May 2022

Net Zero Market Reform

Phase 3 Assessment and Conclusions

nationalgridESO

Navigation

This version of the Net Zero Market Reform document has been optimised for printing out or viewing on a tablet.

Page navigation explained

Back a page

Forward a page

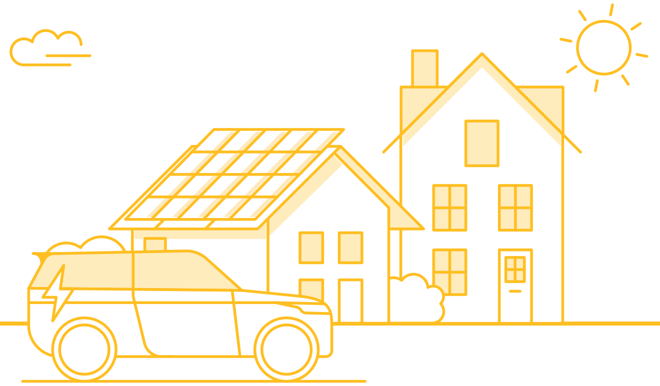
Return to contents

From here you can navigate to any part of the publication

Text Links

Click highlighted orange text to navigate to an external link. Or to jump to another section of the document

Contents



Foreword

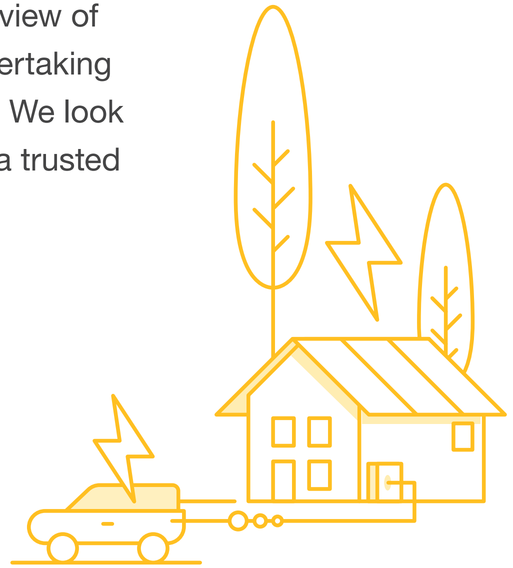
I am delighted to publish the findings from Phase 3 of National Grid ESO's Net Zero Market Reform programme of work. Net zero is the challenge of our generation, and industry and government are united in our ambition to achieve it.

Reflecting on the last year, and on the huge amount that has been done in this programme, one must think of the work in the context of the environment we are in. We are living through an energy and affordability crisis, worsened by Russia's terrible war in Ukraine. We simply cannot be complacent and assume that net zero will happen at any cost – we must do all we can to ensure an affordable and fair transition for all consumers. Well-functioning markets are key to achieving this, by delivering clear market signals to create the right balance of efficient investment and efficient dispatch. Our evidence shows that the current market design will simply not achieve this outcome.

Cian McLeavey-Reville
Markets Development Senior Manager,
National Grid ESO

In this publication we have focused on assessing the operational elements of market design: location and dispatch. These are initial findings, based on substantial analysis and stakeholder engagement. We have had over 1,500 stakeholder interactions over the course of this programme to date. I am thrilled with this level of engagement, and the positive feedback for ESO's strong independent voice in driving the debate forward in this area. Input from our stakeholders through our co-creation workshops, webinars, surveys and discussions has been crucial throughout this programme. As we move into the next phase of examining in greater detail the areas of focus in our initial conclusions, and the wider complimentary reforms required, it is vital that we continue to work even more closely with our industry partners.

There is much more work to be done prior to any decision on reform of the operational market design, and the ESO will not be the ultimate decision-maker. BEIS has recently announced its Review of Electricity Market Arrangements and Ofgem are undertaking a technical assessment of locational market options. We look forward to working closely with BEIS and Ofgem as a trusted strategic partner in both of these projects.



Net Zero Market Reform / Foreword 04

Executive Summary

In Phase 3 of our Net Zero Market Reform programme, we have identified four fundamental issues that illustrate why the status quo market design is not set up to deliver net zero cost-effectively:

1. Constraint costs are rising at a dramatic rate
2. Balancing the network is becoming more challenging and requires increasing levels of inefficient redispatch
3. National pricing can sometimes send perverse incentives to flexible assets, that worsen constraints
4. Current market design does not unlock the full potential of flexibility from both supply and demand

Our assessment found that the four issues outlined above are arising because GB's existing market, where wholesale market trading does not account for the physical limits of the electricity system, was not designed for the net zero transition.

To solve these problems in an effective and enduring manner, net zero market reform must at its heart address how wholesale markets deliver signals for assets to dispatch where and when it is best for the whole system. For this reason, our Phase 3 assessment has focused on the 'operational' aspects of market design: Location (the locational granularity of the wholesale price) and Dispatch (which determines when assets should generate or consume and at what capacity). Of course, these elements are only part of the wider net zero market design framework that we developed in Phase 2. The next stage of analysis will advance our thinking on these other aspects of market design, not least those needed to deliver investment for timely decarbonisation of the power sector.

We have assessed the options we previously identified in Phase 2 for the location and dispatch market design elements against our assessment criteria.

Our assessment found that real-time, dynamic locational signals are needed to inform how both supply and demand assets dispatch in operational timescales. Neither national nor zonal pricing can deliver efficient locational signals as GB transitions to a net zero energy system. In a high renewables system, the value of energy varies significantly depending on the time and location. A single national price with locational network charges obscures the locational value of energy in operational timescales, leading to inefficient market outcomes and avoidable network congestion. Zonal pricing would not be an efficient and enduring solution, as the fast-evolving nature of the GB electricity system would require zone boundaries to be both granular and adaptable to changes in congestion dynamics. This would be highly challenging to achieve and would add significant regulatory risk to market participants.

Net Zero Market Reform / Executive Summary 05

Executive Summary

Our assessment found that nodal pricing offers superior outcomes for Value for Money, Consumer Fairness, Adaptability and Full Chain Flexibility. Incorporating locational value into the wholesale energy price through nodal pricing enables congestion to be resolved as part of the market clearing process rather than by the System Operator via redispatch. This delivers considerable efficiency and innovation benefits. It also shifts some financial risk to market actors that are best placed to manage it. Evidence shows this would provide value for money by enabling more efficient utilisation of existing infrastructure, particularly flexible assets, substantially reducing GB's network congestion costs in operational timescales. Over time, substantial whole system cost savings and benefits would be realised through more efficient siting of generation, storage and demand as well as reduced network build.

When GB's self-dispatch model was originally introduced, ESO's role as residual balancer was expected to reduce. The reverse has been happening over the last decade as ESO redispatches an increasing proportion of the market but without the appropriate market infrastructure and tools. The status-quo self-dispatch design does not appear to be an enduring solution for a net zero future without substantial investment or reform.

Our assessment found that central dispatch with self-commitment offers superior outcomes relative to self-dispatch for Value for Money, Adaptability, Full Chain Flexibility and Competition. Central Dispatch would enable the full resource of the wholesale market to be efficiently deployed to meet balancing requirements by co-optimising energy and reserves and levelling the playing field for all types of energy resource and market actor, including new entrants and non-traditional resources such as demand response.

The capability of nodal pricing combined with central dispatch to unlock major efficiency savings is synergistic, with nodal pricing enabling markets to coordinate supply and demand at each node and central dispatch enabling balancing of the system as a whole using the full diversity and capabilities of available energy resources. Both nodal pricing and central dispatch with self-commitment scored highly for Adaptability, with the highest potential to provide an enduring solution for net zero. Nodal pricing enables changes in supply, demand and network conditions to be automatically reflected in nodal prices and Financial Transmission Rights (FTRs), and it can be extended to lower voltages in time or combined with alternative options. Central dispatch was assessed to be adaptable for net zero as it would enable greater competition and innovation across the energy resource base with co-optimisation of energy and reserves, greater transparency and the flexible option of self-commitment.

We think it is credible to implement nodal pricing and central dispatch within five years. There are some key questions that remain to be answered such as what additional market reforms are required to complement nodal pricing. There are also legitimate stakeholder concerns that must be investigated further, such as how nodal pricing would impact different cohorts of market participants, and to what extent different consumer segments should be exposed to locational price signals. We will be tackling these questions in the next phase of the programme, whilst supporting Ofgem on their technical assessment of locational market options and BEIS on their Review of Electricity Market Arrangements.

Net Zero Market Reform / Executive Summary 06

Net Zero Market Reform as part of the bigger picture

We see the market reforms outlined in this document as an enduring foundation for long-term net zero market design; however, reforms of this scale must not preclude actions in the shorter term to improve the status quo design. Similarly while market reform is crucial to achieve net zero cost-effectively, it is vital that we do not consider markets in isolation from other key workstreams.

Net Zero Market Reform / Net Zero Market Reform as part of the bigger picture 07

Net Zero Market Reform as part of the bigger picture

1) Ensuring the right network development: pace and coordination of investment is critical

The scale of investment in transmission infrastructure required to facilitate net zero is unprecedented: last year's Networks Options Assessment (NOA) recommended >£16bn investment in new onshore transmission assets over the next 20 years, and this will only grow due to the further increases in renewable generation forecast by FES 2021.

Connecting 50GW of offshore wind by 2030 will have an enormous cost impact as well as broader societal impacts on coastal communities and the environment that need to be carefully managed. We are delivering work as part of the BEIS-led Offshore Transmission Network Review (OTNR) to design a more coordinated network to support the delivery of offshore wind targets with the aim of better optimising the costs and benefits.

The ability to connect new generation currently exceeds the pace at which the industry can approve, consent and deliver major transmission projects. This means that, unless we develop ways of speeding up the delivery of transmission infrastructure, the constraint costs that would most efficiently be mitigated by network reinforcement will continue to rise beyond their optimal level. The ESO is collaborating closely with Ofgem on their Electricity Transmission Network Planning Review (ETNPR) along with the ESO's onshore and offshore network planning reviews. One of our main objectives is to identify strategic investments - both to ensure transmission network capability is there ahead of need and also to identify potential whole energy system optimisations that deliver value.

Identifying and delivering greater levels of anticipatory investment in the transmission system, however, will not change the fundamental goal to optimise the aggregate cost of generation, constraints and networks in order to achieve net zero at lowest overall cost to consumers.

2) Ensuring the right resource mix: capacity adequacy will become a different challenge

A fully decarbonised electricity generation mix in 2035, combined with the significant increase in demand, will present new challenges in ensuring system adequacy. We will be hugely reliant on a much higher penetration of weather-dependent generation (wind and solar), which will drive the need for greater system flexibility. Many of the flexible technologies that we will depend on to balance the system may also be impacted by weather (e.g. storage, interconnectors, demand).

ESO is in the process of undertaking a capacity adequacy study covering the period 2025 – 2040. This will help us better understand the dynamics of a renewables heavy system and inform our view of the standards we need to set to ensure adequacy.

3) Ensuring operability: the system will face increased challenges

As the GB power system decarbonises, there will be a number of engineering challenges that need to be solved, such as low inertia and short circuit levels. The ESO ambition to operate a zero-carbon electricity system by 2025 will solve these challenges for short periods. As the system further decarbonises there will be a need for more of these services. Co-ordinated system operator activities and flexibility markets will be used as standard to manage distribution issues as well as transmission issues.

Net Zero Market Reform / Net Zero Market Reform as part of the bigger picture 08

Net Zero Market Reform as part of the bigger picture

4) Ensuring consumers are at the heart of a just transition

Empowering consumers to participate in net zero is fundamental. For example, our Crowdflex innovation project with Octopus Energy is investigating how much residential consumer flexibility could potentially be unlocked, which will feed into our Net Zero Market Reform analysis on how to unlock it in a fair and efficient manner. Our Virtual Energy System innovation project will also help to model the impact of consumer behaviour in the wider system.

Unlocking the value of domestic demand side flexibility by ensuring it can compete on a level playing field with supply side resources, with access to fair reward, will be a cornerstone of achieving net zero and is integral to our assessment of net zero market design. In parallel, we are working to remove barriers in the current market that prevent domestic demand side response from being aggregated and bid into the balancing mechanism in order to mitigate this issue as much as possible over the shorter-term prior to the implementation of wider market reform.

5) Ensuring a smart, flexible system through digitalisation and data

The sheer complexity of the whole net zero energy system, with smart appliances in homes responding to price signals, millions of EVs and heat pumps, and thousands of decentralised assets taking part in wholesale and balancing markets, means that the digitalisation of processes and systems is vital. Increased data sharing will be needed to provide digital systems with the information needed to optimise markets and control room decision making. A major digital transformation is required, not just for ESO but for the industry as a whole, and it must be coordinated across different voltage levels, energy vectors and economic sectors. Increased visibility of distributed generation and demand will be crucial.

We published our updated ESO Digitalisation Strategy & Action Plan in June 2021, aligned with the recommendations of the Energy Data Taskforce. Transforming our data capabilities is foundational to delivering on our digital objectives, and to the wider digital transformation of the UK's energy sector. Our data transformation involves strengthening our data and information culture, upskilling our people, building new capabilities and ways of working with data, and delivery of our strategic Data and Analytics Platform.

Net Zero Market Reform / Net Zero Market Reform as part of the bigger picture 09

Programme to Date

January 2021 | April 2021 | November 2021 | May 2022

Phase 1:
High level scoping

Phase 2:
Case for Change and Market Design Options Assessment Framework

Phase 3:
Detailed Assessment and Conclusions: Operation (Location and Dispatch) Market Design Elements only

High level analysis of GB market landscape

International case studies

Project scope definition

Case for Change

Modelling inputs

3 net zero scenarios → Weather data (2009 – 2019) → 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

Market Design Options Assessment Framework

Define assessment criteria

Define options assessment framework

Identify design options for assessment

Preliminary assessment; shortlist taken forward to Phase 3

Refinement of Operation market design framework options

Detailed assessment of Operation market design options against criteria

Present conclusions and publish report

Continuation of programme and supporting BEIS and Ofgem in their respective market reform work (see “next steps”)

Net Zero Market Reform / Programme to Date 10

Introduction

Our Phase 2 work concluded that the current market design requires reform to achieve net zero at lowest whole system cost. In Phase 3, drawing upon first-hand evidence relating to the system's performance, we focused on the challenges arising in operational timescales due to inaccurate market signals. We found that the existing market arrangements, established for a different type of electricity system, are increasingly incompatible with the one that is emerging to meet net zero.

Context of the GB status quo design:

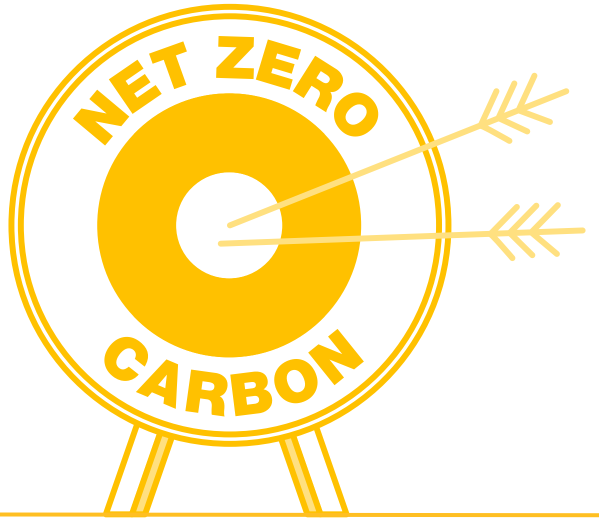
When the existing design (the New Electricity Trading Arrangements or NETA) was established, in 2001, generator location and output was predominantly not dependent on weather resource, and flexible demand was minimal. In this context, the production of near real-time locational signals was not prioritised. NETA is underpinned by generators and suppliers contracting bilaterally, or via spot markets, independently of ESO, under the premise that all generators regardless of location can serve load anywhere in the country. Generators inform ESO up to Gate Closure of their dispatch schedule. The role of the ESO was envisaged to be that of a 'residual balancer': responsible for fine-tuning the dispatch of generation to ensure continuous energy balance and for protecting the limits of the system, but not intervening in a major way.

Net zero implications for near real-time operation:

Since 2001, the proportion of intermittent renewable generation in GB's electricity mix has risen from less than one percent in 2001 to just under 30% in 2020 (DUKES, 2021). The 2021 FES Leading the Way scenario suggests that this could potentially rise to 85% by 2035. A large proportion of this resource is at the network periphery (for example, wind in North Scotland, distribution-connected solar), often far from demand. As weather-driven, non-dispatchable assets, these can, at certain times, congest the transmission network at relatively short notice. Flexibility, the ability to adjust supply and demand to balance the system, is needed to manage intermittency so that electricity can be used when and where it is needed.

The limitations of operating a high-renewables, flexible system under the current market arrangements have already emerged, leading to rising costs and operational issues. We have identified four key issues below:

1. Constraint costs are rising at a dramatic rate
2. Balancing the network is becoming more challenging and requires increasing levels of inefficient redispatch
3. National pricing can sometimes send perverse incentives to flexible assets, that worsen constraints
4. Current market design does not unlock the full potential of flexibility from both supply and demand.



Net Zero Market Reform / Introduction 11

Introduction

Consequences for GB system operation:

Our Phase 3 assessment found that the issues listed above are arising because participants in the GB market are not exposed to locational signals to inform trading decisions in operational timescales. This means that the wholesale market outcome and the physical constraints of the system are increasingly divergent. To maintain reliability, ESO conducts redispatch: it corrects the market outcome via the Balancing Mechanism (BM) amongst other tools. This document discusses why increasing levels of redispatch are leading to inefficient market outcomes and evaluates the extent to which different design options could effectively address these issues.

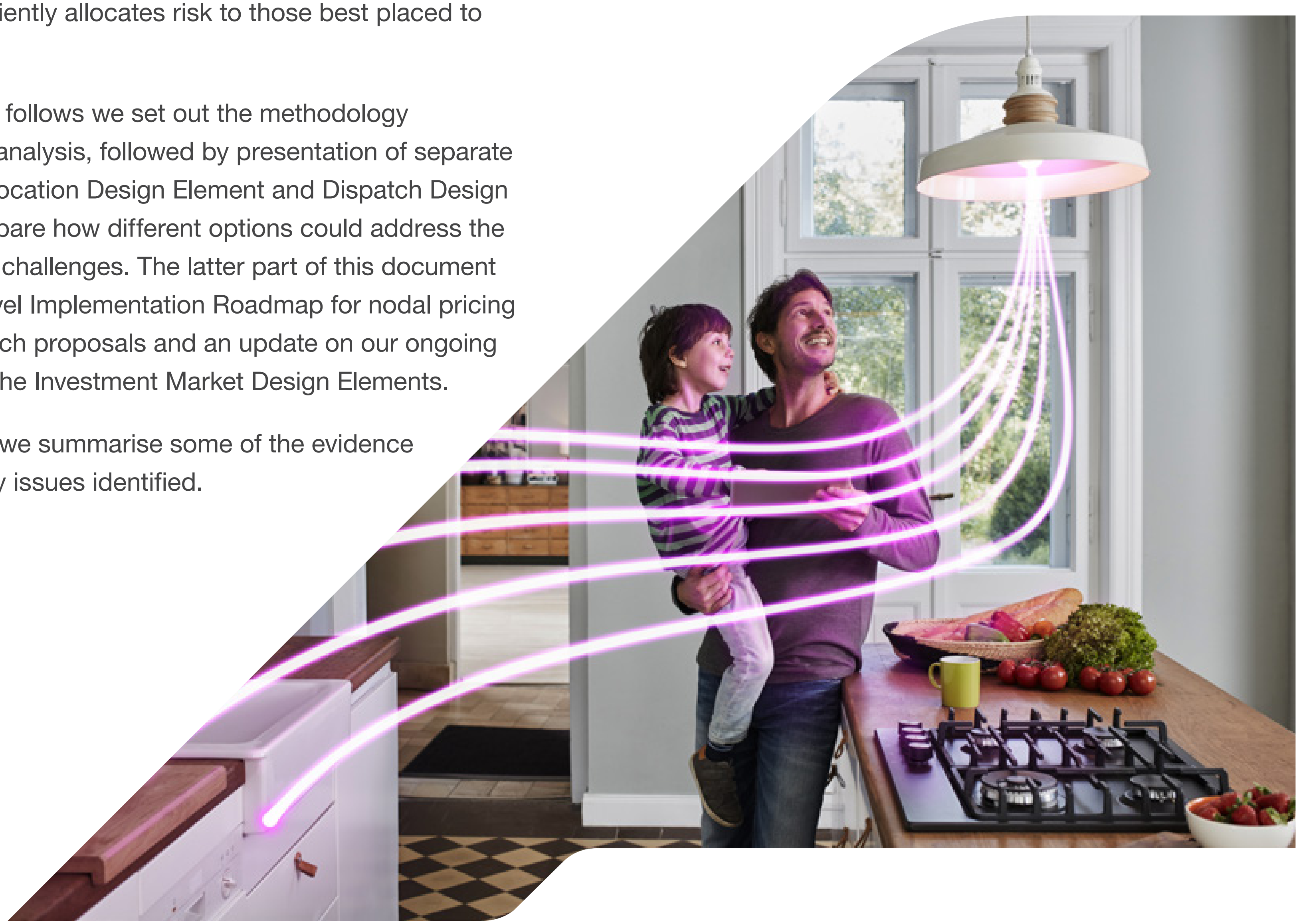
Purpose and structure of this document:

This document explains and presents the evidence for how nodal pricing, combined with central dispatch, would be the most effective option to address these issues by incorporating accurate locational signals into the wholesale price so that the market is able to resolve congestion more efficiently. Working in conjunction, these mechanisms would result in consumers collectively paying less overall for their wholesale energy and have the greatest potential to deliver net zero at least cost.

We also found that, with appropriate implementation design, nodal pricing efficiently allocates risk to those best placed to manage it.

In the section that follows we set out the methodology underpinning our analysis, followed by presentation of separate analyses for the Location Design Element and Dispatch Design Element that compare how different options could address the above-mentioned challenges. The latter part of this document sets out a high-level Implementation Roadmap for nodal pricing and central dispatch proposals and an update on our ongoing work concerning the Investment Market Design Elements.

On the next page we summarise some of the evidence supporting the key issues identified.



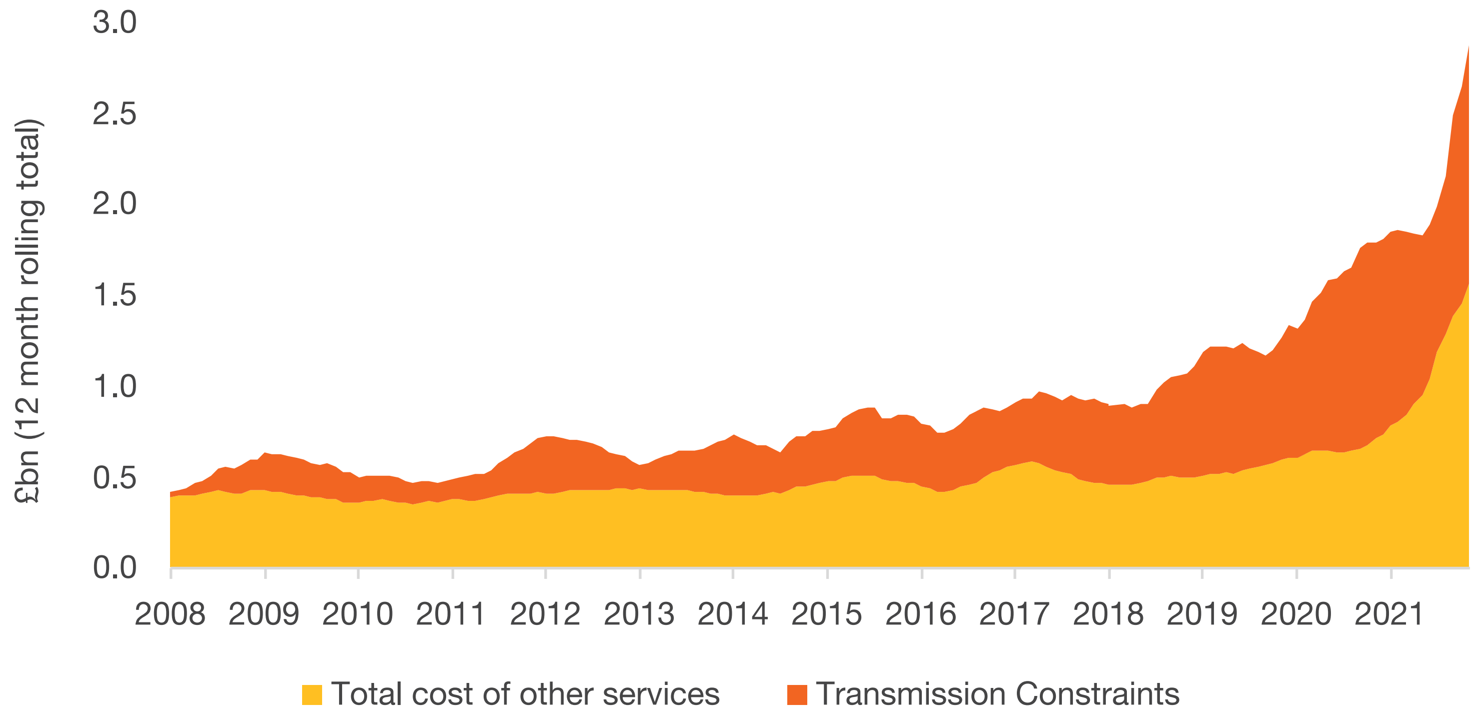
Net Zero Market Reform / Introduction 12

Evidence Supporting Key Issues:

1a.

Despite significant transmission investment, constraint costs have already increased 8-fold since 2010

ESO balancing services costs, 12-month rolling (£m)



The cost of managing congestion on the transmission network has increased significantly: annual transmission constraint costs increased 8-fold from £170 million in January 2010 to £1.3bn in January 2022. (Congestion costs in 2021 were ultimately considerably higher than the NOA 6 forecast of £0.6bn). The premise of the current design, that any generator can serve load at any location, does not reflect the physical reality of the transmission system as, increasingly, at certain times and in certain locations, generation output exceeds network capacity.

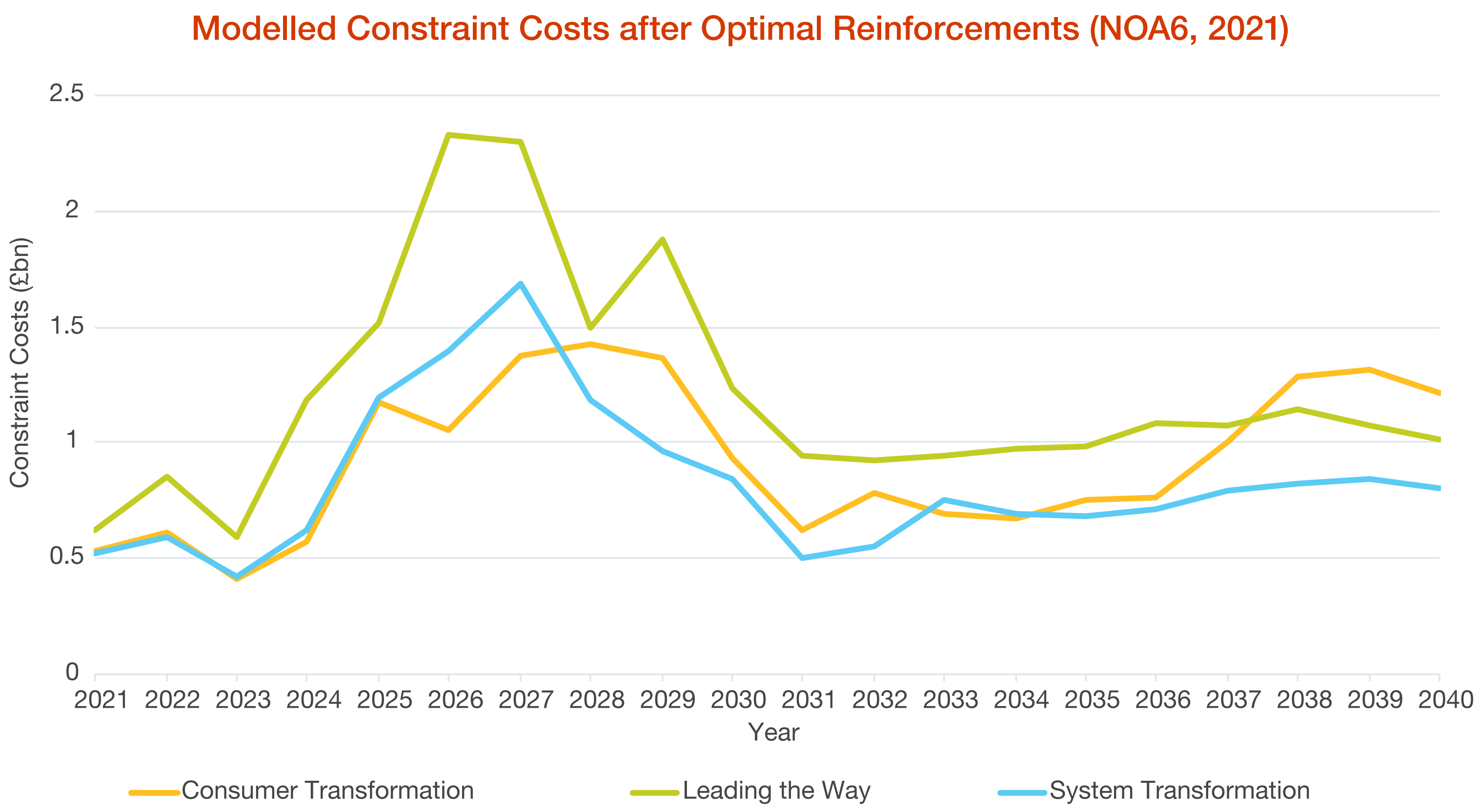
Net Zero Market Reform / Introduction 13

Introduction

Evidence Supporting Key Issues:

1b.

ESO projections indicate continued dramatic growth in constraint costs after optimal reinforcement



Looking forward, ESO projections indicate that transmission congestion costs will rise steeply in the first half of this decade and could reach an annual cost of £2.3bn per year by 2026. Costs reduce in the late 2020s when investments in the transmission network will facilitate the transfer of more renewable generation to southern demand centres, but remain substantially higher than historic levels.

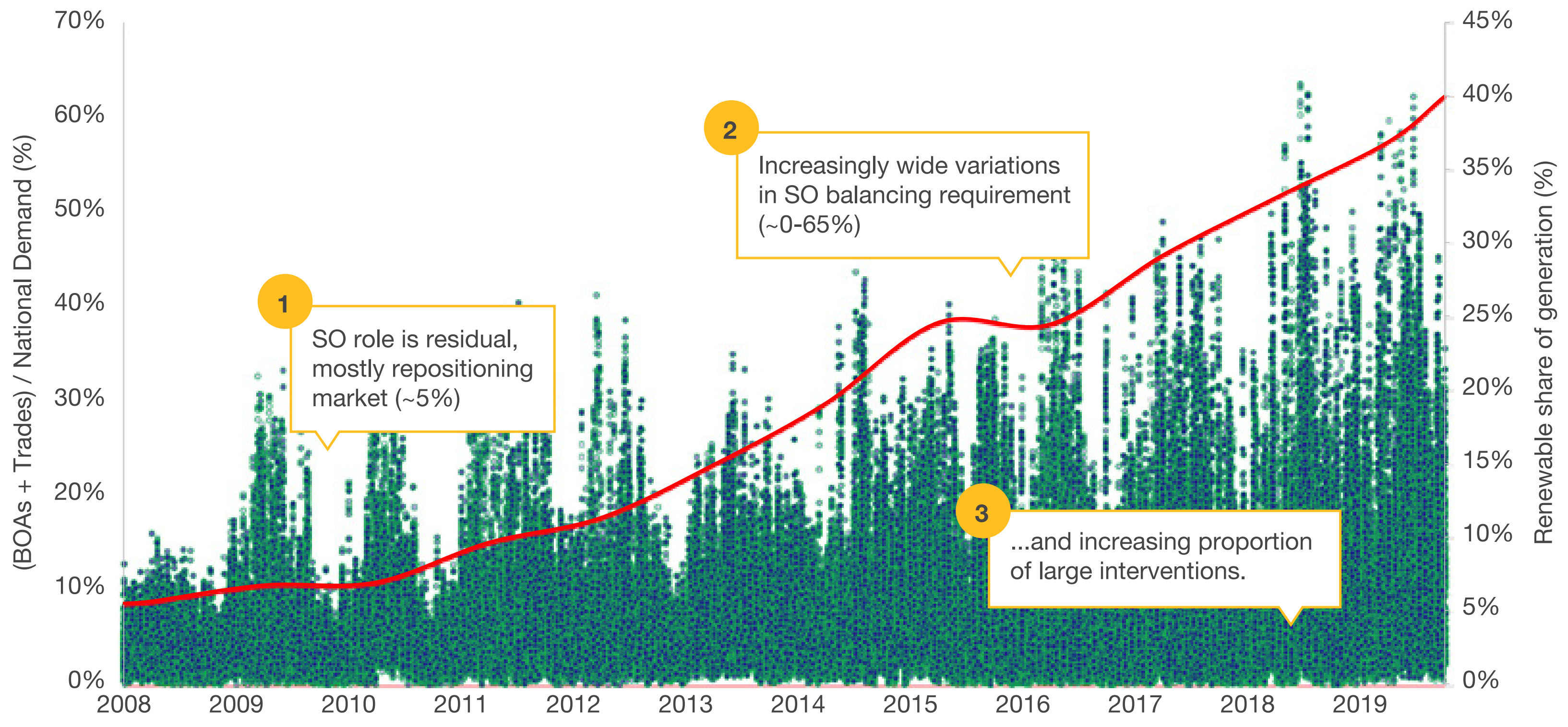
Net Zero Market Reform / Introduction 14

Evidence Supporting Key Issues:

2.

Balancing the network is becoming more challenging and requires increasing levels of inefficient redispatch

System Operator balancing as proportion of national demand (%) vs renewable share of generation



A rapid change in how and where electricity is generated has meant the ESO now frequently redispatches more than 50% of demand, up from around only 10% in 2008. Much of this is to solve the locational constraints arising from renewable energy being transported to demand centres. The ESO is effectively at times acting as central dispatcher but under very condensed gate closure timescales. This undermines the light-touch balancing role envisaged for ESO when the current market design was introduced.

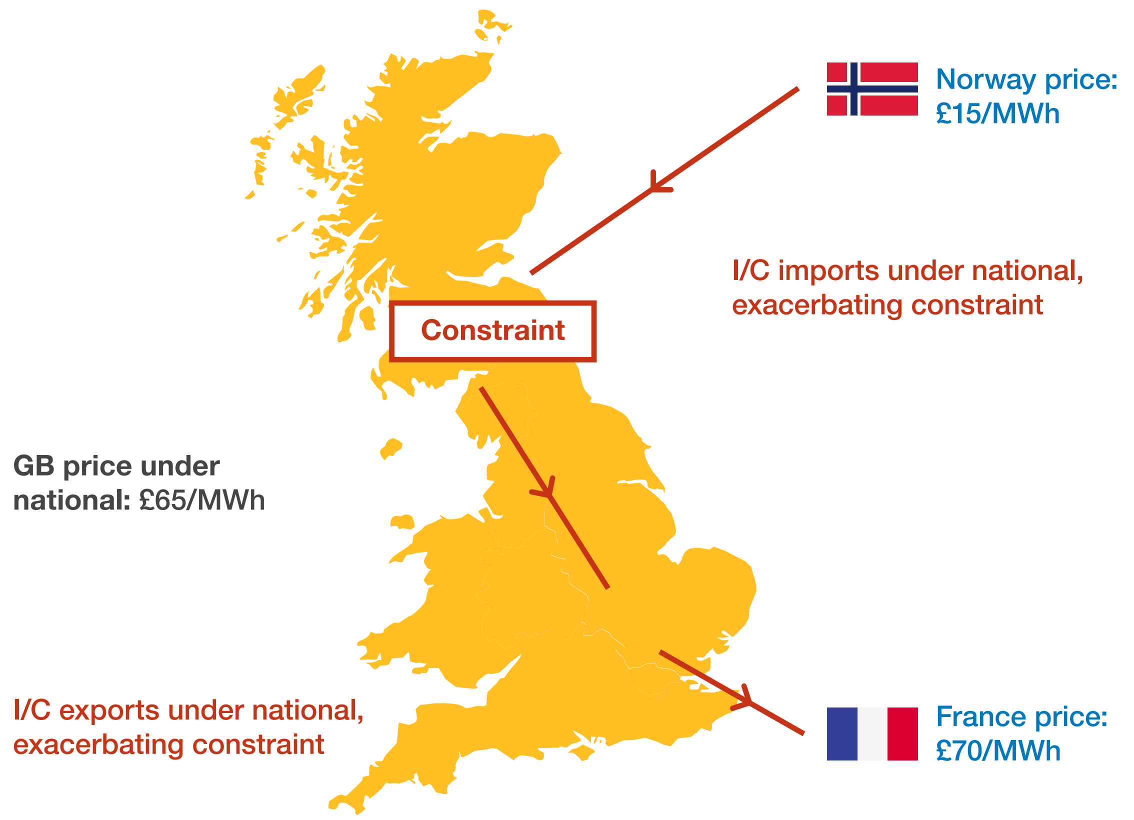
Net Zero Market Reform / Introduction 15

Evidence Supporting Key Issues:

3.

The status quo national price is sometimes providing inaccurate incentives for key technologies

Illustrative interconnector flows under national pricing with North/South constraint (illustrative prices)



Interconnectors and storage are at times incentivised by the current market design to flow in a direction that exacerbates constraints. For example, there are periods when high renewable generation in Scotland causes constraints, but the GB national price is sufficiently high to incentivise interconnectors from the Norwegian market to export into North England. In such circumstances the interconnector aggravates the constraint. A similar dynamic is also seen with battery storage. The issue is likely to grow dramatically in line with substantial projected increases in capacity to 2035 for both technologies.

Net Zero Market Reform / Introduction 16

Introduction

Evidence Supporting Key Issues:

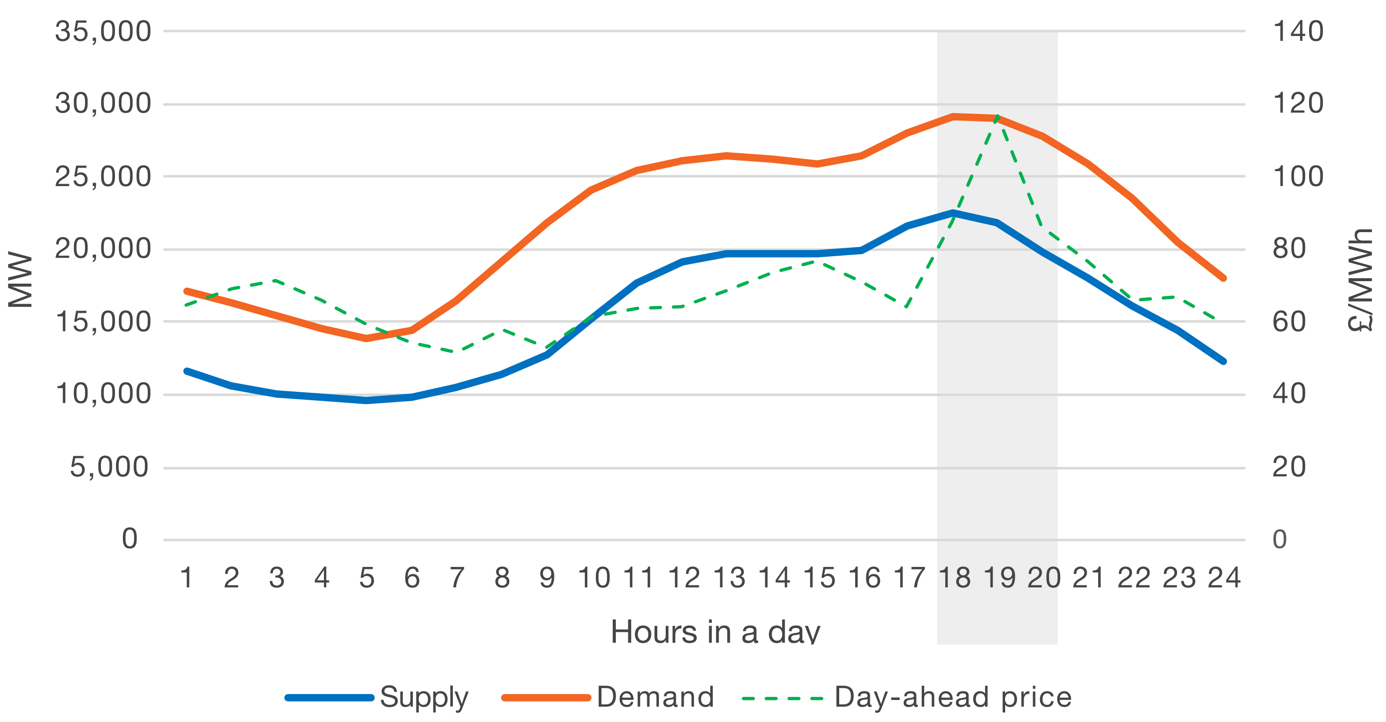
4a.

Current market design does not provide the signals required to unlock the full potential of the diverse range of sources

Illustrative local supply and demand profiles under national pricing with prevailing South constraint

Location in South (Illustrative)

Demand is incentivised to reduce load to address scarcity... (although not as much as it should be)



Under the status quo market design, flexible technologies cannot contribute their full value to the system. The single national price provides an averaged view of supply and demand across the country. This means that flexible assets located behind a transmission constraint receive a dampened signal to 'turn up' to alleviate the constraint. Conversely, assets located in front of a constraint are not adequately incentivised to 'turn down' to avoid exacerbating the constraint.

Evidence Supporting Key Issues:

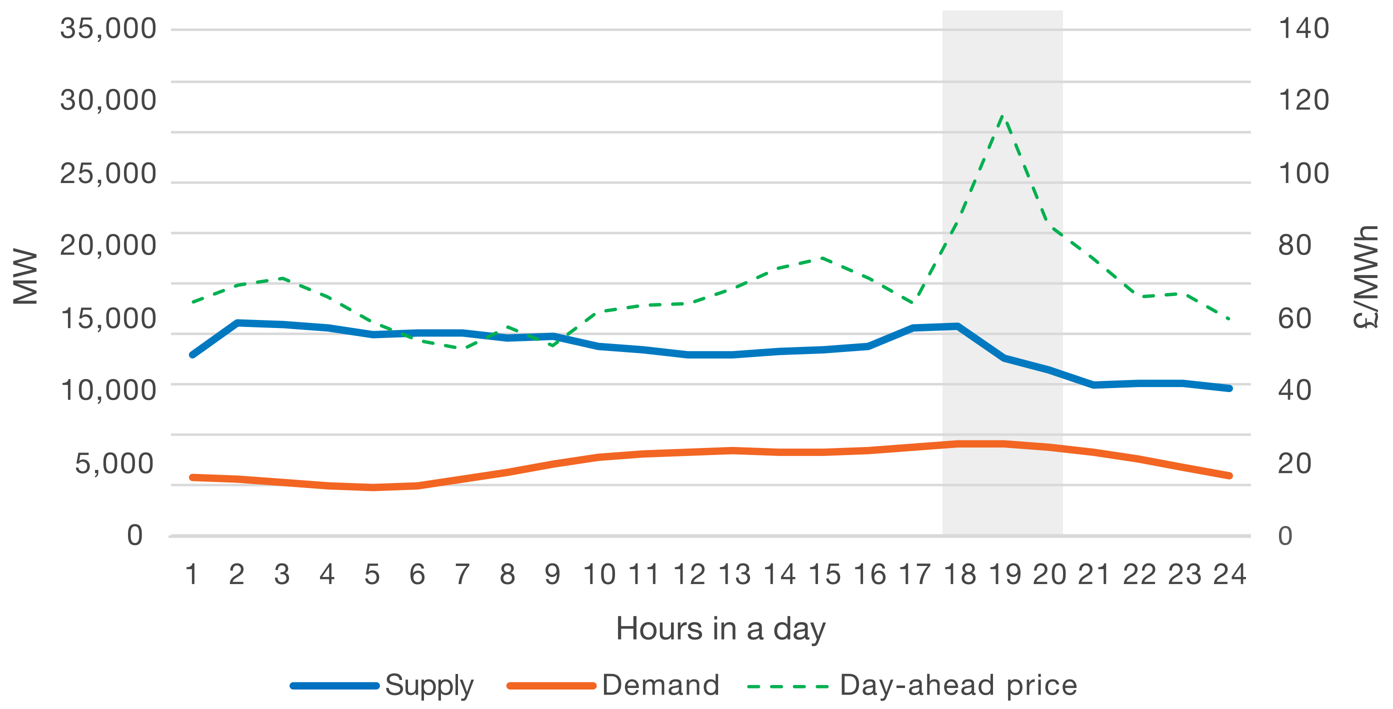
4b.

Current market design does not provide the signals required to unlock the full potential of the diverse range of sources

Illustrative local supply and demand profiles under national pricing with prevailing North constraint

Location in North (Illustrative)

...but low demand location is also incentivised to reduce load despite no scarcity issue ....and at times this exacerbates constraints.



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Net Zero Market Reform / Introduction 18

Approach and Methodology

In the third phase of the Net Zero Market Reform programme, we:

1 Developed our Phase 2 Market Design Options Assessment Framework (A detailed explanation of which can be found in our Phase 2 report).

2 Clarified our assessment criteria

3 Conducted a detailed assessment of the operational market design elements

This work was completed together with our Phase 3 partners FTI Consulting.

A detailed quantification of the potential benefits of nodal pricing and central dispatch in a GB context was not in scope for this phase. Ofgem are currently undertaking a technical assessment of nodal pricing in GB which will include analysis of the costs, benefits and potential distributional impacts.

1 Development of Phase 2 Assessment Framework

In Phase 2, we identified eight key elements of market design, which fell into two broad categories: ‘Investment’ and ‘Operation’. Within each category we determined the appropriate sequence in which to assess the elements based on their main dependencies. This includes identifying elements as first order (1-5) or second order (6-8) priorities.

In Phase 3 we made the following changes:

a) Operation market design elements were assessed first

The requirements for policy interventions to support investment are the product of missing signals provided in operational timescales. Resolving deficiencies in the wholesale market design is therefore a critical prerequisite to addressing the degree and nature of further investment interventions. We have therefore assessed the Operational market design elements before the assessment of the Investment elements.

Our Next Steps details our intentions for assessing the options that fall within the Investment market design elements.

b) New market design options added to the framework:

Following our review and analysis of international jurisdictions we have identified two further market design options which we have added to our framework: a scarcity price adder and flexibility spot markets. More detail on these options is included in the Investment section of the report.

The next page provides an updated view of our assessment framework for Phase 3.

Net Zero Market Reform / Approach and Methodology 19

Approach and Methodology

Updated Assessment Framework

First Order Elements

Operation	1 Location	National wholesale market (with locational network charges)	Zonal wholesale market	Nodal wholesale market	Scarcity price adder	
Operation	2 Dispatch	Bilateral self dispatch		Central dispatch and co-optimisation		
Investment	3 Low Carbon Central Planning	Bespoke arrangements	Inter low carbon tech competition	Broad-based investment mechanism		
Investment	4 Capacity Adequacy	Bespoke arrangements	Traditional Capacity Market		Wholesale price signals only	
Investment	5 Flexibility	Short-term market revenue stacking only	Bespoke arrangements	Long-term flexibility contracts	Joint procurement with firm capacity	Spot Markets

A scarcity price adder would support capacity adequacy but sits in Operation as it is linked to the wholesale price.

Procurement through spot markets cuts across Flexibility investment and ancillary service markets but will be assessed within the latter.

6 Low Carbon Support Mechanism
7 Settlement Period Duration
8 Ancillary Service Market Design

- Indicates predominant status quo arrangements
- Indicates option eliminated in Phase 2
- New option added for Phase 3
- Second Order Elements

Net Zero Market Reform / Approach and Methodology 20

Approach and Methodology

2 Clarification of existing assessment criteria and the addition of full chain flexibility criterion:

In Phase 2, we identified nine assessment criteria for evaluating net zero market design. Specific stakeholder events were held to validate that these objectives are broadly agreed upon by industry. Following further consultation with stakeholders, we have clarified the definition of two of the existing assessment criteria that we established in Phase 2 and introduced one addition:

a) Our definition of "Investor Confidence" has been clarified. Good regulatory practice suggests that risks should be placed with those best placed to manage them, and our assessment judged primarily on this basis. It also takes into consideration the aim of minimising costs of finance, subject to appropriate risk allocation.

b) We refined the definition of "Whole System" to focus exclusively on the facilitation of decarbonisation across other energy vectors.

c) We introduced an additional criterion, "Full Chain Flexibility", to reflect whether a market design option enables the contribution of flexibility from all assets at all levels of the electricity system. This includes consideration of the impact across voltages and the impact on demand side response (DSR), previously addressed under "Whole System".

Assessment Criteria:	
Decarbonisation	Provides confidence that carbon targets will be met
Security of Supply	Ensures that adequacy and operability challenges can be met
Value for Money	Ensures that the electricity system (network build, short-run dispatch and long-run investment) is being delivered efficiently
Investor Confidence	Investors are exposed to appropriate risks (e.g. risks they can manage) and finance costs are minimised subject to appropriate risk allocation
Deliverability	Transition from current market design to target design is deliverable in an appropriate timeframe
Whole System	Facilitates decarbonisation across other energy vectors
Consumer Fairness	The costs of the system are fairly shared across all consumers
Competition	Facilitates competition within and across technologies, between generation and demand and across connection voltages
Adaptability	A market design that can adapt to changes in technology or circumstances with limited disruption within a reasonable time frame
Full Chain Flexibility	Market design enables the flexibility from all assets at all levels of the electricity system to contribute

Net Zero Market Reform / Approach and Methodology 21

Approach and Methodology

3 Phase 3 Assessment Approach

Our approach to the assessment was in three parts:

1) Identification of hypothesised pros and cons: scoping of all the arguments for and against the different market design options.

2) Assessment of the validity of the hypothesised pros and cons of each option in a GB context. This process included:

a. Assessment of options against economic principles

b. Analysis of how market design options have been applied in other jurisdictions[1]. The objective was to test practicality of options, and to identify their impact as well as any unintended consequences, while considering their applicability to the GB context

c. Assessment of options against historical challenges which may persist into the future (e.g. transmission charging and investment challenges)

d. Integration of stakeholder responses to hypothesised pros and cons following engagement via workshops, questionnaires, roundtables and bilateral discussions

3) Scoring: design options were scored against each of the ten assessment criteria on a seven-point scale ranging from ‘Significant negative impact’ to ‘Significant positive impact’. The added granularity enabled us to distinguish between options in a more nuanced way than the Phase 2 RAG assessment.

Stakeholder engagement

Engagement with our stakeholders has been critical for this programme and has helped shape our thinking throughout. In total we have had over 1,500 attendees to our large-scale events. During Phase 3 we had bilateral discussions with over thirty organisations and hosted four workshops covering the design options under assessment. To understand stakeholder views in more depth, we hosted a roundtable discussion with a representative range of stakeholders where participants discussed the materials provided in the public workshop.

During Phase 3 we also launched our webpage where you can find key outputs from our work programme including our publications, slide decks and webinar recordings and also subscribe to our mailing list for future updates.

1 Examples from how mechanisms (e.g. central dispatch with self-commitment) are used internationally have been used in this document for illustrative purposes. Their use does not mean that ESO is considering any particular design as a ‘target’

Net Zero Market Reform / Approach and Methodology 22

The Location Design Element

The Location market design element considers the locational granularity of the wholesale price. Our Phase 3 assessment also takes into account interactions with locational signals provided through transmission charging and mechanisms to account for transmission losses.

Single National Price

Uniform price clears across entire market.

International examples:

UK

Germany

National Price

In a national wholesale market, for each settlement period the price of electricity is uniform for all market participants (both demand and supply) regardless of their location on the network. The System Operator resolves congestion that arises by 'redispatch': instructing select generators and/or loads to change their schedule. In GB redispatch is primarily conducted through the Balancing Mechanism. This model is used in the GB market and in France, Germany and Spain amongst other countries.

How are locational signals communicated in the current GB national market?

There are three main transmission-level locational signals in the current GB market: Transmission Network Use-of-System charges (TNUoS), Transmission Loss Factors and the Balancing Mechanism.

TNUoS charges are levied on generators and suppliers to recover allowed revenue for Transmission Owners for the cost of building and maintaining transmission infrastructure. At the same time, TNUoS charges are designed to provide, as far as is reasonably practicable, a cost-reflective price signal to influence investment and operation decisions. TNUoS tariffs vary by location for supply and demand (with GB divided into 27 supply zones and 14 demand zones) but are not time-varying and are updated annually to reflect the changing generation, demand, network context and to implement charging methodology changes. Ofgem (Ofgem, 2022b) has recently established a process to consider possible reforms to TNUoS charges in order to address issues including the charges' predictability and cost-reflectivity.

Since April 2018, a locational element has been established to the adjustment of contracted volumes to account for transmission losses, applied on an average seasonal basis across 14 transmission demand zones.

The near real-time locational value of energy is crudely expressed via system actions in the Balancing Mechanism (BM). ESO can instruct BM-participants to turn up or down if they are located where an action can resolve a locational issue such as a network constraint, with the cost of these interventions recovered through BSUoS charges. The methodology for the latter is currently undergoing reform: Ofgem (2020) recently approved the proposal to recover costs exclusively from suppliers through industry code CMP308 (Ofgem, 2022a), and will shortly decide on whether or not to adopt the proposal to recover these costs on an ex-ante fixed volumetric basis (NGESO, 2022).

Net Zero Market Reform / Location 23

The Location Design Element

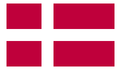
The Location market design element considers the locational granularity of the wholesale price. Our Phase 3 assessment also takes into account interactions with locational signals provided through transmission charging and mechanisms to account for transmission losses.

Zonal Pricing

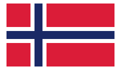
System divided into a small number of zones with individual prices.

International examples:


Australia


Denmark

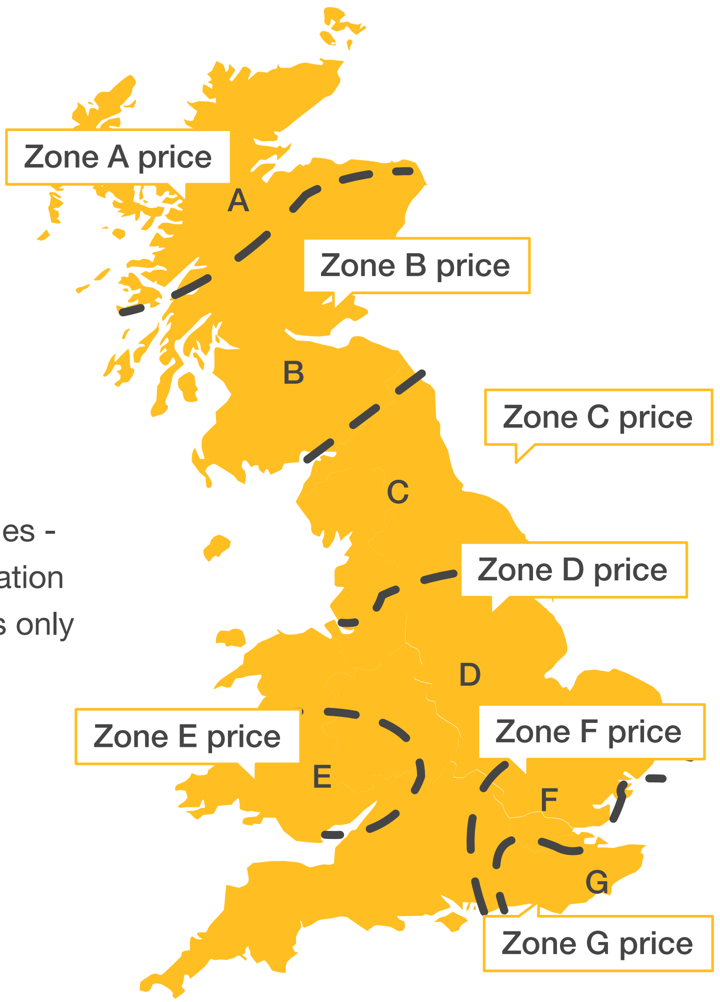

Italy


Norway


Sweden

Key:

– – Boundaries - for illustration purposes only



National Price | Zonal Pricing | Nodal Pricing

Weaker locational signals → Stronger locational signals

Zonal Pricing

In a zonal (or regional) wholesale market, the transmission system is divided into several zones and the wholesale price of electricity clears, for each settlement period, as a separate uniform price for each zone. The same zonal definitions are typically applied to day-ahead and balancing markets. There can be any number of price zones within a single country. For example, Italy currently has seven zones, Sweden has four zones and Denmark has two. When zone boundaries reflect transmission constraints, the wholesale price will vary between each zone. The European Capacity Allocation and Congestion Management Regulation requires that ENTSO-E review EU bidding zone configurations every three years to ensure zone boundaries achieve efficient congestion management and overall market efficiency.

How are locational signals communicated in a zonal market?

Transmission capacity limits between zones are reflected by variation between day-ahead energy prices for the different zones. In operational timescales, generators are incentivised to supply when their zonal price is high and to switch off when it is low (potentially anticipating higher revenues through the balancing market) while consumers are incentivised to consume energy when their zonal price is low and to reduce demand or use onsite generation when it is high. Over time, zones that experience sustained high prices, reflecting high demand relative to supply, can expect to see increased investment in generation. Sustained differences in zonal prices inform transmission network investment decisions.

Zonal markets provide strong locational signals in both operational and investment timeframes, provided the zonal boundaries accurately reflect transmission congestion and are updated in a timely manner. The market clearing process, however, does not account for congestion within zones. Where intra-zonal congestion does occur, it is resolved via redispatch. Within the zones, network tariffs can be designed to signal locational value, while network tariffs between zones should be designed to avoid double charging for the same locational constraints.

Net Zero Market Reform / Location 24

The Location Design Element

The Location market design element considers the locational granularity of the wholesale price. Our Phase 3 assessment also takes into account interactions with locational signals provided through transmission charging and mechanisms to account for transmission losses.

Nodal Pricing

System divided into many "nodes" with individual prices.

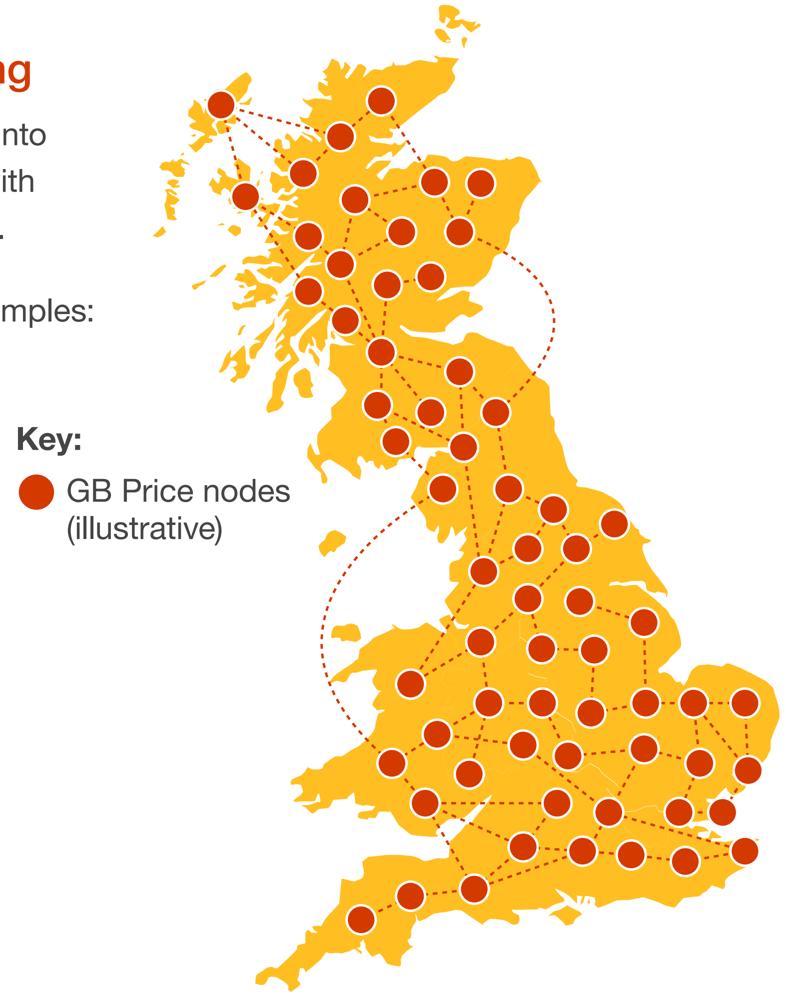
International examples:

USA

New Zealand

Canada

Singapore



National Price | Zonal Pricing | Nodal Pricing

Weaker locational signals → Stronger locational signals

Nodal Pricing/ ('Locational Marginal Pricing')

In markets with nodal pricing, every transmission system injection point (such as a generator busbar), offtake point (such as a distribution substation), and transmission line intersections at transmission substations, are typically defined as nodes. Markets with nodal pricing typically have hundreds or even thousands of nodes, each with different prices, which reflect the full cost of supplying (taking into account energy, network constraints and energy losses) - an incremental unit of consumption at each node per settlement period. For this reason, nodal pricing is also known as locational marginal pricing (LMP).

Nodal pricing is used in several US markets (incl. PJM, MISO, CAISO, ERCOT), as well as other global markets including New Zealand and Singapore. It is planned to be introduced in Ontario, Canada in 2023-24.

The objective of nodal pricing is to ensure the least cost energy balancing across the system while ensuring transmission constraints are respected. The nodal pricing optimisation process achieves this by generating a centralised schedule for each settlement period. Markets with nodal pricing therefore combine it with central dispatch.

How are locational signals communicated in a nodal market?

A central algorithm calculates the price at each node per settlement period. In some markets, nodal prices are determined at both the day-ahead stage (in the day ahead market) and close to delivery (the real time market). Other markets such as New Zealand only have a real time market.

Similar to zonal pricing, nodal pricing provides strong locational signals in both operational and investment timeframes though nodal markets are typically more granular. If applied to the whole transmission network, closer to the full cost of resolving transmission constraints would be embedded in wholesale energy prices, with areas behind constraints seeing lower wholesale prices while areas in front of constraints seeing higher prices, influencing dispatch, consumption and siting decisions. For example, assets that can manage their production or consumption flexibly, such as batteries, would be incentivised to locate where nodal prices are volatile. The need to build or reinforce transmission would be reduced by development of energy resources at a node and would be limited to resolving situations where the cost of reinforcement is lower than the cost of congestion (reflected in nodal prices).

Net Zero Market Reform / Location 25

Summary Assessment of Location Design Element

Full assessment and scoring rationale found in separate annex

	National wholesale market	Zonal wholesale market	Nodal wholesale market	
1 Decarbonisation	Minor -ve impact	Minor +ve impact	Minor +ve impact	The level of decarbonisation is driven primarily by the amount of low carbon support. However, a nodal or zonal market design may help to foster greater "fiscal credibility" and curtailment reduction which will enhance the effectiveness of decarbonisation investments.
2 Security of Supply	Minor -ve impact	Minor +ve impact	Minor +ve impact	The level of security is driven primarily by (1) the reliability standard; and (2) policies / regulations to deliver that standard -not by locational market designs. However, a nodal or zonal market design may provide greater value for money with capacity adequacy investments.
3 Value for Money	Significant -ve impact	Moderate +ve impact	Significant +ve impact	Consideration of transmission limits results in more efficient dispatch, while more granular locational price signals are likely to lead to more efficient long-run investment outcomes. Transfers from consumers to generators of constrained-off payments are removed.
4 Investor Confidence	Moderate -ve impact	Moderate +ve impact	Moderate +ve impact	More granular locational price signals allocate greater locational risks to investors –this is more efficient as generators now have to consider their impact on the grid. Financial instruments allow hedging of this risk and there is limited evidence that investors are exposed to risks they cannot manage.
5 Deliverability	Minor +ve impact	Minor -ve impact	Moderate -ve impact	Case studies on the cost of transitioning to nodal markets show significant (gross) costs associated with locational market reform. However studies show that costs are likely be far lower than the benefits. Transition to new market design can be implemented relatively quickly with a streamlined and effective stakeholder engagement process.
6 Whole System	Minimal impact	Minor +ve impact	Moderate +ve impact	Greater locational price signals could reduce the cost of decarbonisation in other energy vectors by incentivising more efficient siting decisions.
7 Consumer Fairness	Overall bill impact / Variation in retail bill: Significant -ve impact / Moderate -ve impact	Overall bill impact / Variation in retail bill: Moderate +ve impact / Moderate +ve impact	Overall bill impact / Variation in retail bill: Significant +ve impact / Significant +ve impact	A nodal market could enable bill reduction for consumers in aggregate and provides policymakers with more policy levers when compared with national market (e.g. consumers can be exposed to the national, nodal or blended price).
8 Competition	Moderate +ve impact	Moderate +ve impact	Moderate +ve impact	All designs help support competition in wholesale electricity markets, including in terms of liquidity. Market power issues, which arise under all designs, can be mitigated.
9 Adaptability	Moderate -ve impact	Moderate +ve impact	Significant +ve impact	Nodal designs (and zonal markets to a lesser extent, through a manual boundary update process) are able to adapt to changes in demand/generation/network conditions automatically, whereas national design cannot since they are 'blind' to the transmission network configuration.
10 Full-chain Flexibility	Moderate -ve impact	Moderate +ve impact	Significant +ve impact	Nodal market design (and zonal markets to an extent) would allow more market participants, including DER and DSR, to respond to more granular locational signals more easily.

Key: contribution towards a net zero market

Significant -ve impact · Moderate -ve impact · Minor -ve impact · Unclear impact · Minimal impact · Minor +ve impact · Moderate +ve impact · Significant +ve impact

Net Zero Market Reform / Location 26

Summary Assessment of Location Design Element

Full assessment and scoring rationale found in separate annex

	National wholesale market	Zonal wholesale market	Nodal wholesale market	
1 Decarbonisation				The level of decarbonisation is driven primarily by the amount of low carbon support. However, a nodal or zonal market design may help to foster greater "fiscal credibility" and curtailment reduction which will enhance the effectiveness of decarbonisation investments.
2 Security of Supply				The level of security is driven primarily by (1) the reliability standard; and (2) policies / regulations to deliver that standard -not by locational market designs. However, a nodal or zonal market design may provide greater value for money with capacity adequacy investments.
3 Value for Money				Consideration of transmission limits results in more efficient dispatch, while more granular locational price signals are likely to lead to more efficient long-run investment outcomes. Transfers from consumers to gene… …off payments are removed.
4 Investor Confidence				More granular locational … consider their impact on … to risks they cannot man… …t as generators now have to …idence that investors are exposed
5 Deliverability				Case studies on the cost … However studies show th… quickly with a streamline… …th locational market reform. …ign can be implemented relatively
6 Whole System				Greater locational price … more efficient siting deci… …centivising
7 Consumer Fairness	Overall bill impact / Variation in retail bill	Overall bill impact / Variation in retail bill	Overall bill impact / Variation in retail bill	A nodal market could en… compared with national … …more policy levers when …e).
8 Competition				All designs help support competition in wholesale electricity markets, including in terms of liquidity. Market power issues, which arise under all designs, can be mitigated.
9 Adaptability				Nodal designs (and zonal markets to a lesser extent, through a manual boundary update process) are able to adapt to changes in demand/generation/network conditions automatically, whereas national design cannot since they are 'blind' to the transmission network configuration.
10 Full-chain Flexibility				Nodal market design (and zonal markets to an extent) would allow more market participants, including DER and DSR, to respond to more granular locational signals more easily.

Consumer fairness

Our assessment for consumer fairness was split into two considerations: firstly, the overall impact on average consumer bills, and secondly the potential regional variation in consumer bills.

Key: contribution towards a net zero market

Significant -ve impact · Moderate -ve impact · Minor -ve impact · Unclear impact · Minimal impact · Minor +ve impact · Moderate +ve impact · Significant +ve impact

Net Zero Market Reform / Location 27

Discussion of the Location Design Element

Nodal pricing scored most highly in our assessment. The full rationale for the scoring is provided in the separate Annex. Here we focus on where nodal pricing would bring benefits for GB in the context of meeting net zero that distinguish it from other options: Value for Money, Full-chain Flexibility, Adaptability and Consumer Fairness. We also address the areas of Investor Confidence and Deliverability where stakeholders have raised concerns.

As discussed in the Phase 3 Approach, the locational granularity of the wholesale price will inform decision-making in both investment and operational timescales. By contrast, retaining the single national price whilst reforming locational signals elsewhere, such as via CfDs or the Capacity Market, would not provide an accurate operational signal and risks introducing market distortions. This analysis therefore focuses on nodal pricing and zonal pricing since they can provide locational signals in operational timeframes.

Value for Money

As set out in the Approach section, our Phase 3 assessment of value for money of different locational options is based on economic principles, evidence from other jurisdictions and stakeholder feedback. Ofgem are currently undertaking a technical assessment of nodal pricing in GB which will include analysis of the costs, benefits and potential distributional impacts. The following section sets out four key sources of value that arise from incorporating more granular locational signals into the wholesale price.

1 Nodal pricing removes financial transfers from consumers to constrained-off generators

Generators currently have a financially firm access right to export energy, reflecting the assumption inherent in NETA that any generator can serve any load. If an asset is denied the right to export, as happens when generators are curtailed due to transmission constraints, it is entitled to compensation for its contracted wholesale revenue. The cost of these 'constrained-off' payments is one component of balancing costs and is ultimately paid for by consumers via BSUoS. Under nodal pricing, constrained-off costs are removed since assets whose output would cause constraints are not dispatched (see Appendix 2). Constrained-off payments under existing arrangements, are distinct from dispatch instructions to increase consumption or reduce generation, which remain under nodal pricing. In zonal markets, the need for constrained-off payments arising is reduced; however, wherever intra-zonal congestion arises consumers continue to pay constrained-off payments. The efficacy of zonal pricing in this regard therefore depends on the zone boundary accurately reflecting the network constraint, which is challenging to achieve. We discuss below in Adaptability how the fast-changing generation background and transmission network in GB means that zone boundaries would only temporarily and partially reflect congestion, meaning that some constrained-off payments would likely remain.

Discussion of the Location Design Element

Value for Money (cont.)

2 Nodal pricing drives large cost savings through more efficient dispatch

Under the current GB model, the wholesale market does not account for network conditions. The System Operator redispatches following Gate Closure via the Balancing Mechanism (BM) to ensure network limits are not breached, paying units that receive instructions to alter their output. As discussed ESO is redispatching a greater portion of the GB market due to the increasing mismatch between wholesale market outcomes and the physical constraints of the transmission grid. The redispatch costs are then passed to consumers via BSUoS charges. Under CMP308, from 1st April 2023 (Ofgem, 2022a), these will be applied solely to demand such that generators will no longer be exposed to the balancing costs they cause.

By embedding the locational value of an action in the wholesale price, nodal pricing enables market participants to optimally dispatch supply or demand in the right location and at the right time, avoiding the need for redispatch following Gate Closure and ensuring the efficient use of interconnectors. This would enable a significant improvement relative to the current market design by improving allocative efficiency and price formation such that the marginal cost of producing would be closer to the marginal benefit to consumers. Consumers' preferences would more strongly influence how resources are allocated, reducing the risk of overbuilding generation infrastructure at consumers' expense (see below). Zonal pricing would not be able to unlock dispatch benefits to the same extent as nodal pricing, since the accuracy of locational signals in operational timescales is reduced and depends on the accuracy of zone boundaries in reflecting constraints (see Adaptability section). The next chapter deals fully with how central dispatch can better optimise for network and operational factors in a high-renewables grid.

3 Accurate locationally granular price signals would enable efficient siting and development of energy resources

Locational signals are currently provided via TNUoS, which influences siting of assets to some degree, as evidenced by the variation in wind asset location in GB currently. Nodal prices could provide more accurate and efficient long-run incentives compared to TNUoS charges due to their greater locational and temporal granularity and their symmetrical treatment of supply and demand. While TNUoS sends long-run investment signals with some locational granularity, these are not as accurate as those provided by nodal prices as they are less locationally granular (assuming nodal pricing would be applied to nodes across the entire transmission network) and the tariff methodology uses proxies and treats supply and demand differently. By contrast, nodal prices provide an accurate and dynamic symmetrical signal for supply and demand that over time provides an efficient investment signal: for example, where nodal prices would be persistently high due to transmission constraints, the investment signal to develop local resources in front of the constraint would be strengthened, including demand reduction (e.g. energy efficient retrofits) in buildings using electrified heating and supply-side options such as solar panels or combined heat and power. Ultimately the more efficient siting and development of energy resources would reduce total system costs. The extent to which zonal pricing would improve on the current arrangements depends on zone granularity and the extent to which zone boundaries accurately reflect transmission network congestion.

Net Zero Market Reform / Location 29

Discussion of the Location Design Element

Value for Money (cont.)

4 More accurate and granular price signals enable whole system optimisation

Some stakeholders suggested that insufficient transmission network build is the fundamental cause of constraints and this applies to any wholesale market design. They suggest that the priority for decarbonising at lowest cost should therefore be accelerating network build. We agree that accelerating efficient levels of network build and connections is crucial to net zero, but do not consider it mutually exclusive from efficient electricity market design. Rather, it is prudent to minimise the risk of gold-plating the transmission network by co-ordinating transmission buildout with the introduction of locationally granular wholesale market signals such that:

1. Renewable resources are incentivised to locate in an optimal location
2. Transmission congestion is optimally managed: flexible assets in specific locations are incentivised to turn up/down at specific times
3. Clear signals are given for where transmission network reinforcement is required to cost-effectively reduce persistent congestion

As a consequence, nodal pricing - or zonal pricing to a lesser extent depending on zone granularity and the extent to which zone boundaries accurately reflect network constraints - would enable much greater whole system optimisation, realising cost savings for consumers. In addition, increasing system efficiency would also help reduce delivery risk associated with transmission network reinforcement at the required pace and scale.

Design trade-offs will impact Value for Money:

The extent to which the above sources of value are realised under zonal or nodal pricing implementation would depend on some key design choices. For example, the benefits of more efficient demand side dispatch would be most fully realised via a design with greater demand side exposure to locational prices (see Consumer Fairness). Similarly, the extent of grandfathering policies would influence the extent to which savings from constrained-off payments would be passed through to consumers.

Discussion of the Location Design Element

Facilitating Full-chain Flexibility

1 Nodal pricing would unlock accurate flexibility in operational timescales

GB flexible capacity will both dramatically increase and comprise radically different sources in 2050 versus today. For example, under the FES 2021 Leading the Way scenario, Vehicle to Grid technology is projected to increase from near zero today to potentially 39GW in 2050, while demand side response capacity could increase more than five-fold to 44 GW in 2050. It is critical that these assets are exposed to dynamic locational signals so that they are incentivised to help mitigate constraints and to shift demand to periods of high local supply.

Under the single national wholesale price, assets lack visibility of near real-time variations in local energy supply and demand. As an ex-ante capacity-based charge, the current TNUoS charges do not provide effective short-run signals to market participants that dynamically reflect system needs. This means that when there is a local transmission constraint, assets in that area are not accurately and directly incentivised to address it through the price of energy at that time.

Some demand response is successfully elicited through network charges via the Triad mechanism (NGESO, 2018), which is applied to half hourly metered consumers: demand is measured during three Triad events over the winter season (essentially proxies for peak demand), which is then used as the basis for calculating the consumer's residual charges. This particular mechanism has proved that network charges can be designed to incentivise significant demand response and the uptake of energy services, as many consumers employed demand-management and forecasting services in order to reduce their demand in anticipation of the three Triad periods. While Triads have successfully driven some demand response, the mechanism is being phased out in 2023 as it is enabling some market participants to avoid residual network charges, increasing the cost burden for others (Ofgem, 2019). What is needed for a net zero future, however, is the enabling of demand-side flexibility in each settlement period of the year.

In theory, TNUoS tariffs could be designed to mimic the kind of locational price signals in operational timeframes that would be signalled through nodal or zonal pricing. It would be administratively inefficient and impractical, however, to attempt to do this, requiring Ofgem to design a much more complex tariff methodology and given the existence of the wholesale electricity market and its efficiency in reflecting short-run marginal costs. Incorporating locational signals in energy prices is a far more streamlined and efficient solution compared to the status quo, requiring no administered updates once established and reducing the fragmentation of flexibility value. Wholesale markets are also complemented by well-established and evolving financial markets and market information/monitoring services, enabling market participants to manage risk. By contrast, market participants would not have the means to hedge against highly dynamic TNUoS charges and would be subject to ongoing regulatory risk associated with the administrative setting of the TNUoS tariffs.

Nodal pricing would provide an accurate locational signal for flexible assets to optimise against in near real-time. Zonal pricing could realise more demand-side potential than the status quo; however, not to the same extent as nodal prices, as zonal markets are less granular and as their potential is limited by the significant challenge of ensuring zone boundaries continue to accurately reflect evolving system conditions, as explored further in the Adaptability section. Nodal pricing effectively creates a market behind each node, which would additionally drive greater optimisation at the local level. Suppliers can also aggregate resources and offer them into the wholesale market or to DNOs/DSOs that are managing the distribution network behind the node.

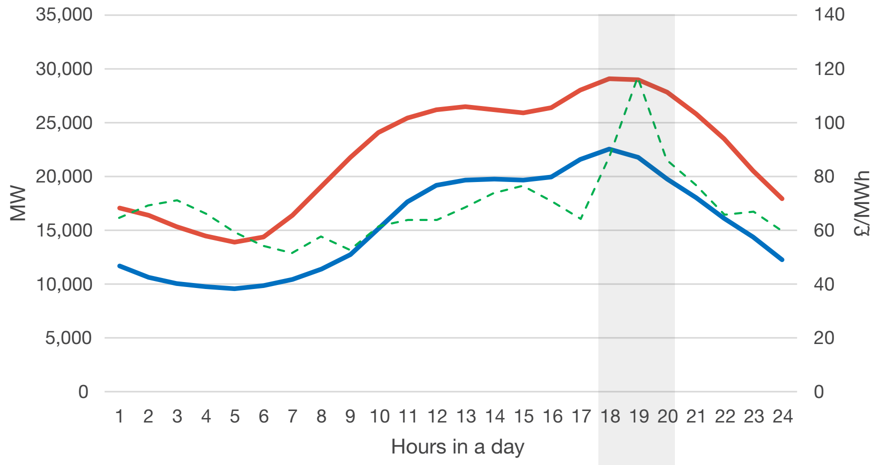
Discussion of the Location Design Element

Illustrative comparison of demand and supply profiles with prevailing North/South constraint (national versus nodal pricing)

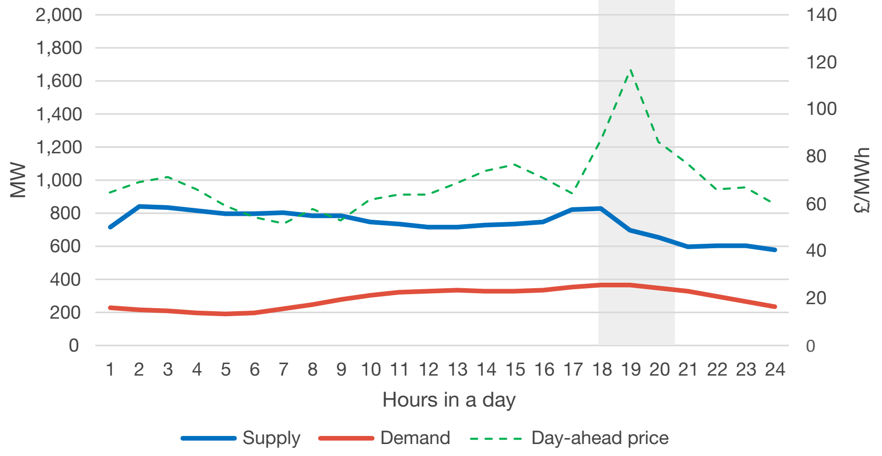
National price signal

Demand in South receives muted incentive to reduce. Northern demand also incentivised to turn down despite surplus local supply.

Location in South (Illustrative)



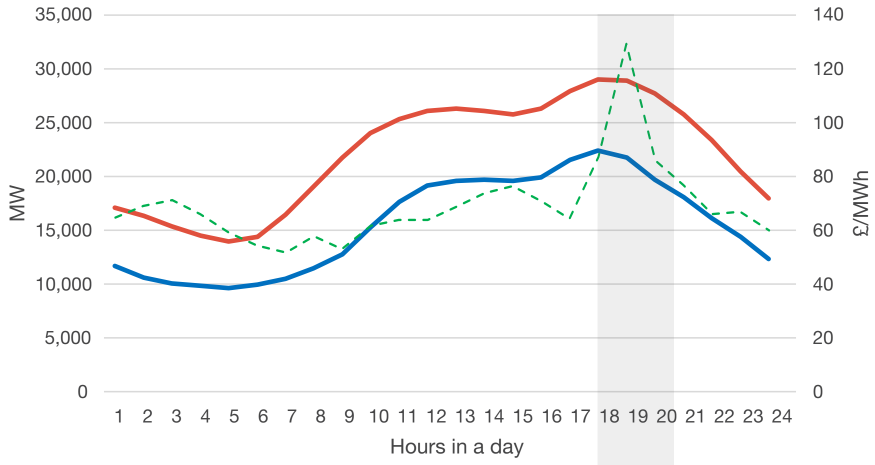
Location in North (Illustrative)



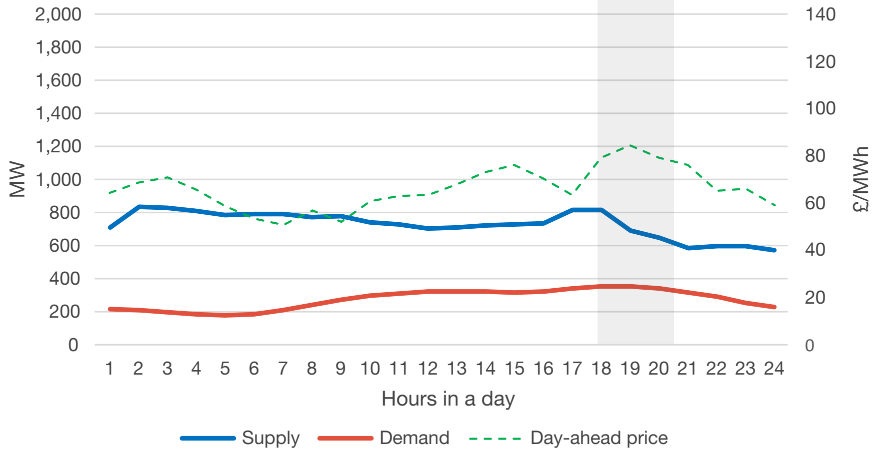
Nodal price signal

Demand in South receives stronger incentive to reduce. Lower incentive for Northern demand reflecting surplus generation.

Location in South (Illustrative)



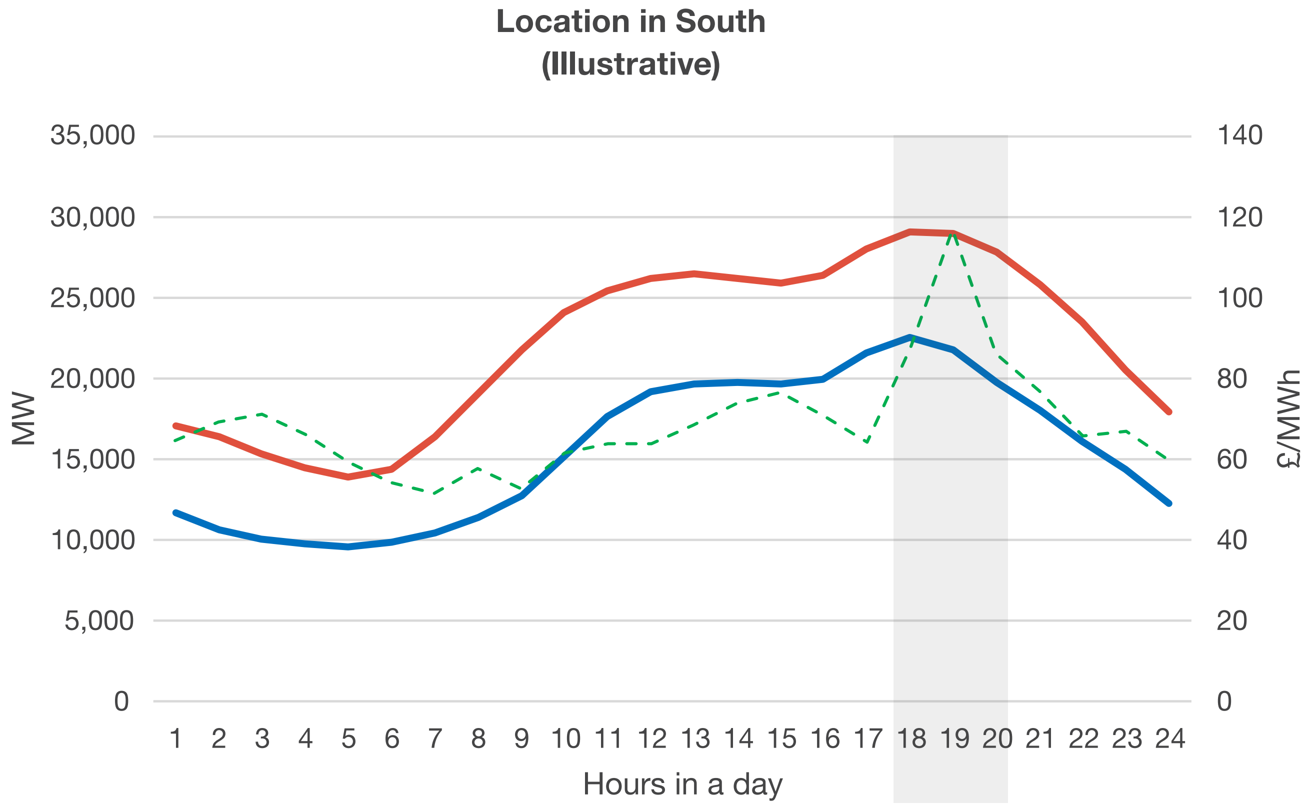
Location in North (Illustrative)

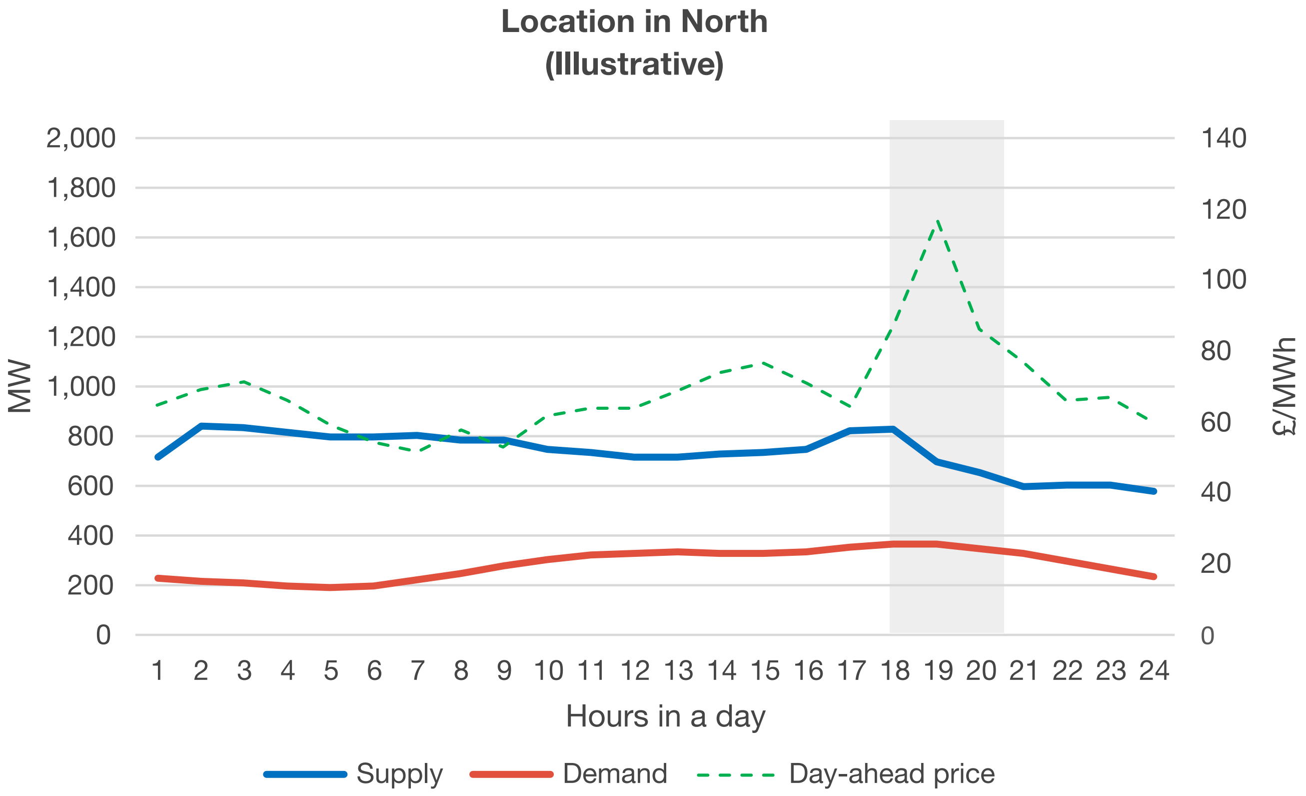


Net Zero Market Reform / Location 32

Discussion of the Location Design Element

National price signal

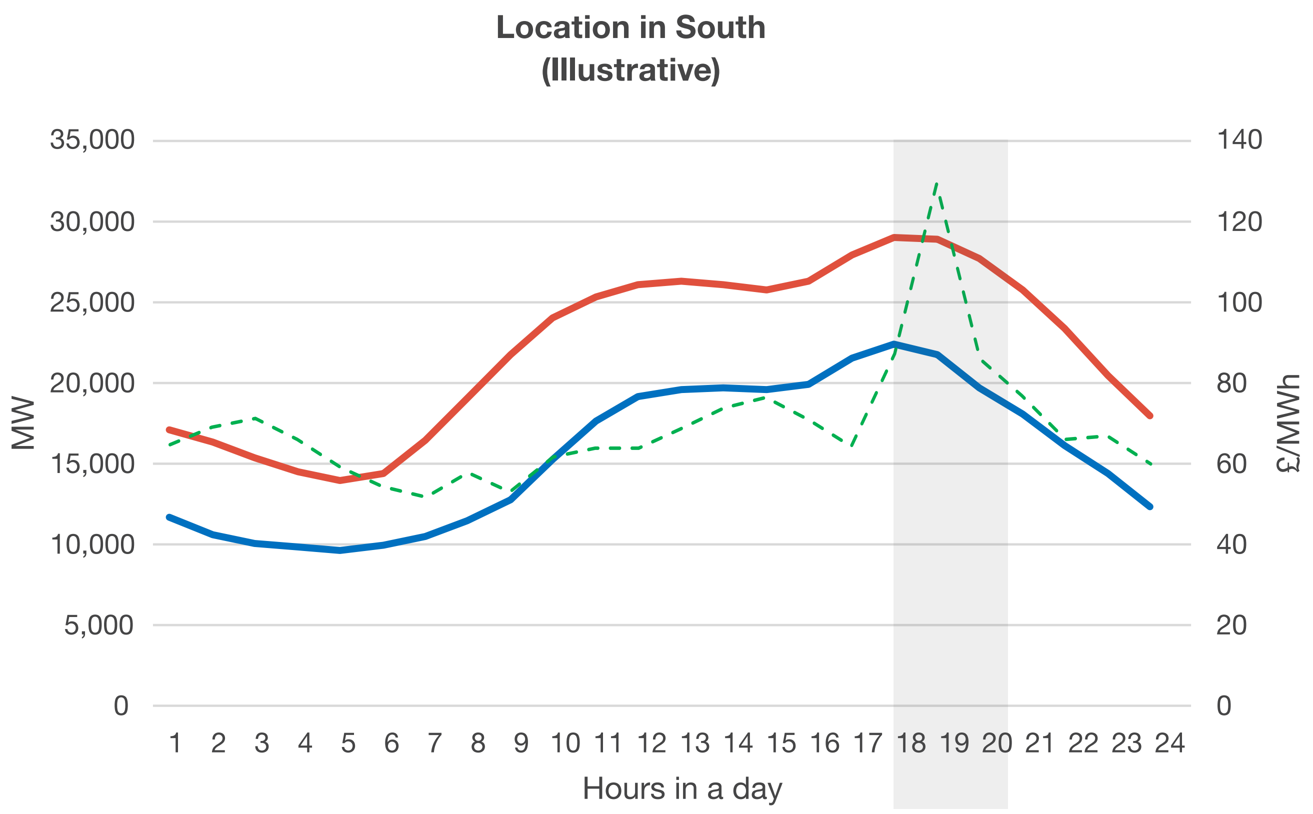


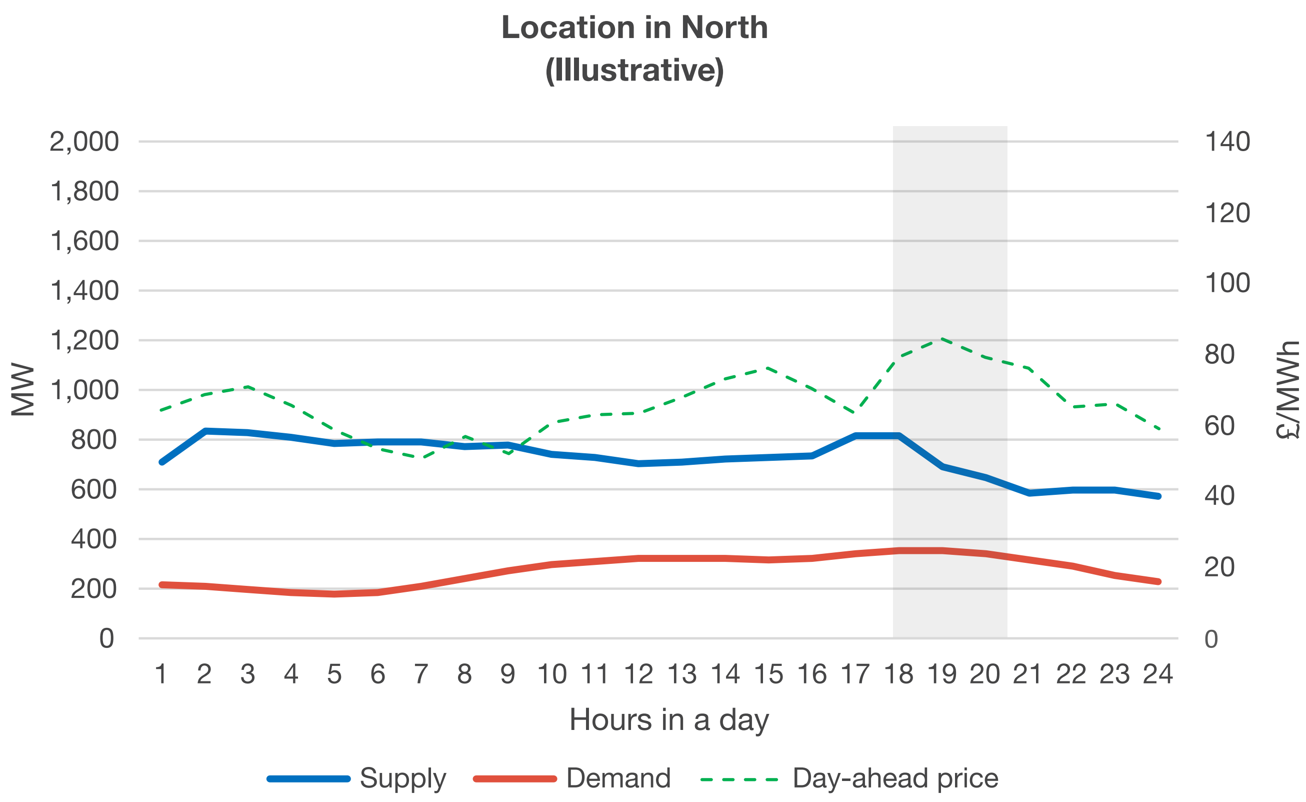


Net Zero Market Reform / Location 33

Discussion of the Location Design Element

Nodal price signal





Net Zero Market Reform / Location 34

Discussion of the Location Design Element

Facilitating Full-chain Flexibility (cont.)

2 **Nodal/ zonal pricing would effectively remove perverse incentives for assets with two-way flows**

Interconnectors and storage are at times incentivised by the current market design to flow in a direction that exacerbates constraints.

Interconnector import scenario from Norway to North England:

GB - Norway: when the prices in GB are higher than those in Norway the interconnector will likely import into GB. Should this happen at a time when there is also high wind in Scotland and North England then this could cause, or exacerbate, network constraints associated with moving power north to south in GB.

Interconnector export scenario from South England to France:

GB – France: at times of high wind output in GB a low GB wholesale price means interconnectors are incentivised to export to the Continent. With the need to transport energy southwards, exports to France can exacerbate constraints in the South-East/ London area, especially where there are already outages.

Under current arrangements, where an interconnector importing or exporting would cause a network constraint, ESO can use the Balancing Mechanism to increase demand or reduce generation around a constraint, and can also pay for the interconnector to change the flow direction as an interconnector trade.

ESO must pay above the price spread to secure a change in direction. The cost of changing the interconnector flows is currently paid by GB consumers via BSUoS costs. Additional constraint costs related to these perverse interconnector flows have arisen in South-East England, North England where the North Sea Link to Norway connects, and between Ireland and GB.

This issue is likely to increase as interconnector and storage capacity increases. Under the FES Leading the Way scenario, interconnector capacity will increase from 7 GW in 2021 to 27 GW in 2035 and battery storage capacity from 5 GW to 23 GW.

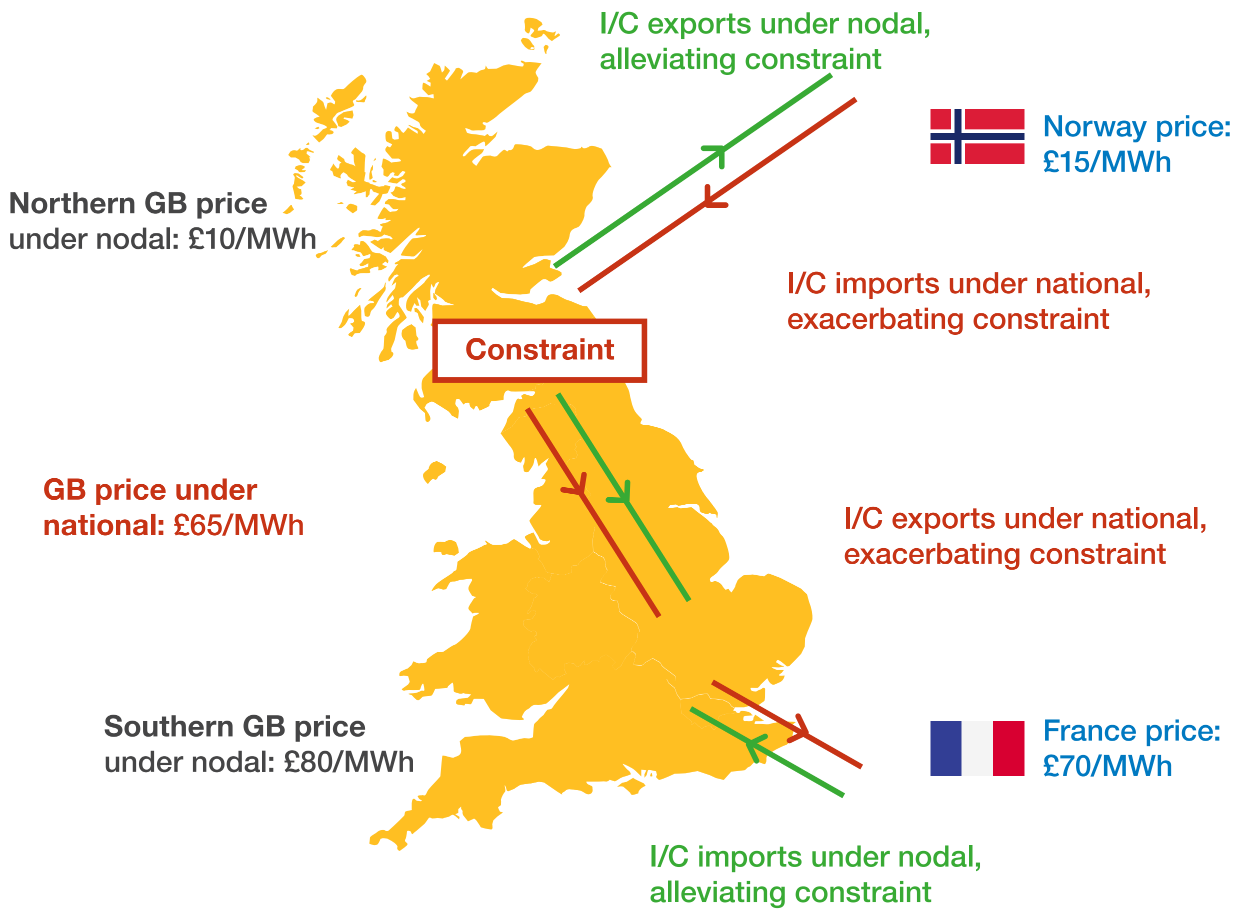
Locationally accurate wholesale signals, via nodal or zonal pricing, would enable batteries and interconnectors to respond to price signals that reflect the system conditions, so that they behave in a way that supports the system.

See illustrations on next page

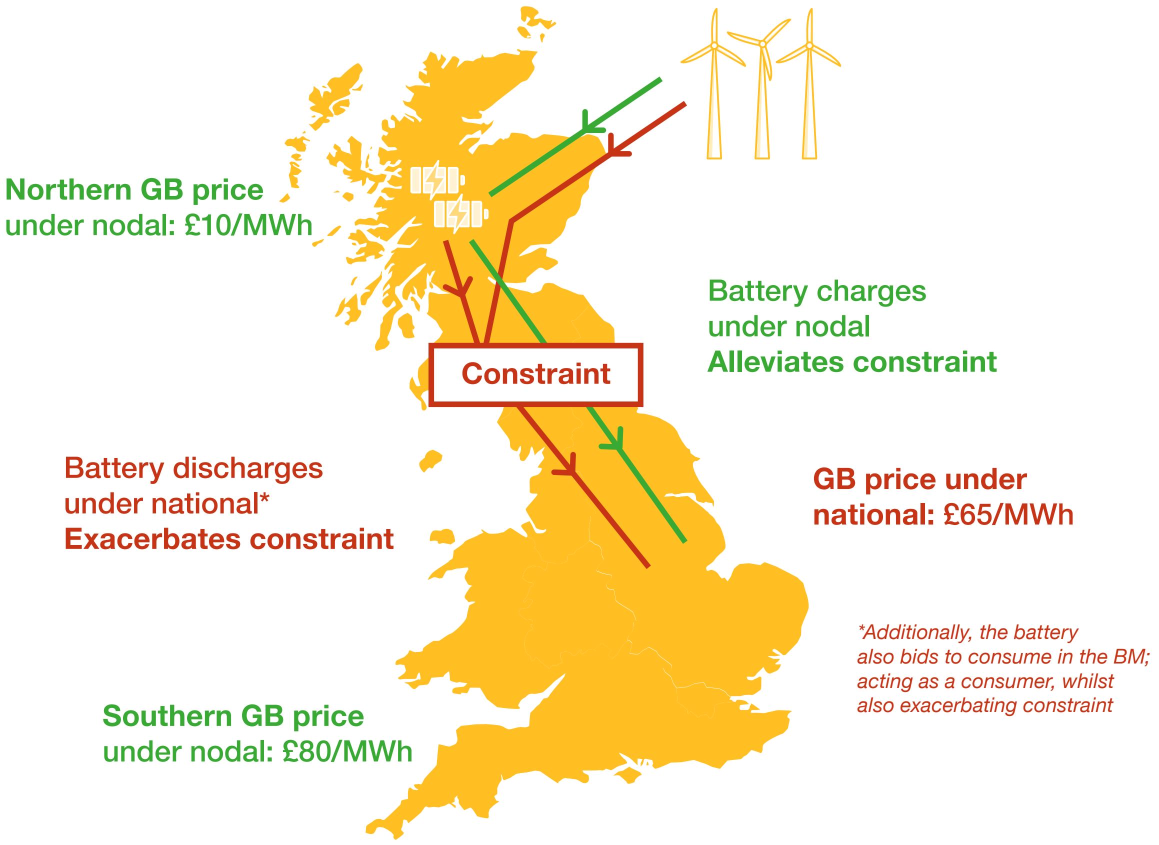
Net Zero Market Reform / Location 35

Discussion of the Location Design Element

Illustrative comparison of interconnector flows under national and nodal pricing



Illustrative comparison of battery discharge under national and nodal pricing



Prices are illustrative in both maps

Discussion of the Location Design Element

Adaptability

1 Nodal pricing has the greatest potential to be adaptable and resilient

National pricing scored low on adaptability due to the high need for interventions in operational timeframes: as discussed above, the absence of locational signals in the GB wholesale price is leading ESO to redispatch a greater portion of the market to resolve transmission constraints. TNUoS charges are failing to provide signals that accurately reflect system conditions in operational timescales.

A zonal market is likely to be more adaptable and resilient relative to current arrangements; however, the need to redefine boundaries between zones to reflect new constraints would be inevitable, since network constraints track the transmission line build and changes to the geographical distribution of supply and demand. The Electricity Ten Year Statement (ETYS) boundary heatmap (see next page) shows how boundaries are projected to evolve as the GB electricity system changes. These movements would need to be reflected in updated zonal boundaries. We consider the risk of not achieving this, with consequent delays, to be significant.

Where the zonal boundary is no longer accurate, intra-zonal congestion would increase as recently happened in Italy (Terna, 2018), Germany and Austria (Jao, 2018), and as is arising in Sweden (ENTSO-E, 2022). The rise in European markets of unscheduled flows, where the physical flow of electricity differs from commercial schedules, indicates zonal market prices are failing to reflect congestion patterns. Unscheduled flows drive consumer welfare loss as they take up interconnector capacity that would otherwise be used for cross-zonal trade to reduce wholesale prices (ACER, 2022). Both the CAISO market in California and the ERCOT market in Texas, which both originally introduced zonal pricing, moved to nodal pricing rather than increase the granularity of the zones. In Australia, a series of market reform programs have been conducted to address congestion management issues in the zonal National Electricity Market, most recently in 2021, with a key issue relating to zone boundaries reflecting jurisdiction boundaries rather than congestion. Zonal pricing therefore scored lower than nodal pricing.

Nodal pricing is more adaptable, since changes in supply, demand and network conditions are automatically reflected in nodal prices and FTRs.

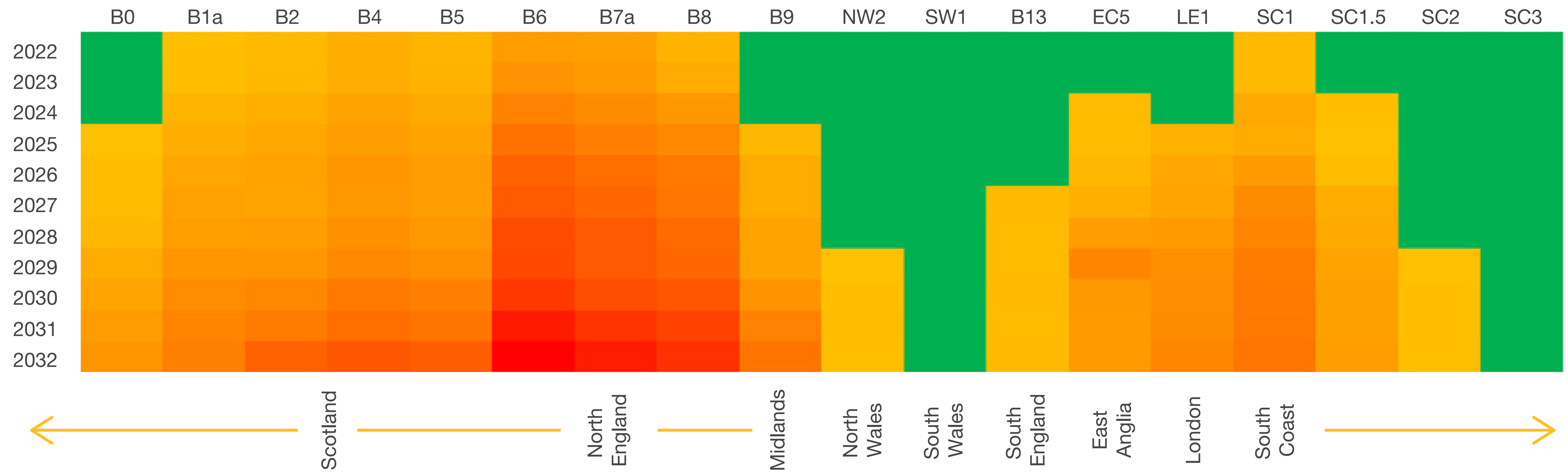
2 Nodal pricing could potentially be extended to lower voltages in time or be combined with alternative options

In time, nodal pricing could potentially be applied to lower voltage levels as conditions permit, with improved monitoring and control at the distribution level and growth in DER. Nodal pricing could be implemented at a suitable transmission voltage level in the first instance, with the option of later extending to lower voltages and/or combining with alternative options such as more granular distribution use-of-system network charges (DUoS) or local energy market solutions as the energy system develops with digitalisation, distributed energy resources (DER) growth and improved Distribution System Operator (DSO) capabilities.

Discussion of the Location Design Element

Excess flows beyond boundary capability if no action is taken to reinforce the system (Electricity Ten Year Statement, 2021)

The GB congestion background is projected to change significantly in the coming years, meaning that zone boundaries would need to be repeatedly updated to remain effective.



This heatmap shows how new constraints are projected to evolve over the next ten years across different regions. In North England new red zones evolve, and new constraints arise in the South-West which is currently unconstrained.

Net Zero Market Reform / Location 38

Discussion of the Location Design Element

Investor Confidence

To score well against this criterion it is necessary that a market design allocates risk to those market participants who are best placed to manage it effectively. It should also minimise the costs of finance, subject to appropriate risk allocation.

1 Investors could better manage risk with nodal pricing compared with zonal pricing and status quo of national pricing plus TNUoS

In Phase 2, we found that locational market signals in the form of TNUoS tariffs impose substantial ongoing regulatory risk for investors, generators and retailers. Stakeholders' concerns regarding TNUoS charges, particularly in relation to lack of cost-reflectivity, unpredictability and rising charge levels, with increasing divergence between North and South, have led to the establishment of multiple task forces aimed at TNUoS reform (Ofgem, 2022). A significant issue is that market participants have no tools to manage the price risk associated with TNUoS tariffs. The methodology which determines tariffs changes frequently and unpredictably under the CUSC open governance process. This results in participants facing substantial tariff volatility due to ongoing regulatory risk. For these reasons, the current arrangements scored less well compared to zonal and nodal pricing.

By contrast, in zonal and nodal market designs, market participants can effectively partially hedge their exposure to locational price differences through financial instruments such as Financial Transmission Rights (FTRs), which give the holder rights to congestion rents between two nodes or zones. FTRs are commonly used in nodal markets and use of FTRs between adjacent bidding zones is a feature of the EU target model, though some jurisdictions use alternatives.[2] We found that FTRs are an efficient way of enabling risk to be managed by those best placed to do so, which is a significant advantage compared with existing TNUoS arrangements. A full explanation of how FTRs work and are used in practice is provided in Appendix 1.

We found that zonal pricing would reduce investor confidence relative to nodal pricing since participants cannot hedge against the risk of bidding zone boundaries changing, which would inevitably be necessary. The process through which new boundaries are defined could introduce significant regulatory risk to the market, as previously described in the Adaptability section. Regulatory risk would also remain for transmission charging applied within zones.

Some stakeholders have raised concerns over a potential increase in Weighted Average Cost of Capital (WACC) on renewable development project costs in nodal markets as nodal price volatility could add forecasting complexity and new transmission capacity build could significantly alter nodal prices:

a) Stakeholder concern: nodal price volatility adds forecasting complexity

Some stakeholders indicated that the increased number of variables to account for when forecasting nodal prices would lead to a rise in wholesale prices as trading parties increase risk premia to insulate themselves from price volatility. We note that market design should aim to ensure that energy prices accurately reflect the real-time state and full marginal costs of the power system. If achieved, this can result in highly volatile energy prices, indicating the system's need for flexible resources. Energy price volatility is therefore a primary value driver for flexibility assets though the assets' response will in turn dampen the volatility.

Net Zero Market Reform / Location 39

2 For example, Electricity Price Area Differentials (EPADs) are used in the Nord Pool market, which allow for hedging of differences between the system price and bidding zone prices.

Discussion of the Location Design Element

Investor Confidence (cont.)

All electricity markets are necessarily sophisticated due to the complexity of the engineering and economic problems that must be solved. Financial markets, market monitoring and information services are also an intrinsic part of the existing market design, enabling market participants to effectively manage and mitigate risk. Market participants are therefore already used to operating in this complex trading environment, either directly or with the support of third parties. The introduction of zonal or nodal pricing would further develop these existing arrangements and nodal pricing would remove regulatory risk premia associated with TNUoS tariffs.

During our stakeholder engagement process, we did not find or receive firm evidence to suggest that nodal pricing would raise the cost of capital for investment in key technologies. Similarly, our research of other jurisdictions did not reveal historic evidence of an enduring negative impact on investment (see next page). Other variables, such as a jurisdiction's approach to reducing carbon emissions or improving the performance of its electricity markets, were more highly correlated to investment in energy resources. Introducing nodal pricing and central dispatch did not lead to increased average wholesale prices, and in several instances evidence suggests generators paid substantially lower operational costs through more efficient fuel use and ramping (see under Value for Money in Dispatch section). It is important to note that, in the absence of a counterfactual, there can be no definitive proof of the cause and effect of implementing nodal pricing on either cost of capital or subsequent investment.

b) Stakeholder concern - new transmission capacity build can significantly alter nodal prices

Some stakeholders expressed concern that the introduction of new transmission lines in a region could substantially alter nodal prices. We did not find this risk to be a key differentiator from the status quo, where the locational signals in the form of TNUoS tariffs are similarly calculated to reflect the transmission network background. The annual Networks Options Assessment (NOA) process, which provides a ten-year outlook of transmission build, would be similarly used to inform investment decisions.

Financial Transmission Rights (FTRs), mentioned above, are effectively used to hedge their holders against both congestion risk and the risk of nodal or zonal prices changing due to new transmission build.

2 Various options to mitigate impact of change in risk profile resulting from a move to zonal or nodal pricing

Investor risk associated with the implementation phase of new arrangements must also be considered as there would inevitably be some disruption. Investors will face some uncertainty as the detailed design of new arrangements are developed. Risk associated with this uncertainty can be mitigated by ensuring the policy-making process is transparent, well communicated and efficiently managed.

3 Various options to mitigate negative impacts on existing assets

A move to nodal or zonal pricing would represent a significant change for existing assets, potentially negatively impacting the rate of return on their investments that were established under different market conditions. There are multiple ways, however, to mitigate impacts on existing assets, such as the grandfathering of FTRs (see Appendix 1), should policymakers decide this is necessary.

Net Zero Market Reform / Location 40

Discussion of the Location Design Element

Investor Confidence (cont.)

Evidence from international case studies shows sustained investment in renewable assets during and after nodal pricing implementation.

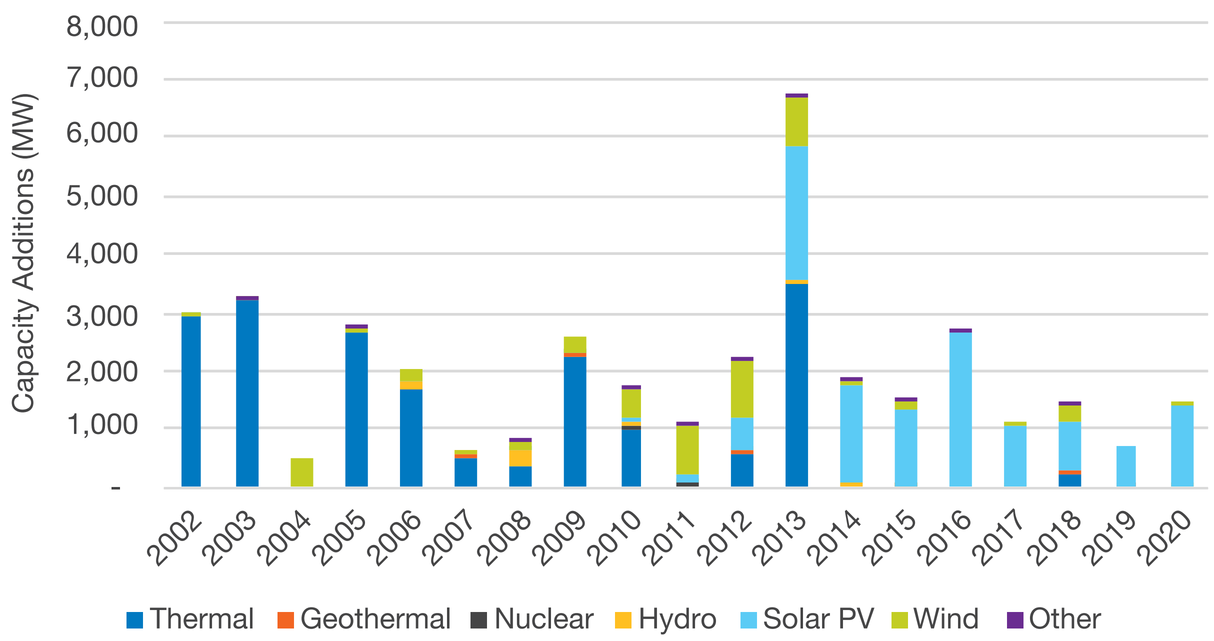
In several regions, other improvements to market design and policies to boost renewables buildout have been introduced in parallel to nodal pricing and have played an important role in driving investment. While the counterfactual of what investment would have happened without nodal pricing cannot be known, we have not seen evidence that implementing nodal pricing had a detrimental impact on investment.

California (CAISO)

Texas (ERCOT)

New Zealand

CAISO Capacity Additions (MW) since LMP implementation



California (CAISO):

California moved from a self-dispatch, zonal market to implement central dispatch with nodal pricing in 2009. During the transition period between 2003 and 2009, overall electricity generation capacity increased by 14%, including a 19% increase in natural gas capacity, 74% increase in wind and 675% increase in solar (California Energy Commission, 2022). Following nodal pricing Go-Live in 2009, in keeping with California's ambitious renewables targets, solar PV penetration has increased from 13 MW in 2009 to over 13 GW in 2020, wind capacity has increased by about 130%, while gas capacity has reduced 10%. Tax rebates and the 'net metering tariff' have underpinned the state's vast expansion of utility and distributed solar PV capacity. Financial Transmission Rights were available from the point of implementation of nodal pricing.

Source: California Energy Commission

Net Zero Market Reform / Location 41

Discussion of the Location Design Element

Investor Confidence (cont.)

Evidence from international case studies shows sustained investment in renewable assets during and after nodal pricing implementation.

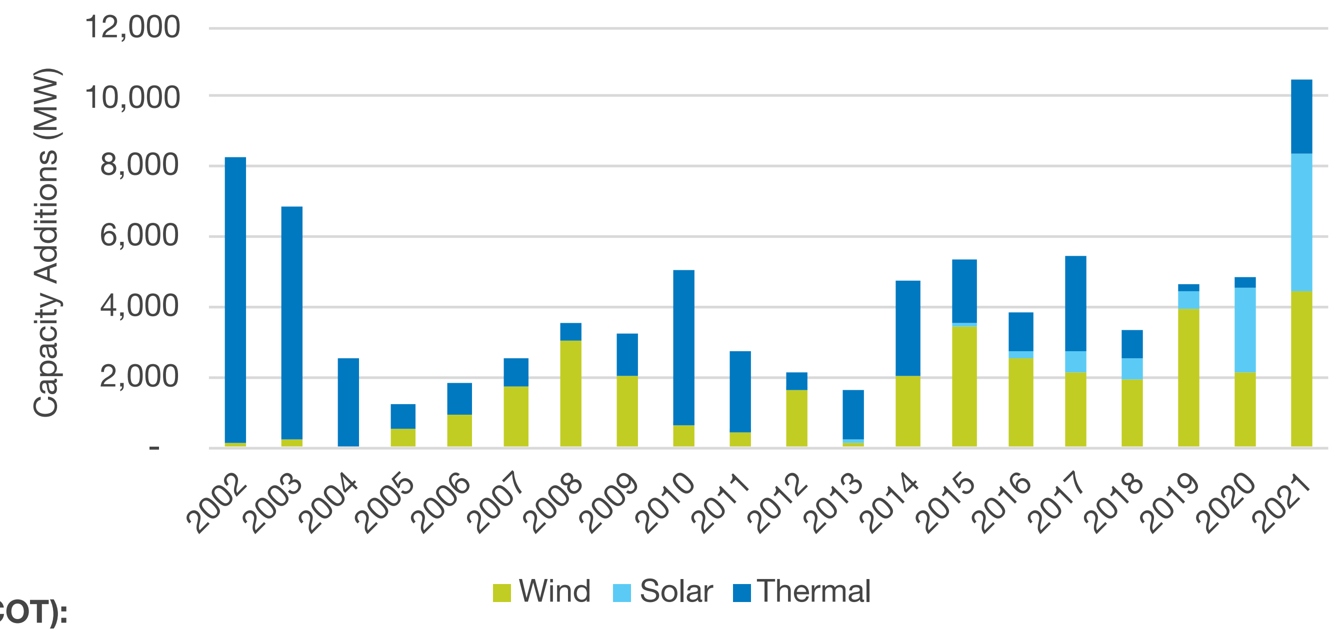
In several regions, other improvements to market design and policies to boost renewables buildout have been introduced in parallel to nodal pricing and have played an important role in driving investment. While the counterfactual of what investment would have happened without nodal pricing cannot be known, we have not seen evidence that implementing nodal pricing had a detrimental impact on investment.

California (CAISO)

Texas (ERCOT)

New Zealand

Texas Capacity Additions (MW) since LMP implementation



Texas (ERCOT):

Nodal pricing was implemented between 2002 and 2010. Since that period, installed wind capacity has tripled, from c.10 GW in 2010 to over 33 GW in 2022 with a further 4.4GW currently under construction (Windexchange, 2022). Relevant to the GB context, 67% of Texas wind capacity is located in West Texas, away from demand centres and therefore with reasonable expectation of lower nodal wholesale prices (ERCOT, 2021a). The introduction of Competitive Renewable Energy Zones (CREZ), whereby wind generators were guaranteed access to the transmission network, appears to have provided sufficient certainty to wind asset owners to invest. Wind generators in Texas are eligible for subsidy protection (federal production tax credits and state renewable energy credits, introduced in 1999) but rely on the state's energy-only market, which has benefited from ERCOT'S focus on ensuring market design delivers a well-functioning wholesale market and efficient price signals. Financial Transmission Rights were available from the point of implementation.

Source: US Energy Information Administration

Net Zero Market Reform / Location 42

Discussion of the Location Design Element

Investor Confidence (cont.)

Evidence from international case studies shows sustained investment in renewable assets during and after nodal pricing implementation.

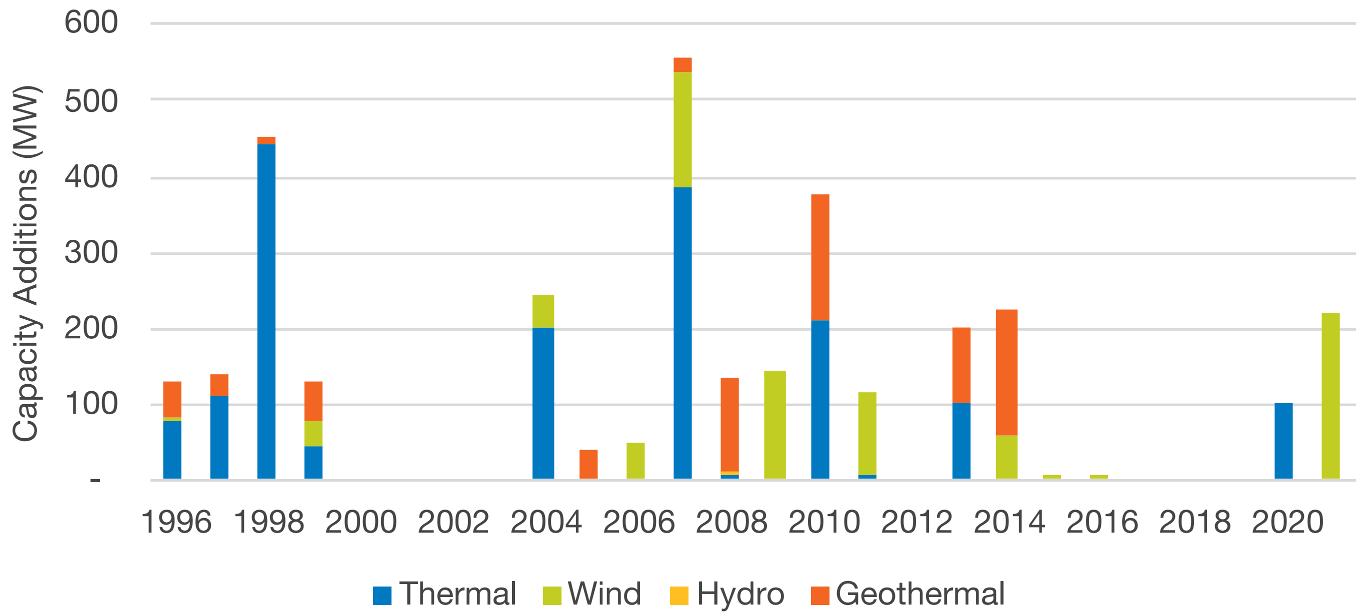
In several regions, other improvements to market design and policies to boost renewables buildout have been introduced in parallel to nodal pricing and have played an important role in driving investment. While the counterfactual of what investment would have happened without nodal pricing cannot be known, we have not seen evidence that implementing nodal pricing had a detrimental impact on investment.

California (CAISO)

Texas (ERCOT)

New Zealand

New Zealand Capacity Additions (MW) since LMP implementation



New Zealand:

New Zealand was the first jurisdiction to introduce nodal pricing, in 1996, with Financial Transmission Rights being introduced in 2013. New Zealand has a low carbon energy system, with c.53% of its generation from hydro and 5% of from wind (IEA, 2020). Since 1996, New Zealand has built one third of its current generation capacity (3.3 GW) of which c.25% is renewables capacity. New Zealand's substantial hydro capacity makes it less comparable with the GB market context but indicates that nodal pricing has proved to be an enduring model in a market with considerable flexible capacity.

Source: December 2021 CDR

Net Zero Market Reform / Location 43

Discussion of the Location Design Element

Consumer Fairness

Our assessment for consumer fairness was split into two considerations: firstly, the overall impact on average consumer bills, and secondly the potential regional variation in consumer bills.

1 Nodal pricing has greatest potential to reduce consumers bills (in aggregate)

Relative to national or zonal pricing, nodal pricing could drive significant cost savings for consumers in aggregate via reduced constraint costs, improved demand side flexibility and more efficient generator dispatch (see Value for Money above). Network charges and balancing costs would be lower compared with the current market design and these savings would also be passed through to consumers.

2 Various options for managing exposure of consumers to nodal prices

The interpretation of 'fairness', in terms of consumer bills, is inevitably highly subjective. It could range from:

- Consumers should bear equal retail tariffs irrespective of location; to
- Consumers should bear a cost-reflective tariff (reflecting the cost they impose on the system).

Currently in GB, although domestic consumers are not exposed to locational wholesale prices, the cost-reflective principle already exists in the setting of electricity network charges. For example, DUoS charges are the principal driver of regional differences in retail prices. The 2020/2021 DUoS charges on an average consumer bill varied by £73 between the Southern and North Scotland zones (Ofgem, 2022c). Our assessment scoring is consistent with this principle of cost-reflectivity and finds that nodal/zonal market designs enable retail tariffs to be more cost-reflective than national tariffs.

Net Zero Market Reform / Location 44

Discussion of the Location Design Element

Consumer Fairness (cont.)

Stakeholders raised that limiting nodal pricing to the supply side would significantly reduce its efficiency at the expense of a complex implementation process. We expect that supply-side only exposure to nodal prices would still be cost-effective; however we agree that to harness the full value of nodal pricing it is necessary to realise the potential savings via more efficient dispatch of demand side flexibility and distributed assets for which the demand side would need to be at least partially exposed to locational prices.

Demand side exposure could be varied by consumer type and according to which party is best placed to incur risk. For example, industrial and large commercial consumers may be better placed to directly manage this risk than residential customers. It should be noted that suppliers play a key role in mediating price signals by designing retail tariffs, managing risk on consumers' behalf and responding to consumers' preferences. Retail market design and the incentives suppliers are subject to are therefore highly relevant.

International experience suggests that exposing consumers to regional differentiation can however be politically contentious. There are a variety of ways to address this point and we have set out examples from other jurisdictions opposite. Several regions took a transitional approach, initially continuing to settle consumers at the national price before gradually moving to settling consumers at the weighted average of nodal prices in their region or to full nodal settlement. Other approaches include introducing nodal pricing to residential consumers and small businesses on an opt-in basis and compensating residential consumers for differences in average electricity prices between regions using credits and charges (Birkett et al., 2020; Savelli et al., 2020).

Consumers less exposed to nodal prices

Ontario (nodal pricing to be implemented in 2023)

- 'Active' (i.e. dispatchable), transmission-connected consumers (c.14% of load): settled at nodal price.
- Remaining 86% 'passive load' – settled at single province-wide price and can opt-in to nodal price.

PJM

- Similar to Ontario, allows customers to choose to be settled at their node. (PJM, 2014).
- Load which does not opt-in to nodal settlement is charged at the weighted average nodal price (not including the load that has settled at the node).

CAISO

- Three load zones settled at weighted average of LMPs per zone. Zones correspond to DNO territories.
- Allows Custom Load Aggregation Points (CLAP) (CAISO, 2021a) – consumers can apply to aggregate their load over one or more nodes. Load in a CLAP can be scheduled, priced and settled jointly. Requires approval by CAISO.

ERCOT

- All I&C load is settled nodally.
- All load in areas where electricity is open to retail competition (retail access load) is served at nodal prices (this represents c.75% of customers (ERCOT, 2021b)). Co-operatives and municipalities have rates determined by their cooperative/ town council.

Consumers more exposed to nodal prices

Net Zero Market Reform / Location 45

Discussion of the Location Design Element

Deliverability

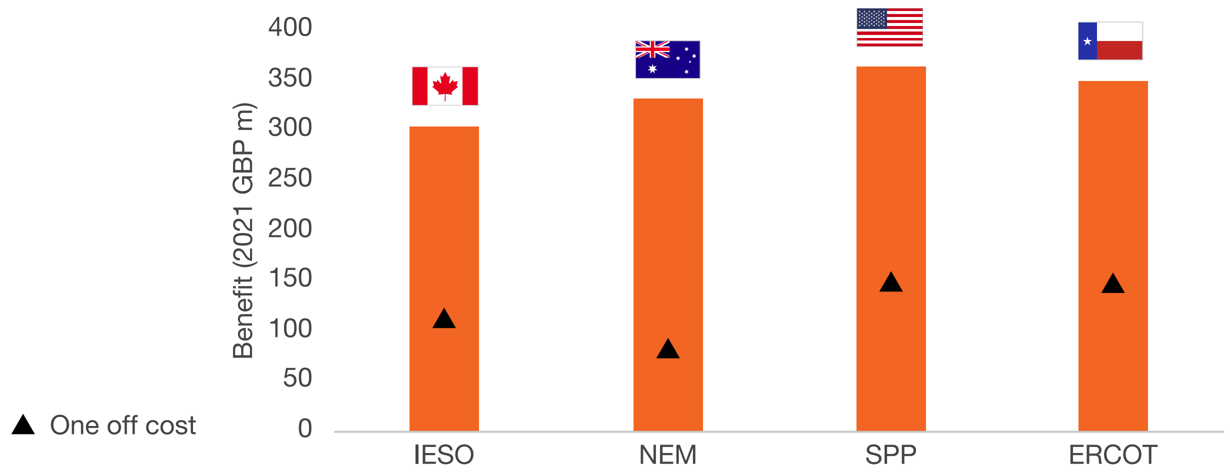
1 International experience suggests substantial one-off costs for nodal pricing outweighed by ongoing benefits

Relative to the baseline of existing arrangements, nodal pricing would involve the greatest change and cost to implement and would include the following one-off costs:

- **System Operator implementation costs:** costs to institute the processes, new IT & software systems. International review indicates costs have varied between £84 - £151m. Notably, ERCOT implementation overran with consequent cost increases.
- **Market participant costs:** costs to update systems and capabilities. International review indicates costs have varied between £50k and £600k per participant depending on their experience of operating in electricity markets with nodal pricing and central dispatch. We expect the cost to GB market participants would benefit from the availability of 'off the shelf' solutions that have already been developed.

Assessment of jurisdictions that implemented nodal pricing found that these one-off costs, which relate to the bundled solution of nodal pricing and centralised dispatch, would likely be considerably outweighed by the benefits that accumulate year on year. Following implementation, the ongoing additional costs of nodal pricing would be near to the ongoing costs of existing arrangements. Updates to ESO systems in particular are already required to adapt to electricity system evolution, with increasing digitalisation and diversification of market participants. Therefore, while the current arrangements scored better than zonal or nodal pricing, they did not score highly for Deliverability.

Indication of relative scale of benefits vs implementation costs of locational market reforms



	IESO	NEM	SPP	ERCOT
Installed capacity (GW)	38	52	95	135
Year of study	2015	2020	2004	2008
Implementation year	2023	n/a	2007	2010

Sources: Brattle (2017); NERA (2020); Ventyx (2009); CRA (2008)

2 Implementation timeframe greatest for nodal pricing, dependent on legislative and engagement processes

Based on international experience, implementation of nodal pricing would take between 4-8 years, depending on the efficiency of the stakeholder engagement and legislative processes. The implementation of zonal pricing would be heavily dependent on the time required to agree zone boundaries (see under Adaptability).

Net Zero Market Reform / Location 46

The Dispatch Design Element

The term dispatch mechanism relates to the balance of responsibility between market participants and the Market Operator/System Operator (MO/SO)[3] in determining when assets should generate or consume, at what capacity and for what duration.

The dispatch mechanism design can be broken down into three components:

Operational Schedule

Scheduling plan of resources to match supply and demand and to cover relevant contingencies

Unit Commitment

Refinement of operational schedule; issuing of instructions to specific plants e.g. with long notice periods

Operational Dispatch

The issuing of real-time dispatch instructions to fine-balance generation and demand

We considered three types of dispatch mechanism:

1. **Central dispatch with centralised commitment:** A central clearing algorithm, administered by the MO/SO, is used to schedule, commit and dispatch units to minimise system costs subject to security needs.
2. **Self-dispatch (the status quo):** participants self-schedule and commit their output. Following Gate Closure, ESO performs a redispatch role to manage energy balancing, congestion and operability issues that remain after the market clearing process.
3. **Central dispatch with self-commitment:** a central clearing algorithm, administered by the MO/SO, is used to schedule, commit and dispatch resources. Assets can additionally opt to self-schedule (see below).

In practice, markets with central dispatch and self-commitment vary in the proportion of the market that is centrally scheduled. This is a function of market design rules, the resource mix and other parameters. We did not conduct a deep analysis of central dispatch with centralised commitment since it does not give assets optionality in how they access the wholesale market.

National/Zonal Pricing → Self-dispatch (status quo)

Different locational wholesale market designs tend to be paired with specific dispatch mechanisms. National and zonal pricing are typically paired with self-dispatch. All jurisdictions with nodal pricing combine it with central dispatch, due to the need for a central clearing algorithm to calculate nodal prices.

Nodal Pricing → Central dispatch with self-commitment

3 In nodal markets with central dispatch, the 'Market Operator', responsible for running the clearing engine and determining the dispatch schedule, can be a separate entity from the 'System Operator' who provides the Market Operator with operational inputs such as network capacity and also issues dispatch instructions. In this document when referring to central dispatch we refer to the two roles separately although recognising that in a GB context they could be combined.

Net Zero Market Reform / Dispatch 47

The Dispatch Design Element

Key aspects of self-dispatch and central dispatch designs

1 Ancillary services co-optimisation

A major differentiator between self-dispatch and central dispatch models is that under central dispatch, scheduling of energy, reserve (and in some markets additionally other ancillary services) are undertaken within the same process, so that the two markets are 'co-optimised'. The co-optimisation process automatically determines whether the asset provides energy and/or ancillary services, based on what would provide most system value. To ensure that asset owners do not incur opportunity cost from providing either energy or reserve, they are selected for whichever provides the higher variable profit. For example, an asset would not be selected to provide reserve if it could earn its owner greater profit supplying energy. In the same way, an asset that could earn more from providing reserve would not be selected to provide energy.

In the current GB design and in most EU markets, ancillary services are procured separately from energy. Participants can therefore alter their prices if they know competitors have already committed to trading a particular product.

2 Bidding formats and market clearing

The type of information provided in bids and offers and the way that these are cleared is connected to the choice of dispatch mechanism. Central dispatch self-commitment markets such as NYISO, CAISO and MISO use multi-part bidding formats which explicitly account for individual units' operational and opportunity costs (e.g. start-up costs) and their technical constraints (Herrero et al., 2020). Where appropriate (e.g. for renewables) it is possible to submit simple price-quantity bids and offers. The objective of multi-part bids is to give the MO/SO the fullest possible visibility of all asset resource and capabilities in its jurisdiction at the time of market clearing and therefore before the scheduling process.

In the current GB self-dispatch market, participants submit bids and offers into the BM with asset-level technical information but crucially system operation considerations are split from the wholesale energy market. Companies that own multiple generation units can combine orders for multiple assets and then optimise dispatch for their portfolio. In this way a greater degree of the scheduling process is left to market participants.

Net Zero Market Reform / Dispatch 48

The Dispatch Design Element

3 Combining central dispatch with self-commitment

In many jurisdictions, central dispatch is combined with bilateral trading and self-commitment. Participants who 'self-commit' provide or consume energy without being optimised by the MO/SO in either the day-ahead or real-time markets. They can inform the MO/SO of how their resource will run, but not submit a formal offer with information on price, start-up and other costs. The option to self-commit gives market participants optionality in that they are not financially committed to providing energy; however, the resource becomes a price taker and is not remunerated for their start up and minimum load costs as is the case for centrally scheduled assets. For example, PJM's market arrangements combine central dispatch with some elements of a decentralised model, including self-scheduling and voluntary participation in the day-ahead market for some market participants, though participation in the real-time market is mandatory if a participant bids into the day-ahead market and is scheduled as day-ahead schedules are financially binding.

The extent of self-commitment needs to be limited, however, by the practical need to centrally calculate the nodal prices, requiring sufficient volume of offer prices and a minimum fraction of bids to be price-elastic to deliver meaningful prices, and to ensure efficient market outcomes (CEPA, 2021).

Important design considerations are the period in which market participants can self-schedule and how self-scheduling participants are settled.

In US-style central dispatch markets, bilateral physical contracts struck at specified nodes are netted off participants' metered volumes at that node with cash out of deviations between committed and metered output by node at the real-time nodal price.

Illustrative central dispatch clearing with self-schedules

Source: CAISO (2019)

Net Zero Market Reform / Dispatch 49

Dispatch process: main stages

Central dispatch (with centralised commitment)

Central dispatch (with self-commitment)

Self-dispatch

-36h | -24h | -18h | -12h | -6h | -1h | Real-time

Gate Closure

1 Operational schedule

Submit capacity available and Bid/Offer data at Day Ahead.

Run Long Term Scheduling algorithm to determine which plant to run.

2 Unit commitment

- Refinement of operational schedule.
- Issuing instruction (commit) plants with long notice period.

3 Operational dispatch

- The issuing of dispatch instructions to fine-balance generation and demand.

Key

Market Participants

Market Operator (MO)

Italy

Poland

Greece

Malta

Cyprus

Participant-to-participant trading

Day ahead market

MO runs dispatch optimisation algorithm… (absence of Intra day trading) …to determine clearing price

MO dispatches power at clearing price.

…and determines final production schedule

Net Zero Market Reform / Dispatch 50

Dispatch process: main stages

Central dispatch (with centralised commitment)

Central dispatch (with self-commitment)

Self-dispatch

-36h | -24h | -18h | -12h | -6h | -1h | Real-time

Gate Closure

1 Operational schedule

- Submit availability and price.
- Suppliers can self-schedule or submit incremental offers.
- Buyers submit bids to buy.

- MO clears DA market based on participant bids/offers and schedules using a security constrained tool.
- MO determines financially binding schedules.

2 Unit commitment

- Update offers, self-commit additional units, submit additional self schedules.

- MO may run an intra day unit commitment process to commit short-start units.
- Instruction to non-committed plants.

3 Operational dispatch

- Security constrained instructions to fine balance generation and demand and resolve constraints.

Bilateral contracts can exist alongside a centrally-determined clearing price

Bilateral market – OTC and forward trades

Day ahead market

Intra-day trading: market participants can choose to self-commit or self schedule generation to cover bilateral trades or cover them with spot market purchases if this is lower cost.

MO has no role in bilateral trading but determines the clearing price

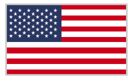
MO dispatches power at clearing price.

…and determines final production schedule.

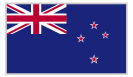
Key

Market Participants

Market Operator (MO)


USA


Canada


New Zealand


Singapore

Net Zero Market Reform / Dispatch 51

Dispatch process: main stages

Central dispatch (with centralised commitment)

Central dispatch (with self-commitment)

Self-dispatch

-36h | -24h | -18h | -12h | -6h | -1h | Real-time

Gate Closure

1 Operational schedule

- Submit intended position, capacity available and Bids/Offers.
- Monitors (to ensure sufficient capacity is available).

2 Unit commitment

- Can change intended position, availability and price.
- Monitors and issues instruction in case of insufficient margin.

3 Operational dispatch

- Dispatch instructions to fine balance generation and demand and resolve constraints.

Key

Market Participants

Market Operator (MO)

UK

Spain

France

Austria

Germany

Participant-to-participant trading

Bilateral market – OTC and forward trades

Day ahead market

Intra-day trading

Participant-to-MO trading

Balancing mechanism and ancillary services called

Trading period

Net Zero Market Reform / Dispatch 52

Summary Assessment of Dispatch Design Element

The assessment provides a relative comparison of central dispatch with self-commitment and self-dispatch against our assessment criteria. We have not included central dispatch with centralised commitment in the assessment given its unsuitability for the future GB market as discussed in the previous section. Our scoring of this element is independent from our assessment of Location and does not account for the role of central dispatch in enabling nodal pricing.

	Central dispatch: Centralised commitment	Central dispatch: Self-commitment	Self-dispatch	
1 Decarbonisation		Minimal impact	Minimal impact	Level of decarbonisation driven primarily by the amount of low carbon support, and not by dispatch market designs per se.
2 Security of Supply		Minimal impact	Minimal impact	Level of security is driven primarily by the (1) reliability standard and (2) policies / regulations to deliver that standard, and not by dispatch market designs per se.
3 Value for Money		Moderate +ve impact	Moderate -ve impact	A central dispatch market design could provide greater value for money to consumers as it enables the system operator to manage high volumes of intermittency on a system-wide basis.
4 Investor Confidence		Moderate +ve impact	Moderate +ve impact	Both dispatch market design options would have a positive impact on investor confidence towards net zero, due to ability to hedge their risk appropriately.
5 Deliverability		Moderate -ve impact	Unclear impact	Moving to a central dispatch model would require a full market reform, which could potentially be costly. Long term sustainability of maintaining self-dispatch market design towards net zero is currently unclear.
6 Whole System		Minimal impact	Minimal impact	Both dispatch market design options would have a negligible impact on other energy vectors.
7 Consumer Fairness		Minimal impact	Minimal impact	Both dispatch market design options would have a negligible impact on consumer fairness.
8 Competition		Moderate +ve impact	Minor -ve impact	A central dispatch model presents limited upfront costs for prospective new entrants (these costs would be similar across all market participants including incumbents), meaning lower barriers to entry and greater market transparency.
9 Adaptability		Moderate +ve impact	Significant -ve impact	A central dispatch model is more adaptable to changes in technology and real-time market conditions as it can (1) enable delivery of all locational market design elements; and (2) better facilitate co-optimisation between energy and ancillary services (e.g. reserves).
10 Full-chain Flexibility		Moderate +ve impact	Minor -ve impact	Self-commitment central dispatch is likely to more efficiently accommodate the flexibility potential of all assets in the energy system.

Key: contribution towards a net zero market

Significant -ve impact · Moderate -ve impact · Minor -ve impact · Unclear impact · Minimal impact · Minor +ve impact · Moderate +ve impact · Significant +ve impact

Net Zero Market Reform / Dispatch 53

Discussion of the Dispatch Design Element

The full rationale for the scoring is provided in the separate Annex. Here we focus on where central dispatch with self-commitment would bring benefits for GB in the context of meeting net zero that distinguish it from self-dispatch: Value for Money, Competition, Full-Chain Flexibility and Adaptability. It also addresses the areas of Deliverability where stakeholders have raised concerns.

Value for Money

1 Central dispatch facilitates greater system efficiency than self-dispatch

Under the current self-dispatch mechanism, market participants (both generators and loads) are incentivised to buy or sell ahead of time rather than face imbalance charges. The continuing growth of non-dispatchable intermittent generation, however, is making it harder for a growing proportion of the GB market to self-dispatch the energy it has presold. Owners of non-dispatchable assets must refine their positions in intraday markets or, as may be easier, allow their unbalanced energy to be corrected via the BM and incur, or receive the system imbalance price.

When GB's self-dispatch model was originally introduced, the ESO's role in balancing the market was expected to reduce. The reverse trend has been happening over the last decade with ESO managing an increasing proportion of trades but without the appropriate infrastructure and tools, and in a limited timeframe. Moving Gate Closure so that ESO has more time to redispatch would reduce the opportunity for flexible assets to respond to transparent, near real-time wholesale price signals and would increase reliance on the BM. While the current review of the BM may reveal opportunities for improvement, the mechanism is fundamentally limited in providing transparent, forward-looking signals for flexible assets.

Even with the strongest possible incentives to self-balance under self-dispatch, a central dispatch model with day-ahead and real-time scheduling is better positioned to optimise across the system: all generators, rather than just BM units, as well as consumers (via retailers) are incentivised to provide the MO/SO with granular information on their asset capabilities and start-up costs at the day-ahead stage. At the point of dispatch, the MO/SO can access this greater diversity of assets to manage unforeseen energy imbalances. When combined with nodal pricing, flexible assets and demand response can use the day-ahead locational prices to prepare to respond to forecast congestion.

International empirical studies indicate that following the implementation of nodal pricing and central dispatch, generators incurred substantially lower operational costs through more efficient fuel use and ramping (c.2.1% in CAISO (Wolak, 2011) and 3.9% in ERCOT (Triolo & Wolak, 2021). In the GB net zero context, the increasing proportion of intermittent renewables will drive a greater need for flexible operation of assets. Such relevant flexible plant will include decarbonised thermal assets (BECCS, CCUS, hydrogen). Central dispatch may also facilitate greater optimisation of storage cycling.

Net Zero Market Reform / Dispatch 54

Discussion of the Dispatch Design Element

Value for Money (cont.)

2 Central dispatch delivers major savings by co-optimising energy and reserves

In recent years, ESO has introduced incremental improvements towards real-time procurement of ancillary services to realise efficiencies and improve competition; however, under current arrangements, all ancillary services are still scheduled separately from energy. This results in inefficient procurement since ancillary service providers must account for their opportunity costs of not dispatching energy (for instance potential BM revenues) when choosing whether to trade. As discussed above, by ensuring that asset owners do not incur opportunity cost from providing either energy or reserve, co-optimisation enables greater competition for both services.

A central dispatch model would significantly improve short-run dispatch outcomes as it can enable near real-time co-optimisation of energy and some ancillary services. Evidence from jurisdictions that implemented co-optimisation suggest that substantial savings can be made (see Value for Money above).

3 Central dispatch would reduce some gaming risks

Evidence from other markets[4] highlights the risk of participants gaming between the wholesale market and balancing services markets to resolve network constraints, which can be exacerbated by abuse of market power. Where the clearing mechanism is pay-as-bid, generators in front of network constraints can increase their prices knowing they will still be dispatched, while generators behind the constraint can decrease their prices to ensure they will be compensated for downward redispatch[5]. There is evidence in the Italian zonal market that gaming of the redispatch process is driving increased balancing costs (Wolak, 2021). Similar concerns drove both the PJM and CAISO markets to transition from zonal to nodal pricing in the early 2000s.

Nodal pricing combined with central dispatch would eliminate this particular gaming risk. It must be noted that abuse of market power is a risk for all market designs and therefore requires effective market monitoring and mitigation measures. With the introduction of nodal pricing, enhanced market monitoring would be necessary and has proven to be effective when established in other jurisdictions.

4 For example, increased costs due to inc-dec gaming was one of the main reasons to move from zonal to nodal markets in CAISO, see Alaywan et al. (2004)
5 This type of gaming is sometimes referred to as the "inc-dec game" see Eicke and Schittekatte (2022)

Net Zero Market Reform / Dispatch 55

Discussion of the Dispatch Design Element

Competition

1 Central dispatch could considerably improve competition

A central dispatch model could increase competition in wholesale markets by improving market access and transparency. The MO/SO acts as counterparty to all centralised market trades, providing a simple route to market, reducing the burden on new entrants to find a trading partner and to enter into bespoke contracts. While market participants would have the choice to trade in the centralised market or self-commit, it is expected that a larger portion of the market would be settled centrally compared to today, meaning new entrants would have greater visibility of prices and improved access to market data. Co-optimisation of energy and ancillary services and increased standardisation of products under central dispatch serves to maximise the depth of the wholesale market.

Facilitating Full-chain Flexibility

1 Improved competition with central dispatch critically important for flexibility

Our analysis found that a central dispatch market design would be better suited to unlocking the potential of Full-chain Flexibility. Greater access and a more direct route to market, with a central algorithm matching trades, would facilitate greater participation of small and aggregated flexible energy resources who will have a crucial role in achieving net zero. Improved transparency and real-time price availability compared to the self-dispatch model would help guide the decision-making of flexibility providers across all levels of the electricity system.

Some stakeholders questioned whether a move to central dispatch, and the consequent reliance on the MO/SO's central processes and computing power, would constrain the operation of decentralised assets. We found that DER participation in centrally-dispatched markets such as CAISO and NY ISO is advanced. In CAISO, aggregations of 100kW can provide energy at day-ahead or real-time and aggregations of 500kW and above can provide ancillary services. Aggregations must be under the same Sub-Load Aggregation Point (there are 23 Sub-LAPs covering around 12,000 nodes) (CAISO, 2021b). In NY ISO, to minimise impact on the central dispatch processing time, NYISO will combine the offers of all DER Coordinating Entity Aggregation (DCEA) less than 1 MW into a "Super Aggregation" (SA) at the same transmission node, in order to be considered by NYISO's Security Constrained Economic Dispatch tool as a single resource.

2 Central dispatch facilitates energy arbitrage for demand

The combination of centralised day-ahead markets and real-time spot markets used in CAISO, ERCOT, NY ISO and other markets facilitates active participation of demand-side assets in operational timescales. In this model, large consumers and retailers submit the price and volume at which they are willing to purchase in the day-ahead market. These bids are cleared against offered supply. The resulting schedule represents a financial commitment. When suppliers or large consumers schedule demand in the day-ahead market that they do not ultimately consume, the differential is sold at the real-time market price, incentivising demand response during periods of high real-time prices. Under current arrangements, demand side assets not in the BM have limited opportunity for arbitrage against real-time prices.

Net Zero Market Reform / Dispatch 56

Discussion of the Dispatch Design Element

Adaptability

1 Self-dispatch model not meeting expectations or needs

The current self-dispatch model is far from meeting the original expectations at the inception of NETA that ESO's residual balancing role would reduce over time. ESO's activity in the balancing timeframe has increased significantly to the extent that it is, in practice, close to conducting central dispatch to balance the system but without the appropriate tools to do this efficiently (see Introduction). The current model has therefore not adapted to GB's decarbonising electricity system and we have not found evidence to suggest it can be adequately reformed for net zero.

We do not believe that transformation capability (for example adapting dynamic parameters to reflect new technologies) is a differentiator between the central and self-dispatch models.

2 Centralised dispatch model enables adaptability to near real-time market conditions

As we move to net zero, we expect considerable innovation and greater diversity of energy technologies and business models. Co-optimisation would give the MO/SO access to a wider range of resources for energy and system balancing needs in near real-time. Increased visibility of available resource and the ability to conduct day-ahead scheduling across the system reduces redispatch requirements at point of delivery.

3 Under either option, uncertainty regarding interaction with distribution system

It is critical that future markets are set up to accommodate participation by distribution-connected resources. Further coordination between markets at different voltages will be necessary to ensure whole system efficiency and to avoid perverse trading incentives. A key area of uncertainty is how a central dispatch market would interact with DNOs/DSOs and local markets. Globally, coordination between transmission and distribution level markets is nascent in both self-dispatch and centrally dispatched jurisdictions. We found that, under central dispatch, DERs could find it easier to optimise between transmission and distribution level markets because:

1. **Co-optimisation of energy and ancillary services reduces coordination burden:** DERs must currently optimise between the wholesale markets, DNO, local markets and multiple transmission-level markets (e.g. ancillary services, BM, wholesale markets). Under central dispatch, with energy and ancillary services co-optimised, the market landscape is streamlined, better facilitating price optimisation.

2. **Improved wholesale market price transparency:** A larger portion of the wholesale market would be settled centrally than as is the case today, meaning new entrants would have greater visibility of ESO prices and improved access to ESO market data.

Additionally, locationally accurate, transmission-level price signals would enable DERs to realise greater value in resolving transmission-level congestion. Improving the business case for these assets at wholesale market level could lead to increased flexible capacity available to trade in distribution-level markets.

Nevertheless, the interaction of central dispatch and self-commitment with the distribution system market arrangements, and how these might evolve in the longer run, is something that requires deeper exploration through stakeholder engagement.

Net Zero Market Reform / Dispatch 57

Discussion of the Dispatch Design Element

Deliverability

1 Sustainability of self-dispatch model highly uncertain

Moving to central dispatch with self-commitment would be a substantial change from the status quo. It would mean implementing centralised markets potentially for both day-ahead and real-time timeframes, new scheduling and pricing software, robust access protocols, and changes to metering and settlement processes, amongst other requirements. This would involve substantial one-off costs for the ESO and market participants (see the 'Deliverability' criterion under previous section on Location).

However, we found the deliverability of the self-dispatch mechanism for net zero to also be highly uncertain. As discussed in the Introduction, ESO can be considered as already transitioning to a de facto central dispatch role but without the supporting market infrastructure. Given the continued trajectory of transmission congestion (as evidenced by NOA 6) we expect that further interventions and considerable investment in ESO dispatch processes will be necessary to improve day-to-day operation of the self-dispatch mechanism.

Net Zero Market Reform / Dispatch 58

Implementation Roadmap

We believe it is credible to implement nodal pricing and central dispatch within five years. The implementation process can be divided into three phases:

1 Assessment Phase

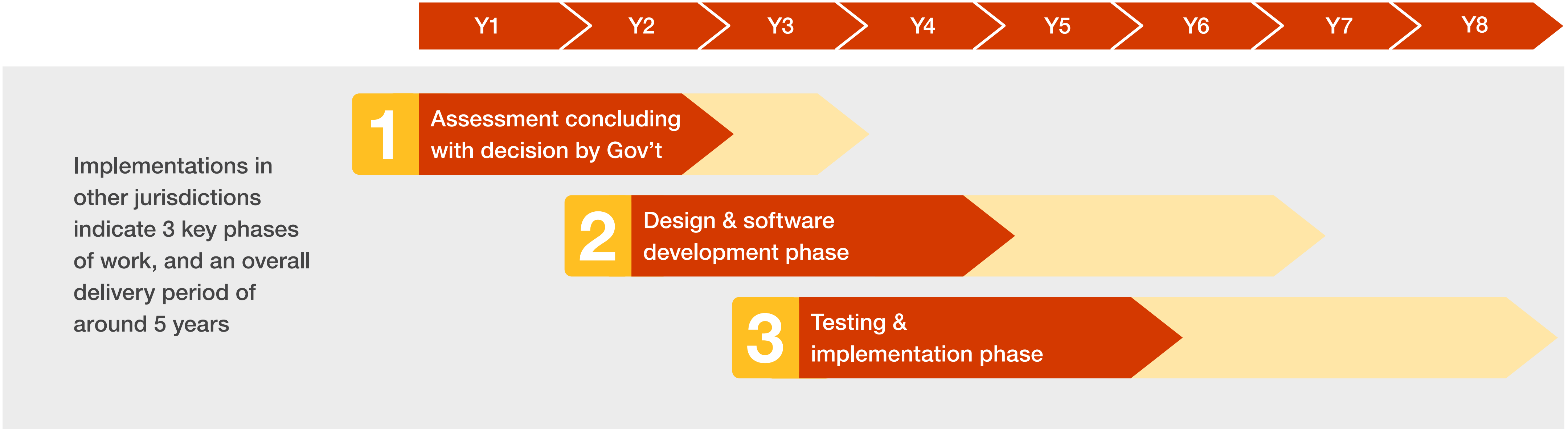
2 Design & Software Development Phase

3 Testing & Implementation Phase

Most efficient delivery of nodal pricing and central dispatch would require significant overlap between these staggered phases, with an overall delivery period of between 4-8 years.

The design of the stakeholder engagement process, and the scope of what is included in the transformation and legislative process are key factors that influence the delivery timeframe of a nodal market. Changes to the scope can delay implementation. For example, in ERCOT (Texas), implementation was delayed twice due to stakeholders requesting that additional market design changes be delivered alongside the transition to nodal pricing. Experience from other jurisdictions indicates that implementation can be expedited by taking fundamental choices early in the design process and resisting the temptation to introduce additional market design and software changes.

Given the high stakes for consumers, a well-designed and comprehensive stakeholder process is necessary. Experience in the MISO and CAISO markets shows that nodal pricing can be achieved more quickly with an efficient and effective stakeholder approach. Four years may be the shortest realistic implementation period based on international precedents.



Net Zero Market Reform / Implementation Roadmap 59

Update on Investment Market Design Elements

In our Phase 2 Options Assessment Framework, we identified four key components of electricity market design relating to Investment. Three of these were categorised as 'first order' meaning that their assessment should logically be conducted before the fourth 'second order' element.

Investment elements identified as first order:

1. **Low Carbon Support:** The degree to which the low carbon technology mix is determined by the government. It is assumed that the government will continue to determine the overall carbon reduction requirement for the electricity sector.

2. **Capacity Adequacy:** The degree to which the firm capacity technology mix is determined by government.

3. **Flexibility:** The degree to which both the overall flexibility requirement itself, as well as the flexibility technology mix, is determined by government. Unlike low carbon and capacity adequacy, the government does not currently determine overall flexibility requirements (e.g. via a flexible capacity target).

Investment elements identified as second order:

4. **Low Carbon Support Mechanism:** The degree to which variable renewables generation is protected from wholesale price volatility.

As discussed in the Approach section, following our Phase 3 assessment of the Operation market design elements, we will assess the Investment market design elements listed above (see Next Steps).

Since Phase 2 we have also identified two additional investment design options we will consider in our assessment:

1. **Scarcity price adder for Capacity Adequacy:** Scarcity price adders provide additional remuneration for electricity by providing top-up revenue to assets that are available to generate via a wholesale price premium. The value of the top-up increases as the supply margin decreases, reflecting the added value of availability at times of limited supply. The objective of scarcity adders is to strengthen the forward-looking investment signal to assets that can be available at times of system stress, in addition to that already provided via wholesale and other balancing markets.

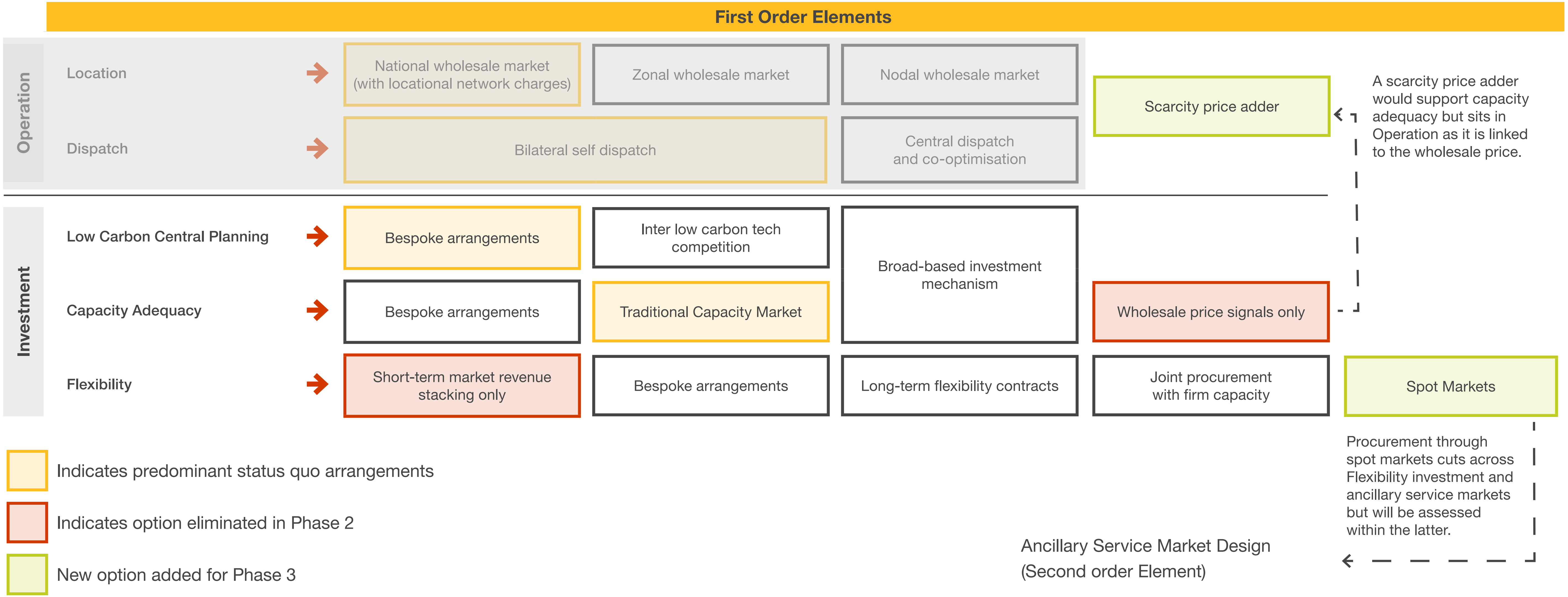
2. **Spot markets for Flexibility:** Flexibility services, which a central authority (likely the Market Operator) procures in near real-time. The central authority determines the requirements for specific flexibility products. Resources are rewarded based on near real-time supply-demand clearance for each flexibility service. These flexibility services can be co-optimised with one another and in centrally dispatched markets, these services may be co-optimised with the real-time spot market for energy.

We intend to conduct a full assessment of the Investment market design element options in a similar manner to our Phase 3 assessment of the market design options relating to Operation.

Net Zero Market Reform / Update on Investment Market Design Elements 60

Update on Investment Market Design Elements

The following diagram shows the first order market design elements and reform options which remain to be assessed.



Net Zero Market Reform / Update on Investment Market Design Elements 61

Next Steps

There will be three main priorities for the next phases of ESO's Net Zero Market Reform programme, which will encompass the full range of market design elements scoped in our Phase 2 publication.

1) Support OFGEM's Technical assessment of locational pricing options

In addition to supplying data required to model nodal pricing in a GB context, we will provide evidence from our work to date to complement and help inform the assessment.

2) Detailed assessment of nodal pricing and central dispatch implementation considerations, including impact on stakeholders

This will consider in greater detail the impact of nodal pricing and central dispatch on different stakeholder cohorts, including end-consumers. It will also explore the key implementation design options and consider realistic end-to-end implementation processes and associated timelines.

3) Assessment of other market design elements under a nodal pricing and central dispatch model

Having established that nodal pricing and central dispatch should form the foundation of an enduring net zero market design, the other market design elements will be assessed against this baseline. These include:

a) First Order Investment elements (Low Carbon Support, Capacity Adequacy, Flexibility)

b) Elements identified in Phase 2 as 'Second Order'

- i. Settlement Period Duration: How frequently the market for trading and balancing is settled. Reducing the settlement period may help to reveal the additional flexibility value within time periods.
- ii. Ancillary Services Market Design: The precise nature and volume of balancing services required are a residual outcome of other market design, which drives the proportion of flexibility and intermittent renewables capacity on the system.
- iii. Low Carbon Support Mechanism: The degree to which variable renewables generation is protected from wholesale price volatility.

Future stakeholder engagement

Input from our stakeholders through co-creation workshops, webinars and bilateral discussions has been crucial throughout this programme so far and will continue to play a central role in our work going forwards. As we move into this next phase of more detailed assessment of reforms, it is vital that we work even more closely with our industry partners, as well as with Ofgem and BEIS.

Interaction with BEIS' REMA programme

On 7 April 2022, in its wider policy paper on British Energy Security Strategy, the government announced that BEIS will be undertaking a comprehensive Review of Electricity Market Arrangements (REMA) in Great Britain, with high-level options for reform to be set out this summer. We expect that nodal pricing and central dispatch will be identified amongst these high-level options, all of which would be subject to extensive stakeholder consultation and detailed assessment by BEIS prior to any formal implementation decision. ESO looks forward to supporting BEIS as a trusted strategic partner in the REMA programme.

Net Zero Market Reform / Next Steps 62

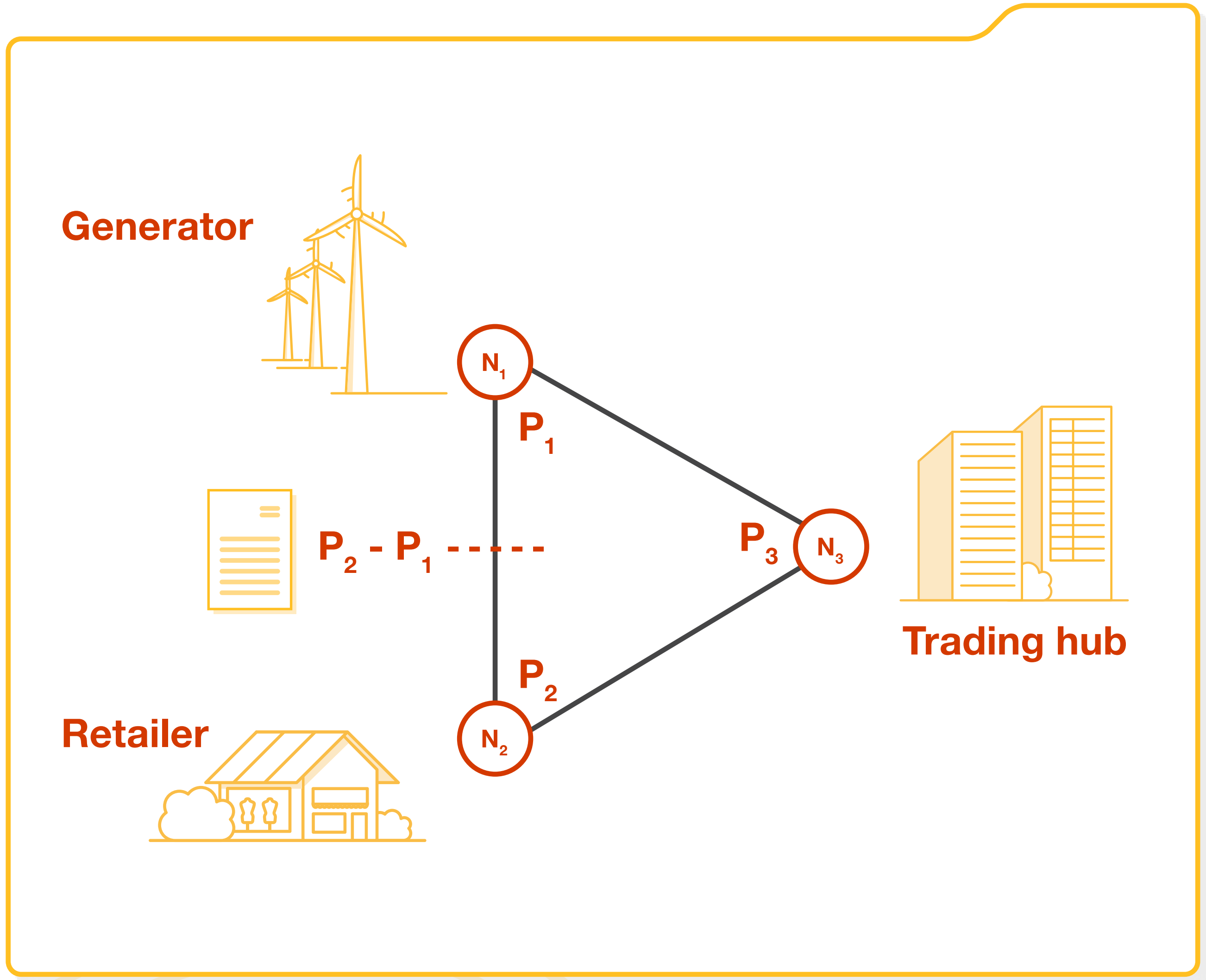
Appendix

Appendix 1: Financial Transmission Rights (FTRs)

In all nodal markets, FTRs are a financial instrument widely used by retail suppliers and generators to hedge their exposure to pricing differences between nodes. There are many forms of FTRs, but all are created by the market making entity (i.e. the SO/MO) and are funded through the difference between the charges on withdrawals and the payment for injections (otherwise known as congestion rent), so there is a natural limit to the amount of FTRs that can exist at a point in time.

FTRs hedge congestion charges such that generators and buyers are essentially buying power at the trading hub price plus or less any credits/charges for incremental losses.

How they work



Generator

- A generator can sell power forward at a trading hub and buy an FTR to hedge congestion between its location and the trading hub. In the example shown, the generator holds an FTR from N1 to N3, receiving P3 - P1 at settlement (as well as P1 in the wholesale market).
- The generator can use the same FTR to hedge sales to different buyers at the hub in different periods.
- The FTR hedges congestion charges so the generator is essentially selling power at the trading hub price (plus or less any credits/charges for incremental losses).

Retailer

- A power consumer or retailer can buy power forward at a trading hub and buy an FTR to hedge congestion between its location and the trading hub. In the example shown, the retailer/consumer holds an FTR from N1 to N2, covering retail volume, receiving P2 - P1 at settlement. Alternatively, retailer could buy power at the trading hub and hold an FTR from N3 to N2.
- The buyer can use the same FTR to hedge purchases from different generators at the trading hub in different time periods.
- The FTR hedges congestion charges so the buyer is essentially buying power at the trading hub price (plus or less any credits/charges for incremental losses).

Net Zero Market Reform / Appendix 63

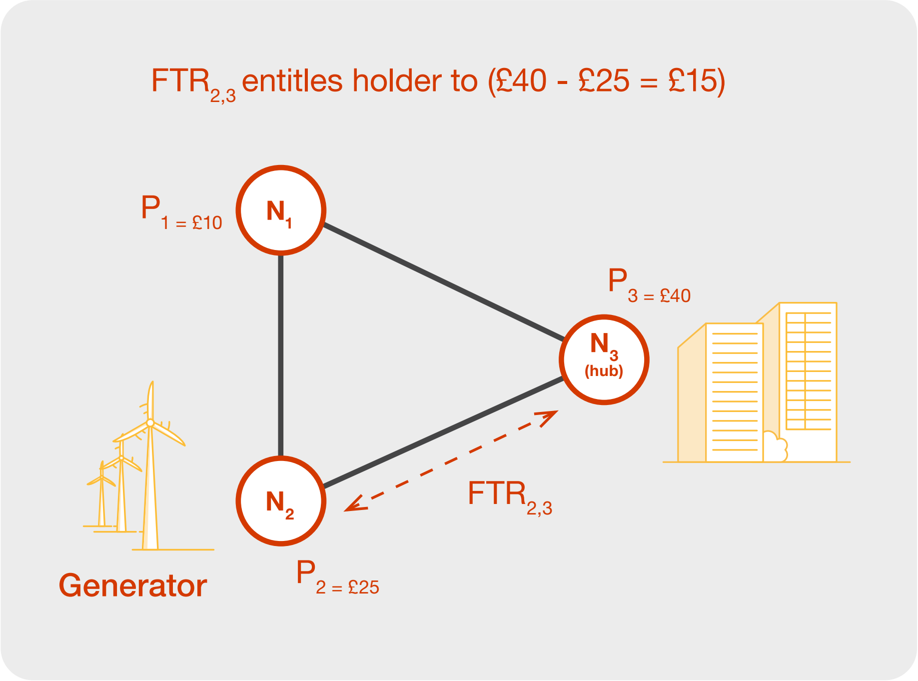
Appendix 1: Financial Transmission Rights (FTRs)

How are FTRs purchased and used?

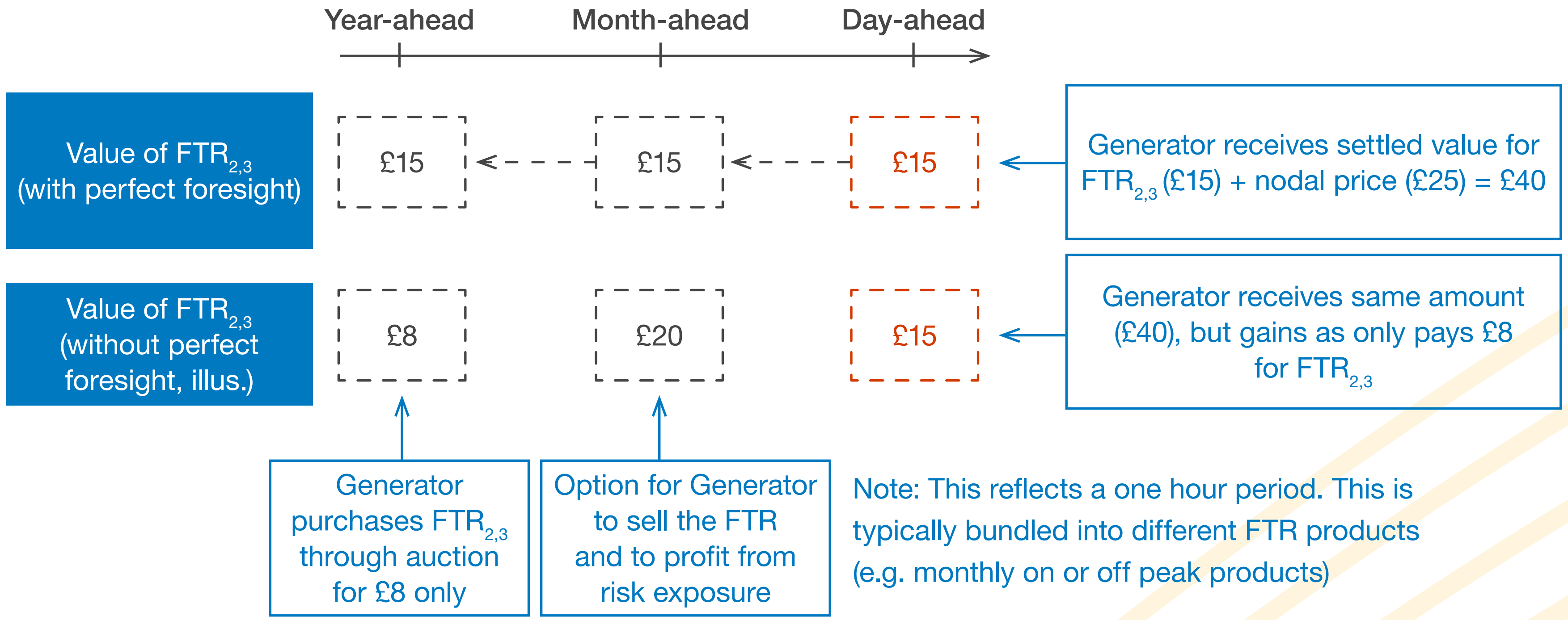
The graphic below represents a stylised 3-node example to illustrate the purchase and use of FTRs. In this system, each node has a different nodal price due to transmission constraints and the nodal prices are calculated at dispatch. Node 3 represents the trading hub. In this example the generator is exposed to the price at Node 2 but wishes to be hedged against this risk and instead be exposed to the Node 3 price. The generator therefore purchases an $FTR_{2,3}$ for each MW for each hour across the year.

As illustrated below, there can be opportunities over the duration of the FTR to profit from risk exposure and the final FTR value settled at the day-ahead market could involve a gain or loss depending on the original value of the FTR at time of purchase. With perfect foresight, the original value of the FTR, purchased in advance (e.g. year-ahead, month-ahead) would equal the final value when sold in an FTR auction or settlement through the day-ahead market. As foresight is usually imperfect, however, the FTR holder would make a gain or loss depending on the difference between original and final value of the FTR, with the difference in value reflecting any change in conditions over time such as new investment in generation, demand reduction or transmission networks that impacts congestion.

Stylised example of FTR purchase



Example of Generator revenue from FTR settled at Day Ahead



Note: This reflects a one hour period. This is typically bundled into different FTR products (e.g. monthly on or off peak products)

FTRs can be obtained through (1) annual or monthly auctions; (2) the secondary market; or (3) ex-ante allocation. We discuss (3) in the next slide.

Net Zero Market Reform / Appendix 64

Appendix 1: FTR Auctions

Typically, FTRs are bought and sold through competitive auctions administered by the SO, which award the FTR holder an entitlement to the congestion charges between the FTR sink (load location or hub location) and source (generator location or hub location) across the relevant time period. Evidence from other jurisdictions shows that transaction costs for purchasing FTRs are minimal.

As payments made by retailers will exceed payments received by generators as long as there is congestion, FTR auction revenues are returned to load/consumers because they pay for the transmission system. Ultimately full recovery of transmission network costs is required, collected through congestion charges (i.e. nodal prices) and/or transmission charges; the share of costs collected from each mechanism is a policy decision though market design should aim to provide the sharpest locational signals possible. There are two broad theoretical approaches to allocating auction proceeds to consumers:

- **Socialise all proceeds across all consumers –** The auction delivery body would pass on benefits by reducing transmission network charges.
- **Allocate value through the allocation of FTRs to users of the transmission network** (typically retailers, who would pass on benefits to consumers, assuming a competitive market) – In other jurisdictions, allocated FTRs are known as Auction Revenue Rights (ARRs). ARRs are slightly different to FTRs as specific rules regarding who can hold them can apply and long-term rights can be provided. Allocating ARRs/FTRs helps develop the FTR market.

Holders of allocated FTRs (or ARRs) have two options:

1. **Retain it** (and receive a fixed revenue based on the outcomes of the FTR auction); or
2. **Convert it to an FTR** for self-scheduling (by receiving the difference in nodal prices at settlement in the day-ahead market).

In jurisdictions with nodal markets, there exists variation in relation to auction timeframes and the duration of FTRs, driven by demand and resulting from stakeholder processes. All US ISOs, however, have monthly auctions and auctions extending out a year in either annual or seasonal terms.

Overview of FTR trading timescales

Shorter duration → Longer duration

Monthly

- All US ISOs have a monthly auction, covering the prompt month
- Some ISOs hold back capacity especially for these auctions
- Sometimes referred to as reconfiguration auctions
- Allows retailers to reconfigure their hedges from month to month

Annually

- All US ISOs run auctions extending one year, either in seasonal or annual terms (“delivery auctions”)
- For seasonal auctions, FTRs are sold in seasonal durations so market participants can buy an FTR covering one season without having to buy the FTR in other seasons

Future Years

- First implemented in PJM in 2008 covering 3 years beyond the current delivery year
- NYISO also began selling 2-year auctions each year and 1.5-year auctions every 6 months
- ERCOT sells 6 month FTRs in rolling auctions, extending out 3 years

Net Zero Market Reform / Appendix 65

Appendix 1: FTR Auctions

Long duration FTRs

Conceptually, there is no barrier to running an auction extending to longer timeframes such as ten years. The result, however, could be risky financial instruments, rather than hedges, with the FTRs potentially selling for a large discount relative to the eventual payout and reducing the value of the offset to transmission costs they provide. For example, the NYISO auctioned five year FTRs in 2000 but did not do this again as low demand meant the FTRs sold for very low prices, reducing the benefits to consumers.

Allocating FTRs to enable the transition to nodal pricing

To facilitate the transition to nodal pricing, FTRs can be allocated to support the grandfathering of existing generation investments. Key implementation considerations or decisions for allocating FTRs to support grandfathering include: capacity-based versus volume-based allocation; whether to allocate FTR options, FTR obligations (charge applicable if direction of congestion opposite to hedged direction) or both; eligibility criteria; and length of contracts. Experience in North America, however, shows there has been very limited grandfathering of generator entitlement to use the transmission system during transitions to nodal market design.

Net Zero Market Reform / Appendix 66

Appendix 2: Illustration of Constraint Resolution

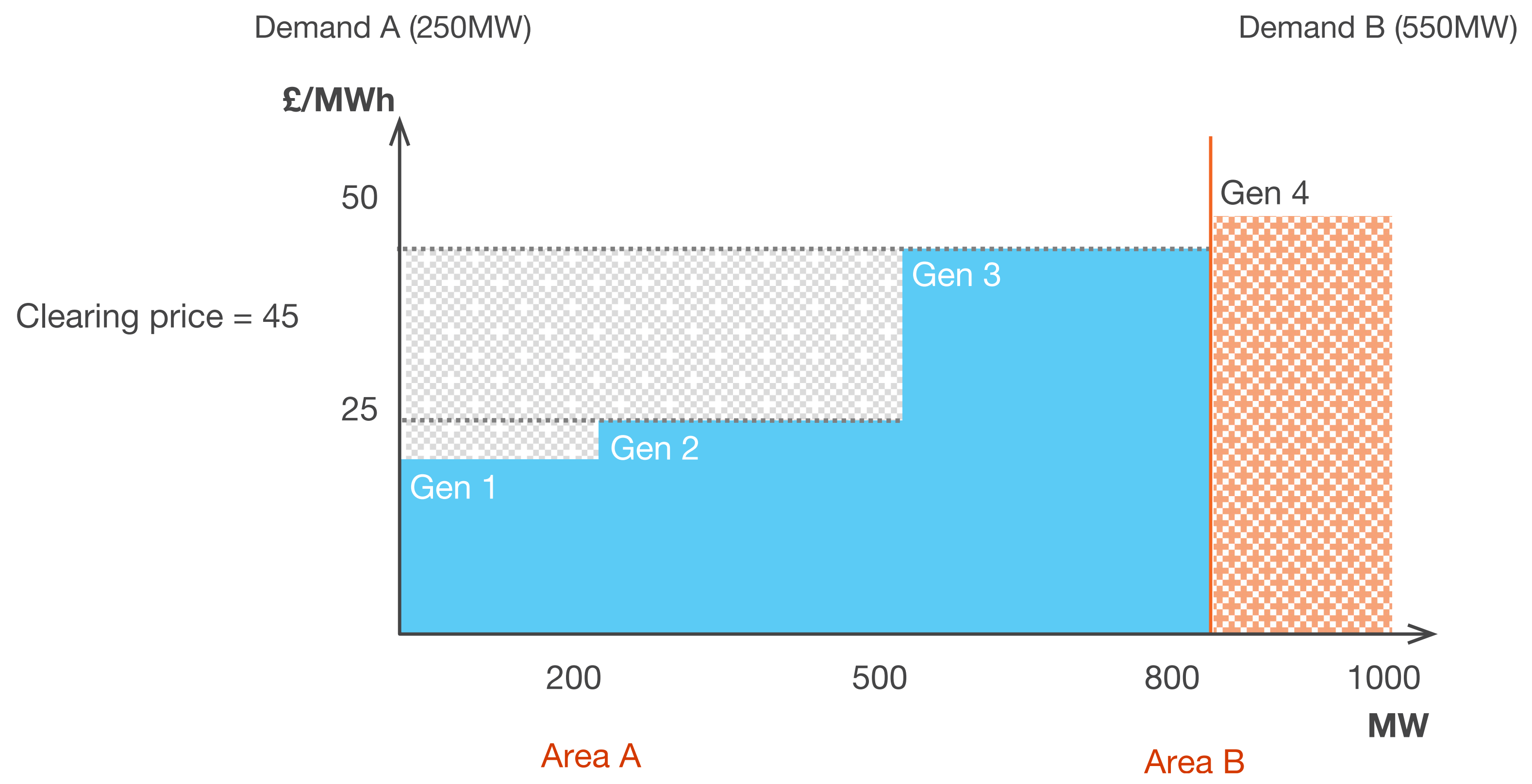
The following diagrams illustrate how constraint costs arise and are resolved under the GB status quo and under nodal design.

Constraint costs under status quo design

1 **Generators 1, 2 and 3 are contracted in the wholesale market, at £45/MWh, to deliver 800MWh of generation.**

Status quo

ESO finds network between Area A and B is constrained. Only 50MW can pass between the two regions, but 250MW is contracted in Area B.



In this illustrative representation of an energy system, there are 4 generators with total capacity of 1000MW.
Area A: Generator 1 and Generator 2 total capacity is 500MW. Area A demand is 250MW
Area B: Generator 3 and Generator 4 total capacity is 500MW. Area B demand is 550MW

- Inframarginal rent earned by generators
- Balancing costs - SO sells back excess
- Wholesale market revenue retained by the constrained off generator despite no output
- Balancing costs - SO buys to constrain-on

Net Zero Market Reform / Appendix 67

Appendix 2: Illustration of Constraint Resolution

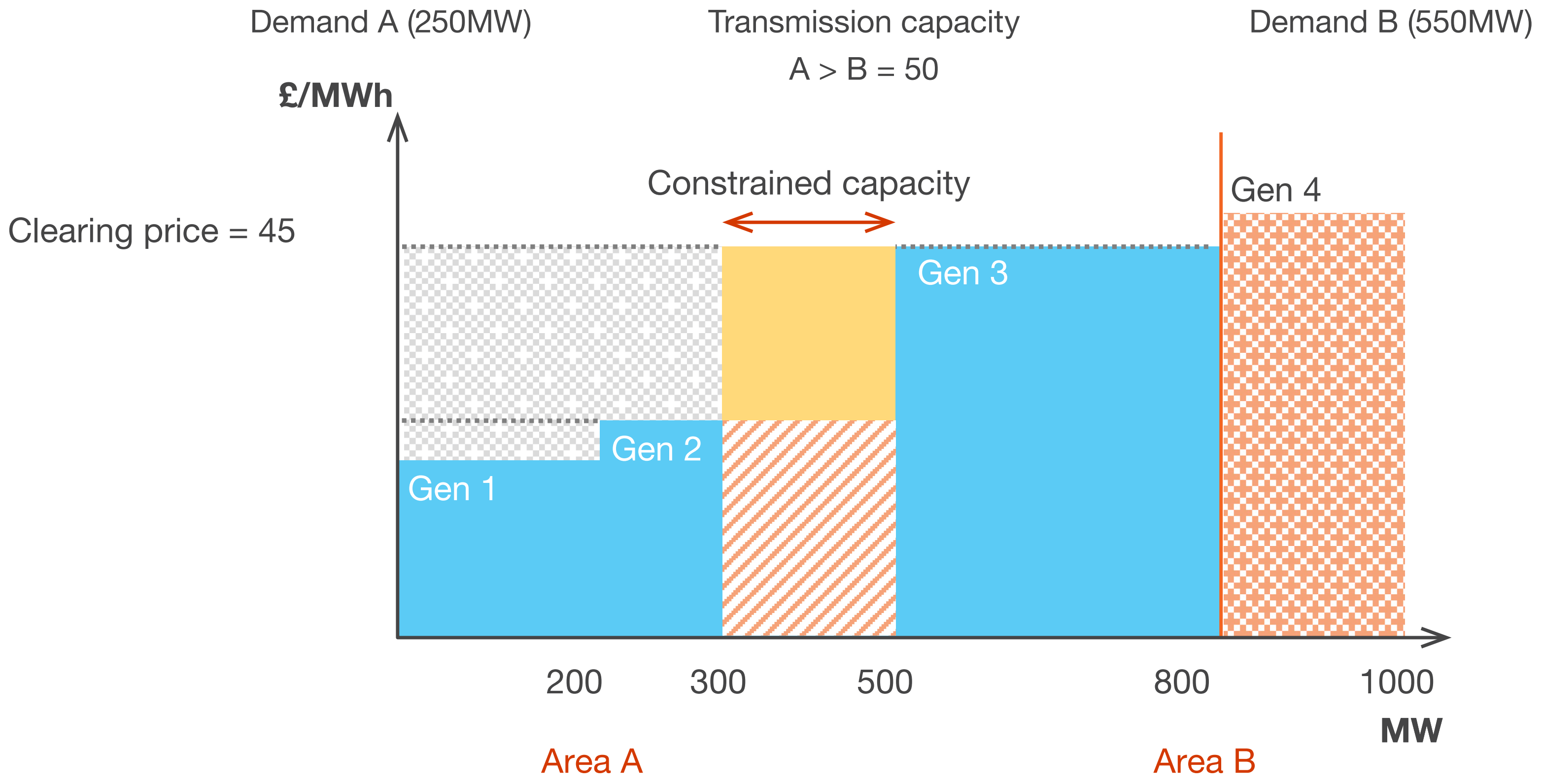
The following diagrams illustrate how constraint costs arise and are resolved under the GB status quo and under nodal design.

Constraint costs under status quo design

2 **ESO instructs Generator 2 to turn down by 200MW. Generator 2 is still paid for its wholesale market contract, and buys back its excess from ESO.**

ESO instructs Generator 4 to turn on and deliver remaining 200MW to Area B.

Status quo



In this illustrative representation of an energy system, there are 4 generators with total capacity of 1000MW.
Area A: Generator 1 and Generator 2 total capacity is 500MW. Area A demand is 250MW
Area B: Generator 3 and Generator 4 total capacity is 500MW. Area B demand is 550MW

- Inframarginal rent earned by generators
- Balancing costs - SO sells back excess
- Wholesale market revenue retained by the constrained off generator despite no output
- Balancing costs - SO buys to constrain-on

Net Zero Market Reform / Appendix 68

Appendix 2: Illustration of Constraint Resolution

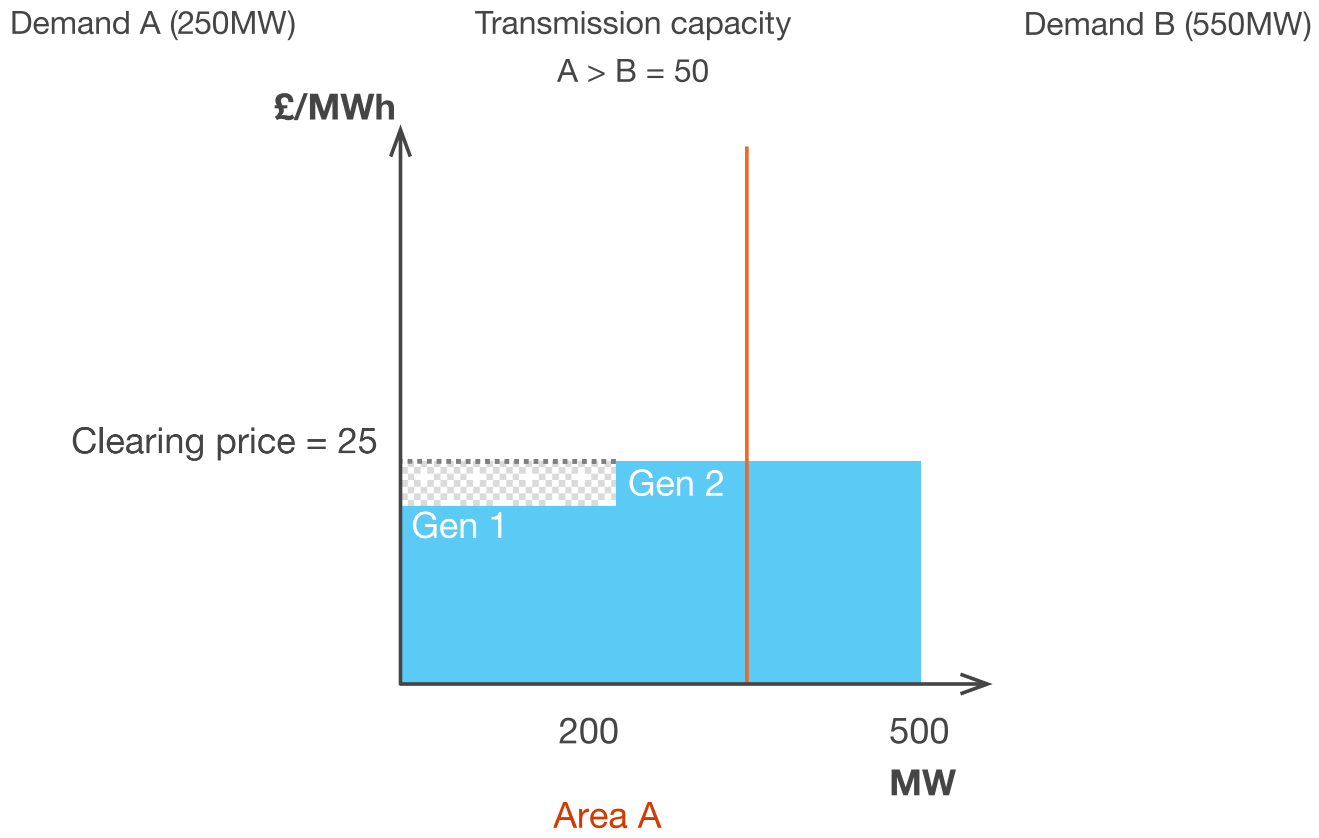
The following diagrams illustrate how constraint costs arise and are resolved under the GB status quo and under nodal design.

Constraint costs under nodal design

1 Generators 1, 2 are contracted to deliver 300MW at clearing price of £25. Accounting for transmission capacity algorithm clears 250MW for Area A, and 50MW for Area B.

Illustrative nodal representation

Generator 2 is not contracted to deliver energy that cannot be delivered across the transmission constraint.



Inframarginal rent earned by generators

Balancing costs - SO sells back excess

Wholesale market revenue retained by the constrained off generator despite no output

Balancing costs - SO buys to constrain-on

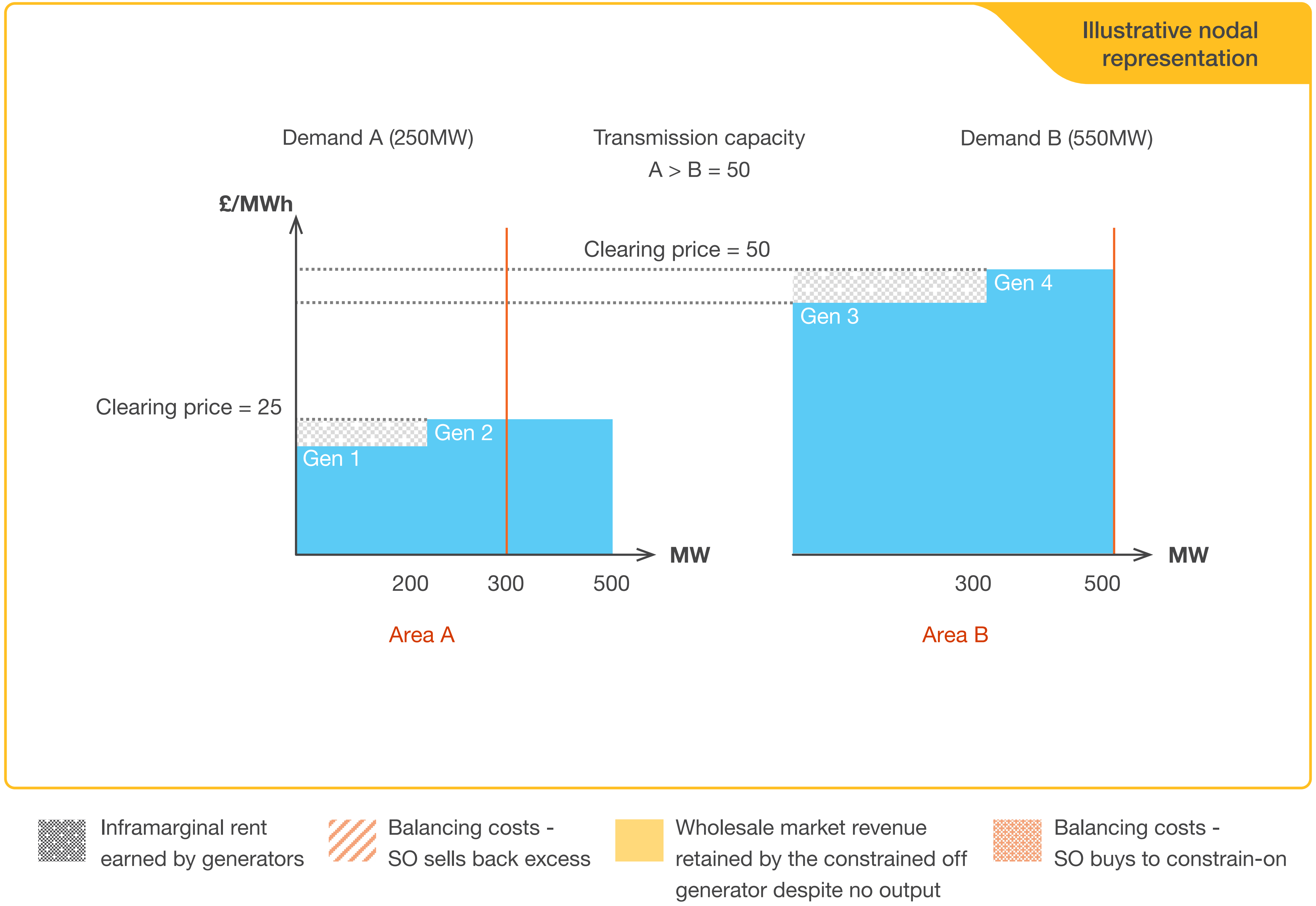
Net Zero Market Reform / Appendix 69

Appendix 2: Illustration of Constraint Resolution

The following diagrams illustrate how constraint costs arise and are resolved under the GB status quo and under nodal design.

Constraint costs under nodal design

2 Generators 3 and 4 are cleared at £50/MWh to deliver 500MW to Area B, without the ESO intervening after Gate Closure.



Net Zero Market Reform / Appendix 70

Glossary

Ancillary Services:
Services procured by the ESO to support operation of the electricity system.

Arbitrage:
In an energy context, this usually refers to the practice of buying energy when the price is low, storing this energy and then selling it when the price has risen.

Auction Revenue Rights (ARRs):
ARRs are a theoretical approach to allocating auction proceeds to consumers through the allocation of FTRs to users of the transmission network (typically retailers, who would pass on benefits to consumers, assuming a competitive market).

Balancing Mechanism (BM):
The Balancing Mechanism is a tool that the ESO uses to balance residual electricity supply and demand, following gate closure. It allows participants to set prices for which they will increase or decrease their output if requested by the ESO. All large generators must participate in the BM, whereas it is optional for smaller generators.

Balancing Services Use of System Charge (BSUoS):
The BSUoS recovers the cost of day-to-day operation of the transmission system. This cost is determined by the balancing actions the ESO takes each day. Generators and suppliers are liable for these charges (though currently undergoing reform), which are calculated daily as a fixed volumetric tariff for all users.

Capacity Market (CM):
The Capacity Market is designed to ensure security of electricity supply. This is achieved by providing a payment for reliable sources of capacity, alongside their electricity revenues, ensuring they deliver energy when needed.

Capacity:
The power output of an electricity generation technology usually measured in Watts (or kW, MW or GW).

Congestion Rents:
The price difference multiplied by the power flow (MW) over a transmission asset.

Constraint:
A constraint is where the network cannot physically transfer the power from one region to another.

Contract for Difference (CfD):
A private law contract between the Low Carbon Contracts Company (LCCC) and a low carbon electricity generator, designed to support investment in low carbon generation by reducing its exposure to volatile wholesale prices.

Demand Side Flexibility:
The ability of energy users to adjust demand in response to market signals.

Demand Side Response (DSR):
A deliberate change to a consumer's natural pattern of electricity consumption, brought about by a signal from another party.

Distributed Energy Resource (DER):
Small-scale electricity supply or demand resources connected to the grid at distribution level.

Distribution Network Operator (DNO):
Distribution Network Operators own and operate electricity distribution networks.

Distribution Use of System Charge (DUoS):
DUoS charges are collected from consumers (via suppliers) by Distribution Network Operators (DNOs) to recover the cost of investing in and maintaining the local distribution network.

Net Zero Market Reform / Glossary 71

Electricity Ten Year Statement (ETYS):

The Electricity Ten Year Statement (ETYS) is the ESO's view of future transmission requirements and the capability of Great Britain's National Electricity Transmission System (NETS) over the next 10 years.

Financial Transmission Rights (FTRs):

FTRs are a financial instrument widely used by suppliers and generators to hedge their exposure to pricing differences between nodes.

Flexibility:

The ability to adjust either the supply or demand of electricity.

Frequency:

The number of oscillations, alternating between positive and negative voltage, per second that electrical current oscillates. ESO is required to routinely keep the frequency within one percent (0.5Hz) of 50 oscillations per second (i.e. 50Hz) by controlling the second-by-second (real time) balance between system demand and total generation, though ESO aims to achieve a stricter operational target of maintaining frequency within 0.2Hz of 50Hz in normal conditions.

Gate Closure:

In relation to a settlement period, the spot time 1 hour before the spot time at the start of that Settlement Period. This is the point by which BSC parties must submit information to NGESO regarding their planned production or consumption in a settlement period.

Gigawatt (GW):

A measure of power. 1 GW = 1,000,000,000 watts.

Grandfathering:

A term used in policy to respect incumbents' existing rights (i.e. old rules) to some extent, which could be on a temporary or permanent basis, in order to facilitate a policy transition (i.e. new rules).

Inertia:

Inertia is a form of energy storage that addresses imbalances between supply and demand over short time periods, which helps support the stability of the electricity system. Higher levels of inertia, which has traditionally been provided by large rotating fossil fuel generators and some industrial motors, help to slow the rate of change of frequency and aid system operation.

Interconnectors:

Transmission assets that connect the GB electricity market to electricity markets in other countries and allow market participants to trade electricity between these markets.

Intermittent Generation:

Types of generation that can only produce electricity when their primary energy source is available. For example, wind turbines can only generate when the wind is blowing.

Market Operator:

An entity responsible for running the clearing engine and determining the dispatch schedule. The Market Operator can be a separate entity from the 'System Operator' who typically provides the Market Operator with operational inputs such as network capacity and also issues dispatch instructions.

Net Zero:

When the total amount of greenhouse gases emitted in a year reaches zero, after all emissions and all carbon sequestration have been accounted for. This is the current UK target for 2050.

New Electricity Trading Arrangements (NETA):

New arrangements for the buying and selling of electricity introduced in England and Wales in March 2001 and extended to Scotland in April 2005 under BETTA (British Electricity Trading and Transmission Arrangements).

Node:

Every transmission system injection point (such as a generator busbar), offtake point (such as a distribution substation), and transmission line intersections at transmission substations, are typically defined as nodes.

Redispatch:

A process that ESO undertakes to balance the system if market imbalance exists following gate closure (via the BM amongst other tools).

Renewables:

Electricity generation from renewable resources, which are naturally replenished, such as sunlight or wind.

Residual Balancer:

The envisaged role of the ESO under NETA, fine-tuning the dispatch to protect the limits of the system, but not intervening in the wholesale market in a significant way.

Net Zero Market Reform / Glossary 72

Settlement Period:

Electricity is currently traded in 30-minute settlement periods in the GB market, with each day split into 48 settlement periods starting at 00:00. Each period is settled in isolation through settlement calculations involving metered data, contract data and physical data.

Short Circuit Level (SCL):

Short circuit level is the amount of current that flows on the system during a fault. These faults can be caused by a lightning strike, weather conditions or equipment failure. During the fault, the system can see a direct connection to the earth and current flows from all sources into it. Having adequate SCL is vital during such a fault as it helps ESO to maintain system voltage.

System Operator (SO):

An entity entrusted with transporting energy in the form of natural gas or electricity on a regional or national level, using fixed infrastructure. The SO may not necessarily own the assets concerned and could be an independent SO, as is the case for National Grid ESO. For example, the latter operates the electricity transmission system in Scotland, which is owned by Scottish Hydro Electricity Transmission and Scottish Power Transmission as well as the corresponding system in England and Wales, which is owned by National Grid Electricity Transmission.

Transmission Losses:

The energy dissipated in the form of heat that is “lost” due to electrical resistance when electrical currents travel through the transmission network.

Transmission Network Use of System Charge (TNUoS):

TNUoS charges recover the cost of installing and maintaining the transmission system in England, Wales, Scotland and Offshore. Suppliers and generators both pay for TNUoS which ultimately gets passed through to consumers.

Triad:

The three half-hourly settlement periods with the highest electricity transmission system demand that must be separated from each other by at least ten days. These settlement periods occur between November and February; it is not known in advance precisely when they might occur though typically take place on weekdays around 4.30 to 6pm. The triad mechanism is used to calculate half hourly metered consumers’ annual residual network (TNUoS) charges.

Vehicle-to-Grid Technology (V2G):

Enables energy stored in electric vehicles to be fed back into the national electricity network (grid) to help supply energy at peak times of demand.

Voltage:

Voltage is also known as the electric potential difference, which is an electric pressure that causes electrons to move in a wire or electrical conduct. Unlike system frequency, voltage varies across different locations on the network, depending on supply and demand for electricity, and the amount of reactive power in that area. The larger the voltage, the larger the amount of electricity moved through the network.

Weighted Average Cost of Capital (WACC):

The weighted average of the cost of equity and the cost of debt, where the weighting is provided by the gearing ratio.

Zone Boundary:

This represents the border of zonal markets, where the transmission system, within the territory of the electricity market, has been divided into several zones. Zone boundaries should be delineated based on the existence of network congestion.

Net Zero Market Reform / Glossary 73

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Net Zero Market Reform / Bibliography 75


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