is the formalised role of the SO in scheduling units from the DA stage and the introduction of SCUC/SCED. Since intraday trading continues, there is an overlap between decentralised market participant scheduling decisions and SO central co-ordination. Market participants translate the results of the DA/ID markets into advisory schedules which they submit to the SO. As a central dispatch market, these schedules are only final when confirmed by the SO; however, parties can continue to change their schedules through the day. Similar to the current BM, the SO may alter these schedules via redispatch instructions.

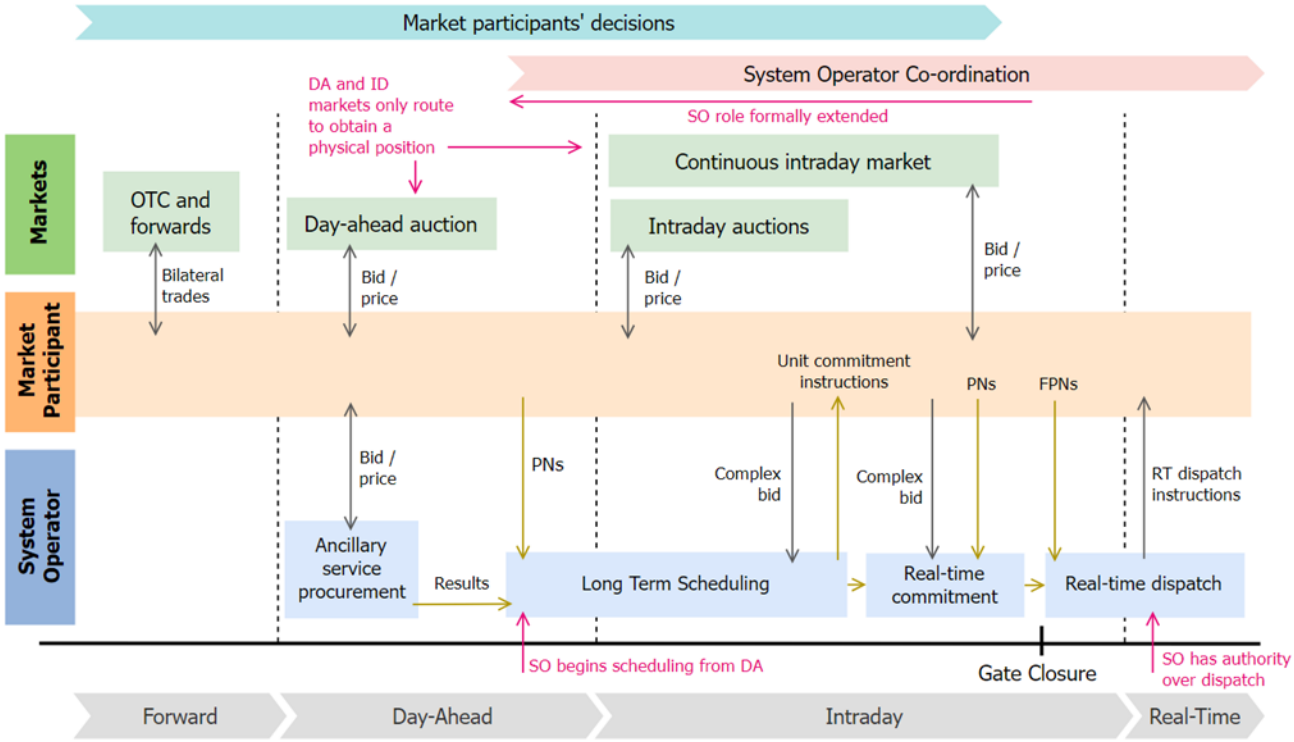

Figure 10: National central dispatch with hybrid scheduling market process

We have so far identified the following potential advantages and disadvantages:

Hypothesised advantages	Hypothesised disadvantages
• SO long-term scheduling process could enable **better management of intertemporal and network constraints** • **Potentially more transparent dispatch governance** thanks to formalisation of ESO de-facto central dispatcher role • Unit-level bidding would bring **market monitoring benefits** and potentially **facilitate a level-playing field** • Unit bidding may give greater certainty of generation and demand in particular locations, **reducing uncertainty in scheduling timescales** • **Continued physical trading** at DA/ID **would avoid impacting cross-border trading** processes	• Absence of wholesale locational incentives means **market continues to produce infeasible dispatch**, leading to high redispatch • **Structural overlap between market and SO redispatch** could continue to blur redispatch decision making and lead to reduced market efficiency • **Implementation could be disruptive** and introduce new risks for market participants • All physical trading moves to DA and ID which could **impact collateral requirements** • Unit-level bidding would **reduce some flexibility for market participants** • Central dispatch mechanism relies on **participation models to optimise market participants' schedules** • MO and SO separation could limit potential for **co-optimisation of energy, ancillary services, and transmission** • **Algorithmic dispatch has risks** such as long time to solve

4.5 Zonal Model 2: Central dispatch with hybrid scheduling

This model resembles many of the dispatch features described in Model 2-N but with the addition of zonal pricing which would reduce SO constraint redispatch volumes.

The SO would also be required to calculate available transmission capacity on zone boundaries. Decentralised markets would then run while respecting the transmission capacity made available by the SO. Imbalances would be settled at the unit-level with zonal imbalance prices.

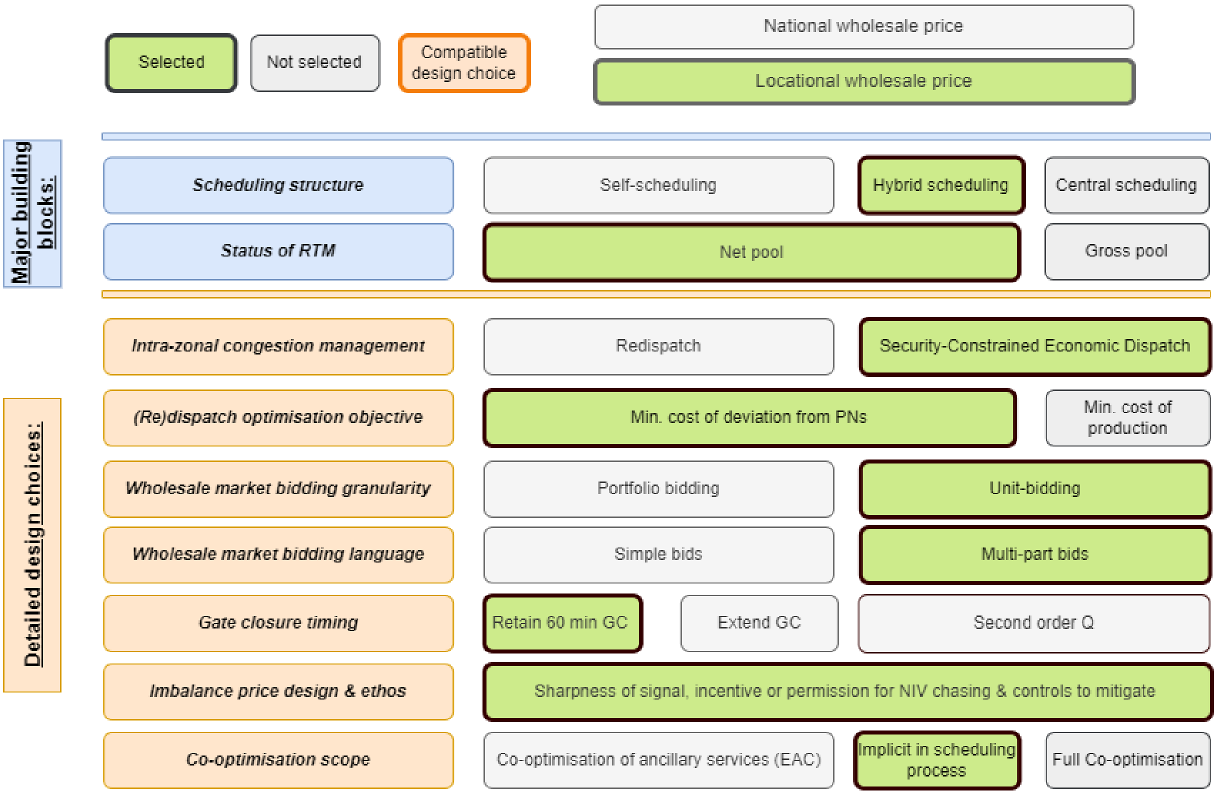

Figure 11: Zonal central dispatch with hybrid scheduling building blocks

As with the national model above, the SO would have a formalised role in scheduling units from the DA stage unlike self-dispatch today. Since intraday trading continues, there is an overlap between decentralised market participant scheduling decisions and SO central co-ordination. Market participants translate the results of the DA/ID markets into advisory schedules which they submit to the SO. As a central dispatch market, these schedules are only final when confirmed by the SO; however, parties can continue to change their schedules through the day. Similar to the current BM, the SO may alter these schedules via redispatch instructions. The main differences are:

- The SO would calculate the available transmission capacity between zones and release this capacity to the wholesale market.
- The DA and ID auctions would now need to account for boundary limits when clearing the market. As such, they would become price coupling auctions.

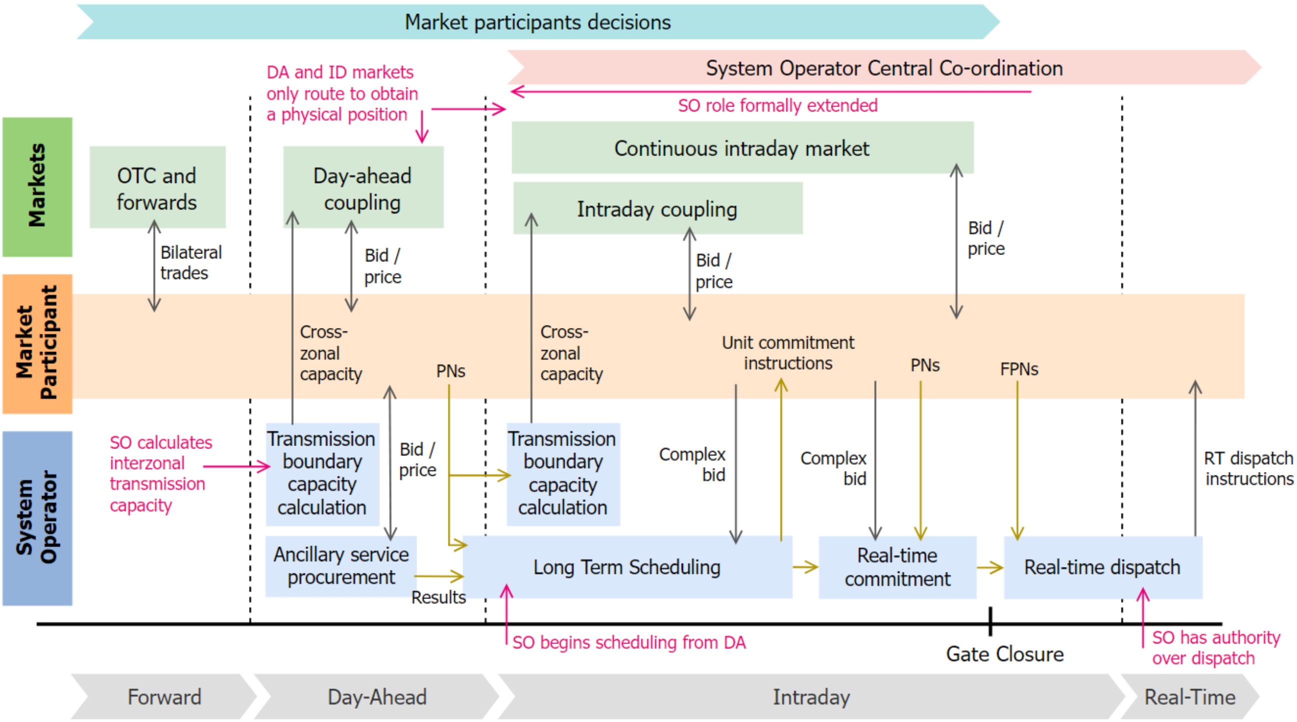

Figure 12: Zonal central dispatch with hybrid scheduling market process

We have so far identified the following potential advantages and disadvantages:

Hypothesised advantages	Hypothesised disadvantages
• Locational incentives from **zonal pricing would significantly improve the efficacy** of scheduling and dispatch decisions to respect network capability, avoiding costly redispatch • SO long-term scheduling process would enable **better management of intertemporal and network constraints** • Unit-level bidding would bring **market monitoring benefits** and potentially **facilitate a level-playing field** • Unit bidding may give greater certainty of generation and demand in particular locations, **reducing uncertainty in scheduling timescales** • Zonal pricing would **reduce scope for market power exploitation** given consistent price signals at different timeframes • Locational price signals should support **efficient investment decisions** • **Continued physical trading** at DA/ID **avoids impacting cross-border trading** processes	• **Structural overlap between market and SO redispatch** could continue to blur redispatch decision-making and lead to reduced market efficiency • **Implementation could be disruptive and introduce new risks** for market participants • All physical trading moves to DA and ID which could **impact collateral requirements** • Unit-level bidding would **reduce some flexibility from market participants** • Central dispatch mechanism relies on **participation models to optimise market participants' schedules** • MO and SO separation could limit potential for **full co-optimisation of energy, ancillary services, and transmission** • Potential impact on **collateral requirements** due to move from **physical to financial forward trading** for interzonal trade • Additional **implementation complexities** from zonal pricing • Potential for **inefficient allocation of interzonal capacity** in different timeframes

• **Potentially more transparent dispatch governance** thanks to formalisation of ESO de-facto central dispatcher role • **Some opportunity to co-optimise transmission capacity** for energy and balancing between zones.	• **Algorithmic dispatch has risks** such as long time to solve

4.6 National Model 3: Central dispatch with gross pool

GB maintains a national wholesale price, but dispatch arrangements would be modified to reflect a fully centralised approach, akin to models which exist in Australia and the US; albeit none of these jurisdictions uses national pricing.

All scheduling and dispatch decisions would be derived by the central SO/MO entity. Forward trading would necessarily be financial, and the balancing or 'real-time' market would be the only physical market to determine which assets are dispatched. This model would require a move from portfolio bidding to unit bidding.

This dispatch model would use an optimisation algorithm to calculate the dispatch solution that maximises social welfare while respecting all the relevant network constraints. The national price would be a by-product of this optimisation. There are several options for how to calculate the national price: one route would be to use the 'unconstrained' price as in the former GB pool.

This model facilitates full co-optimisation of energy, ancillary services[1], and allocation of transmission capacity.

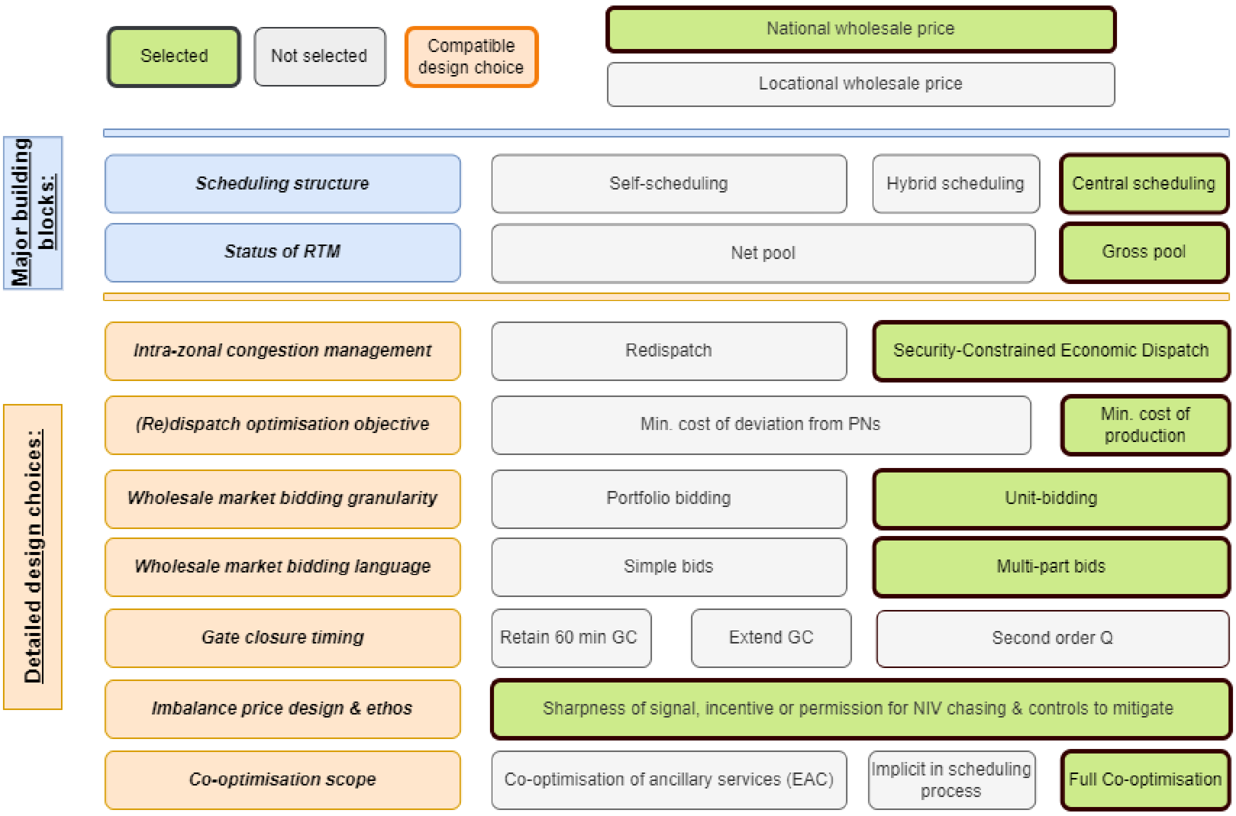

Figure 13: National central dispatch with gross pool building blocks

[1] In the context of co-optimisation, ancillary services only include response and reserve services. Certain services such as stability and inertia are not within scope.

Market participants trade in the financial forward market as a hedge against the physical market clearing price. They submit multi-part bids to the SO DA auction or can decide to self-schedule (and become a price-taker). The SO clears the DA market to find the least-cost dispatch solution which respects system constraints and unit physical constraints (e.g. storage state of charge). After the DA market, market participants revise their bids and offers for the real-time clearing. While not depicted below, we see significant arguments under this model to introduce a third 'intraday' settlement as is done in some US markets to allow parties to reposition themselves in response to changing system conditions.

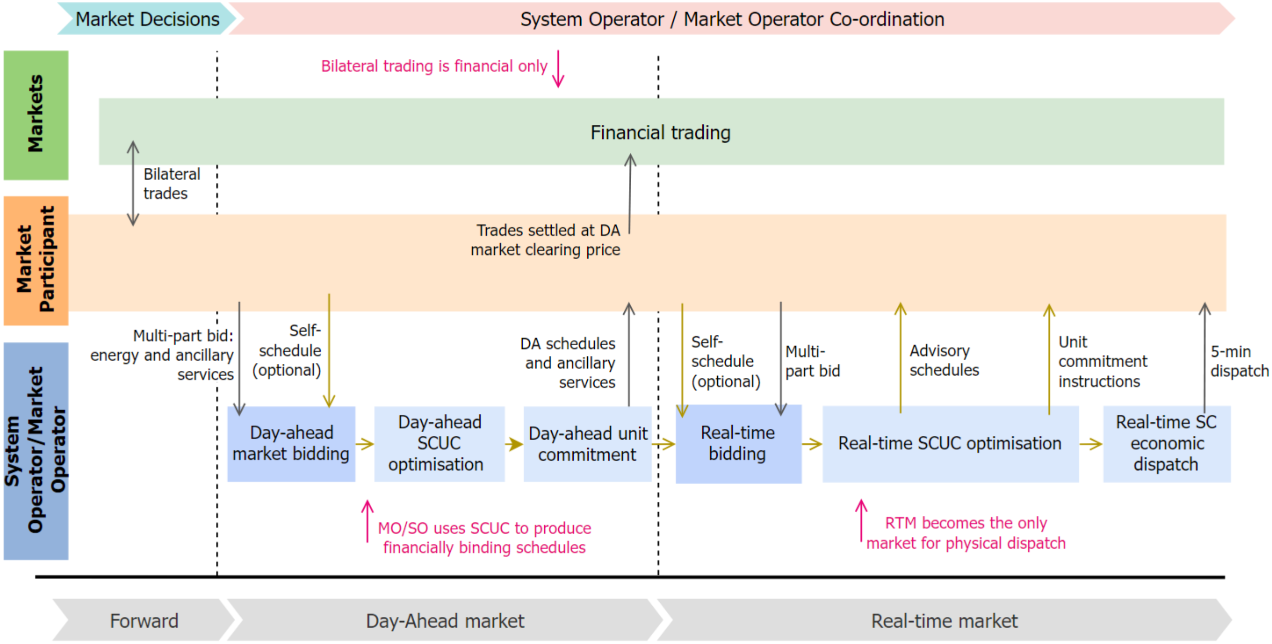

Figure 14: National central dispatch with gross pool market process

We have so far identified the following potential advantages and disadvantages:

Hypothesised advantages	Hypothesised disadvantages
• Central dispatch **optimises to minimise cost of production**, theoretically supporting efficient dispatch which respects network and intertemporal constraints • SO-operated day ahead market could **facilitate effective information sharing** between the market and SO for scheduling • Unit-level bidding would bring **market monitoring benefits** and potentially **facilitate a level-playing field** • Unit bidding may give greater certainty of generation and demand in particular locations, **reducing uncertainty in scheduling timescales** • **Full co-optimisation** of energy, transmission capacity, and ancillary services could lead to consumer savings and reward flexible assets • Moving from continuous trading to auctions would **pool liquidity and maximise social**	• **Potentially significant change that would be complex to deliver** • **Risk of disorderly bidding if there is mismatch between nodal** dispatch **and national** price incentives. Avoiding disorderly bidding entails redispatch costs, reducing consumer value for money • **Managing fixed costs** (e.g., start-up, no-load) could be challenging and **could require make whole payments at cost to consumers** • **Central dispatch mechanism relies on participation models** to optimise market participants' schedules • Moving from continuous trading to auctions **could inhibit market from responding to forecast changes,** reducing system efficiency

welfare, since least cost assets are cleared rather than faster traders	• Potential negative impact on **investor confidence and cost of capital** due to move to **forward financial trading** • **Mismatch between status of GB and bordering trade** may expose cross-border market players to new risks and may **impose implementation challenges** • Unit-level bidding would **reduce some flexibility** for market participants • **Algorithmic dispatch has risks** such as long time to solve • **Coordination between transmission and distribution level markets could be complex to manage** when physical capacity is only allocated in real time market

4.7 Zonal Model 3: Central dispatch with gross pool

The final model is similar to National Model 3, but settlement is on a zonal rather than national basis. Zonal pricing would price energy and congestion, aligning incentives with (some of) the physical needs of the system.

As with National Model 3, the zonal price would be a by-product of this optimisation. There are several options for how to calculate the zonal price which would shape market outcomes and efficiency: one route would be to use the 'unconstrained' price as in the former GB pool. The Australian NEM market uses the regional reference price.

This option would also facilitate co-optimisation of energy, transmission capacity and ancillary services.

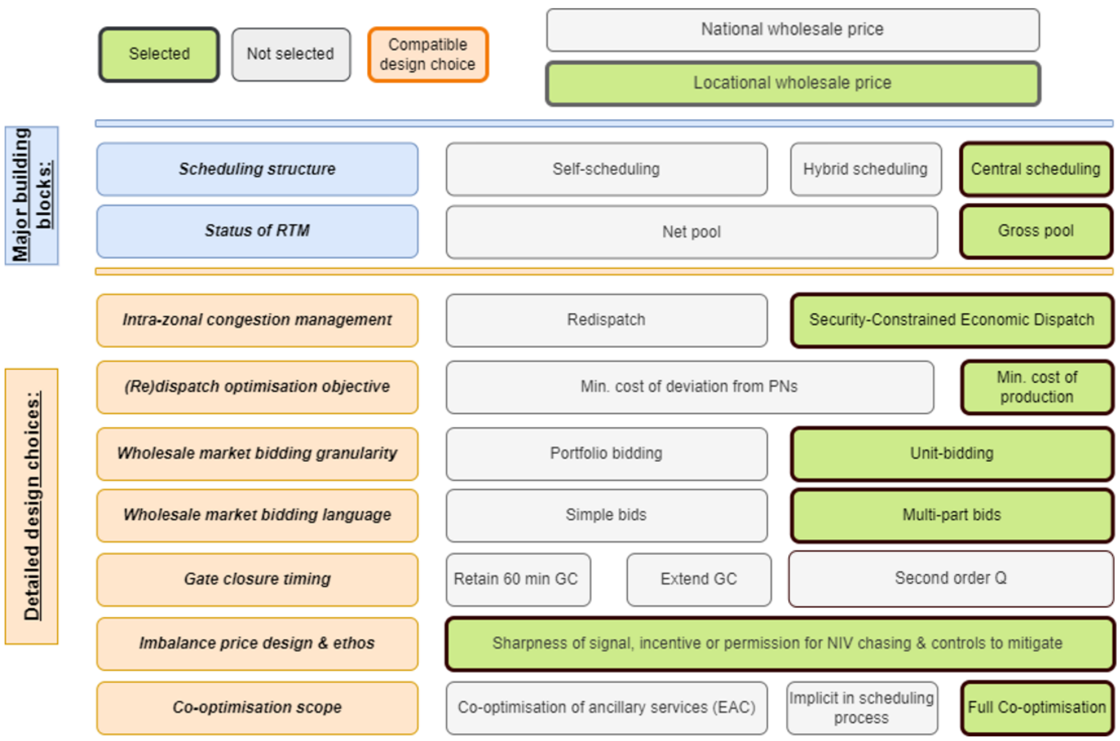

Figure 15: Zonal central dispatch with gross pool building blocks

The market process is exactly as described in National Model 3; the only difference is market participants are settled at the zonal market clearing price rather than the national clearing price.

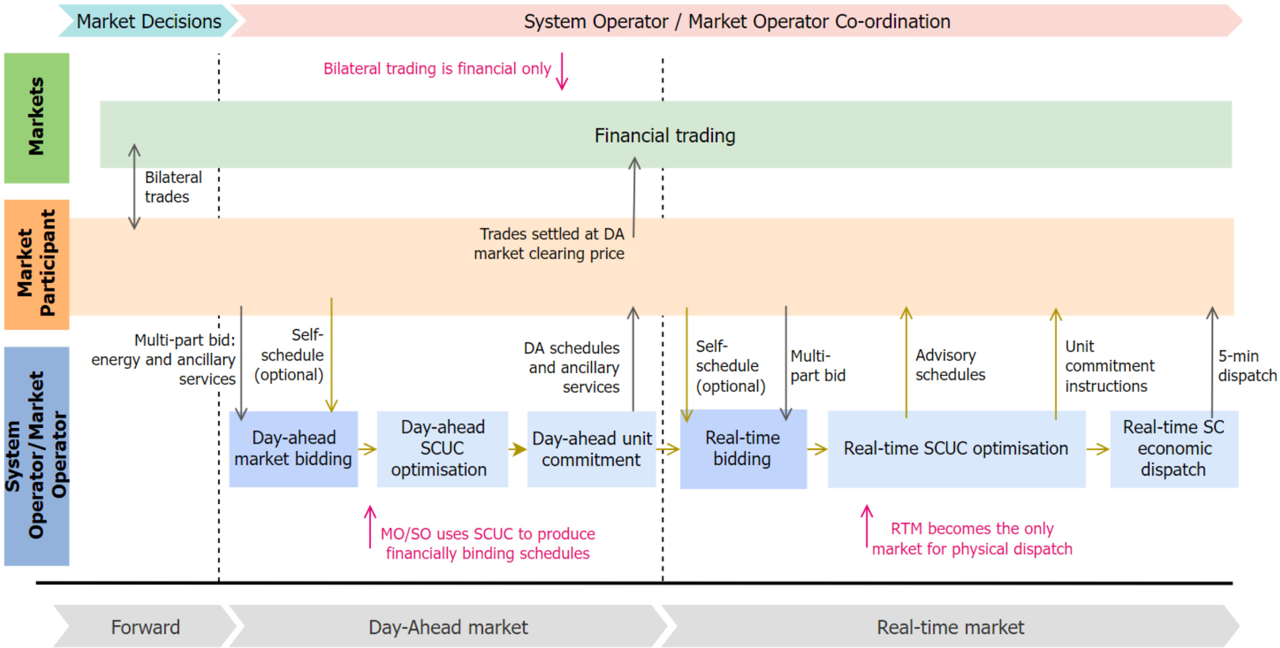

Figure 16: Zonal central dispatch with gross pool market process

We have so far identified the following potential advantages and disadvantages:

Hypothesised advantages	Hypothesised disadvantages
• Locational signals from **zonal pricing would significantly improve the efficacy** of scheduling and dispatch decisions to respect network capability, avoiding costly redispatch • Central dispatch **optimises to minimise cost of production**, theoretically supporting efficient dispatch which respects network and intertemporal constraints • SO operated day ahead market could **facilitate effective information sharing** between the market and SO for scheduling • Unit-level bidding would bring **market monitoring benefits** and potentially **facilitate a level-playing field** • **Zonal pricing should reduce scope for market power exploitation** given consistent price signals at different timeframes • Unit bidding may give greater certainty of generation and demand in particular locations, **reducing uncertainty in scheduling timescales**	• **Potentially significant change that would be complex to deliver** • **Risk of disorderly bidding if there is mismatch between nodal** dispatch **and zonal** price incentives. Avoiding disorderly bidding entails redispatch costs, reducing consumer value for money • **Managing fixed costs** (e.g., start-up, no-load) is challenging and **could require make whole payments at cost to consumers** • **Central dispatch mechanism relies on participation models** to optimise market participants' schedules • Moving from continuous trading to auctions **could inhibit market from responding to forecast changes which could require adding an intra-day market auction.** • Potential negative impact on **investor confidence and cost of capital** due to move to **forward financial trading** • **Mismatch between status of GB and bordering trade** may expose cross-border

• **Full co-optimisation** of energy, transmission capacity, and ancillary services could lead to consumer savings and reward flexible assets • Moving from continuous trading to auctions **pools liquidity and maximises social welfare**, since least cost assets are cleared rather than faster traders • **Zonal pricing should incentivise more efficient locational investment decisions**	market players to new risks and may **impose implementation challenges** • Unit-level bidding would **reduce some flexibility** for market participants • **Algorithmic dispatch has risks** such as long time to solve • **Coordination between transmission and distribution level markets could be complex to manage** when physical capacity is only allocated in real time market

5 Comparison of strawmen model key features

The table below compares the main features of the dispatch models, focusing on the interface between market participants and Market and System operators.

Table 4: Comparison of dispatch models key features

<table>
<tr><th rowspan="2">Dispatch feature</th><th rowspan="2">Description</th><th rowspan="2">Status Quo</th><th colspan="3">Model 1 – Self-Dispatch</th><th colspan="2">Model 2 – Hybrid</th><th colspan="2">Model 3 – Gross Pool</th></tr>
<tr><th>National 1a</th><th>National 1b</th><th>Zonal</th><th>National</th><th>Zonal</th><th>National</th><th>Zonal</th></tr>
<tr><td>Nature of forward trading</td><td>Can you strike physical trades outside of spot market or do they need to be financial contracts?</td><td colspan="4">Financial and physical</td><td colspan="4">Financial only</td></tr>
<tr><td>Mandatory participation (for assets above size threshold)</td><td>In which markets is participation mandatory?</td><td colspan="6">BM only</td><td colspan="2">DA and RT</td></tr>
<tr><td>Wholesale market bidding</td><td>Do market participants bids relate to a specific unit?</td><td colspan="4">Portfolio-based</td><td colspan="4">Unit-based</td></tr>
<tr><td>Freedom to schedule</td><td>Where are scheduling decisions made and how?</td><td colspan="4">Portfolio owners</td><td colspan="2">Both market participants and SO (SO can send scheduling instructions before gate closure)</td><td colspan="2">SO. Market participants can self-schedule, but they become price takers.</td></tr>
<tr><td>SO control over time</td><td>Does the SO have control over scheduling, dispatch and/or redispatch?</td><td colspan="4">Redispatch</td><td colspan="2">Dispatch and redispatch. SO can also send scheduling instructions before gate closure</td><td colspan="2">Scheduling, dispatch, and redispatch</td></tr>
<tr><th>Dispatch feature</th><th>Description</th><th>Status Quo</th><th colspan="3">Model 1</th><th colspan="2">Model 2</th><th colspan="2">Model 3</th></tr>
</table>

<table>
<tr><th></th><th></th><th></th><th>National 1a</th><th>National 1b</th><th>Zonal</th><th>National</th><th>Zonal</th><th>National</th><th>Zonal</th></tr>
<tr><td>Imbalance design</td><td>Is the market incentivised to balance, or does the SO have the mandate to do it?</td><td colspan="2">Incentivised to resolve energy imbalance</td><td>Incentivised to be in a balanced position</td><td colspan="3">Incentivised to resolve energy imbalance</td><td colspan="2">Incentivised to follow SO dispatch instructions</td></tr>
<tr><td>Congestion management</td><td>Is congestion managed after GC via redispatch or is it integrated into SO scheduling decisions?</td><td colspan="4">Redispatch</td><td colspan="2">Security Constrained[2] optimisation provides advisory redispatch which is subject to control room approval/edits</td><td colspan="2">SO makes scheduling and dispatch decisions, integrating congestion into market clearing</td></tr>
<tr><td>Intertemporal constraints management</td><td>How are intertemporal constraints meant to be managed?</td><td colspan="4">Market participants optimise as part of portfolio trading. SO respects unit physical constraints in redispatch.</td><td colspan="2">Market clearing accounts for unit constraints thanks to unit-bidding. SO respects intertemporal constraints in long-term scheduling (up to 30hrs ahead) and redispatch</td><td colspan="2">Market clearing process accounts for intertemporal constraints</td></tr>
<tr><td>Scope for co-optimisation</td><td>What services can be co-optimised?</td><td colspan="3">Response and Reserve only</td><td>Limited co-optimisation of interzonal transmission capacity for energy and AS</td><td colspan="2">Limited co-optimisation of energy, transmission capacity and AS in SO redispatch decisions</td><td colspan="2">Full co-optimisation of energy, transmission capacity and AS</td></tr>
<tr><td>Market monitoring enforcement</td><td>What methods are available to monitor market power?</td><td colspan="4">Ex-post enforcement</td><td colspan="4">Ex-ante mitigation</td></tr>
</table>

[2] Security Constrained optimisation algorithms (Unit Commitment and Economic Dispatch) are well-known tools for power system operation which optimise the scheduling/dispatch of system assets to guarantee secure and low-cost operation.