



Autumn Markets Forum

Net Zero Market Reform Update

18th November 2021
NGESO Markets

Welcome

Agenda

- | | |
|---|-------------|
| 1. Welcome | 13.00-13.10 |
| 2. Phase 2 Overview | 13.10-13.15 |
| 3. Case for Change – Key Challenges | 13.15-13.30 |
| 4. Q&A Session | 13.30-13.45 |
| 5. Market Design Options Assessment Framework | 13.45-14.05 |
| 6. Q&A Session | 14.05-14.20 |
| 7. Next Steps, Feedback and Close | 14.20-14.30 |

New

Appendix 1: Question and answers from session

Phase 2 Overview

Jan 21

Apr 21

Nov 21

Apr 22

Phase 1: Scoping and stakeholder landscape

Phase 2: Case for Change and Identification of Options

Phase 3: Assess options; present recommendations

Case for Change

Modelling inputs

- Net zero scenarios
- Weather data over ten year period
- 5 future snapshot years

Hourly dynamic dispatch model

Modelling outputs

- Supply and demand profiles
- System characteristics and requirements
- Profitability analysis

Identify key challenges for net zero markets

Identify Options & Develop Assessment Framework

Define objectives assessment criteria

Define market assessment framework

Identify options for assessment

Assess options against criteria, shortlist taken forward for Phase 3

Ongoing discussions with Trade Associations and Industry Stakeholders

We hosted several workshops with stakeholders on the case for change

During our case for change workshops we asked stakeholders for their views on the key barriers/challenges in today's market design...

Investment

- Effectiveness of market signals
- Transparency of capacity targets
- Policy uncertainty
- Inability to stack revenues
- Uncertainty around future revenue
- Duration of contracts

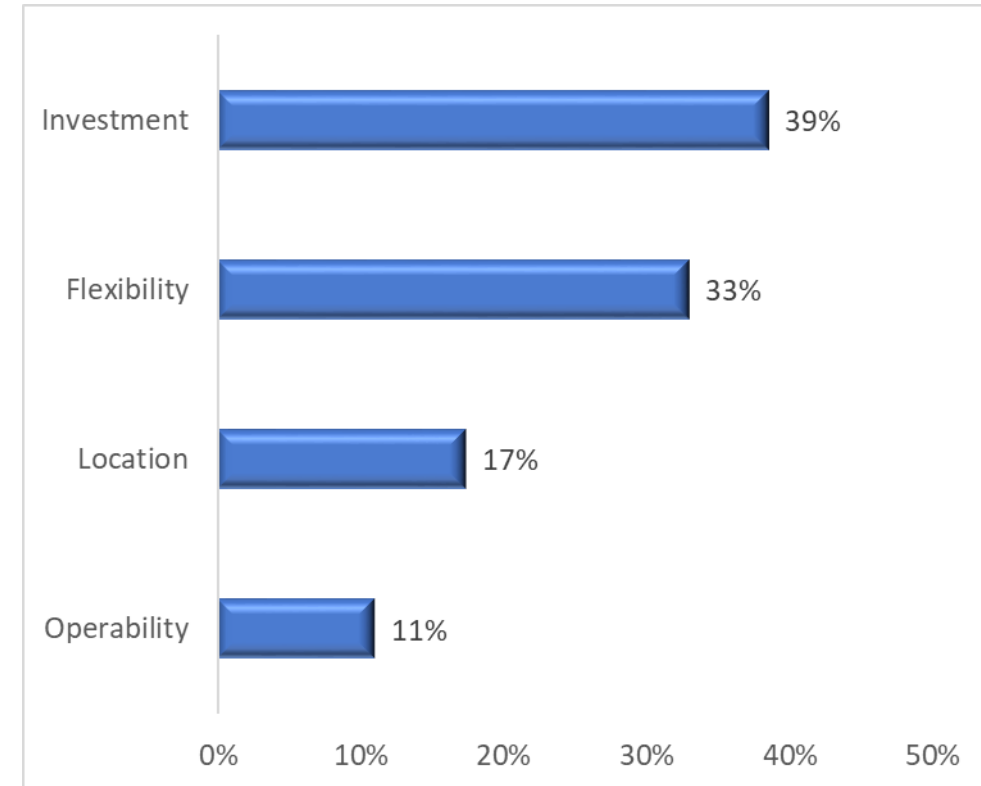
Flexibility

- Level playing field for flexible vs other technologies
- Lack of investment signals for flexibility
- Unclear future flexibility requirements
- Demand-side engagement

Location

- Volatility and unpredictability of TNUoS
- Inability to hedge
- Lack of effective and cost-reflective locational dispatch signals
- Conflict between locational signals and other drivers

What do you think is the most significant issue with current market design?

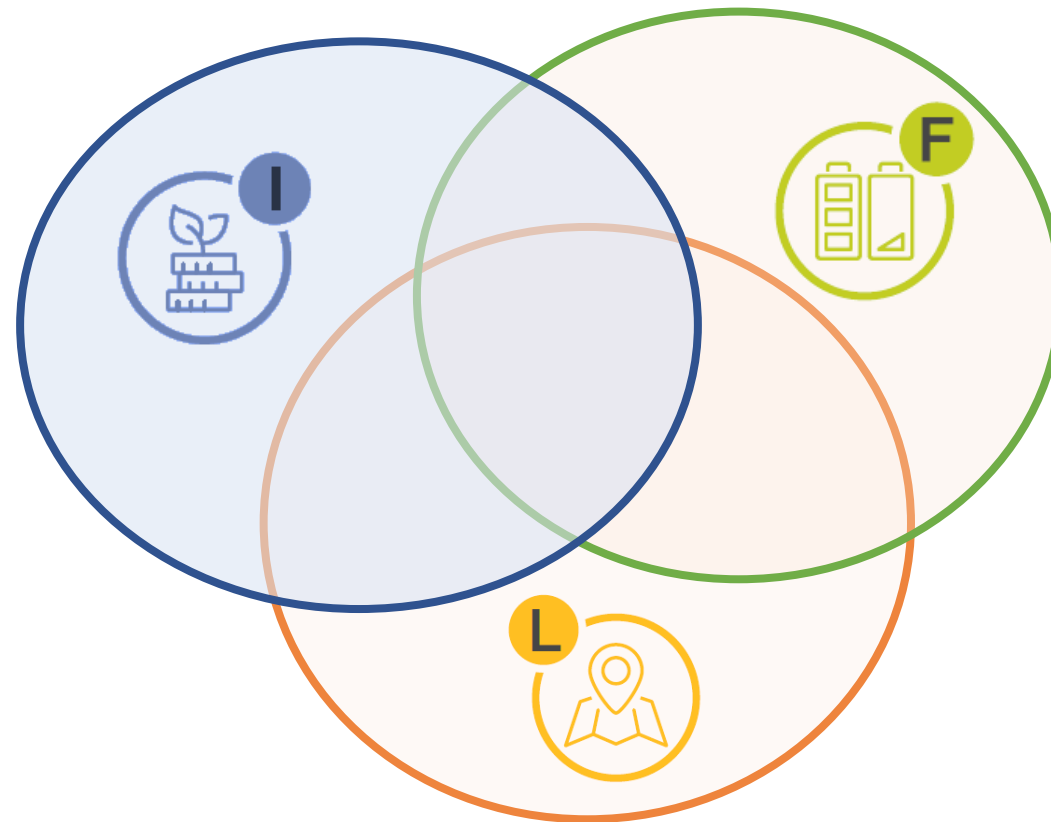


Case for Change: Key Challenges

The case for change has highlighted a number of issues to be addressed for net zero markets which can be consolidated into 3 key challenges

There is a need to **invest** at unprecedented scale and pace

Substantial capacity growth required across all scenarios, including developing first-of-a-kind technologies to commercial scale



There is a need to manage dramatic energy imbalances with **flexible and firm technologies** across both supply and demand

The future electricity system will undergo extreme and often rapidly fluctuating mismatches in supply and demand. New technologies are required to minimise curtailment, to reduce peak demand, exploit flexible potential, and to provide firm capacity

There is a need to incentivise assets to **locate and dispatch** in locations that will minimise whole system costs

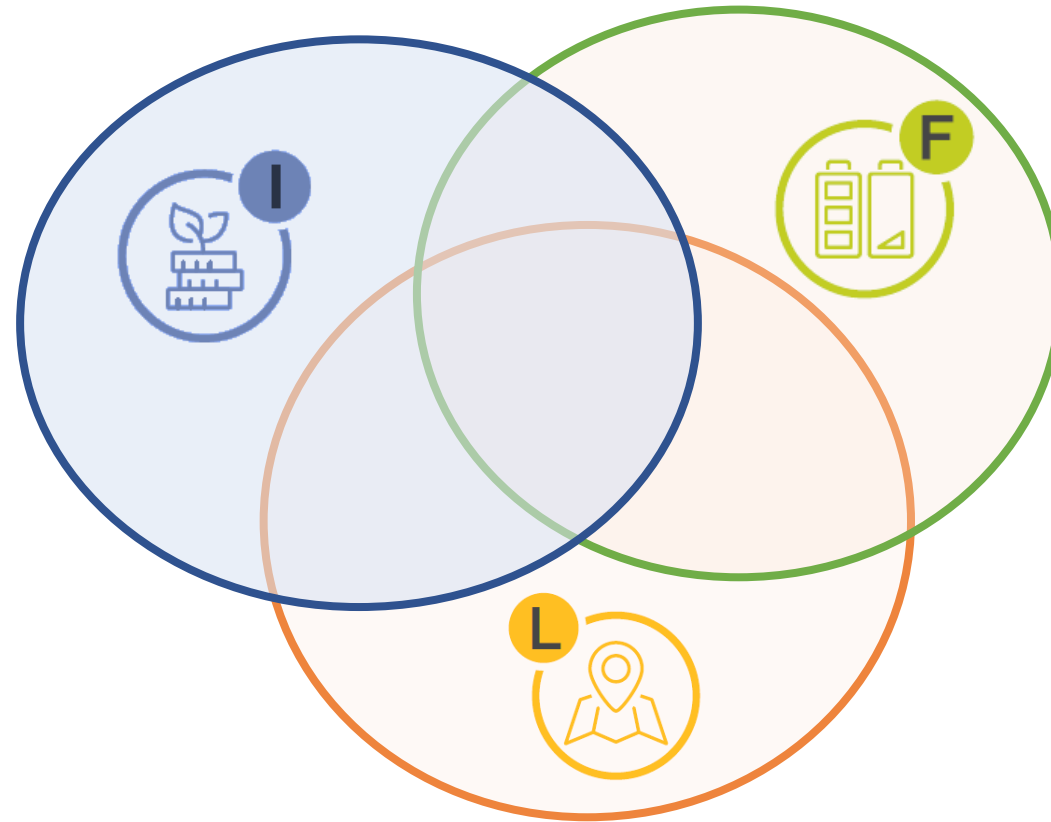
Net zero markets must optimise between exploiting low generation costs, reducing transmission network reinforcement costs, and avoiding network congestion costs.

Some issues fall under more than one of the key challenges as portrayed in the Venn diagram

The case for change has highlighted a number of issues to be addressed for net zero markets which can be consolidated into 3 key challenges

There is a need to **invest** at unprecedented scale and pace

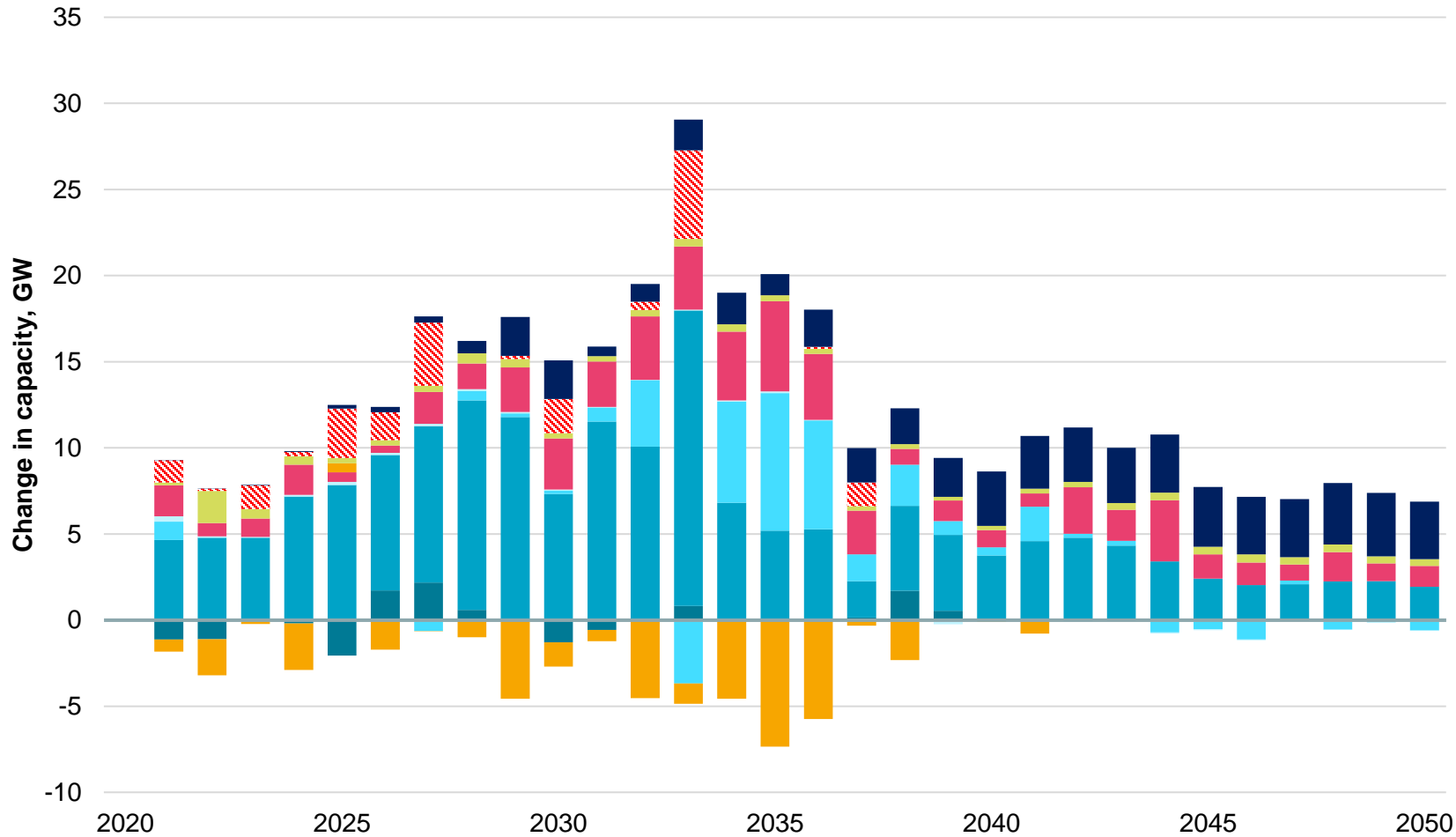
Substantial capacity growth required across all scenarios, including developing first-of-a-kind technologies to commercial scale





Most years have over 10GW of new build with the 2030-35 period seeing a sustained build out of 15GW pa. This presents a significant challenge for the market.

Annual capacity change (new build and retirement), GW (Leading the Way)



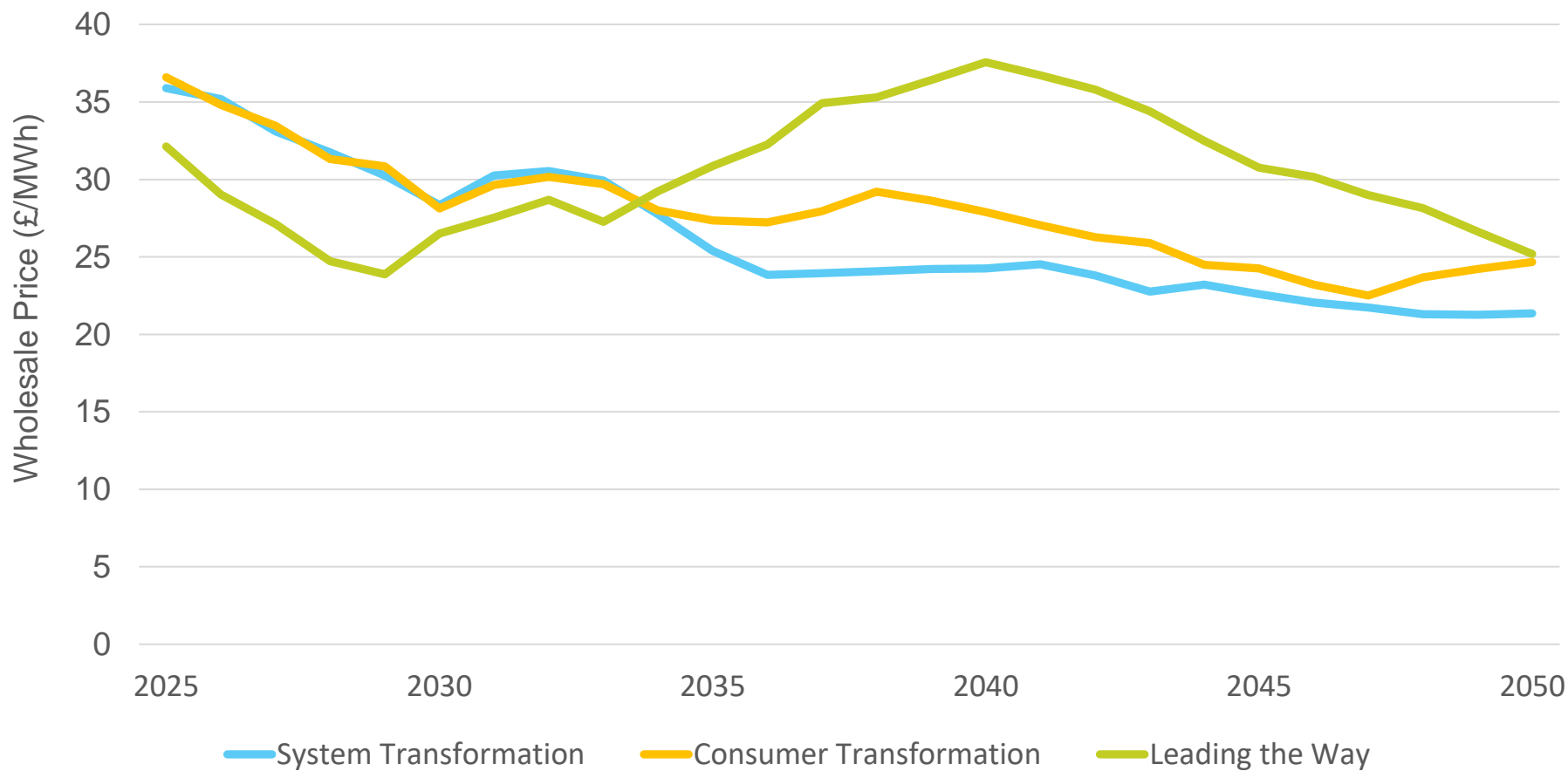
- Electrolysis
- ▨ Interconnector
- Demand Turndown
- High Carbon Flexible
- Storage
- Other Renewable
- Low Carbon Flexible
- Low Carbon Intermittent
- Low Carbon Baseload

Grouping	Technology
High Carbon Flexible	CCGT Gas Peaking CHP Gas Coal
Low Carbon Flexible	Biomass CCS Gas Hydrogen
Low Carbon Intermittent	Offshore Wind Onshore Wind Solar
Low Carbon Baseload	BECCS Nuclear



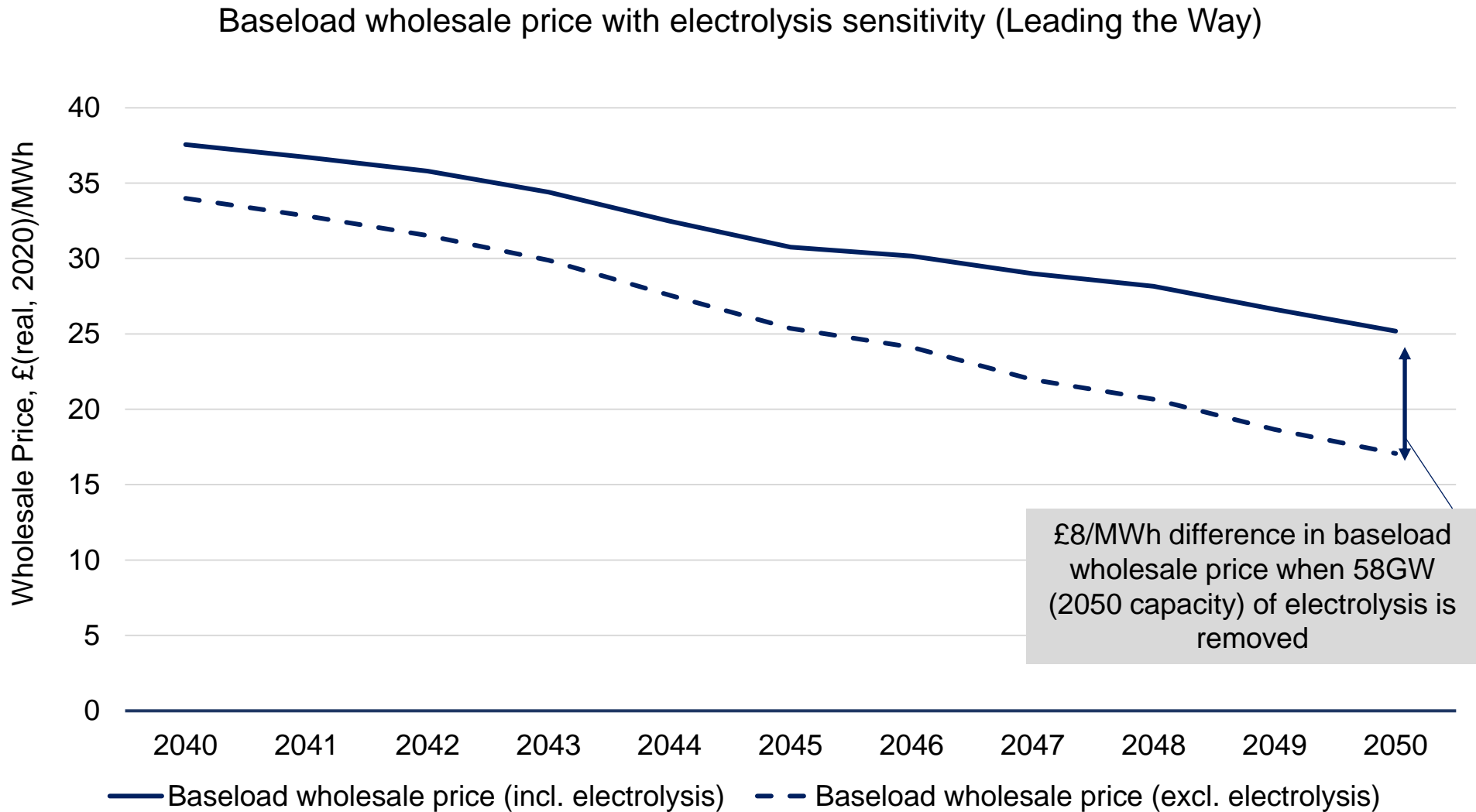
Declining wholesale price makes investment case difficult for non-supported projects

Baseload Wholesale Price (All scenarios)





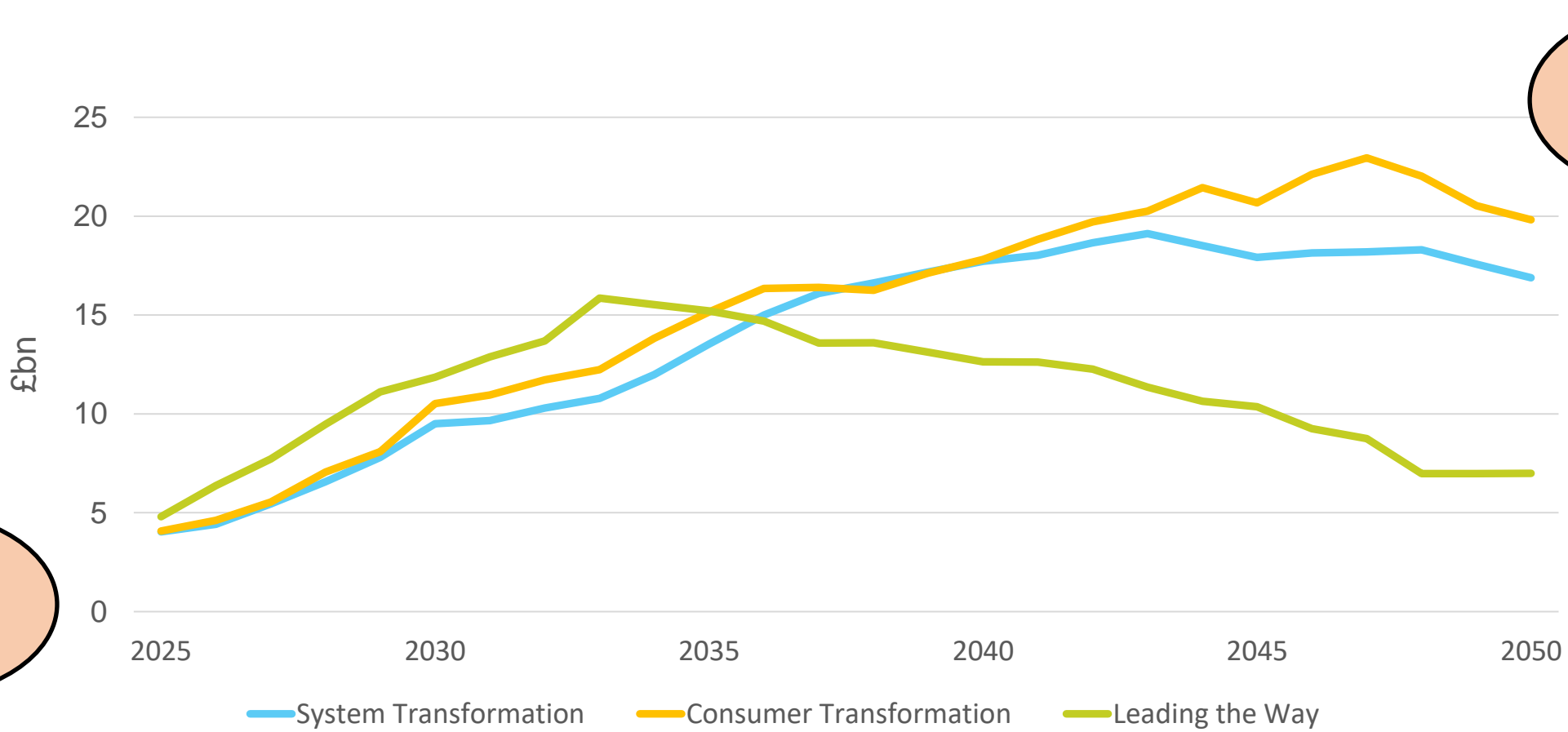
Lack of flexibility will worsen price cannibalisation





Increase in total CfD payments risks market efficiencies and reliance on policy commitment

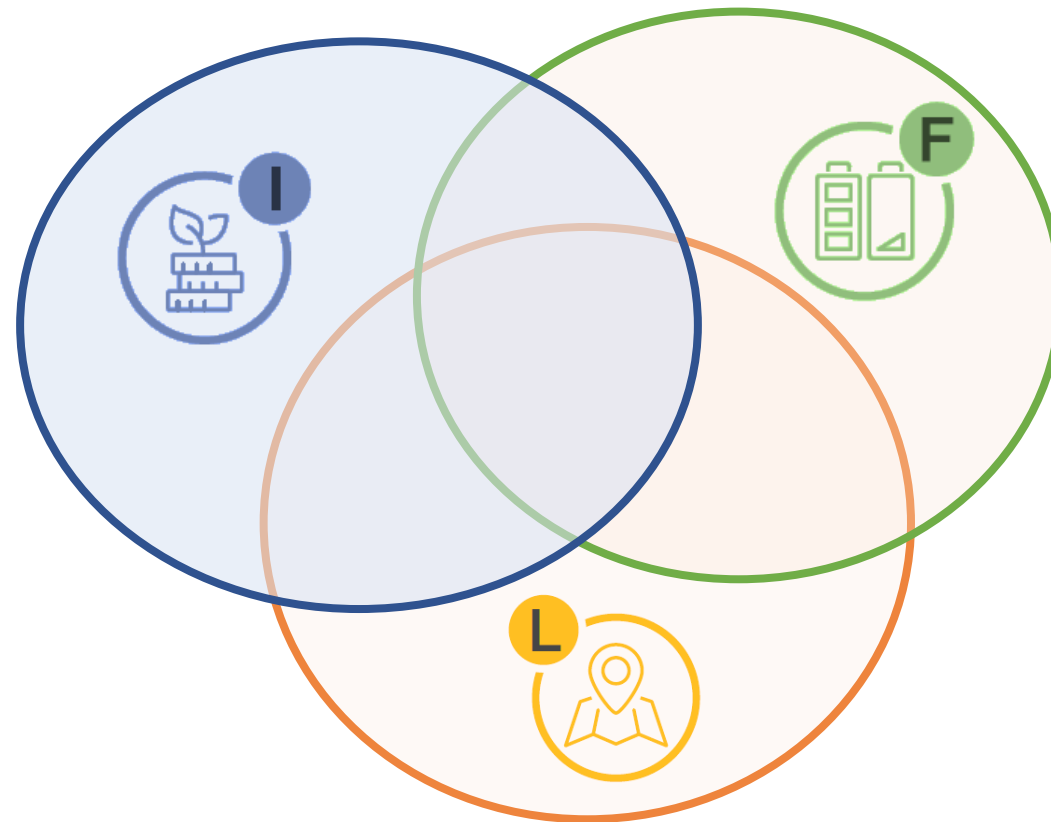
Total CfD support (All scenarios)



Historic CfD Support Cost: 2020 - £2.3bn

Maximum CfD Support Cost: 2047 - £23bn

The case for change has highlighted a number of issues to be addressed for net zero markets which can be consolidated into 3 key challenges

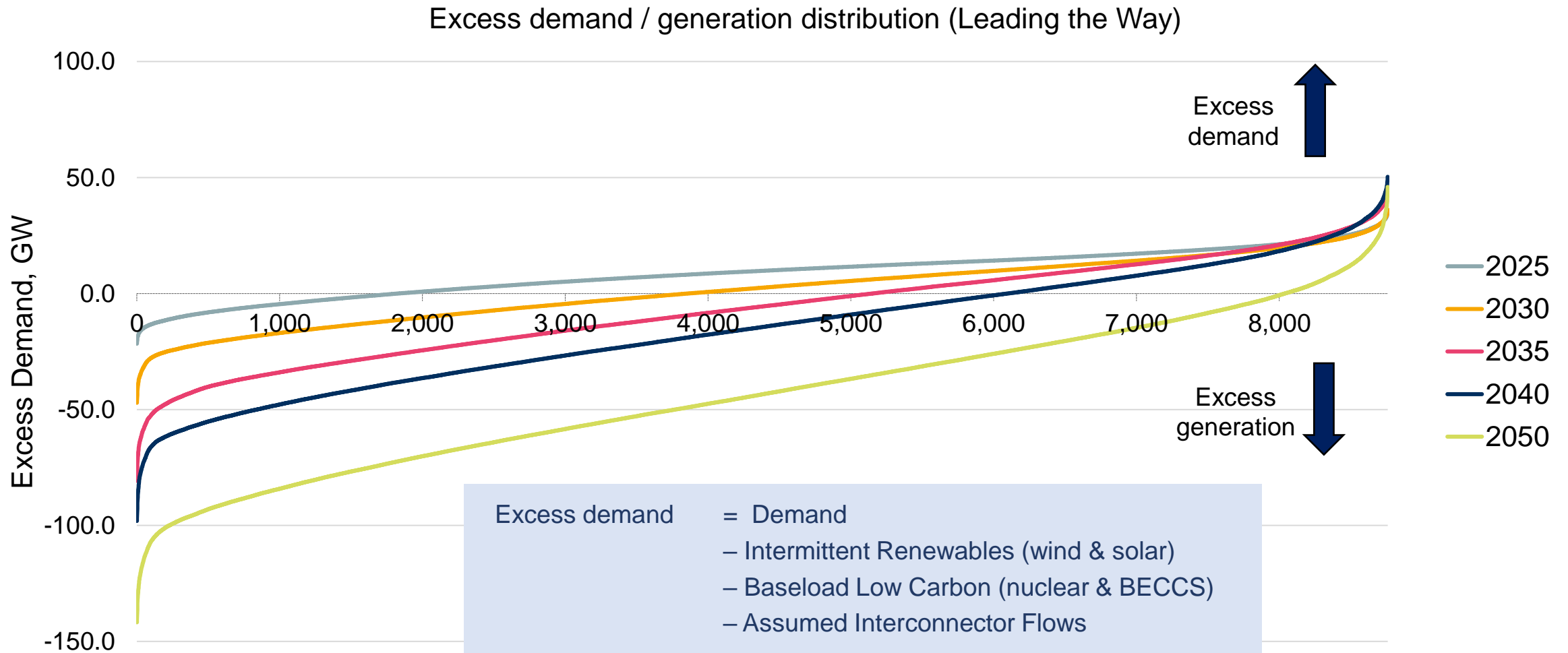


There is a need to manage dramatic energy imbalances with **flexible and firm technologies** across both supply and demand

The future electricity system will undergo extreme and often rapidly fluctuating mismatches in supply and demand. New technologies are required to minimise curtailment, to reduce peak demand, exploit flexible potential, and to provide firm capacity



Periods of both excess generation and excess demand will become more extreme and prolonged

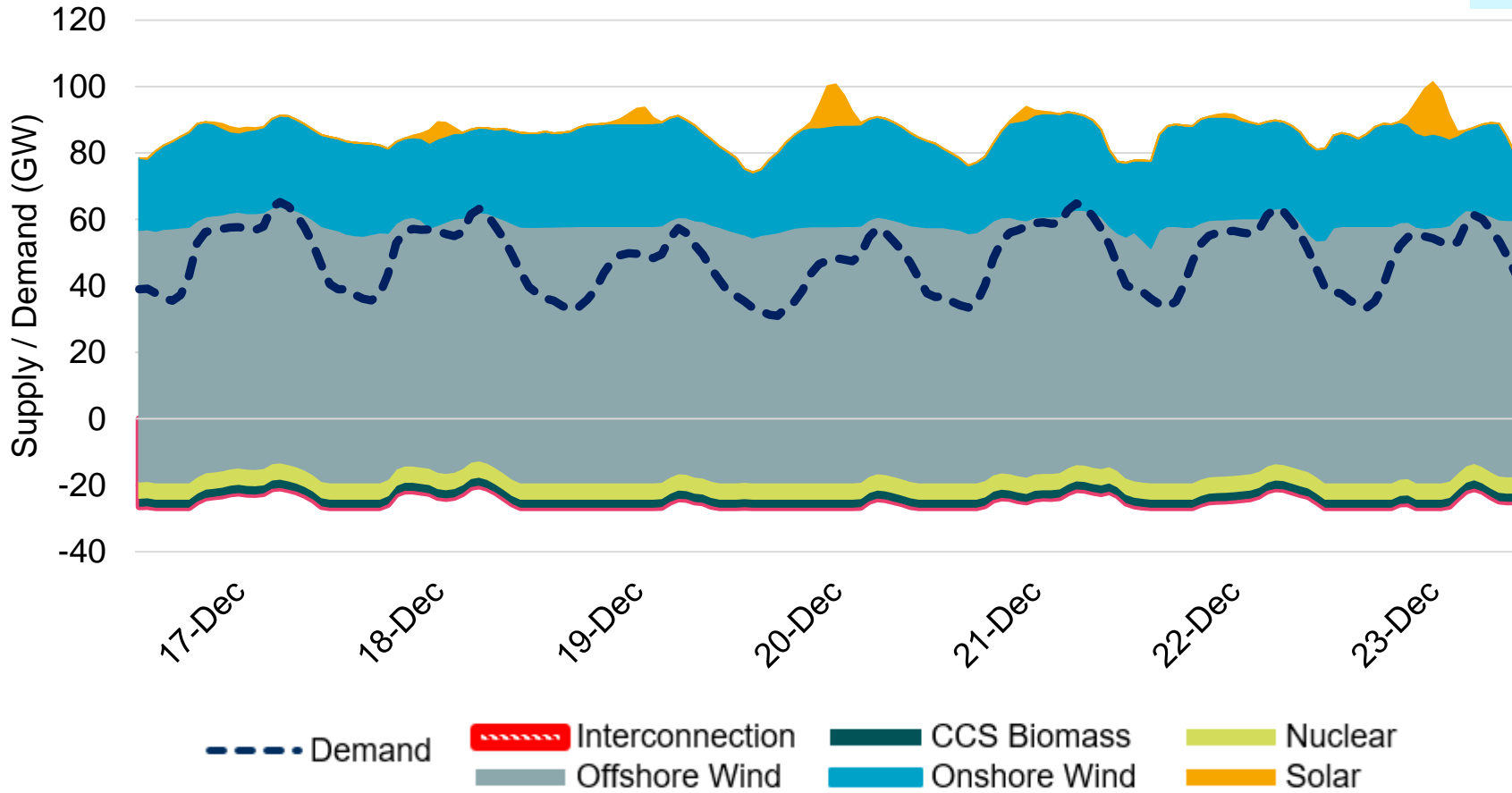




An intermittent renewable-heavy system will have prolonged periods of excess generation during periods of low demand

Excess generation: December 2035 (Leading the Way)

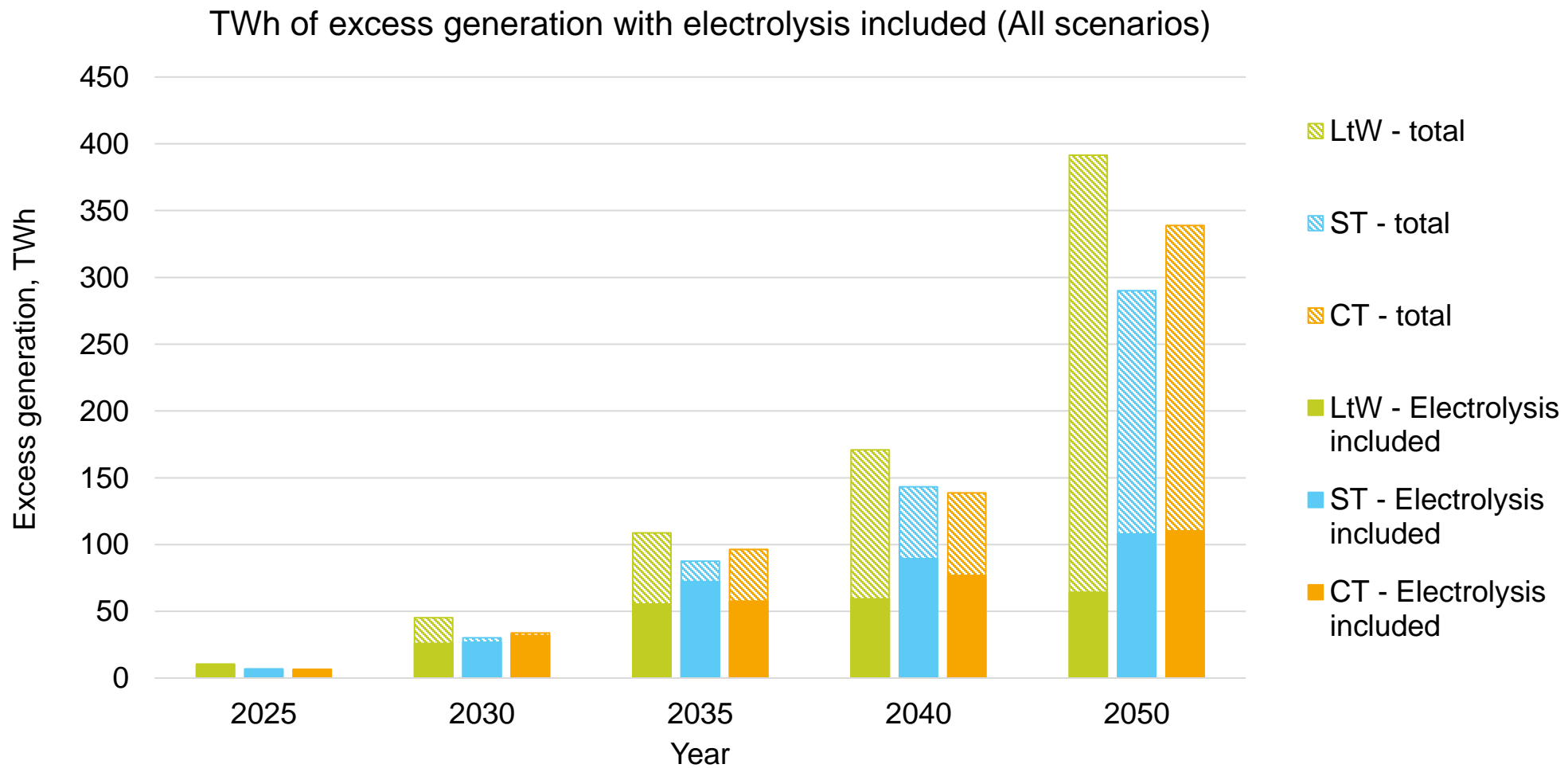
Avg excess: 39GW



For a period of one week in December 2035 our modelling shows almost continual excess generation at an average of 39GW.



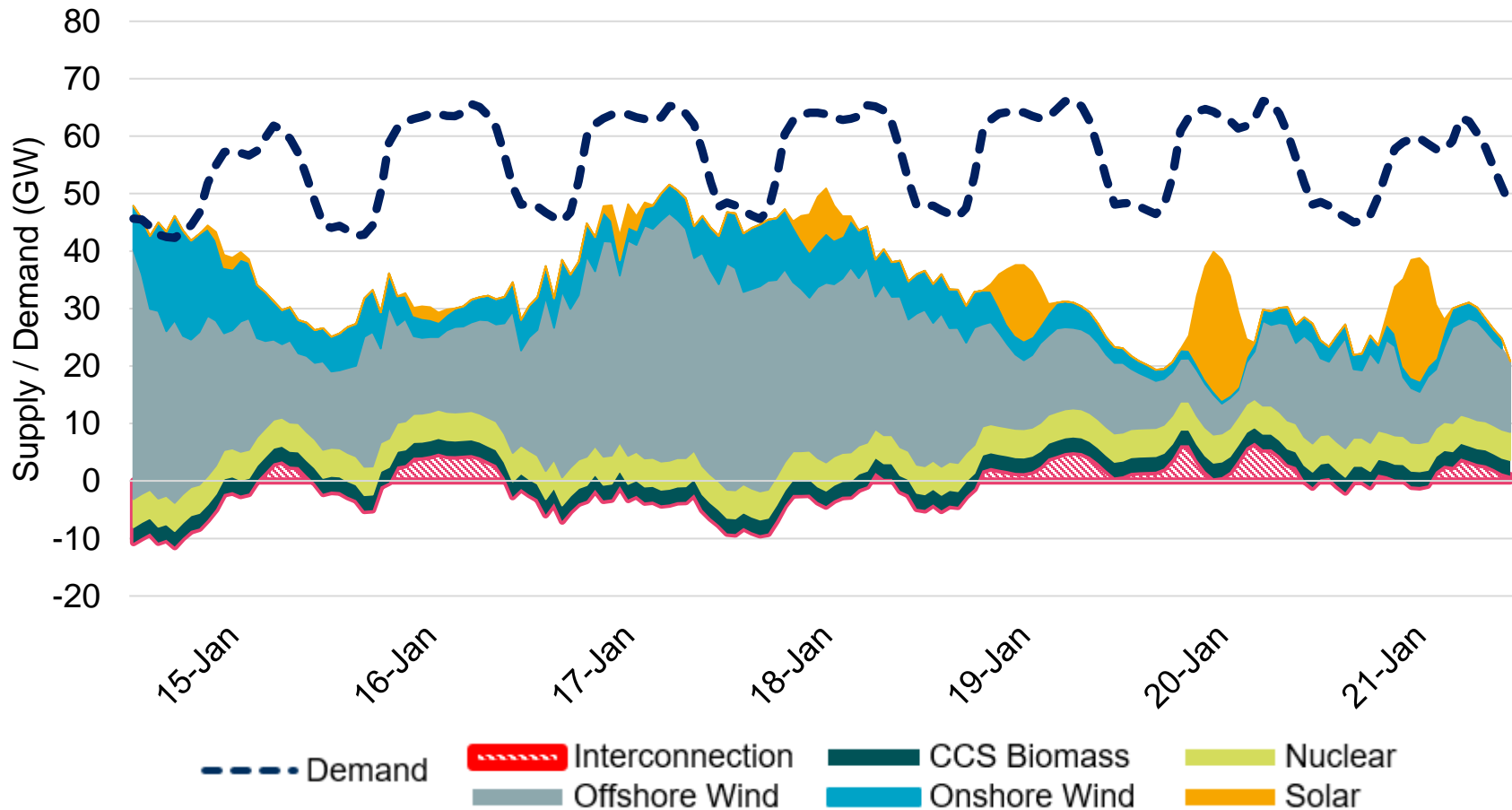
Higher levels of electrolysis mitigate the risk of substantial renewables curtailment in periods of excess generation





A highly weather-dependent renewable-system will have prolonged periods of excess demand during periods of low wind

Excess demand: January 2035 (Leading the Way)



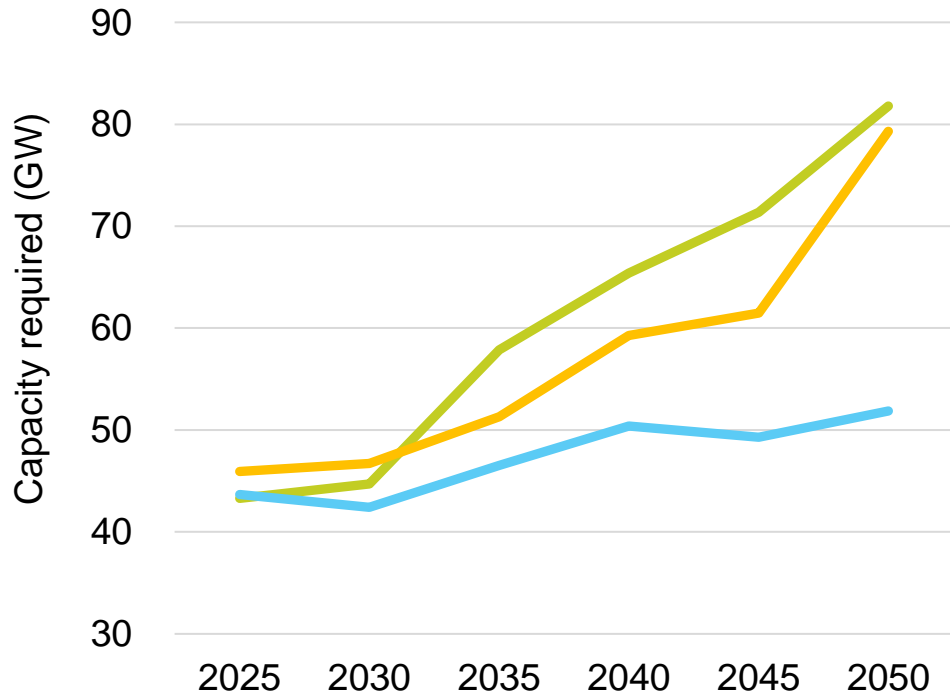
Avg excess:
21GW

For a period of one week in January 2035 our modelling shows almost continual excess demand at an average of 21GW.

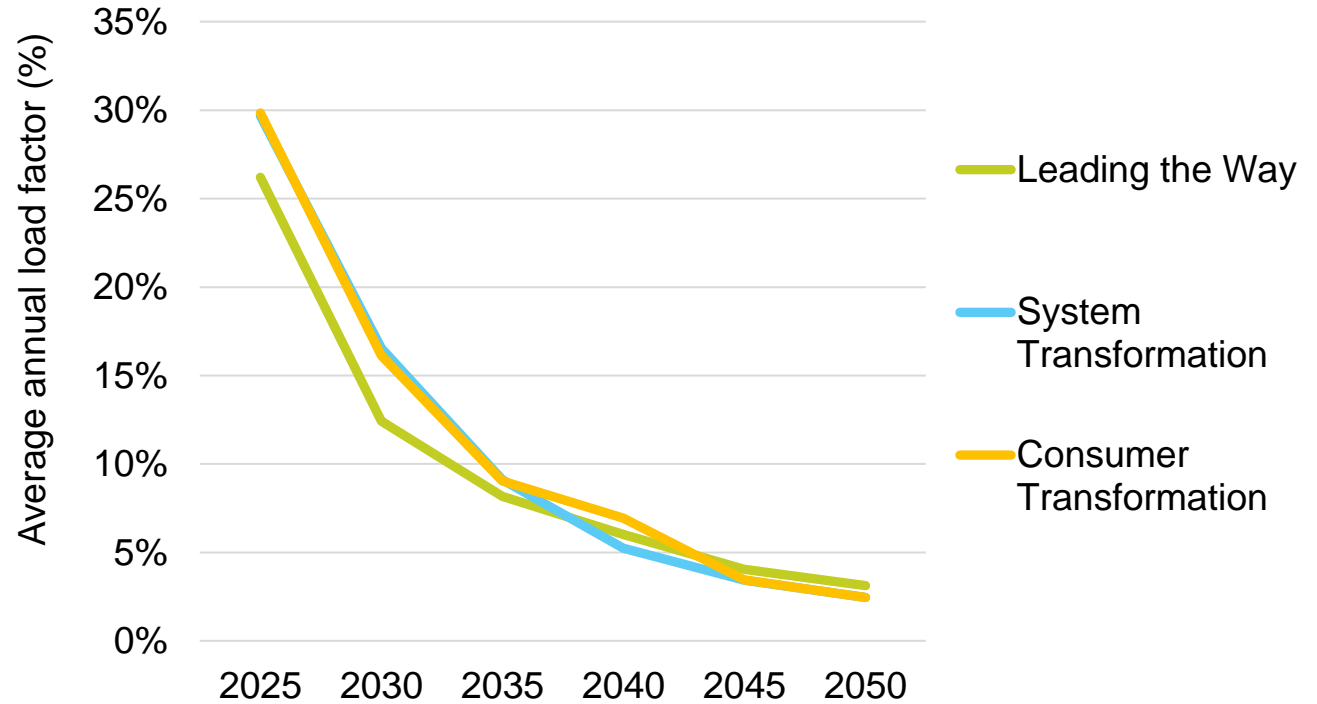


Increasing firm capacity is required to manage periods of excess demand, however average load factors decrease

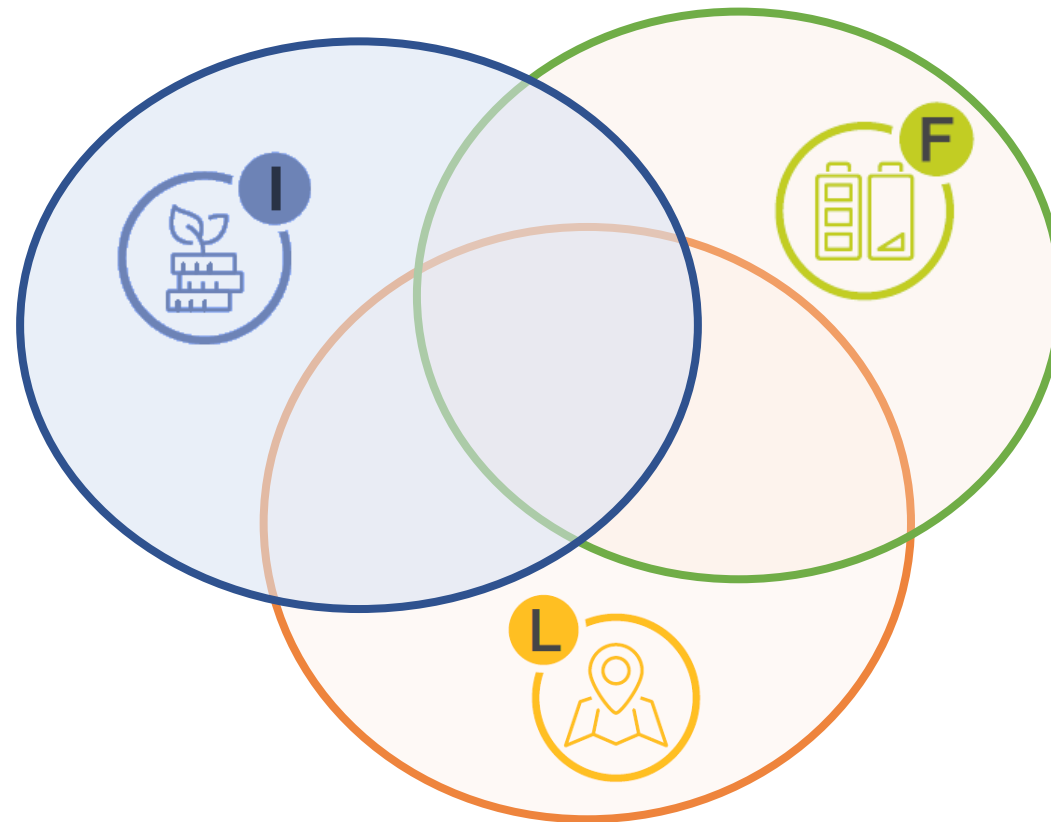
Equivalent firm capacity required (All scenarios)



Average load factor of flexible capacity (All scenarios)



The case for change has highlighted a number of issues to be addressed for net zero markets which can be consolidated into 3 key challenges



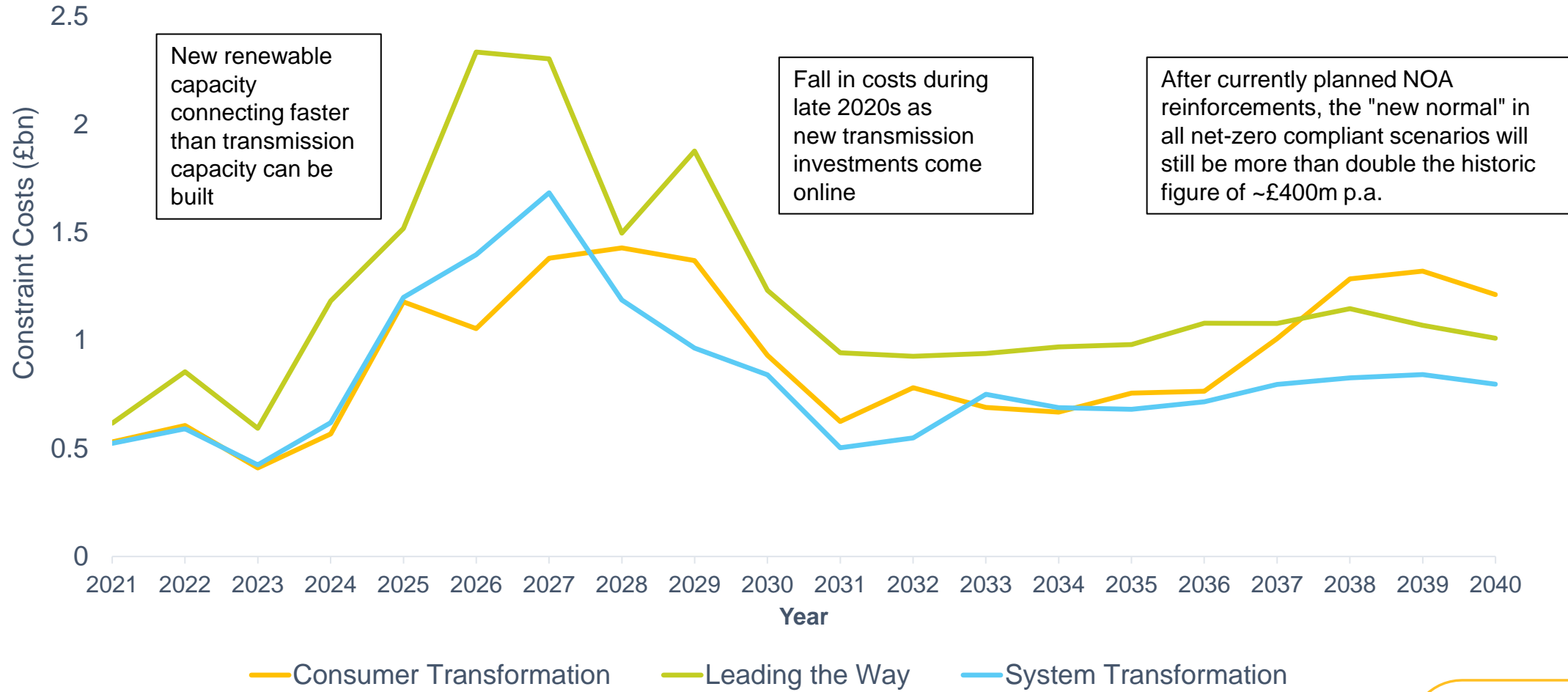
There is a need to incentivise assets to **locate** and **dispatch** in locations that will minimise whole system costs

Net zero markets must optimise between exploiting low generation costs, reducing transmission network reinforcement costs, and avoiding network congestion costs.



Latest NOA projections indicate likelihood of “new normal” annual constraint costs more than double historic costs.

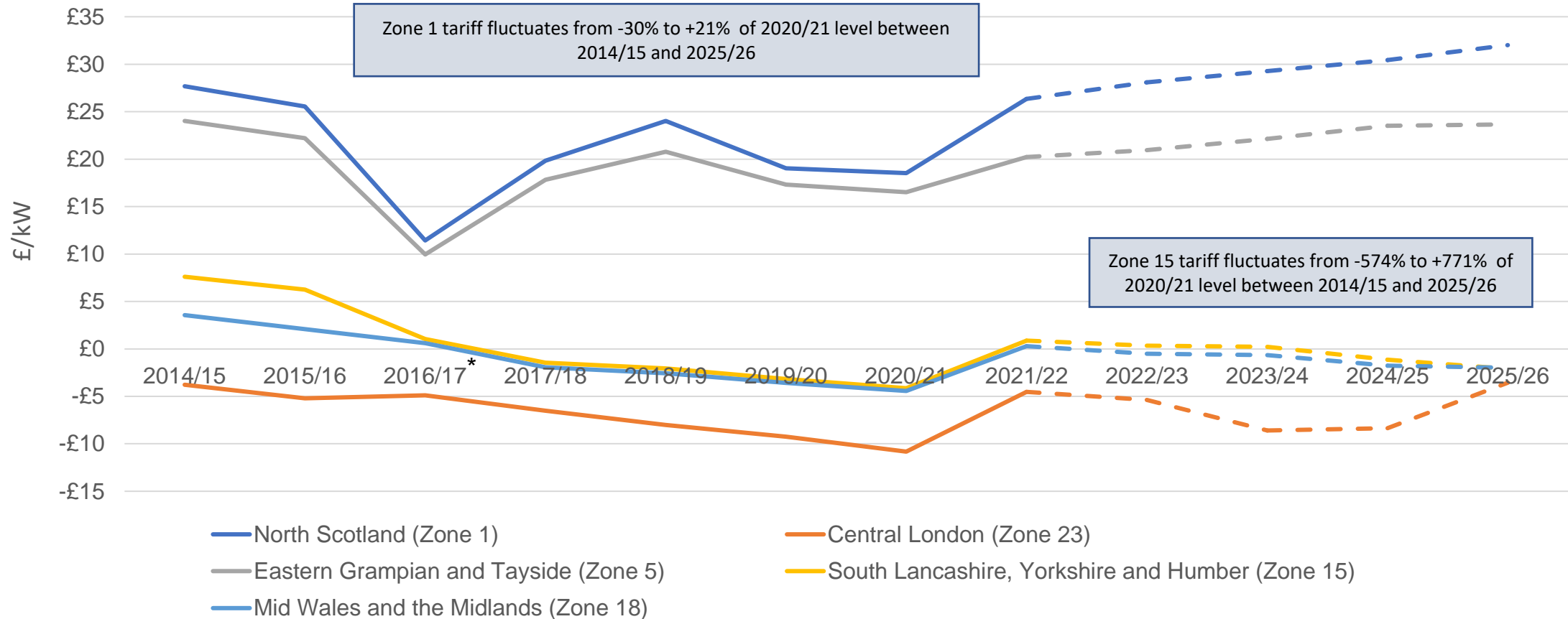
Modelled constraint costs after NOA6 optimal network reinforcements (All scenarios)





Volatile and unpredictable TNUoS tariffs may inflate the cost of capital

TNUoS wider generation tariff for intermittent renewables (historic and forecast)



*Average Load Factor (ALF) used to illustrate tariffs for 2016/17 was 30% and therefore cannot be directly compared to subsequent years (ALF = 40%)

Q&A

Market Design Options Assessment Framework

We have set out 9 market design assessment criteria

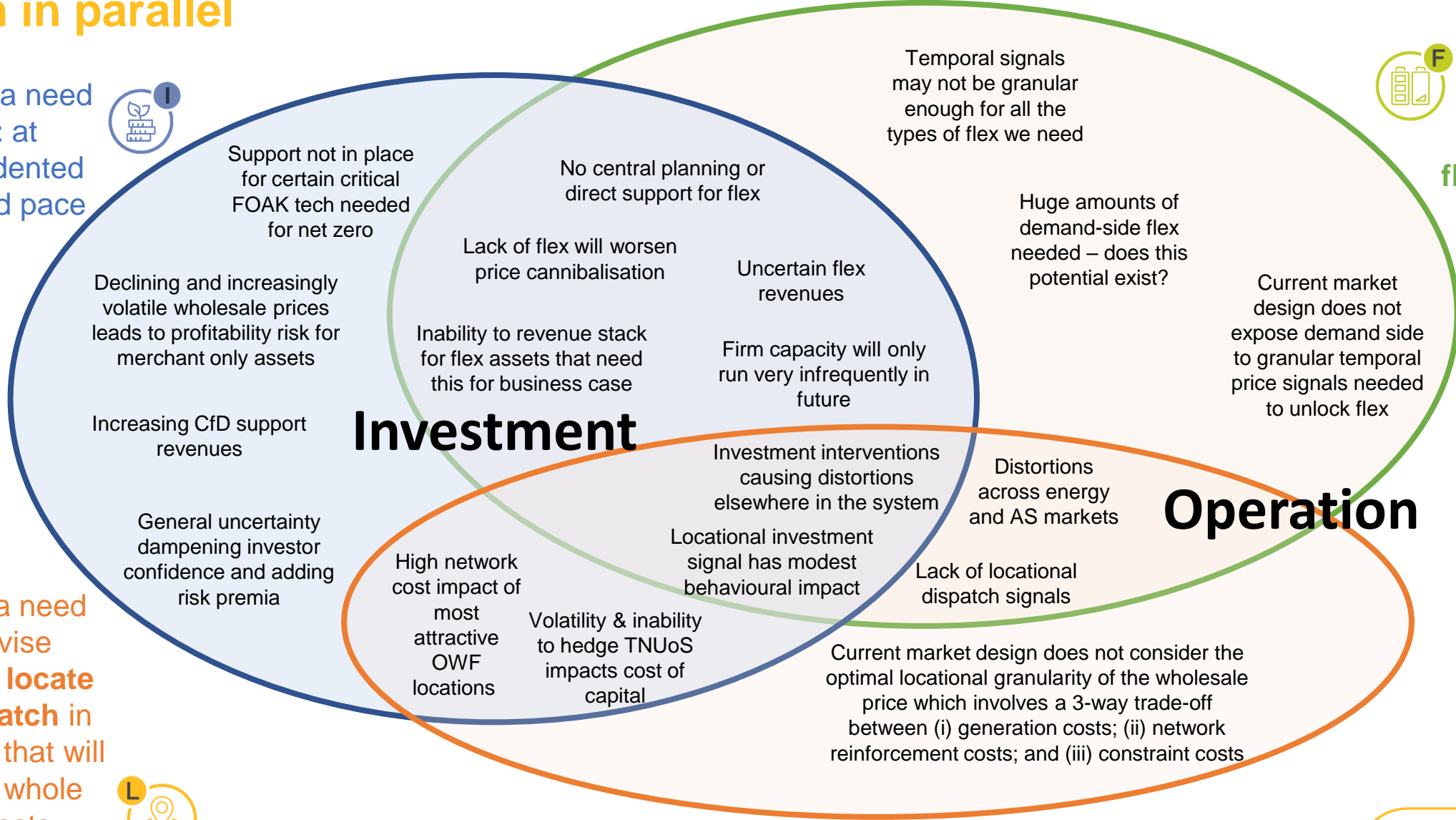
Decarbonisation	▷	<ul style="list-style-type: none">Provides confidence that emissions reduction targets will be met
Security of supply	▷	<ul style="list-style-type: none">Provides confidence that adequacy and operability challenges can be met
Low cost	▷	<ul style="list-style-type: none">Provides confidence that the electricity system is being delivered efficiently<ul style="list-style-type: none">Network build, short run dispatch and long run investment are efficient
Competition	▷	<ul style="list-style-type: none">Allows competition within and across technologies, including between supply and demand side
Investor confidence	▷	<ul style="list-style-type: none">Investors are exposed to appropriate risks (e.g. risks they can manage) and the costs of finance is minimised
Consumer fairness	▷	<ul style="list-style-type: none">Consumers are rewarded for participating in the system but those that cannot are not faced with steep cost increasesSome consumers are not unduly favoured (e.g. by location)
Deliverability	▷	<ul style="list-style-type: none">Transition from current market design to target design is deliverable in a relevant timeframe
Adaptability	▷	<ul style="list-style-type: none">A market design that can adapt to changes in technology or circumstances with limited disruption within a reasonable timeframe
Whole System	▷	<ul style="list-style-type: none">Facilitates decarbonisation across other energy vectors and optimises across electricity transmission and distribution

These are the primary objectives of the policy trilemma

**No explicit weighting:
order not
representative of
relative importance**

Weaker interactions between investment and operation issues means we can split our options assessment into two categories and assess them in parallel

There is a need to **invest** at unprecedented scale and pace



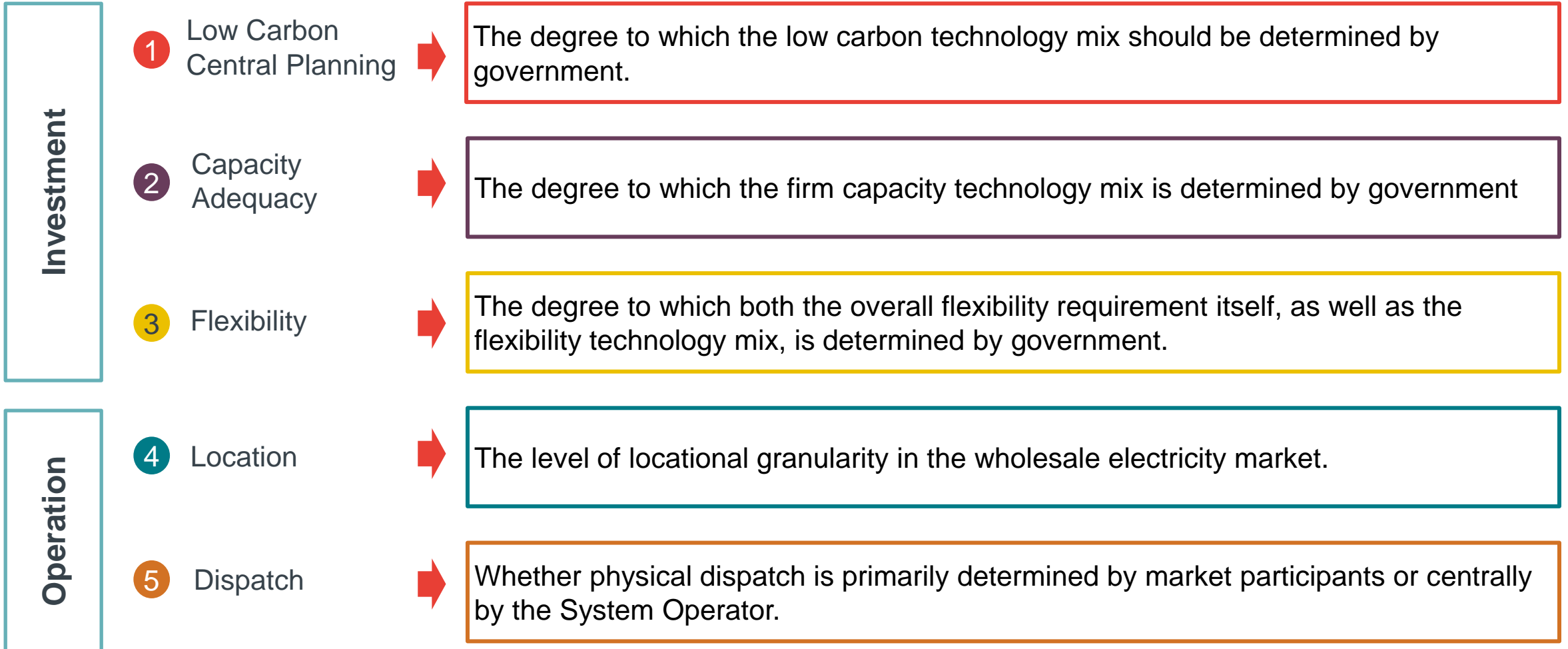
There is a need to manage dramatic imbalances with **flexible** and **firm** technologies across both supply and demand

There is a need to incentivise assets to **locate** and **dispatch** in locations that will minimise whole system costs

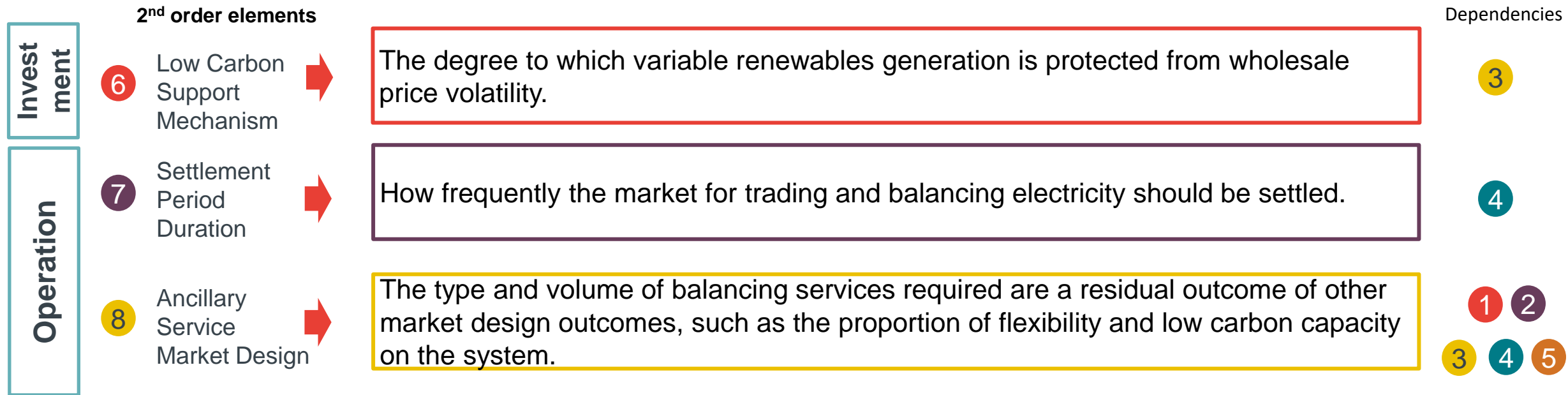


What are the main high-level market design elements and in what order should they be assessed?

1st order elements



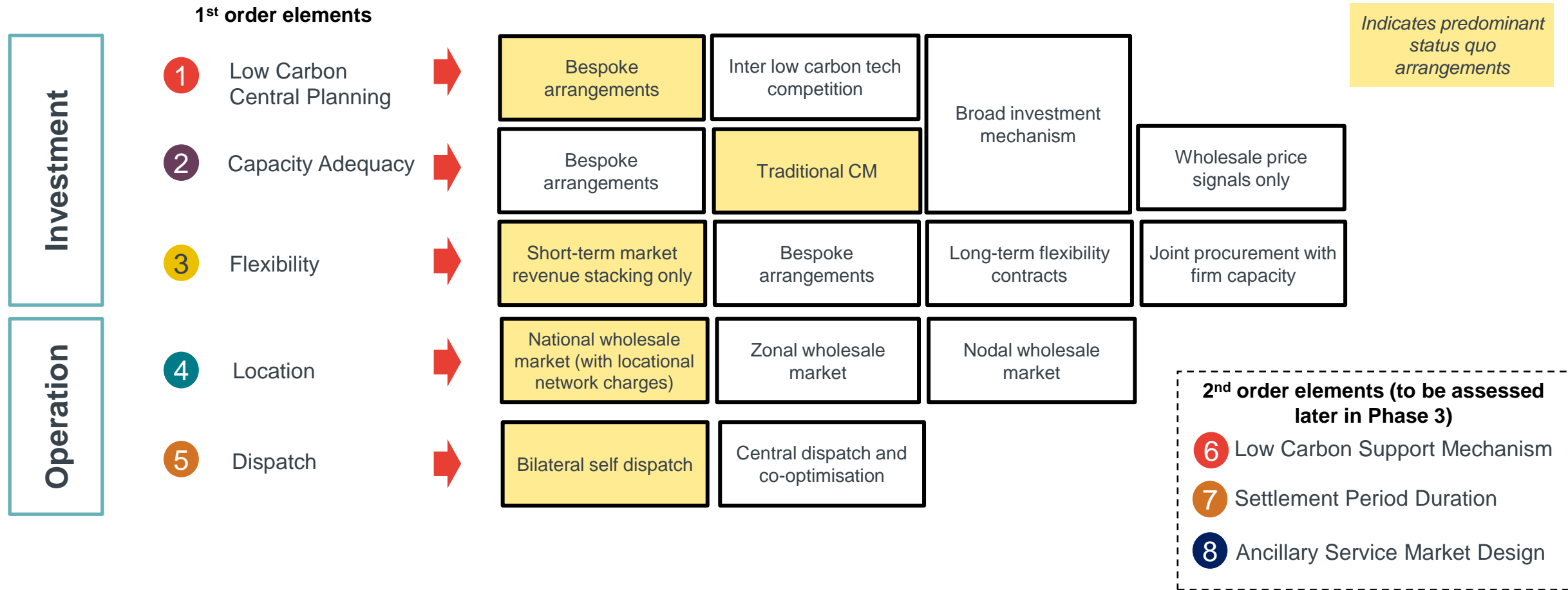
What are the main high-level market design elements and in what order should they be assessed?



These 3 Market design elements are not included in this preliminary assessment

- Assessment for these elements is highly dependent on the outcome of the first 5
- The relative merits of different options for these market design elements cannot be assessed accurately until the preferred options for the first five have been established
- These market design elements are to be assessed in Phase 3

What are the options for each market design element?



Flexibility Assessment Summary (RAG Rating):

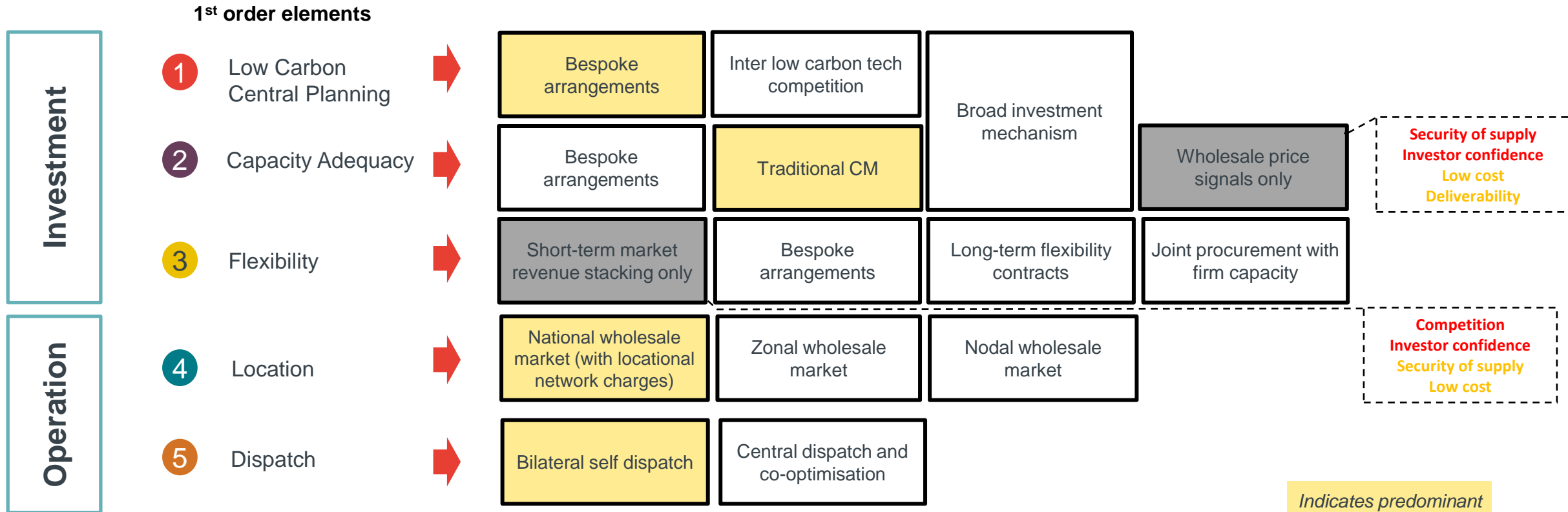
Propose ruling out: Short term market revenue stacking only

Criteria \ design option	Short term market revenue stacking only	Longer term ancillary service contracts for flexibility	Flexibility procured jointly with firm capacity	Bespoke arrangements
Decarbonisation	Not directly affected, but if less flex then possibly more RES curtailment	Not directly affected, but if less flex then possibly more RES curtailment	Not directly affected, but if less flex then possibly more RES curtailment	Not directly affected, but if less flex then possibly more RES curtailment
Security of Supply	Firm capacity addressed separately; unclear if there will be sufficient techs to address ramp rate requirements.	Targeted capacity linked to operability and reliability standards	Targeted capacity linked to operability and reliability standards	Targeted capacity linked to operability and reliability standards
Low cost	Higher WACC, but lower risk of over procuring flex	Lower investor WACC but risk of over procurement	Lower investor WACC but risk of over procurement	Lower investor WACC but risk of over procurement
Competition	Competition likely to favour technologies that primarily provide firm capacity and only some flex	Order of firm capacity and flexibility auctions could create unlevel playing field and tech bias	Joined up procurement of firm capacity and flexibility can provide more of a level playing field	Very limited competition between technologies delivering flexibility and limit to demand participation
Investor confidence	Limited bankable revenues associated with flexibility.	Some risks with the investor but access to some bankable revenues	Some risks with the investor but access to some bankable revenues. Also greater novelty in approach.	Low risks with the investor
Consumer Fairness	Not clear this choice affects consumer fairness	Not clear this choice affects consumer fairness	Not clear this choice affects consumer fairness	Not clear this choice affects consumer fairness
Deliverability	Similar to the status quo	Relatively, limited change from status quo	More complex auction arrangements required, increasing if in broad investment mechanism	Likely to be manageable
Adaptability	Dynamic response to changes in technology costs	Arrangements can be adapted in response to new developments e.g. new technologies	Arrangements can be adapted in response to new developments e.g. new technologies	Arrangements can be adapted in response to new developments e.g. new technologies
Whole system	T&D optimisation possible. SofS risks may limit decarbonisation via electrification.	T&D optimisation possible but depends on a consistent approach to D flex procurement.**	T&D optimisation possible but depends on a consistent approach to D flex procurement.**	T&D optimisation possible but requires ESO/DSO coordination.

Progress to shortlist?



2 market design element options have been eliminated



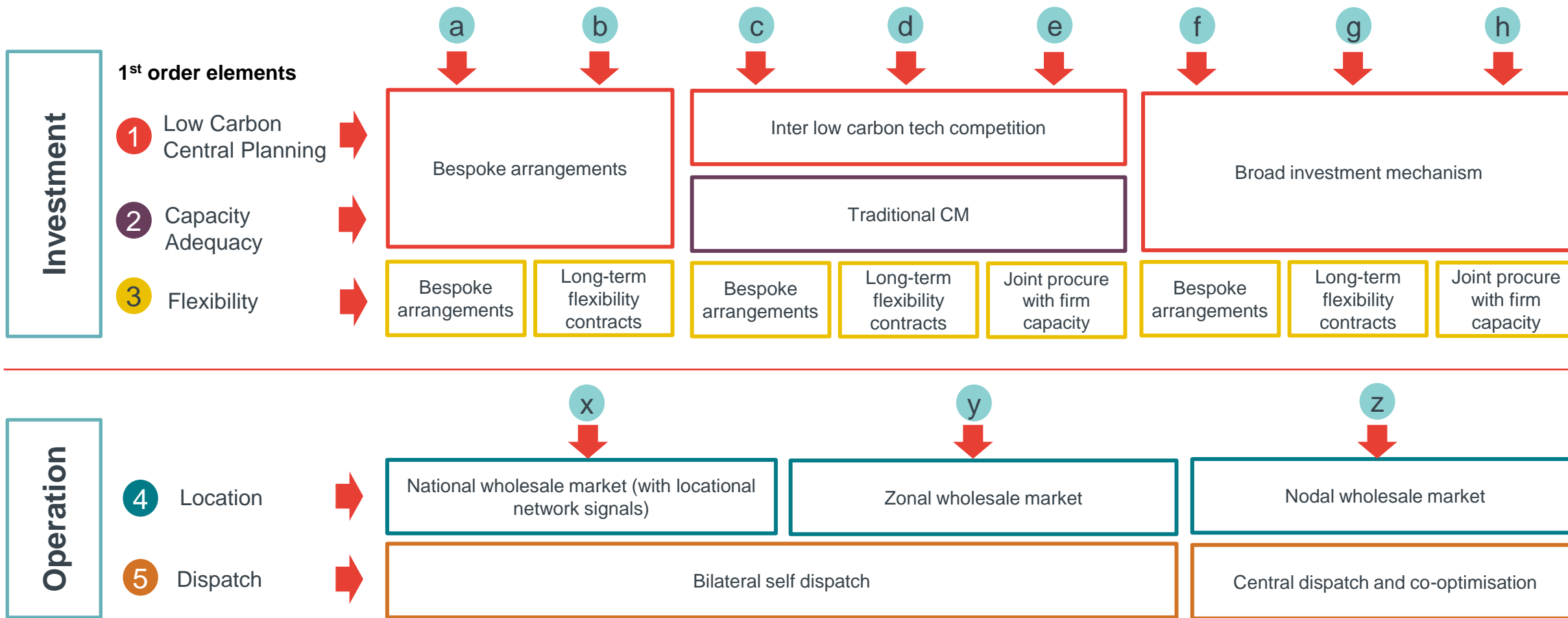
- Based on the RAG analysis, we recommend eliminating from further consideration:
 - Wholesale price signals only
 - Short-term market revenue stacking only

Indicates predominant status quo arrangements

Red and amber RAG scoring for eliminated options

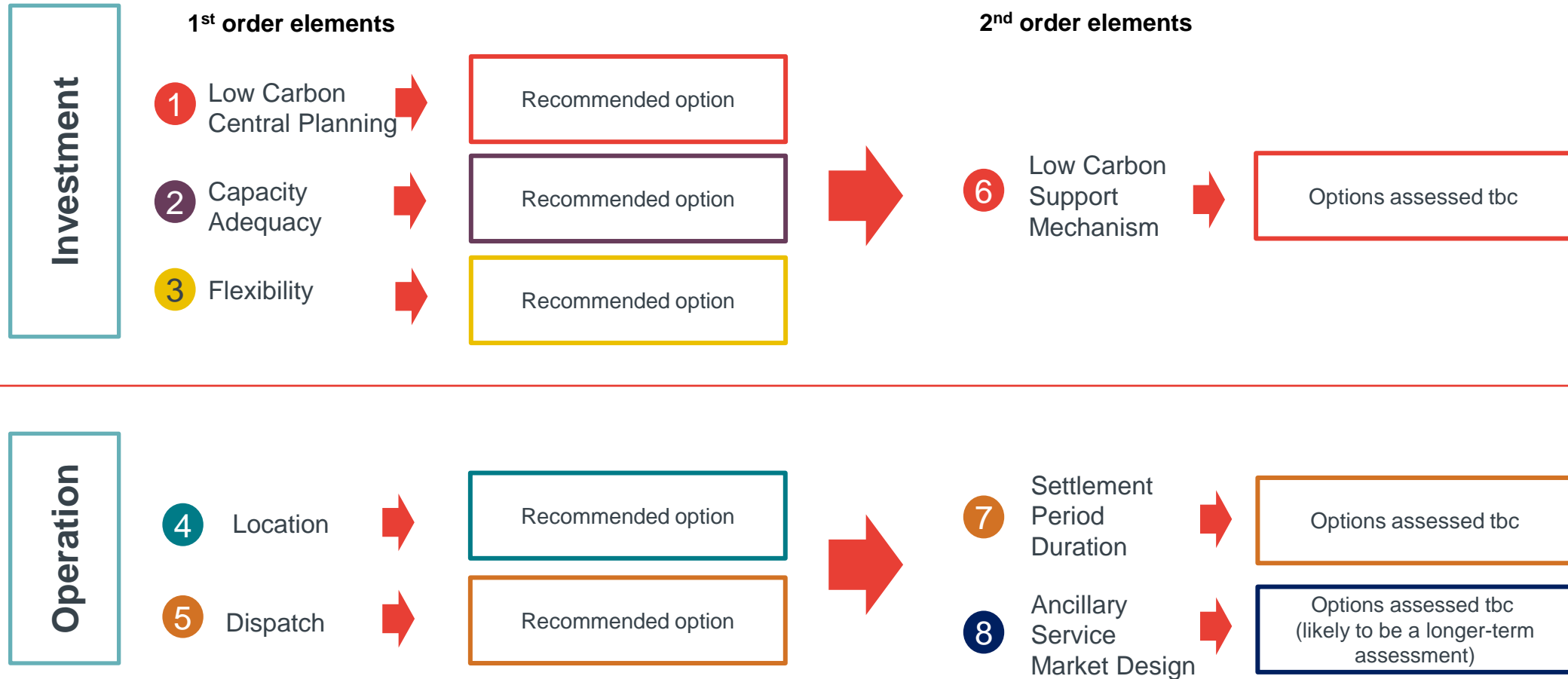
8 packages of investment reforms and 3 packages of operation reforms to be assessed in Phase 3

All investment packages could reasonably be combined with any of the locational and operational options. This gives 24 packages (8 x 3). The investment (8) and operation (3) options can be assessed in isolation.



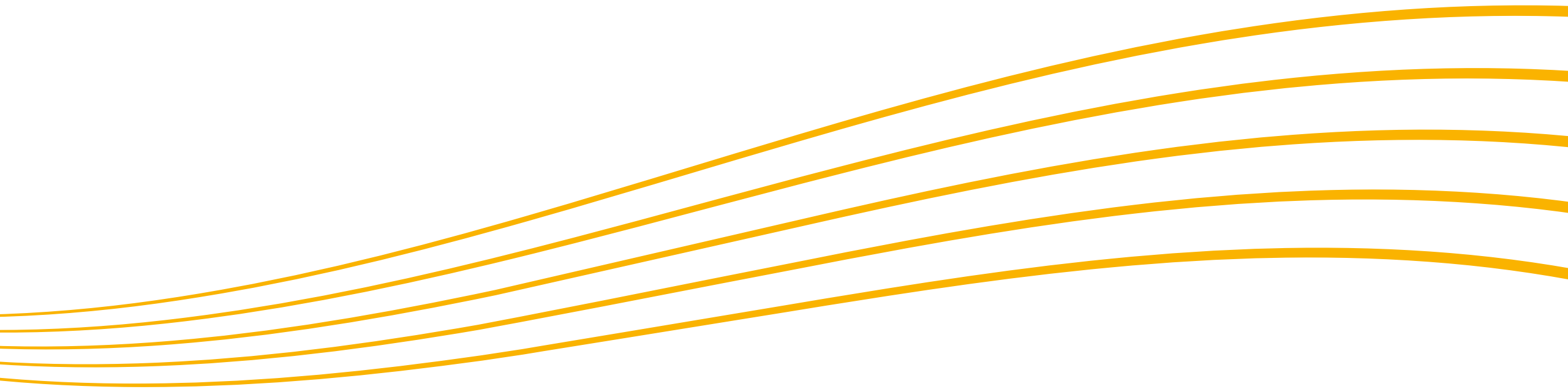
Note: As the decision on self-dispatch or central dispatch is effectively automatic based on the locational decision it does not constitute a further option dimension

Once market design elements 1-5 have been assessed and recommended options are chosen, elements 6-8 can then be assessed



Q&A

Next steps



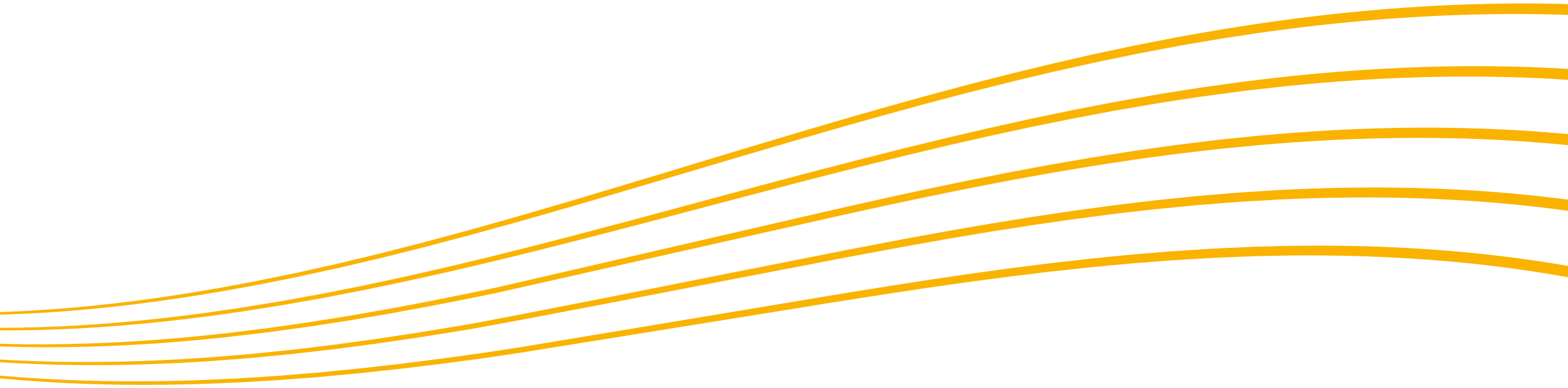


Any further questions or comments?

Contact us:

email: simon.targett@nationalgrideso.com

Appendices



Appendix 1: Q&A – General

The questions have been categorised into General, Investment, Flexibility, Locational and Market Design Options Assessment Framework. If you would like to discuss any of the answers provided or you have any further questions then please contact simon.targett@nationalgrideso.com

Which part of the website will the paper be uploaded to?

You can download our interim report [here](#)

How are you thinking about the political trade-offs inherent in various market designs? Are BEIS/Ministers involved in this process?

We recognise the political trade-offs involved however these are outside the scope of our assessment. We have been speaking to BEIS and Ofgem regularly throughout this project and they have had visibility of all the work that we have done so far.

Can you provide a list of which market participants you talked to?

Over 250 stakeholders participated in our workshops during Phase 2 of the project, from a wide range of stakeholder categories as detailed in the appendix of our interim report. For anyone that did not participate and would like to in the future please go to our [webpage](#), subscribe for updates and we will provide detail on future events.

Are the LCC Frontier Economics reports or summaries especially more detail on the modelling available (assumptions) in the public domain?

More details on the assessments and modelling assumptions can be found in our interim report which can be downloaded [here](#).

Is there an opportunity to submit written evidence to this process? As there would be for a BEIS consultation process? Workshops are useful but necessarily don't get into the real nub of the issues.

During Phase 2 of the project, we encouraged richer discussion via interactive workshops in preference to the submission of written evidence. However, we will consider this feedback and whether written evidence may be appropriate to compliment the further external engagement events throughout Phase 3.

Appendix 1: Q&A – Investment

The questions have been categorised into General, Investment, Flexibility, Locational and Market Design Options Assessment Framework. If you would like to discuss any of the answers provided or you have any further questions then please contact simon.targett@nationalgrideso.com

What does the investment scale look like and where are we today compared to what good looks like?

Please refer to page 9 of our interim report which can be downloaded from our webpage [here](#). This shows the scale of capacity build needed for the Future Energy Scenario Leading the Way. As the scenario uses actual existing and pipeline capacity build as the starting point it is a reflection of where we are today.

How have you considered future offshore networks in the analysis? In order to meet scale of investment, this will be critical as onshore investment will hit planning blockers

Yes, offshore wind makes up a significant proportion of capacity across scenarios out to 2050. The commitment to reaching 40GW of offshore wind by 2030 is achieved in 2 of the 3 net zero Future Energy Scenarios. In System Transformation the commitment is reached in 2031. We see further increases through the 2030s and in Consumer Transformation reaches 80GW by 2040 and 113GW by 2050.

What sets a market price when there is nothing left that's not on a CFD or other support mechanism?

Peaking plant such as hydrogen OCGTs and CCUS with non-zero marginal costs will have a greater role in price setting after non-abated gas plant have retired.

An important consideration for net zero market design will be that the true marginal costs of flexible capacity are accurately reflected in wholesale price formation. Support mechanisms which protect generation from wholesale price exposure, such as CfDs, are unlikely to be appropriate for flexible capacity.

Hitting NZ too soon and way before in 2035 is costly. Building more RES in a market that is not technically capable of accommodating it is costly, so has a CBA been done to see the best trajectory?

The case for change analysis uses the net zero Future Energy Scenarios and the associated capacity mix and build trajectory. The Future Energy Scenarios represent a range of credible ways of reaching the net zero targets. To construct the scenarios, FES determines the right mix of generation, demand and flexibility to ensure the ESO can meet its Loss of Load requirements, and do not principally focus on minimising cost. This means there may be a more optimal build trajectory, however scale and pace of investment will still exist. The Net Zero Market Reform project is looking to assess the market arrangements needed rather than the optimal capacity build trajectories.

Appendix 1: Q&A – Flexibility

The questions have been categorised into General, Investment, Flexibility, Locational and Market Design Options Assessment Framework.

If you would like to discuss any of the answers provided or you have any further questions then please contact simon.targett@nationalgrideso.com

What is your definition of LDES - does it exclude existing pumped storage?

Pumped Hydro Storage is included in all scenarios (up to 4.7GW by 2050 in Leading the Way). Compressed Air Energy Storage (CAES) is included in Leading the Way and System Transformation (up to 6GW by 2050 in Leading the Way).

Other than Hydrogen, no further longer-term inter-seasonal storage is included in the Future Energy Scenarios. Although we do recognise and currently have a dedicated workstream exploring the potential for LDES to manage energy imbalances cost-efficiently.

For the additional low load factor firm capacity that will be needed, do you have some analysis of the likely distribution of dispatch durations?

The analysis we undertook considered the average online hours per start as a measure of the distribution of dispatch duration.

In the Leading the Way scenario, the maximum online hours per start roughly halves between 2025 and 2030 from around 40 hours to 20 hours per start.

By 2050 average online hours per start are broadly consistent across the first 30GW of flexible capacity at around 5 hours per start.

What price of H2 is assumed in the production of H2 from electrolysis?

The hydrogen price was based on the assumption that blue hydrogen is the marginal source (so driven by gas and to lesser extent carbon price) . Within the commodity price section of the [FES data workbook](#), there is more detail on the gas and carbon price assumptions.

In the presentation you outlined huge need for demand side flex - is this necessary - what are the consequences if huge demand side flex does not emerge?

If demand side flexibility is not deployed to the levels required across the scenarios the likely consequences include 1) significant levels of renewable curtailment and 2) increased price cannibalisation.

Excess generation is projected to increase to as much as 400TWh (as shown on slide 16) in 2050 in the Leading the Way scenario. High levels of demand side flexibility can mitigate the risk of substantial renewables curtailment in periods of excess generation.

The impact of flexibility on wholesale price cannibalisation can also be seen in the sensitivity analysis on slide 11 with the removal of 58GW of electrolysis reducing the wholesale price by one-third.

Appendix 1: Q&A – Flexibility

The questions have been categorised into General, Investment, Flexibility, Locational and Market Design Options Assessment Framework. If you would like to discuss any of the answers provided or you have any further questions then please contact simon.targett@nationalgrideso.com

What policy support is assumed for Hydrogen production, as that will limit electrolysis numbers?

The FES takes into account all policy drivers when estimating the new technologies likely to be implemented within their scenarios. Currently the most relevant policy driver for hydrogen is the UK Hydrogen Strategy published in August, which built on the commitments from last year's 10 Point Plan, and clarified that hydrogen is a key element in the plan to deliver net zero. This was backed up by a combination of some of the following areas of policy:

- Firm targets (e.g. 5GW of low carbon hydrogen production by 2030)
- Support for 'first of a kind' projects via the Net Zero Innovation Portfolio
- Dedicated funding (e.g. £240m of government co-investment in production capacity through the Net Zero Hydrogen Fund)
- Longer term revenue support via the Hydrogen Business Model
- Demonstration projects increasing in size over the period from 2023 to support demand creation

How do falling load factors and rising need for intermittent/scheduled generation square with your view of falling wholesale pricing? I've seen others saying the two will balance

It's important to note that the wholesale prices presented are not a forecast but instead a projection based on current market conditions and delivery of the technology mix as assumed in the FES scenarios.

The Consumer and System Transformation scenarios do see a continued fall in wholesale prices out to 2050 in parallel with the increasing zero-margin cost intermittent generation. In contrast, in the Leading the Way scenario the wholesale price initially falls but trends back upwards through the 2030s due to significant deployment of flexible technologies increasing overall demand levels.

The impact of flexibility on the wholesale price can also be seen in the sensitivity analysis on slide 11 with the removal of 58GW of electrolysis reducing the wholesale price by one-third.

Appendix 1: Q&A – Flexibility

The questions have been categorised into General, Investment, Flexibility, Locational and Market Design Options Assessment Framework. If you would like to discuss any of the answers provided or you have any further questions then please contact simon.targett@nationalgrideso.com

What is the assumption on flexibility on electrolysis plants? E.g. said plant may have long term contracts to supply H2 somewhere else

According to the FES assumptions, electrolysis plant operation is based around the relative price of hydrogen and electricity. Electrolysis plant is assumed to operate when production of hydrogen is profitable.

Should long duration storage to alleviate constraints be more seriously considered as an alternative to network reinforcements and to support flex need?

Storage to help mitigate constraint costs is being seriously considered. The wider ESO are currently working with consultants DNV to understand how much storage could, cost-effectively, reduce constraint costs by between now and 2030. This is not as an alternative to network reinforcement, but an addition that could be delivered faster than network reinforcement. We expect to have the results of this analysis by the end of the year and will discuss the results with stakeholders soon. In the longer term the NOA process could potentially consider storage as an alternative to network reinforcement as it doesn't currently.

A few times it was mentioned that we need a lot more flexible capacity in the future - what are the implications for change? Do we need a targeted intervention to support storage across all durations?

The specific implications for change will be explored in our 3rd phase of work. We acknowledge the need for increased flexibility and note flexible technologies face declining load factors and potentially declining clearing prices in ancillary service markets from our analysis. Consequently, we have identified flexibility as a key market design element in our assessment framework. Options we have identified for assessment in Phase 3 will consider all technologies needed for net zero including all durations of storage.

How do your projections work with long duration electrical storage such as Form Energy's LD Iron:Air battery? Wouldn't that put a floor under negative prices and a cap on positive prices?

The FES scenarios do not include Iron:Air rust battery storage, however like any form of storage by arbitraging between low and high price periods it will act to stabilise prices in extreme periods of excess generation or excess demand.

Appendix 1: Q&A – Flexibility

The questions have been categorised into General, Investment, Flexibility, Locational and Market Design Options Assessment Framework. If you would like to discuss any of the answers provided or you have any further questions then please contact simon.targett@nationalgrideso.com

How can you avoid blackouts without untested and undeployed month long hydrogen storage?

The FES scenarios represent 3 credible pathways to net zero. Hydrogen as long-term storage is present in all the net-zero scenarios to differing degrees. Leading the Way in particular has significant electrolysis, hydrogen storage and hydrogen generation (which requires 22TWh of hydrogen by 2050). This loop creates an important longer-term storage of energy.

All scenarios also rely on other technology types to ensure security of supply is maintained. The FES team have carried out extensive analysis to ensure they have identified the most credible options in the future technology mix.

We will continue to consider how markets are best placed to deliver an appropriate asset mix in the third phase of this project.

Could the ESO estimate oversupply as part of the FES? The volumes of excess RES are likely to be significant and managing these will be key to support the development of additional RES capacity.

The FES dispatch analysis takes into account oversupply of renewable output from an energy perspective (i.e. where this output may need to be curtailed for energy rather than network reasons).

At times when there is high renewable output we expect the market price to reduce and provide a signal for demand such as EVs to ramp up, storage to fill and interconnectors to export. As we can still sometimes see oversupply despite these actions, the scenarios also see hydrogen production via electrolysis increasing at these times so that the excess energy can be stored for future use – either converted back to electricity or to meet direct hydrogen demand elsewhere in the energy system.

There may be some periods where it remains more economic to curtail this excess output rather than invest in additional electrolyser capacity (e.g. if the load factors are too low) but, in general, the FES scenarios seek to ensure security of supply primarily whilst limiting curtailment where possible.

Appendix 1: Q&A – Location

The questions have been categorised into General, Investment, Flexibility, Locational and Market Design Options Assessment Framework.

If you would like to discuss any of the answers provided or you have any further questions then please contact simon.targett@nationalgrideso.com

Do constraint costs include thermal constraints, voltage and inertia spend in the BM as well as specific market products (Pathfinders)? And what about the risk of NOA reinforcements changing?

The graph on p.13 of the [interim report](#) shows costs of system actions taken in the BM to avoid thermal constraints. The costs do not include voltage, inertia and Pathfinders.

The NOA process recommends optimal network reinforcement decisions on the basis of projected costs; however, these are subject to change in later NOA iterations which will impact constraint costs accordingly.

If we need better locational signals would we not be better doing a bit more command and control than waiting another 10 years for Ofgem to do another TransmiT?

We are conscious there are trade-offs between developing the most optimal market design and implementing reforms to meet Net Zero timescales. To reflect this challenge, we have included Deliverability in our assessment criteria. The appropriate governance and timescales for consultation and implementation of any reforms to locational signals will ultimately be determined by BEIS and OFGEM.

Am I correct in saying that the costs of network congestion are less than 10% that of the costs of new generation/flexible capacity i.e. ~£20bn versus ~£1-2bn?

The annual cost of network congestion, as shown on p. 13 of the interim report, range from £593m - £2.3bn in the Leading the Way scenario. This excludes, however, the cost associated for network reinforcement already designated as optimal under the Network Options Assessment (NOA) process. The most recent NOA report projects the total costs of the projects it recommends for investment to be £13.9bn.

Are you investigating nodal pricing?

Yes we are considering the full spectrum of locational granularity of the wholesale price, from the status quo of a single national wholesale price through to zonal and nodal pricing; see the 'Market Design Options Assessment Framework' section of the Net Zero Market Reform project [publication](#).

Appendix 1: Q&A – Location

The questions have been categorised into General, Investment, Flexibility, Locational and Market Design Options Assessment Framework.

If you would like to discuss any of the answers provided or you have any further questions then please contact simon.targett@nationalgrideso.com

How sensitive are constraint costs to (likely?) delays in transmission reinforcement or long repair times of subsea links?

The NOA process which optimises the delivery of transmission reinforcements seeks to find when a reinforcement provides more benefit in reduced constraint cost than the investment cost. The NOA optimises the delivery date, so that the benefit is realised at the optimal time, and investment is not made ahead of need. In the case of many major reinforcements (such as the East Coast HVDC, and the East Anglia reinforcements) these are termed critical options (in our NOA6 analysis) meaning they start providing benefit on the earliest date the TOs have indicated they can deliver them. A natural extension of this is if they are delayed or unavailable, then there will be additional constraint costs incurred.

On the scale of costs, we see in the NOA that a number of large reinforcements mitigate a large part of the constraint cost towards the end of this decade. Without the reinforcements being available (either because they are delayed, or they are not providing capability due to an outage), then the constraint cost are likely to rise significantly.

Have you considered fully the impact of location of zero carbon generation? Hydrogen and CCUS powered thermal power stations are likely to want to connect at the same locations as OSW and I/C?

To conduct the Network Options Assessment (NOA), ESO considers the volume and locations of zero carbon generation which forms part of the FES scenarios. The future forecast constraints and required network reinforcements that we see then in the NOA are a function of the location of the demand and generation leading to significant north to south flows and flows from offshore wind. In the case of siting generation, the FES uses various sources of data including Crown Estate leasing information about offshore wind.

It is difficult to quantify how the regional distribution of electrolyzers and CCUS affect the NOA6 constraint costs; however, if flexible demand and generation is located in an efficient way then this can help to reduce or alleviate constraints, and change the need for some network reinforcements. This ultimately saves the consumer money. The efficient siting of flexible demand and generation in the future – through market signals, network planning regimes and other mechanisms - will play an important role in how what future network needs to be developed and reduce the overall cost to consumers.

Is a postage stamp approach to TNUoS charges being considered to move away from locational pricing?

Any change to the locational granularity of the wholesale market must be considered in conjunction with the corresponding changes to network charging. In other jurisdictions that have implemented nodal wholesale prices, the locational element of transmission charges has been removed.

Appendix 1: Q&A – Location

The questions have been categorised into General, Investment, Flexibility, Locational and Market Design Options Assessment Framework.

If you would like to discuss any of the answers provided or you have any further questions then please contact simon.targett@nationalgrideso.com

Interesting view about locational signals need. Boundary constraint costs are increasing exponentially at £10m/d now handsomely paying off already subsidised wind so is mkt splitting needed?

Zonal pricing (effectively market splitting) is one of the options we are taking forward for further consideration in phase 3.

Given the likely need for renewable capacity in Scotland to hit CB6/net zero, is there a risk that if sales prices are discounted by locational dispatch signals this undermines the investment needed.

We have identified the trade-off between lower constraint and network costs, and lower costs of generation at the network periphery, as a key part of our assessment of locational market design options. We will be exploring the ramifications of different options in Phase 3, including the potential impact of locational dispatch signals on intermittent RES at the network periphery. We welcome stakeholder evidence in this area.

Can you provide an update on the 5 Point Plan for Constraint Management? (Benefit from storage for this problem against other options is specifically being investigated here).

Storage to help mitigate constraint costs is being seriously considered. We are working with consultants DNV to understand how much storage could cost-effectively reduce constraint costs by between now and 2030. This is not as an alternative to network reinforcement, but as something additional that could be delivered faster than network reinforcement. We expect to have the results of this analysis by the end of the year and will discuss the results with stakeholders soon. In the longer term the NOA process could consider storage as an alternative to network reinforcement, but we don't have the capability to include that in the NOA analysis yet.

For up to date information on the progress of ESO's 5 point plan, please see our [webpage](#).

LMP does not stack up with increased renewable deployment - this should be reflected in the assessment scorecard

The trade-off between ensuring investment in renewable capacity and facilitating cost-efficient dispatch is reflected in our Phase 2 assessment criteria and will continue to be an area of focus in Phase 3.

Appendix 1: Q&A – Location

The questions have been categorised into General, Investment, Flexibility, Locational and Market Design Options Assessment Framework. If you would like to discuss any of the answers provided or you have any further questions then please contact simon.targett@nationalgrideso.com

You noted the locational assessment was not part of the modelling. How have you concluded the relative weight of higher constraints costs vs investor confidence for instance?

Our assessment criteria include 'Value for Money' and 'Investor Confidence'. We recognise the interaction between these objectives, however our Phase 2 analysis does not suggest an explicit relative weighting. Phase 3 aims to produce further evidence to inform the relative magnitude of these factors.

One of the issues identified by the TNUoS regime is volatility of charging. This could be fixed through providing fixed TNUoS to align with CM/CFD periods similar to FTRs under a nodal scheme

Fixed TNUoS charges that align with CM/ CfD periods would reduce tariff volatility; however, this would be at the expense of a significant reduction in cost-reflectivity, given the fast-changing generation background used to calculate TNUoS charges. Cost-reflectivity of charges is crucial to incentivise efficient siting of assets.

What is the trade-off between constraint payments and increases to the wider tariff?

Increasing investments in transmission capacity (the cost of which is recovered via the wider TNUoS tariff) can help to reduce constraint payments. This trade-off is already optimised via the ESO's Network Options Assessment (NOA) process.

The full trade-off is three way: by increasing the wider TNUoS tariff you may reduce investment in intermittent RES at the edge of the network, where generation costs are lower. Phase 3 will attempt to quantify the relative orders of magnitude of this trade-off.

How would you envisage a nodal wholesale market working and how would it interact with current services on offer?

Our Phase 3 work will include developing potential models for how the different market design options could work in a GB context. We intend to share the results of this analysis in Spring 2022.

Appendix 1: Q&A – Market Design Options Framework

The questions have been categorised into General, Investment, Flexibility, Locational and Market Design Options Assessment Framework. If you would like to discuss any of the answers provided or you have any further questions then please contact simon.targett@nationalgrideso.com

Do you need to also determine nature of investment signal for flexibility as a 2nd order element?

We will continue to review our framework through Phase 3, and in particular will be considering different dimensions of each of the Market Design Elements. As our framework matures we may introduce more second order Market Design Elements.

Do you think that zonal and nodal prices would reduce investment uncertainty? And if not how do they deal with the investment challenge of uncertainty?

In the current market design, investors face both uncertain wholesale prices and uncertain network charges. According to international precedents, nodal pricing could be introduced in conjunction with flat network charges, reducing one driver of uncertainty. While nodal prices may be volatile, they would not be subject to the same methodological risk as is the case for current TNUoS charges.

Given the level of central planning should there not be an option in the mix with less locational pricing and more locational planning taking into account political issues?

We recognise that there are political considerations surrounding the locational element in electricity market design; however, these are outside of the scope of this assessment.

Any change to the strength and nature of locational signals must be justified on the basis of the 3-way trade-off between exploiting low generation costs, reducing transmission network reinforcement costs, and avoiding network congestion costs.

Which assets do you see responding to zonal prices via changing dispatch?

Any form of dispatchable asset will be able to respond to zonal prices. While the majority of dispatchable capacity is currently generation, in the future, demand-side assets will be a valuable source of flexibility. Key enablers such as more granular temporal signals in retail tariffs are needed to accelerate the greater contribution of demand side flexibility.

Appendix 1: Q&A – Market Design Options Framework

The questions have been categorised into General, Investment, Flexibility, Locational and Market Design Options Assessment Framework. If you would like to discuss any of the answers provided or you have any further questions then please contact simon.targett@nationalgrideso.com

Will your report give the detail behind the conclusion that short term stacking will not deliver the investment certainty required to deliver security whilst there is a clear direction to invest in very large amounts of non-firm/non-flex capacity?

Who did you talk to exclude short term revenue stacking? Sounds like you ignored a part of the market and only talked to one technology type!

Please could you explain again why you eliminated short-term revenue stacking? Main reason seemed to be investor confidence, but that means more consumer risk?

In your AS session this morning, it was all about moving to short term flexibility markets. How does your conclusion on the need for longer term markets align with this?

For the avoidance of doubt, we are not proposing the exclusion short-term revenue stacking as part of holistic net zero market design. We are proposing on the basis of our preliminary traffic light assessment that short-term revenue stacking only will not be adequate to ensure the scale and pace of flexible capacity required to facilitate net zero at lowest cost. In other words, short-term revenue stacking will continue to be an important vehicle for flexibility procurement in future, but will need to be supplemented by other procurement mechanisms. This preliminary conclusion is subject to review in Phase 3, which will include a more detailed assessment of each option for this market design element.

We talked to over 250 stakeholders in our workshops during Phase 2 of the project, from a wide range of stakeholder categories including flexible asset owners and flexibility providers.

How would central dispatch make choices between carbon-based and low/no-carbon generation, simply on merit order, ie price per MWh?

Under the precedent of the E&W Electricity Pool pre-2001, dispatch decisions were made according to a constrained schedule which adjusted the unconstrained merit order to co-optimize for reserve and unit commitment. In theory, constrained schedules could also take into account carbon. This market design element will be assessed in greater detail in Phase 3, including a consideration of the principles underpinning dispatch algorithms.

Appendix 1: Q&A – Market Design Options Framework

The questions have been categorised into General, Investment, Flexibility, Locational and Market Design Options Assessment Framework. If you would like to discuss any of the answers provided or you have any further questions then please contact simon.targett@nationalgrideso.com

Have you done much assessment of how the 'short term market revenue stacking model' will change in future for flex? Growing uncertainty that this will be a long lasting business model for flex.

Yes, our analysis looked at different projections for flexible assets' market revenues. We concluded that the combination of low load factors for flexible assets and static or declining revenues from wholesale, ancillary service and balancing markets may make it increasingly challenging for flexible assets to maintain their investment case without additional support mechanisms. Phase 3 will consider the alternative options we have identified for securing investment in flexible capacity which include long term contracts, joint procurement of firm and flex and bespoke arrangements.

Bespoke arrangements sound like continuation of the non-level playing field approach applied by the ESO (which leads to higher costs to consumers)?

We have identified a wide range of options for each market design element. Bespoke arrangements are just one of the options identified, which also include a very market-based determination of the low-carbon and firm capacity mix, such as a Broad Investment Mechanism. Phase 3 will assess all these options in greater detail, having already identified the impact on costs to consumers as an important assessment criterion.

In terms of assessing market design options, at what point are you seeking to bring in the finance/investor perspective to understand the risks associated with various existing, new, novel tech.?

We have specifically included investor confidence as one of our market assessment criteria and we are extremely keen to hear feedback from the investor community. Several investors attended our workshops over the summer, and we have several events targeted at investors planned for phase 3. Please sign up [here](#) if you would like to be a part of our ongoing engagement work.

Appendix 1: Q&A – Market Design Options Framework

The questions have been categorised into General, Investment, Flexibility, Locational and Market Design Options Assessment Framework. If you would like to discuss any of the answers provided or you have any further questions then please contact simon.targett@nationalgrideso.com

On the flexibility RAG, does this mean you will move away from the current day ahead procurement and back to long term contracts that we used to have but longer still?

No, short-term markets will continue to be fundamental to how ESO operates the electricity system. Our Case for Change analysis suggests that revenues from short term markets only (even when stacked) will be insufficient for incentivising the required level of investment in flexibility.

Surely competition problem for only short term flexibility stacking is it overly favours existing assets with limited CAPEX requirement? Not sure it's anything to do with firm v non firm

We acknowledge that STMR stacking may favour existing assets. One of the options we have identified for the flexibility market design element is the joint procurement of firm and flex capacity. As part of Phase 3, we will be further assessing the potential of this option to create more of a level playing field between existing assets and new assets with high capex requirements.

Is shorter settlement period (e.g. 5 min) relevant to these packages?

We will be considering settlement period duration in further detail in Phase 3. We have identified settlement period duration as a second order market design element as we believe that it would most efficiently be considered following a decision on the optimal locational granularity of the wholesale price.

Presuming that zonal or nodal dispatch would discount wholesale power prices for generators in northern parts of GB, what would it do to consumer prices in the south?

During periods when the system is unconstrained, there would be no price differential between zones. During periods of constraint, however, zonal or nodal dispatch would result in a potentially significant cost differential between locations. This differential would reflect the relative cost of marginal generation between zones or nodes. Aurora Energy Research has done some analysis which suggests that the differential could average around £10-£12/MWh between North and Southern zones (Aurora ER for Policy Exchange, p.9; [link](#)) from 2030-2050.

The impact on consumer prices in the South will depend on additional policy decisions on the extent to which lower average wholesale prices in the South should be passed on to customers. It may not be inevitable that the full extent of the differential would be passed on to all customers.

Appendix 1: Q&A – Market Design Options Framework

The questions have been categorised into General, Investment, Flexibility, Locational and Market Design Options Assessment Framework. If you would like to discuss any of the answers provided or you have any further questions then please contact simon.targett@nationalgrideso.com

Is it correct that nodal pricing creates locational market power? Doesn't it just expose locational market power that is currently exercised in the BM?

Any locational market power that already exists in the market could be exercised in the Balancing Mechanism but is somewhat opaque. Phase 3 will assess the potential of nodal pricing to improve the transparency of market concentration, expediting investment in locations where there is market power. It will also assess evidence from jurisdictions which have implemented LMP and instituted market monitoring to address market power issues.

Have you considered the role of Residential DSR?

The potential role of DSR has been considered in phase 2:

1. The LCP modelling work took the FES technology mix projections, which include residential DSR assumptions, as an input.
2. Our 'Whole System' assessment criterion was included to ensure that future markets facilitate option solutions across different voltages and energy vectors.

We will continue to consider through Phase 3 how net zero markets are maximally accessible to residential-scale flexibility providers.

Are there any suggested timelines for LMP implementation? What's realistic and viable in terms of timelines and costs of implementing LMP

We will consider different forms of implementation of LMP as part of Phase 3. The feasibility of implementing LMP alongside achieving zero carbon operation will be a major focus and deliverability will be one of the assessment criteria.

Is it worth disaggregating flexibility market arrangements given the sheer range of role (i.e., time horizons), likely solutions and underpinning technologies and investment cases?

We will continue to review our framework through Phase 3, and in particular will be considering different dimensions of each of the Market Design Elements. The wide variation in characteristics, including the commercially viable time-horizon, of different storage technologies, will be an important consideration in Phase 3 of the project.