Public

RNP: Balancing and Settlement Reforms

IEP 5: Policy Design, CBA & Implementation Update

8 September 2026

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Agenda

	Item	Presenter	Time
Welcome and Intro	**Session Objectives**	**Seb**	10.00
Topics	***Lowering the BM threshold***		
	Policy design update	NESO	10:05 - 10:20
	Proposed to-be TOM	Baringa	10:20 – 11:20
	MP costs	Baringa	
	CBA analysis	Baringa	
	Breakout discussion	All	11:20 -12:00
	Lunch		12:00-13:00
	Shorter Settlement Period		
	Policy design update	NESO	13:00 -13:15
	Proposed to-be TOM	Baringa	13:15 – 14:15
	MP costs	Baringa	
	CBA analysis	Baringa	
	Breakout discussion	All	14:15 -14:55
	Break	All	14:55 – 15:10
All Together	**Playback discussion**	All	15:10 - 15:40
	Wrap up and next steps	Seb	15:40 – 16:00

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Welcome & Intro

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What we require from the IEP

This is your opportunity to test and challenge key elements of the CBA and implementation assessment methodology.

This pack provides some detailed thinking on the implementation assessment and impacts of reforms on market participants to be informed through discussion with you.

Experience & Insight

Your industry knowledge and expertise will be used to represent key groups across industry, feeding into assumptions regarding how we model representative behaviour from those participant groups.

Data & Evidence

Several inputs and assumptions will be dependent on data and evidence provided by you – e.g. on operational behaviours. We will set out data requirements to support our modelling and assessment of cost impacts. We also welcome voluntary data and evidence submissions that support your perspectives.

Constructive Engagement

We will always value challenge and feedback on our proposed approach. We will consider and take into account your challenge in our modelling choices and implementation planning.

Please use this session to share experiences or real concerns that relate to the Balancing & Settlement reforms

Please refrain from side conversations, and respect others' opinions

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Key principles to guide our session

Aligning on key principles to ensure we get the most out of today's session

Materiality	Focus effort on the most impactful drivers and changes, prioritising modelling, analysis and assessment of impacts on areas with the greatest influence on decision-making, scale, complexity, and cross-participant impact.
Transparency	Use regular external stakeholder touchpoints to update on progress, and to seek challenge, evidence and data on our approach. We will share the CBA methodology and key notes from IEP discussions to wider industry.
Evidence-Based	Analysis will be grounded in data and subject matter expertise, incorporating inputs from stakeholders where relevant. We will weight perspectives more highly where supported by data and evidence to support arguments for certain modelling choices and implementation planning.
Managing Uncertainty	All modelling and implementation analysis has limitations and necessary abstractions/ assumptions. Confidence levels, sensitivities, etc will be used to inform assessment of key uncertainties

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Lowering the BM Threshold

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Update on Policy Design

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Lower BM: Proposed design overview

	Threshold	Requirements	Scope	Aggregation	Contract
Retrospective application	≥30MW	Full participation: Dynamic parameters; Bids and Offers; PNs; operational metering	Existing Demand assets and Generation assets commissioned post-G99.	Already aggregated units can remain aggregated. Future aggregation not permitted.	A new connection contract will be required (similar to a BEGA) which will allow the option of CVA or SVA metering for settlements.
Full participation for new* assets	≥10MW	Full participation: Dynamic parameters; Bids and Offers; PNs; operational metering	New* Generation and Demand.		
Visibility-only for new* assets	≥1MW	PNs and operational metering	New* Generation Units only	Aggregation allowed however then must participate fully in BM.	

Implementation approach

Now	Phase 0	Existing visibility programmes
From 2029	Phase 1	All new* assets above 30MW
From 2030	Phase 2	All new* assets above 10MW
From 2032	Phase 3	1MW visibility + 30 MW retrospectivity for post-G99 assets

Elements of design still under consideration

- Level of retrospectivity: threshold and how far back
- Aggregation arrangements
- Visibility option and demand threshold
- Contractual arrangements

*New: applies to assets not currently connected to the NETS, including those in the connections queue and those who have already received Gate 2 offers

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Clarification Questions

Policy Update

Proposed To-Be TOM

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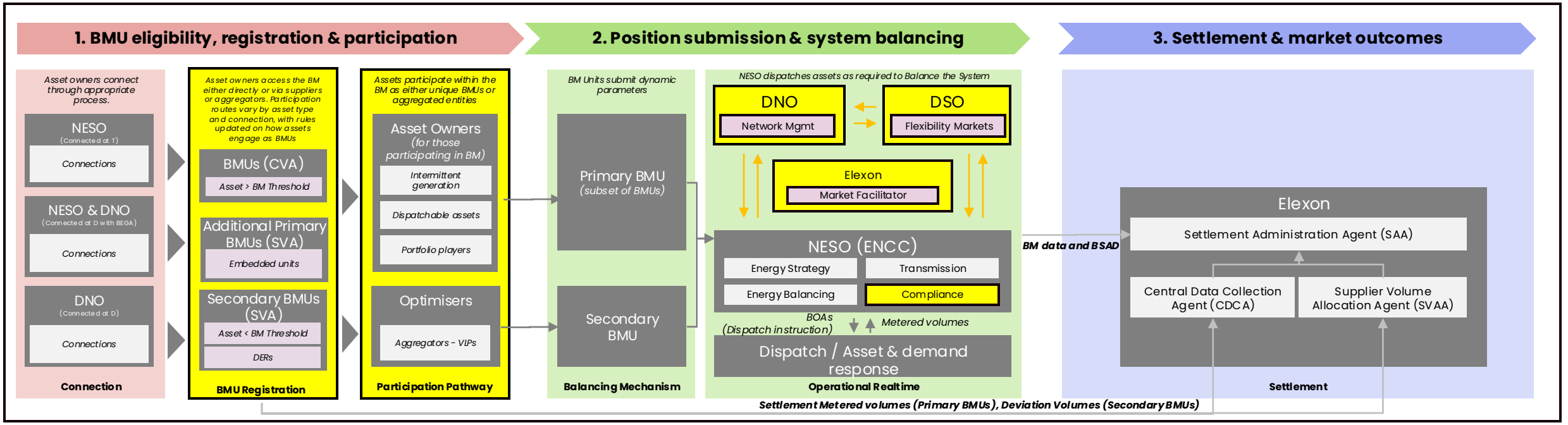
LBM | To-Be Process Overview

Key

No functional change to core capabilities, business processes, systems architecture or technology components

Functional change to core capabilities, business processes, systems architecture or technology components

Simplified To-Be diagram of information flows from participants impacted by Lowering BM Threshold



Key Change	Underlying Assumption	Key Change	Underlying Assumption	Key Change	Underlying Assumption
• Increase in volume of connectees requesting changes to their Connection agreements	• NESO Connections Team can scale to accommodate demand	• NESO processes and utilises a higher volume and granularity of data within strategy and operational timeframes	• Data-sharing infrastructure can accommodate increased data volumes and submission frequencies.	• Elexon conducts settlement calculations on an increased numbers of BMUs	• Systems are scaled to process the increased volume of settlement data resulting from wider participation.
• BMU registration process reformed to enable lower BM units to register in a streamlined process	• Processes redesigned to reduce fragmentation and increasing registration and testing throughput.				
• A broader range of assets become subject to BM metering, operational and data requirements.	• Proportionate metering and compliance requirements are introduced for newly eligible assets.	• NESO increase their access to a sufficiently large and valuable pool of D-connected assets	• Primacy rules are defined by the market facilitator • NESO's IT infrastructure adapts to meet requirements set by the primacy rules		
• Licensing thresholds and exemption orders are redefined (e.g. reviewing BEGAs).	• DESNZ and NESO establish appropriate thresholds for newly in-scope, unlicensed generators	• New data-sharing arrangements created with DNO/DSOs & TOs			
• Participants build more granular physical and commercial position management capabilities to submit accurate asset-level data		• Compliance, monitoring and assurance activities expand to reflect increased participation	• NESO has sufficient operational capability, resource and tooling to support enhanced monitoring		

Other assumptions: (1) Connections Reform changes are implemented prior to B&S go-live. (2) Market participation BMU routes remain unchanged (CVA BMU, SVA Primary BMU and SVA Secondary BMU)

10 mins

Clarification Questions

TOM Update

Market Participant Costs

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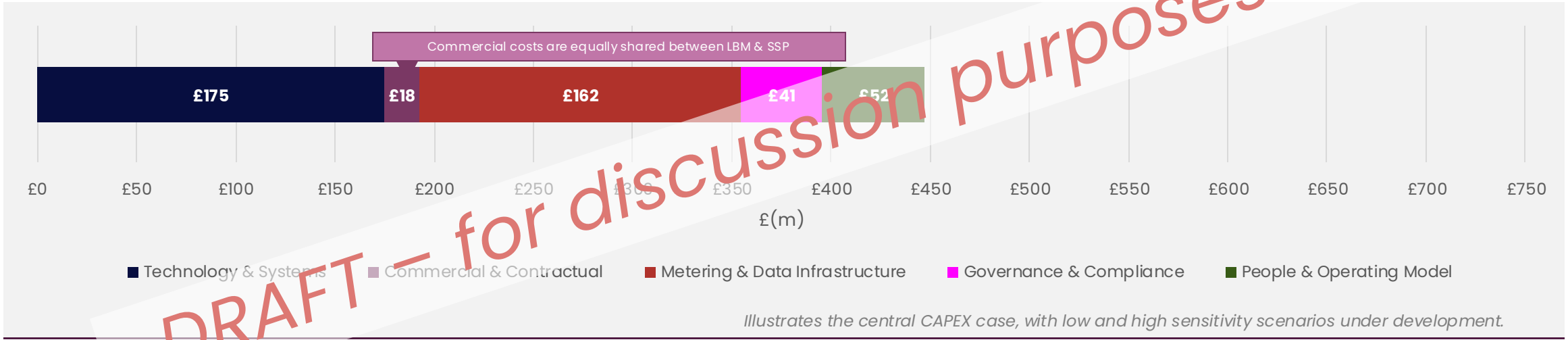
LBM DRAFT FINDINGS | CAPEX costs for Market Participants

Overview	LBM expands direct participation of smaller and distributed assets & demand in the Balancing Mechanism, with costs driven primarily by metering upgrades, system changes and additional operational capability required to manage a significantly larger volume of BMUs.



Illustrates the central CAPEX case, with low and high sensitivity scenarios under development.

TOP THREE COST CATEGORIES (% of total cost)

1. TECHNOLOGY & SYSTEMS (c. 39%)

- **Technology and systems costs are driven by the significant increase in BMUs and asset-level operational activity**, requiring MPs to manage a much larger volume of operational data and processes.
- **Participants with trading desks are expected to enhance trading and operational systems**, including forecasting, scheduling, dispatch, PN/FPN submission, telemetry integration, and settlement reconciliation capabilities.
- **Suppliers face additional retail system costs**, reflecting changes to settlement, billing, and supporting operational platforms.

2. METERING & DATA INFRASTRUCTURE (c.36%)

- **Metering and enablement costs cover both retrospective upgrades** for existing >30MW assets brought into scope and incremental requirements **for future assets** commissioned to 2050 (c.2250 assets).
- Site enablement costs vary. Central assumptions c.£15k per 1–10MW site for visibility only (incremental turnkey metering/data interface, telemetry, communications, installation, integration and testing) and c.£50k per 10–50MW site for active BM participation (incremental turnkey operational metering, telemetry, communications, BM interface integration, installation and testing)*. Costs are scaled using asset growth projections from the Future Energy Scenarios Holistic Transition pathway.
- Costs extend beyond physical meters and include the supporting telemetry, communications, data, systems integration, installation and testing required to enable visibility, control and settlement processes.

3. PEOPLE & OPERATING MODEL (c.12%)

- **People and operating model take into account the internal process changes** requiring participants to manage a significantly larger volume of BMUs and operational processes.
- **Participants with trading desks may require new operational capabilities** for forecasting, monitoring, dispatch activities and FPN submission across a larger population of assets.
- This includes: process redesign, governance, controls and onboarding of additional operational staffing to support BM participation at scale.

*The assumptions are indicative central costs per site. Actual costs will depend on existing site capability, with reasonable sensitivities of c.£2k–£40k for visibility-only sites and c.£20k–£100k for active BM participation.

LBM DRAFT FINDINGS | Impacts by Cost Category and Archetype

Change is mainly concentrated in onboarding more assets, rather than developing a new capability — with cost is driven by IT architecture and site connectivity

RAG* High Cost · Medium Cost · Low Cost

Cost category	Asset owners	Suppliers	Aggregators / VLPs
Trading & position management	ETRM extended to carry more BMUs. Mostly configuration and scaling, not new capability.	Same ETRM build as asset owners. Complexity sits in portfolio and netting: an integrated book nets generation, flex and retail.	Platforms are already cloud-native and multi-asset, so change is incremental.
Scheduling, nomination & dispatch	Vendor licence uplift is a distinct driver: scheduling vendors price on MW under management, so cost scales with capacity onboarded.	Same EDT/EDL core, plus new demand sites in scope.	Reconfiguration of Secondary BMUs based on new aggregation requirements.
Settlement & billing	Metered data reconciliation per BMU, imbalance allocation, losses and Elexon interfaces.	Adds retail and B2B settlement, customer billing and tariff systems; heavier testing.	Systems are already built for asset-level revenue allocation; change is incremental.
Forecasting & analytics	Per-asset FPN-grade forecasting for sites that have never submitted one. This is a coverage extension to new sites, not an accuracy upgrade	Carries demand-side as well as generation forecasting; demand granularity is the larger element.	Extending existing per-site models to newly in-scope assets.
Metering & infrastructure	Pipelines, storage, validation and system-side metering integration.	Largest firm-level data build. Customer and embedded-site data at volume, plus smart-meter data.	Ingestion and connectivity across many small assets. Telemetry data model is typically flexible to absorb new assets.
Operating model & people	Registration, controls and training for a much larger asset population.	Broadest internal footprint, reaching customer operations (I&C demand) as well as trading.	Dispatch operations are already core business, so mainly scaling existing processes.
Compliance & obligations**	Registration and BSC obligations, plus physical performance against dispatch instruction.	Updating controls and compliance spanning generation, supply and customer sites.	Large-generator rules may apply to small assets and sites.

Notes:
*RAG indicates relative scale of change. Descriptions are grounded in participant engagement; the effort values behind the RAG are structured judgement, not participant-validated.
***Scope depends on an unresolved question: whether newly in-scope sites face full Grid Code*

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Lowering the BM Threshold: DRAFT Effort & Cost by Archetype

Cost category	**Asset owners** (with trading desks)	**Suppliers** (with trading desks)	**Aggregators / VLPs**
Trading & position management	300 – 1,500 days	250 – 1,300 days	150 – 700 days
Scheduling, nomination & dispatch	500 – 2,200 days	300 – 1,400 days	300 – 1,300 days
Settlement & Billing	200 – 900 days	500 – 2,400 days (incl. B2B & B2C)	120 – 500 days
Forecasting & analytics	150 – 800 days	250 – 1,200 days	200 – 900 days
Metering & data infrastructure	460 – 1,930 days	575 – 2,365 days	405 – 1,700 days
Operating model & people	380 – 1,630 days	485 – 2,050 days	270 – 1,200 days
Compliance & obligations	300 – 1,300 days	380 – 1,580 days	218 – 950 days
TOTAL firm-level	**CAPEX: £1.7 – 7.7m** (2,290 – 10,260 days)	**CAPEX: £2.0 – 9.2m** (2,740 – 12,295 days)	**CAPEX: £1.2 – 5.4m (**1,663 – 7,250 days)

Note: Blended day rate £750/day has been applied to calculate CAPEX costs. This is representative of an average of current internal FTE or external contractor daily cost.

Clarification Questions

MP Costs

CBA Analysis

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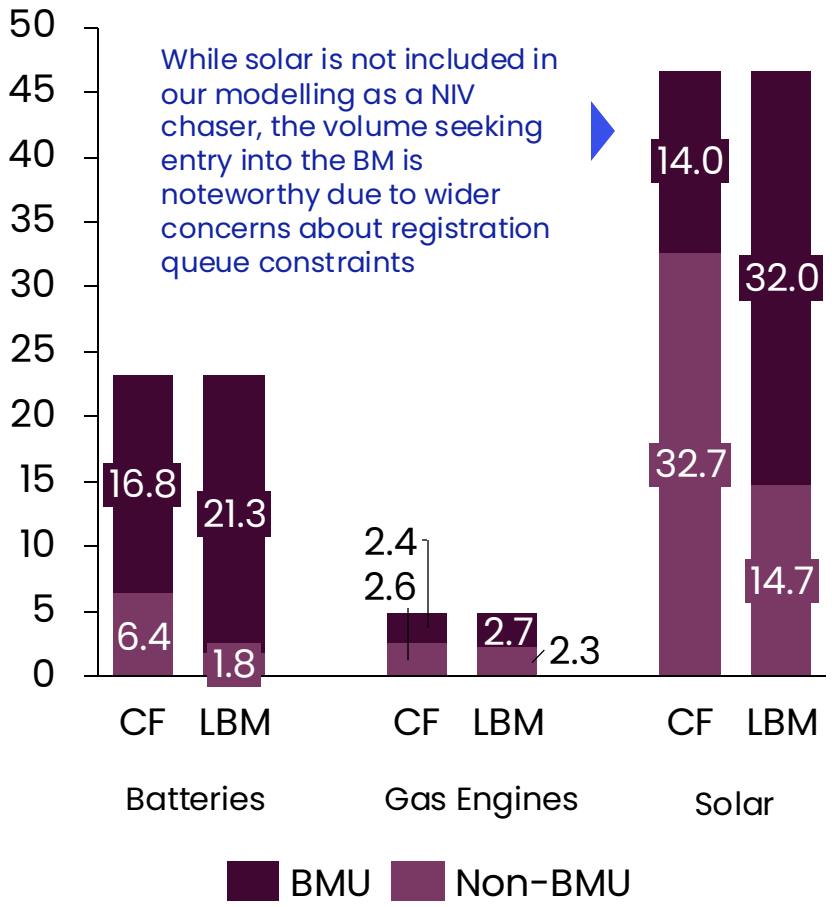
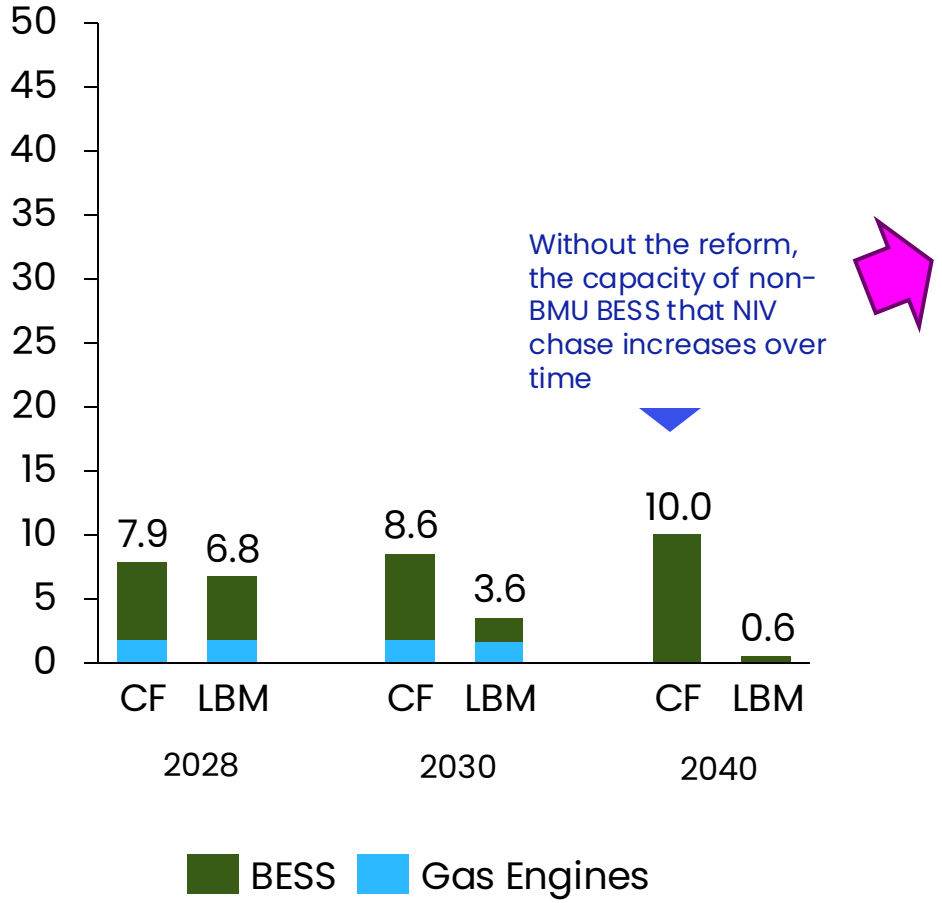
Lowering the BM threshold (LBM): NIV chasing capacity

More resources move into the BM → **Less physical NIV chasing**

Relative split of capacity that is a BMU and non-BMU, Under the CF and LBM, (GW, 2030)



Total capacity of physical NIV chasing assets Under CF and LBM, (GW)



Identified impact mechanisms resulting from reduced NIV chasing under LBM:

1. Fewer counterproductive actions and more BM competition may lead to lower costs of resolving imbalance
2. Potential for less NIV chasing to reduce costs of resolving constraints
3. Reduced reverse procurement volumes and ability to procure reserves earlier at lower cost

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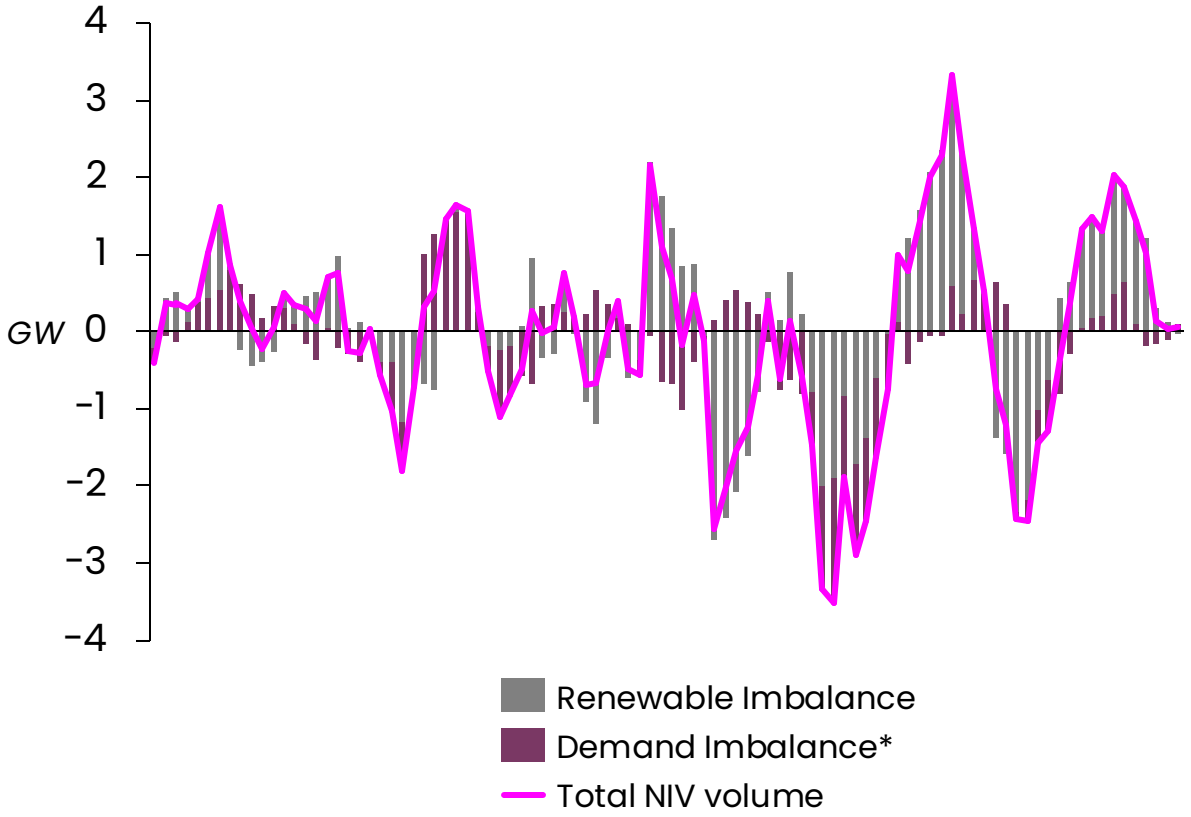
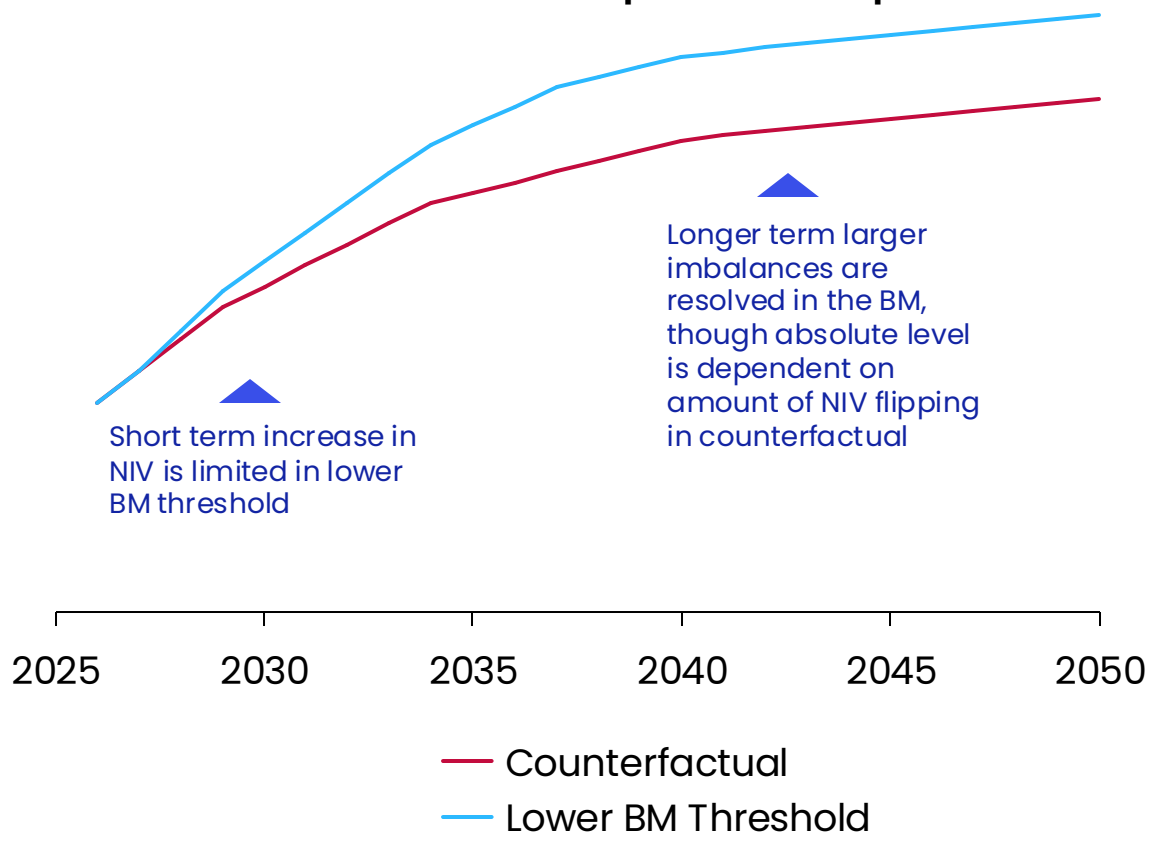
Lowering the BM threshold (LBM): NIV Chasing Volumes

More resources move into the BM → **Less physical NIV chasing**

Systemwide Net Imbalance Volume (GW, representative day, 3 April 2040, under HT FES scenario)



Illustrative reduction in absolute NIV per settlement period



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* Demand Imbalance is a negative such that the total NIV is a measure of how long/short the system is

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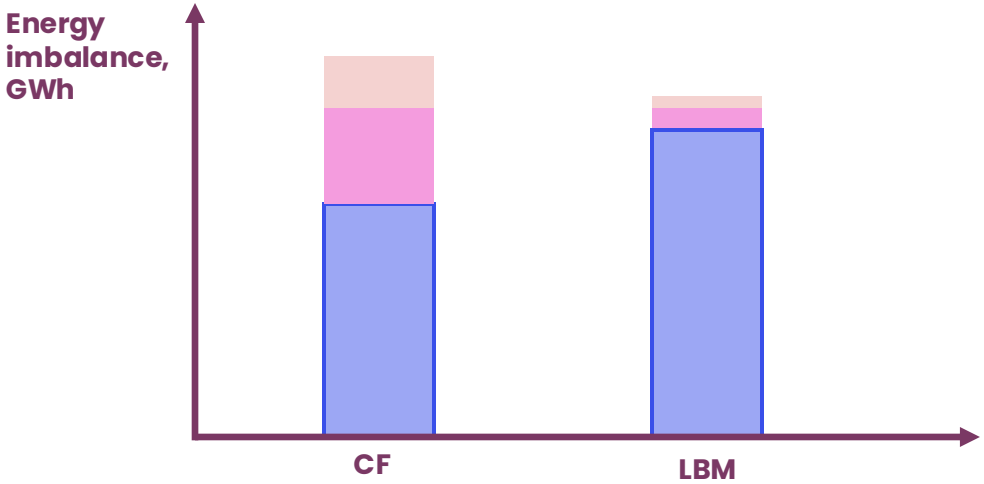
Lowering the BM threshold (LBM): What we expect to see (1/5)

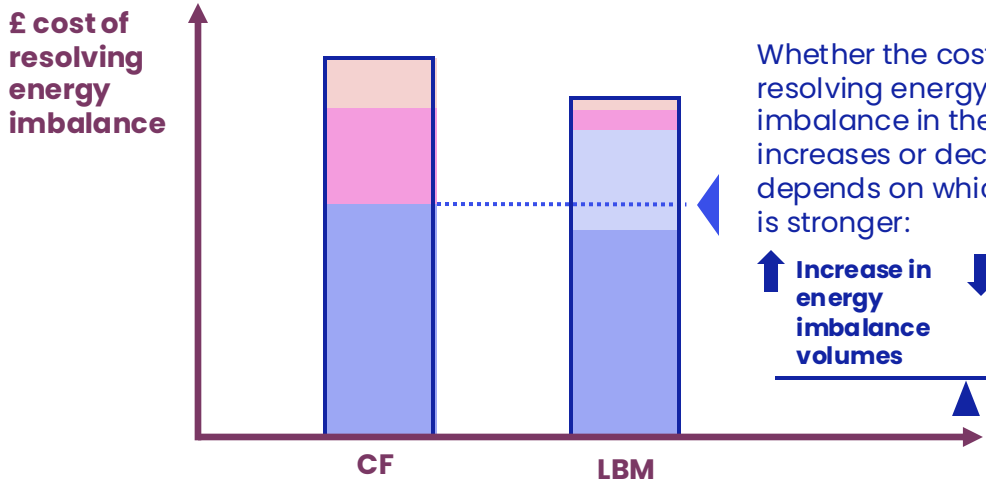
More resources move into the BM → **Less physical NIV chasing**

1 More energy imbalance being resolved in the BM…



- Energy imbalance resolved in the BM
- Energy imbalance resolved through physical NIV chasing
- Counterproductive actions on energy imbalance linked to lack of visibility of NIV chasing, and non-BMU dispatch

…but at potentially a lower total cost



Whether the cost of resolving energy imbalance in the BM increases or decreases depends on which driver is stronger:

- **Increase in energy imbalance volumes**
- **More competition in the BM reducing costs**

- Cost of energy imbalance being resolved in the BM
- Revenues paid to physical NIV chasers
- Cost of counterproductive actions
- Total cost of resolving energy imbalance

What are counterproductive actions?

After Gate Closure (GC), NESO has a fairly accurate forecast of system-wide energy imbalance, and may take early action to proactively resolve x% of this. Typically, these early actions are cheaper than actions that may be taken closer to real time. But these early actions may end up being counterproductive and may need to be unwound:

- Fully, if the direction of energy imbalance flips relative to expectations, or
- Partially, if energy imbalance is reduced to such a low level that early actions could lead to overshooting.

Higher volumes of counterproductive actions are associated with NESO's lack of visibility – as well as how extensively early actions are used. Ongoing NESO workstreams to improve visibility may also reduce counterproductive actions in the counterfactual – we vary how significant this CF visibility improvement is likely to be in in the Central /Low/ High cases (see sl. 51).

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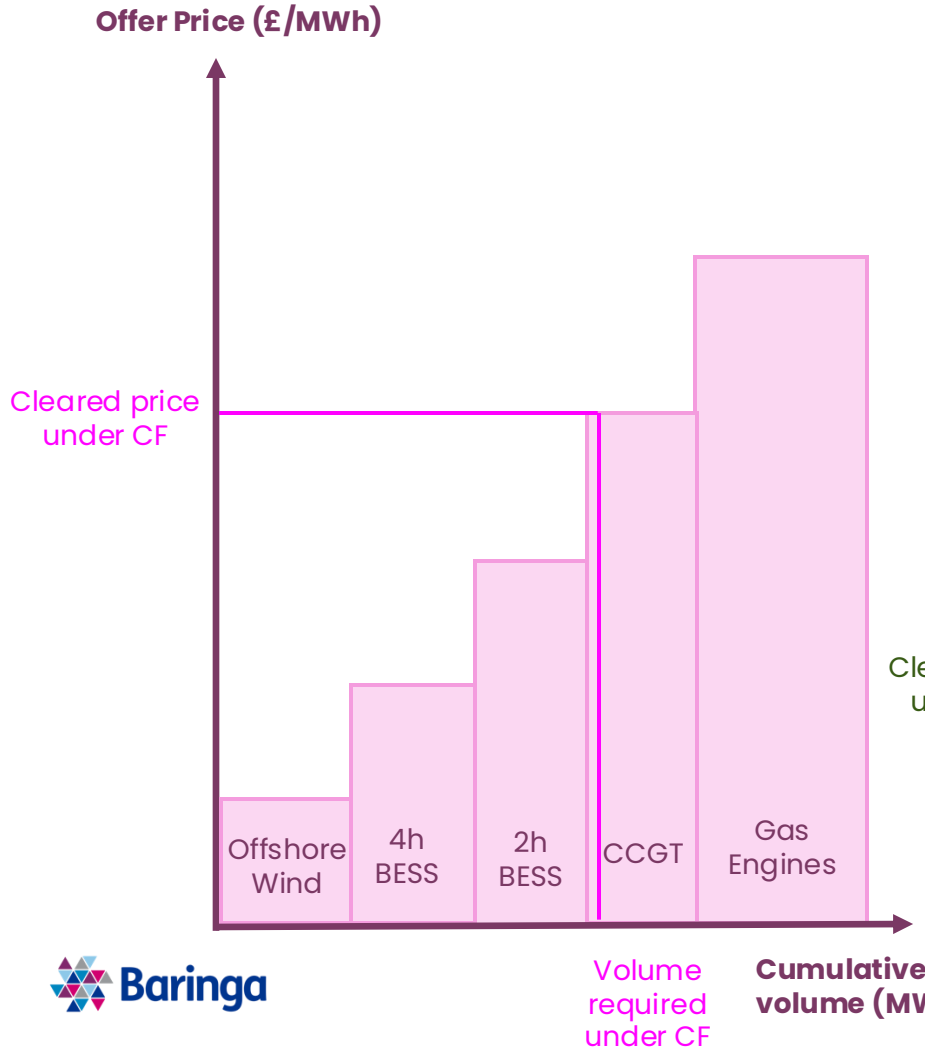
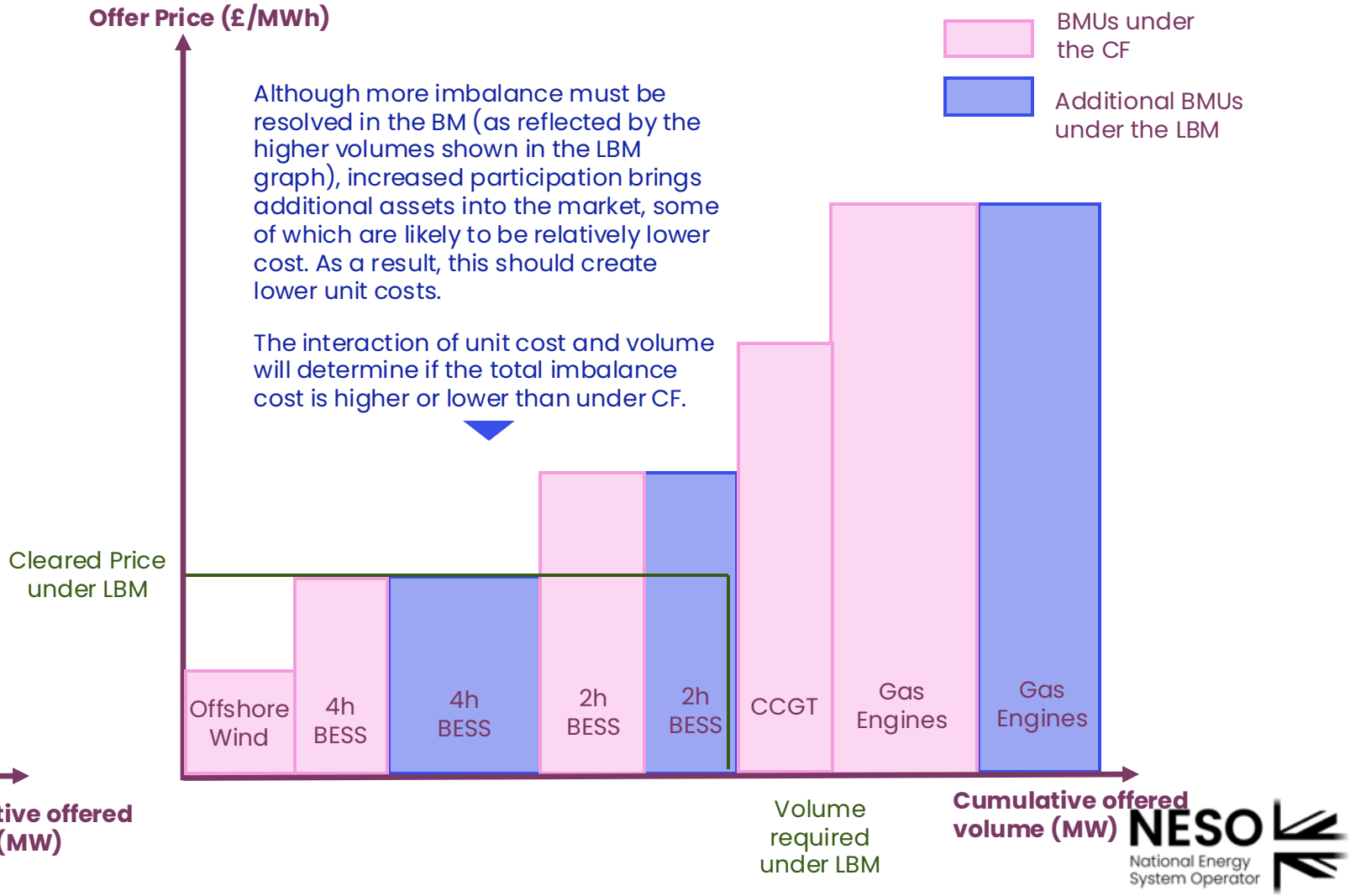
The effect of additional participation in the BM

The merit order of available BM actions for resolving energy imbalance changes – but so does the imbalance volume

Illustrative merit order under CF



Illustrative merit order under LBM



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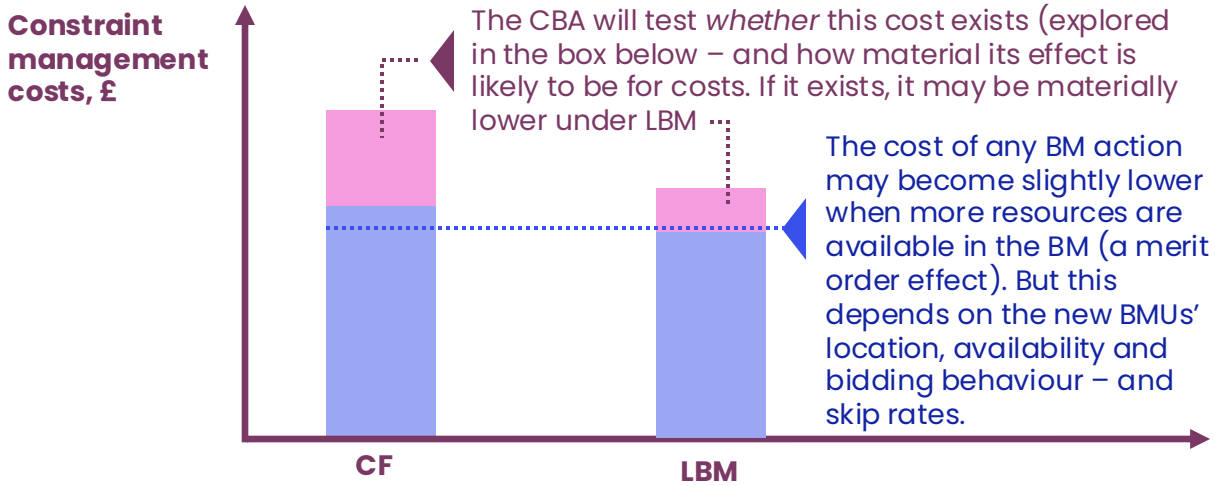
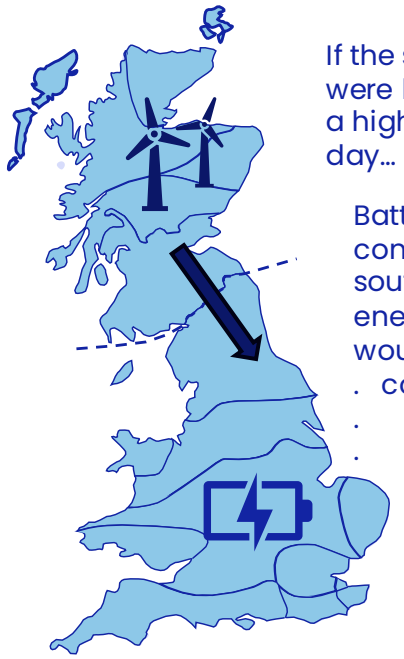
Lowering the BM threshold (LBM): What we expect to see (2/5)

More resources move into the BM → **Less physical NIV chasing**

2 Lower constraint management costs – an indirect impact





If the system were long on a high wind day…

Batteries consuming in the south to resolve energy imbalance would increase constraint management actions.

An illustration of when NIV chasing may worsen congestion

It's a high wind day, leading to network congestion on the B6 Scotland-England boundary.

If the system was then expected to be long (i.e., more wind and or less demand is expected to materialise), NIV chasing BESS would increase their consumption.

This would reduce energy imbalance, but if most NIV chasing BESS capacity was located in England, this would worsen constraints that need to be resolved, necessitating even greater turn-up of generation in the South.

Is physical NIV chasing likely to be <u>systematically</u> correlated with constraint management cost inefficiencies?

Does physical NIV chasing systematically worsen network constraints? What would we have to believe for this to be the case? Modelling will test:

- Are periods of high constraint management costs correlated with periods when the system is long / short?
- Are more NIV chasing assets located in demand – constrained areas?
- Are there more NIV chasing volumes when the system is long / short?

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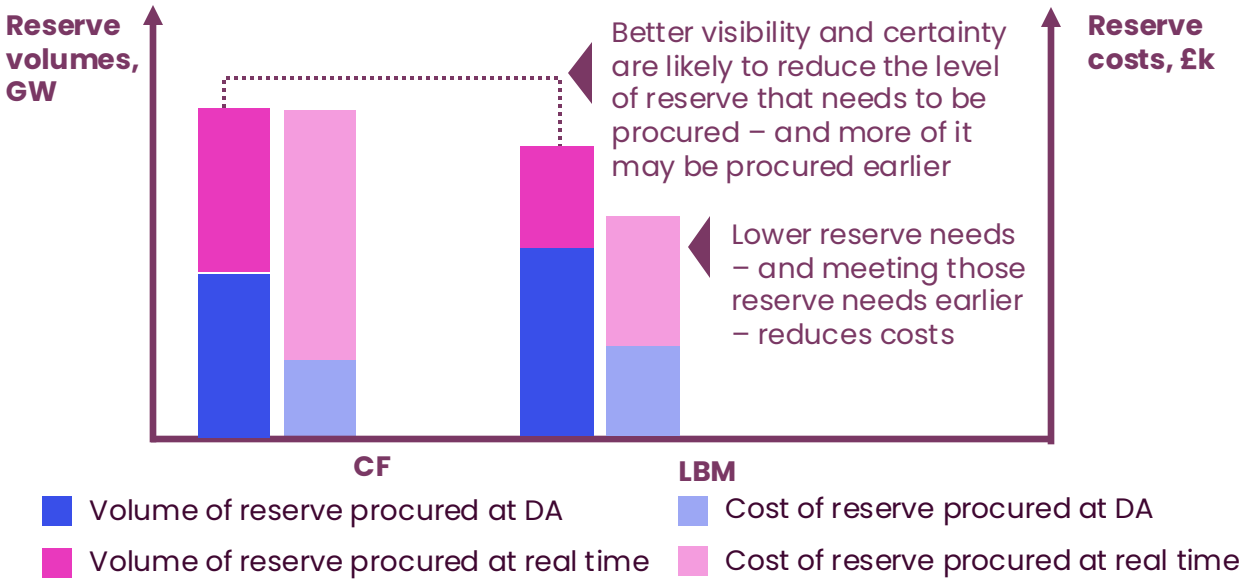
Lowering the BM threshold (LBM): What we expect to see (3/5)

More resources move into the BM → **Less physical NIV chasing**

3 Better visibility, lowering the cost of reserve procurement



NIV chasing is seen by NESO as demand imbalance — generators changing their output to chase the perceived NIV changes demand imbalance relative to forecast and hence inflates the apparent demand uncertainty the system operator must hold reserve against.

In Baringa's reserve procurement model, NIV chase volumes are added directly to the forecast demand without NIV chasing, before applying the hour-of-day standard deviation percentage, so removing NIV chasing reduces the effective demand level that this standard deviation is applied to. As a result, this shrinks the demand contribution to total reserve requirement and therefore the total reserve requirement.

How are we modelling Reserve procurement?

We calibrate the standard deviation of forecast error using historic 4h-ahead forecasts against outturn, matching NESO's reserve procurement horizon. Wind and solar standard deviation is bucketed by load factor, whilst demand standard deviation is bucketed by hour of day and expressed as a percentage of output level.

For each period in the modelled horizon, we look up the relevant standard deviation for wind, solar and demand, scale by the scenario's capacity and demand levels, and align our modelled Reserve procurement to NESO's security standard. Comparing scenarios with and without NIV chasing gives us the hourly MW difference in reserve, which we value against reserve procurement costs.

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Lowering the BM threshold (LBM): What we expect to see (4/5)

Impacts on market participants, and what we expect to see from wider modelling

There are likely to be significant distributional impacts from the system-wide effects we discussed in the previous slides - particularly for NIV chasing assets, who are likely to lose out. High skip rates and ANM restrictions would make this worse.

MP archetype	Most significant impacts	Analytical approach
BMUs	Some lost revenue due to greater BM participation, reduction in BM imbalance and reserve requirements	Captured through additional participation and increased imbalance volumes in BM and reduced reserve volumes
BMUs	Additional revenue opportunity from participation in the BM (dependent on skip rates, primacy arrangements, lack of active participation)	Captured through additional participation and increased imbalance volumes in BM and reduced reserve volumes
10-50 MW future BMUs	Lost physical NIV chasing opportunities post GC and NIV chasing revenue	Captured by estimating lost revenue in NIV chasing module
1-10 MW (visibility to NESO)	Additional costs of BM participation / visibility provision	Estimated under Implementation workstream

Distributional impacts that are expected to be less material would also be considered through qualitative analysis

Non-physical traders	Enhanced transparency of 1-50MW positions enabling smaller spreads Some reduction in arbitrage opportunities given loss of trading counterparties post GC given greater BM participation (and adherence to FPNs)?	Qualitative analysis (low materiality)
Supplier BRPs	Some additional access to flex resources to support balancing position but potentially some increase in complexity to manage resources	Qualitative analysis (low materiality)
Aggregators	Some reduction in 'gatekeeping' advantage to provide access to BM? But retained value in delivering scale and optimisation services	Qualitative analysis of extent to which 10-50MW assets will self serve vs participate through aggregators

=positive impact =neutral impact =negative impact

Knock-on effect

Material distributional impacts would have knock-on effects that will be considered for a system-wide CBA and for consumer impact. These include:

Second order impacts of any revenue loss on CfD and CM modules – and on investment

Knock-on effects on ID prices and premia – e.g., 10-50MW RES units may seek to self-balance more in the ID, or
NIV chasers may seek to recover more of their revenue through ID trading

Largely captured in the ID module – but we may supplement quantitative findings with qualitative assessment

Pass-through of costs/benefits to consumers through bills

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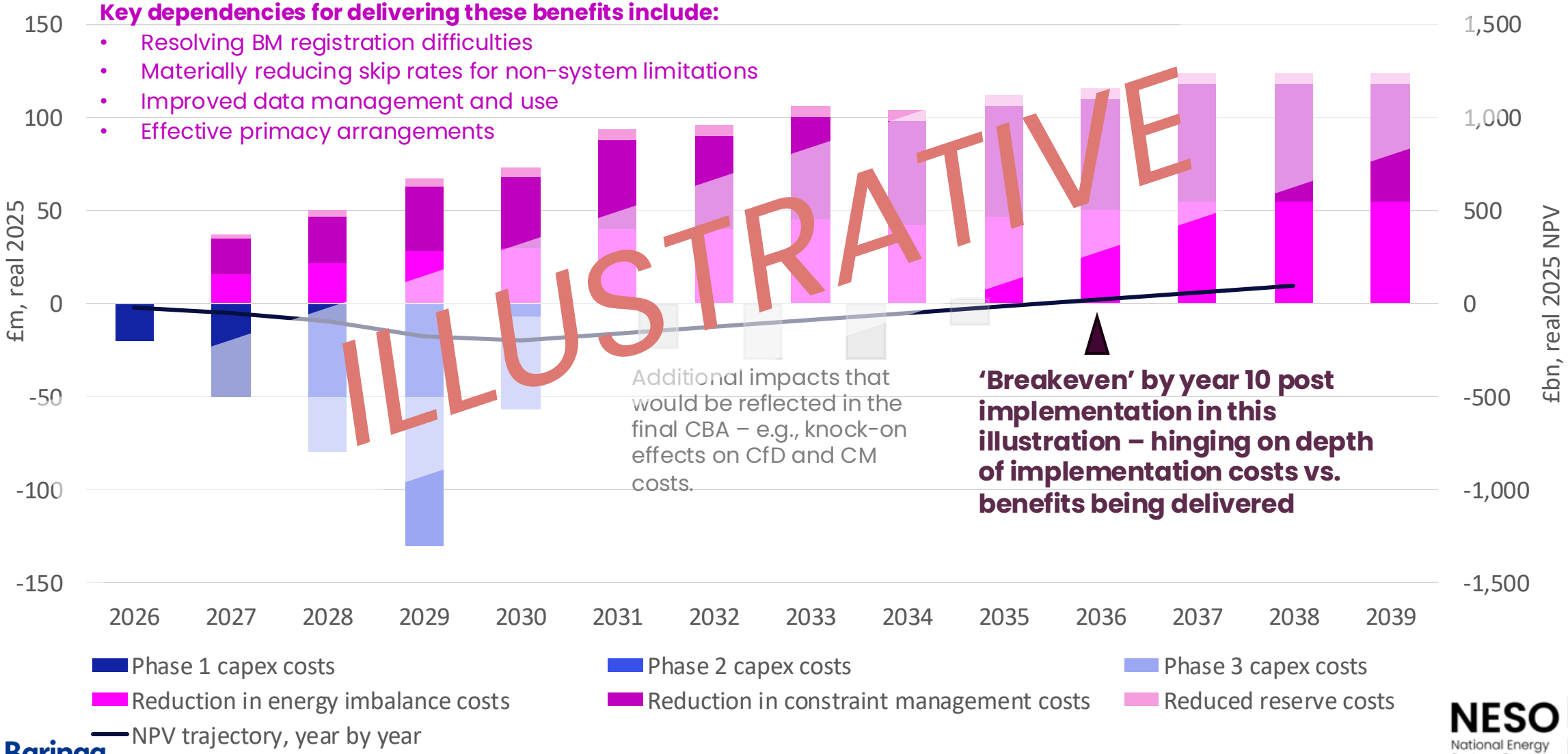
Lowering the BM threshold (LBM): What we expect to see (5/5)

Illustrative: CBA outcomes and Net Present Value – does not indicate any expectation of positive NPV

Key dependencies for delivering these benefits include:

- Resolving BM registration difficulties
- Materially reducing skip rates for non-system limitations
- Improved data management and use
- Effective primacy arrangements



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Clarification Questions

CBA Analysis

40 mins

Break Out Discussion

LBM Updates

Breakout discussion: LBM

40 mins to discuss the key assumptions and provide views

To-Be TOM:

- Do you have any suggested amendments to the key changes or underlying assumptions that would materially affect the reform's impacts or cost analysis?

Implementation cost estimates:

- Are the top 3 cost drivers as you expected?
- Does the overall cost estimate (central case) appear to be of the right order of magnitude?
- Are the relative impact ratings across cost categories and archetypes appropriate?
- Do you have any further information/evidence that would support or counter the content (if confidential please share following the session)?

CBA analysis:

- What are your views on the anticipated outcomes?
- Are there any key drivers of positive or negative impacts that you think should be reflected differently?

CBA key assumptions (see pre-read and handout):

- Which assumptions do you agree and disagree with and why?
- What additional evidence/data should we draw on to finalise the assumptions?

**NB: Include counterfactual assumptions in the discussion*

Shorter settlement periods (SSP)

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Update on policy design

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Policy Design Update | Shorter Settlement Period

Fundamental design

	Length	MTU	Gate Closure	Balancing window
Settlement Period	15-minute (base case)	Aligned to the Settlement Period for both DA and ID	60 minutes	75 minutes
	5-minute			65 minutes

Implementation approach

	Metering group	Timeline	Meter rollout	Transition period	Enduring
Phasing and metering	Wholesale and large consumers	2032	Site-specific basis	N/A	Wholesale and retail settlement aligned. Load shaping only for retail customers without metering capability.
	Retail consumers (domestic and small commercial)	2035	Aligned with current replacement cycles	Load shaping for all retail consumers	

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Clarification Questions

SSP Policy Design

Proposed To-Be TOM

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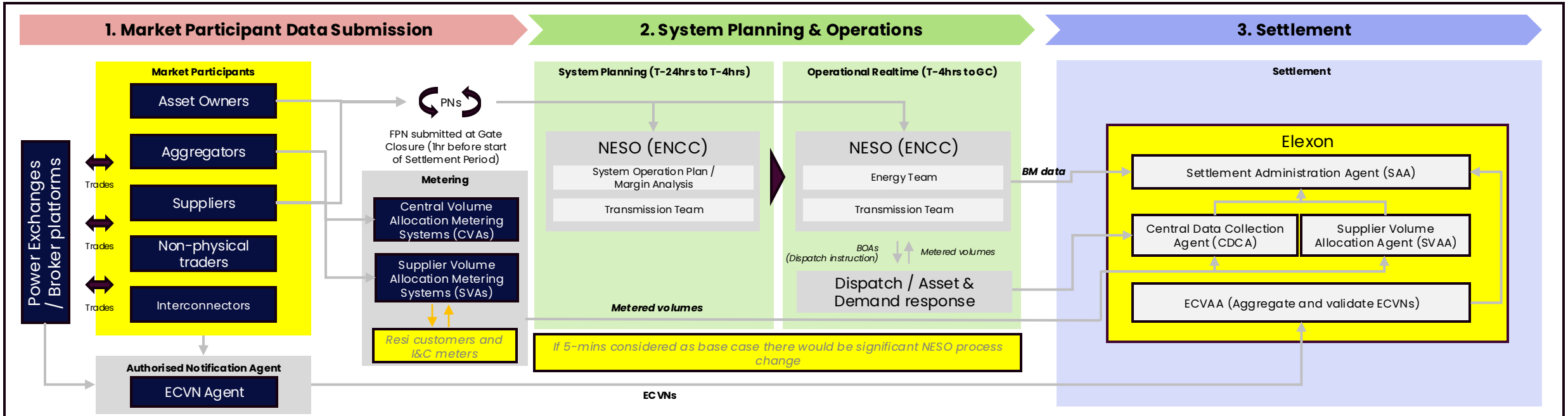
SSP | To-be Process Overview

Key

No functional change to core capabilities, business processes, systems architecture or technology components

Functional change to core capabilities, business processes, systems architecture or technology components

Simplified To-Be diagram of information flows from participants impacted by SSP



Key Change	Underlying Assumption	Key Change	Underlying Assumption	Key Change	Underlying Assumption
• Market participants can trade at a 15-minute granularity	• SSP arrangements apply equally to all asset types including interconnectors	• Greater volume of data needs to be ingested into ENCC systems	• Assume OBP and related central systems are designed and scaled to process increased data volumes under SSP without material degradation in performance or settlement timelines.	• Meter data requirements increase where demand-side settlement moves to SSP granularity. • Transitional arrangements: Elexon to use load-shaping for non-enabled sites to translate gaps between meter interval and settlement interval.	• Sufficient smart (SMETS2 with firmware upgrade)/ advanced meter capability exists.
• Market participants can submit FPN data at 15-minute intervals, increasing submission volumes.	• 15-minute SSP can remain partially human-in-the-loop; 5-minute SSP is likely to require automation and algorithmic trading oversight.	• Shorter intervals create tighter decision windows for forecasting, position management, and dispatch.			
• ECVNs / MVRNs are submitted across a greater number of shorter settlement intervals.	• Agents submitting ECVNs/MVRNs adapt their processes to reflect new shorter settlement			• SSP changes the granularity at which imbalance volumes and prices are calculated, increasing settlement calculation complexity. Systems may need to be upgraded and/or support windows extended to allow for greater processing time.	• Assume the reform changes settlement granularity only, with no wider concurrent changes to imbalance pricing methodology (with exception of reviewing CADL) or technical design of ancillary services.
• Power exchanges and broker platforms redesign products and internal processes to accommodate SSP.	• Sufficient liquidity develops in shorter-duration trading products to allow participants to manage imbalance exposure efficiently.	• Ancillary service settlement processes that use Settlement Periods would need to be assessed and, where required, reconfigured	• Assume STAR and other relevant NESO systems can scale to process increased dispatch, settlement and reporting data volumes under SSP.	• Interfaces into EMRS may need to be adapted for aggregation of the shorter settlement period.	• Assuming that Capacity Market and CfDs are not aligned to the shorter settlement period as this is independent from the BSC. (Though they could be amended.)
• Commercial regimes that explicitly reference Settlement Periods migrate to SSP granularity.	• Regimes not directly linked to SPs, e.g. Capacity Market, RO, FiTs, TNUoS and CfDs, require limited direct change. [Further analysis required]	• ENCC balancing window compressed from ~90 to ~75 minutes	• Arrangements to mitigate impact on assets with longer technical response times (e.g. CCGTs requiring 60–89 min notice to deviate) to be designed.	• BM actions need to be allocated and settled across a greater number of shorter intervals.	

10 mins

Clarification Questions

SSP TOM

Market participant costs

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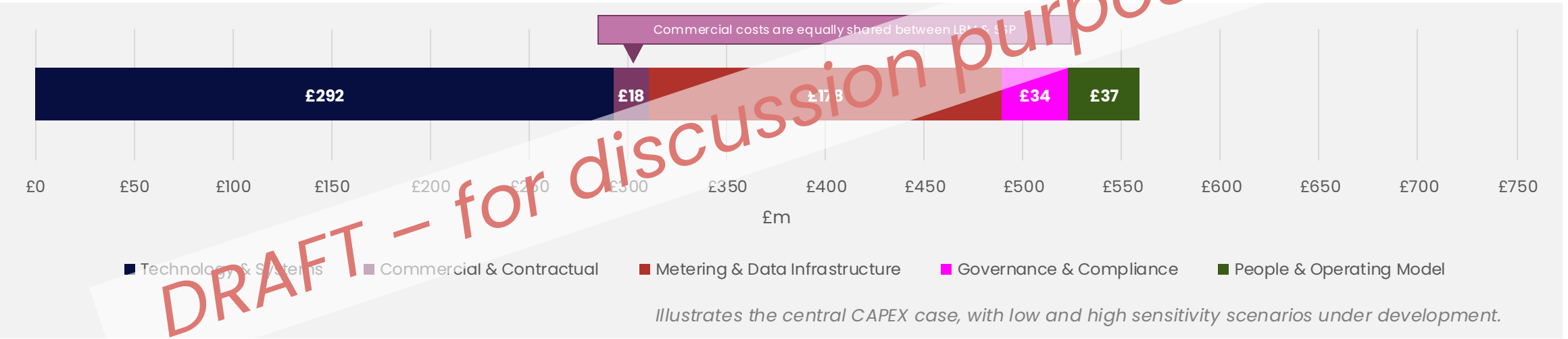
DRAFT FINDINGS | SSP CAPEX costs for Market Participants (15 mins)

Overview	SSP increases the frequency of data exchange across operational and settlement processes. Due to the nature of the change (granularity), implementation costs are concentrated in Technology & Systems and Data & Metering reflecting the scale of system and process change required.



Illustrates the central CAPEX case, with low and high sensitivity scenarios under development.

TOP THREE COST CATEGORIES (% of total cost)

1. TECHNOLOGY & SYSTEMS (c. 52%)

- **Industry data models and flows will need to** enable ability to manage and ingest 15-minute granularity data.
- **Core systems reconfiguration** include trading, forecasting, settlement and position management systems.
- **Suppliers face the highest costs**, reflecting changes across wholesale trading, customer-facing and settlement & billing platforms.

2. METERING & DATA INFRASTRUCTURE (c. 31%)

- **SMETS2 meters assumed compatible** via firmware updates or configured to support changes in read intervals (assumed costs recovered from Suppliers), with no accelerated replacement of domestic meters beyond existing smart meter rollout and MHHS plans.
- **Other settlement meters reconfigured** through remote configuration or site visits (c.£1.5k per affected metering point). A 10% meter-package replacement rate is assumed for incompatible meters (c.£17.5k per replacement)*. Costs allocated to Asset Owners.
- **Additional investment is required in data capture, processing and reporting capabilities** to manage significantly higher data volumes.

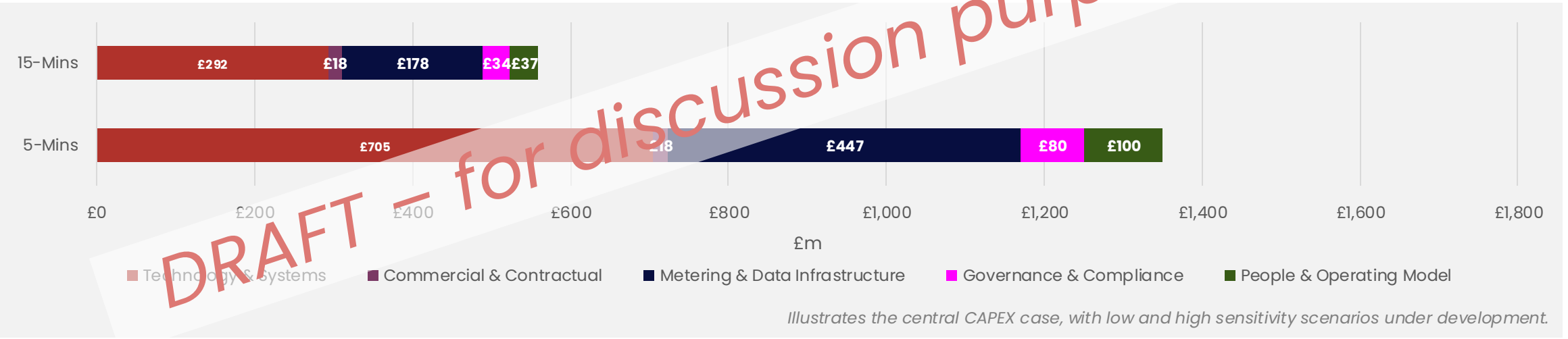
3. PEOPLE & OPERATING MODEL (c. 6%)

- **Operating models may need redesign** to support more frequent forecasting, scheduling, trading and settlement activities.
- **Investment in process redesign, controls, training and automation** to operate effectively at 15-minute granularity.
- **Roles & responsibilities may need to be redefined to across commercial and operational functions**, particularly for organisations with active portfolio management responsibilities.

*Indicative central assumptions. Replacement covers the meter package, installation and testing, reusing compliant CT/VT circuits; new CTs/VTs and major electrical works are outside this case.

Summary of Findings | SSP Sensitivity for Market Participants (5 mins)

Overview	Reducing the settlement period from 15 minutes to 5 minutes increases estimated market participant CAPEX from approximately £559m to £1.35bn, an increase of around £790m (142%). At 15 minutes, participants can largely adapt existing systems and retain some human-led processes. Five-minute settlement requires near-real-time data processing, automated trading, continuous forecasting and more frequent settlement activity. Consequently, technology, data and operating-model costs rise substantially.



Illustrates the central CAPEX case, with low and high sensitivity scenarios under development.

TOP THREE COST CATEGORIES

1. TECHNOLOGY & SYSTEMS (c. 55%)

- **Near real-time market operations require extensive system redesign**, replacing processes that remain viable under 15-minute settlement and automate trading, forecasting, scheduling and settlement activities.
- **Suppliers and active market participants face the greatest impact**, reflecting the breadth of changes across trading, customer and settlement platforms.

2. DATA & METERING (c. 35%)

- **Data processing requirements more than double**, driven by the need to capture, validate and reconcile market data at significantly higher frequencies.
- **Investment is required across data ingestion, storage, validation and analytics capabilities** to support near real-time operations.
- **Increased system integration and data management complexity** drives substantial additional technology and operational costs.

3. PEOPLE & OPERATING MODEL (c. 8%)

- **Operating models shift from human-led execution to automated decision-making** and exception management.
- **New controls, governance frameworks and monitoring processes** are required to oversee increasingly automated operations.
- **Investment in training, process redesign and change management** is needed to embed new ways of working across commercial and operational teams.

Shorter Settlement Periods (15-min): Impacts by Cost Category and Archetype

Settlement granularity is embedded across the estate, so all four archetypes are affected; RAG shows the relative scale of change driving the cost estimates through indicative RAG statuses with only materially affected central bodies included

RAG* High Cost | Medium Cost | Low Cost

Cost category	Asset owners	Suppliers	Aggregators / VLPs	Non-physical traders
Trading & position management	ETRM and deal capture must carry 15-min granularity; product and contract definitions change.	ETRM and deal capture must handle 15-min granularity; plus new customer-facing products.	Platform trading module Extended, footprint of systems smaller than other archetypes.	Largest category for this archetype as business mostly focused on the trading stack
Scheduling, nomination & dispatch	PN/FPN at 15-min, ECVN, EDL dispatch handling and control-room tooling.	PN/FPN at 15-min, ECVN, EDL dispatch handling and control-room tooling.	PN/FPN at 15-min, ECVN, EDL dispatch handling and control-room tooling.	Minimal contract notifications only.
Settlement & billing**	Settlement engine, imbalance calculation and metered data reconciliation at double volume.	Highest as it adds retail settlement, billing and smart-meter data at 15-min.	Settlement data ingestion and revenue allocation to move to 15 minutes.	Imbalance on net position and trade reconciliation only.
Forecasting & analytics	Demand and generation models re-fit to 15-min, backtested on new history.	Demand granularity is the larger element.	Granularity needed for models for small, weather-driven, behind-the-meter Asset.	Market models to be reconfigured.
Data & Infrastructure***	Time-series volume doubles; pipelines, storage and validation all change.	Largest data build. Adds smart-meter data storage and processing at volume.	Ingestion and storage scaling across many small distributed assets.	n/a
Operating model & people	Deal lifecycle process redesign.	Broadest footprint, reaching customer operations as well as trading.	Lowest. Dispatch is already core business; scaling existing processes.	Lean organisations with few processes to adapt (no physical).
Compliance & obligations	Reporting at finer granularity, audit trail and record retention.	Broadest surface across generation, supply and customer sites.	Mainly reporting and record retention changes.	Transaction reporting at 15-min granularity is the main change.

Notes:
**RAG indicates relative scale of change. Descriptions are grounded in participant engagement; the effort values behind the RAG are structured judgement, not participant-validated.*
***Whether incumbent billing platforms absorb a 15-min settlement hierarchy by configuration or need rebuild is being explored.*
**** SMETS2 meters support 15-min via a firmware upgrade and a residual storage-capacity constraint is managed through the SDR. SMETS1 replacement sits in the counterfactual and is excluded.*

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Shorter Settlement Periods (15-min): DRAFT Effort & Cost by Archetype

Cost category	Asset owners	Suppliers	Aggregators / VLPs	Non-physical traders
Trading & position management	400 – 2,200 days	350 – 1,900 days	250 – 1,100 days	300 – 1,500 days
Scheduling, nomination & dispatch	220 – 1,140 days	305 – 1,570 days	180 – 820 days	35 – 135 days
Settlement & billing	445 – 2,310 days	845 – 4,220 days	220 – 970 days	165 – 740 days
Forecasting & analytics	350 – 1,600 days	450 – 2,200 days	300 – 1,300 days	300 – 1,300 days
Data & infrastructure	450 – 2,200 days	700 – 3,400 days	350 – 1,600 days	n/a
Operating model & people	220 – 965 days	300 – 1,400 days	150 – 700 days	120 – 500 days
Compliance & obligations	200 – 900 days	250 – 1,100 days	130 – 600 days	150 – 650 days
TOTAL firm-level	**CAPEX: £2.6 – 12.9m** (2,285 – 11,315days)	**CAPEX: £2.4 – 11.8m** (3,200 – 15,800 days)	**CAPEX: £1.26 -5.66m** (1,580 – 7,090 days)	**CAPEX: £ 1 - 4.7m** (1,070 – 4,825 days)

Note: Blended day rate £750/day has been applied to calculate CAPEX costs. This is representative of an average of current internal FTE or external contractor daily cost.

Shorter Settlement Periods (5-min): Impacts by Cost Category and Archetype

A step change rather than a linear uplift: 5-minute settlement forces automation and near real-time data streaming across the whole estate

RAG* 🔴 High change 🟠 Medium 🟢 Low

Cost category	Asset owners	Suppliers	Aggregators / VLPs	Non-physical traders
Trading & position management	🔴 Algorithmic execution now mandatory; ETRM cannot run 5-min manually.	🔴 Algorithmic execution now mandatory; ETRM cannot run 5-min manually.	🔴 Platform trading module automated; lower base but real time throughout.	🟠 Algorithmic trading adaption is already highest across this archetype.
Scheduling, nomination & dispatch	🔴 PN/FPN and EDL move to streaming submission; control room automated.	🔴 Demand BMUs and customer-site paths also move to streaming.	🔴 Dispatch engine must run near real time across many small assets.	🟢 Minimal contract notifications only.
Settlement & billing	🔴 6x settlement volume; engine and metered data reconciliation rebuilt.	🔴 Billing and smart meter data at 5-min.	🔴 Settlement ingestion and revenue allocation at 5-min granularity.	🟠 Amber. Imbalance on net position and trade reconciliation only.
Forecasting & analytics	🔴 Intra-hour models re-fit and run continuously, not on a scheduled cycle.	🔴 Demand forecasting at 5-min as well as small embedded assets.	🔴 Behind-the-meter assets are hardest to model at this resolution.	🔴 Price and spread models re-fit at 5-min; the commercial edge.
Data & infrastructure**	🔴 Streaming pipelines replace batch as a must have for core operations.	🔴 Largest data build. Smart-meter volumes exceed current platform limits.	🔴 Streaming ingestion from many distributed sites is the main cost.	⚪ n/a
Operating model & people	🔴 Trading and Risk shifts from human decisions to supervising automated execution.	🔴 Broadest change: trading, settlement and customer operations all automate.	🟠 Automation is already core to the business model.	🟠 Lean teams, but the desk becomes an engineering function.
Compliance & obligations	🔴 Audit trail for automated decisions; far larger record retention volume.	🔴 Widest surface across generation, supply and customer sites.	🟠 Proportionate scope; reporting and record retention.	🟠 Transaction reporting volume rises sharply at 5-min.

Notes:
**RAG indicates relative scale of change. Descriptions are grounded in participant engagement; the effort values behind the RAG are structured judgement, not participant-validated.*
*** SMETS2 meters support 5-min via a firmware upgrade and a residual storage-capacity constraint is managed through the SDR. SMETS1 replacement sits in the counterfactual and is excluded.*

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Shorter Settlement Periods (5-min): DRAFT Effort & Cost by Archetype

Cost category	Asset owners	Suppliers	Aggregators / VLPs	Non-physical traders
Trading & position management	1,050 – 5,700 days	910 – 4,940 days	650 – 2,860 days	780 – 3,900 days
Scheduling, nomination & dispatch	780 – 3,960 days	550 – 2,860 days	550 – 2,530 days	180 – 770 days
Settlement & billing	1,000 – 5,200 days	1,800 – 9,000 days	500 – 2,200 days	400 – 1,800 days
Forecasting & analytics	840 – 3,840 days	1,080 – 5,280 days	720 – 3,120 days	720 – 3,120 days
Data & data infrastructure	1,260 – 6,160 days	1,960 – 9,520 days	980 – 4,480 days	n/a
Operating model & people	650 – 2,860 days	780 – 3,640 days	390 – 1,820 days	310 – 1,300 days
Compliance & obligations	480 – 2,160 days	600 – 2,640 days	310 – 1,440 days	360 – 1,560 days
TOTAL firm-level	**CAPEX: £4.3 – £21.1m** (6,060 – 29,880 days)	**CAPEX: £ 5.4 – 26.7m** (7,680 – 37,880 days)	**CAPEX: £ 2.9-13m** (4,100 – 18,450 days)	**CAPEX: £1.9 – 8.8m** (2,750 – 12,450 days)

Note: Blended day rate £750/day ahs been applied to calculate CAPEX costs. This is representative of an average of current internal FTE or external contractor daily cost.

Clarification Questions

SSP Market Participants

CBA analysis

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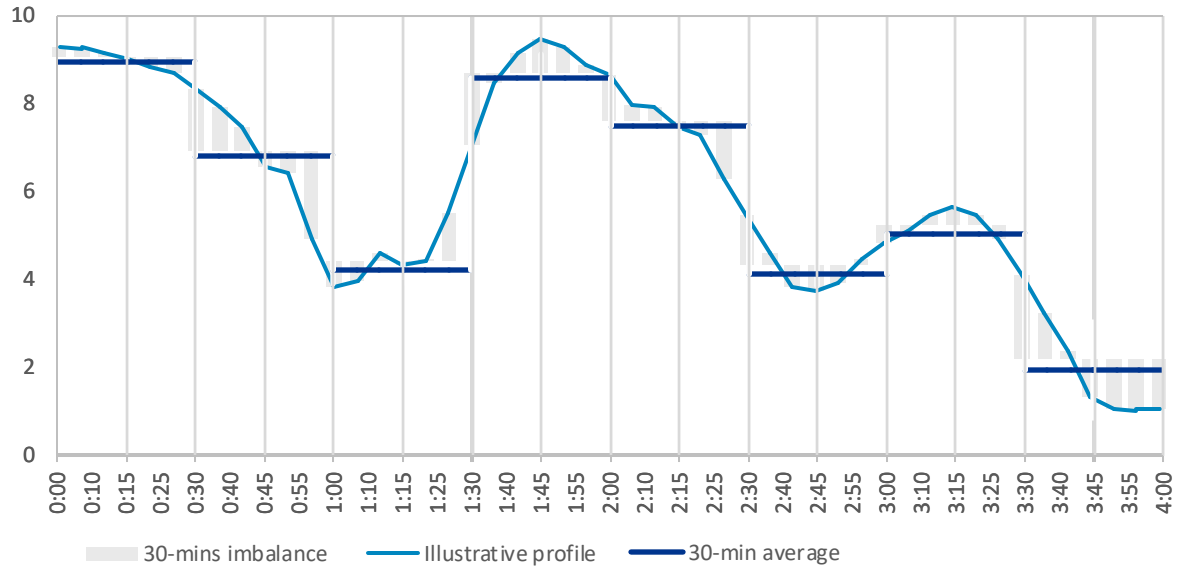
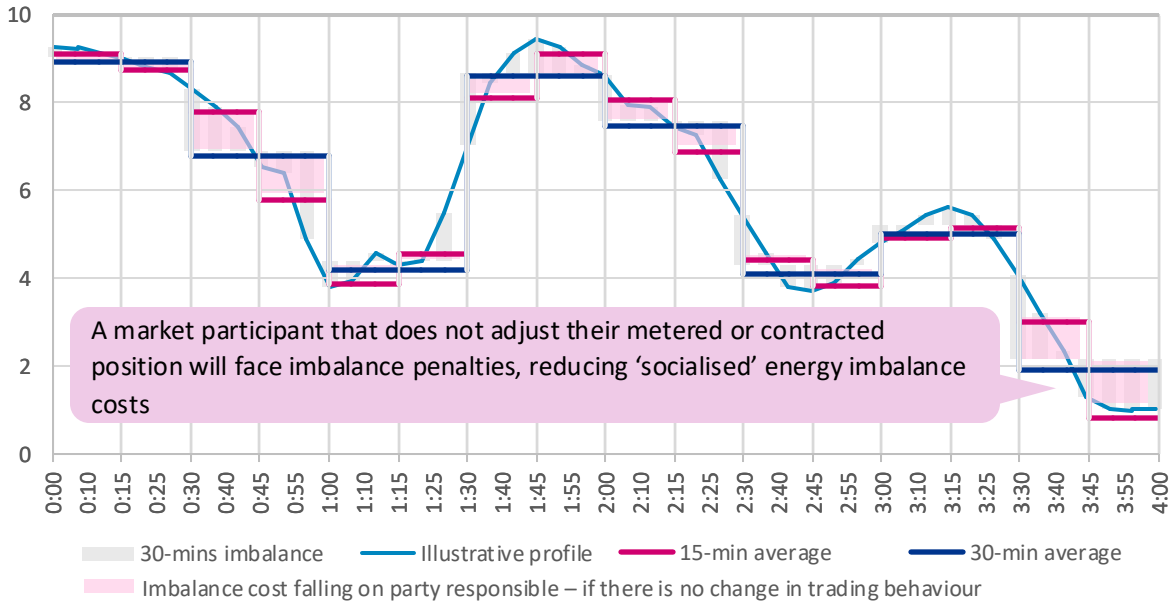
Shorter settlement period (SSP): What we expect to see (1/6)

More granular imbalance price signals → **Incentive to self-balance at greater temporal granularity**

1 **Under the counterfactual, MPs can be both short and long within a SP but have a net imbalance position of zero…**



…but under SSP, market participants face more granular imbalance price signals which we assume feed through to MTU



Within-settlement period imbalance is resolved in real-time in the BM through a mixture of bids and offers. The cost of these actions is not borne by the participant responsible for the imbalance

The imbalance price is also likely to be distorted due to netting of imbalance actions to resolve both long and short positions within each settlement period

This should incentivise MPs to better align their contracted position to their expected metered position at the new shorter SP granularity – through trading/contracting at a more granular market time unit (MTU)

But, this also means greater imbalance costs for market participants that face forecast error, such as intermittent RES

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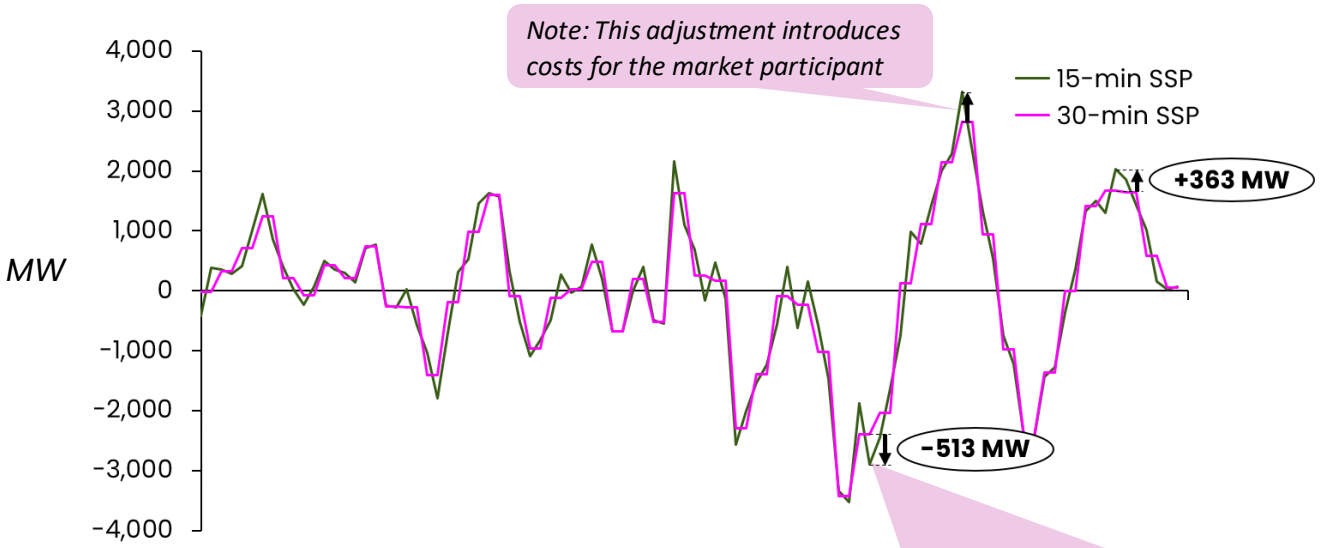
SSP: What we expect to see (2/6)

More granular imbalance price signals → **More energy imbalance resolved in wholesale markets, less in BM**

2 Where a move to shorter SPs leads to a change in market participant behaviour, more of the energy imbalance is resolved in wholesale markets (largely ID), reducing energy imbalance volumes and costs in the BM

Example of difference in modelled signal over a 24-hour snapshot (3 April 2040, under HT FES scenario)



Where a market participant adjusts their contracted position to be in balance at the shorter ISP granularity, this reduces BM energy imbalance actions

Is resolving energy imbalance in wholesale markets more efficient than resolving it in the BM?

Shifting volumes from the BM to wholesale markets will reduce total system costs to the extent that this resolution comes at a lower cost.

Some of the shift of volumes from the BM to wholesale markets will represent a risk/cost transfer – i.e. MPs taking on costs that were previously incurred by NESO in the BM.

However, there are several reasons why we might expect this to also result in total system cost savings:

1. More assets are able to participate in wholesale markets, enabling imbalance shape to be resolved using a more efficient production mix (e.g. enabling DSR).
2. Some assets that participate in the BM may be more likely to be available further ahead of time – e.g. due to unit commitment or intertemporal optimisation reasons.
3. Resolving further ahead of time may also allow the same assets to dispatch at lower cost

There will also be an interaction between 15-minute imbalance signals and NIV chasing. A 15-minute signal should allow NIV chasing to be more helpful as the signal is less aggregated. However, some NIV chasers may be less able to participate at 15-min imbalance. And sharper imbalance signals may lead to more volatile NIV chasing that increases the prediction challenge for NESO.

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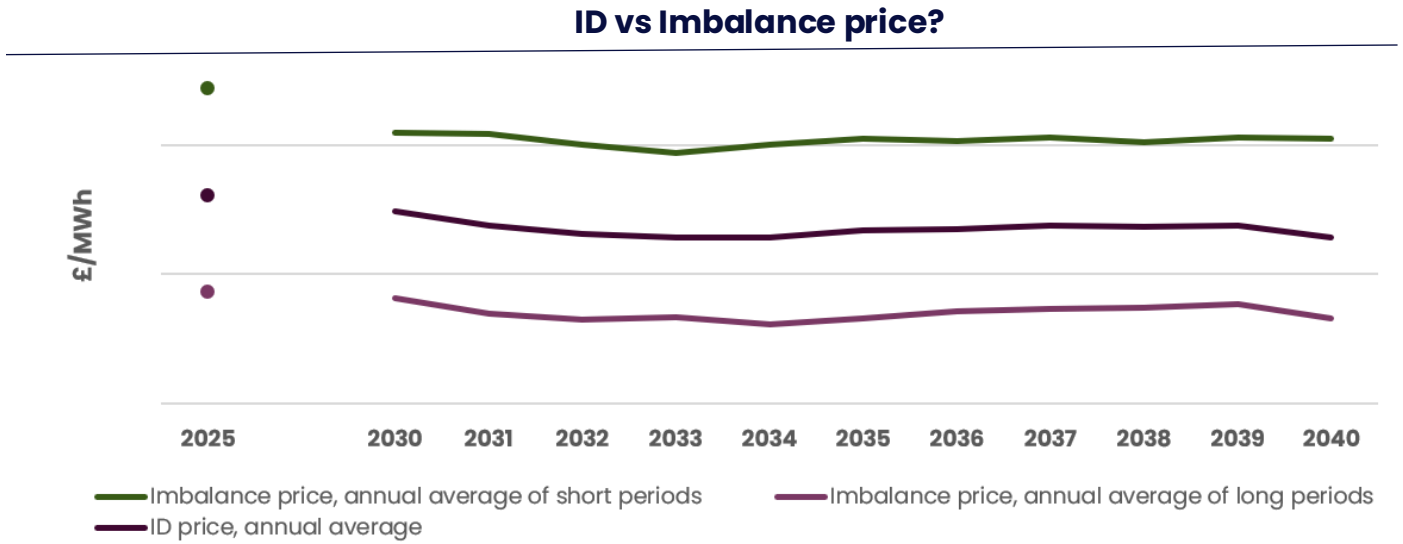
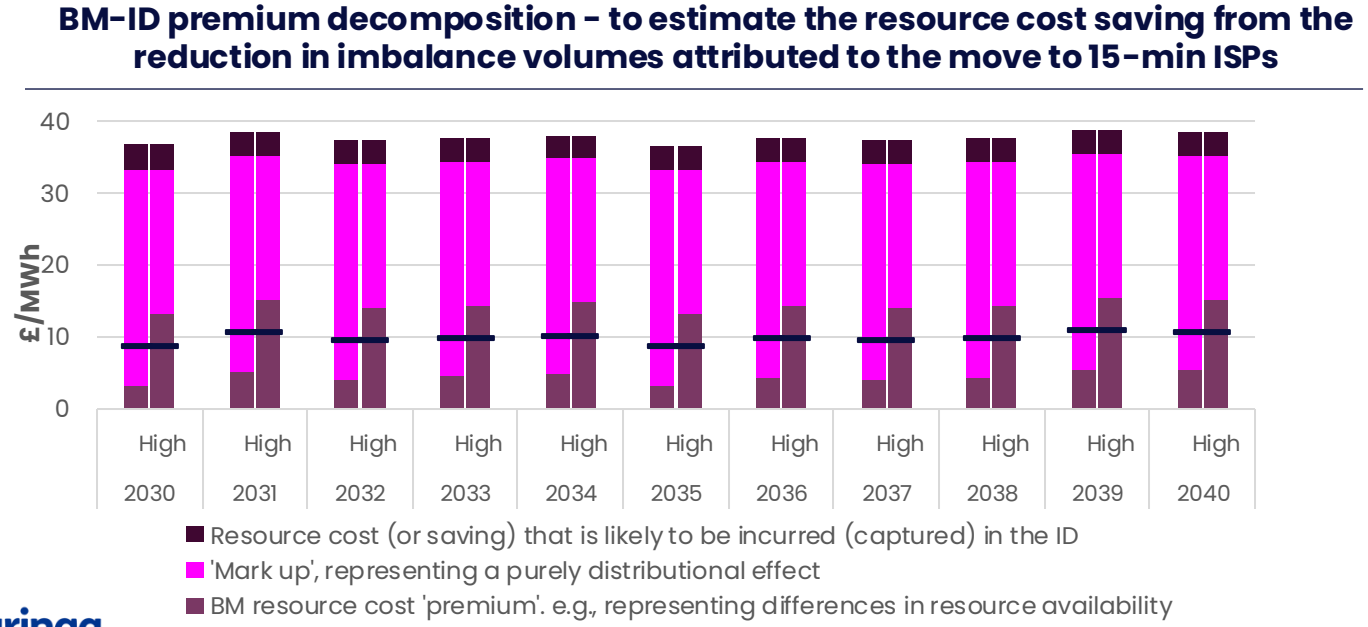
SSP: What we expect to see (3/6)





Benefit driven through resolving shape in the wholesale market

- The extent of system cost benefit relative to pure transfer of risk/cost between NESO and MPs will be driven by the premium on resolving shape through the BM vs wholesale market.
- By encouraging more volume to be resolved in the wholesale market, SSP will likely result in some increase in the ID price.
- However, on the assumption that it is more efficient to resolve this imbalance through the wholesale market, we would expect this additional cost to be less than the savings resulting in the BM.
- This will drive a key benefit from the policy option.

- The resulting reduction in imbalance may also allow NESO to reduce its reserve procurement volume needs – see LBM slide on reserve procurement

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SSP: What we expect to see (4/6)

Impacts on market participants, and what we expect to see from wider modelling

=positive impact =neutral impact =negative impact

MP archetype	Most significant impacts	Analytical approach
Merchant and CfD-backed intermittent generation	Higher imbalance costs due to increase in forecast error 'diversification' with higher SSP granularity	Sub-30-min forecast-error sampling, Imbalance-cost module
'Pay as produce' PPA-backed intermittent generation	Possible need to renegotiate PPAs to reflect SSP shape/imbalance (at additional cost given offtaker exposure)	Qualitative analysis
Mid-merit, peaking & flex (incl. BESS)	Capture finer volatility/spreads (noting potential impacts on liquidity)	DA/ID at finer granularity + imbalance cost
	Lower BM revenues for some assets as a result of reduced imbalance volumes / Increased BM revenues for some flex assets that can respond to more granular imbalance price Some return of revenue through RCRC*	Reduction in imbalance in BM model
	Additional challenges with ramping/outages for some technologies	More granular imbalance in BM model
Less responsive assets (e.g. nuclear)	More limited exposure given forward contracting. Some small additional costs due to ramping/outages	Techno-economic constraints in modelling
Portfolio players / aggregators / optimisers	Value from cross-market optimisation at finer granularity	Qualitative analysis

Knock-on effect

Material distributional impacts would have knock-on effects that will be considered for a system-wide CBA and for consumer impact.
These include:

Second order impacts of any revenue loss on CfD and CM modules – and on investment

Knock-on effects on ID prices
Largely captured in the ID module – but we may supplement quantitative findings with qualitative assessment

Pass-through of costs/benefits to consumers through bills

**NB: May be some offsetting of impacts and benefits to some participants through RCRC, meaning those MPs who are better able to manage imbalance than average may end up as winners*

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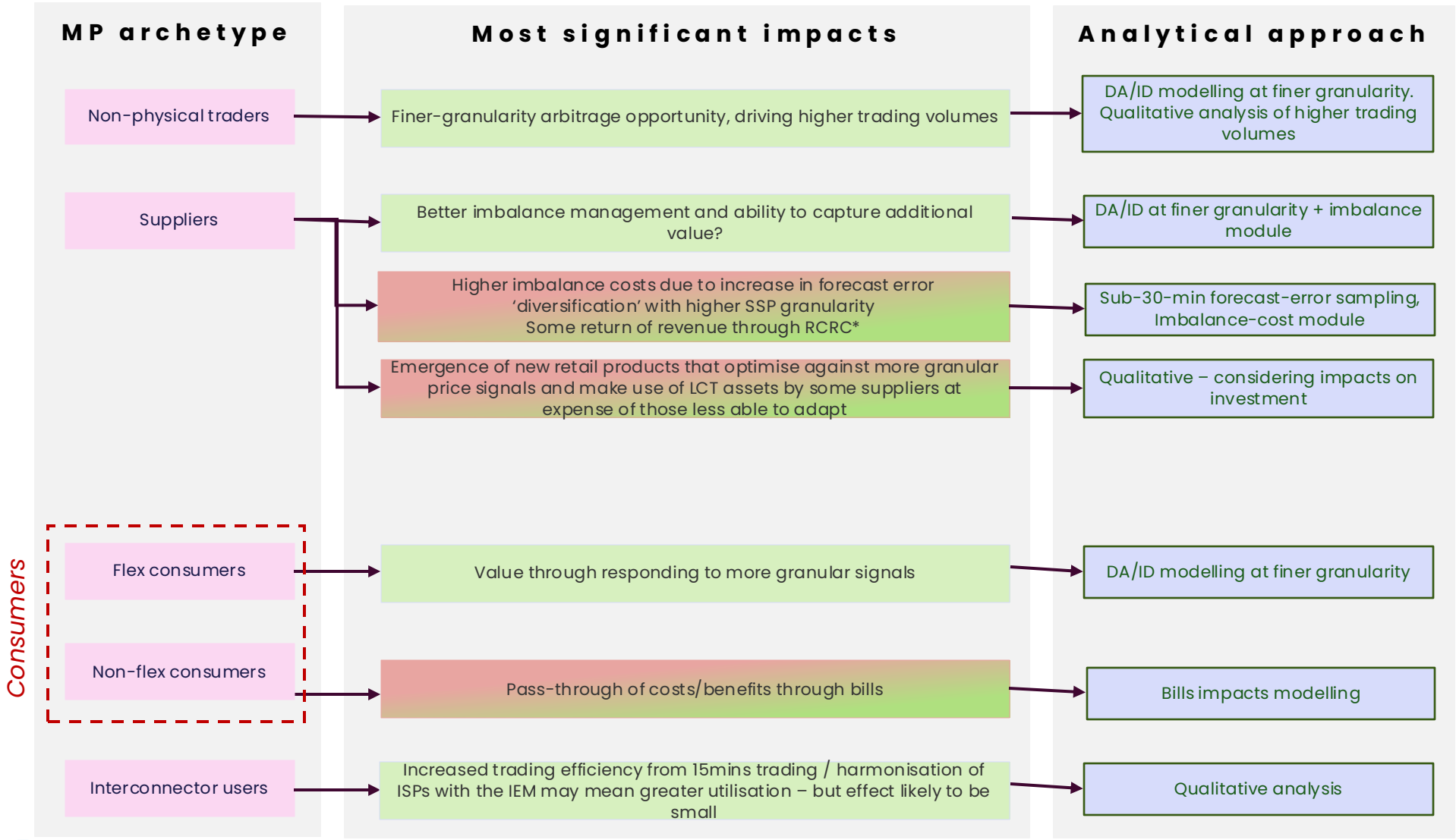
SSP: What we expect to see (5/6)

Impacts on market participants, and what we expect to see from wider modelling

=positive impact =neutral impact =negative impact



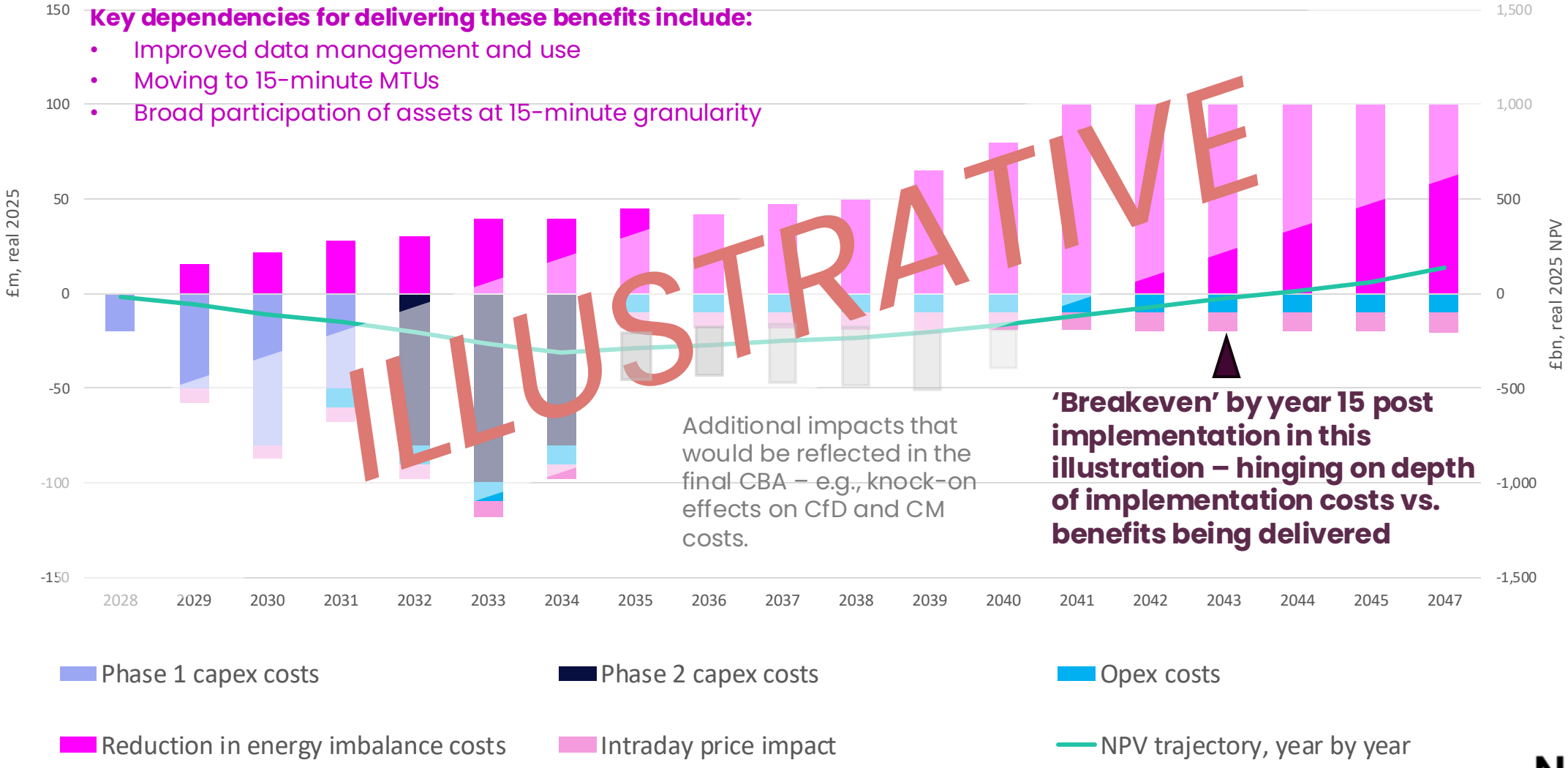
*NB: May be some offsetting of impacts and benefits to some participants through RCRC, meaning those MPs who are better able to manage imbalance than average may end up as winners

SSP: What we expect to see (6/6)

Illustrative: CBA outcomes and Net Present Value – does not indicate any expectation of outturn NPV

Key dependencies for delivering these benefits include:

- Improved data management and use
- Moving to 15-minute MTUs
- Broad participation of assets at 15-minute granularity



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Clarification Questions

SSP CBA Analysis

Breakout discussion: SSP

40 mins to discuss the key assumptions and provide views

To-Be TOM:

- Do you have any suggested amendments to the key changes or underlying assumptions that would materially affect the reform's impacts or cost analysis?

Implementation cost estimates:

- Are the top 3 cost drivers as you expected?
- Does the overall cost estimate (central case) appear to be of the right order of magnitude?
- Are the relative impact ratings across cost categories and archetypes appropriate?
- Do you have any further information/evidence that would support or counter the content (if confidential please share following the session)?

CBA analysis:

- What are your views on the anticipated outcomes?
- Are there any key drivers of positive or negative impacts that you think should be reflected differently?

CBA key assumptions (see pre-read and handout):

- Which assumptions do you agree and disagree with and why?
- What additional evidence/data should we draw on to finalise the assumptions?

Break Out Session

SSP Update

Annex - CBA: Key assumptions

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Principles for defining inputs and assumptions to CBA modelling

"All models are wrong, but some are useful" – George Box (Statistician)

1. **Avoid "boiling the ocean":** CBA modelling should be designed to capture the expected impacts of options relative to the counterfactual. Model complexity and resource is targeted proportionate to the importance of the relevant inputs/assumptions. This means avoiding unnecessary focus on enhanced representation of bits of the market that have a minimal impact on the benefits case.
2. **CBA analysis is intended for option appraisal, not option design**: CBA is not intended to produce/ assess new designs but rather to appraise options, and variants, that have already been designed.
3. **Avoid analysis paralysis**: Some areas of the reform will remain subject to inevitable uncertainty or dependencies on future outcomes. Several tools can be used to support decision making under uncertainty (e.g. sensitivity testing) but cannot eliminate it. Remaining uncertainty should be presented transparently but we must avoid pursuing spurious accuracy of things that are inevitably uncertain.
4. **Simple and transparent > Complex and opaque**: Where genuine uncertainty exists, simple but transparent analysis is preferred over complex analysis that creates a false sense of precision but is opaque. Complexity should be reserved for the things that are most significant to the outcomes, and where it adds genuine high-value precision. This often means abstracting from uncertain specifics to reflect sufficiently representative outcomes – e.g. assuming away minority / corner cases.
5. **Recognise limitations**: Limitations are inevitable but should be reported transparently, including the potential impacts on decision making.
6. **Modelling alongside other evidence**: Modelling is one component feeding into decision making but cannot capture all relevant factors. Broader analysis going beyond the modelling is just as important and should be incorporated into decisions transparently.

Counterfactual assumptions (1/2)

We summarise below the evidence base and principles surrounding assumptions under each of the core cases

Central case assumes defined programmes and improvements are delivered

Low case reflects better outcomes under counterfactual such that options deliver lower benefits

High case reflects worse outcomes under the counterfactual such that options deliver greater benefits

Assumption	Evidence source	Central case	Low case	High case
Enhanced visibility impact on counterproductive actions	1. Current levels of forecast error associated with system imbalance 2. Extent of early actions taken by ENCC (TBC) 3. NESO workstreams – e.g. PRA	Reflects improved visibility of non-BMU behaviour to same level as BMUs. Does not reflect any forecasting improvements of NIV chasing specifically	Also reflects improved NIV chasing visibility	More limited visibility improvements from PRA, etc in relation to non-BMU behaviour
Enhanced visibility impact on reserve procurement	1. Engagement with NESO reserve procurement teams 2. NESO workstreams – e.g. PRA	Assume visibility improvements from ongoing NESO workstreams do not affect reserve procurement at DA	Improved net demand forecasting reduces reserve procurement requirements	N/A – High Case tested through assumptions on options rather than counterfactual
Post-GC trading volumes	1. Data on recent trading volumes post GC 2. Analysis of pre/post P342 trading behaviour	*Impacts on trading and liquidity are tested through tipping point analysis (particularly on Package 2) rather than through Central/Low/High Cases*		

Counterfactual assumptions (2/2)

We summarise below the evidence base and principles surrounding assumptions under each of the core cases

Central case assumes defined programmes and improvements are delivered

Low case reflects better outcomes under counterfactual

High case reflects worse outcomes under counterfactual

Assumption	Evidence source	Central case	Low case	High case
Voluntary participation of 10-50MW assets	1. NESO connections register – historic voluntary BM participation by technology and location 2. FES Holistic Transition – future capacity trends	Assume constant % of voluntary participation with capacity growth	Additional growth in BM participation driven by enhanced ability and value in BM participation	Assume flat absolute MW voluntary participation
Non-BMU physical NIV chasing	1. Approach and evidence base discussed in last IEP with feedback provided	Reflects 'best expectation' of NIV chasing dynamics based on stakeholder engagement	Greater risk aversion in NIV chasing - lower volumes and less 'unhelpful' actions	Greater risk appetite in NIV chasing - higher volumes and more 'unhelpful' actions
BMU intentional imbalance positioning	1. NESO data on improved FPN accuracy 2. Engagement with ENCC on key drivers of system operation challenges	Assume no intentional BMU physical NIV chasing – i.e., that BMUs follow FPNs to metered positions to comply with Grid Code requirements. BMU NIV chasing is limited to imbalance positioning, i.e., intentional differences in traded volumes and metered positions, *explored through the trading and liquidity tipping point analysis* We do not vary this assumption under High and Low Cases based on: 1. Assumption that long-term, systematic deviations between FPNs and metered positions would be enforced against 2. ENCC view that BMU physical NIV chasing is not a key system operation challenge		
Interconnector trading restrictions	1. NESO announcement on IC trading restrictions 2. NESO views based on engagement with EU TSOs	Interconnector trading limits applied as per today and adjusted for new interconnection in the future. We assume that some form of restriction remains independent of IEM participation based on NESO engagement with EU TSOs. Not varied under High/Low case but may be tested under 'Congestion' sensitivity.		

NB: We discussed our approach to non-BMU physical NIV chasing in the last IEP

LBM assumptions (1/2)

We summarise below the evidence base and principles surrounding assumptions under each of the core cases

NB: Implementation cost estimates will also vary under the Low and High Cases

Central case makes our most robust assumption about option benefits delivered

Low case reflects worse outcomes under the option

High case reflects better outcomes under the option

Assumption	Evidence source	Central case	Low case	High case
10-50MW capacity that falls under threshold	1. NESO connections register – historic voluntary BM participation 2. FES Holistic Transition – future capacity trends	In line with NESO connections register dataset adjusted for FES pathway	Reduce forward looking participation to reflect intentional sizing of capacity below the 10 MW threshold	No change to central case – other metrics varied instead
BM onboarding limit	1. NESO ENCC input ***BM registration noted as a key dependency to deliver benefit***	Assumes BM registration and onboarding is enhanced to allow for new assets to be incorporated into the BM without significant delays	Consider introducing some limit on BM registration and onboarding per year	No change to central case
Skip rates	1. Open Balancing Platform programme plan 2. Baringa analysis 3. Clean Flexibility Roadmap 2026 4. LCP delta: Skip Rates Report	Assume no 'uneconomic' skips from go-live: i.e., remaining skips based only on systems services requirements	Avoidable skip rates fall linearly from implementation to 2035. All new LBM BMUs face tech-specific level of skips	No change to central case
Primacy restrictions – ANM	1. DNO's Network Headroom Reports 2. UKPN's constraint breaches report	Application of exclusion restrictions - TBC	Application of exclusion restrictions - TBC	No restrictions on utilisation of ANM assets assuming Primacy rules allow effective deployment

LBM assumptions (2/2)

We summarise below the evidence base and principles surrounding assumptions under each of the core cases

NB: Implementation cost estimates will also vary under the Low and High Cases

Central case makes our most robust assumption about option benefits delivered

Low case reflects worse outcomes under the option

High case reflects better outcomes under the option

Assumption	Evidence source	Central case	Low case	High case
Primacy restrictions – flex services	1. Market Participant engagement 2. DNO flex procurement and dispatch data (License Condition 31E returns)	No interaction between BM access and flex services	TBC	No interaction between BM access and flex services
Non-participation for techno-economic reasons	1. Subject matter expert views – both Baringa and external stakeholders 2. Implementation assessment	EfW, Bio-CHP and Demand flexibility (CLF) choose not to actively participate in the BM	In line with the central case	In line with central case
Enhanced visibility impact on counterproductive actions	1. Current levels of forecast error associated with system imbalance 2. Extent of early actions taken by ENCC (TBC) 3. NESO workstreams – e.g. PRA	New BMUs participating in the BM under LBM (and reduced NIV chasing as a result) directly fed through the approach – benefits vary under Central/Low/High cases as a result of differences in assumptions of the level of benefit delivered under ongoing NESO workstreams under the Counterfactual, rather than as a result of differences in LBM treatment/assumptions		
Link with reduced reserve requirements	1. Engagement with NESO Reserve procurement teams 2. NESO workstreams – e.g. PRA			

Approach as outlined for Counterfactual

SSP assumptions (1/2)

We summarise below the evidence base and principles surrounding assumptions under each of the core cases

NB: Implementation cost estimates will also vary under the Low and High Cases

Central case makes our most robust assumption about option benefits delivered

Low case reflects worse outcomes under the option

High case reflects better outcomes under the option

Assumption	Evidence source	Central case	Low case	High case
Active adoption of SSPs Note: Applicability to 5mins is still being investigated	1. Official reports on MTU uptake post 15min SDAC and SIDC implementation by the Market Coupling Steering Committee (MCSC), Market and System Design (MSD) joint group 2. Stakeholder engagement	All relevant* volumes to shift to the more granular MTU for 15 mins **volumes for baseload generators that do not significantly vary their dispatch may continue trading at less granular MTUs, with no impact on outcomes*	N/A – not varied under the Low/High case, as evidence post IEM implementation of 15min MTUs and SSP suggests 80+% adoption of 15min MTUs in EU-wide DA power trading by Jan 2026, only a few months after SDAC implementation.	
Cross-border trading at shorter MTU in ID and DA markets	1. ENTSO-E's Market Information on SDAC and SDIC 2. Stakeholder engagement	Cross border trading between GB and IEM markets moves to 15-mins		
Load shaping for those without 15-min metering capabilities	1. Implementation team assumptions 2. Input from DESNZ smart metering team (confidential) 3. Market participant engagement, including with Elexon	Load shaping is not modelled explicitly Extensive load shaping unlikely to be necessary given meter upgrades by 2035 retail implementation date. Improved Elexon load shaping profiles are increasingly accurate given the growing number of customers whose metering data can be used as a reference. Load shaping is only needed for within 30-minute shapes and is therefore highly targeted, improving accuracy where needed.		

SSP assumptions (2/2)

We summarise below the evidence base and principles surrounding assumptions under each of the core cases

NB: Implementation cost estimates will also vary under the Low and High Cases

Central case makes our most robust assumption about option benefits delivered

Low case reflects worse outcomes under the option

High case reflects better outcomes under the option

	Assumption	Evidence source	Central case	Low case	High case
Approach as outlined for Counterfactual	Enhanced visibility impact on counterproductive actions	1. Current levels of forecast error associated with system imbalance 2. Extent of early actions taken by ENCC (TBC) 3. NESO workstreams – e.g. PRA	Reduced structural imbalance being resolved in the BM directly feeds through the approach, reducing system imbalance expectations, with implications for counterproductive actions and reserve procurement. As in the case of LBM, SSP benefits in this area may also vary under Central/Low/High cases as a result of Counterfactual assumptions about the level of benefit delivered under ongoing NESO workstreams.		
	Link with reduced reserve requirements	1. Engagement with NESO Reserve procurement teams 2. NESO workstreams – e.g. PRA			

NB: As outlined above, we do not identify an evidence base for varying assumptions driving SSP market impacts under the Low and High Cases. But, the robustness of SSP market impacts can be tested under alternative SSP design variants, e.g., impacting on the timing of SSP applicability to retail, and under alternative implementation timeframes.
The overall CBA of the SSP reform will also vary as a result of the range of implementation pathways and cost estimates under the Low and High cases.

Key question for stakeholders: Are there any assumptions impacting a key driver of variation in the size of the SSP market impacts under the Central/Low/High that we have not considered?