Department for
Energy Security
& Net Zero

Incremental Reforms to Wholesale Electricity Markets

Review of Wholesale Electricity Markets

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Glossary of Terms

A/S	Ancillary Services
ACER	Agency for the Cooperation of Energy Regulators
AEMC	Australian Energy Market Commission
AEMO	Australian Energy Market Operator
aFRR	Automatic Frequency Restoration Reserve
AGC	Automatic Generation Control
BECCS	Bioenergy with Carbon Capture and Storage
BESS	Battery Energy Storage System
BETTA	British Electricity Trading and Transmission Arrangements
BM	Balancing Mechanism
BMU	Balancing Mechanism Unit
BSC	Balancing and Settlement Code
BSCP	Balancing and Settlement Code Procedure
BSIS	Balancing Services Incentive Scheme
CADL	Continuous Acceptance Duration Limit
CAISO	California Independent System Operator
CCGT	Combined Cycle Gas Turbine
CCUS	Carbon Capture, Utilisation and Storage
CD	Centralised Dispatch
CEGB	Central Electricity Generating Board
CfD	Contracts For Difference
CM	Capacity Market
CMA	Competition and Markets Authority

CPF	Carbon Price Floor
CT	Consumer Transformation
DA	Day Ahead
DC	Dynamic Containment
DCDA	Data Collection and Data Aggregation
DESNZ	Department for Energy Security and Net Zero
DGES	Director General of Electricity Supply
DM	Dynamic Moderation
DMAT	De Minimis Acceptance Threshold
DNO	Distribution Network Operator
DR	Dynamic Regulation
DSO	Distribution System Operator
DSR	Demand Side Response
DTI	Department of Trade and Industry
EBSCR	Electricity Balancing Significant Code Review
EEX	European Energy Exchange
EMR	Electricity Market Reform
ENTSO-E	European Network of Transmission System Operators of Electricity
EPEX	European Power Exchange
EPS	Emissions Performance Standard
ERCOT	Electric Reliability Council of Texas
ESC	Electricity Settlements Company
ESO	Electricity System Operator
EU	European Union
EU ETS	European Union Emissions Trading Scheme

FERC	Federal Energy Regulatory Commission
FES	Future Energy Scenarios
FPN	Final Physical Notification
FTR	Financial Transmission Right
GB	Great Britain
GEMA	Gas and Electricity Markets Authority
ICE	Intercontinental Exchange
ID	Intraday
IDM	Intraday Market
IESO	Independent Electricity System Operator
IMO	Independent Market Operator
IPN	Initial Physical Notification
I-SEM	Irish Single Electricity Market
ISO-NE	Independent System Operator New England
ISP	Imbalance Settlement Period
LCCC	Low Carbon Contracts Company
LDES	Long Duration Energy Storage
LFAS	Load Following Ancillary Service
LMP	Locational Marginal Pricing
LNG	Liquified Natural Gas
MEL	Maximum Export Limit
mFRR	Manual Frequency Restoration Reserve
MHHS	Market Wide Half Hourly Settlement
MISO	Midcontinent Independent System Operator
MNZT	Minimum Non-Zero Time

MO	Market Operator
MPLC	Market Power License Condition
MSP	Market Scheduling and Pricing
MSQ	Market Schedule Quantities
MTU	Market Time Unit
MZT	Minimum Zero Time
NBM	Nordic Balancing Model
NEM	National Electricity Market
NETA	New Electricity Trading Arrangements
NG	National Grid
NGESO	National Grid Electricity System Operator
NIV	Net Imbalance Volume
NYISO	New York Independent System Operator
NZEM	New Zealand Electricity Market
OCGT	Open Cycle Gas Turbine
Ofgem	Office of Gas and Electricity Markets
ORDC	Operating Reserve Demand Curve
OTC	Over The Counter
PAR	Price Averaging Reference
PJM	Pennsylvania New Jersey Maryland Interconnection
PN	Physical Notification
PPA	Power Purchase Agreement
PSA	Pooling and Settlement Agreement
RCM	Reserve Capacity Mechanism
REMA	Review of Electricity Market Arrangements

REMIT	Regulation on Wholesale Energy Market Integrity and Transparency
RTO	Regional Transmission Organization
SCR	Significant Code Reviews
SEL	Stable Export Limit
SEMO	Single Electricity Market Operator
SMP	System Marginal Price
SO	System Operator
SPEN	Scottish Power Electricity Network
SRMC	Short Run Marginal Cost
SSEN	Scottish and Southern Electricity Networks
STEM	Short Term Energy Market
SWIS	Southwest Interconnected System
TCLC	Transmission Constraint License Condition
ToU	Time Of Use
TSO	Transmission System Operator
UDS	Unit Dispatch System
UK	United Kingdom
UK ETS	United Kingdom Emissions Trading Scheme
VRE	Variable Renewable Energy
WEM	Wholesale Electricity Market
WEMDG	Wholesale Electricity Market Development Group
WEMS	Wholesale Electricity Market Study
XBID	European Cross-Border Intraday

Executive Summary

The Review of Electricity Market Arrangements (REMA) consultation document set out a compelling case for the need to look at reforms in the GB electricity market. The changing generation mix, and policies designed to bring forward renewable technologies, have been challenging the market's ability to deliver the right incentives for efficient solutions. Key issues raised by the consultation, and previous work, highlighted concerns around significant and rapid increases in system costs, increasing prices and high costs days in the Balancing Mechanism (BM), and increasing security of supply risk due to a deficit of low carbon dispatchable power. Furthermore, the increasing electrification of other sectors, such as transport and heat, highlight the need for a more flexible system to cope with increased likelihood of demand fluctuations. Allied to developments in metering and greater digitalisation and computer processing power, this also suggests opportunities to create a more efficient system that minimises losses and costly re-dispatch.

Against this backdrop of a compelling case for reform is the equally compelling need to increase the UK's investment in low carbon technologies, infrastructure, and usage. Market re-design and policy changes are likely to impede investment signals. This is due to the mere fact that change creates uncertainty which in turn reduces investors' ability to assess future revenues. This can result in a 'wait and see' approach to investment. To mitigate this, the Government is considering whether incremental reforms could address the issues raised in the REMA consultation and either provide a staggered approach to reform or offer solutions that do not require a fundamental re-design of the GB electricity wholesale market.

Arup was appointed by the Department for Energy Security and Net Zero ('DESNZ') in 2022, to assess three broad incremental reforms and their potential to improve the efficacy of the GB electricity market design as outlined below in Figure 1.

Figure 1: Incremental reforms that are being considered

- Changing dispatch arrangements from self-dispatch to central dispatch
- Increasing the temporal granularity of settlement periods and gate closure
- Introducing changes to the Balancing Mechanism and complementary arrangements

Arup's work ("the study") was based on a combination of data supplied via a stakeholder engagement process, internal expertise, and internal and external benchmark data. The findings from this project will support policy formation and inform strategic decisions in the future.

The study has broadly drawn conclusions by exploring the incremental reforms through two key lenses:

- Implementation – timelines, cost, and impact on market participants.
- System impacts – likely impacts on key market outcomes (assessment criteria listed below).

Methodology and Results

This report uses a mixed methods approach to qualitatively assess the categories of incremental reform. It has considered:

- Literature Review & Analysis.
- International Case Studies.
- Stylised Examples.
- Interviews with Market Experts.

It is not intended to be a full impact assessment, but rather a qualitive assessment for the policy development process; with the aim of making recommendations on which incremental reforms should be taken forward in the next stage of the policy design process.

A baseline - review of existing market arrangements

Academic literature on how and why GB moved from the England and Wales Electricity Pool to the New Electricity Trading Arrangements (NETA) (and British Electricity Trading and Transmission Arrangements (BETTA)) and the current self-dispatch system was reviewed. The roles and responsibilities of all market actors in the current wholesale market framework have been described. The study also looked at the key market trends and explored the main market reforms and issues that policy makers and regulators had previously considered.

Central dispatch

Central dispatch can reduce some of the costs created by constraints. This is because the method is likely to reduce, but doesn't eliminate, the benefit to generators when behind a transmission constraint. The review of literature suggested that markets with an element of central dispatch could lead to more accurate price formation by managing some of the system services well ahead of delivery.

Central dispatch is a complex reform, with numerous design choices and a variety of models in place across the world. Central dispatch can reduce flexibility for market participants.[1] This can, in part, be mitigated by allowing market participants to self-dispatch under certain rules. This option, however, limits some of the central dispatch benefits because it risks splitting up liquidity between the open market and that run by the System Operator/Market Operator (SO/MO).

This study analyses a market design model of central dispatch with self-commitment, akin to the model found in the US (but without the nodal pricing aspect). Arup’s view is that this proposal provides key benefits because it can be done through incremental reform and it retains elements of the current design. It also gives optionality to market participants and allows for more flexibility. Moreover, retaining the forward market pretty much intact facilitates hedging and risk management for market players, without requiring retail market reforms. Finally, central dispatch with self-commitment lends itself to nodal pricing if this was the route GB pursued.

A central dispatch model could help facilitate other potential benefits through co-optimisation and market power mitigations. The efficiency of the system could be improved if the electricity system was co-optimised between energy and ancillary/reserve products and services. A centrally dispatched model is a necessary, but not sufficient, condition to enable this. Further, a centrally dispatched system allows, to some extent, for ex ante pricing rules to mitigate against market power concerns. The realisation of these benefits depends on the detailed design of how a centrally dispatched model would be implemented.

The model is not without its own drawbacks and challenges. Whilst it is an advantage for units with long start-up times and high start-up costs, the optionality may impact investment signals. The ability to self-commit alongside the central commitment process could split liquidity, reducing the chance for efficient price formation. Finally, it does not take away the BM opportunity cost from the bidding strategy of certain market participants.

The study has outlined the key design parameters of the model and stepped through the three main stages of the dispatch process.

- Operational Schedule: Creation of a scheduling plan by the SO/MO to match generation to demand.
- Unit Commitment: Refinement of the Operational Schedule and issuing of instructions to units with long start-up times.
- Operational dispatch: Real-time dispatch instructions to market participants to balance supply and demand.

[1] For example, in some jurisdictions such as the US, central dispatch appears to reduce intraday flexibility for market participants since it removes opportunities for forward-trading. However, this isn’t the case in all markets, with the I-SEM being an exception.

It is expected that bidding at Forward Markets will be much more detailed. This would mean market participants needing to provide more economic and dispatch parameters. These parameters are detailed in the report and are used to deliver a high-level stylised example.

Arup's view is that GB would need at least five years to transition to a central dispatch market design. The implementation timescales and impacts to market actors have been investigated. There are not many markets around the world that have transitioned from 'self' to 'central' dispatch, and central dispatch is often coupled with locational market pricing. Transitions that could be seen as similar have been looked at, such as market transitioning to nodal pricing with central dispatch or the transition of the GB market from central to self-dispatch in the early 00s. The analysis and discussions with market participants suggested that such a transition would be long and costly, and it is difficult to justify as incremental.

The ESO will need to bear most of the effort with IT and documentation costs being the highest for most market actors. The impact on the key market actors has been assessed based on the following criteria using a RAG rating methodology:

- IT system upgrade.
- Data management.
- Scheduling and settlement.
- Energy trading.
- Forecasting.
- Documentation.

The results are shown below in Figure 2.

Figure 2: Implementation impact of centralised dispatch on key stakeholders

Arup's stylised simulation of a centralised dispatch suggested that a centralised dispatch model could lead to reduced system costs mainly due to lower balancing costs as shown in Table 1.

Table 1: Stylised example of potential changes to system costs

Proposed Central Market Design						Current Self-Dispatch				
Generator	Energy Capacity (MW)	Energy Price (£/MWh)[2]	Reserve Capacity (MW)	Reserve Offer (£/MWh)	System Cost (£)	Energy Capacity (MW)	Energy Price (£/MWh)	Balancing Capacity (MW)	Balancing Offer (£/MWh)	System Cost (£)
Wind	600	£119	0	£0	£71,200	600	£108	-200	-£100	£84,800
Biomass	1280	£124	0	£0	£158,720	1280	£108	0	£0	£138,240
CCGT-1	442	£124	230	£160	£91,608	442	£108	230	£175	£87,986
CCGT-2	0	£124	504	£0	£0	1217	£108	0	£0	£131,436
CCGT-3	420	£124	420	£145	£112,980	420	£108	420	£175	£118,860
CCGT CCUS	1446	£124	0	£0	£179,304	1446	£108	0	£0	£156,168
Pumped Storage	398	£124	200	£180	£85,352	398	£108	200	£250	£92,984
Nuclear	2852	£124	0	£0	£353,648	2852	£108	0	£0	£308,016
Total Cost					£1,052,812					£1,118,490

[2] Based on volume-weighted average of constrained and unconstrained prices.

Recommendation 1: Centralised dispatch is too different from the current design to be considered an incremental reform. It is unclear whether the costs of implementation would outweigh the benefits. Some of the potential benefits are also dependent on design choices. Given its enabling role, central dispatch should be considered as part of a package of reforms, alongside other design choices such as co-optimisation, and greater temporal and locational granularity.

The evidence reviewed, the feedback from market participants, and the stylised example analysed suggest that a centralised dispatch model can help reduce balancing costs and enable co-optimisation of some system services ahead of time. Moreover, the bidding format can improve transparency and supports more consistent and equal treatment of different types of generation assets. This could reduce the volume required to be procured post gate closure leading to lower constraint management and balancing costs. This should remove part of the BM opportunity cost that generators include in their asset optimisation process.

The implementation of the centralised dispatch model, however, is likely to be lengthy and complex, with the ESO having to undertake significant work. In addition, the model will not resolve all the costs associated with dealing with constraints; there will still be a BM and this combined with the fact that constraints are not always known well ahead of real time means there will still be opportunity cost factored in the optimisation strategy of market participants. This will be exacerbated by the fact market participants will have the option to self-schedule their output which means they could keep their optimisation strategy unchanged. This will reduce the impacts of a central dispatch approach. Arup's view is that the benefits of a standalone central dispatch reform should not be material enough to justify the cost and complexity of such a transition.

Further, the sheer degree of code changes and the significant change in the role of the ESO strongly suggest this is too fundamental a reform to undertake incrementally within the existing framework. This view was shared by all market participants Arup interviewed.

Increasing temporal granularity

This section has investigated the potential of increased temporal granularity to deliver market outcomes aligned with the REMA objective. Arup has assessed the implementation impact based on the assessment criteria described below. In this study increased temporal granularity refers to three main options:

- Shortening the Imbalance Settlement Period (ISP) and dispatch interval granularity from 30 minutes to 15 minutes or 5 minutes.
- Shortening the MTU from 30 minutes to 15 minutes or 5 minutes.
- Bringing the gate closure interval from 60 minutes down to 30 minutes, 15 minutes, or 5 minutes.

Shorter ISP and MTU have been looked at together, whilst a shorter gate closure interval was investigated separately.

The academia and market commentators are generally aligned in that a shorter ISP and MTU can deliver benefits. In particular it can:

- More accurately allocate the cost of the actual balancing actions taken by ESO to market participants.
- Reduce balancing costs.
- Improve market incentives for flexible and intermittent generation.
- Improve cross border trading.
- Improve Intraday (ID) market liquidity.

Shortening gate closure interval is also viewed positively by most market stakeholders. The main recognised advantages are:

- Bidding in the BM for energy balancing would better reflect actual market conditions.
- Incentives for flexibility provision would be improved.
- Integration of Variable Renewable Energy (VRE) sources would be facilitated.

When considering shortening the gate closure interval, however, there is a balance between market and balancing efficiency i.e.,

- Giving the right amount of time to the ESO to identify and execute the system balancing actions to ensure system reliability and security of supply.
- Giving BMUs enough time to respond (dispatch their units or reduce their demand) to balancing actions ordered by the ESO.

The analysis conducted as part of this study concluded that the biggest implementation impact is expected to be related to IT systems, Billing and Metering. ESO and Metering Services and Equipment providers will be affected the most followed by Generators and Retailers. Arup's analysis was based on reviewing existing literature, internal expertise, and discussions with market participants.

Analysis of international examples suggested that implementation would take between 2 and 4 years. This is based on analysis of international and historical examples of similar magnitude.

A theoretical model of a market with increased temporal granularity was constructed by Arup. This model looked at the key market design parameters and how the key market actors are affected. The impact on the key market actors based on the following criteria and using a RAG rating methodology was assessed:

- IT system upgrade.
- Data management.
- Scheduling and settlement.
- Energy trading.
- Forecasting.

- Documentation.

Based on Arup's simulated stylised example, transitioning to a shorter settlement period would mean:

- Both daily price spreads and baseload prices increase by reducing the settlement period below 30-minutes.
- Period-to-period price variability drops as temporal granularity increases.
- Wholesale revenues for flexible generators increase as we move towards shorter settlement periods.

To test the potential impact on wholesale prices, Arup's in-house energy market simulation model (developed in PLEXOS) simulated market prices using unprofiled demand data below 30-minute granularity (this was scaled to match the Future Energy Scenarios (FES) demand scenarios). The simulation looked at the effect that shortened settlement periods might have on prices and on the generation output of flexible technologies in 2025, 2030 and 2035. A peak winter day and a summer day were modelled. The modelled days were based on National Grid's (NG) Consumer Transformation (CT) scenario in FES, whilst the three different years represent generation mixes at different stages of decarbonisation. In 2035 the generation mix is fully decarbonised under the CT scenario.

GB market participants view the transition to a shorter ISP positively. They believe that implementation will be challenging but doable and compatible with advancements in IT technology and generation mix. Furthermore, the discussions with participants suggested that moving to increased granularity will most likely require more algorithmic/automated scheduling and dispatch of units. Market participants did not view data management as a major issue. They also saw settlement code changes as being manageable. Participants suggested that increasing temporal granularity should lead to spikier prices whilst the impact on liquidity could be positive, but it is not easy to land on firm views. One market participant recommended that reforms for a shorter ISP could be integrated with the current Market wide Half Hourly Settlement (MHHS) programme, to enable synergies in implementation. One market participant raised concerns around the potential of reducing gate closure below 60-minutes as the existing generation mix is not necessarily able to respond to shorter times. Finally, all market participants preferred a gradual approach to reforms compared to a "big bang" approach.

The analysis and discussions with market participants suggested reducing the ISP and MTU are both steps that are well aligned with the market direction. Increased temporal granularity options have been assessed based on the following criteria:

- Impact on wholesale market prices.
- Impact on balancing costs.
- Liquidity.
- Impact on interconnection.
- Impact on low carbon investment.

- Interaction demand.
- Impact on security of supply.

Arup’s analysis and stakeholder discussion suggested that increased temporal granularity options better reflect market operation which should lead to a fairer allocation and potentially a reduction of balancing costs. The market expectation is that part of the volume traded to the BM will transition to the ID market which, in turn, should also lead to lower balancing costs. A shorter ISP also enhances investment and market participation incentives for flexible assets like Battery Energy Storage Systems (BESS) and Demand Side Response (DSR). With regards to DSR participation, and more specifically domestic DSR, Arup’s view is that upscaling and speeding up the smart meter roll-out is an essential pre-requisite. Finally, a shorter ISP has the potential to improve cross border trading.

Recommendation 2: A transition to a 5-min ISP and MTU is likely to deliver higher benefits versus a 30-min or a 15-min ISP and MTU and is likely to be better suited to a future GB electricity market with greater flexibility requirements.

It is not possible to simulate shortened gate closure because there is not the data on which to base changes in balancing actions required by the ESO. There is also limited quantitative evidence on assessing the impact of shortening the gate closure interval. Most of the qualitative analysis suggests that reducing gate closure could allow for improved bidding and more transparent bidding in the BM, better opportunities for flexible generators and better integration of Variable Renewable Energy (VRE) by allowing for output adjustments closer to real-time. On the other hand, reducing the gate closure interval too much could lead to adverse effects when it comes to system costs and security of supply. Moreover, the gate closure interval needs to be linked with the existing generation mix. In the GB market combined cycle gas turbine (CCGT) generators that provide the lion-share of flexibility can cope well with a 60-minute gate closure interval, but it is not clear how well they would be able to cope with anything shorter than this.

Our view is that that the generation mix development along with the IT technology advancements should allow transitioning to a 30-min gate closure. Many US markets work effectively with 30 minutes gate closure intervals (PJM, ISO-NE), However, this may, in part, be enabled by other design features. Nodal pricing, five-minute settlement periods, and co-optimisation of energy and reserve are examples of design choices that reduce the amount of balancing actions required and are multitudes lower than the number of balancing actions seen in GB. Given the scale of actions required currently, shortening gate closure would pose significant challenges to ESO. As such, thorough discussions and testing should be undertaken with the ESO before deciding whether to pursue this move.

Recommendation 3: As technology and the generation mix advances a 30-minute gate closure interval should be considered further through a Cost Benefit Analysis (CBA). Anything below that could lead to adverse impacts when it comes to system costs and security of supply.

Balancing Mechanism changes

The cost of balancing the GB system has risen dramatically over the past 15 years. In 2008 the total costs associated with system balancing were around £500m per year. Last year (2022) they were above £3bn and they are forecast to grow further.

The growth is largely due to the increasing cost of dealing with constraints. There has, however, also been growing concerns that generators are able to charge very high prices in the BM. Indeed, the last few years have seen year-on-year increases and records for the highest cost balancing days and a large part of this is increased pricing by generators in the BM.

There has also been a growing trend of flexible generators, such as CCGTs and open cycle gas turbines (OCGTs), to not sell their power in the open market, but take the risk of reserving the power to allow it to be bought up at higher prices in the BM.

Given the concerns with the BM several reforms are considered.

- Locational BM products – as the GB gas market used to have, it is possible to introduce location specific products in the hope it sends a price signal on which areas are good to invest in and dispatch generation to.
- Cash-out changes – making cash-out less marginal and less penal in the hope that this reduces the market participants assessment of imbalance risk and reduces the risk premia they attach to market prices.
- Administrative Offer pricing rules – as being explored by Ofgem. A few options were explored:
- Limiting generators' ability to amend their schedules with little notice.
- Restricting BM access or BM bidding flexibilities for generation capacity that is withdrawn with little notice.
- Changing the rules for how parties structure their BM bids.
- Introducing new licence obligations that require generators to operate and behave in a manner that delivers in consumers' interests; and,
- Introducing direct measures to restrict BM offer prices.

Ofgem has chosen to proceed with an option that, using a new licence condition, would mean generators must not make an excessive benefit if they are only offering all their power to the BM (known as having a zero Physical Notification (PN)). This effectively means they would need to price near their long-run marginal costs if they only offer their power into the BM.

A purely qualitative approach was used to explore and assess, at a high level, the pros and cons of the different potential reforms.

Applying a cap on BM offer prices can be complex where there is a balance of setting the cap at the right level (taking varying generator costs into account) and not hampering investment signals. Moreover, such an option could lead to offer prices congregating around the cap. Further, complex rules around bidding parameters are unlikely to have a significant effect and be difficult to implement.

Changing the cash out mechanism, in Arup's view, could have adverse market effects as it reduces the incentive on market participants to balance their position ahead of real-time. Moreover, such a move contradicts the aims of the Electricity Balancing Significant Code Review (EBSCR).

The introduction of locational products in the BM bears the risk of generating market power for participants located in areas where services are required. This could lead to increased costs for consumers. On the other hand, Arup's view is that long-term investment signals are already in place in the form of transmission charges.

Of the options considered, Arup's consider the option being taken forward by Ofgem as the preferred one. It could, however, be simpler and more effective to amend the Transmission Constraint License Condition (TCLC) to include offer prices. Limits on offer prices are not likely to create a missing money problem as the Capacity Market (CM) is equipped to deal with this issue. Further work should be undertaken to really assess the profits of flexible generators in GB, as the evidence suggest there are some fundamental concerns, that are likely to grow, as our stock of dispatchable power plants decrease.

Recommendation 4: Proceed with an enhanced version of Ofgem's proposal to cap BM generator margins if they submit a Physical Notification between zero and their Stable Export Limit (SEL).

Review of the existing market arrangements

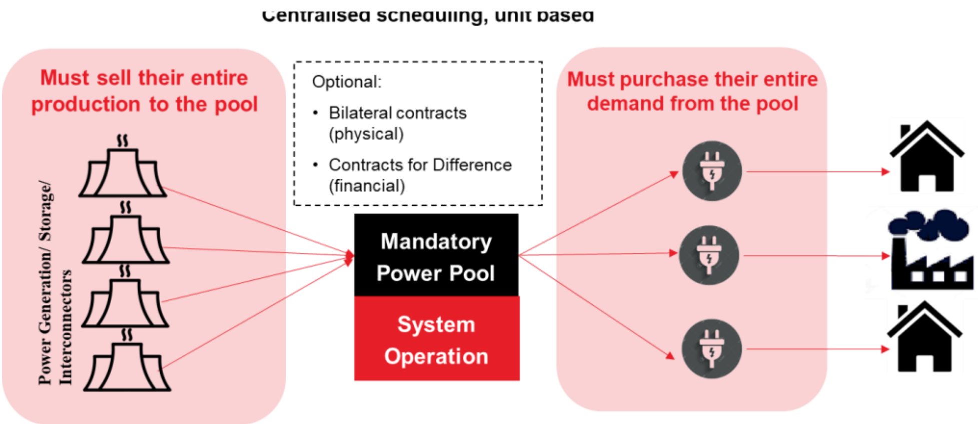
Summary and review of the electricity market design in GB

With a history of approximately 140 years, the GB electricity market has been through, and is undergoing, a number of regulatory and technical changes. In recent history, the UK electricity wholesale market has experienced three significant reforms: the introduction of the Electricity Pool of England & Wales in the 1980s, the implementation of NETA in the 2000s, and the Electricity Market Reform (EMR) in 2013. The most recent reform is the ongoing Review of Electricity Market Arrangements (REMA), announced in July of last year.

The GB electricity market opened in March 1990, allowing suppliers and generators to operate through a Gross Pool system.

- The Electricity Pool of England & Wales ('the Pool') was a mandatory electricity market (see Figure 3) established under the Pooling and Settlement Agreement (PSA) framework.

- It was centrally dispatched, with the System Marginal Price (SMP) set by the marginal price offered by the most expensive generator[3] setting the wholesale market price for each settlement period.
- All generators and suppliers were required to buy and sell from the Pool, meaning that generators and suppliers did not trade with each other, but bought and sold from the pool run by the System Operator (SO).
- The GB pool was a market that cleared one day ahead of real time. All generation units would be ranked relative to the bidding price and then a combination of units would be selected, based on load forecasting information and reserve demands.
- Costs associated with payment to these generators were equally shared by consumers, which also included capacity payments.



Initially the market saw a decrease in prices and an increase in competition which in turn benefited consumers. However, the Pool design soon came under increasing scrutiny. Generators complained about the lack of transparency in dispatch decisions, liquidity and hedging remained extremely low and there were concerns regarding market power, particularly behind network constraints.

The first physical bilateral market was introduced to England and Wales through the NETA in March 2001. It replaced central dispatch with a self-dispatch energy-only market.

- This design was introduced to stimulate competition and unify the GB electricity market.
- NETA accommodated four electricity market products with different functions: Forward Market, Power Exchange (spot market), Balance Mechanism, and Imbalance Settlement.
- Bilateral trading was a fundamental principle for NETA and the intention of the design was that physical electricity trading should follow the principles of other commodities.

[3] M. Grubb & D. Newbery (2018): UK Electricity Market Reform and the Energy Transition: Emerging Lessons

- Under NETA all generators had to submit a balanced offer, requiring them to contract all output, and therefore removing the incentive to exploit the spot market - if under-contracting occurred, sellers were encouraged to increase the spot price above the marginal cost, and vice versa[4].

These principles are still in place today through BETTA. BETTA (see Figure 4) saw the inclusion of Scotland from the 1st of April 2005, creating a single electricity market for the whole of Great Britain (GB).

- Under BETTA, NG is the National Electricity Transmission System Operator (NETSO) managing transmission in England and Wales and acting as the SO in Scotland.
- Under this model, there are optional central trading arrangements, with much of the trading of final positions taking place as bilateral trades done on the day of delivery.
- Market participants that are out of balance on delivery, under BETTA, are expected to incur a cost that is higher compared to the money they would spend to balance their positions.
- As such this market design was intended to incentivise market participants to balance their positions more accurately.

Initially, under the NETA/BETTA reform, the increased competition significantly reduced electricity prices. During the early 2000s, GB was also benefiting from the ‘dash for gas’ which increased North Sea gas production and facilitated a growth in gas fired electricity generation.

As the decade progressed fewer generation assets were coming online, and reserve margins began to fall. In 2006, the UK reserve factor of power generation capacity dropped to 22% from 35% at the beginning of the reform[5]. It has been argued that the new market design eroded generator profits and did not provide sufficient investment signals. This led to a trend of generation and supply being dominated by the so called “Big Six” vertically integrated suppliers (British Gas, EDF Energy, E.ON, Npower, Scottish Power, and Scottish Southern Electricity). Together they accounted for 70% of GB electricity supply market share[6]. Throughout the noughties concerns grew that the British energy supply market was lacking competitive pressures and the wholesale market could be partly to blame.

In 2008 Ofgem published an energy supply probe where smaller suppliers and new entrants raised concerns around the lack of liquidity and the functioning of the wholesale market as a whole. Competition concerns failed to dissipate and in 2014, the Competition and Market Authority (CMA) launched an investigation into the Energy Market[7]. The CMA concluded that firms participating in the wholesale market could not exercise coordinated market power. There were, however, some periods where generators could exercise locational market power

[4] M. Grubb & D. Newbery (2018): UK Electricity Market Reform and the Energy Transition: Emerging Lessons
[5] J. Liu, J. Wang, & J. Cardinal (2022): Evolution and reform of UK electricity market
[6] Ofgem (2020): Electricity supply market shares by company: domestic (GB)
[7] CMA Energy Market Investigation (2006)

because of transmission constraints. The CMA recommended that policy makers should explore a locational market design to alleviate these.

Figure 4: BETTA Market Model Overview

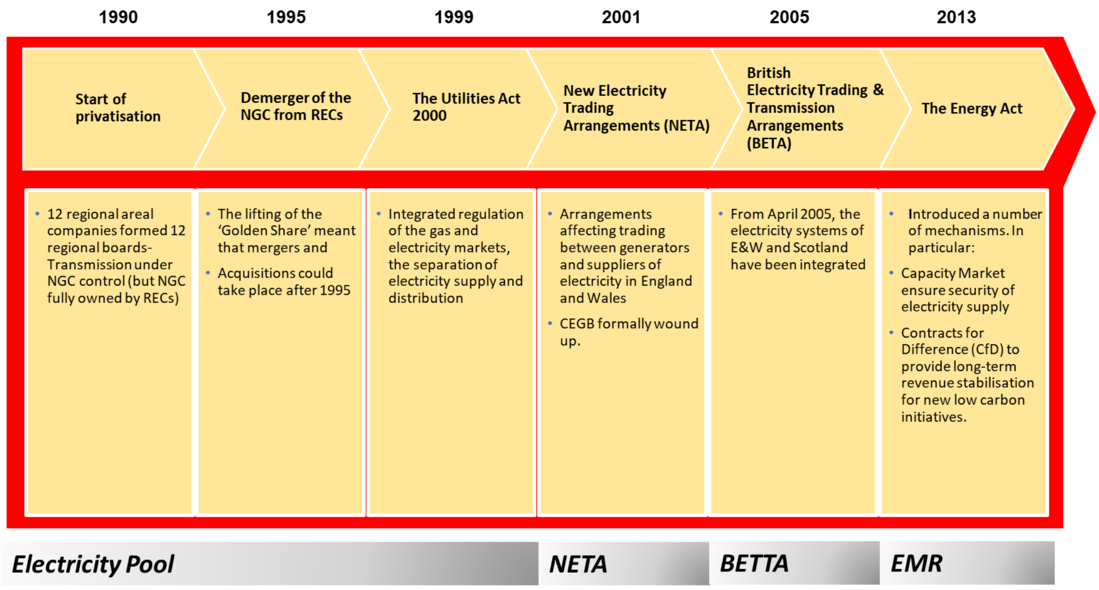
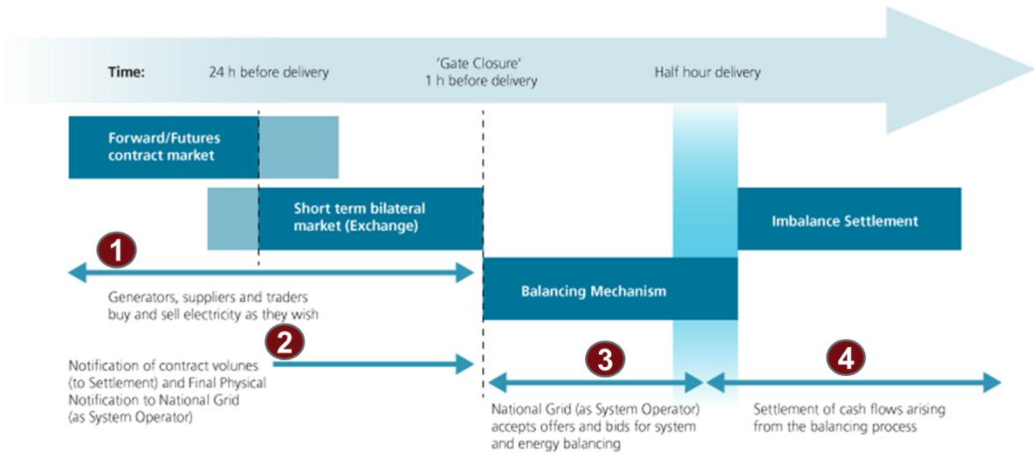


Figure 5: The key electricity market reforms over the past 30 years



Ofgem has raised a few issues and made some significant changes to the rule book since the introduction of BETTA

In 2012 Ofgem introduced the Transmission Constraint Licence Condition (TCLC), which aimed to stop generators gaining an ‘excessive’ benefit during transmission constraints.

In March 2014, the regulator referred the energy market to the Competition Markets Authority to investigate competition concerns. Whilst the remedies focused on the retail market and resulted in the price cap, the CMA did recommend that a location marginal pricing design be considered for GB wholesale electricity market, noting its theoretical superiority. This was informed by analysis conducted by Ofgem which showed some generators have market power during tight market conditions.

In 2018 Ofgem launched a Significant Code Review (SCR) into transmission charging arrangements and further review has followed. These reviews and changes to the network charging regime aimed to adapt the rules to the changing generation mix and in part create more locational investment signals.

In 2019 Ofgem announced its first REMIT against an electricity market participant; InterGen was fined over inaccurate submission of ‘Dynamic Parameters’ data.

At the behest of Ofgem the ESO was legally separated from National Grid PLC in April 2019. Unconvinced that a legally separated ESO was sufficient to enable the body to take on the rules necessary for net zero, the regulator recommended full legal separation and the sale of the ESO by National Grid in January 2021.

Ofgem's energy supply probe highlighted concerns with wholesale market liquidity being a barrier to entry for new suppliers. This led to two further reviews of liquidity and then to the ‘Secure and Promote’ licence condition.

Ofgem runs a ‘Cap and Floor’ regime to support interconnector investment. This has helped bring forward several new (Belgium - NEMO, Norway - NSL, Netherlands - Britned) interconnectors.

By the early 2010s concerns were growing that the GB energy only market design would struggle to signal the right investment signals to enable security of supply during the transition to net zero, which, at the time, was planned c. 2045 for the electricity sector. The EMR legislation brought forward significant changes in the electricity market design and was a response to the simultaneous problems of securing sufficient investment in low carbon alternatives and delivering reliability within the market. Figure 6 provides an overview of key EMRs over the past 30 years.

To encourage the required development of renewables, the EMR's response was set out through a combination of four mechanisms:

- The Carbon Price Floor (CPF) was introduced to address the lack of a credible carbon price.
- The Emissions Performance Standard (EPS) was designed to limit carbon emissions from any new power stations.
- The Capacity Market (CM) mechanism aimed to ensure sufficient and reliable capacity by providing payments to encourage investment in new capacity or for existing capacity to remain open[8]. It essentially pays generators to be available at times of stress. Due to their intermittent nature, wind and solar were derated to such an extent that it was not economical for them to bid into the CM, resulting in most of the payments being awarded to gas-fired generators. The mechanism also incentivised new market entrants, with new generators being eligible for 15-year contracts, whereas existing generators could only receive one-year contracts. Auctions in the CM are held bi-annually, and most of the capacity is procured four years ahead of time.
- The Contracts for Difference (CfD) is a long term, private law contract, between the generator and the Low Carbon Contracts Company (LCCC), an entity fully owned by the government. LCCC agrees to pay the generator the difference between an estimate of the market price for electricity (the 'reference price') and an estimate of the long-term price needed to bring forward investment in a given technology (the 'strike price'). The strike price for most projects is set via an auction and varies from project to project. This essentially removes most of the risk from renewable generation assets. The scheme offers long-term contracts that guarantee a fixed price for their electricity. CfDs for wind and solar are 15 years in length and are seen as essential for stimulating and supporting investment of new and needed renewable projects.

The introduction of the EMR programme meant that the GB market stopped being an energy only market. The changes did not, however, fundamentally change the rules and market design set out in BETTA. While the policies introduced under the EMR package were successful in significantly reducing carbon intensity of the GB network, average consumers bills remained largely unchanged. Additionally, after more than a decade, new challenges have emerged with the accelerated net zero targets, rising global energy costs and increasing need for energy security posing a real challenge to the GB electricity market.

[8] DESNZ, UK (2015): Electricity market reform: contracts for difference

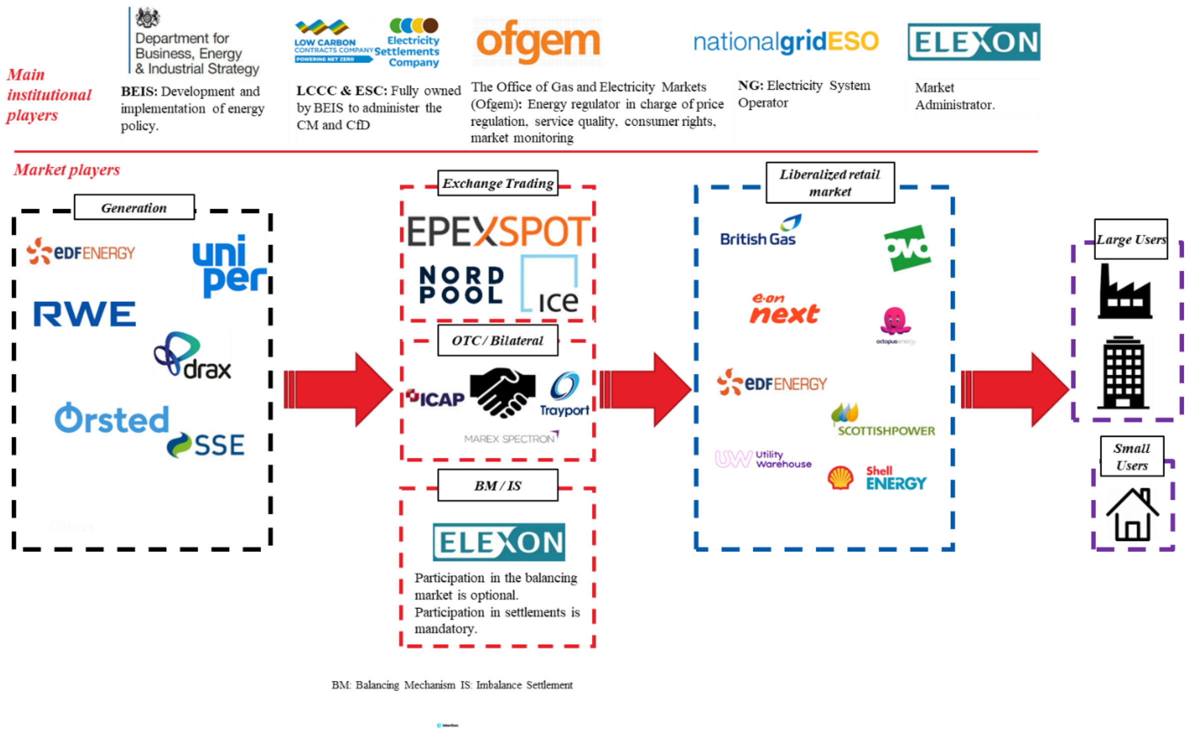
Existing GB market overview

The GB electricity market is the tool that links generators, transmission and distribution network owners, regulatory bodies and policy together. Its purpose is to ensure that supply to end consumers is affordable, secure, and low carbon whilst all market participants are remunerated for their service.

The GB market is a bilateral contract market, incentivising generators and suppliers to sell and purchase electricity via wholesale trading ahead of its physical delivery. Real-time balancing of the system is the responsibility of the SO, the ESO.

The GB electricity market is sophisticated and involves numerous participants that form complicated and structured relationships. In Figure 6, below, the main markets, key statutory bodies, and main industry players are defined according to the current market structure.

Figure 6: Key GB electricity market actors



The wholesale electricity market is the coming together of several 'markets':

- Forwards, Futures and Options - electricity is traded Over The Counter (OTC) or via an exchange which can be from years ahead up to days ahead of delivery. This market allows suppliers and generators to hedge their positions to effectively manage their price and volume risk. So far, the vast majority of trades are bilateral contracts delivered through the OTC market (instead of a futures exchange).
- Day-ahead Market (DAM) – DA trades occur either through matching bids and offers in a spot market exchange or through bilateral contracts in OTC deals. Nordpool and EPEX are the spot market exchange operators (DA and ID) for GB. Both exchanges

offer half-hourly, hourly and block products along with some more complex bidding. Broadly the hourly DA auctions close at around 11am and the half-hourly auctions close at around 3pm on D-1. The market is operated through a blind auction run by the exchange and all half-hours of the delivery day are traded in the auction. This is considered to be where the 'electricity price' is actually realised.

The DAM also allows large industrial and commercial electricity consumers to balance their short-term electricity position. The role of the DAM has become increasingly important for market participants due to the rising penetration of renewable generation in the market.

- Intraday Market (IDM) – Intraday products are offered both via an exchange operated auction and via continuous trading. They allow market participants to trade half hourly products and adjust their position close to real time. As soon as a buy- and sell-order is matched, the trade is executed. The ID auction clears at 8am on the delivery day whilst continuous trading occurs up to gate closure for BM Units (BMUs - essentially generators that participate in the BM) and up to 15-minutes before real time for non-BMUs.

  This market allows generators and suppliers to react to short term signals such as demand forecasts errors, commodity prices and generator activity/faults. Market participants have a high level of flexibility and can adjust their position closer to real-time.

- The main tools the ESO uses to balance demand and generation in real time are the BM and Imbalance settlement. The former is used to procure physical power in real time whilst the latter is used to penalise participants that over or underdelivered versus their contracted position. The BM is run by the ESO whilst Imbalance settlement is run by Elexon (a wholly owned subsidiary of the ESO).

- Balancing Mechanism – a residual pool where the ESO accepts submitted bids and offers (from BM participants) to balance the system. It is the ESO's primary tool to balance demand and supply within the GB network in real time. The BM is a continuous open online auction with 30-minute-long trading periods. For every half-hour period, the BM will signal how much it costs to provide power. The auction gate then opens 60-90 minutes before gate closure and market participants can submit bids and offers.

  At gate closure, competitively priced bids and offers are accepted. Once accepted, a Bid Offer Acceptance (BOA) is issued, and market participants adjust their output accordingly. In 2020, 1,800 daily balancing instructions were issued, and balancing services now regularly exceed 50% of national demand.

- Imbalance Settlement - a process for settling parties' positions based on their traded position and their metered consumption or volumes. Parties which are short (i.e., have under-delivered compared to their final notified position) are charged the Imbalance Price on their residual (out-of-balance position) position. Parties that are long (i.e., have over-delivered compared to their final notified position) are paid the Imbalance Price for their out-of-balance position. It is worth noting that imbalance applies to portfolios, but the ESO manages individual units in the BM.

It should be noted at this point that under the current system design the imbalance penalty is not always delivering its intended purpose. On a few occasions the imbalance penalty price (cash out price) ends up being lower than the actual electricity price. In this case the market participant is benefiting from being out of balance. As a result, Arup have seen several market players trying to increase their financial gains by trying to exploit the gap between the imbalance penalty and the market price. This strategy is called Net Imbalance Volume (NIV) chasing.

The main overseers of the wholesale market are the CMA, DESNZ and Ofgem. Since market opening, a large number of players have entered the market on the generation, distribution and supplier side.

The main statutory bodies are:

- DESNZ: created in February 2023 and took on the energy policy responsibilities of the former Department for Business, Energy, and Industrial Strategy (BEIS). BEIS was responsible for business, industrial strategy, and science and innovation with energy and climate change policy, merging the functions of the former BIS and DECC.
- CMA: began operating fully on the 1st of April 2014, when it assumed many of the functions of the previously existing Competition Commission and Office of Fair Trading, which were abolished. The CMA concluded an energy market investigation in June 2016 and mandated a number of remedial actions.
- Office of Gas and Electricity Markets (Ofgem): the regulatory authority for the gas and electricity markets. The principal objective of Ofgem is to protect the interests of existing and future electricity and gas consumers.
- Gas and Electricity Markets Authority (GEMA): the governing body of Ofgem, GEMA oversees work undertaken and provides strategic direction.

The main market operating actors are:

- National Grid: NG is the transmission owner in England and Wales and also fills the SO role. As the transmission owner, NG own and maintain the electricity transmission network. As the SO, NG ensures that supply and demand of electricity is met. They ensure balance within the network and constantly monitor frequency ensuring it stays within 50Hz. National Grid is regulated by Ofgem.
- National Grid ESO: The electricity SO for GB. It is part of NG plc but is a legally separate entity.
- Interconnectors: These are large High Voltage Direct Current (HVDC) cables that link the GB market with neighbouring markets. This allows for electricity to be traded and flow across borders. The GB market is linked with France, Belgium, Norway and the Netherlands whilst a new interconnector between the GB and Denmark is about to be completed by 2030.
- Scottish and Southern Electricity Networks (SSEN) and Scottish Power Energy Networks (SPEN) in Scotland are owners of the Scottish Transmission network.

- Elexon: Was established in 2000 to manage the Balancing and Settlement Code (BSC) and oversees the strategic operation and day-to-day management of this. It is a wholly owned subsidiary of the ESO. Its main role is to compare the amount of electricity generators have contracted with their metered output. It then makes sure that suppliers and generators pay or get paid to settle any imbalances.
- Low Carbon Contracts Company (LCCC): Plays a key role in managing the CfD scheme for low carbon generators. They are responsible for managing the Supplier Obligation Levy which is the main funding tool for CfD payments.
- Electricity Settlements Company (ESC): It is a wholly owned subsidiary of DESNZ and its responsibility is to oversee and manage financial transactions related to the CM. It is a private company wholly owned by DESNZ.
- EMR Settlement Ltd: EMR Settlement Ltd is a subsidiary of Elexon and acts as a settlement provider on behalf of the LCCC (CfD) and the Electricity Settlement Company (CM).
- Energy exchanges: These are electricity and relevant commodities exchanges that brings together bids and offers. This is essentially where the market price is defined. Trading on an exchange reduces the risk for market participants whilst ensuring increased transparency on finding the right market price.
- OTC market: This is where market participants can trade electricity outside of the energy exchanges through bilateral contracts. 80% of the contract transactions in the UK electricity market are done via OTC forward contracts. The OTC market is run by Trayport.
- Distribution Network Operators (DNOs): own and operate the distribution networks in GB.
- Generators: Generators are the assets that generate electricity that is then supplied electricity onto the grid.
- Suppliers: are companies that purchase electricity that then supply to consumers. Examples of suppliers includes EDF Energy, E.ON, and Scottish and Southern Energy.

Key GB market trends

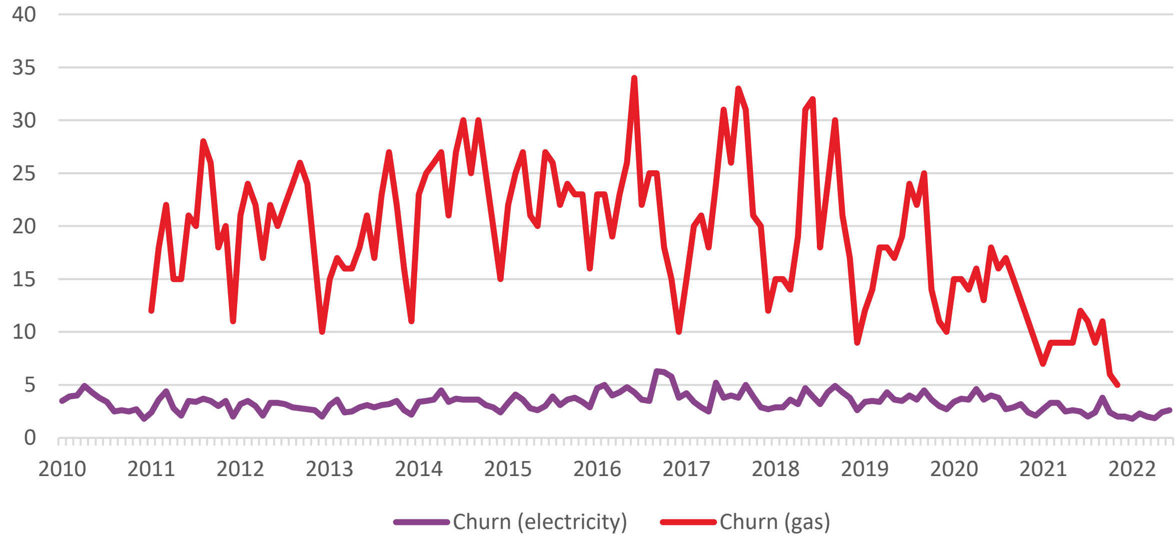
Liquidity

Liquidity is a key metric of well-functioning competitive markets. The same rule applies for electricity and gas markets. Increased liquidity often reflects many buyers and sellers taking part in the market. Moreover, liquid markets reduce entry barriers for new market players by making it easier to buy and sell electricity and gas at fair market prices that better reflect the real market fundamentals. Conversely, illiquid markets may lead to large price movements that make it very difficult for market participants to manage their positions. This can create additional risk which will ultimately result in higher costs.

Churn is often cited as one of the main metrics used to assess liquidity in energy markets. Churn rate indicates the number of times a unit of electricity is traded. Figure 8 shows the historical churn rates in electricity and gas markets since 2010. Gas churn rate has been consistently higher when compared to electricity. Gas churn rate averaged at 15.2 point in the last five years whilst it was nearly halved in 2022 averaging at 7.4 points. This rapid decline in churn is likely related to the energy price crisis due to the war in Ukraine and lack of Russian supplies in the European market. As prices has increased the amount of capital required to trade (known as margin calls) has increased massively, making the collateral requirement greater and reducing the ability of market players to trade.

There are many products and platforms available for traders of power in the GB market, but most of electricity trades are done OTC. Baseload products persistently dominate, accounting for the majority of OTC trade volumes. The average churn ratio in Q2 2022 was 2.31, which is 0.28 points higher than the previous quarter. It is also 1.4 points lower than in Q2 2021 demonstrating liquidity has decreased quarter-on-quarter but increased year-on-year. An interesting facet of the energy price crisis has been a migration from OTC trading to exchange based trading and growth in the ICE electricity future market.

Figure 7: Churn Rates: Electricity and Gas



Bid-offer spread

Perhaps a more accurate measure of market liquidity is a measure of the difference between what buyers are willing to pay for a commodity and what sellers are willing to accept for it; this is called the bid-offer spread. When the bid-offer spread is narrow it implies demand and supply are well matched and buyers and sellers broadly agree on the value of a commodity. On the other hand, a wide bid-offer spread means that demand and supply are mismatched, leading to ‘unfair’ prices for market participants. Electricity bid-offer spreads have been consistently higher than gas bid-offer spreads.

Electricity bid-offer spreads have increased by an average of 0.02 percentage points to 0.45% in Q2 2022 from the previous quarter. They are, however, still about 0.15 percentage points lower than in Q2 2021. Electricity and gas bid-offer spreads since 2010 are shown in Figures 8 and 9.

An interesting point demonstrated below is that following the jump in prices post 2021 the spot bid-offer spread dropped significantly below the front month and front season bid-offer spread[9]. This implies that the spot product is more liquid that the front month and front season ones. This is likely linked to price levels. Very high prices mean that buying commodity further out the curve costs more (as they translate to more volume) and are more difficult to manage from a credit risk perspective.

Figure 8: Bid-offer spread: Electricity

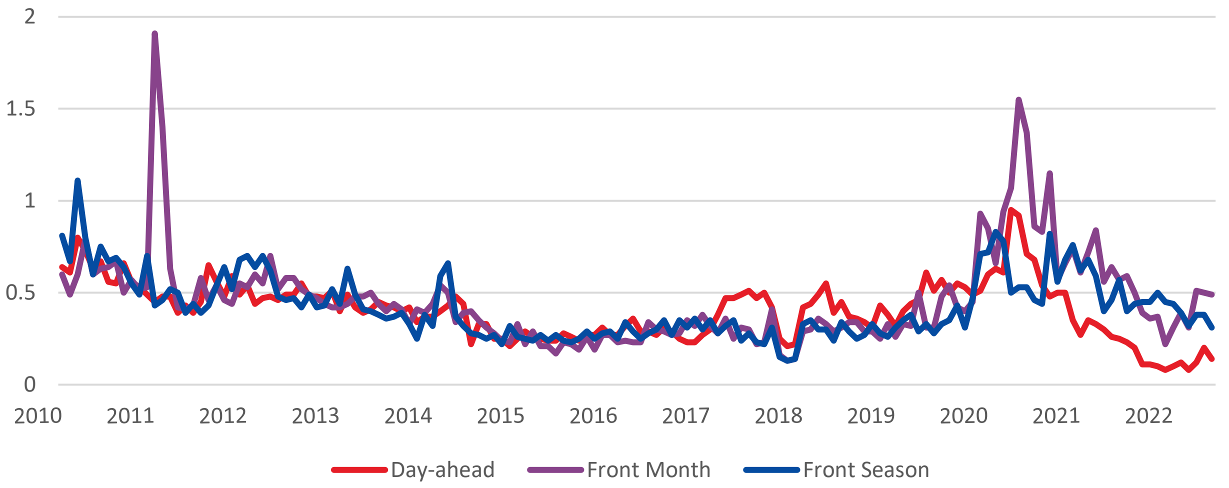
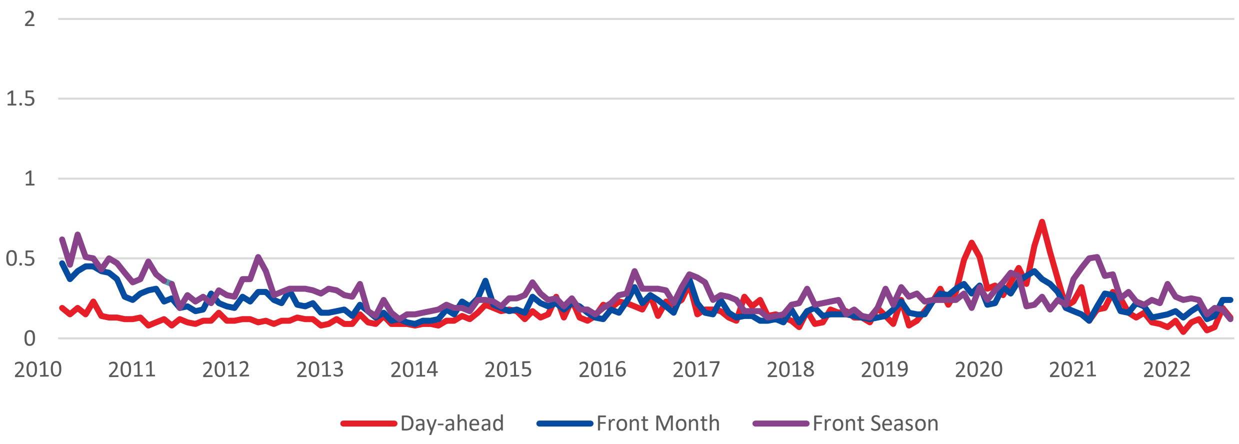


Figure 9: Bid-offer spread: Gas



[9] Refers to the price of the month and season ahead respectively; i.e., if we are in the month of July 2021 the front month would be August 2021 and the front season Winter 2021.

Evolution of historical wholesale prices[10]

Electricity prices are impacted heavily by increasing gas prices due to the importance of gas-fired power stations as the marginal generation unit to meet demand. This is the most significant driver of the increase in wholesale electricity prices. Carbon, weather, and generation mix changes (in the GB and interconnected markets) are the other key drivers of wholesale electricity prices.

Gas is a global commodity and as such it is affected by geopolitical events, production levels, infrastructure, shifts in national energy strategies and key weather events around the globe. During the late 2019 gas prices started to drop and eventually ended 80% lower in May 2020. This was due to a combination of events; new LNG supply capacity combined with warmer weather and low gas demand in Asia resulted in an abundance of LNG supply heading into Europe (including the UK). This led to Europe becoming a global LNG sink due to its well-developed gas pipeline network and market status.

Gas prices started to increase significantly towards the end of 2020 as the extremely cold temperatures in both Europe, the north of China and South Korea diverted LNG away from Europe, with the latter having to rely heavily on its stored gas. Moreover, the end of the strict lockdowns, along with a wider switch of Asian economies from coal to gas meant the period of cheap gas was coming to an end. As a result, prices saw a dramatic rise of ~360% in 2021.

European market participants were expecting the completion of Nord-stream 2 to deliver additional gas into Europe and ease prices slightly. When Russia invaded Ukraine in February, however, Germany cancelled the completion of the project. Flows via the other Nordstream pipeline (Nord-stream 1) were gradually reduced until Gazprom moved to completely shut the pipeline on the 31st of August 2022. This caused prices to rebound after a small drop at the start of 2022. The complete halt of Russian imports then created major security of supply concerns across Europe (including the UK).

As a result of the war in Ukraine, Europe ramped up its efforts to significantly reduce its reliance on Russian gas. To do so it has increased the continent’s LNG import capacity and sped up its efforts to decarbonise its economies. These changes involve major infrastructure changes and until they start to materialise (at least until 2025) prices will remain volatile across Europe.

Carbon prices have also risen significantly. Since the UK left the EU, they have opted to create their own Emissions Trading Scheme called the UK ETS. UK ETS prices follow similar trends to EU ETS prices. EU ETS prices have seen significant increases in 2021 in response to increased energy demand, more aggressive decarbonisation policies and the start of phase 4 of the EU ETS.

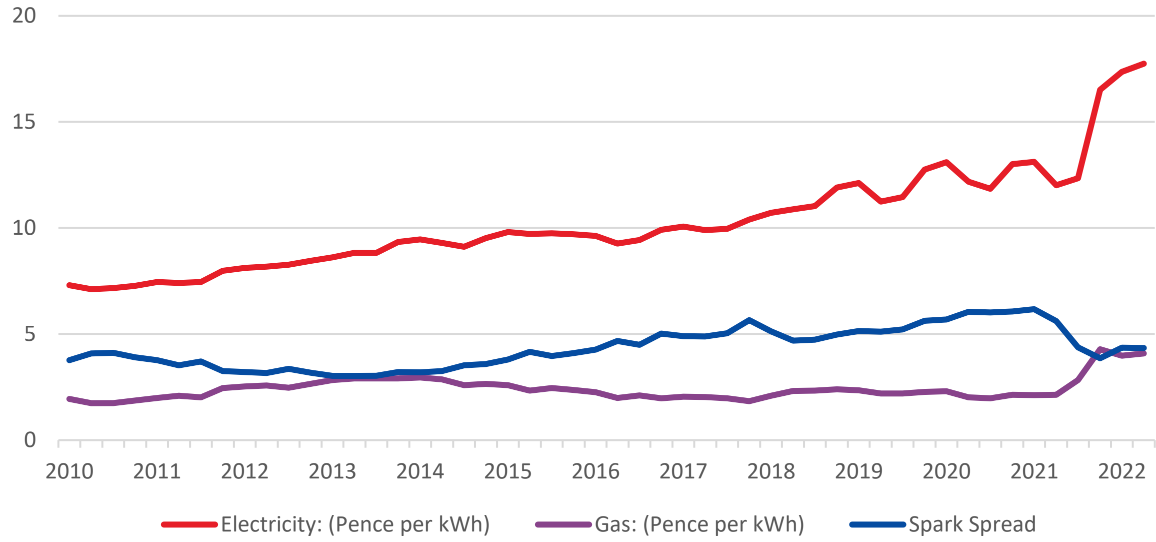
Outside of gas and carbon, prolonged issues for nuclear generation in France and the unavailability of several nuclear reactors have been pushing power prices higher in the GB

[10] In this section any price changes mentioned refer to day-ahead weekly average prices for both gas and electricity.

market. A record of 26 out of 56 reactors have been offline due to the discovery of cracks and corrosion in pipes used to cool reactor cores. This has a significant impact as France was the largest exporter of power in Europe. Due to the outages France has been mostly importing power from neighbouring countries, increasing supply constraints. There are also concerns that issues might continue over the coming winter months. As the UK is interconnected with France, UK power prices have also been affected.

Figure 10 shows electricity and gas prices and spark spreads between 2010 and 2022.

Figure 10: UK Gas and Electricity Prices, and Spark Spread

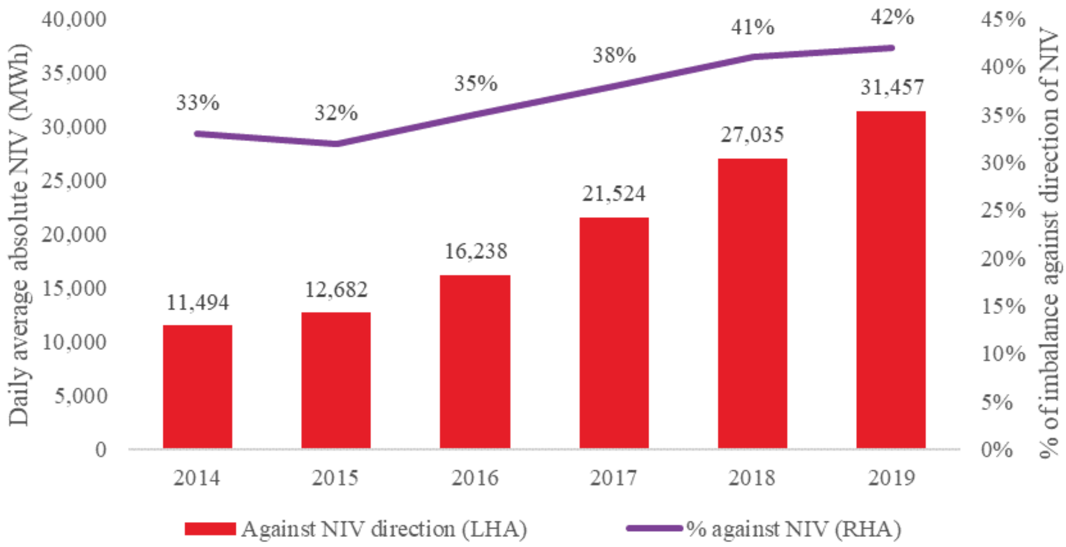


NIV Chasing

The Net Imbalance Volume (NIV) is the sum of the volume of all bids, offers and other balancing service actions in each settlement period, and indicates whether the system is long (negative NIV) or short (positive NIV). Ofgem's 'Electricity Balancing SCR' concluded that generally, market participants would not be able to sufficiently forecast the NIV and the Imbalance Prices flowing from it. It has, however, been noted by Elexon that participants able to 'anticipate the system length and adjust their positions accordingly would have a powerful commercial advantage in respect of trading strategy'.

If a market participant is able to anticipate the direction of the market, it could take part in 'NIV chasing' as a preferred strategy. Being in imbalance to the opposite direction of the system means that a party would gain financially versus having traded its position in the wholesale market. In such a scenario, a party may deliberately incur an Energy Imbalance Volume in order to pay, or receive, the imbalance price instead of the market price. If it knew the direction of the market length, the party may be able to benefit though being out of balance and being exposed to the imbalance price. From an ESO perspective, it is not helpful that NIV creates a strong flex incentive that operates parallel to the BM, when the BM is trying to balance many other products as well as energy.

Figure 11: Imbalance Volume for all parties against NIV direction[11]



Elexon have found that between 2014 and 2019 the absolute volume of daily imbalance in the opposite direction to the NIV has increased by over 170%, increasing from 11.5MWh in 2014 to over 30MWh in 2019 (Figure 11). Over that period, the proportion of imbalance against the direction of NIV has increased from 33% to 42%.

Elexon found non-physical traders and interconnector users have had the highest percentage of imbalance volumes in the opposite direction of the NIV, suggesting NIV chasing could be a trading strategy that has been increasingly adopted by some parties. Cornwall Energy have argued that non-licenced generators like non-physical traders and interconnector parties have a significant advantage with respect to NIV chasing as a strategy, as they are not required to fix their output with contract notifications until 15-minutes before real time. At gate closure, non-licenced generators can wait and see which actions NG instructs under the BM and run the opposite way to the NIV if they forecast that the imbalance price is higher than their marginal cost.

Exploring Central Dispatch

Introduction

In this section, the dispatch element of electricity market design is explored with a focus on exploring central dispatch models. The purpose of this section is to:

- Recommend a centralised market design (considering the scope of the study).
- Provide a stylised example and simulation of the proposed market design.
- Understand its potential to alleviate the issues created by the current market design.

[11] LHA - Left Hand Axis, RHA - Right Hand Axis

- Flag its drawbacks and provide a qualitative view of their magnitude.
- Assess its implementation complexity and the impact the various market actors.
- Provide the views of industry experts on such a reform.

The purpose of exploring a central dispatch model is principally to assess whether this model could cost effectively address some of the current challenges faced such as growing constraint costs and increasing balancing requirements in GB. A central dispatch model could also offer additional potential benefits through co-optimisation of energy and ancillary services (A/S) and attempt to limit market power with ex-ante pricing rules. These benefits are, however, very dependent on the design of a central dispatch model.

This section begins with an introduction to the various dispatch models implemented globally. More detailed case studies relating to three markets where central dispatch has been implemented are then summarised.

A potential central dispatch model for GB is then presented, followed by a simulation of this model. Next, implementation of central dispatch in GB and the impact on market actors are considered, respectively. The following section summarises viewpoints from market participants interviewed by Arup in relation to central dispatch.

Finally, an assessment of central dispatch and recommendations, followed by conclusions is presented.

Key takeaways

The study analyses a centralised dispatch with self-commitment market design. In Arup's view such an approach fits better with the "incremental reform" approach.

Arup's stylised example and analysis indicates that there are potential savings to be achieved through co-optimisation of A/S that could limit opportunity cost for generators.

There are no international examples of transitioning from 'self' to 'centralised' dispatch. Based on analysis of transitions considered of similar scale Arup's view is that GB would need at least 5 years to implement such a reform.

NGESO will need to bear most of the effort/cost with IT and documentation costs being the highest for most market actors.

Centralised dispatch is too different from the current design to be considered an incremental reform. It is unclear whether the costs of implementation would outweigh the benefits.

Overview of dispatch models

A key element of electricity market design is the way generation assets are dispatched. Dispatch refers to the process of determining which generation assets will supply power to the transmission system, at what capacity and for how long. Across the globe there are two prevailing design approaches, namely the:

- Centralised or central dispatch model.
- Decentralised or self-dispatch model.

It should also be noted that the dichotomy between self-dispatch and central dispatch is slightly false. In reality, most central dispatch models allow elements of self-dispatch through allowing some level of self-commitment by generation assets. Equally, in a self-dispatch market, the ESO will dispatch through a BM and ultimately have control of what generation assets are instructed to generate.

In the following sections, an overview of the dispatch models is provided.

Table 2 identifies markets where both models are implemented.

Table 2: Examples of central and self-dispatch electricity markets[12]

Market	Dispatch	Pricing	Main generation sources
ERCOT	Central dispatch with self-commitment	Nodal	Natural gas, wind, coal
PJM	Central dispatch with self-commitment	Nodal	Natural gas, nuclear, coal
MISO	Central dispatch with self-commitment	Nodal	Natural gas, coal, wind, nuclear
CAISO	Central dispatch with self-commitment	Nodal	Natural gas, wind, hydro
Ontario	Central dispatch with self-commitment (planned)	Nodal (planned)	Nuclear, hydro
New Zealand	Central dispatch with self-commitment	Nodal	Hydro, geothermal
Singapore	Central dispatch with self-commitment	Nodal	Natural gas
Italy	Central dispatch with centralised-commitment	Zonal	Natural gas, hydro

[12] Ahlqvist et.al, 2019; Arup Analysis, 2022

Australia	Central dispatch with centralised-commitment	Zonal	Coal, natural gas
Greece	Central dispatch with centralised-commitment	National	Natural gas, wind, coal
Poland	Central dispatch with centralised-commitment	National	Coal
GB	Self-dispatch	National	Natural gas, wind
SEM	Self-dispatch	National	Natural gas, wind
France	Self-dispatch	National	Nuclear, hydro
Germany	Self-dispatch	National	Coal, natural gas, wind
Denmark	Self-dispatch	Zonal	Wind, biofuels
Norway	Self-dispatch	Zonal	Hydro
Sweden	Self-dispatch	Zonal	Hydro, nuclear

Central Dispatch

In a market design with central dispatch, the responsibility for scheduling, commitment and dispatch of generation units lies with the SO (e.g., the ESO in GB). This process takes place ahead of real time, usually at the DA stage. This is the point at which the system price is determined. The main alternative design is a self-dispatch (or decentralised market) design where generation units make independent dispatch decisions and the SO acts as the residual balancer.

In a central dispatch model, the intention is to use the SO to manage resources, deciding how much should be produced by each generation unit to attempt to provide the least cost generation solution. In theory, because the SO is dispatching, it can avoid costly redispatch caused by constraints. There will, however, still be a cost associated with the SO doing this because it still has to renumerate those generation assets behind a constraint. This is because in a uniform price system, constraints are deliberately assumed away in the clearing price.

In a central dispatch system (specifically, the central dispatch models used in the US), generation units and flexible loads signal to the SO the prices at which they are willing to supply to the system and reduce consumption respectively. The SO (who may also be the MO) requires that producers report detailed economic and dynamic parameter information at the DA bidding stage. This is also the case for self-dispatch systems, but the parameters are not taken into account as part of the bidding process. The SO then uses this information to run a ‘least cost’ optimisation algorithm that matches supply to demand, subject to production and network constraints (thus reducing constraint costs). Through this process the SO will also determine the system price which will be set at a level that ensures fair remuneration for all dispatched units at the lowest cost for consumers.

A key element of a market with central dispatch is its ability to co-optimise energy with A/S. Whilst the BM does implicitly procure energy and A/S, the products are not formally ‘stacked’ in markets with self-dispatch, where energy and A/S are procured separately. This can then lead to imperfect optimisation of resources. Markets with central dispatch typically co-optimise A/S with energy as observed in the US (NYISO, PJM, CAISO, ERCOT, MISO), Alberta, Singapore, Australia and New Zealand. There is a body of evidence to show that co-optimisation can be successful in reducing energy and A/S costs, as well as supplying consistent price signals to providers of both energy and A/S (Grant Read, 2010) [13] . Typically, it is reserve and frequency regulation that is co-optimised with energy, although in certain markets other A/S are also co-optimised.

In England and Wales, the government decided to move away from the central dispatch arrangements in the Pool to a self-dispatch market with bilateral trading between suppliers and generators. There were concerns that a lack of competition and the prevalence of market power was inflating power prices in the Pool, overcompensating some generators while paying others too little. There were further concerns that the Pool lacked transparency and did not enable market liquidity and hedging. Under the Pool there was limited liquidity and forward trading, which made it difficult for market participants to manage their risks and for new entrants to enter the market. This lack of liquidity was partly due to the design of the Pool, which relied on physical trading of electricity in large blocks through a single pool. This made it difficult for traders to make smaller, more frequent trades, which are necessary for effective risk management.

In many of the centrally dispatched US markets, SOs have pricing rules in place to guard against market power concerns, with the markets (CAISO, ERCOT, PJM, ISO New England) all having caps on the price generators can charge, typically based on the Value of Lost Load (VoLL). These caps range from $1,000/MWh to $5,000/MWh, with some markets having “soft” and “hard” caps.

Centralised markets often operate as part of a nodal pricing design which involves determining multiple prices for different locations on the transmission grid. In addition, many of these markets also have rules on how far ahead suppliers have to hedge, which in turn supports liquidity further along the price curve (e.g., more than 1 year ahead of time). For example, ISO-NE mandates that all suppliers hedge 80% of their demand 3 years ahead of time. The US markets that are centrally dispatched have better liquidity compared to GB with an ability to buy and sell power several years ahead.

For flexibility (DSR and energy storage), central dispatch has historically been perceived, perhaps incorrectly, as less favourable in terms of ability to participate. The introduction of IDMs in central dispatch markets with self-commitment (e.g., PJM) and technology-specific

[13] Read (2010), Co-Optimization of Energy and Ancillary Service Markets (in Handbook of Power Systems I, ed. Pardalos, Rebennack, Pereira & Iliadis).

bidding parameters has positively impacted the ability of flexibility to participate under central dispatch arrangements.

Central dispatch has the potential to encourage flexibility options such as batteries because automation allows many smaller units to be dispatched simultaneously. This can reduce the need to rely on larger units and can lead to a greater utilisation of smaller flexibility units. Central dispatch can also minimise market entry barriers for new players with a simpler route-to-market on offer, as well as providing a visible spot price to guide decisions by flexibility providers.

Self-Dispatch

In a self-dispatch system, which is currently the way the GB market is designed, generation assets and demand (i.e., suppliers) independently form bilateral contracts for the buying and selling of electricity. The market price in a self-dispatch market is formed in the open market. In this type of market, the SO plays the role of the residual balancer and takes control close to real time. In the GB market this is 60-minutes ahead of real time.

Generation (and flexibility) units make their own dispatch decisions. They can update their dispatch notification up to the point of gate closure (1-hour ahead of real time in GB). Electricity is traded through bilateral contracts between suppliers and generators or via exchanges[14]. Generators and suppliers prepare operating plans of their anticipated behaviour together with respective contractual positions which is then submitted to the SO. Prices are formed by the interaction between buyers and sellers on the open market (OTC or via exchanges). A buyer or a seller will post a bid or offer to buy or sell electricity for a given trading block. This should be based on what they consider the value of power to be at that point time. Generation assets can then choose whether they generate to honour contracts or buy/sell the energy from the market.

Post gate-closure the SO takes control of the market to balance the system. In self-dispatch markets, generation and demand are compensated or penalised for deviations from their nominated portfolio position. This differs from central dispatch markets, where participants are compensated for SO deviations from scheduled unit positions. The SO balances the system mainly through a BM, with additional support from A/S.

Self-dispatch systems are predicated on the belief that competition between generators drives efficient outcomes and allows market participants to have the freedom to optimise their assets. This is partly why self-dispatch markets tend to favour uniform price designs, because this allows, barring transmission constraints, a greater pooling of competition.

The role of the SO is intended to be small, acting as a residual balancer and managing the power system in real-time with limited rights on DA scheduling of the transmission network. Such provisions are normally implemented to avoid an operator's monopoly influence on the

[14] Ahlqvist, Holmberg and Tangerås (2019): Central- versus Self-Dispatch in Electricity Markets.

electricity markets in the long run. Self-dispatch places the emphasis on competitive market pressure to create positive market outcomes and avoid generators earning too much profit.[15]

Self-dispatch markets depend on healthy levels of liquidity to provide efficient outcomes. Low levels of liquidity can make it difficult for buyers and sellers to have a stable reference price on which to base decisions. This can increase risk for the market and imply increased costs.

In addition, energy systems with significant transmission capacity, self-dispatch should not lead to significant issues with transmission constraints. Conversely, in systems with significant constraints, self-dispatch can lead to increased constraints as generators have no incentive to consider constraints when making their dispatch decisions. In some cases, e.g., when a portfolio generator has market power on both sides of constraint, there is actually a financial incentive for a generator to exacerbate a constraint. In GB this has led to the ESO taking more and more actions in the BM to undo the market outcome and create one which reflects the actual physical needs of the system.

Unlike with central dispatch, self-dispatch does not enable co-optimisation of energy and A/S, which in turn, can lead to increasing balancing and constraint costs. These costs are factored into a generator's bidding decision as an opportunity cost.

Case studies of central dispatch

In the following section of this report, three case studies of electricity markets with central dispatch arrangements are explored. PJM (US), I-SEM (Ireland) and NEM (Australia) markets have been selected to cover a range of central dispatch model designs. Table 3 summarises the key features of each market in relation to dispatch.

Table 3: PJM, I-SEM and NEM dispatch arrangements

Market	Pricing	Self-commitment	Co-optimisation	Physical markets	Financial Markets
PJM	Nodal	Yes	Yes (reserve and regulation)	DA, real time	Forwards/futures, FTRs
I-SEM	National	No	No	DA, intraday, real time	Forwards/futures, FTRs
NEM	Zonal	Yes	Yes (reserve and regulation)	Real time	Forwards/futures

[15] Ahlqvist, Holmberg and Tangerås (2019): Central- versus Self-Dispatch in Electricity Markets.

PJM

Introduction

The Pennsylvania-New Jersey-Maryland (PJM) market in the USA covers 13 states[16] and the district of Columbia with trading zones.

Dispatch market design

Nodal (or Locational Marginal Pricing (LMP)) pricing with central dispatch arrangements have been in place since 1998. This model was implemented following an unsuccessful 1-year trial with a zonal pricing with central dispatch market design in 1997 (see box below for further detail).

> **Zonal pricing with central dispatch**
>
> In 1997, PJM implemented central dispatch arrangements with a single zone pricing system due to opposition to LMP. All transactions in the spot market were priced at the unconstrained price. Where transmission constraints arose, more expensive generators were called upon by the SO and the resulting congestion costs averaged across all market participants. Other design features included no compensation for generators who were constrained off (regardless of whether their bids were below the unconstrained price) and the ability of market participants to elect themselves to be centrally scheduled by the ISO or self-schedule through bilateral transactions. PJM moved fairly quickly from a centralised dispatch model with a uniform price to a nodal market. This was because even with a zonal price and centralised dispatch, there were still significant constraint costs.

Spot markets

The PJM market has been a two-settlement market since 2000, with DA and real-time (or balancing) markets. Both markets follow a two-step process, where security-constrained economic dispatch of the system is performed first, followed by the calculation of LMPs (hourly at DA and for 5-minute intervals in real-time). The objective of both is to meet load and reserve requirements, whilst minimising total production cost and accounting for transmission constraints.

Clearing prices are determined from demand and generation bids and offers, bilateral transactions schedules and system conditions (e.g., transmission constraints). Generation assets submit price and volume information, incremental offers and plant technical data (e.g. ramp rates, no-load costs, etc.).

[16] Delaware, Illinois, Indiana, Kentucky, Maryland, Michigan, New Jersey, North Carolina, Ohio, Pennsylvania, Tennessee, Virginia and West Virginia.

Physical trades in these ex-ante markets are firm, and a participant is financially exposed in real-time if it cannot adhere to its commitments (e.g., has to buy back what it has sold or sell what it has purchased in the real-time market at the imbalance settlement price).

In 2017, PJM introduced ID offers to introduce more flexibility. Participants can submit bids/offers that vary hour-by-hour from 18:30 D-1 up to 65 minutes before the operating hour, enabling a more accurate reflection of their costs throughout the operating day.

Generation assets can elect to participate in the centrally co-ordinated DAM (where PJM schedules their generation) or alternatively self-schedule their generation. For the latter, generation assets submit an hourly generation schedule. Generation assets that are scheduled in the DAM are financially bound to sell their output in real time.

A/S

In terms of A/S, PJM operates markets for regulation and reserve, which are co-optimised during the scheduling and dispatch process via the A/S Optimizer.

Other markets

In addition to these physical markets, there are also financial markets, which include Financial Transmission Rights (FTRs). FTRs are financial contracts that enable market participants to hedge the price risk exposure associated with transmission congestion charges between locations.

PJM also has a separate CM (Reliability Pricing Model) to drive investment in generation and a price cap based on the VoLL ($1,000/MWh) to counteract participants exhibiting market power.

SO/MO

PJM Interconnection LLC, or PJM, is the Regional Transmission Organization (RTO). The RTO is responsible for transmission of electricity and operating a competitive wholesale electricity market. PJM holds the role of both SO and MO.

Liquidity

PJM has high liquidity levels and is the most liquid futures market in the US with the lowest reported bid-ask spreads[17]. In 2019, the churn rate in PJM was 2.88x and bid-offer spreads averaged at $0.46/MWh[18]. This liquidity is supported by the auction of FTRs, which facilitate hedging and competition, aiding liquidity.

[17] See https://www.nationalgrideso.com/document/232686/download
[18] See https://www.pjm.com/-/media/committees-groups/task-forces/afmtf/2020/20201222/20201222-item-03-independent-consultant-report-presentation.ashx

Integrated Single Electricity Market (Ireland)

Introduction

The Integrated Single Electricity Market (I-SEM) has been in operation since October 2018. It replaced the previous Single Electricity Market (SEM), which had been in operation since 2007. I-SEM brings together the two regions of Ireland into a single electricity market.

Dispatch market design

I-SEM market design comprises central dispatch (with no self-commitment) alongside national (i.e., uniform) pricing.

Spot markets

I-SEM comprises DA and ID (spot) markets. The latter enables participants to adjust their physical positions, where required, for example to take into forecast changes or outages. Both markets are physical, ex-ante markets. There is also a balancing (energy and non-energy) market. Figure

Figure 12 outlines the timeframes associated with each market.

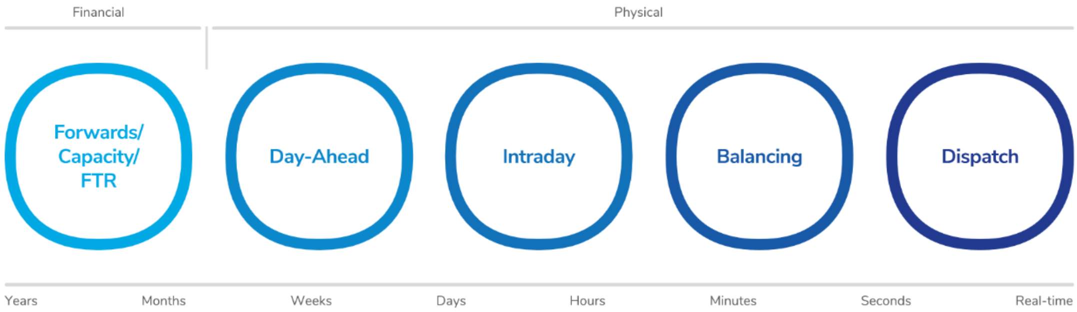
Generation units submit availability information, commercial (simple and complex), technical offer data (representing the operating characteristics of the unit) and A/S potential. The MO uses this data and information, alongside other inputs (e.g., demand bids, renewable forecasts, and system constraints) to clear the market through a centrally cleared DA auction.

The DA market opens at 11:00 19 days in advance of the trading day and closes at 11:00 the day prior (D-1). The market is then cleared, and market schedules published at 13:00 D-1. The IDM opens at 11:45 on D-1 with gate closure 1-hour prior to the trading period. Through the BM, the imbalance settlement price is determined, reflecting the TSOs balancing actions required.

Participation in the DAM is not mandatory but is the only way to hold a physical position in the I-SEM. Generation units cannot self-schedule their output.

As required by EU legislation, priority dispatch is provided to certain classes of generators (which include renewable generators >400kW and commissioned before July 2019). Output from these assets is maximised as far a technically possible.

Figure 12: SEM Market Time Frames



A/S

Reserve, frequency response, reactive power and black start are the main A/S procured in I-SEM. These services are not co-optimised with energy and instead procured under regulated arrangements by the TSOs separately, but work is underway to progress to competitive tenders for these services.

Other markets

I-SEM has a CM (Capacity Renumeration Mechanism), in addition to two markets for energy-related financial instruments (forwards/futures market and FTR auctions). The latter enables market participants to hedge their position in the spot markets.

SO/MO

In I-SEM different entities hold the SO and MO roles. EirGrid (Republic of Ireland) and SONI (Northern Ireland) are the SOs in their respective regions. The MO is the Single Electricity Market Operator (SEMO), which is jointly owned by EirGrid and SONI.

Liquidity

The SEM Committee was exploring options to improve liquidity in the market as discussed in the 2017 Decision Paper "Measures to Promote Liquidity in the I-SEM Forwards Market". Since then, an OTC platform has been established and a designated Market Maker began operating on Trayport. Both have contributed to improved liquidity.

Australian National Electricity Market

Introduction

The electricity market in Australia is divided into multiple markets. Here the focus is on the National Electricity Market (NEM), which covers 5 regional market jurisdictions across eastern and south-eastern Australia[19]. The NEM began operations as a wholesale spot market in 1998.

Dispatch Market Design

The NEM operates as a zonal market with central dispatch arrangements.

Spot markets

In the NEM, a real time market operates, where the MO matches supply and demand and determines dispatch prices for each 5-minute trading interval based on the price of the marginal unit. The MO uses the 'least cost' combination of generation assets to serve demand, with the objective of minimising total production cost, whilst accounting for system constraints and forecast output from renewables (i.e. Security Constrained Economic Dispatch).

Generation assets must submit offers by 12:30pm D-1 but can rebid multiple times thereafter through the trading day to respond to, for example, new forecast information or plant outage. These assets must provide a valid reason to accompany the bid.

Renewable generators participate in the central dispatch process in a limited way and are known as "Semi-scheduled Units". Self-commitment is allowed in the NEM. Both a market price cap and market price floor apply under the National Electricity Rules. These are currently AUD15,100/MWh and AUD1,000/MWh.

Generation assets submit details on the price and quantity of power they can generate in each period, ancillary service potential, and plant technical capabilities. For renewable "semi-scheduled" generation, the Australian Energy Market Operator (AEMO) uses forecasts of solar and wind generation and technical parameters submitted by assets to inform expected generation.

The AEMO has recently reviewed its market design because of growing concerns with constraints costs in its zonal system. A study undertaken by NERA consulting suggests significant benefits for consumers associated with a move to nodal market design. There is, however, significant resistance from generators which has impeded its implementation despite the significant anticipated benefits for Australian power consumers.

[19] New South Wales (including Australian Capital Territory), Queensland, South Australia, Tasmania and Western Australia.

A/S

The AEMO operates a number of A/S markets, which include regulation, reserve, voltage support and system restart. Regulation and reserve (known as the Frequency Control A/S) are co-optimised with energy during the scheduling and dispatch process.

Other markets

NEM participants can enter into futures/forward contracts to manage spot price risk via the Australian Securities Exchange (ASX) or OTC. A capacity mechanism is under consideration.

Participants

The AEMO is responsible for managing the wholesale electricity and gas markets, including the operation of the NEM and the Wholesale Gas Market (WGM). Their role is to act as the MO, matching supply and demand and determining prices that retail suppliers pay; acting as the clearing entity for wholesale market transactions in the process. They also act as the SO; scheduling and dispatching generation; managing and maintaining system reliability and security.

Pros and cons of central dispatch

Table 4 sets out the pros and cons of central dispatch, when compared with self-dispatch, based on previous GB experience, the case studies above and other learnings from other markets where central dispatch models have been implemented. Please note that the table compares a purely centralised market (with no self-commitment and hence very limited flexibility) to a self-dispatch model.

Table 4: Pros and cons of central dispatch versus self-dispatch

Pros and Cons of Central Dispatch	
Pros	**Cons**
• Enables more efficient dispatch versus purely self-dispatched system through better coordination of resources. • Allows for co-optimisation of A/S which can lead to more efficient system management. Co-optimisation is of increasing importance for securing liquidity within operational timescales with greater levels of intermittent generation (and their associated uncertainty). • Removes a significant part of the opportunity cost baked into bidding	• Requires significant reform which will have a significant impact/ cost across the industry. If treated as an incremental reform its complexity and deliverability challenge could hinder other reforms. • Lacks flexibility as market participants are committed well ahead of dispatch and have less freedom to make position adjustments (in designs where IDMs do not exist). • There is a risk of market power exploitation from market participants. This risk, however, also exists in a

prices of generation assets (as constraints are managed ahead of gate closure/ real time) which can lead to increased costs to consumers. • Could facilitate more efficient cross-border trading through better management and consideration of intra-zonal constraints. • Could enhance market transparency compared to the status quo. This is because prices are in one place run by the market operator and published for all to see. Currently, prices are formed on various different forums, OTC and the exchanges EEX N2EX and ICE. In some recent cases, N2EX and EEX have markedly different prices, for the same period of delivery. In addition, a central dispatch model should have a clear set of pricing rules known to all market participants. This can help build trust from suppliers in the cost of the energy they buy. • Reduces the familiarisation cost of new market entrants. • Could pool liquidity opposed to relying on generation assets to self-balance. This is of increasing importance as the share of intermittent generation rises, where swings in output from renewable generation units could be significant.	self-dispatch market (see opportunity cost point on the left). • If unsupported by other measures, central dispatch can adversely affect liquidity as the market is purely a physical day head market with no longer-term products offered by the market operator. This has been overcome in some markets with the use of mandatory hedging and financial instruments (e.g., FTRs in nodal markets). Hedging and clearing is simpler in self-dispatched markets. • Does not facilitate participation of demand side as easily.

A GB model of central dispatch

Key market design parameters

There are a number of different design options to consider for a central dispatch model.

Table 5 provides an overview of the key design parameters for central dispatch.

Table 5: Central Dispatch Design Parameters

Design Parameter	Description
System Operator and Market Operator	The key design choice relates to whether the MO is a separate entity to the SO, or whether both roles are held by the same entity. In terms of responsibilities, typically, the MO will operate the dispatch optimisation tool to determine a dispatch schedule, whilst the SO supplies operational inputs (e.g., network capacity) and issues dispatch instructions.
Bidding formats	The cost data and information that need to be submitted to the SO/MO to inform scheduling can vary between markets and technology. Whether a generation asset is centrally scheduled or has instead elected to self-schedule, can also dictate the data and information needing to be submitted to the SO/MO. The key design choices are (a) what bid-format needs be submitted to the SO/MO; (b) should bid-formats be technology-specific; (c) should those generation units electing to self-schedule submit the same data and information as those units that are centrally scheduled; and (d) design of any subsequent uplift payments to compensate generation assets for the additional costs incurred when increasing their output at the request of the SO/MO.
IDM	Central dispatch models may or may not have an IDM operating alongside the central scheduling process. Generation assets and demand can trade in the IDM to adjust their existing (self-scheduled) position or self-commit additional generation assets. Furthermore, the SO/MO may also run an ID unit commitment process to schedule additional generation assets or further generation from generation assets committed at the DA stage. The key design choices pertain to (a) whether an IDM is present; and (b) whether an additional, ID unit commitment process is run by the SO/MO.
Unit Commitment	There are two main dispatch mechanisms under central dispatch models: (1) centralised commitment; and (2) self-commitment. The main difference is the ability for units to self-schedule their output outside of the central scheduling process. Under (1) all units are centrally scheduled, however, under (2) self-scheduling is possible. The key design choices relate to (a) centralised versus self-commitment; and (b) if self-scheduling is permitted, to what extent is it allowed (e.g., are there any limits imposed, for example, on capacity/volume or technology types).

Co-optimisation with A/S	Under a central dispatch model, both energy and A/S can be scheduled within the same process (i.e., co-optimised). This contrasts to self-dispatch, where energy and A/S are procured and dispatched separately. Black start, frequency response, inertia, reserve, intertrips and Super Stable Export Limit (SEL) could all potentially be co-optimised with energy. The key design choices are in relation to (a) whether co-optimisation is undertaken; (b) if undertaken, which A/S should be co-optimised, and (c) what is possible from a co-optimisation perspective taking into account technological capability to co-optimise multiple, complex services.
Market Clearing	In central dispatch models, the market might clear once or multiple times. The point at which the market clears can also vary (e.g. DA, ID or across both horizons). In terms of clearing price, it is typically pay-as-clear opposed to pay-as-bid, whilst an unconstrained (i.e., price based on schedule not factoring in network constraints) and constrained (i.e. price based on schedule factoring in network constraints) clearing price may be published. The key design choices pertain to: (a) when and how often the market clears; (b) price formation; and (c) whether unconstrained and constrained clearing prices are published (and which price participants will receive).

Introduction to how a GB model of central dispatch could operate

Introduction

In the following, Arup sets out a central dispatch model that could be explored by DESNZ. It must be stressed that this model, along with other options for dispatch, would need to be explored in much greater detail by both DESNZ and the ESO before a decision is taken on a preferred approach, especially given change to the dispatch process is more of a significant change than an incremental change.

The design choices have been made to make the model as incremental as possible, whilst also addressing the main issues with the current model, such as constraint costs. Based on the challenges faced by the GB electricity market and the aims and objectives of REMA (decarbonisation, security of supply, affordable electricity costs for consumers), Arup considered a central dispatch with self-commitment model. It is thought there are several advantages of this model over a purely centralised commitment model, including the following:

- REMA discusses moving from a self-dispatch to a central dispatch model in the context of “evolving the status quo”. Going from the current self-dispatch arrangements to a central dispatch model with centralised commitment could be viewed as much more than an incremental market reform. Central dispatch with self-commitment would retain some of the current arrangements, whilst seeking to adjust certain dispatch design elements to better address some of the challenges faced.

- Further to the above point, a central dispatch model with self-commitment would provide market participants with optionality on how they access the wholesale market as they are able to make the decision themselves as to whether they go through the centralised commitment process or self-commit. Central dispatch with centralised commitment would not afford market participants that opportunity. Allowing for this optionality may be more amenable to market participants as they retain a level of independency in how they operate. This would enable units with long start up times or high start-up costs to self-schedule during periods they may not have been called upon through the central commitment process. It should, however, be noted that this optionality could potentially split liquidity between markets, and this should be explored further.
- Bilateral forward and spot markets for participants to trade the delivery physical contracts would still exist alongside the centralised commitment process. This would not be the case for central dispatch models with centralised commitment. The spot price will be more visible than for centralised commitment and therefore facilitate greater forward hedging/trading (OTC and on exchanges) and support the participation of price responsive demand. The presence of spot markets also allows for market participants to adjust their position between the DA and real-time, reducing the number of balancing actions required in the BM. This would help address the concerns associated with central dispatch on the inability to address the impact of large forecast errors (e.g., change in wind forecast) and unplanned outages between DA and real time.
- If nodal pricing is to be implemented in GB, central dispatch with self-commitment also lends itself to nodal pricing. All existing markets operating with nodal pricing have elected to combine it with central dispatch with self-commitment because of the need for a central clearing algorithm to determine nodal prices.

The model is not without its own drawbacks/challenges, for example:

- Whilst it’s an advantage for units with long start-up times and high start-up costs, the optionality may impact investment signals. This would occur if self-scheduled generation assets, which effectively bid in at zero cost, frequently displace generation assets that would have been committed by the SO/MO in the absence of the ability to self-schedule.
- As mentioned above, the ability to self-commit alongside the central commitment process could act to split liquidity between the two options leading to reduced price transparency and reduced competition, as well as hindering market entry.
- Risk of manipulation/gaming through market participants overstating costs when submitting cost data into the central commitment process to reflect, for example, opportunity costs of holding back capacity for the BM. The key difference is that a central dispatch approach enables ex-ante rules on price setting to be developed, which can be complemented by ex-post monitoring. Self-dispatch markets, however, only allow for ex-post investigation into market power abuse or market manipulation.

Investigations can be lengthy and complex and relying on an ex-post only approach is, arguably, less likely to effectively manage market power concerns.

It should be noted that the proposed design does not include any location pricing (like central dispatch designs in the US). The design allows market participants to self-schedule which is similar to most US market designs and differs from the I-SEM which is a purely central dispatch design.

Central dispatch model design

In the following sub-sections, the key design parameters of the model are outlined and the three main stages of the dispatch process are discussed:

- Operational Schedule: Creation of a scheduling plan by the SO/MO to match generation to demand.
- Unit Commitment: Refinement of the Operational Schedule and issuing of instructions to units and to generation assets with long start-up times.
- Operational dispatch (BM): Real time dispatch instructions to market participants to balance supply and demand.

If a decision is taken to implement a central dispatch model, significant further work would be required (mostly by the SO) to design and implement it. Exact timings for the GB market would need to be explored to further understand which timings would enable the best possible scheduling decisions.

Operational schedule

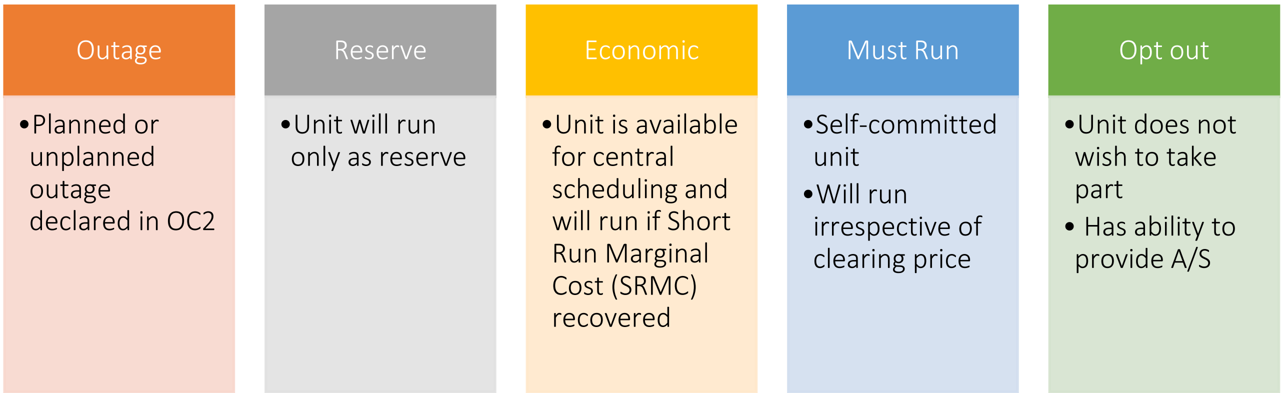
At the DA stage, the SO/MO develops the Operational Schedule. Generation and flexibility assets can elect to participate in the central commitment process operated by the SO/MO (see box below) or voluntarily choose to self-schedule their output through pre-agreed bilateral trades. This provides assets with optionality in how they access the wholesale market.

It has been assumed the SO and MO roles and responsibilities are held by the same entity (i.e., ESO), performing the scheduling, unit commitment and dispatch actions. This will likely mean larger capital requirements, greater financial reporting requirements and the need for additional and/or upgrades to systems. Given the ESO’s experience in running the BM, and use of Elexon as the clearing entity for the BM, it should be well placed to undertake to perform the MO role.

For those participating in the central commitment process, participants (generation assets and flexible demand) submit to the SO/MO:

- Unit commitment status of “Economic”.
- Bid/offer data (plus incremental bid/offer data).
- Technology-specific dynamic parameters.
- Details of A/S potential for use by the SO/MO in the BM.

Figure 14: Unit commitment status



Requiring the submission of detailed cost data and information provides the SO/MO with complete visibility of unit capabilities to inform the scheduling process [20]. The table below shows the economic and dynamic parameters that generation assets would need to submit. Dynamic parameters refer to technical capabilities of generation units. For example, this can be in terms of how quickly if can increase or decrease generation, what is maximum load, what is the minimum load required for the plant to generate safely, how quickly a plant can shut down and start up again and several others. Under the existing rules, dynamic parameters are intended to represent only the technical capabilities of the plant, as, usually, set out in the equipment operational and maintenance manuals. They are not intended to have any economic (i.e., cost) element to them. In contrast the economic parameters are how much generation assets are willing to be paid to deliver a particular capability, namely start up and generation costs.

Table 6: Economic dynamic parameters

	Units	*CCGT OCGT Biomass CCUS H2*	*Pumped hydro LDES*	*Nuclear*	*Short/mid duration*	*Wind/Solar*	*Interconnector*
Economic Energy Offer	**MW, £/MWh**	✓	✓	✓	✓	✓	✓
Self-Scheduled Energy	**MW**	✓			✓		
No Load Cost	**£/h**	✓	✓	✓			

[20] It should be noted at this point that in the current system the ESO sees benefits from the management of intertemporal constraints. As the system becomes more volatile the ESO is turning up and down dispatchable plant much more frequently than they used to. It makes increasing sense to use asset technical capabilities in market clearing to optimise over multiple settlement periods.

DC-DM-DR High Offer	**MW, £/MWh**				✓		
DC-DM-DR Low Offer	**MW, £/MW/h**				✓		
Cold Start Up Cost	**£**	✓					
Warm Start Up Cost	**£**	✓		✓			
Hot Start Up Cost	**£**	✓					
Economic Reserve Offer	**MW, £/MWh**	✓	✓				✓
Self-Scheduled Reserve Offer	**MW**	✓					
Black Start Offer	**MW, £/MWh**	✓	✓	✓	✓	✓	✓

Table 7: Dispatch dynamic parameters

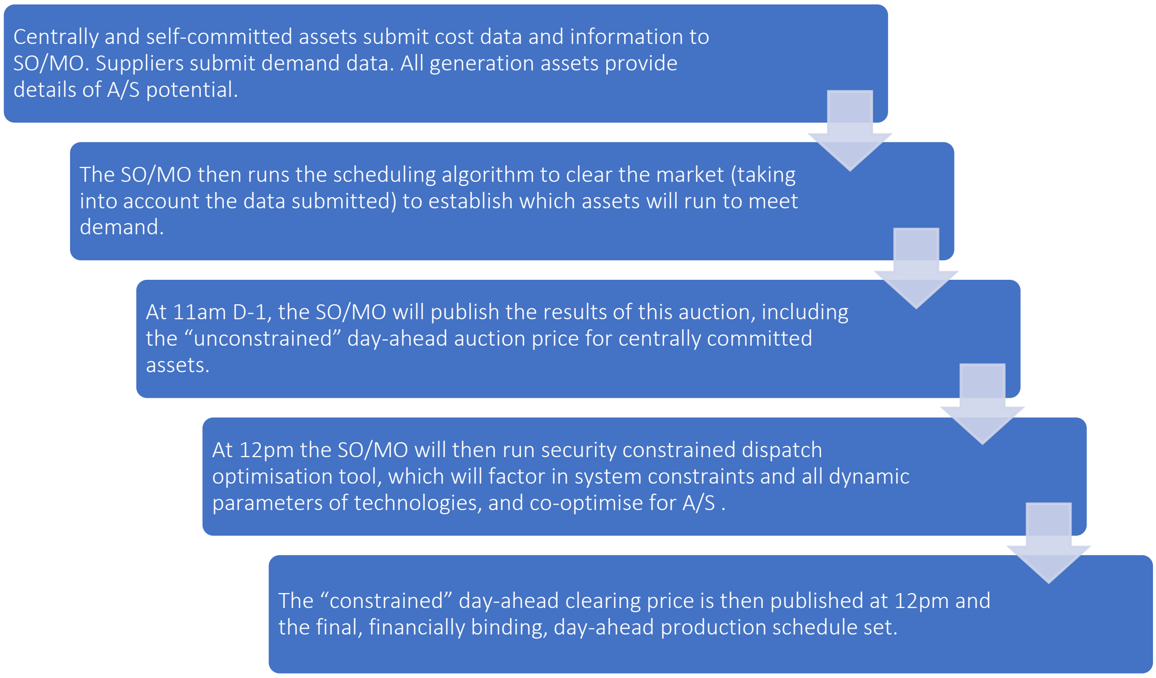
	Units	*CCGT OCGT Biomass CCUS H2*	*Pumped hydro LDES*	*Nuclear*	*Short/mid duration*	*Wind/Solar*	*Interconnector*
MEL	**MW**	✓	✓	✓	✓	✓	✓
SEL	**MW**	✓	✓	✓		✓	✓
Super SEL	**MW**	✓	✓	✓			✓
Hot Start UP Time	**hrs**	✓					
Warm Start Up Time	**hrs**	✓		✓			
Cold Start Up Time	**hrs**	✓					
MNZT	**hrs**	✓	✓	✓			
MZT	**hrs**	✓	✓	✓			
Ramp Rate	**MW/min**	✓	✓	✓			✓
Maximum Cycles Per Day	**#**				✓		

Minimum Cycles Per Day	**#**				✓		
Minimum Charge/Discharge Limit	**MWh**				✓		
Maximum Charge/Discharge Limit	**MWh**				✓		
State of Charge	**%**				✓		
Outage/Maintenance Notifications	**MWavail**	✓	✓	✓	✓	✓	✓

For those who choose to self-schedule, participants must notify SO/MO of their unit commitment status ("Must Run" for self-committed generation), Initial Physical Notification (IPN), bid/offer data for any further generation (or flexible demand) that could be centrally dispatched, technology-specific dynamic parameters, and details of A/S potential for use in BM. Market participants who self-commit are effectively price takers and will not recover their start-up and no-load costs.

Figure 13 outlines a high-level view of the Operational Schedule process.

Figure 13: Operational Schedule process

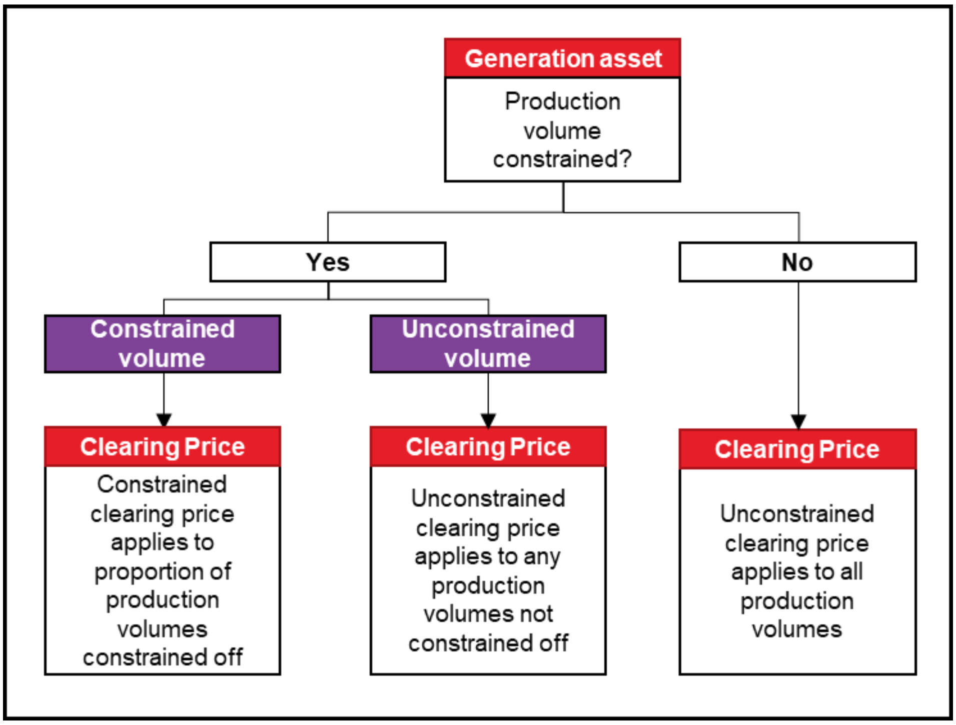


As highlighted in the figure above, the dispatch optimisation tool will co-optimise for A/S as part of the scheduling process, determining whether participants provide energy or A/S. Participants with A/S contracts will be renumerated for the service (energy or chosen ancillary service) that delivers the most system value and provides the participant with the highest profit (thus does not incur opportunity cost). This is opposed to self-dispatch models, where energy and A/S are procured separately, leading to imperfect optimisation of both resources.

The applicable clearing price for a generation asset will depend on whether the asset has any production volume constrained off. Figure 16 summarises which clearing price will apply. Note that the model assumes that a generation asset could elect to take the constrained volume into the ID auction in the hope the constraint has eased.

The production schedules are financially binding. This could help prevent situations, which have occurred in the current market, where a unit decides close to gate closure that they will no longer generate, before submitting high bids/offers in the BM.

Figure 16: Clearing price determination



Unit commitment

As the dispatch process moves ID, the SO/MO refines the Operational Schedule as follows:

- Market participants with units that have short start-up times can update their offers available to the SO/MO for uncommitted generation (from either committed units with surplus generation capacity or uncommitted units), whilst self-schedulers can submit additional self-schedules.
- The SO/MO runs an additional ID unit commitment process to centrally-commit additional units and generation not previously committed at the DA stage that are required over and above the DA operational schedule (where required). Participants who self-schedule can also elect to trade in the IDM to cover bilateral positions with spot market trades if more economically favourable.

- As with the Operational Schedule stage, the SO/MO first clears the IDM using the latest demand data plus the updated and new offers and self-schedules with an unconstrained ID clearing price published at 7am. To note, that for simplicity Arup have assumed that DSR does not participate in this stylised example.
- The security constrained tool is then utilised to determine the constrained schedule and clearing price, reflecting system constraints and co-optimising for A/S. This is published at 11am ID. See Figure 16 for applicable clearing price.
- The SO/MO then begins issuing instructions to units with long start-up times before dispatching power at the applicable clearing price at gate closure (1 hour before real-time).

Operational Dispatch

During operational dispatch, the model assumes the BM operates as it does currently (in practice, this may not be the case). The BM operates from gate closure through real-time with instructions issued by the SO/MO to continuously balance supply and demand as follows:

- Market participants will submit bids and offers to increase or decrease generation or demand.
- The SO/MO will use the dynamic parameters of units, submitted to the SO/MO at DA (default parameters to be used if not submitted), to issue security-constrained instructions to match supply to demand, whilst resolving for system constraints.
- For imbalances, all participants can elect to face the cash-out price or balance their position in the spot market.
- Final production schedule for Settlement Period is determined.

Simulation of central dispatch model

Market outcome simulation

To illustrate the outcome of the central dispatch model outlined above, the outcomes for the stylised scenarios under this market structure have been simulated below. After the key assumptions for the scenario are outlined, the key information for the units involved in the scenario are provided. To note, more details on the dynamic parameters and market outcomes are shown in the Appendix and only summary results are presented here. Following this, a timeline of the events and actions that market actors undertake in this hypothetical scenario is presented. The purpose of the simulation is to indicate how a central dispatch approach with self-commitment would affect market prices, balancing costs, and incentives on market players. The simulation is a stylised microeconomic example and not intended to replace any modelling that would be required for a full impact assessment of central dispatch.

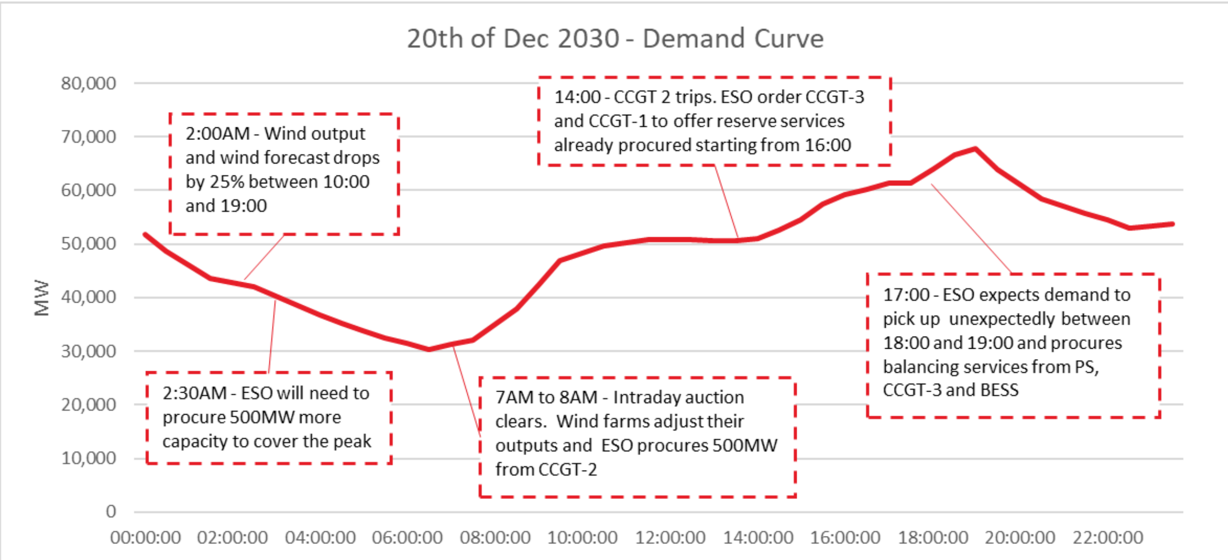
Market scenario

For this simulation, two scenarios have been analysed using the 2030 demand shape from the ESOs 'Leading the Way' FES scenario (2022).

- Winter day in 2030.
- ESO/MO must curtail part of the wind due to transmission constraints.
- Moreover, wind forecast reduces significantly ID and the ESO will need to commit additional units on ID.
- CCGT committed at ID stage trips and SO/MO utilises reserve already procured at DA stage.

In Figure 14 the narrative throughout the day and the overview of actions taken by the ESO is shown. In the charts that follow a stylised example of the merit order based on market events that the SO/MO would need to manage is presented.

Figure 14: Market scenario narrative



Scenario simulation

This scenario simulates how the DA and ID auctions would clear for a single trading period i.e.,

- What are the constrained and unconstrained prices.
- How each unit is remunerated according to these prices.
- How much and what type of A/S has the SO/MO procured from each generation unit and flexible demand.
- The events that took place during the day under each scenario.

How market actors responded were also simulated as well as the way in which market actors behave at the balancing stage. The dynamic unit parameters used for this example are shown in detail in the Appendix.

Day Ahead Auction Results

The tables in the Appendix show the amount of each service procured from each generator. The numbers are indicative and are based on information provided (also in the Appendix). With regards to the energy offer and self-committed energy offer, each generator would receive the auction clearing price. With regards to reserve, frequency services and black start each generator would have been paid as per their bid listed in the dynamic parameter tables above.

Unconstrained Price: £108/MWh

Constrained Price: £124/MWh

Intraday Auction Results

Generators would be remunerated in the ID auction in the same way as in the DA auction described above.

Unconstrained Price: £130/MWh

Constrained Price: £130/MWh

Figure 15: Day ahead merit order with some wind constrained

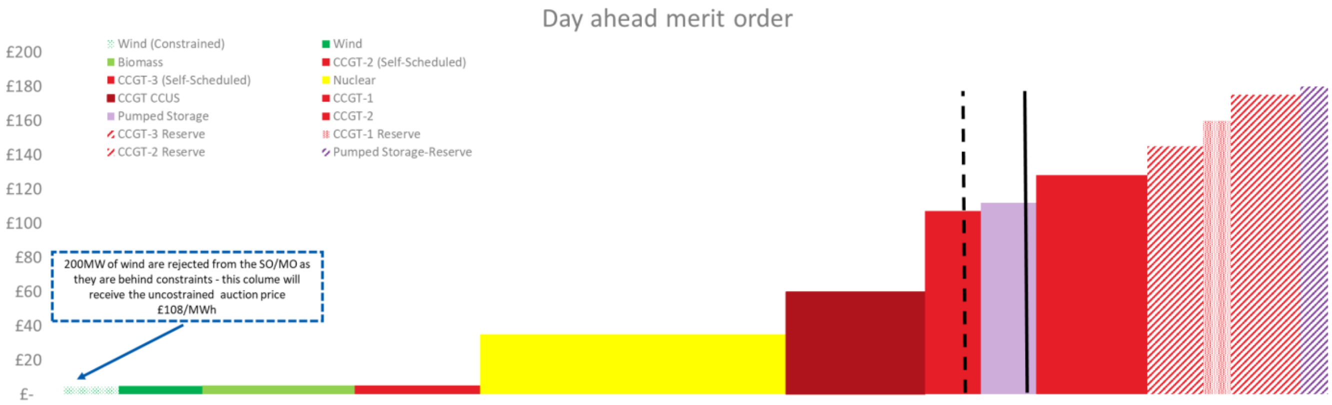


Figure 16: SO/MO procures additional capacity from CCGT-2

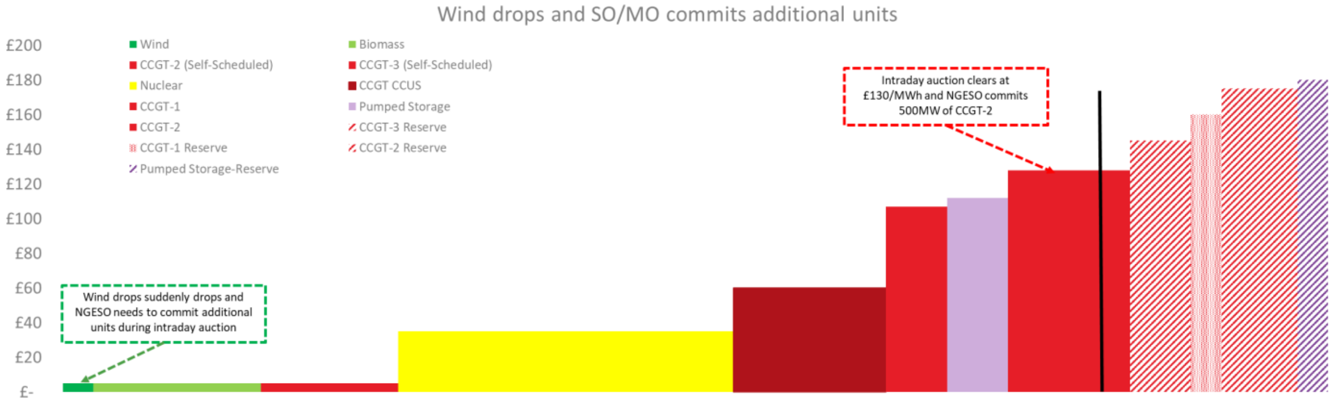
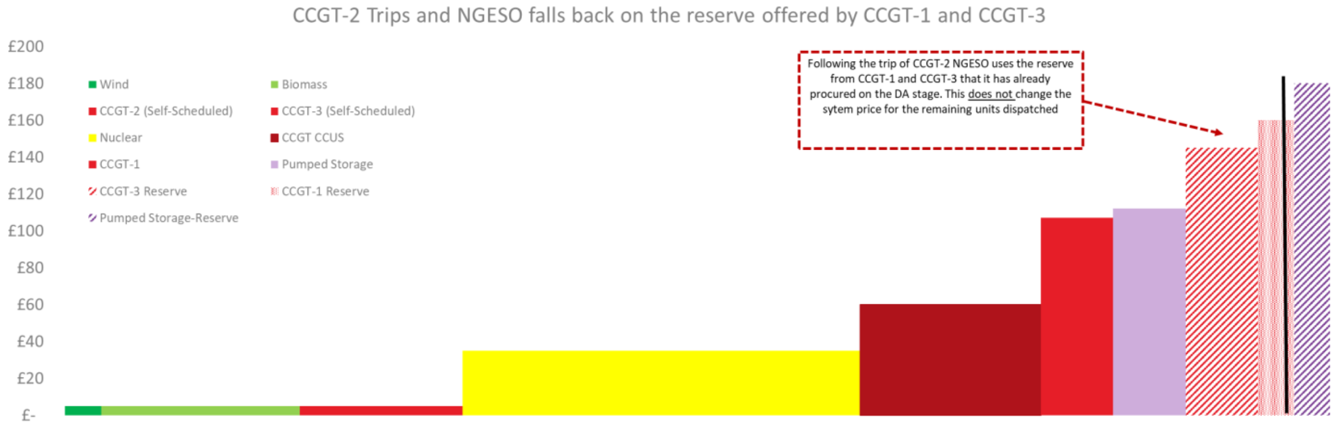


Figure 17: SO/MO utilises the reserve that has already procured from CCGT-1 and CCGT-3



The above changes could also impact the BM costs and revenue achieved by generation assets. The table below summarises the hypothetical revenues/cost for generators from both the BM and the energy only market in the existing and the central dispatch design. With regards to BM cost, Arup have used the P50 offer price from 2021 and assumed that the ESO would need to purchase the reserve offered by CCGT-1 and CCGT-3 in the BM. The revenues/costs over a 1-hour period were analysed. For the BM cost the P50 for bids and offers over the last 3-years were used.

In the self-dispatch scenario (i.e., the current design) all market participants receive the market price, even if they are constrained off by the ESO; based on their FPN and output. Constrained plant are also renumerated in the BM (to turn down) and additional plant are paid to increase their output. In the scenario shown, wind generators are paid to turn down and CCGTS are required to increased output.

The central dispatch model tries to address the issue of constraints before the market is finally settled. In the central dispatch scenario, wind units are constrained at DA stage and only receive the constrained price for their full capacity (i.e., not paid to turn down in the BM). Arup has assumed that reserve is offered at lower prices compared to BM offers. The rationale behind this is that at DA stage market participants have less visibility hence less market power which reduces their bidding prices.

Table 8: Impact on system cost of stylised example

	Proposed Centralised Market Design					*Current Self-Dispatch*				
Generator	Energy Capacity (MW)	Energy Price (£/MWh)	Reserve Capacity (MW)	Reserve Offer (£/MWh)	System Cost (£)	Energy Capacity (MW)	Energy Price (£/MWh)	Balancing Capacity (MW)	Balancing Offer (£/MWh)	System Cost (£)
Wind	600	£119	0	£0	**£71,200**	600	£108	-200	-£100	**£84,800**
Biomass	1280	£124	ver	£0	**£158,720**	1280	£108	0	£0	**£138,240**
CCGT -1	442	£124	230	£160	**£91,608**	442	£108	230	£175	**£87,986**
CCGT -2	0	£124	504	£0	**£0**	1217	£108	0	£0	**£131,436**
CCGT -3	420	£124	420	£145	**£112,980**	420	£108	420	£175	**£118,860**
CCGT CCUS	1446	£124	0	£0	**£179,304**	1446	£108	0	£0	**£156,168**
Pumped Storage	398	£124	200	£180	**£85,352**	398	£108	200	£250	**£92,984**
Nuclear	2852	£124	0	£0	**£353,648**	2852	£108	0	£0	**£308,016**

Total Cost					£1,052,812					£1,118,490

In Table 8 demonstrates that in this stylised example, the proposed market design could deliver around £66k of cost savings (over a 1-hour period) by managing some of the constraints and reserve well ahead of gate closure. In the stylised scenario, the market price is higher in central dispatch model, but the total system costs are lower. This is because the ESO takes less costly actions in the BM to resolve constraints. Please note that this is a highly stylised indicative example and does not consider the full market dynamics and generator behaviour (i.e., the potential mitigation of the opportunity cost coming from the BM opportunities). More detailed modelling and analysis will be required to define the potential system benefits that could be delivered by moving to a centralised market design.

The table below summarises the differences in behaviour of the generators and relevant market actors analysed in the stylised example in the current market design versus the central dispatch design.

Table 9: Behaviour comparison of key simulated assets

Generator	Current model (self dispatch)	Central dispatch model
Wind	• Wind farms aim to sell all their forecasted output at the DA stage (auction or OTC). Most wind farms will bid in the spot markets with negative prices to account for their lost opportunity of getting the subsidy (ROCs or CfDs). • They will re-balance/ optimise their position (usually via a third party) up to gate closure (continuous ID, ID auction). • If they are behind a constraint, they will generate irrespectively and be bid down by the SO. This will be at negative prices to account	• Wind farms will participate in both constrained and unconstrained auctions as price takers, and they will be remunerated for both their constrained and unconstrained output based on the relevant price. Their bidding will still be subject to the existing rules and likely to bid in the auction at negative prices. • They can opt to self-schedule however the expectation drawing from international experience is that most wind farms will opt to be scheduled centrally as there should not be a strong incentive to self-schedule. • They will rebalance their output both in the

	for support received on their output.[21] • Post gate-closure their imbalance is settled at cash out prices.	continuous IDM and ID auction. • Post gate closure most constraints will have been acknowledged and managed in the two auctions. So, wind farms behind constraints, will not need to be bid down at negative prices (i.e., get paid to generate). • Any imbalance post gate-closure will be settled on cash out prices.
Gas/oil fired flexible units	• Gas/oil fired flexible units will bid in the DA and intraday auctions based on their Short-Run Marginal Cost (SRMC) and the BM opportunity cost (see Balancing chapter for more information). • Units are not bound to provide any dynamic parameters as part of their bidding on the DA stage. • Reserve contracts are procured outside of the DA and ID markets. • Units will use the continuous IDM to optimise their position. • Units will aim to secure BM contracts for their available units at prices well above their SRMC. • Post gate closure they will need to provide all their	• Units can opt to self-schedule or be committed centrally by the SO at the day-ahead stage. • Both self-scheduling and centrally committed units provide all their dynamic parameter information to the SO (i.e., the same information). • Centrally committed units will receive the constrained and unconstrained price for their output accordingly, whilst their dynamic parameters will be used to calculate the system price. • Self-scheduled units act as price takers and their dynamic parameters are not considered for setting the system price. • Both self-scheduled and centrally committed units

[21] Even though the CfD scheme has rules preventing remuneration in case prices go negative for more than 6-hours which has been extended for AR4 to any settlement period that prices go negative.

	dynamic parameters and unit availability information to the SO and receive an instruction on whether they will be required to run or not. • Any position imbalance will be settled on cash-out prices.	should provide their availability and price for reserve provision at both the DA and ID auctions. • The BM format does not need to change materially. Units that have opted to self-dispatch can either generate power or buy back the power and then commit their unit in the BM. Units that were unsuccessful in the DA auction can be used in the BM. • Centrally committed units could probably include an opportunity premium in their SRMC to account for increased likelihood of their unit being used in the BM if they are not committed. This is similar to the way market participants currently bid in the DA market. • The expectation is that as certain A/S will be procured at the DA stage, the BM requirements (volume and prices) should be reduced.
Nuclear	• Nuclear acts as a baseload unit with close to zero flexibility (must-run and price taker). • Their output is progressively hedged (sold) in advance.	• Arup expect such units to self-schedule as they have no flexibility, and their output would be hedged in advance. • No difference in their behaviour versus the current market. • They would still need to provide all their dynamic

		and outage information to the SO for the ID and DA auctions. • There should be opportunities for the provision of A/S in the ID and DA auctions.
Biomass	• Biomass units will balance their position in the DA market and rebalance their position in the IDM. • Their output is predictable, and the expectation is that they hedge their output in advance and, as many of them will be receiving subsidies, it should be in their interest to run. • They should be bidding in both the spot and BM markets based on their SRMC including the opportunity cost resulting from foregone subsidies.	• Large biomass units are likely to self-schedule as they should have rather low flexibility (operation is usually similar to coal-fired power stations), low cost to run (subsidised) and their output is likely to have been hedged in advance. International examples from coal fired power stations support this assumption. • No difference in their behaviour versus the current market. • They would still need to provide all their dynamic and outage information to the SO for the ID and DA auctions. • Biomass plants may opt to sell certain units for reserve at the DA and ID auctions whilst there may also be opportunities to offer A/S at the DA and ID auctions (e.g., reactive power or Super SEL).
Pumped Storage	• Pumped storage assets have the advantage of being able to respond fast and reliably to balance the system.	• The expectation is pumped storage assets would opt to be centrally committed. • They will most likely still include a significant amount of opportunity cost

	• The BM opportunity cost plays a key role in their optimisation strategy as their technical characteristics means that they are usually a preferred option for the ESO. • They act as both a demand and a generation unit, so they participate in the DA auctions accordingly.	as their advantage lies in responding fast to balance the system. So, it is likely that the BM will remain a key revenue stream. • Their behaviour in the BM will not change when compared to the current system.
BESS	• BESS make most of their revenue by offering frequency response which is procured from the SO via a DA auction. • They bid in the auction by considering the wholesale market arbitrage opportunities. • They currently do not have a significant participation in the BM but this is likely to change.	• It is expected that frequency response will be one of the A/S that will be co-optimised during the central unit commitment and scheduling process. • BESS units are likely to participate in the DA and ID auction which will be run by the SO and submit their bids for both wholesale and frequency response and get remunerated based on the highest bid and system requirements. • BM opportunity cost is likely to be included in their bids going forward. • More complex bidding format including both charging and discharging may be seen. • Their bidding will include their dynamic parameters as described above.
The ESO	• The ESO in the current market is supposed to act as a residual balancer. It's role has, however, been expanded and they are increasingly taking	• The ESO will be running the DA and ID auctions (currently ran by exchanges). • Their algorithm will co-optimise along with energy

	scheduling/dispatch decisions outside of the BM via SO trades and new ancillary service products (this is one of the reasons central dispatch is being considered). The ESO takes control post gate closure and submits dispatch order to the units required to balance the grid. • The process is mostly relying on decisions made by the control room operators with the process being mostly manual. • The ESO procures A/S via separate and multiple processes.	constraints, frequency response, reserve, reactive power, and black start. • They will run the BM as they do now, but with potentially more transparent data.
Spot Energy Exchange (N2EX, EEX)/Spot OTC market	• Spot exchanges run the DA and ID auctions.	• Spot exchanges could run the DA and ID auctions but on behalf of the ESO. • It is unlikely that there will be two different DA and ID auctions. • Spot exchanges could still run the continuous IDM.
Future Energy Exchange/Forward OTC market	• The futures and forward markets allow market participants to trade future and forward contracts for energy and enabling them to manage their risk effectively (hedge).	• Based on Arup's view and feedback received from ICE it is expected that their role will remain the same following a transition to a central dispatch model • There may be increased demand for financial products like CfDs to hedge.

Implementation

Moving from self-dispatch to central dispatch will be a major undertaking. Below, Arup discuss potential implementation costs, risks and timelines, as well as the impact on key market actors.

Implementation timeline

It is important to state upfront, and as touched upon above, that transitioning from self-dispatch to central dispatch arrangements would very likely require major market reform opposed to incremental market reform. This is supported by the interviews we have conducted.

International experience

Most examples of markets in other jurisdictions that have moved to central dispatch have done so alongside other market reforms, in particular, the introduction of nodal pricing. Furthermore, these markets have some significant differences to the GB market in terms of, for example, size and generation mix. Past experience is therefore not directly relevant for a GB scenario. That being said, there is still useful information and learnings from these markets that can inform the implementation of central dispatch in GB as outlined in Table 10.

Table 10: International experience of central dispatch implementation

Market	Overview	Timeline
NZEM	In 1992, the Wholesale Electricity Market Study (WEMS) was undertaken, which recommended a major evolution of existing electricity market arrangements. This study was then critiqued by the government across 1992-1993 before the establishment of the Wholesale Electricity Market Development Group (WEMDG) in June 1993. The aim of the WEMDG was to develop proposals for the wholesale electricity market arrangements, which were issued to government in 1994. 1995 saw the government announce the pathway to the implementation of a wholesale electricity market before the reformed New Zealand Energy Market (NZEM) with nodal pricing and central dispatch began operating in October 1996.	c. 4 years
PJM	The journey to nodal pricing with central dispatch began for PJM in 1993 when the PJM Interconnection Association was formed to administer the power pool. Zonal pricing was initially introduced in 1997, however, following dispatching issues, PJM issued a request to the Federal Energy Regulatory Commission (FERC) to move to nodal pricing. This was approved in November 1997 with nodal pricing then implemented on 1st April 1998.	c. 5 years
NYISO	The establishment of New York Independent System Operator (NYISO) to replace the New York Power Pool saw the introduction of nodal (Locational Marginal Pricing - LMP). Planning began in the mid-1990s and was followed by the proposal to FERC in 1997. FERC approved the proposal via a series of orders issued across 1998 and early 1999 before inception of NYISO in December 1999.	c. 5 years

ISO-NE	ISO-NE was created in 1997 to operate the regional power system, implement wholesale markets and ensure open access to transmission lines. In 1999 it began managing the wholesale market and submitted a proposal to implemented nodal pricing to FERC. Subsequently, nodal pricing with central dispatch was introduced in 2003 as it implemented Standard Market Design.	c. 6 years
MISO	MISO developed its competitive electricity market between 1999 and 2005, which saw the introduction of a centralised wholesale market with nodal pricing to replace the many local bilateral markets.	c. 6 years
CAISO	In 2002, shortly after the California energy crisis, FERC instructed the ISO to reform its electricity market design, and a major market design initiative followed, which saw the market structure change from a decentralised, zonal market to a centralised, nodal market in 2009.	c. 7 years
ERCOT	ERCOT transitioned from zonal to nodal pricing, whilst centralising the dispatch decision-making in 2010. The reform took a total of c. 7 years following the initial order by the Public Utility Commission in 2003 requiring a nodal market structure to be defined. The implementation was initially planned for 2006, however, several delays occurred on the back of project complexity, inclusion of additional market design elements and delays to software delivery.	c. 7 years
IESO	As part of the Market Renewal Program to deliver more efficient, stable and reliable electricity markets, IESO (Ontario) began implementing nodal pricing in 2016 with planned go-live anticipated in 2023. The programme has slipped with launch now planned for May 2025 due to the significant level of work required to upgrade/replace IT systems required to dispatch and settle the wholesale market.	c. 6 years

As can be seen from international experience the implementation of nodal (and other market design elements) with central dispatch can be a lengthy process, which has taken, from initial design to go-live, at least 5 years in most markets with delays to timelines very common. Our view based on this evidence is that it would take at least 5 years in GB to implement central dispatch.

Implementation of NETA

Another historical transition that could inform potential implementation timeline is GB's own experience in moving in the opposite direction i.e., from central dispatch to self-dispatch as the England and Wales Electricity Pool was replaced by NETA. The NETA were introduced with the aim of delivering more competitive, marked-based arrangements, whilst maintaining a secure and reliable electricity arrangements. The process began in October 1997 with the Minister for Science, Energy and Industry inviting the Director General of Electricity Supply (DGES) to consider how a review of electricity arrangements might be undertaken. Public consultations, review of the existing and potential future arrangements and design proposals followed across 1997-1998 before acceptance of DGES proposals in the 1998 White Paper on Energy Policy. Publication of a framework document in November 1998 outlining the forward plan was followed by an intensive programme of work which was then undertaken across 1999-2001 including:

- Further development the design proposals.
- Incorporation of the Balancing and Settlement rules into the BSC.
- Building, testing and implementation of new software and IT systems.

The Utilities Act 2000, which received Royal Assent on 28 March 2000, made a provision for the implementation of NETA to replace the Pool and on the 27th March 2001, the Pool was replaced by NETA. From inception to go-live, the implementation of NETA took approximately three and a half years.

Consultations, code reviews and legislation

Estimates of potential implementation timelines could also be informed by the typical timelines associated with government consultations, Significant Code Reviews (SCR) in GB (for electricity and gas), licences changes (e.g. transmission, ESO, generator, etc.) and the time taken to prepare and pass legislation.

- Consultations typically take a minimum of three months with a further three months to review and analyse responses. It is anticipated, and recommended (to encourage strong stakeholder participation), to have a series of consultations to develop central dispatch design proposals and then further refine before seeking approval.
- Implementing a central dispatch model is arguably a major market reform, as opposed to an incremental one, and would likely require primary legislation to be passed to give Ofgem or DESNZ the powers to facilitate the implementation. This is due to the scope and size of the changes required. For the Utilities Act 2000, this was introduced in Parliament in January 2000 and received Royal Assent on 28 July 2000, however, the time taken to pass legislation can vary widely.
- In terms of the BSC, the ethos at present is centred around self-dispatch, for example around cash-out, dynamic parameters (Section Q, 2 Data Submission by Lead Party) and roles and responsibilities (Section J, 5. Party Responsibilities), and so significant modification or a complete re-write would be needed in order to move to central dispatch. The BSC is currently well above 1000 pages and has been through a number of modifications since its introduction, resulting in a very complex code. The previous SCR undertaken for balancing that was completed in 2014, the EBSCR, took 4 years.
- A similar timeframe (4 years) for other key licences (e.g., Transmission Licence, Generation Licence and ESO Licence) and codes should be expected. Contractual arrangements between market participants and the SO/MO would also have to be updated.

High level view of implementation pathway

Based on the above, implementation of central dispatch could entail the key interrelated work packages outlined in Table 11, with some needing to be conducted in parallel where possible (and feasible).

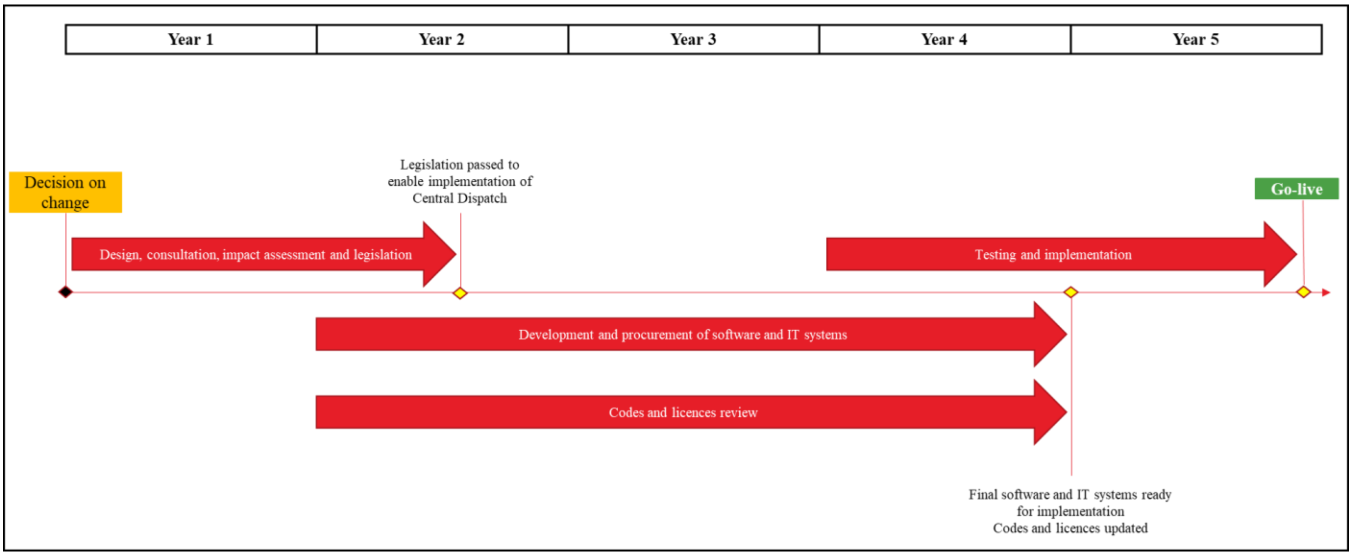
Table 11: Implementation work packages

Work package	Description
Central dispatch design, consultation(s) and impact assessment	• Development of potential central dispatch design proposals, consultation, and stakeholder feedback review and analysis. • Further consultations on refined shortlisted proposals and then on final selected design. • Conduct an Impact Assessment (IA) before approval to proceed is sought.
Preparation, introduction and passing of required legislation	• The expectation is that the introduction of central dispatch would require primary legislation (as it cannot be done through the BSC). • This legislation will need to be drafted, debated, and voted on.
Software and IT systems design and build	• The move to central dispatch will require significant changes to software (e.g., new scheduling and pricing software) and IT systems to operate under the new arrangements. • The transition will likely require an Automatic Generation Control (AGC) system to enable the SO to remotely control the real power output of generators in response to frequency requirements. • This work package will encompass the design, procurement and delivery of software and systems.
Codes and licences review, consultations and modifications	• Review existing codes and licences, identify required modifications, and consult on changes before amending as required. • Key codes and licences that will need modification are the BSC, grid code and the ESO licence. • Counterparty contracts/agreements between the ESO, operating as SO and MO, with market participants would also need to be updated.
Testing and implementation	• Robust testing of the new arrangements and associated software, IT systems, processes, and procedures before go-live.

A dedicated review of potential implementation timelines needs to be conducted to provide a thorough and accurate estimate of timings. Arup expect implementation would take at least 5 years to implement, and the process steps (design, consultations, legislation) and requirements (changes to software, systems, codes and licences) are likely to be very similar to a move from national to nodal pricing. This is a view also held by the ESO as discussed in our interview and as covered in their Net Zero Market Reform programme of work, which reviewed international experience, to arrive at an estimate of 4-8 years for implementation (central dispatch plus nodal pricing), but that it could credibly be implemented within 5 years.

A high-level view of a potential implementation timeline is presented in Figure 18.

Figure 18: High-level implementation timeline



Implementation cost and risk assessment

Data relating to the implementation costs for central dispatch is sparse, making it difficult to accurately estimate the costs. As with implementation timelines, the assessment of costs to implement central dispatch are complicated by the bundling of market design changes (e.g., implementation alongside the introduction of nodal/zonal pricing). If reforms to dispatch arrangements are pursued, a full study exploring implementation costs and risks should be conducted once the design of dispatch arrangements are further developed.

As others (including the ESO) have identified, this report sees two broad categories of cost associated with the implementation of central dispatch:

- SO/MO costs: costs associated with procuring new or updating existing software and IT systems, developing of processes and procedures and re-writing (in part or full) codes and licences to reflect central dispatch arrangements.
- Market participant costs: these costs would predominantly cover the costs associated with procuring or updating software and IT systems and capabilities to operate within a central dispatch market, developing the necessary processes, procedures and governance arrangements and ensuring compliance with the new codes and licences.

The implementation of central dispatch is anticipated to incur significant one-off costs for both the ESO and market participants. In the Net Zero Market Reform programme of work, the ESO estimate costs associated with the implementation of nodal pricing with central dispatch as:

- SO costs of between £84 and £151 million based on a review of international experience. This would cover the procurement of new or upgraded IT systems and software, development of new processes and changes to/re-writing codes and licences.
- Market participant costs of £50,000 to £600,000 per participant. This cost would be to update IT systems and software, as well as capabilities. It is expected that those participants who have more experience of nodal pricing and central dispatch will be better equipped and thus likely incur lower costs. The ESO identified the availability of existing 'off the shelf' IT and software solutions from other markets could also support lower costs for participants.
- Ongoing costs: the ESO expects similar costs to the current self-dispatch arrangements.

Some examples of the costs, include:

- NETA implementation: The Department of Trade and Industry (DTI) and Ofgem implemented NETA at a cost of £39 million. Ofgem estimated that, in total, businesses in the industry might have incurred costs of up to £580 million over the first 5 years of NETA, including costs associated with adapting their operating procedures and IT systems. They also estimated that participants could additionally incur operating costs of £30 million a year.
- PJM: one-off implementation costs of the transition to nodal pricing of c. $200m.
- ERCOT: Initial estimates by their consultants estimated the cost (to ERCOT) of implementing a nodal system as between $59.7 million and $76.3 million, however, the final cost ended up in the region of $550 million.

As part of Ofgem's Locational Pricing Assessment work, which also reviewed international case studies and discussions with system vendors and market participants, an estimate of £500m has been made. The ESO acknowledges that their assessment as part of the Net Zero Market Reform programme may need to be revised upwards.

As can be seen from the above examples, costs range significantly and a much more detailed study of costs is recommended.

Implementation of central dispatch will have a number of interrelated risks, many of which will apply to other market design changes. These are outlined in Table 12 (in no particular order).

Table 12: Central dispatch implementation risks

Risk	Description
Delays to implementation	Delays could arise from a number of sources, including changes to scope (e.g., modification to existing or inclusion of additional market design elements), hold-up of legislation, underestimation of the complexity of the project or delivery of the required software and IT systems.

Cost overruns	Increasing costs could arise from delays to implementation timeline, software and IT systems procurement challenges, lack of oversight on the implementation process and increasing project complexity. This has been a common theme in other jurisdictions (e.g., ERCOT).
Selection of the right hardware and software	It will be essential to procure the right software and IT systems to ensure successful and efficient operation of the central dispatch arrangements. A thorough assessment of options and robust testing programme will be key to mitigate the risks of inadequate IT systems and software.
Stakeholder engagement level and challenge	Transitioning to central dispatch and nodal pricing, or any other market design, will be more successful, and efficient, where all stakeholders are fully engaged with the transition. If stakeholders are not fully engaged there is the risk of delays through challenge (including legal challenges) and general unpreparedness amongst market participants.
Data availability	Success of central dispatch arrangements will heavily depend on the availability and efficient communication of good quality data from market participants and weather forecasters to inform scheduling. The development of a common platform would help mitigate the risks associated with poor data and communication issues. When interviewed, the ESO flagged that the data quality received in US markets is much better quality when compared to GB.

Implementation considerations for key market actors

Generators (and project developers)

- Through the implementation of central dispatch, generators who choose not to self-schedule will see their dispatch decisions made by the SO/MO.
- We would expect renewables generators to largely self-schedule given that their generation is supported by CfDs, which are based on metered output. However, the international experience suggests that most wind farms will opt to be scheduled centrally.
- Generators will need to significantly change their bidding format and their bid submission process.
- They will also need to change their contracting arrangements with the ESO and spot exchanges which would now be used only for continuous trading.
- Generators that have PPAs with counterparties will need to be amended to reflect the fact that the new DA price is defined by the ESO. It may also need some adjustment on risk sharing, as the price formation (and hence the agreed price) will need to change.
- Generators will need to amend their contracts with third parties that undertake their balancing.
- Significant changes to the Generator Licence and applicable codes will be required.

- Flexible generators will need to re-assess their optimisation strategies (self-dispatch versus central dispatch, their reduced opportunity cost in the BM, and their opportunity to offer additional A/S in the central auction). This means that flexible generator would need to form a view of how the SO would schedule their before deciding whether to self-schedule, but we would expect them to be able to this successfully over time.
- Loss of control of dispatch decisions could impact revenue certainty. As such, the investment signals under the new arrangements will need to be understood.
- Lower barriers to market through central commitment process (opposed to having to find a counterparty to trade with under self-dispatch).
- Optionality in how they access the wholesale market.
- Software and IT systems will need to be upgraded/replaced to facilitate and operate under central dispatch arrangements.
- Internal processes and procedures (including governance) will need to be updated.

Energy suppliers

- There will be changes to Supply Licence and applicable codes.
- There will be changes to how suppliers access the wholesale market. Financial products may be used to enable energy suppliers to manage the risk (e.g., CfDs as in the case of I-SEM). In the ISO-NE, energy suppliers are required to hedge 3 years ahead (although this is not considered part of the study's suggested market design).
- Trading desks of energy suppliers will need to adjust their position management activities with the DA auction now run by the ESO.
- No changes are expected in their billing and metering.
- No significant changes are expected in supplier hedging strategies, pricing and product offering processes.
- Energy suppliers price forecasting processes may need some adjustment.
- Supplier contracting with different parties may need to change to reflect the move to central dispatch. For example, suppliers that have PPA agreements will need to amend them to reflect the new dispatch process.
- We expect that overtime the move would affect suppliers hedging and market access. As the Day ahead price is set by the ESO, compared to currently where the there are two different days ahead auctions as well as an OTC market. We expect this to concentrate liquidity and improve price transparency, and give suppliers greater confidence on wholesale market access.

Elexon

- Elexon will still bear the responsibility for the imbalance settlement as there will still be a BM and market participants will still need to settle their imbalances. They are likely to have greater responsibility after a move to central dispatch; operating the clearing and settlement process for DA and ID auctions as well, not just balancing (e.g., expanded BSC).

- The above will require greater data and reporting requirements, as well as increased resourcing needs to administer the expanded BSC.
- They will also have an active role in amending the existing BSC code or delivering a new market code. This is expected to be a major task requiring additional staff resources.

The ESO

- Changes to the ESO Licence and Grid codes will be required.
- Changes to roles and responsibilities; the ESO would hold SO and MO roles and responsibilities; becoming the SO will require the ESO to develop new IT systems and new processes.
- The ESO will now need to co-optimise the A/S mentioned above at the DA stage and possibly refine at ID.
- Software and IT systems will need to be upgraded/replaced to facilitate central dispatch incurring additional resource and cost. For example:
- The ESO will need to develop and run a new more complex algorithm to co-optimise energy and A/S. This would require additional resources for it to be developed; furthermore, it will require IT/ process upgrades to accommodate for increased processing power and memory.
- Testing/readiness assessment of new software and systems will require a notable amount of time both from the ESO and its counterparties.
- The ESO will need to develop a robust data validation and data management process as the submission of data will change.

Interconnectors

- A central dispatch model would have a minor impact on interconnectors, and the process of participating in DA auction would be similar to existing arrangements.
- Changes to Interconnector Licence and applicable codes.

EMR Settlement Ltd & LCCC

- Updates to existing CfD agreements and amended drafting of future CfD terms and conditions. There would be a requirement to define relevant index' for Intermittent Market Reference Prices for renewables and the Market Reference Price for nuclear.
- Levy forecasts will need to reflect the new central dispatch arrangements.

Exchanges

- Spot exchanges will not be running the DA and ID auctions, but they could have a role in running IDMs up to gate-closure (or shorter time for non-BMUs).
- They may opt to scale up their offering of future products. In doing so they may need to develop futures products, and then design and consult on these with market participants.

- The SO could opt to outsource the delivery of the auction to one of the existing exchanges, however, the SO is likely to view this move as adding extra complexity. Moreover, the auction will need to be run in a different mode taking constraints and dynamic parameters into account that fit better with the SO's activity.

Forward market

- No significant changes are foreseen to the operation of the forward market. Discussion with market participants were aligned with this view. The fact that changes will only apply to the DAM and IDM, along with the fact that market participants will be allowed to self-schedule, suggests there will be a demand to hedge forward from suppliers and generators.

DESNZ and Ofgem

- Responsibility to define central dispatch design options, timelines for implementation and testing requirements.
- Study the impact of central dispatch on key market actors.
- Lead on SCRs, licence changes, consultations, policy design and legislation.
- Support and provide general oversight on the transition to central dispatch and operations once implemented.

Market Actor Implementation Assessment

The table below summarises the implementation effort/complexity that would be required for each market actor based on the above implementation considerations.

Figure 19: Market Actor Implementation Assessment

Market participant perspectives

For this study, Arup interviewed 4 market participants, (Elexon, the ESO, trading exchange (ICE), and a flexibility provider) that were deemed relevant to provide insight to the incremental reforms discussed. Arup defined a set of questions which were agreed with DESNZ and were communicated to the participants in advance. Naturally, not all the questions were relevant to every part. Arup has summarised the responses and key messages below.

Incremental vs non-incremental

All the experts interviewed for this project disagreed that changing to a central dispatch model should be classified as an 'incremental' reform. They view such a reform as very complex and one that requires a lot of preparation and includes significant risks. In general market participants:

- Suggested that moving to a central dispatch model is a step backwards.

- Felt that the implementation of central dispatch would cost a lot and would not resolve the key issues faced by the market.
- A key issue raised was the lack of automation, which is where they thought money should be invested.
- Moving to centralised dispatch with nodal pricing means the market is potentially locked into a position which it cannot get out of.

Implementation requirements and complexity

With regards to implementation:

- The ESO stated that they have a list of pre-requisites that would need to be in place if central dispatch was to be implemented in the GB market. These include things such as information imbalances/inaccuracies and automatic generator controls.

When it comes to changes in the BM market participants said that:

- Amending the codes would require between 18 and 24 months. They claimed that this should be a localised change as the balancing will still be part of the process.
- Elexon's IT systems can handle the switch over to Centralised dispatch but will need some adaptation.
- One market participant said that depending on the level of implementation, if the central dispatch system is creating power generating profiles/ shapes for market participants, there is a large amount of complexity in the architecture of their system that will need changing. For instance, understanding the uncertainty that the central dispatch system will bring to the BESS's state of charge in terms of optimisation. They already deal with some of that within the BM, but this should be an additional factor that will bring more uncertainty to the optimisation process.

Level of change

Apart from the ESO, market participants did not have strong views on whether they preferred a transition to a fully centralised dispatch market design compared to one that allowed for self-commitment. The ESO has two reasons they believe that self-commitment is better for the system:

- The first is from a transitional perspective. They understood that when the US markets moved to centralised dispatch a lot of the markets started with higher proportions of self-commitment. They then built trust in the commitment process, with it taking 10 to 15 years before they started to move to the mass being centrally committed.
- The second is that there are going to be a lot of participants who don't trust the participation model or the way that the SO is clearing, and as such, would prefer to self-commit. Moreover it can take time for the ESO to keep up with innovations by providers, so leaving that option open allows innovation to happen and maintains a certain degree of centralised efficiency.

Market participants viewed a ‘big bang’ change with caution and suggested a CBA would be required before any decision is made.

Market operation aspects

When asked whether the ESO should also take on the role of the MO market participants views were that:

- It made little difference to them on who operates the spot market (the ESO or a third party on behalf of the ESO) as long as the outcome is clear.
- If the ESO had the capability or the appetite to be the MO and run the ID and DA auctions, the current system would need to change as it cannot accommodate the changes using the current grid codes and BSC. The system would need changes and there would be no benefits with trying to fit the new changes into the existing system.

With regard to the BM, market participants said:

- That there is always a role for a mechanism that ensures the market aligns with the real time power system. It ensures sufficient energy to balance in real time to resolve any residual issues. So, the role of the BM has grown significantly because there’s a misalignment between congestion management, voltage, inertia, and national pricing structure. Even in a perfect market arrangement, which allows the resolution of physical issues in line with the economic issues, the demand will never be exactly as forecasted so there will always be a need for a BM, even in centralised markets.
- They do not believe that the proposed market design change will be a big issue for the BM operation.
- A lot of work has been done to open the BM to different sorts of Demand Side Response (DSR) and different sorts of distributed generation.
- They would prefer that the market comes up with a new design that continued to provide early adopters the ability to participate in the BM.
- They would not like to see all the progress made in that area going to waste.
- They raised concerns if the change occurred without taking into account the needs and requirements of such technologies.

When it comes to co-optimisation with A/S:

- The ESO have considered the co-optimisation of the wholesale market with the reserve, frequency response and black start.
- The more that is co-optimised, the more difficult it is to solve and the longer it will take to build an algorithm and optimiser, adding to the total time of implementation.
- They also said that there are huge opportunity costs of not having co-optimisation (such as increased liquidity).
- They suggested that co-optimising additional markets can add significantly to implementation costs. This is particularly evident in the experience of ERCOT. They co-

optimised at day-head but not at real time. This cost them four times as much to build the real time capability, making it a massive trade-off.

With regards to liquidity, experts suggested it is difficult to give a response. One market participant said that one way liquidity is currently impacted is through the incentives for assets in front of constraints to wait until they know they are going be turned on at the BM, rather than preclear and A/S co-optimisation would certainly help.

Automatic Generation Control

One consideration for moving to more automated dispatch is how the ESO would continue to manage system frequency. Implementing “algorithmic dispatch” would mean dispatching according to the results of an algorithm with minimal human interpretation of the advice provided. In effect the ESO would move to a position where they would dispatch using a closed loop control while an operator would have a supervisory role, only taking over in the event of clear problems with the dispatch advice.

The ESO believes new frequency services would be required to implement this approach. Internationally, system operators use AGC as part of their market services to provide further automation and move closer to the ideal of algorithmic dispatch.

With AGC, the system operator measures frequency and calculates an Area Control Error (ACE). To minimise the ACE the system operator implements a proportional/integral control method so that frequency is always pulled back to the target. The target would be 50Hz unless the system operator is deliberately setting the frequency target high or low (to reduce clock deviations, as an example). AGC then adjusts the real power output of generators in response to control signals from the system operator, typically within two to five seconds. Control signals are transmitted via telemetry to remote terminal units (RTU) at the generator.

Currently in GB, to manage equivalent frequency variations, the ESO uses the droop setting on generator governors to control the rate of power produced by a generator according to grid frequency. This approach relaxes frequency control close to the nominal frequency (50Hz) compared to AGC. The ESO also procures DR and DM frequency response services to increase the supply of continuous frequency regulation capability. These services deliver the capability more efficiently than traditional governor control and separate the frequency regulation objective from the frequency containment objective, providing greater transparency of the requirements.

Adapting the ESO’s current suite of services to give the same effect as AGC has several challenges: In the case of Bid Offer Acceptances (BOAs), the lag between the issuing of balancing instructions and asset response can lead to frequency deviations. Under current arrangements, the ESO can manually adjust its view of demand to manage system frequency. Introducing algorithmic dispatch would rely on a forecast demand curve. If these frequency deviations are picked up by the demand forecasting algorithm it may lead to unstable ESO balancing instructions. The ESO believes that AGC or a similar service would be required to mitigate this risk.

Existing GB response services effectively implement a proportional control so that deviations are arrested, but they do not implement an integral control so that frequency is pulled back to target.

Careful consideration of the full control cycle, and the lags and sampling delays in the services available, is therefore required before implementing algorithmic dispatch, to avoid more actions being taken by human operators rather than less, and an increase in other undesirable effects (such as unwinding etc).

Assessment and recommendation

To assess the merits of moving to a central dispatch model, the approach used two broad lenses; implementation and system impacts. It is important that this is not a full CBA of the option, but rather a qualitive assessment to helpful refine the options in the policy development process. Below, the central dispatch model is qualitatively assessed against the assessment criteria set out in the Executive Summary of this report.

Implementation of Central dispatch

- Ability to implement in existing code and licencing framework – analysis indicates that it would be extremely difficult for central dispatch to be implemented within the existing the code and licencing framework. The changes require rewriting of large sections of the code. More importantly, the central dispatch model is a fundamentally different philosophy of market participants self-balancing and the ESO acting as residual balancer. This could result in numerous logical inconsistencies within the code and make changes subject to legal challenge.
- Timeline to implement - It is highly doubted that central dispatch can be implemented within the existing framework. Arup's view is that primary legislation would be required to enable the change to happen, but expert legal advice should be sought to confirm this. If it could be implemented within the existing framework, it would require complicated SCRs, which (from Arup's experience) would likely take 4 years to finish. There would also be the risk of legal challenge after the review has taken place.

Arup believe 5 years is a reasonable estimate for implementing a central dispatch model.

- Cost and risks – Moving to central dispatch would create significant implementation costs, similar to those seen for a nodal market redesign. A mapping exercise of constraints and the required software would be similar to that for nodal markets – although some costs, such moving to algorithmic trading, are arguably costs that should be incurred at present. Market participants would face significant costs in adjusting their process to the new model (described below). It should be noted that moving to algorithmic trading approach has been unsuccessfully tried before. During the mid-2010s the ESO had a work programme to develop an algorithmic dispatch system and spent ~£100m on it. This has not, however, resulted in moving to algorithmic dispatch and dispatch still requires manual actions from its control room. The ESO has an updated programme to develop a more digitalised approach to dispatch, although this is unlikely to result in a purely algorithmic dispatch.

- Impact on market actors – The central dispatch model has wide ranging implications for market actors. It would require a market operator to run the central dispatch and DAM and IDM. Whilst the existing ESO and its subsidiary Elexon has the capability to do this, they do not have to be the parties that run the process/market. The existing exchanges would face a significant impact; Arup do not think that both the current exchanges, N2EX and EEX, as well as brokers would need to operate in this market in the same way as currently. It is expected that as the market operator is largely running the physical market, it is likely that the current services provided by both EEX and N2EX would no longer be required. The ICE futures market is likely to face an expansion off the back of a change to central dispatch and would see a shift to financial products to manage physical delivery risks. More details on the effect on market actors are provided in the sections above.
- Overall likelihood to deliver, including resistance from stakeholders. Strong resistance from existing market participants to this change should be expected. Overall central dispatch would mean significant change for market participants and could create uncertainty to their revenues. As such, market participants may challenge the approach.

System Impacts of a Central Dispatch model

- Impact on wholesale market prices: Price formation under a central dispatch model is fundamentally different to the existing market. In the current design, market participants reveal the market price via their interactions on the OTC market and via the auctions run by EEX and N2EX. There are currently no rules in place that limit or cap prices that market participants can offer to sell at. Prices in this model tend to be determined by the traders' assessment of the prevailing fundamental conditions of demand and supply. In practice this means traders have their view on what market merit order is and what the price setting (i.e., the mostly costly generation unit needed for supply to match demand). The risk of imbalance is factored into the price in the wholesale market for peak products. This comes through expectations of balancing prices and NIV.

In a central dispatch model, the market price is administratively determined by the MO/SO. The parameters used to set prices are detailed policy design choices. This inherently provides the opportunity to have greater control of the prevailing market prices. There will always be the need to provide the right incentives for market participants to invest and dispatch efficiently. Such an approach can, if implemented properly, be more transparent for market participants who all have a clear understanding of the rules.

In the central dispatch model the market clearing price clears from the constrained schedule and takes account of transmission cost and system need within the price formulation (it reduces the merit order available to the ESO). This suggests that the prevailing wholesale market price would be higher than the current clearing price (which does not take account of constraints). However, it is likely, as demonstrated by the stylised example, that the overall system costs would be lower because the number and cost of BM actions is significantly reduced – see below.

One key benefit is that central dispatch does enable market power concerns to be addressed directly in the pricing formulation by the SO[22]. Central dispatch stipulates clear rules and parameters for charging and technical aspects. This means generators have to submit cost information to help determine their marginal cost on which prices are based. In addition, generators must submit audited technical parameter information to the SO – this is commonly the 'equipment servicing instruction manual'. This is a more ex-ante approach to tackling market power risks than in GB which relies on competition to foster competitive outcomes and ex-post investigations to tackle any potential abuses. This does, however, still require difficult assessments of when prices genuinely reflect scarcity and when they are abuse of market power.

- Impact on balancing costs: Under a central dispatch model, the market clears at a price that takes account of the constraints. This would shift the costs of constraints from the BM (currently) to the wholesale market. As such, imbalance price and volumes would be significantly lower because any imbalance is centrally controlled by the SO/MO and market participants only face operational non delivery risk (e.g., outages).

The total impact on the costs of balancing the system are key to determining the impact. A central dispatch model would reduce some of the overall balancing costs by lowering some of the revenues that would have made from dealing with constraints in the BM. These would, however, only partially address the problem caused by constraints because of the increase in market prices.

- Liquidity: The impact on liquidity is difficult to estimate and would ultimately depend on a whole suite of policy choices, including retail reform. There is no clear reason why liquidity would be adversely affected; many central dispatch models have good levels of liquidity. A central dispatch model would focus liquidity at the DA and ID stage, and most likely enhance ID liquidity. It is also anticipated that there would be a shift to trading on financial products to manage hedging and delivery risks.
- Impact on interconnectors: Moving to a central dispatch is not expected to significantly affect interconnectors and cross border trading. The bidding process for interconnectors will change though. Moreover, transitioning to increased algorithmic trading could lead to enhanced flexibility in cross border trading.
- Impact on low carbon investment: Implementing a centralised model is a significant change for market participants. Understanding the full implications for return on investment will depend on numerous detailed policy decisions. This change is likely to harm investment across the board, because it is assumed that investors prefer certainty on their capture price and expected load that is achievable. The change would lead to significant periods of time in which investors would have significant difficulty in forecasting capture prices and load expectations; this has the potential to negatively

[22] ISO-NE is operated using a centralised dispatch model

affect investment. Arup would argue that investment is principally determined by the subsidy mechanisms currently in place, such as a CfD. As such, we consider clarity on the support mechanism as the key determinant of investment. Further, to attract global investment funds the key for investment is likely to be the relative generosity of the support's schemes compared to Europe, the US and China.

Once a central dispatch model has been established, algorithmic trading[23] should facilitate the participation of smaller flexible assets like batteries, other storage options, and DSR in the wider market. This is because a central dispatch model enables the SO to simultaneously aggregate and dispatch lots of smaller units rather than having to rely on larger units for simplicity. This would help the future investment case for low carbon flexibility by allowing technologies, such as batteries, to capture a much larger share of the wholesale market rather than relying predominantly on A/S provision. Further, participation from flexibility providers could also benefit from greater transparency created by centralised dispatch if implemented in such a way that participants could see where constraints were.

It is, however, doubtful that the move to central dispatch fundamentally changes the investment case for all low carbon generation technologies and the impacts are likely technology/capability specific. The need for CfDs, and other subsidy mechanisms would be required, especially for large scale investments (Nuclear, CCUS hydrogen, pumped storage and interconnectors).

- Interaction with demand – It is not clear that moving to a central dispatch model would facilitate greater demand participate in and of itself. A clearer reference price could make it easier for DSR to realise value than is currently possible. The move to algorithmic trading is likely to increase the participation of DSR in providing flexibility. As above, this is because it provides greater scope for control room to accept and aggregate the supply of many smaller generating units rather than relying on larger generator units. In terms of incentivising DSR, much would depend on the detailed design options. Crucially to this, and for other sources of flexibility, is the ability to adjust positions and offerings as close to real time as possible. In the central dispatch model set out the design proposed includes an IDM. Centralised dispatch models that have had most success with DSR, such as PJM, have mechanisms that allow almost real time adjustments to key generation parameters which better reflect the supply and demand conditions. Should a centralised dispatch model be taken forward, allowing for real time balancing for certain technologies alongside the design appears to be the best model to foster a DSR market. It should be noted that to allow full demand side participation requires households to have smart meters and the market rules to have full half hourly (or less) settlement.
- Impact on security of supply. When considering security of supply, the distinct concepts of capacity adequacy and system reliability are considered. In terms of capacity adequacy, the proposed model should not significantly alter the results of the existing

[23] We note that it is entirely possible to have algorithmic dispatch in self-dispatch market designs, however it Is not as fundamental as in central dispatch design and we consider this benefit less likely to be realised in self-dispatch.

market. It is highly questionable that the market revenues would be such that we could move to a purely energy only market. It is more likely that a capacity adequacy policy would be required. In terms of system reliability, a central dispatch could potentially improve the outcomes compared to the current levels. This is largely because a centralised dispatch approach allows for contingency reserves to be co-optimised alongside general dispatch, giving the SO much more control. The benefit from this is likely to be marginal given that GB has historically had a resilient system.

Conclusions

The above analysis and assessment of centralised dispatch indicate that it is too different from the current design to be considered an incremental reform. It is unclear whether the costs of implementation would outweigh the benefits as some of the potential benefits are dependent on design choices. Given its enabling role, central dispatch should be considered as part of package of reforms, alongside other design choices such as co-optimisation, greater temporal and locational granularity.

Exploring increased temporal granularity

Introduction

In this section, the temporal granularity element of electricity market design is explored with a focus on exploring shortening gate closure and settlement periods models. The purpose of this section is to:

- Make a recommendation on the preferred settlement and gate closure intervals.
- Review the available literature.
- Provide a stylised example and simulation of a shortened settlement period.
- Understand the potential of increased temporal granularity to alleviate the issues created by the current market design.
- Assess its implementation complexity on the various market actors.
- Flag its drawbacks and provide a qualitative view of their magnitude.
- Provide the views of industry experts on such reforms.

Section 5.2 provides a review of the benefits of increased temporal granularity based on the existing literature. It also introduces the various approaches implemented globally.

Section 5.3 describes a model with increased temporal granularity and its impact to the key market actors. Section 5.4 assesses the implementation steps and requirements based on international examples.

A potential shorter settlement model for GB is simulated in Section 5.5 which is derived using Arup's PLEXOS market simulation model. Section 5.6 summarises viewpoints from market participants interviewed by Arup in relation to increased temporal granularity.

An assessment of a shorter settlement period and shorter gate closure followed by conclusions is presented in Section 5.7.

Key takeaways

A transition to a 5-min settlement period is likely to deliver higher benefits versus a 30-min or a 15-min settlement period and is likely to be better suited to a future GB electricity market with greater flexibility requirements.

As the technology and generation mix advances, a 30-min gate closure interval should be considered further through a CBA. Anything below that could lead to adverse impacts when it comes to system costs and security of supply.

The analysis conducted as part of this study concluded that the biggest implementation impact is expected to be related to IT systems, billing and metering.

Review and analysis

Electricity markets require second by second balancing to ensure system frequency is maintained. The cost of maintaining this balance will change second by second depending on the demand and supply conditions prevailing at the time, for example, the current wind speeds or whether it is half time in a world cup final. Theoretically, this would suggest that market prices should truly reflect costs, and as such, they should be set at the most granular level possible. As the system transitions to net-zero there is an increasing need for greater flexibility from both demand and supply, as more intermittent generation is in operation. By making the electricity pricing periods more granular there is the potential to encourage greater amounts of flexibility from both demand and supply side providers. Given the theoretical benefit of greater temporal granularity and increasing need for more flexibility, it is logical to explore whether the GB market should consider finer temporal granularity design options. In this report the following changes are investigated:

- Shortening the imbalance settlement period (ISP) and dispatch interval granularity from 30-minutes to 15-minutes or 5-minutes.
- Shortening the MTU from 30-minutes, to 15-minutes or 5-minutes.
- Bringing the gate closure interval down from 60-minutes to 30-minutes, 15-minutes or 5-minutes.

GB is not alone in considering the introduction of finer temporal granularity in its market. Over the past 10-15 years, many markets across the world have decided to proceed with similar market design changes. These changes have the potential to deliver much needed system benefits, but also require significant changes to the operation of all market participants including generators, the ESO, consumers and market operators.

This section explores the potential of the different temporal granularity options to improve the existing electricity market design. It provides an overview of how a system with increased granularity would perform against our key assessment criteria. This is done by:

- Reviewing the literature and experience of other countries.
- Creating a market model with increased temporal granularity.
- Assessing the impact on market actors.
- Discussing with industry experts.
- Simulating how shorter settlement periods would affect prices and the generator output/ mix.

Increasing the granularity of ISP and Market Time Unit

The main design element of increased temporal granularity is the ISP. This refers to the time interval during which financial transactions are being settled for energy being bid in the market. Normally the ISP will also determine the minimum market unit as market participants can only trade with the SO in real time, hence there is no incentive to trade products of higher granularity with third parties via exchanges or in the OTC market. Advances in metering and IT technology have allowed various countries to introduce finer time resolution in their electricity market designs. The settlement process ensures that market generators are paid for the energy provided in the market. In most markets the settlement and dispatch periods are the same. In the GB market, both the settlement and dispatch periods are 30-minutes. An equal length of settlement period and dispatch interval can help increase the market participation of various players by providing accurate price signals to market participants[24]. When the settlement period and dispatch intervals do not match - such as in the Australian NEM, where the dispatch interval is five minutes compared to the settlement period which is 30 minutes - the seller is not paid based on the price of power in five-minute intervals, but for the average price over a 30-minute period[25]. Previously it has been difficult to have more granular settlement periods due to limitations in metering and IT capabilities. Improvements in technology now make shorter settlement periods easier to introduce. The length of settlement periods in different markets range from between five minutes and one hour.

The main benefits a more granular ISP could deliver are:

- The financial settlement more accurately reflects the actual balancing actions taken by SO.
- Reduction in balancing costs.

[24] International Renewable Energy Agency (2019): Increasing time granularity in electricity markets.
[25] Australian Energy Market Commission (2017): Fact sheet: how the spot market works.

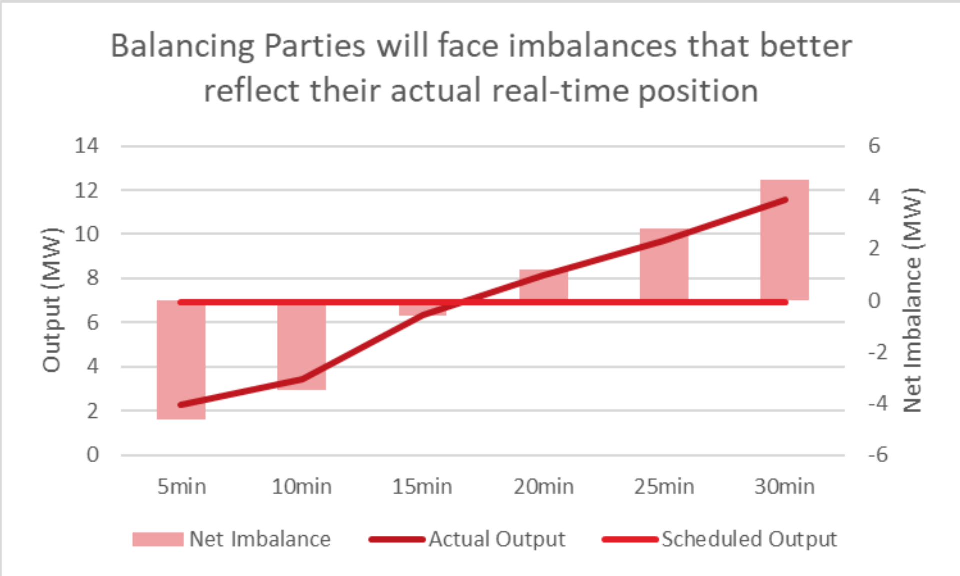
- Improves market incentives for flexible and intermittent generation.
- Improved cross border trading.
- Improved IDM liquidity.

Financial settlement would more accurately reflects actual balancing actions

Currently the ISP in the GB market is set at 30-minutes. This means that Balancing Parties would need to either buy/sell their imbalance in the market or face the imbalance market price. During the 30-min settlement period, a balancing party can be both short and long (e.g., when it ramps up or down). The amount on which their position will be settled will be their net imbalance over the 30-min settlement period. In

Figure 20 we present an illustrative example of a market participant that was off balance over the full 30-min period but will not face any imbalance charges as its short and long positions netted each other off.

Figure 20: Illustrative example of scheduled versus actual imbalance



In the case illustrated above the SO needs to take both upward and downward balancing actions within the 30-min settlement period to balance the system. However, these costs cannot be passed to the responsible balancing party and therefore cannot be recovered. Introducing a shorter settlement period would allow the SO to allocate of imbalance charges more accurately. This creates fairer imbalance pricing and more incentives for balancing parties to balance their position more accurately.

Reduction in balancing costs

In a report conducted by Frontier Economics (2016)[26] market participants (including the GB market) suggested that an ISP of finer granularity could encourage balancing parties to trade more power in the IDM, using more granular generation forecast to reduce their imbalance.

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[26] CBA of a change to the imbalance settlement period, a report for the ENTSO-E, Frontier Economics 2016

This in turn would reduce the number of balancing actions required by the SO post gate closure, resulting in lower costs overall. It should be noted, however, that several stakeholders that took part both in the Frontier Economics report and in our interviews were sceptical on whether a material shift from balancing to IDMs would be made simply by changing the ISP. This would partly depend on what products the market creates in response. Developing short duration peak products (e.g., 5-minutes peak products ID as seen in other markets listed below) could allow market participants to balance their own positions better (better shape and smaller clip sizes), which could potentially reduce the need for ESO energy balancing actions.

Improvement of market incentives for flexible and intermittent generation

Increasing the ISP granularity creates incentives for shorter duration, fast response technologies like DSR and BESS. Having a 5- or 15-min settlement period would provide more opportunities for flexible technologies to offer their energy either in the ID or BM. Furthermore, intermittent renewable assets could have more opportunities to offer balancing services especially if the shorter ISP is combined with a short enough gate closure. This is especially so if new 5-min peak products are provided by the market, either through exchanges or on the OTC.

Improved cross-border trading

Increasing ISP granularity should allow for better utilisation of interconnector flexibility. Cross border demand and supply (and hence prices) could fluctuate within the current 30-min settlement period, but it could be balanced overall in the case that there is excess GB supply at the start of the 30-minutes and excess demand towards the end. Agency for the Cooperation of Energy Regulators (ACER) has proposed moving to a 15-min settlement period. TSOs should have brought into force the new rule three years following the regulation enforcement however delays due to COVID and exemptions have applied. TSOs of a synchronous area may jointly request an exemption of the rule[27]. When this happens and if GB has still 30-minutes ISP and MTU, it would mean that the demand for more granular flexibility could not be met by flexibility in GB. As such, interconnector flows could be sub-optimal as electricity from the higher priced market could flow to the lower priced market for part of the Half Hour. On the contrary if GB moves to 15- or 5-min settlement this would improve the optimal flow of electrons. Moreover, ID trading at finer units will free up capacity in the opposite direction for the remaining of the 30-minutes if price spreads justify it.

The GB market was decoupled from the EU electricity markets due to Brexit. This means that interconnector capacity is now being allocated via explicit auctions as opposed to implicit allocation, that occurred previously, when the GB and EU markets were coupled. Moving to explicit allocation of interconnector capacity is not always efficient and does not guarantee that flows happen from the higher priced market to the lower priced market. If the market moves to 5-min or 15-min ISP and MTU it is likely that algorithmic trading will be incentivised for DAM and IDM due to increased granularity. Such a move is likely to result in a form of re-coupling as the flows between the two markets will need to be optimised through algorithms that essentially

[27] Commission Regulation (EU) 2017/2195 of 23 November 2017 establishing a guideline on electricity balancing.

fits better with implicit allocation. This would most certainly involve re-negotiating part of the EU-UK Trade and Cooperation Agreement, that currently does not allow for implicit trading.

Improved IDM liquidity

ID liquidity could be improved mainly due to more efficient cross border trading and the fact that trading volumes are likely to move from the BM to the IDM. Increased liquidity should lead to a reduction in the bid-ask spreads and, as a consequence, quicker transactions and lower collateral requirements from market participants. The view of GB market participants according to Frontier Economics survey in 2016 was that liquidity would be only slightly increase if we move to a 15- or 5-min ISP (0.69%). Industry experts interviewed for this report did not have a clear view on how liquidity would be affected by moving to a shorter ISP as they did not anticipate major changes in bidding strategies.

It should be noted that increased temporal granularity is not to be looked at in isolation when considering efficiency improvements in intra-day markets. It should rather be part of a wider solutions to the issues faced by intra-day markets (e.g. fragmentation among different markets).

Shortening the gate closure interval

Another temporal aspect of the market is gate closure. Gate closure refers to the point where all market activity stops and the SO takes control of market participant actions. The period between gate closure and real-time is called the balancing window. During the balancing window the SO will ensure that supply and demand are balanced whilst all system constraints are satisfied.

As the GB electricity market moved from being a centralised pool market to a self-dispatch market the requirement for gate closure - when control is transferred back to the SO to balance the system - became a necessity. Right before gate closure balancing responsible parties (or BMUs in the GB market) are required to provide their Final Physical Notifications (FPN). In the time between gate closure and real time the ESO will call upon different resources such as regulated reserves and units participating in the BM to ensure system stability.

The fact that the provision of system management services and energy supply are separated creates inefficiencies in the system that leads to sub-optimal unit dispatch. Several stakeholders have argued that reducing the timeframe between gate closure and real-time could reduce the number of balancing actions required by the ESO and the need for regulated reserve. The expectation of these stakeholders is that this would naturally reduce system management costs. This will, however, depend on the cost of the required actions and on whether most SO actions are taken after gate closure. In reality, energy balancing is only a fraction of the actions taken post gate closure, with the majority most likely related to system balancing (e.g., thermal constraints, inertia etc.).

- The rationale behind having an interval between gate closure and real time is to:
- Gives enough time for the SO to identify and execute the system balancing actions to ensure system reliability and security of supply.

- Gives BMUs enough time to respond (dispatch their units or reduce their demand) to balancing actions order by the ESO.

The key design parameter when it comes to gate closure is the definition of the interval between gate closure and unit dispatch. As described in our international example review below different countries have different approaches to gate closure interval. The gate closure interval influences the system management approach taken by the ESO:

- Reactive management (≤60 minutes).
- Short duration window (sub-15 minutes).
- Medium duration window (15-minutes to 60-minutes).
- Proactive management (>60-minutes) – which is also called a long duration window.

Overall, a longer interval (i.e., proactive management) favours balancing accuracy at the expense of market efficiency whereas a shorter interval could improve market outcomes but could lead to sub-optimal balancing of the system (Katz and Kumar, 2019[28]). Shorter gate closure allows for optimal forecasting which may reduce system balancing costs. It also provides incentives for fast responding flexible asset (e.g., batteries and DSR) and has the potential to enhance IDM liquidity. Dispatch decisions would be made on less information which supports market transparency. On the other hand, reducing the gate closure interval too much could reduce the ESO's options to balance the system and lead to spikier prices and increased system costs due to low availability of resources (Petitet and Perrot, 2019[29]).

Feedback received through expert interviews (analysed in the relevant section) suggest that SOs prefer a longer gate closure. On the other hand, market participants especially fast response assets (like BESS and DSR) and renewable generators, fell like they would benefit from a shorter gate closure interval.

Facchini, Rubino, Caldarelli, and Di Liddo (2019[30]) have pointed out that the changing generation mix has played a key role in enabling the GB to reduce its gate closure interval from 3.5 hours to 1 hour. They suggested that as flexible gas generators gradually replaced the aging UK coal fleet the SO could balance the system closer to real time. This is simply because the response (warm-up time mostly) time of CCGT units is much lower when compared to coal fired units. Expanding on this observation, it can be inferred that since this transition, the capacity of fast response assets (mostly BESS and DSR) has been growing continuously and is expected to grow further. This supports the arguments of transitioning to a shorter gate closure interval.

Another enabling factor for shortening gate closure is the advancement of IT technology. SOs around the world need to run security constrained unit commitment dispatch models and issue

[28] National Renewable Energy Laboratory (2019): Opening Markets, Designing Windows and Closing Gates: India's Power System Transition – Insights on Gate Closure.
[29] Petitet et al. (2019): Impact of gate closure on the efficiency of power systems balancing.
[30] Facchini et al. (2019): Changes to Gate Closure and its impact on wholesale electricity prices: The case of the UK.

dispatch decisions. This process takes time and usually involves a few manual/ non-automated interventions. Current technology should allow for this process to be run by efficient algorithms at significantly faster times.

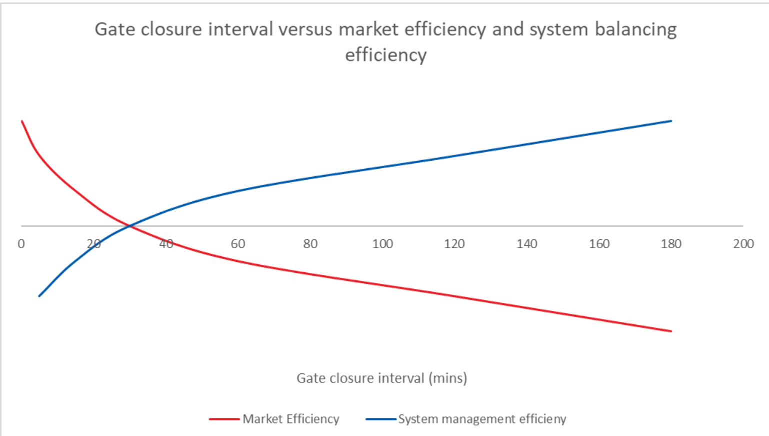
Globally there is a trend across markets to bring gate closure closer to real time. The European Agency for the Cooperation of Energy Regulators (ACER) has recommended that the gate closure should be brought as close to real time as possible and sees three main benefits (ACER, 2022[31]):

- Bids in the BM would better reflect actual market conditions.
- Enhanced incentives for flexibility provisions.
- Better integration of intermittent renewable energy sources.

Even though there is enough documentation supporting the transition to a shorter gate closure interval nearly all of it is based on qualitative analysis. Petitet and Perrot (2019) delivered one of the very few quantitative studies on the subject. They found that a 30-min gate closure leads to more balancing actions but a lower cost versus 15-min gate closure intervals. It should be noted, however, their analysis is based on the existing market and does not consider increased penetration of renewable and flexible assets.

Currently the gate closure in the GB market is 1-hour. The REMA consultation considers shortening gate closure as a measure that could deliver system benefits whilst not being overly complex to implement and can be done within the existing codes and licences. Overall, the available literature, along with feedback received from industry experts, suggest that there should be some benefits by reducing gate closure and the ESO should have the capability to drop it below 1-hour.

Figure 21: Illustrative example of how gate closure affects market outcomes and system management



[31] Decision No 03/2022 of the European Union Agency for the Cooperation of Energy Regulators of 25 February 2022 on the amendment to the methodology for pricing balancing energy and cross-zonal capacity used for the exchange of balancing energy or operating the imbalance netting process.

This should be possible without compromising system security. Moreover, the gate closure interval should be set at a level where market efficiencies are not overhauled by sub-optimal system management due to limited options and time available to the ESO.

Benefit and Drawbacks

A summary of the theoretical benefits and drawbacks of increasing temporal granularity in the existing GB market design is presented in the table below.

Shorter ISP and MTU		**Shorter Gate Closure**	
Benefits	**Drawbacks**	**Benefits**	**Drawbacks**
Allows for better management of uncertainty around matching supply and demand. Enhances investment/ market participation incentives for fast response flexible assets. Enhances incentives DSR participation. More accurately reflects balancing costs allowing for fairer allocation of costs among balancing parties. Has the potential to reduce balancing cost by encouraging more ID trading. Allows for more efficient cross-border trading. Incentivises market participants to upscale their automation capabilities (e.g., algorithmic trading).	Can lead to spikier pricing. Requires significant investment from certain market participants especially on IT systems and metering. Does not significantly alter the market behaviour of large generators that currently provide the bulk volume of flexibility. Does not address major system management issues (constraint management and market power). Creates complexity to the Market Wide Half Hourly Settlement transition. Could create uncertainty to investors relying on CfD and CM.	Allows for better management of uncertainty around matching supply and demand. Enhances investment/ market participation incentives for fast response flexible assets. Enhances incentives DSR participation. Allows for demand updates closer to real time which is important especially for renewable resources with variable output. Should move some of the energy balancing volume to ID trading. Incentivises market participants to upscale their automation capabilities (e.g., algorithmic trading). It is relatively straightforward to introduce from a Code and License perspective.	If reduced too much it could lead to an increase in balancing costs by limiting the options available to the SO. The current generation mix's response time poses limitation on how close gate closure can be brought to real-time; the ESO suggested that most CCGTs have ramp up rates between 60-89minutes. Does not address major system management issues (constraint management and market power).

It is relatively straightforward to introduce from a Code and License perspective.			

Examples from other countries

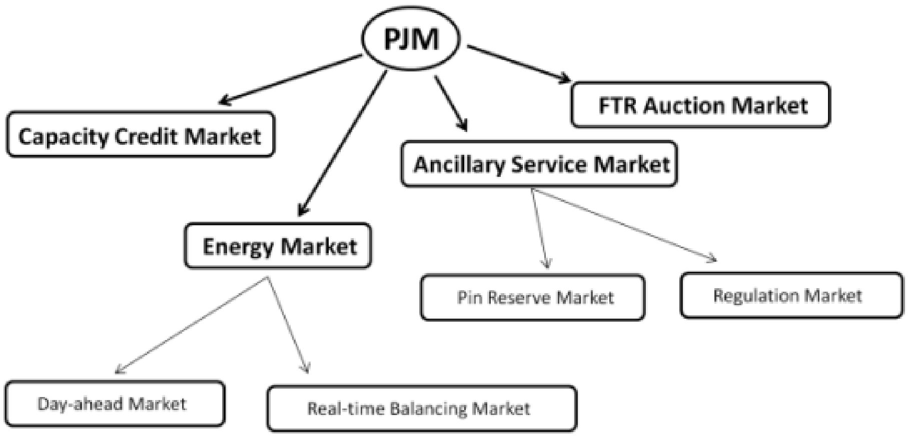
California

California has proposed to reduce the granularity of traded products from 1 hour to 15 minutes to remove barriers to the integration of variable renewable energies (VREs). The reduction in the size of the scheduling intervals was hoped to enable power generating resources to follow the load curve more closely as forecasted by CAISO.

Balancing Energy Market in the PJM – A case study of real-time balancing energy market.

The PJM manages one of the largest, competitive wholesale markets and power grids, spanning 13 states and the District of Columbia. The PJM fully integrates the DA and the real-time markets. PJM's operation involves co-optimisation of the supply side and the use of a bid-based, security-constrained economic dispatch with locational marginal prices (LMP). The market has operated a real-time energy market and a DAM since 1997 and expanded this to become a LMP-based real-time energy market in 1998. The PJM began accumulating real-time data at five-minute granularity intervals from August 2007 onwards.

Figure 22: PJM market overview



The PJM operates a real-time BM in which the clearing prices are calculated every five minutes, based on the SO's security-constrained economic dispatch[32]. The real-time market is a spot market allowing the SO to match demand and generation instantaneously and reduce

[32] A. Ott (2003): Experience with PJM Market Operation, System Design, and Implementation

marginal losses from congestion. The real-time BM has a sperate accounting settlement to the DA, it is settled based on hourly integrated quantity deviations from the DA scheduled quantities and real-time prices integrated over the hour. The prices for both the BM and the DAM are calculated under the nodal mode using LMP[33].

Real time operation of the BM reflects the actual real-time operating conditions. Generators that are not dispatched in the DAM have the ability to alter their bids for use in the real-time BM. Every five minutes, the PJM system transmits an electronic signal to market operations centres that then transmit the signal to generating plants, indicating how much electricity they should be producing. Generators are expected to adjust their output according to this signal. In some cases, ignoring PJM's dispatch instructions may result in financial penalties[34]. In the real-time market, the electronic signal is sent out every five minutes to indicate output to generators. Generators can adjust their offer for up to 65 minutes before the next hour and those who are chosen for dispatch will be paid by real-time LMPs. Dispatch decisions are primarily made using an automatic real-time Unit Dispatch System (UDS), this optimally determines the resource commitment and dispatch[35].

The need for real-time products has been suggested as essential for a competitive wholesale electricity industry. The Federal Energy Regulatory Commissions (FERC) in the US highlighted this need as a part of their Order 2000. This instructed that RTOs must ensure its transmissions customers have access to a real-time BM that is developed and ran by and independent entity (not connected to participating market players). The FERC implied these real-time markets were essential for supporting competitive electricity markets and non-discriminatory behaviour[36].

The PJM has experienced increasingly negative balancing costs in recent years, a stark difference to GB's recent balancing costs. In 2021, Monitoring Analytics, the external market monitor of the PJM, reported that balancing costs further decreased by $97.1 million, from -$133.8 million in 2020 to -$230.9 million in 2021[37]. Some of these savings can be attributed to the 'perfect dispatch' tool implemented in 2008. It is a real-time dispatch performance assessment designed to perform an assessment of PJM dispatch actions to determine how well the overall real-time dispatch process managed uncertainties. By 2009, this process has resulted in an estimated savings of $122 million due to a reduction in production costs due to dispatch and forecast process improvements[38]. To note, the GB market does not have AGC

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[33] B. Gisin et al. (2010):" Perfect Dispatch" - as the measure of PJM real time grid operational performance
[34] PJM (2023): How PJM & Generators Continually Balance the Grid.
[35] B. Gisin et al. (2010):" Perfect Dispatch" - as the measure of PJM real time grid operational performance
[36] E. Hirst (2001): Real-time balancing operation and markets – Key to competitive wholesale electricity markets
[37] Monitoring Analytics (2022): 2021 State of the Market Report for PJM
[38] A. Ott (2010): Evolution of Computing Requirements in the PJM Market – Past and Future

technology on its generation units that enables frequency to be controlled. This means our ESO would be unlikely to have the confidence to move to real-time market.

Germany

In 2011, Germany reduced the dispatch interval to 15-minutes from 1 hour for the IDM to enable the valuation of flexibility. After the success of the 15-minute contracts on the IDM, EPEX launched an additional 15-minute ID auction at 3 p.m. one day before the delivery date in December 2014[39], helping fine-tune the portfolios after the hourly DAM and facilitate trading for intra-hour variations in power production and consumption.

Gate Closure in Germany

The German energy market incentivises market participants to adjust their position as close to real time as possible. In Nordpool the gate closure is essentially zero whereas in the EPEX Spot market participants can amend their position 30-minutes of 5-minutes ahead of real time. The minimum MTU is 15-minutes and markets participants can trade in 15-minute periods of whole blocks of hours. The German SO can accommodate position adjustments with such short notice by re-dispatching units ahead of real time to manage transmission constraints and maintain sufficient spinning reserves in the system. Market participants can then adjust their position within specific limits.

EU

Prior to the implementation of the pan-European single ID coupling via the commercial XBID project in 2018, many national IDMs had sub-hourly products, such as 30-minute products traded in continuous IDMs in France, Germany, GB, Luxembourg, Switzerland. Note that following Brexit the GB is not part of the XBID anymore.

In addition, 15-minute products were traded in Austria, Belgium, Germany (both continuously and auction), Hungary, Luxembourg (both continuously and auction), The Netherlands, Slovenia and Switzerland.

Furthermore, the XBID system, which is the European project aiming to deliver a single IDM across different European zones, now supports a wide range of products.

ACER decided in 2018[40] to harmonise gate opening (at 3pm on DA) and closures times (60 minutes) for the pan-European IDM. However, it views shorter gate-closures very positively. Currently, gate closure is 30 minutes in the Finnish-Estonian border which ACER has said it “should not be considered as an exception, but rather as a preferred solution”. ACER’s view is that shorter gate closure intervals improve system balancing and security as market participants can adjust their output closer to real time. At the same time 30-minutes gives enough time to TSO to deliver system balancing actions. In other national markets across

[39] EPEX (2014b), 15-minute intraday call auction, EPEX Spot.

[40] ACER Consultation

Europe, the local ID gate closure time is five minutes before the beginning of physical delivery. These countries are Austria, Belgium, Germany/Luxembourg.

Brazil

Brazil is now introducing hourly prices in power markets. It also aims to introduce dispatch intervals of 30-minutes. The half-hourly dispatch and hourly pricing are currently being tested, and Brazil expects to fully introduce them at the beginning of 2020[41]. The law also aims to increase the granularity of wholesale market price formation to increase short-term flexibility

Australia

When it was established in the 1990s, the NEM adopted a 5-minute dispatch period, which is considered the shortest possible timeframe practicable. It has since adopted a 30-minute settlement period based on the limitation in metering and data processing (AEMC, 2017b)[42].

In 2017 the Australian Energy Market Commission (AEMC) introduced a rule to change the financial settlement from 30 to 5-minutes. This means that the price in the market will align with the physical delivery. With this change, the AEMC expects that in the long run, efficient price signals to the market will lead to lower wholesale electricity costs.

With the increasing penetration of VREs (Variable Renewable Energies), the role of flexible technologies is expected to increase, however, the mismatch in dispatch and settlement periods has led to many inefficiencies in the operation and generation mix. Inefficient price signals have also impeded the pickup of flexible sources entries, such as fast-response generation or demand-side response.

In recent years, the spread between 5-minute dispatch prices and 30-minute settlement prices has increased and is expected to rise further. By matching the physical electricity system and financial settlement period, the AEMC expects that investment in flexible and fast response technologies will increase. The change in this rule is expected to help power generators to take more efficient decisions, which would ultimately lead to lower power prices for consumers. The 5-minute financial settlement rule is also expected to reward customers who are able to respond to peak demand for short intervals only.

Nordic Market

The current gate closure periods of the Nordpool market are 60-minutes in the IDM and 45-minutes in the BM restrict the use of commercial power trade to cover the variations in power generation and demand. In its report “Building an efficient Nordic power market”, Fortum Energy suggested reducing the gate closure of Nord Pool to 15-minutes in both ID and BM, arguing that a 15-minute gate closure would help improve the use of commercial resources

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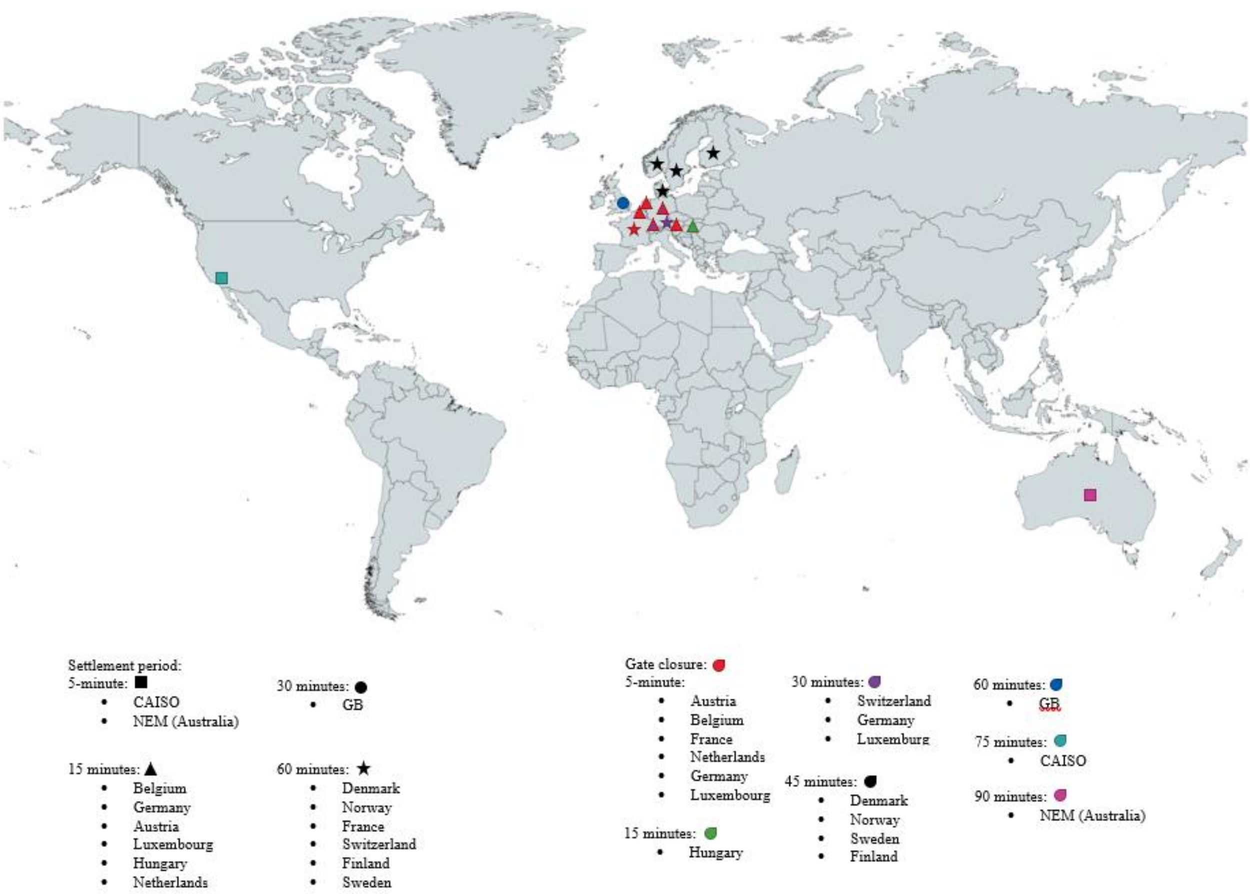
41 Batlle, C. et al (2018), “Brazil considers reform of the electricity sector”, Oxford Energy Forum, June, pp. 21–24

42 AMEC (2017b), Rule determination – National electricity amendment (five minute settlement) rule 2017, Australian Energy Market Commission, Sydney

and reduce the number of occasions when the fast TSO reserves are activated (Fortum, 2016)[43].

In 2016, Nord Pool, Elering (the Estonian TSO) and Fingrid (the Finnish TSO) launched a pilot with a 30-minute gate closure time in the IDM on the Estonian-Finnish border, replacing the previous 60-minute gate closure. Based on positive feedback from market participants, the pilot was implemented as an interim solution until the XBID project commenced (Baltic Electricity Market Forum, 2016)[44].

Figure 23: Settlement and gate closure intervals in international markets



Note: The Nordic Markets are set to reduce their settlement periods from 60-minutes to 15-minutes on the 22nd of May 2023.

43 Fortum (2016), “Building an efficient Nordic power market”, Fortum Energy Review.

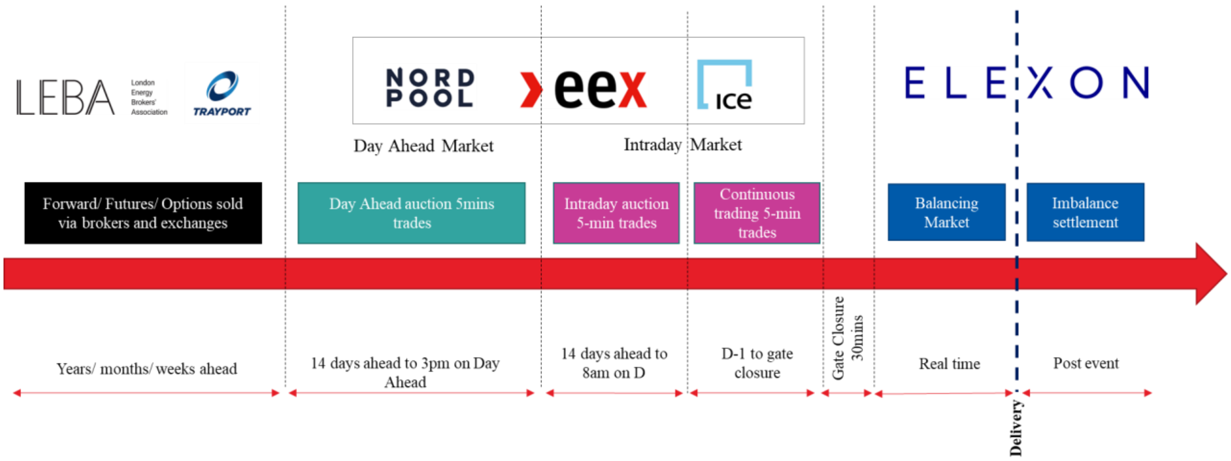
44 Baltic Electricity Market Forum (2016), Nord Pool update 2016, Baltic Electricity Market Forum.

A model with increased temporal granularity

Key market design parameters

Below a description of the key market design parameters in a system with increased temporal granularity is outlined. In the visuals we have used 5-minutes for the ISP and 30-minutes for gate closure. This does not reflect our conclusion and it is only used as a visual example. Our recommendation will be provided in the relevant section.

Figure 24: Overview of 5-min settlement design



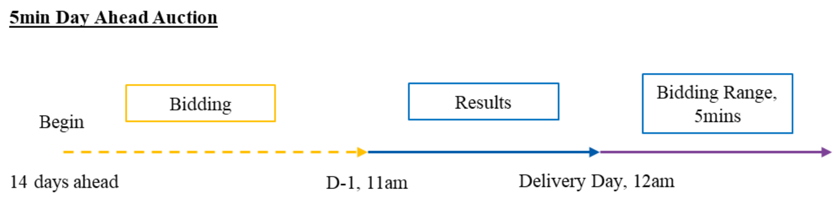
Dispatch and settlement: Dispatch and settlement will be fully aligned. ESO will dispatch generators in the shorter ISP minute intervals and generators will also bid to generate electricity according to the new shorter ISP.

Gate Closure: Gate closure interval would be reduced and BMUs will notify the ESO about their final dispatch plans (FPN) closer to real-time.

Demand & Supply: Demand and supply will be matched every 5-minutes

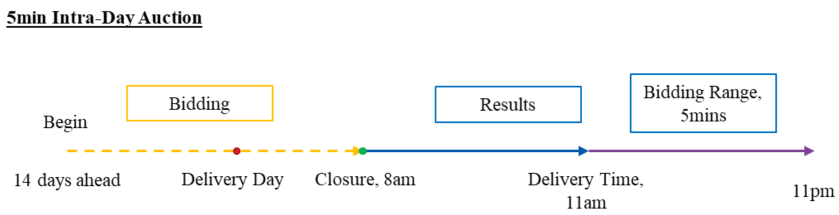
DA auction: The format of the auction is expected to remain the same and run by Nordpool and the European Energy Exchange (EEX) as it is done now. Order books will open 14 days ahead of delivery and will close on 11am one day ahead of delivery. The results will be published as soon as possible after the close of bidding. The only type of contracts offered will be 5-minute contracts. Exchanges will offer all types of bids that they currently offer (simple bids, block bids, complex bid and flexi bids) but the price will be settled in 5-minutes instead of 30-minutes.

Figure 25:5min Day Ahead Auction process



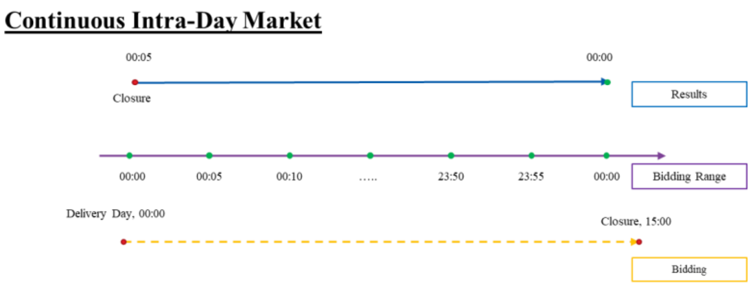
ID auction: As per above (DA auction) a full transition to products settling every 5-minutes is expected. Auction will still be performed by Nordpool and EEX. The bidding will stop at 8 am on the day of delivery and the bidding range will be from 11am to 11pm.

Figure 26: 5min Intra-Day Auction process



ID continuous trading: ID trading will take place around the clock until gate closure for BMUs and 15-minutes before real-time for non-BMUs. BMUs will be able to trade and adjust their position closer to real time whereas the situation will remain the same for non-BMUs. Continuous trading will also take place using the new shorter ISP.

Figure 27: Continuous Intra-Day Market process



Minimum Trading Volume: It would be reasonable to reduce the minimum trading volume to 0.05MW (currently 0.1MW). The main benefits for the system under a shorter settlement and shorter gate closure reform will mostly come from DSR and flexibility. This should not affect the bidding and optimisation behaviour of larger fossil fuelled power plants who will still bid for larger blocks (along with baseload and peak). This should reduce entry barriers for smaller DSR and flexibility providers (e.g., it reduces the need of intermediaries – aggregators). A higher number of market participants will benefit market liquidity.

Balancing and Imbalance settlement: Balancing and imbalance settlements will occur in the new shorter ISP intervals. The IPN will be submitted at 11am one day ahead of delivery (no change from current status quo). The FPN and contractual notification will be submitted 30-minutes before delivery which will be the new gate closure interval. It is most likely that the De Minimis Acceptance Threshold (DMAT[45]) will need to drop to 0.008MWh to accommodate for 15-minute or 5-minute ISP and MTU. This is below 0.017MWh, which is the potential error volume created by the granularity of the system. If the market moves to a 5-minute ISP the Continuous Acceptance Duration Limit (CDAL[46]) will need to drop to 5-minutes compared to the 10-minutes that it is now.

Profiled demand profile and settlement: Non metered demand is currently settled based on 8 demand profile classes. The plan is to transition to half hourly settlement of all demand which will change the profiling process. For consumers that have opted-in for their actual demand data to be used there will be no need for profiling. For customers that have opted-out, profiling will use data from similar consumers instead of retrieving their profiling from the existing 8 profile classes. Arup expect the decision to move to a shorter settlement period to also impact and be part of the MHHS programme. As a result, the profiling will also change and be based on 5-minute settlement data.

Implementation

Moving to finer temporal granularity would require significant process, IT, operational and legal / code documentation changes. It would require close collaboration and detailed preparation across all market actors. It is, however, a change that can be made using the existing code framework and could be instigated by Ofgem directing NG ESO to raise a modification proposal. A high-level overview of the main changes different market actors will need to undertake to adapt to the proposed temporal granularity reforms is outlined below. Based on the changes required and looking at international examples, the implementation pathway and main impacts have been assessed.

Implementation considerations for key market actors

Generators

- In this section generators are considered the assets connected directly to the transmission system or large generators connected to the distribution system.
- Generators would need to replace or update their metering equipment. This would include data collection processes and software, metering data management process (storage, reporting and processing).

[45] The De Minimis Acceptance Threshold is a parameter used to eliminate Bid/Offer acceptances of small volume. DMAT is currently 0.1MWh.

[46] CADL is used to flag short duration Bid-Offer acceptances, associated with system balancing actions in the Energy Imbalance Price calculation. A Bid-Offer acceptance relating to any given BMU will be flagged in the system price calculation if it has duration of less than the CADL value in minutes. CADL is currently 10-minutes.

- They will also need to update their IT systems to process larger amounts of data, manage their dispatch and send more frequent notifications to the SO and Elexon.
- Generators will need to change their systems and processes for more frequent scheduling and for calculating settlement data.
- Their systems will also need to have the ability to settle trades over a shorter ISP. This will require additional resourcing on their front desk, IT, and reporting resources.
- Depending on who is responsible for trading and balancing their output, generators might need to develop new forecasting tools to be able to manage imbalances for shorter periods of time.
- They may also need to renegotiate contracts with metering equipment and software providers. This could incur additional costs.
- Generators will need to submit far more regular bids and offers but Arup do not expect significant changes in the behaviour of large conventional generators.
- There should be more opportunity for fast response flexible generation to respond within day and in the BM (BESS, DSR and solar). No changes are expected in the bidding strategies of these players who will continue to target 30-60-minute blocks as per comments received from one of the stakeholders interviewed.
- Renewable generators under a CfD contract will now settle their payments based on the new shorter MTU prices.

Energy Retail

- Energy suppliers will need to process, store and document more granular data; both from larger consumers and from domestic consumers that have opted-in for non-profiled settlement.
- They may need to upgrade or replace smart meters that are not compatible with delivering more granular data in the case they own the meter (or based on the obligation they have towards the customer). They may also need to update data consents with customers to get access to more granular data depending on the current arrangements.
- They will also need to incur additional cost for providing shorter settlement data to Elexon.
- Billing of larger customers or domestic customers that are currently billed on half hourly demand will need to change.
- Suppliers will also need to upscale the data processing capabilities as they will need to profile/ settle their demand in shorter intervals. It is likely that some suppliers will have already explored processing more granular data along-side the smart meter rollout - partly to explore cross-selling and smart advertising opportunities.
- They will need to re-negotiate and re-draft contracts for the purchase and selling of power.
- They may also need to re-negotiate and amend contracts with various parties like metering and DCDA providers.

- They will need to change their price forecasting process. This will require investment in software and allocation of additional resource.
- Their settlement, reconciliation and reporting processes will require front, back, middle office and IT changes.
- They will need to incur additional cost to develop new demand forecasts. Moreover, demand forecasting teams will need to adjust their demand profiles for non-metered customers based on new profiling derived from more granular ISPs.
- Their Time of Use (ToU) tariff offerings and billing will need to be adjusted for the shorter ISP and MTU.
- The transmission and distribution metering systems will now need to be capable of metering data in shorter intervals which will also increase the data processing requirements from the energy suppliers' side.

NG/ESO

- The ESO will need to upscale their technology and procedures to balance the system in the new ISP interval.
- Dispatch decisions and system balancing will need to happen faster and for a shorter ISP. System and processes will need to be amended to accept bids and offer in more granular formats.
- As the ISP becomes more granular the ESO will need to transition from manual management of the system to an automated/ algorithmic management of the system - reports from the Nordic markets also recommend this.
- They will need to upscale the technology capabilities to allow smaller and more agile technologies to take a more active role in system management.
- They will need to change/ update the meters at the exit points from the transmission to the distribution network (only the ones read at the same frequency with the ISP duration).
- They will need to change their processes to provide more granular data of notifications and PNs. Under a system with shorter ISP and gate closure, the ESO would need to issue notifications at a higher frequency.
- The ESO will need to adjust their process to schedule plants over shorter periods of time.
- They will need to amend their systems to enable management, delivery, storage, reporting and validation based on larger and more frequent datasets.
- The ESO may need to work with market participants and Elexon to amend metering data formats to enable the delivery of data in shorter intervals.
- The NG/ESO will need to adapt their loss procuring system and network optimisation process to the new shorter ISP.
- It is likely that they will need to take a rather active role on the amendment of the BSC and other relevant licenses and codes during the transition period.

Interaction with Market-Wide Half-Hourly Settlement (MHHS)

In July 2017 Ofgem launched a SCR aiming to introduce MHHS. In April 2021 they published their decision to transition to MHHS; full transition be completed in 4.5 years (October 2025). Industry will bear the legal responsibility to process HH data for settlement purposes. Elexon will be the programme manager. Under the MHHS domestic consumers will be able to opt-out from HH settlement. In that case their data will be processed at daily granularity. Existing customers will retain their existing data processing arrangement which means they will be able to opt-out to monthly granularity.

Among the key aims of the MHHS are to aid system flexibility and decarbonisation and enable consumers to benefit from innovative products and business models supported by smart meter infrastructure.

Arup's view is that a decision to move to a shorter settlement period should also impact and be part of the MHHS programme. In particular

The MHHS project should be re-directed to the new shorter ISP.

There should not be an option to go for HH settlement. The settlement should be based on the new ISP as two settlement periods will create confusion.

The maximum DSR benefits will be achieved by ensuring all customers have a smart meter installed and being settled on the new ISP.

Considering the market situation, Arup's view is that the same opt-out rules should apply for new and existing customers but there should not be an opt-out option allowing for HH settlement as explained in the point above.

A new project timeframe should be defined which needs to consider work and resource already committed by energy suppliers and the recent disruption the industry had to absorb due to the retail energy crisis. Moreover, should DESNZ decide to move from HH settlement to the shorter settlement period the transition should be managed carefully. Based on feedback received from stakeholders, merging the two together could add complexity and could lead to delays and extra cost.

Elexon

- Elexon will need to adapt their settlement system to the new ISP with the key cost being modifying their IT system and processes.
- In particular they would need to adjust their systems and processes to:
- Calculate and settle imbalances in the new ISP.
- Increase the frequency of data publications.

- They will need to update their data management, data storage, reporting and validation processes.
- As the profiling of Non-HH consumer demand is likely to alter as part of the transition to HH settlement. It is expected that metered customer profiles will be used to define non-metered customers load shape profiles. This should be easily adjusted when the transition to shorter ISP settlement occurs, and there should not be a need to alter the existing profiling methodology to accommodate for the shorter ISP.
- Part of the BSC code will need to be rewritten, with Elexon facilitating and manging code changes with Ofgem the ultimate decision maker. The code changes required should not be very complex and the process should not be very timely especially when looking back at the modification for the move from 3.5 hours to 1 hour gate closure.[47]

Higher temporal granularity implementation impact on licenses and codes

When the GB Market moved to a shorter gate closure (3.5-hours down to 1-hour) the changes required in the BSC were minimal. The changes that had to be undertaken were to change the time from 3.5 hours to 1-hour wherever gate closure was referred to. Moreover, they had to alter timings in clauses that resulted from the assumption of having a 3.5-hour Gate Closure. The had to alter the clauses referring to the “Balancing Mechanism Window Period” and the “Continuous Acceptance Duration” period.

With regards to Code subsidiary documents, they had to make minor changes the “Balancing and Settlement Code Procedure” (BSCP). The changes within the Grid Code were not seen as significant either.

Implementing the modifications related to both the shorter settlement and shorter gate closure in the BSC, the Grid Code and subsidiary documents should be more complicated. Arup’s internal view, based on our expertise, is that these changes should not be of high complexity and should be doable within the timeframes described in the implementation pathways below.

DNOs/ DSOs

- DNOs will need to replace or adjust their meters at the entry points from the transmission to the distribution network to handle data based on the new shorter ISP.
- They will need to change or update meters for large, distribution connected generators along with their data management (storage, validation and processing of data) and data collection process.
- As DNOs become DSO they will need to adapt their system balancing transition process to be compatible with shorter ISP. This means they will need to provide more frequent notifications to distributed balancing parties.

[47] Modification Proposal P12 - Reduction of Gate Closure From 3.5 hours to 1 hour

- They will also need to adapt their future process for scheduling distributed assets for shorter periods of time and calculate their imbalances based on the shorter ISP.
- Their data publication on settlement, scheduling and dispatch will need to be adjusted for the shorter ISP.
- Their billing and charging of consumers will need to change and adapted to the new shorter ISP.
- They will most likely need to take active part in adjustment of the BSC and other relevant codes.
- As with the ESO they will need to incur costs to adapt their network optimisation system and loss procurement system to the shorter ISP.

Interconnectors

- Interconnector administrators will need to submit deemed metered volumes based on the new 15-minute or 5-minute ISP. This is likely to have an impact on process and technology requirements.
- This could also impact the auction for interconnector capacity which can have an effect on interconnector users. This may require consideration of the implications for the Trade Cooperation Agreements with the EU which set rules on how interconnection capacity and commodity prices are matched to determine flows between GB and EU interconnected markets.
- Interconnectors may need to incorporate more automated, and, potentially, algorithmic trading for selling capacity in shorter ISPs. This is because the greater number settlement periods requiring multiple more matching between commodity and capacity.
- They will also need to update their IT systems to process higher amount of data, manage their dispatch and send more frequent notifications to the SO and Elexon.
- Their systems and process will need to be adapted for more frequent scheduling, calculation of settlement data and reporting.
- Their systems will also need to have the ability to settle trades over a shorter ISP. This will require additional resourcing on their front desk, IT, and reporting resources.

Metering equipment stakeholders

- Metering hardware and software providers will need to reconfigure or replace their products (meters and metering software) to be able to process more granular data.
- Some metering equipment would be possible to adapt remotely which should make the process more efficient.
- Data Collection and Data Aggregation (DCDA) providers will continue to collect and aggregate NHH consumer data on behalf of suppliers. They will need to upgrade the storage, validation, and data management process.
- Equipment providers and DCDA providers will need to update their contracts with various stakeholders (generators, suppliers, SO, DNOs etc).

- All new smart meters will need to have the capability to process 15-minute or 5-minute data whilst all the existing smart meters will have to be reconfigured to handle 15-minute or 5-minute data.

EMR Settlement ltd & LCCC

- The CM and CfD now need to be settled in shorter ISP intervals and LCCC will need to adjust their settlement process and data publications and forecasts accordingly.

Energy Exchanges

- Future exchange operators will not need to do any changes as their products are offered in blocks and the settlement period does not affect them.
- Spot energy exchanges (EPEX, Nordpool) will need to modify their process and IT systems to support trading based on the short MTU.
- They will need to upgrade their trading support systems, reporting, data management and publication processes.
- EPEX already offers 15-minute products in the ID continuous market in some countries however this should be adjusted to match the physical reality of the GB electricity market.

Energy trading

- The new more granular ISP and MTU could require the development of new algorithms supporting trading, settlement and clearing.
- Market participants may need to renegotiate bilateral contract agreements for their output due to the new shorter ISP.
- Arup do not anticipate any major changes in the way the OTC forward market works but we may see slightly more variation in peak and overnight products.
- As discussed already, increased IDM liquidity might be seen, driven mainly by the expectation of a shift from balancing volumes to ID volumes. This will, however, need to be tested and confirmed.
- Market participants will possibly need to develop new trading algorithms.
- They will also need to adjust their trading, reporting and risk management processes.
- The hedged volume may change slightly for suppliers and generators that value hedge.

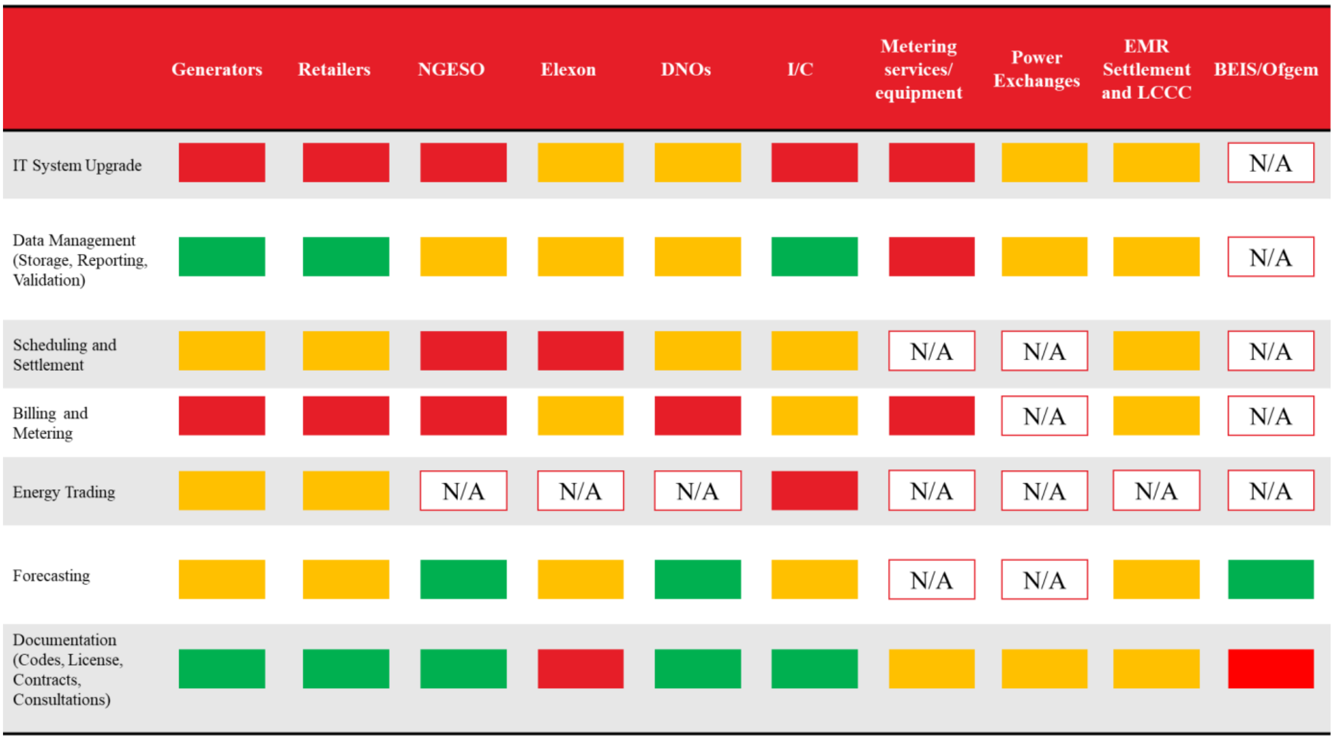
DESNZ and Ofgem

- DESNZ and OFGEM will need to undertake detailed studies to design and define all the key parameters that affect the key market actors.
- Most importantly OFGEM will be the main responsible party for doing or overseeing all the amendments required.
- They will also need to run consultation on specific elements and gather market responses to feed into their policy design.

Market Actor Implementation Assessment

A summary of the implementation effort/complexity that would be required for each market actor is summarised in the table below.

Figure 28: Implementation complexity



International experience

Implementation of 5-minute settlement period – example from Australian NEM

In November 2017, the AEMC made the 5-minute settlement (5MS) rule to reduce the settlement period in the NEM from 30 to 5-minutes. The implementation began in early 2018, initiating a programme to help all the key stakeholders in the market prepare for this. In October 2021 the new 5-minute settlement rule went live. The whole process took just under three years, after plans to take two and a half years were delayed due to the Covid-19 pandemic and the affects it had on the industry.

What were the main challenges in this implementation?

The main challenges that came from was changing all the systems that were currently in place for the old 30-minute settlement system. These main challenges came around:

- Metering for the consumers.
- Distribution network service provider.
- Metering coordination providers.
- Data providers.

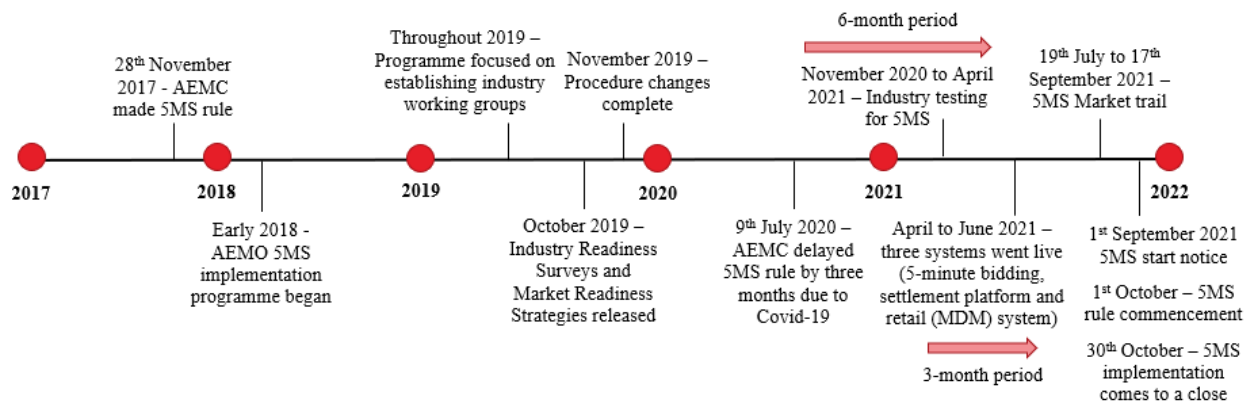
- Energy Retailers.

Energy retailers needed to be able to deal with the larger amounts of data and generators needed to be able to deal with bids every 5-minutes. All these stakeholders were given instructions on how they should get reading for this change and a forum where they were able to ask clarification questions on this process. These instructions, questions and answers are all available on the AEMOs website.

Other than Covid, some challenges that have been faced in the industry during the implementation process included a wide number of issues. These can all be seen on the new 5-minute settlement industry risk and issues register created by the AEMO. Some of the more significant and higher risk issues include:

- Pressure on industry resources coping with the number of changes that need to occur whilst continuing to operate the previous system effectively.
- Large amounts of uncertainty due to a potential 12-month deferral of the new system was being considered. This meant that resources were being allocated away from the implementation process due to the potential of a 12-month deferral of the end date.

Figure 29: AEMO 5-minute settlement implementation timeline

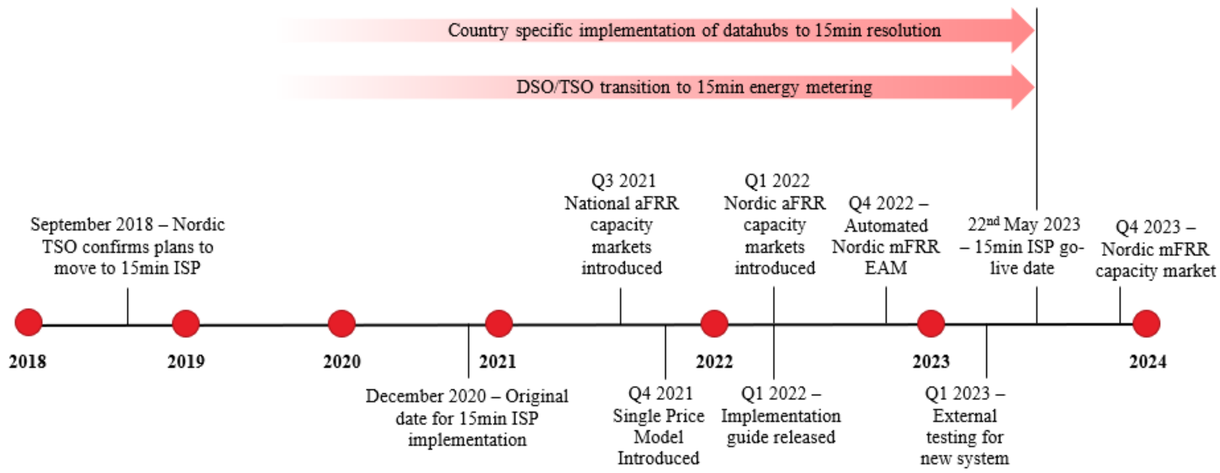


Implementation of 15-minute settlement period – example from Nordic TSOs

The Nordic TSOs in Denmark, Sweden, Norway, and Finland originally planned to transition from a 1-hour settlement period to a 15-minute settlement period in Q4 of 2020. After a stakeholder consultation, the plans have been pushed back to the 22nd of May 2023. This is part of an overhaul to the Nordic energy market via the Nordic Balancing Model (NBM) to align with the EU's aims to integrate European TSO's together to increase security of supply, limit emissions and diminish costs to the consumer. The NBM states their reasoning for wanting to transition to 15-minute imbalance settlement periods as: allowing the green transition in the power system, increasing the possibilities of A/S and electricity market harmonisation in Europe.

One key part of the system that will need to be changed is the messaging of data. There are now four times as many data points per hour being processed and the systems must be updated to be able to cope with this. The Nordic TSOs are set to harmonise the communication channels of each country into one singular communication channel.

Figure 30: Nordic Markets 15-min settlement implementation plan



Implementation costs

In 2020, Ofgem produced a cost-benefit analysis on the prospect of reducing the imbalance settlement period (ISP) from 30-minutes to 15 -minutes, or to 5-minutes in the GB market. This analysis reported on both the costs and benefits of this implementation on GB, taken from a cost benefit analysis conducted by Frontier Economics on behalf of ENTSO-E.

The top five costs associated with reducing the ISP to both 15- and 5-minutes are:

Table 14: shorter settlement periods implementation costs

	15-minute settlement	5-minute settlement
Metering and notification system	£1,444m	£1,843m
Scheduling and settlement	£204m	£271m
Billing systems	£161m	£265m
BRP forecasting, and trading and scheduling	£70m	£23m
Trading platforms	£51m	£73m

As shown here, the most significant cost is the changes to the metering and notifications system, which is approximately six times larger than the next most significant cost, changes to scheduling and settlement, for 5-minute settlement periods and seven times larger for 15-minute settlement. This large cost is due to smart meters needing to be changed to accommodate the increase in time granularity. Ofgem also state that it is likely that these costs may be conservative and could be even greater than those modelled by Frontier Economics.

The profiling and unadjusted costs are also different between 15-minute and 5-minute settlement periods. The main reason for this is due to the different required changes to existing ISP meters, of which the majority are installed in private households. “Profiling” customers would not require changes to the current meters, therefore would result in a lower cost transition.

Table 15: Profiling vs unadjusted costs

	15-minute settlement	5-minute settlement
Profiling costs	£827m	£1,156
Unadjusted costs	£1,912m	£2,848

Implementation pathway and timings for shorter settlement period and shorter gate closure

As well as the costs of implementation, the time it takes is also important. Arup have studied the implementation timelines of the NEM switching to 5-minute settlement periods and the Nordic markets, which are in the process of switching to 15-minute settlement periods. As with the costs, the timeline of a transition to a shorter ISP is still a useful case study if the GB decides to transition to a market with finer temporal granularity.

The NEM started its transition to 5-minute settlement on the 28th of November 2017 when the AEMC created the 5MS rule and the implementation process began in early 2018. For the next few years, the programme was mainly focused on preparing industry stakeholders for the change. The overall transition for the NEM was smooth, other than a brief three month delay due to Covid-19. In November 2020, a six-month period of industry testing took place until April 2021. On the 1st of September 2021 there was a start notice released for 5MS and the rule commencement officially took place on the 1st of October 2021. The whole process took just under four years for the NEM and AEMC. However, without the delay due to Covid-19, this process would likely have taken closer to three and a half years.

In September 2018, the Nordic TSOs in Denmark, Sweden, Norway, and Finland had originally agreed on a transition from 1-hour settlement to 15-minute settlement in December of 2020, however after a stakeholder consultation, this timeframe was deemed to be too short, and the plans were delayed until the 22nd of May 2023. Over this time, country-specific implementation of data hubs and TSOs were preparing for the transition. In Q1 of 2022, an implementation guide was released to help guide relevant market players through the implementation process. The go-live date is set for 22nd May 2023. It is difficult to tell exactly how long this process took, due to the three-year delay from the original date after the stakeholder consultation. From this timeline, however, it can be deduced that just over two years is not enough time, as suggested by the outcome of the stakeholder consultation which led to the large delay. On the other hand, it should be noted that Nordic markets would implement a wider set of changes including frequency response and CM within the same project timeline. This adds more time and cost compared to just reducing the gate closure and settlement period.

With regards to implementation case studies around shortening the gate closure there is limited information available. There is, however, the example of the GB market transitioning from a 3.5-hour to a 1-hour gate closure interval. This process was relatively quick and simple to implement with changes taking less than 1-year to implement.

From these case studies it can be deduced that an implementation of shorter settlement periods should take somewhere between 2-4 years. Based on our review of international markets Arup have put together an indicative implementation pathway below. The pathway below excludes any period of detailed consulting and modelling for the quantification of the shorter settlement and shorter gate closure in the market. Moreover, it excludes any detailed CBA work that could be required. It includes the steps required following the decision to move to a shorter settlement and shorter gate closure.

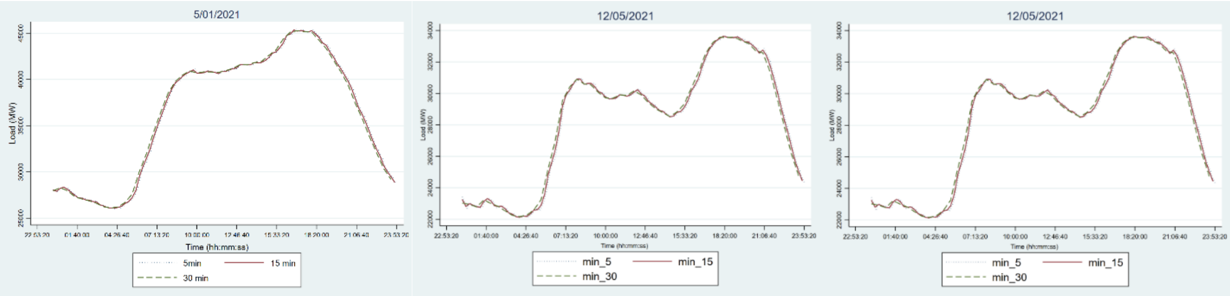
Table 16: Duration of high level steps

High Level Steps	Duration
Decision on shorter settlement and shorter gate closure and rule change proposal	6-8 months
Consultation period	3 months
Establishment of Industry wide working groups	0 months
Code and license reviews	1 year
Industry market readiness surveys and assessment	1 year
Industry testing	6 months
Market trial	3 months

Stylised examples & simulation of market response

In this section a stylised example using our in-house energy market simulation model (developed in PLEXOS) has been created. The effect shortened settlement periods could have in prices and on the generation output of flexible technologies in 2025, 2030 and 2035 was modelled. The days modelled were a peak winter day and a summer day. The modelled days were based on NG's CT scenario from the FES whilst the three different years represent generation mixes at different stages of decarbonisation. In 2035 the generation mix is fully decarbonised under the CT scenario.

Figure 31: Demand under different temporal granularity (2021): Winter Day, Normal Day & Summer Day



Unprofiled demand data provided by ESO have been used to model the effect of 15-minute and 5-minute settlement periods compared to 30-minutes. The demand data simulates a peak winter day, a “normal” day, and a summer day in 2021. The 2021 demand shapes were then applied to the three modelled years. No changes were made to the rest of the model input (i.e., generation mix, generation parameters, weather data & weather data granularity).

Results analysis - Winter Day

The table below summarizes the daily price spread along with the average price for each year. The results below refer to the typical winter day. In most cases as temporal granularity increases both the price and the price spread increase.

Table 17: Temporal granularity results analysis

Year	Price Spread and Avg (30-minutes)	Price Spread and Avg (15-minutes)	Price Spread and Avg (5-minutes)
2025	[73.69 - 307.88] £/MWh Bsld Price: £152.73/MWh	[73.69 – 329.60] £/MWh Bsld Price: £153.60/MWh	[73.69 – 293.05] £/MWh Bsld Price: £160.10/MWh
2030	[55.61 – 81.18] £/MWh Bsld Price: £69.31/MWh	[55.61 – 205.89] £/MWh Bsld Price: £70.53/MWh	[55.61 – 169.94] £/MWh Bsld Price: £76.38/MWh
2035	[35.45 – 57.12] £/MWh Bsld Price: £46.54/MWh	[35.45 – 56.64] £/MWh Bsld Price: £46.25/MWh	[35.45-67.97] £/MWh Bsld Price: £52.39/MWh

For all the years examined, the minimum wholesale price from the price spread remains the same irrespective of the settlement period duration. In general, average wholesale prices were higher for both 5-minute and 15-minute settlement period compared to the baseline temporal granularity. For 2025 and 2030, moving to a shorter settlement period increased the wholesale price range for both 15-minute and 5-minute settlement periods. Also, across all years, the 5-minute settlement periods recorded the highest average wholesale price compared to the baseline temporal granularity.

Table 18: Winter day period-to-period variability

Year	Period-to-Period Variability (30-minute)	Period-to-Period Variability (15-minute)	Period-to-Period Variability (5-minute)
2025	6.63%	3.66%	1.06%
2030	1.60%	3.63%	1.11%
2035	2.00%	0.97%	0.47%

Table **Table** 18 displays the average period-to-period variability. In essence this metric shows how much the price fluctuates from one settlement period to the next. The results indicate that period-to-period variability reduces as we move to a shorter settlement period. This observation holds true for both 2025 and 2035. Period-to-period variability declines for both 5-minute and 15-minute settlement periods compared to that of the baseline temporal granularity. An increase in variability is observed in 2030 as we move from a 30-minute to a 15-minute settlement period. Across all years, the 5-minute settlement period recorded the lowest period-to-period variability compared to the baseline temporal granularity.

Table 19: Winter day flexible technologies – wholesale revenue impact

Year	Revenue (£'000) 30 minutes	Revenue (£'000) 15 minutes	Revenue (£'000) 5 minutes
2025	14,171	14,553	14,442
2030	12,496	13,097	13,970
2035	11,630	11,700	13,503

Table **Table** 19 shows the results for the wholesale revenue impact for flexible technologies on a typical day in winter. The technologies considered were OCGT, CCGT, pumped storage, oil, gas reciprocating engine, BECCS and BESS. The results indicate wholesale revenues for flexible technologies increase as the settlement period shortens. Specifically, in 2030 and 2035 moving from the baseline temporal granularity to a 5-minute settlement periods, yields the highest wholesale revenue impact compared to moving from a 30-minute to a 15-minute settlement period. In 2025 moving to a 15-minute temporal granularity yielded highest revenue benefits compared to that of a 5-minute temporal granularity.

Results Analysis - Summer Day

The table below summarises the daily price spread along with the average price for each year. The results below refer to the typical summer day.

Table 20: Summer day price spread and average price

Year	Price Spread and Avg (30 minutes)	Price Spread and Avg (15 minutes)	Price Spread and Avg (5 minutes)
2025	[35.41 – 72.35] £/MWh Bsld Price: £54.18/MWh	[35.41 – 71.37] £/MWh Bsld Price: £53.65/MWh	[34.84 – 92.21] £/MWh Bsld Price: £64.94/MWh
2030	[35.11 – 51.49] £/MWh Bsld Price: £43.97/MWh	[35.11 – 51.06] £/MWh Bsld Price: £43.73/MWh	[33.25 – 49.53] £/MWh Bsld Price: £49.53/MWh
2035	[18.41 – 54.12] £/MWh Bsld Price: £40.97/MWh	[18.41 – 53.64] £/MWh Bsld Price: £42.90/MWh	[18.41 – 65.23] £/MWh Bsld Price: £49.10/MWh

The results indicate that the price and the price spread reduce slightly as we transition from a 30-minute to a 15-minute settlement period across all years. On the contrary both the price and within day price spreads are seeing a steeper increase when moving to a 5-minute settlement period across all the modelled years.

Table 21: Summer Day Period-to-Period Variability

Year	Period-to-Period Variability (30 minutes)	Period-to-Period Variability (15 minutes)	Period-to-Period Variability (5 minutes)
2025	3.19%	1.54%	0.74%
2030	1.71%	0.83%	0.44%
2035	4.69%	1.98%	0.79%

Table **Table** 21 summarises the period-to-period price variability averaged daily. The results indicate that period-to-period fluctuation reduces as we move to a shorter settlement period. This observation holds true across all years with a 5-minute granularity resulting in the lowest period-to-period price fluctuation.

Table 22: Summer Day Flexible Technologies – Wholesale Revenue Impact

Year	Revenue (£'000) 30 minutes	Revenue (£'000) 15 minutes	Revenue (£'000) 5 minutes

2025	2,445	2,546	3,288
2030	2,743	2,845	3,406
2035	10,414	10,829	12,781

Table **Table** 22 shows the results for the wholesale revenue impact for flexible technologies on a typical summer day. The technologies considered were OCGT, CCGT, pumped storage, oil, gas reciprocating engine, BECCS and BESS. The results indicate wholesale revenues for flexible technologies increase as we move to a shorter settlement period across all years. Specifically, across all years, moving from the baseline temporal granularity to a 5-minute settlement period, yields the highest wholesale revenue impact compared to moving from a 30-minute to a 15-minute settlement period.

Overarching conclusions

Looking at the results it can be concluded that both daily price spreads and baseload prices increase by reducing the settlement period below 30-minutes. For the Summer-Day there was a slight reduction in both as we moved from 30-minute to 15- minute to settlement but both metrics showed a stepped increase with 5-minute granularity. For the Winter Day both metrics were reduced as we moved from 15-minute to 5-minute but were higher when compared to 30-minutes.

Period-to-period price variability drops as temporal granularity increases. When moving from 30-minutes to 15-minutes we have seen a drop across all scenarios and years except for Winter Day 2030. For both Winter and Summer Day, the 5-minute settlement period recorded the lowest period-to-period variability, across all years.

In general, it was observed that the change to a shorter settlement period affects the total generation for a typical winter and summer day compared to the baseline temporal granularity. Moving to a 5-minute and 15-minute settlement period, we observe that total generation from flexible technologies increases by (1.46%-1.86%) and (1.35%-1.86%) for 5-minute and 15-minute respectively with respect to the 30-minute baseline temporal granularity. Flexible generating technologies varying total generation between shorter temporal granularities for both summer and winter were OCGT, CCGT, and BESS. For summer in particular, pumped storage was an additional flexible technology observed to be having varying generation for shorter settlement periods as compared to the baseline temporal granularity.

For the wholesale revenue impact for flexible generators, we can observe that wholesale revenues increase over shorter settlement periods be it a 5-minute or 15-minute temporal granularity compared to the 30-minute baseline temporal granularity. In the Summer Day simulation flexible generator revenues see the highest benefit when moving to 5-minute settlement periods across all years. The same trend is observed in the Winter Day simulation for 2030 and 2035. In the 2025 Winter Day simulation we observed that moving to a 15-minute temporal granularity yielded higher revenues compared to that of a 5-minute temporal granularity. It should be noted that to understand the whole impact we should not look just the wholesale cost in isolation but also the BM and A/S as well. The expectation that efficiencies would be achieved in this space as well.

Industry experts' viewpoint

Implementation and transition challenges

Market participants viewed increased temporal granularity as an incremental reform that has the potential to deliver benefits. They still considered such a change as a significant and difficult challenge:

- One market participant said they were apprehensive about the prospect of a 5-minute settlement and 30-minute gate closure. They raised concerns that shorter settlement period and gate closure times could pose a significant challenge to the ESO's control room operation.
- They raised concerns about the feasibility of shorter gate closures. They said that if there is an optimiser that is continually running and potentially issuing automatic instructions, then shorter gate closures are feasible, but if humans are involved in the process and need thinking time to solve problems, then longer gate closures are more feasible.
- A large part of the settlement code would need to be rewritten and there would be lots of licensing changes.
- With regards to the settlement process, recent IT system changes within Elexon were made, factoring in potential changes in granularity. As such, changes should be considerably easier and one that is conceptually possible to implement.
- Another market participant said that they have already built their system with flexibility for the settlement duration changing. They suggested an issue that they would face would be regarding computational complexity. As the time of the settlement period decreases, the computational complexity over a fixed time window is going to increase significantly both for automated and human traders, as they work out how to best optimise and trade over those periods.

Participants believed that data handling/management should not create major challenges:

- One participant has recently undergone a system upgrade which is fully capable of handling more data.
- Another expert said that a lot of their systems have been abstracted away from the settlement period size.
- Components of the data such as pricing would only cause a small increase in the amount of data that would be created/collected.

Market participants suggested that transitioning to a shorter settlement period would pose a challenge to the wider market. They suggested that as they work with settlement reports of market activity from up to 18 months ago, they would need the transition to be at least of the same length so that it does not complicate settlement reports requiring them to handle data in both the old and the new ISP.

Market participant suggested that this incremental reform could be integrated with the current MHHS programme, to enable synergies in implementation, however, the risk of increased complexity involved in such a move was recognised along with the fact it could lead to delays. They also said that access to 5-minute settlement should be offered to consumers and not be available only for the supply side of the market.

When it came to comparing a drastic single step transition versus an incremental/ gradual transition market participants had mixed views:

- One market participant said they did not have a particularly confident opinion on this and that a CBA would need to be done to decide between the two options.
- Another participant felt that a drastic market change should be treated with absolute caution and should be backed up by robust analysis, evidence, and heavy consultation with industry.
- Overall, the preference of participants would be to look at the incremental changes that would be easier, cheaper, and more accessible first. In parallel to this, they suggested looking at the bigger changes through a CBA.

Market impact

Arup received limited views on this subject. All participant responses were aligned in thinking increasing temporal granularity would lead to spikier prices but did not have a view on the scale of this.

With regards to liquidity market participants had mixed views:

- One market participant was not clear on the effect of higher temporal granularity to liquidity.
- Another market participant did not think that liquidity would be affected.
- Another market participant thought that a shorter ISP and gate closure would increase liquidity, but weren't not sure about the scale of the increase. Their view was that by increasing time granularity, traders would have greater confidence in the fundamentals that they're using because of the shorter time duration.

General views

On more general view, with regards to increased granularity, that market participants touched on was the US example with suggestions that:

- US markets have very good representations of their system and very good data compared to the GB market. Most of their assets are transmission connected and they do not have large number of connections that offset demand like in the GB market.
- Certain US markets rely far less on intermittent renewable resources, and where they do, they have high amounts of RESs and are very predictable, unlike in the GB market.
- On top of the unpredictability of the RESs in GB, the data quality of UK windfarms is also quite poor. Due to this, the GB market doesn't use the market data of windfarms in real-time systems (even though the ESO uses the power-available signal which gives the maximum potential power output of wind generators in real-time).
- US market participants are also highly incentivised to provide very accurate information, which is why the inputs to their models and their algorithms are really accurate. The GB market doesn't have this.
- Overall, they think that there is a big problem with data in GB which will create challenges in a transition to shorter settlement periods and gate closure times.

One market participant suggested that if there was a move to a shorter settlement period, then this would need to go hand in hand with other considerations such as:

- Moving the BM to having a higher resolution than just 1-minute.
- They said that a shorter ISP would enable them to better optimise the BESS state of charge. This would be especially useful in newer markets like Dynamic Regulation (DR) and Dynamic Moderation (DM). In these markets, shorter time granularity would make significant improvements.
- They suggested that the system should move to algorithmic trading along with increasing temporal granularity. A future system in which there are a lot of distributed assets participating in the market that are not being algorithmically dispatched would be a significant challenge.

Assessment and recommendation

Impact on wholesale market prices

Shorter settlement periods

Theory would suggest that shorter settlement periods leads to spikier within day prices, but increased competition should help reduce overall system costs. So, it would be expected that the shorter the settlement period the more marginal, or spikey, they become. This is supported by the stylised modelling of shorter settlement. Arup's simulation indicated that (both Winter and Summer Day) shortening settlement periods leads to spikier prices with a greater range than the current arrangements.

Reduced gate closure

It is difficult to assess the impact of changes in gate closure because of a lack of precedent and the difficulty in modelling it. The available literature and discussions with the industry indicated that a gate closure below 30-minutes would be problematic and could lead to increased system costs but not necessarily wholesale costs. The position set out in this report argues that theoretically, and allied to technological development, 30-minute gate closure provides the right balance between market efficiency and SO operator protection. This position is based on the current view of technological and generation mix developments.

Impact on balancing costs

Shorter settlement periods

Shorter settlement periods are expected to reduce balancing costs, with the shorter the settlement period the greater the reduction. Some of the volume could move from the balancing to the IDM. Moreover, it could enable market participants to match supply and demand in shorter time frameworks i.e., more accurately. Their ability to do this will be affected by what the ID and DA offer in terms of shorter period products, and it is expected that peak 15-minute or 5-minute products will become available as is the case in other markets. Moreover, the allocation of balancing and imbalance cost should be fairer in a market with higher temporal granularity. Over time, as more flexible technologies come online the balancing benefits of shorter settlement are expected to grow further.

Reduced gate closure

The rationale for reducing gate closure is to allow market participants more time and therefore options to balance their own positions. This in turn should lead to reduced actions and costs on part of the ESO. If the gate closure is too short then the ESO is at risk of being a distressed buyer with a very limited number of options in which case balancing costs would be higher. Moreover, resolving energy is only one part of the issues dealt with by the ESO post gate closure which adds more on complexity. As described above Petitet and Perdot's in quantitative study, a gate closure below 30-minutes leads to a reduced number of balancing actions but an increased cost. Moreover, there is a risk that the existing fleet of CCGTs and OCGTs have a declared ramp rate of between 60-89minutes, and that a shorter gate closure does not allow them enough time to respond. It is, however, likely that these declared rates reflect the gate closure periods and not the technical reality. In addition, CCGTs tend to plan their scheduling on daily basis and do not simply switch on and off. Further, we expect that increasing flexible technologies will have shorter ramp up rates and response times. Overall, the expectation is that reducing gate closure to 30-minutes should lead to lower balancing costs compared to the current arrangements.

Liquidity

Shorter settlement periods

A shorter settlement period is likely to aid liquidity and specifically ID liquidity compared to the existing arrangements. Firstly, flexibility providers (e.g., batteries) will most likely increase their market offering. As more smart meters and DSR is enabled, competition for flexibility offerings should grow, creating additional trading opportunities. Moreover, a greater number of trading points is likely to increase the robustness of reference prices and give market participants (mostly buyers) more confidence in what a fair price is, thereby helping liquidity. Flows through interconnectors (i.e., cross border trading) will become more price responsive - hence more efficient - further increasing the flexibility offering which could help liquidity.

Reduced gate closure

Arup would expect reduced gate closure to 30-minutes to increase liquidity because it allows more options for market participants to trade ahead of gate closure. This could add to the options to increase supply or reduce demand from flexibility providers. This is expected to increase liquidity especially for peak products. It is not possible to accurately model and predict the magnitude of this increase.

Impact on interconnection

Shorter settlement periods

As mentioned above increasing ISP granularity improves utilisation of interconnector flexibility especially as the EU moves to a 15-minute settlement period. If GB keeps the existing 30-minute settlement period, interconnector flows could be sub-optimal as flows from the higher priced market to the lower priced market for part of the HH may occur. On the contrary if GB moves to 15 or 5-minute settlement periods this would allow for more efficient flows of electricity. Moreover, ID trading at finer units will free up capacity in the opposite direction for the remaining of the 30-minutes if price spreads justify it.

Reduced gate closure

Arup do not think that a shorter gate closure would have any specific impact to interconnector flows other than those analysed in the other criteria.

Impact on low carbon investment

Shorter settlement periods

Shorter settlement periods are expected to have a positive impact on low carbon investment. This is supported by the stylised modelling which suggests greater profitability for low carbon flexibility providers. However, the impact on investment is more likely to be a gradual response to the market changes and it is not anticipated that shorter settlement periods will create a step change in the investment case for flexibility.

Reduced gate closure

As per the above shortening the gate closure interval should have a positive impact on low carbon and flexibility investment. The impact on investment would be expected to be gradual rather than a step change in the investment case.

Interaction demand

Shorter settlement periods

Shorter settlement periods have the potential to significantly increase demand participation in the market. DSR providers prefer to respond for shorter periods so one would expect significantly greater participation. Should HH settlement be fully resolved and enabled for 15-minutes or 5-minutes, and smart metering penetration increases, a higher demand side offering is expected, through aggregation, in the DA or IDM for peak products. Shorter settlement is viewed as unequivocally positive for DSR, which is enhanced with settlement reform and smart meter roll-out.

Reduced gate closure

Reduced gate closure is expected to benefit participation from DSR because it allows demand to respond closer to real time and therefore better reflect actual conditions (e.g., weather may change, a world cup match may go to extra time). It is difficult assess the scale of this improvement.

Impact on security of supply

Shorter settlement periods

Shorter settlement periods are unlikely to have a significant effect on security of supply. It is likely to indirectly improve capacity adequacy by diving greater opportunities for flexible technologies and thereby reducing overall capacity adequacy needs. This is not seen as a major factor in decision making.

Reduced Gate Closure

Reduced gate closure could create security of supply risks for the SO. Reducing the time interval during which the ESO must manage the system in real-time could theoretically reduce the options available to the SO. The gate closure should also consider the available generation mix and its ability to respond in shorter timeframes. As mentioned above the fleet of CCGTs and OCGTs have declared ramp rate of between 60-89minutes, and a shorter gate closure does not allow them enough time to ramp up. At times of system stress this could create significant risks for the SO. Based on the analysis and literature review conducted in this report it is thought that the possibility of transitioning to a gate closure as low as 30-minutes should be considered. Further work with the ESO control room would be required. Reducing the gate closure sub 30-minutes would lead to increased risks outweighing any potential benefits. However, even a transition to a 30-minute gate closure would require more investment in process automation from the ESO's side.

Recommendation

Based on the analysis of benefits and risks described above, Arup's recommendation is to transition to a 5-minute ISP and MTU. Moreover, it is recommended that the possibility of reducing the gate closure interval to 30-minutes should be considered in close collaboration with the ESO. As the generation mix is changing and flexibility's role is increasing, both these changes have the potential to deliver system benefits as described above.

With regards to the settlement period, a transitioning to a 15-minute ISP has been considered in this study. The main argument supporting this view is to be harmonised with EU markets that GB is linked to, as these markets will eventually transition to a 15-minute ISP. This would allow for optimal flows both in and out of the GB market. Transitioning to a 5-minute settlement would not hinder flows from GB to the EU but flexibility provision from the EU to the GB could be sub-optimal. Available literature suggests that markets globally, including the EU, will continue moving towards an ever-increasing granularity. Hence moving to a 5-minute ISP is a more future proof solution and ensures the GB market avoids having to reduce its ISP further in a few years' time. Moreover, IT technology advancements along with generation mix changes support the transition to higher temporal granularity. Furthermore, in advice provided by CAISO to Ontario IESO they mentioned:

""Do it right the first time" to avoid spending the same money twice. For example, CAISO increased costs and delayed benefits by taking interim steps with hourly and then 15-minute intertie schedules, rather than immediately adopting the more efficient five-minute intertie scheduling process that has been implemented more recently. In hindsight, it would have been more beneficial to implement five-minute intertie scheduling right away. As another example, CAISO implemented the Market Redesign and Technology Upgrade with real-time dispatch on a five-minute basis and unit commitment processes on staggered 15-minute schedules; now CAISO is facing a patch or re-build of those systems to make them consistent."

With regards to gate closure the somehow limited evidence suggests that any interval below 30-minutes would lead to increased balancing costs. Reducing the gate closure to 30-minutes has the potential to allow for better forecasting and adjustment of position especially of intermittent generators. Transitioning to a shorter-gate closure interval will pose challenges to market actors and more specifically to the ESO. Overall Arup's view is that the generation mix development along with the IT technology advancements justify a careful consideration such a transition. Arup note that there should be further discussions with the ESO before making a decision for this move.

Balancing Market changes

Introduction

In this section, changes to the BM are explored. In particular the following three options are considered:

- Administrative offer pricing.
- Changes to the cash out mechanism.
- Locational BM products.

The purpose of this section is to:

- Make a recommendation on the preferred changes to the BM.
- Review the available literature.
- Understand the potential of changes to the BM to alleviate the issues created by the current market design.
- Assess its implementation complexity on the various market actors.
- Flag each option’s drawbacks and provide a qualitative view of their magnitude.
- Provide the views of industry experts on such reforms.

Section 6.2 provides a review of the GB BM and how it has evolved over the years along with a review of the existing literature. It also gives an overview of how the cost and the role of the BM has changed with increasing penetration of renewables.

Section 6.3 analyses administrative changes to the offer pricing rules in the BM, Section 6.4 assess the option of changing the cash out rules and in Section 6.5 the option of locational BM products is discussed.

Section 6.6 summarises viewpoints from market participants interviewed by Arup in relation to changes in the BM. Finally, Section 6.7 provides an assessment and recommendation on the preferred options based on Arup’s view.

Key takeaways

The cost of balancing the GB system has risen dramatically over the past 15 years.

Applying a cap on BM offer prices can be complex when it comes to finding the right balance of setting the cap at the right level whilst not hamper investment signals.

Changing the cash out mechanism, in Arup’s view, could have adverse market effects as it reduces the incentive of market participants to balance their position ahead of real-time.

The introduction of locational products in the BM bears the risk of generating market power for participants located in regions or areas where services are required.

Arup's view on the preferred option would be to proceed with an enhanced version of Ofgem's proposal to cap BM generator margins if they submit a Physical Notification between zero and their Stable Export Limit (SEL).

Balancing Market literature review

Established in 2001, as part of NETA and along with the BSC, the BM is the ESO's primary tool to balance supply and demand in GB's real-time electricity market and ensure the system remains at 50Hz frequency[48]. Generators and suppliers increase or reduce electricity output (based on the bids, offers, and PNs) so the ESO can continually ensure that supply and demand are balanced. GB's BM currently operates on 30-minute settlement periods. At gate closure BM participants must provide the ESO with a PN – an initial view on their expected physical position (how much they expect to generate or consume in the settlement period)[49]. Gate closure is one hour before the settlement period and during this time final PNs, bids and offers must be submitted. Specific bids and offers are accepted by NG. Then during the settlement period, forward commitment of generation is delivered, and any imbalance volumes are settled based on the cost of actions the ESO had to undertake.

The BSC, which sets out the rules for electricity balancing and settlement mechanisms in the GB electricity market can broadly be split into two parts. The first, the balance settlement, applies to actively managing grid power flows and is overseen by NGESO. The second element is the imbalance settlement, which focuses on the penalties imposed on market participants who do not meet their submitted capacity, and this is managed by Elexon. The imbalance price is calculated by Elexon and is the marginal cost to NG during each settlement period. To calculate the marginal cost, the NIV must also be calculated. NIV is the net offer and bid volume accepted during the settlement period and in some cases can be negative. Due to the design of the imbalance settlement mechanism, the instances where NIV is negative implying the imbalance price is lower than the prevailing market price. The price gap can then be exploited by market participants and, as a consequence of this, 30% of trading in the IDM in 2019 was within an hour before the settlement period and 55% was within two hours[50]. These unintended incentives can reduce the market's efficiency and indicate to alter the market design.

In May 2012, the EBSCR was initially launched by Ofgem[51]. It aimed to investigate whether the cash-out price provided the correct incentives for suppliers to sufficiently balance their positions so that NGESO can meet demand when the system is tight. In particular, the review

[48] National Grid ESO (2022): What is the Balancing Mechanism?
[49] ELEXON BSC (2022): Balancing and settlement
[50] Bunn et al (2021): Analysis of the Fundamental Predictability of Prices in the British BM
[51] Ofgem: Electricity Balancing Significant Code Review initial consultation

focused on ensuring that flexibility and peaking generation were valued to improve balancing efficiency and security of supply. The rationale for reform stemmed from three factors that were considered to be dampening cash-out prices at the time. These included the use of an average of the top 500MWh in calculating cash out prices (as opposed to a marginal actions). The second theoretical flaw in the cash-out design was that prices did not include the costs to consumers of blackouts and voltage reductions, and thirdly the dual cash-out price system at the time created unnecessary balancing costs, hindering smaller entities. The review concluded at these market arrangements resulted in insufficient incentives for market participants to provide flexible capacity to meet demand.

Following the EBSCR, Ofgem issued a final policy decision[52] to address the highlighted market design shortcomings. The decision included the following proposals:

- Cash-out prices became marginal by calculating prices using the most expensive 1MW of actions rather than the average of 500 MW of actions taken.
- The cost of disconnections (black-outs) and voltage reduction was included into the cash-out price calculations.
- The way reserve costs are priced was improved by reflecting the value of reserves at times of stress.
- Cash-out pricing was moved to a single price for each settlement period to help simplify arrangements and reduce imbalance costs, particularly for smaller parties.

A further review of these policy modifications showed that their implementation resulted in lower overall imbalance price, but these became higher when the system was tighter.

Covid-19 lockdown and energy system costs

During the COVID-19 lockdown, electricity demand fell by 1.5% and consequently renewables generated a larger share of the UK’s electricity. To balance the system during this time, the ESO had to pay wind farms and nuclear power stations to turn off and pay gas-fired power stations to turn back on. As a result, balancing costs were ~66% higher than the same period in 2019. At the same time GB wholesale electricity prices remain highly reliant on gas prices putting significant pressure on prices, especially during the recent energy crisis.

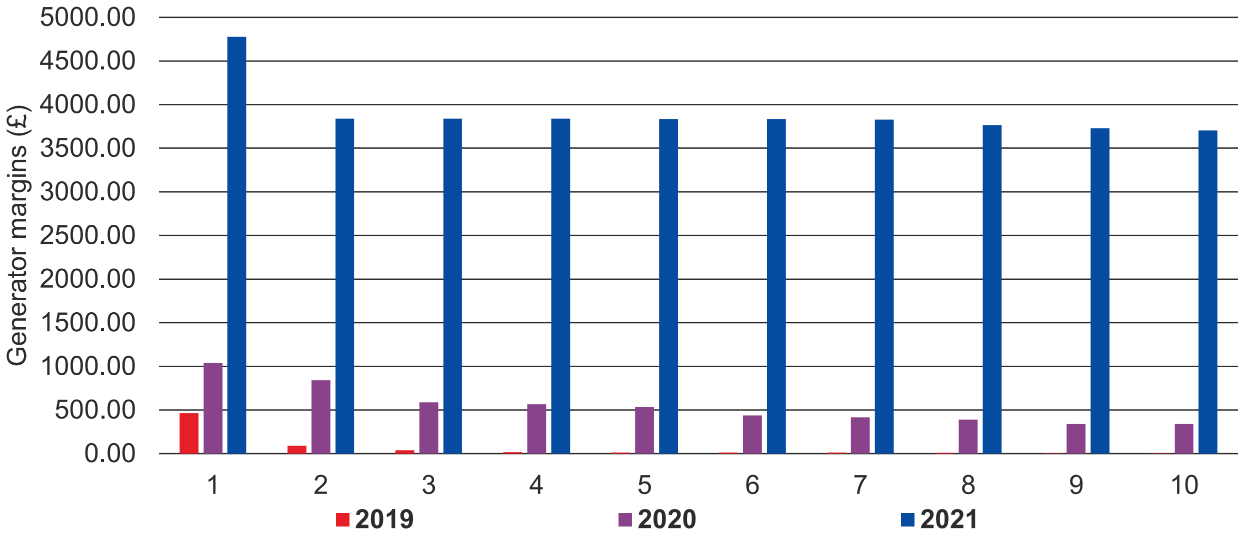
Volatility within the BM has continued to increase in recent years. Over the course of the last year, the BM has experienced multiple ‘high-cost days’ with the ESO incurring over £1.5 billion on energy balancing actions in the BM (a 134% increase over the previous year). This period includes the 24th of November, when £60 million was spent on balancing actions, the highest cost day the BM has ever seen.

Figure 32 captures the top 10 high-cost days for each calendar year from 2019 to 2021. Over the three-year period, the highest maximum bid offer experienced an average annual growth of

[52] Ofgem (2014): Electricity Balancing Significant Code Review: Final Policy Decision

182%, increasing from £621/MWh in 2019 to £4,950 in 2021. The other days within the top 10 also experienced exponential growth over this period, with growth rates from 2020 to 2021 ranging from 400-782%. Most of these actions focused on balancing a series of high-cost days in Q4 of 2021. Several key drivers have been identified as a cause of the high costs days, including system tightness combined with generator bidding behaviour that led to the need to accept capacity offers up to £4,000/MWh. Frontier Economics was commissioned by NGESO to undertake a study which investigated the key cost drivers over some of the highest cost days in the BM in 2021[53]. They found that market participants' behaviour was not inconsistent with BSC rules but that market rules may have intensified the costs. The findings suggest the market is not operating efficiently and supports the case for considering further potential reforms. It is also worth mentioning that stakeholders feel the BM is playing a very different role to what it was originally designed for. BSUoS taskforce illustrated difficulty in developing clear investment signals for a lot of costs currently paid for in BM.

Figure 32: Generator margins from top 10 high-cost days per year (2019-2021)



To assess the margins generators have experienced in recent years, the historical offer price data for CCGTs in the GB balancing market were gathered for the years 2019-21. To establish the margins, the total cost of running of the CCGT generators was subtracted by the offer prices. The total cost of the generators considered both the SRMC and the start-up cost. The margins were calculated for the top ten days per year with the highest offer prices.

Table 23: Generator margins from top 10 high-cost days per year (2019-2021)

	2019	2020	2021
1	£464.52	£1,039.60	£4,777.51
2	£91.38	£839.81	£3,837.43

[53] Frontier Economics (2022): Review of the BM

3	£37.00	£589.57	£3,838.12
4	£16.38	£564.54	£3,838.54
5	£12.78	£533.47	£3,837.01
6	£13.05	£438.98	£3,836.51
7	£12.29	£414.54	£3,827.37
8	£10.76	£390.56	£3,766.12
9	£1.48	£339.35	£3,727.87
10	£0.02	£338.67	£3,702.79

The margins for the top 10 high-cost days over the period from 2019 to 2021 have been assessed and it is evident that GB generators have seen margins increase exponentially. In 2019, the annual average margin for the top 10 days was £65.69, and this has since increased by 5,911% to an annual top 10 average of £3,898.93.

The evidence shows that the GB generators have experienced significant increases in realised margins, whilst total running costs have seen much more subtle changes. The analysis illustrates that growth has been driven by rapidly increasing offer prices from generators and implies the need for an intervention to address this.

The increasing penetration of intermittent renewables and the potential effect on the BM is gaining traction in the academic world. Due to accelerating global decarbonisation targets, increasing concern has been raised over integrating renewables into the power system and the BM's ability to deal with this. Hirth & Ziegenhagen (2015) studied the channels through which VRE sources interact with the BM, highlighting the increased need for deploying balancing reserves due to VREs weather-dependency and the inevitable forecast errors that stem from this[54]. Goodarzi, Perea & Bunn further studied this through German power market forecast data. They found higher wind and solar forecast errors resulted in increased imbalance volumes and this fed through to higher spot prices in the market[55]. Ocker & Ehrhart found that despite increasing variable renewable generation within the German power system, there was no higher demand for balancing reserves, a case now dubbed as the German Paradox[56]. They did, however, find that suppliers then coordinated at a price level significantly higher than the competitive output. They concluded that other factors may be more important than the variability of renewables, namely the design of balancing power markets providing sufficient incentives for generators to provide balancing power themselves and to increase accuracy of forecasts. They also concluded market design changes may be needed and suggested switching the BM from a pay-as-bid to marginal pricing, aiming to emphasise its role as a price

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[54] L. Hirth & I. Ziegenhagen (2015): Balancing power and variable renewables: Three links

[55] S. Goodarzi, H. Perera, & D. Bunn (2019): The impact of renewable energy forecast errors on imbalance volumes and electricity spot prices

[56] F. Ocker & K. Ehrhart (2017): The "German Paradox" in the balancing power markets

signal. Despite the inconclusive findings of the current literature, there is a common underlying agreement throughout that the BM requires some policy intervention to sufficiently accommodate for the changing energy mix.

The ongoing REMA consultation proposes a review of the functioning of the BM, to ensure the market is delivering a cost-minimising, secure, decarbonised energy system. DESNZ have proposed a number of potential changes to the way in which the balancing market operates, including introducing administrative offer pricing rule through either changing the licencing conditions or the BSC rules and dampening the cash-out mechanism. Another suggestion includes increasing temporal and location signals in BM products. For instance, changing BM gate closure time could allow more flexible low-carbon, low-cost technologies to be more responsive to real-time grid conditions[57].

The following sections look to consider each of these options in turn, working through how the proposals might work in practice. For these options a high level the design has been set out along with implementation requirements and an assessment of the pros and cons of the options. A recommendation for any proposals that could be taken forward based on their implementation costs and risks and their potential ability to reduce balancing costs and or locational price signals is provided. This section will include a discussion on any deliverability issues arising from a legal and stakeholder challenge perspective.

Administrative Offer pricing rules either through Licence conditions or BSC rule changes

The first option being considered as part of the REMA consultation relates to administrative changes to the offer pricing rules in the BM. Under this option, rules can be changed to constrain the prices offered in the BM, and ultimately a cap on could prices allowed be created. These are broadly the options that Ofgem (the Ofgem proposal) set out in July 2022 in an open letter which set out a range of potential near term options as a response to the high balancing costs seen in winter 2021. These options included:

- Limiting generators’ ability to amend their schedules with little notice.
- Restricting BM access or BM bidding flexibilities for generation capacity that is withdrawn with little notice.
- Changing the rules for how parties structure their BM bids.
- Introducing new licence obligations that require generators to operate and behave in a manner that delivers in consumers’ interests.
- Introducing direct measures to restrict BM offer prices.

[57] Ofgem: Review of electricity market arrangements

Following the open letter, Ofgem published a call for input in November 2022[58], where they indicated that they had refined the options presented above and were minded taking forward its preferred option of 'introducing a licence condition that prohibits electricity generators from seeking excessive benefit in the BM after submitting zero MW PNs'. This represented a development in thinking since the open letter stage but consisted of introducing a licence condition that would apply only in a situation where a generator revised its PN at the last minute to zero. The onus would then be on the generator to prove why its offer price was not excessive. This approach is very similar to some of the original thoughts behind the market power licence condition, which evolved into the Transmission Constraint Licence Condition (TCLC). The difference here being that the instead of during transmissions constraints, the condition kicks in when a generator was declared they are not generating any power onto the system (zero PN). This type of approach is effectively trying to address market power concerns, with the phrase excessive benefit taken directly from theory of harm in competition economics and law. Under the proposal here, a zero PN is intended to indicate market power (in the same way Transmission Constraints is intended to in imply Market power in the TCLC). The other point to note is that limiting behaviour on Offer pricing was rejected adjusting the Development of the TCLC because of fears it would create a problem of 'missing money', by signalling to generators that very high prices would not be tolerated. However, this was before the CM had been implemented to address the missing money problem.

Ofgem considers the behaviour that has resulted in increased BM prices could be targeted, without impeding pricing signals or unduly disrupting existing trading arrangements. Further, Ofgem noted that it avoided the need to define an explicit price cap value and was therefore more flexible to a changing market environment. It has been agreed though that a clear definition of 'excessive benefit' is needed, and Ofgem will continue to work with market participants as it develops the policy further.

An option that Ofgem appears to have not considered further at this stage relates to the capping of BM prices, where they considered either capping all offers in the BM, or capping offer prices after a generator submitted a zero PN. This would require changes to the BSC and Ofgem found that considerable work would be necessary to ensure any cap is set at the right level to prevent undesirable behaviour, whilst limiting the impact on price signals and competition.

A similar but alternative proposal would see a cap being applied to the margins that generators can make, rather than on the absolute offer price. In theory this would limit excessive prices whilst still allowing generators to recover short run marginal costs (SRMCs) with a return. Like with the cap on prices proposed by Ofgem, capping margins would require consideration for what represented a reasonable margin and would be outside the scope of this work.

[58] https://www.ofgem.gov.uk/sites/default/files/2022-11/Call%20for%20Input%20on%20options%20to%20address%20high%20balancing%20costs.pdf

Below an assessment of the main advantages and disadvantages of the Ofgem proposal is summarised:

Table 24: advantages and disadvantages of Ofgem inflexible offers proposal

Advantages	Disadvantages
• Avoids setting a target that generators would most likely target pricing at. For example, if a cap it set at £5k per MWh, then it is likely offers would gravitate to this level unless there is sufficient competition to drive prices down. In the current market there is not sufficient competition in dispatchable generation units for this to happen. • Excessive benefit measure does not risk disallowing firms to cover their costs. An absolute cap on prices, especially in a highly volatile gas market, could risk not allowing generators to cover their gas costs. • This approach does not risk creating a missing money problem given today's policy environment and the existence of the CM. • Relatively easy to implement given the parallels with the TCLC. • Placing the onus on generators to justify why they have not made an excessive benefit avoids Ofgem having to undertake difficult analysis of cost data submitted by generators. This should speed up any process of investigations.	• Condition only kicks in when PN is zero. This leaves scope for generators to submit PNs at their SEL, and then gain an 'excessive' benefit from their remaining generation capacity up to their Maximum Export Limit (MEL). This may limit the impact of the condition as we see submitting PNs at SEL, and then charging high offer prices for their remaining power in the BM, as the likely response from generators. • The condition is slightly complex and lacks clarity. Normally such licence conditions would come with guidance to minimise uncertainty. This can be addressed with further work, however, there always needs to be a balance between providing clarity and drawing a line in the sand that generators will walk up to (i.e., price at the cap). • Does not address the issue of locational market power at times of transmission constraint. • The option chosen by Ofgem is the best option considered, however, amending the TCLC to include Offer prices would have perhaps been a simpler option and one that covers more instances. It would have also created more pricing uncertainty for generators, and they would have to make assumptions on when transmission constraints were occurring. This would likely result in permeant change of pricing behaviour as generators would not want to risk being caught out by a sudden constraint occurring. • If the option is implemented, it would advisable mentoring the PN's submitted by generators to see if they are submitting at their SELs and charging high offer prices for their remaining power. Further, more work should be done to explore competition concerns in the current wholesale market. Further work on exploring the profits made by flexible generators (i.e., CCGTS, OCGTS. pumped hydro, and biomass) in GB is recommended.

Changing the cash-out mechanism

Another option being explored are changes to the cash-out mechanism. If a market participant generates or consumes less or more electricity than they have contracted for, they can 'cash-out' for the difference. The cash-out (or imbalance pricing) directly impacts market participants incentives to invest in secure supplies, and therefore affects the markets' ability to deliver secure and competitive services.

As described above, in 2018 the methodology used for calculating the cash-out price changed in such a way that resulted in increased cash-out prices. Ofgem moved to a PAR1 approach, where the most expensive 1MWh action was used to determine the price, moving away from the PAR50 approach that had been in place from 2015-2018, where an average of the most expensive 50MWh worth of actions set the price. Theoretically, dampening the cash-out signal would feed through to offer pricing in the BM and in turn influence wholesale market prices.

Generators have the option to bid into the DA market or hold back capacity with a view to participating in the balancing market following gate closure. In making this decision, they will develop a view of their SRMC, which will comprise start-up costs, running/fuel costs, and carbon costs etc. This will inform their pricing strategy for bidding into the DA market.

At the same time, generators will also be looking at a range of other data to inform a view as to what prices in the balancing market might be for a range of settlement periods. In doing so, they will consider weather and market data, as well as expected network constraints.

The generators will then decide the profit maximising action based on the opportunity cost of holding back capacity for the BM compared to participating in the DA market, especially if there are periods where the BM prices are expected to be high.

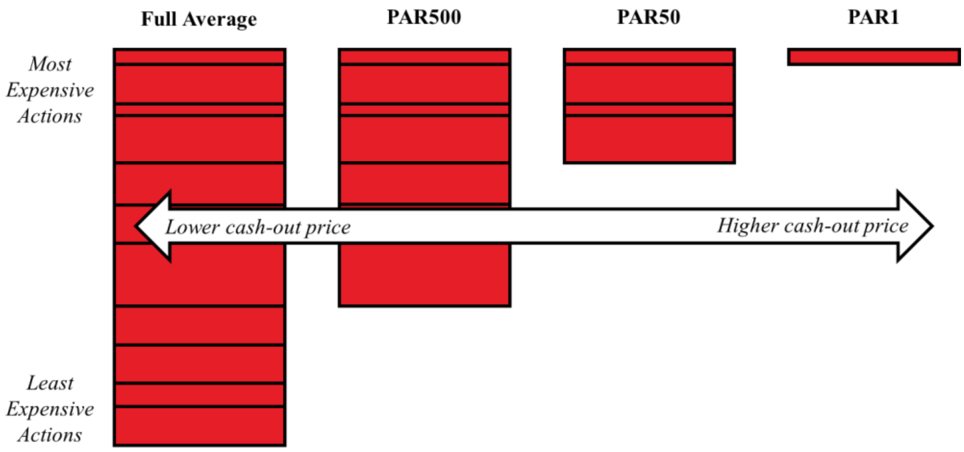
Say a generator's marginal cost to run baseload (including the start-up cost) is £104/MWh. In the absence of any other opportunity this would be the strike price that would be used in the DA and IDMs would be equal to £104/MWh. This means that if the price was above £104/MWh the asset optimization team would sell the unit in the market. Respectively, if the unit was already sold in advance and the market/auction price was below £104 the asset optimization team would buy back the unit. If on the same day the optimisation team believe there is 50% probability to make £350/MWh if they successfully offer the unit in the BM in Block 5. By adding this opportunity cost/ revenue in their calculation, the new strike price is now set at £116/MWh. This price (which is higher than the SRMC) is the price the asset optimisation team will use when they offer their unit in the market.

Further, an assessment of historical cash-out prices indicated that as well as the costs identified above, generators will also price in imbalance risk into their BM offers. If a generator is looking to hold back capacity for the BM, there is a risk that they are not picked up and called on in the BM and are left out of balance from their contracted position. In such a scenario, they would be exposed to the cash-out price for that period, which could be as high as £6,000/MWh in periods of system tightness. To reflect this risk, generators will add a risk premium to their BM offers. This has the effect of pushing up BM costs across the market.

Similarly, if a generator has already sold its capacity into the market, but expects that BM prices are likely to be higher, it may look to buy back capacity at the DA rate with a view to selling into the BM.

If the cash out price is lower, then the incentive to bid into the market is lower and it could be assumed that more units would bid into the DAM. Increasing the PAR on which the cash out is calculated from would decrease the cash out price as the average would be taken over a wider range of actions. An illustrative example is provided below.

Figure 33: Impact on cash-out price from changing PAR



This would have the effect of reversing the changes made in modification P305, which moved from PAR500 to PAR50 and eventually to PAR1. This would be a complete reversal of the principles of the EBSCR of making prices more marginal to send strong incentives. This would have the effect of reducing the cash-out price, therefore dampening the incentive for market participants to balance their position ahead of gate closure. This could then lead to an increase in balancing costs.

Therefore, it is not recommended to consider these options further as there is a risk of increasing balancing costs and contradicts much of the ethos that undermines our market decision (string imbalance signals to drive behaviour).

BM products with increased locational signals

Currently, products offered in the balancing market are not specific to any location and are bid or offered on centralised basis. A third option considered as a way of decreasing BM costs involves moving away from a single central BM offer model to one of locational specific BM products or having a locational market as is done in the gas market. Under this option NGESO could offer price signals to the market for location specific products in an attempt to incentivise generators and developers to invest in locations that are constrained or where BM services are required.

The ESO would identify the need for BM products within a certain area, for example behind a network constraint, and request that generators and market participants within that region submit bids and offers for the relevant settlement periods.

To implement this change, the NG would most likely need to develop a number of products, and that this would likely involve either adapting existing short-term products or creating new long-term products. NG would be required to publish details on these new products to the market, and tender for capacities. In order to provide long run investment signals to the market to where BM services are required, NG would need to publish prices regularly.

The effectiveness of such an approach is questionable. There are already long-term investment signals in the form of transmission charges, and it is unlikely that locational BM products would provide the short-term signals needed. This is because balancing market activity occurs after gate closure and does not give market participants the incentive to change their dispatch decisions.

There is a risk that moving to locational BM products could in fact increase BM costs in the short term as those market participants located in regions or areas where services are required would hold and potentially exert market power. Were those participants to take advantage of their position, they could artificially inflate bids and offers as competition would be expected to be limited in the short term. Locational products, or locational BM market, is likely to effectively result in a zonal market, which the flexible generators having market power in each zone and charging very high prices. In essence generators would set their marginal cost considering the opportunity cost within their own “BM zone”. This would result in bidding behaviour like the one that we would observe under a zonal pricing design.

Industry experts’ viewpoint

With regards to locational products certain market participants suggested that:

- The launch of locational products in the BM could provide the right incentives to build energy assets at the right location.
- In the current market it is easier to get a connection in locations where there are less or no constraints. As a result, batteries get built where there are no constraints as it is less costly.
- Any kind of locational system could provide a financial incentive to build the batteries in the right location.
- They are in favour of strong market drivers that would help solving the locational boundary problems. They said that locational constraints also create a barrier to the development of longer duration BESS.

With regards to introducing caps to the market participants views were:

- Unfavourable around the introduction of caps into the market. They said it would need a cautious approach because there is that balance between scarcity pricing and the right investment incentives.
- The example of Ireland was mentioned where they claimed the use of a €500/MWh cap means that there are occasions they cannot import enough energy to meet their demand.
- Ofgem should ensure that market player do not make excessive benefits from their pricing, however, it is noted that this is more complicated to impose.
- Excessive prices for a short period of time have incentivised investment for technologies like batteries which should benefit the system in the long run.

On wider market issues one market participant claimed that at the moment larger units are getting preference in the BM:

- Their view was that smaller batteries are being consistently skipped over in the BM creates a challenge to investors as they do not generate the returns they expected when they were putting their investment case together.
- They think there needs to be an incentive for storage assets to take a more active role in the BM.
- In their view, higher skip rates could be dealt with through enhanced IT and automation systems. Moving to algorithmic dispatch and automatic bidding from both the ESO and asset side could allow for more efficient dispatch of fast responding storage assets.
- It should be noted that the ESO is not aligned with this position and their view is that they do not have a preference to larger assets when compared to smaller assets.
- It was recognised that there need to be more BESS built to deliver in the BM but there is enough in the pipeline.

Conclusions on BM reform

In the last 5 to 6 years the behaviour of market participants has come under increasing scrutiny. In the last few years very high offer prices have been observed with increased frequency. There have also been numerous successful findings into breaches of the TCLC and REMIT that all focus on generator behaviour in the BM. There is strong evidence to justify concerns regarding market power in the BM, that also suggest that the BM is open to manipulation by generators.

Applying a cap on BM offer prices can be complex when it comes to finding the right balance of setting the cap at the right level (taking varying generator costs into account) whilst not hamper investment signals. Further, such an option is likely to lead to offer prices congregating around the cap.

Changing the cash out mechanism could have adverse market effects as it reduces the incentive of market participants to balance their position ahead of real-time. Moreover, such a move contradicts the aims of the EBSCR.

The introduction of locational products in the BM bears the risk of generating market power for participants located in regions or areas where services are required leading to increased costs to consumers. On the other hand, it can be argued that long term investment signals are already in place in the form of transmission charges.

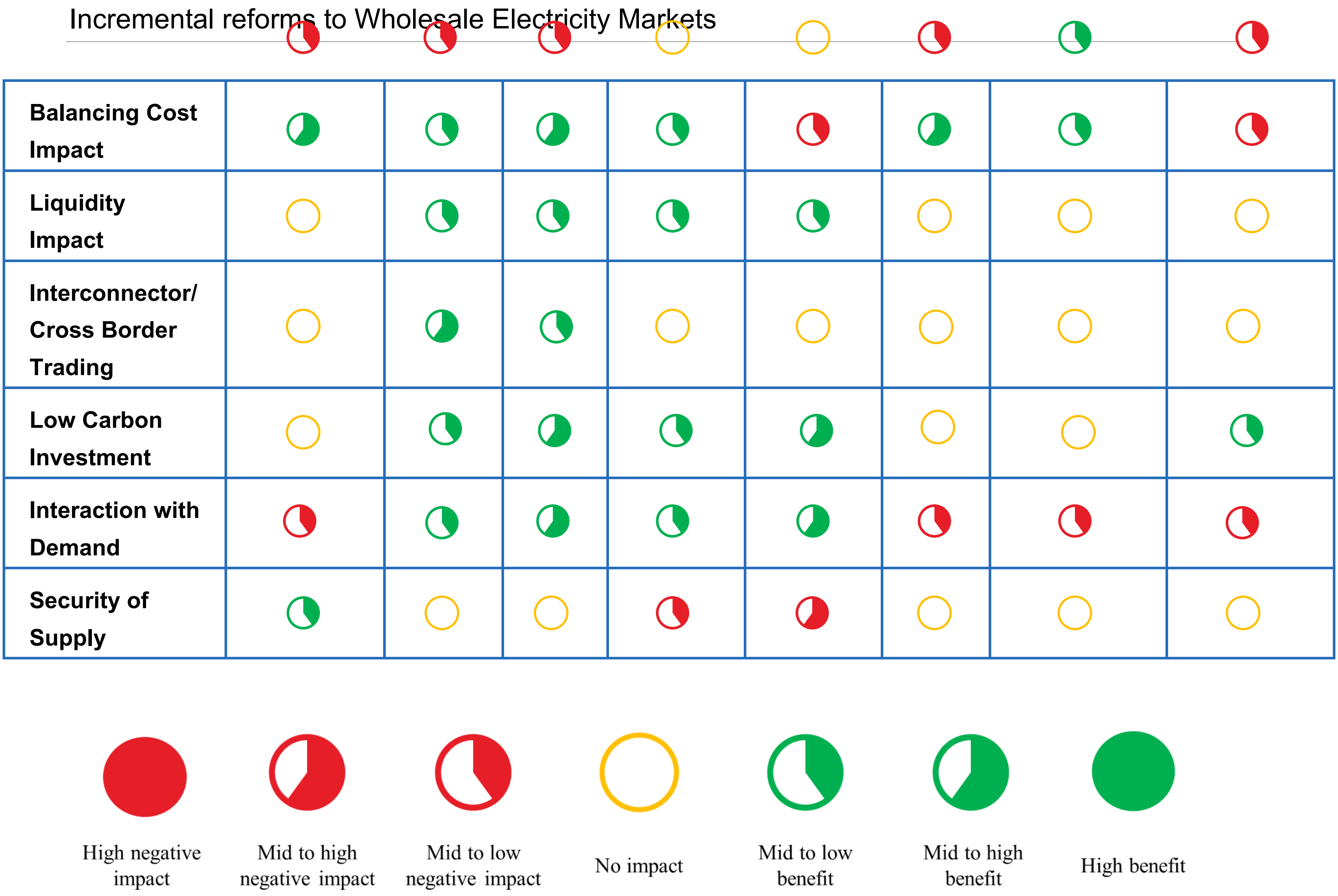
Of the options considered and analysed in this section, the one being taken forward by Ofgem is the preferred one. It is noted that a simpler more effective change could have been to amend the TCLC to include Offer prices. Limits on Offer prices should not be expected to create a missing money problem given we have a CM. It is recommended that further work is undertaken to really assess the profits of flexible generators in GB, as the evidence suggest some fundamental concerns that are likely to grow as our stock of dispatchable power plants decrease.

Conclusions and Recommendations

The table below assesses each options impact/ benefit versus the existing market status. The recommendations are looking to the options that can deliver the highest benefits at the lowest impact versus the current system.

Table 25: Options comparison

Criterion	Dispatch	Settlement Period		Gate Closure		BM Changes		
	Proposed Central Dispatch Model	15min ISP	5min ISP	30min Gate Closure Interval	<30min Gate Closure Interval	Offer Price Cap	Changes in the Cash-Out Mechanism	Increased Temporal & Locational Signals
Implementation Complexity	●	◔		◔	◔	◔	◔	◔
Implementation Cost	●	◔		◔	◔	◔	◔	◔
Market Actor Impact	◑	◔		◔	◔	◔	◔	◑
Market Actor Reception	●	◔	◔	◔	◔	◑	◔	◔
Wholesale Price Impact								



Based on our analysis and assessment of all the options we have four recommendations to make with regards to incremental reforms.

Recommendation 1: Centralised dispatch is too different from the current design to be considered an incremental reform. It is unclear that the costs of implementation would outweigh the benefits. With some of the potential benefits being dependent on design choices. Given its enabling role, central dispatch should be considered as part of package of reforms, alongside other design choices such as co-optimisation, greater temporal and locational granularity.

The analysis undertaken and discussions with market participants suggested that moving to a central dispatch market can help alleviate some of the issues raised within REMA. In the proposed design the ESO will manage known constraints and co-optimise certain A/S (e.g., reserve) well ahead of real time. Moreover, the bidding format proposed will enhance the potential to treat non-convexities appropriately. These should help reduce the constraint management and balancing cost as they will reduce some of the volume required to be procured post gate closure. This should remove part of the BM opportunity cost that generators include in their asset optimisation process.

This is not, however, expected to be material enough to justify the cost and complexity of transitioning to central dispatch. As there will still be a BM along with the fact that constraints are not always know well ahead of real time means there will still be opportunity cost factored in the optimisation strategy of market participants. This will be further supported by the fact that market participants will have the option to self-schedule their output which means they could keep their optimisation strategy unchanged. It is worth noting that the PJM operated for 1 year a central dispatch with uniform price. This approach did not solve the key constraints issues. These were much better dealt with when they moved to a nodal market design.

Another key point that came out from the analysis and discussions with market participants is that central dispatch should not be treated as an incremental reform. It is a significant change in the way the market is operated, and it will require significant changes in the codes and licenses (maybe even a re-write). For the ESO, the implementation is not too far away from what they would have to do for nodal market design. The significant cost and effort required for such a reform could put on hold other reforms that could be simpler to implement and could have a higher positive impact to the market.

In conclusion it is recommended that central dispatch should not be taken forward as a stand-alone incremental reform. It should be considered as part of a wider market reform and should be combined with moving to a nodal or zonal market.

Recommendation 2: A transition to a 5-minute ISP and MTU is likely to deliver higher benefits versus a 30-miute or a 15-minute ISP and MTU and is likely to a better suited to future GB electricity market with greater flexibility requirements.

Based on the analysis and discussions with market participants reducing the ISP and MTU are viewed as steps that are well aligned with the market direction. They better reflect market operation which should lead to a fairer allocation and potentially a reduction of balancing costs. The market expectation is that part of the volume traded to the BM will transition to IDM which should also lead to lower balancing costs. A shorter ISP also enhances investment and market participation incentives for flexible assets like BESS and DSR. With regards to DSR participation and more specifically domestic DSR upscaling and speeding up the smart meter roll-out is viewed as an essential pre-requisite. Finally, a shorter ISP has the potential to improve cross border trading.

Arup's analysis has considered recommending transitioning to a 15-minute ISP. The main argument supporting this view is to be harmonised with EU markets that GB is linked to as these markets will eventually transition to a 15-minute ISP. This would allow for optimal flows both in and out of the GB market. Transitioning to a 5-minute settlement would not hinder flows from GB to the EU but flexibility provision from the EU to the GB could be sub-optimal. Available literature suggests that markets globally, including the EU, will continue moving towards an ever-increasing granularity. As such, moving to a 5-minute ISP is a more future proof solution and ensures the GB market avoids having to reduce its ISP further in a few years' time. Moreover, in Arup's view IT technology advancements along with generation mix changes support the transition to higher temporal granularity. Experience and advice provided by CAISO suggested that a single step approach is a much-preferred option. CAISO moved to 5-minute ISPs via an interim step of 15-minute ISPs which resulted in them spending the same money twice.

In conclusion, it is recommended to move to 5-minute ISP and MTU due to it being a future-proof solution that can deliver higher benefits.

Recommendation 3: Technology and generation mix advancement support the transition to a 30-minute gate closure interval but anything below that could lead to adverse impacts when it comes to system costs and security of supply.

As mentioned above there is limited quantitative evidence on assessing the impact of shortening the gate closure interval. Most of the qualitative analysis suggests that reducing gate closure could allow for improved bidding and more transparent bidding in the BM, better opportunities for flexible generators and better integration of VRE by allowing for output adjustments closer to real-time.

On the other hand, reducing the gate closure too much could lead to adverse effects when it comes to system costs and security of supply. One of the very few qualitative studies conducted by Petitet and Perrot, suggested that reducing the gate closure below 30-minutes leads to fewer balancing actions but higher costs. Moreover, the gate closure interval needs to be linked with the existing generation mix. In the GB market CCGT generators that provide the lion-share of flexibility can cope well with a 60-minute gate closure interval, but it is not clear how well they would be able to cope with anything shorter than this.

In Arup's view the generation mix development along with the IT technology advancements should allow transitioning to a 30-minute gate closure. It has become clear to us that transitioning to a shorter-gate closure interval will pose challenges to market actors and more specifically to the ESO. Therefore, it is recommended that further thorough discussions with the ESO are undertaken before deciding whether to pursue this move.

Recommendation 4: Proceed with an enhanced version of Ofgem's proposal to cap BM generator margins if they submit a PN between zero and their SEL.

As mentioned above the other approaches considered could lead to undesired outcomes i.e., higher costs to consumers and hampering price and investment signals. In particular

- An absolute cap on prices can be tricky to set (considering all the varying generator costs) without hampering investment and pricing signals.
- Moving the cash-out price from PAR-1 to PAR-50 or PAR-500 is against the ethos of EBSCR and could lead to higher balancing costs as it reduces the incentive for market participants to balance their position ahead of gate closure.
- Introducing locational BM products does not necessarily improve long term investment signals. Moreover, it can create market power for generators located behind constraint leading to increased costs to consumers in the short term.

An enhanced version of Ofgem's proposal, where generator margins are capped if they submit a PN between zero and SEL, is viewed as the preferred option being taken forward. It is worth investigating whether an amendment to the TCLC to include Offer prices would be a simpler implementation approach we would capture more instances. It is proposed that further work is undertaken to really assess the profits of flexible generators in GB, as the evidence suggest some fundamental concerns that are likely to grow as our stock of dispatchable power plants decrease. This will need further monitoring.

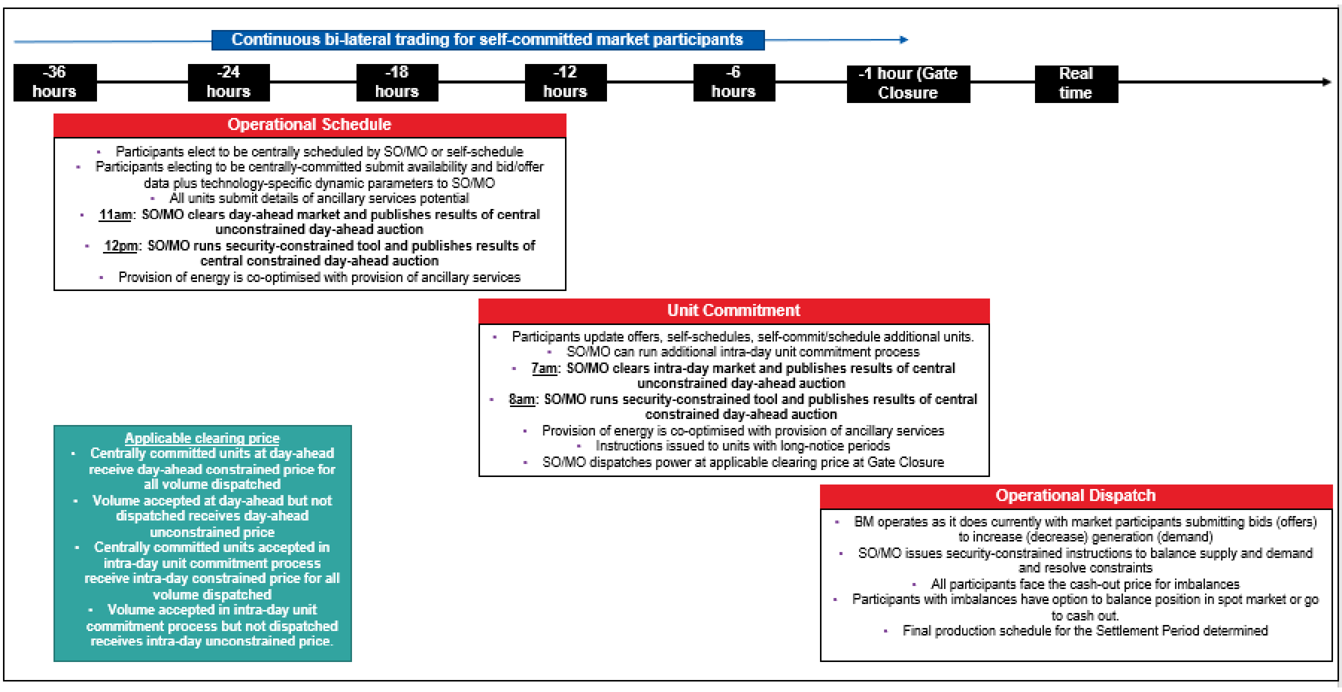
Appendix

Table 26: Economic dynamic parameters

	Units	CCGT-1	CCGT-2	CCGT-3	Pumped Hydro	Nuclear	BESS 1	BESS 2	Wind Farm 1	Wind Farm 2	CCUS	Biomass
Economic Energy Offer	MW, £/MWh	442, 107	775, 128	0,0	398, 115	2852, 35.4	0,0	0,0	300, -65.2	300, -40.2	1446, 59.9	1290, - 38.2
Self-Scheduled Energy	MW	442	-	420	-	-	10	5	-	-	-	-
No Load Cost	£/h						-	-	-	-		
DC-DM-DR High Offer	MW, £/MWh	-	-	-	-	-	25 - 6 - 0, 6.7 - 4.3 - 0	25 - 0 - 0, 5.7 - 0 - 0	-	-	-	-
DC-DM-DR Low Offer	MW, £/MW/h	-	-	-	-	-	25 - 0 - 12, 4.3 - 0 - 4.1	25 - 0 - 12, 3.3 - 0 - 4.8	-	-	-	-
Cold Start Up Cost	£	15,921	27,916	30,257	-	-	-	-	-	-	13,800	52,529
Warm Start Up Cost	£	11,077	19,422	21,050	-	10,993	-	-	-	-	10,900	32,327
Hot Start Up Cost	£	9,693	16,996	18,421	-	-	-	-	-	-	9,693	27,277
Economic Reserve Offer	MW, £/MWh	230, 160	504, 175	0, 0	200, 180	-	-	-	-	-	-	-
Self-Scheduled Reserve Offer	MW	-	-	420, 145	-	-	-	-	-	-	-	-
Black Start Offer	MW, £/MWh	0,0	0,0	0,0	0,0	0,0	0,0	0,0	0,0	0,0	0,0	0,0

Proposed design scheduling, commitment and dispatch

Figure 34: Schematic of potential Central Dispatch Model



Unit Commitment

Unit information

In the tables below we list the information that the different units involved in the simulation will be submitting to the SO/MO. The information is split into two tables one with the dispatch dynamic parameters, one with the economic dynamic parameters and one with dispatch operating parameters.

Table 27: Dispatch dynamic parameters

	Units	CCGT-1	CCGT-2	CCGT-3	Pumped Hydro	Nuclear	BESS 1	BESS 2	Wind Farm 1	Wind Farm 2	CCUS	Biomass
MEL	MW	442	775	840		602	80	60	300	300	963	645
SEL	MW	230	504	420	43	602	-	-	3	3	385	258
Super SEL	MW	220	480	400	35	602	-	-	-	-	365	235
Hot Start-up Time	hrs	8	8	8	-	-	-	-	-	-	8	6

Warm Start-up Time	hrs	48	48	48	-	40	-	-	-	-	48	18
Cold Start-up Time	hrs	49	49	49	-	-	-	-	-	-	49	24
MNZT	hrs	5	6	6	0	72	0	0	0	0	6	-
MZT	hrs	4	4	4	0	72	0	0	0	0	3	-
Ramp Rate	MW/min	23	13	16	120	29.7	-	-			13	14.65
Maximum cycles per day	#	-	-	-	-	-	2.3	1.8	-	-	-	-
Minimum discharge limit	MWh	-	-	-	-	-	68	51	-	-	-	-
Maximum discharge limit	MWh	-	-	-	-	-	20	15	-	-	-	-
State of Charge	%	-	-	-	-	-	90%	100%	-	-	-	-
Outage/ Maintenance notifications	MWavail	884	1161	840	1728	2852	50	50	1200	450	1446	1290

In the tables below we show the parameters taken into account in the DA and ID auctions.

Table 28: Services procured on DA auction

	CCGT-1	CCGT-2	CCGT-3	Pumped Hydro	Nuclear	BESS 1	BESS 2	Wind Farm 1	Wind Farm 2	CCUS	Biomass
Energy Offer Unconstrained	442MW	0MW	0MW	398MW	0MW	0MW	0MW	300MW	300MW	1446MW	1280MW
Energy Offer Constrained	442MW	0MW	420MW	398MW	2852MW	0MW	0MW	200MW	200MW	1446MW	1280MW
Reserve Offer	230MW	504MW	420MW	200MW	0MW	0MW	0MW	0MW	0MW	0MW	0MW
Black Start Offer	-	-	-	-	-	-	-	-	-	-	-
DC/DM/DR High Offer	-	-	-	-	-	25 - 6 - 0, 6.7 - 4.3 - 0	25 - 0 - 0, 5.7 - 0 - 0	-	-	-	-
DC/DM/DR Low Offer	-	-	-	-	-	25 - 0 - 12, 4.3 - 0 - 4.1	25 - 0 - 12, 3.3 - 0 - 4.8	-		-	-

Self-Scheduled Energy Offer	0MW	0MW	420MW	0MW	2852MW	10MW	5MW	0MW	0MW	0MW	0MW

Table 29: **Services procured on ID stage**

	CCGT-1	CCGT-2	CCGT-3	Pumped Hydro	Nuclear	BESS 1	BESS 2	Wind Farm 1	Wind Farm 2	CCUS	Biomass
Energy Offer Unconstrained	442MW	500MW	0MW	398MW	0MW	0MW	0MW	150MW	150MW	1446MW	1280MW
Energy Offer Constrained	442MW	500MW	0MW	398MW	0MW	0MW	0MW	150MW	150MW	1446MW	1280MW
Reserve Offer	230MW	504MW	420MW	200MW	0MW	0MW	0MW	0MW	0MW	0MW	0MW
Self-Scheduled Energy Offer	0MW	0MW	420MW	0MW	2852MW	10MW	5MW	0MW	0MW	0MW	0MW

Modelling Outputs

Figure 35: 2035 Winter Day Wholesale Price Curve

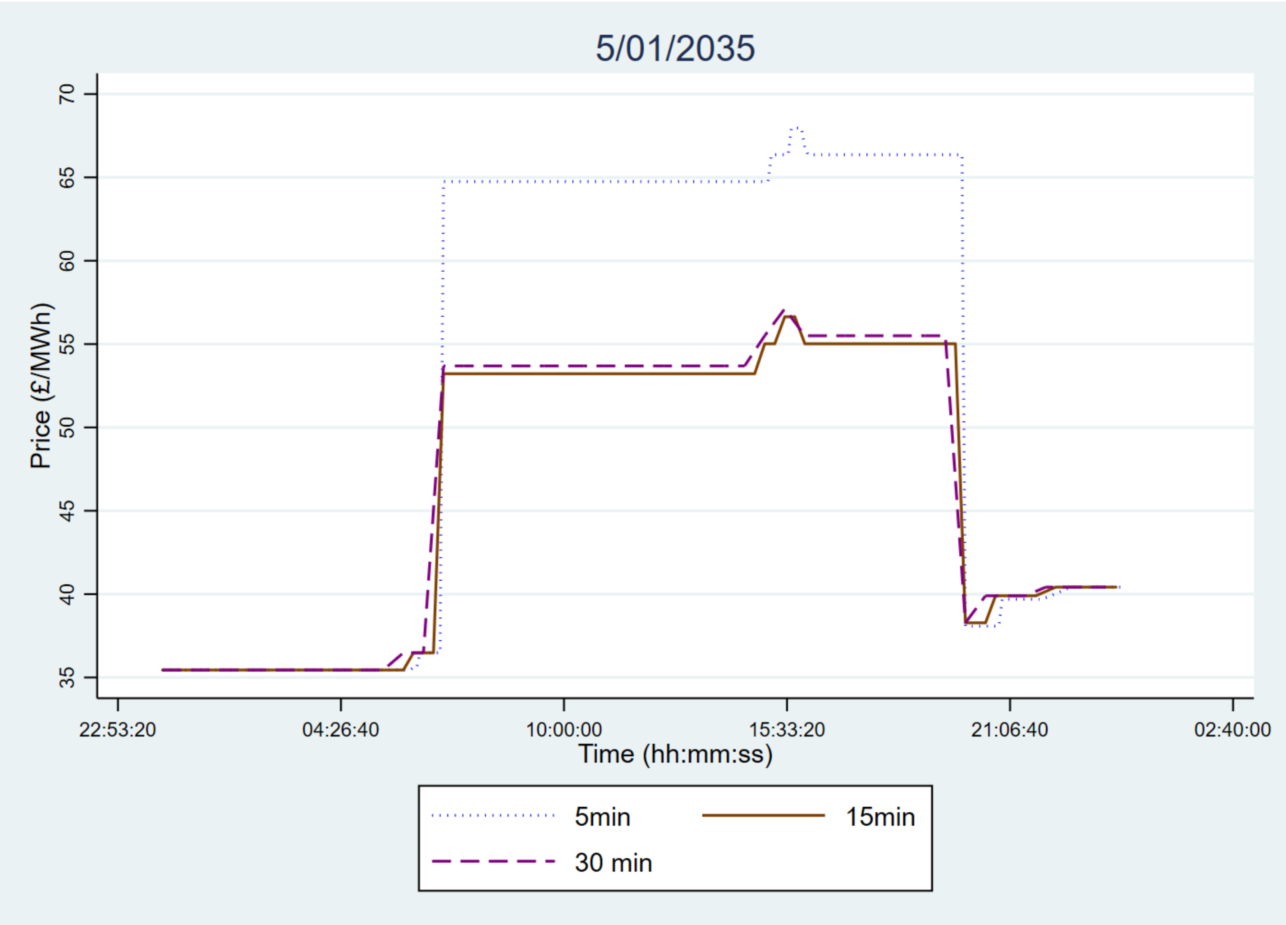
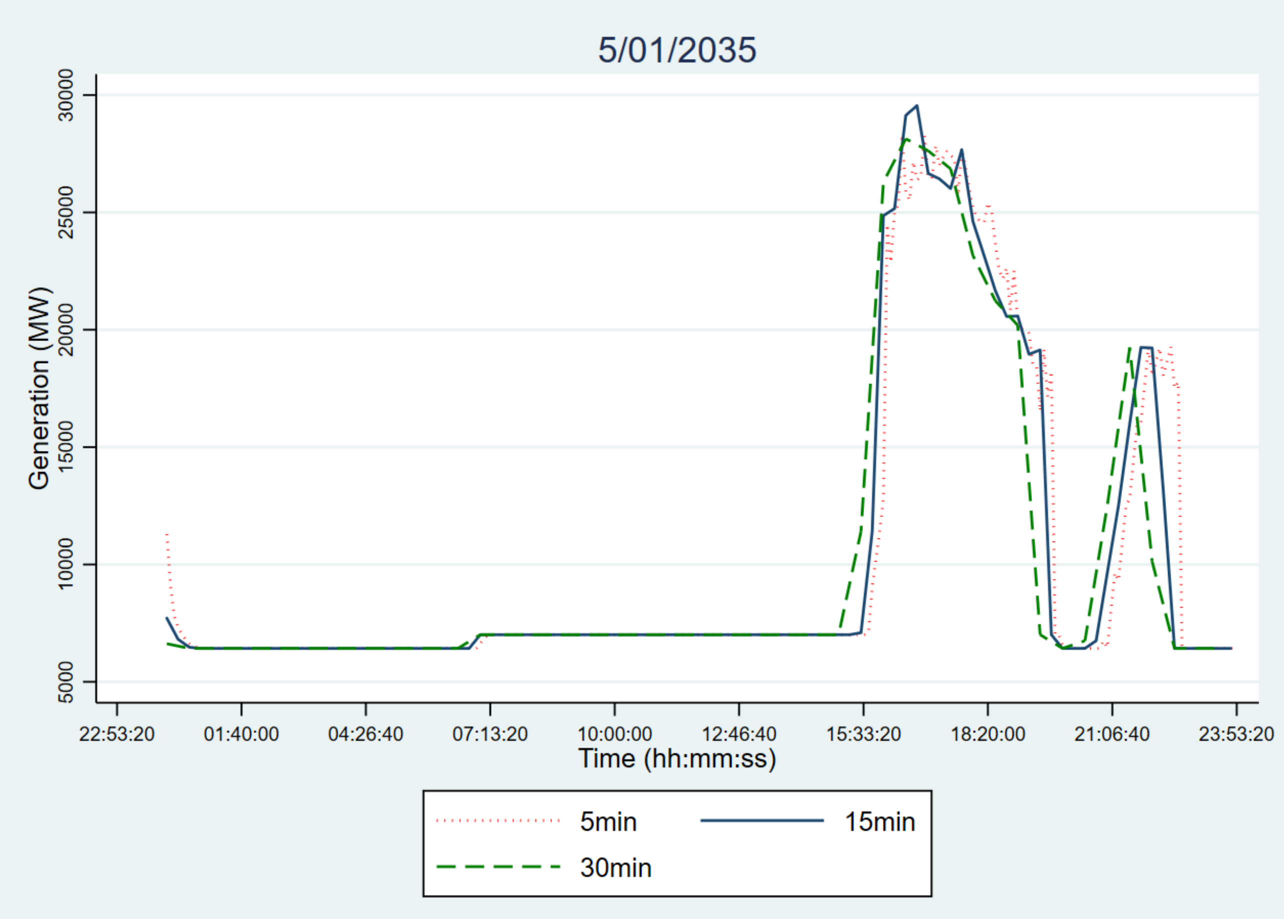


Figure 36: 2035 Winter Day Price Flexible Technologies Generation



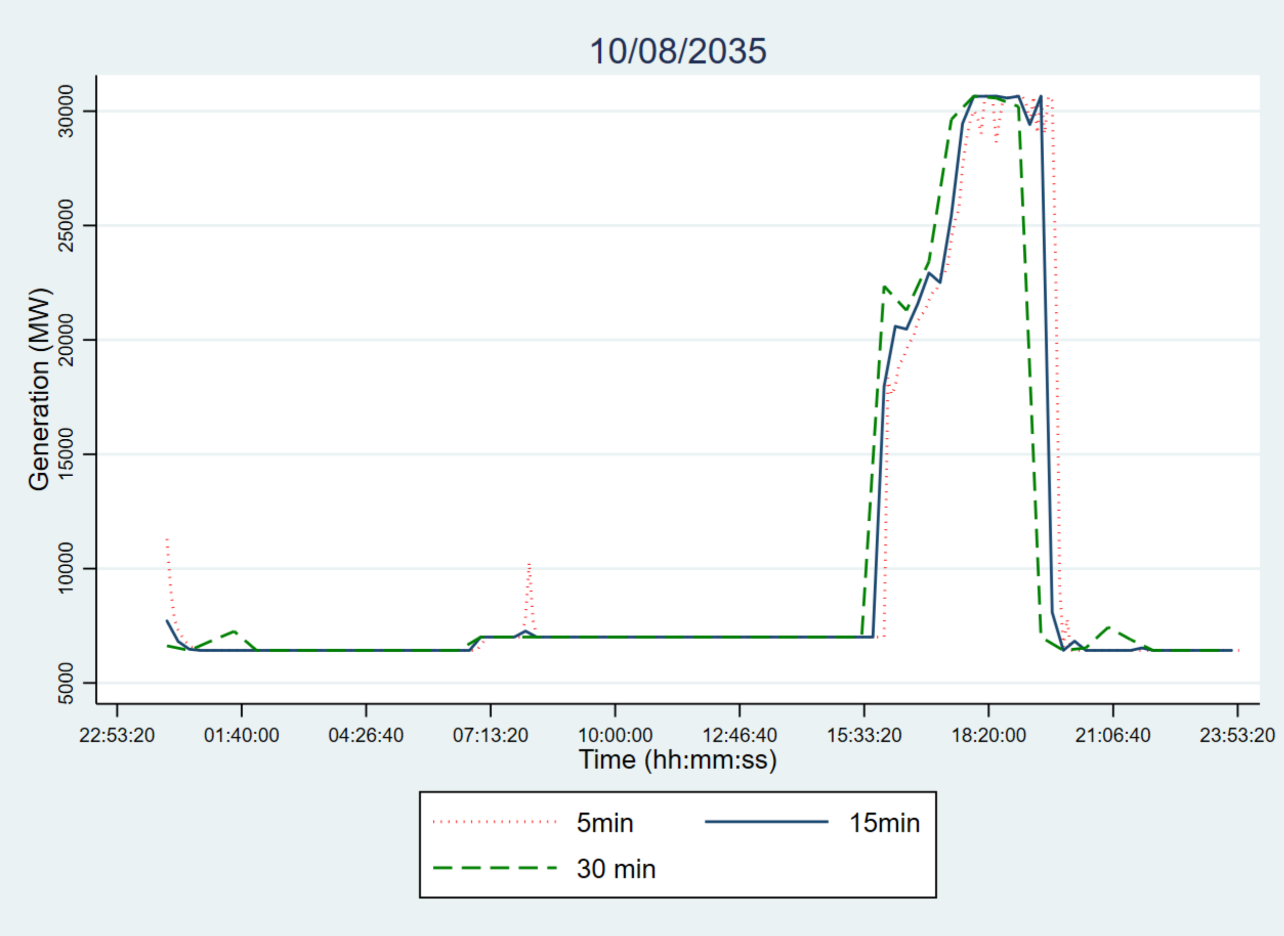
The graph above provides an overview of the total generation of Flexible generating technologies for a typical day in winter. The technologies considered were OCGT, CCGT, Pumped storage, Oil, Gas Reciprocating Engine, BECCS and BESS. Overall, we can observe that the change to a shorter settlement period affects the total generation for a typical winter day compared to the baseline temporal granularity. Moving to a 15-minutes and 5-minutes settlement period yields a total of 240.99 GWh and 242.2 GWh a day compared to 237.78 GWh for the baseline temporal granularity. Consequently, total generation increased by 1.86% and 1.35% respectively for both 5-minutes and 15-minutes settlement periods compared to the baseline temporal granularity. For the 5-min settlement period, flexible generating technologies that varies compared to the baseload temporal granularity were OCGT, CCGT, and BESS. For the 15-minutes settlement period, only OCGT and BESS varies compared to the baseline temporal granularity. It should be noted that total generation from BESS increases as settlement periods become shorter, that is, move from 15 minutes to 5-minutes compared to the 30-minutes baseline temporal granularity. To be specific, for BESS in 2035, moving from 15-minutes to 5-minutes settlement periods compared to the 30-minutes baseline temporal granularity increases generation by 3.8% and 4.77% respectively.

Summer Day: Wholesale Price Impact analysis

Figure 37: 2035 Summer Day Wholesale Price Curve

The diagram above provides an overview of wholesale price curves for a typical day in winter for the year 2035.The curves provide an overview of each temporal granularity, that is, a 5- and 15-minutes settlement period including a 30 min baseline temporal granularity. Prices are measured in £/MWh.

Figure 38: Winter day generation mix



The graph above provides an overview of the total generation of Flexible generating technologies for a typical day in winter. The technologies considered were OCGT, CCGT, Pumped storage, Oil, Gas Reciprocating Engine, BECCS and BESS. Overall, we can observe that the change to a shorter settlement period affects the total generation for a typical winter day compared to the baseline temporal granularity. Moving to a 5 min and 15 min settlement period yields a total of 236.27 GWh and 234.96 GWh a day compared to 232.87 GWh for the baseline temporal granularity. Consequently, total generation increased by 1.46% and 0.90% respectively for both 5-minutes and 15-minutes settlement periods compared to the baseline temporal granularity. For the 5-minutes settlement period, flexible generating technologies that varies compared to the baseload temporal granularity were OCGT, CCGT, Pumped Storage and BESS. For the 15-minutes settlement period, CCGT, Pumped storage, and BESS were the flexible generators changing with respect to the baseline temporal granularity. It should be noted that total generation from BESS increases as settlement periods become shorter, that is, move from 15-minutes to 5-minutes compared to the 30-minutes baseline temporal granularity.

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